FINAL REPORT

Cost- or market-based? Future redispatch procurement in Germany

Conclusions from the project "Beschaffung von Redispatch"

7 October 2019

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Project partners:

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This study is the final report of the project "Beschaffung von Redispatch" commissioned by the German Federal Ministry for Economic Affairs and Energy (Project No. 055/17). The project dealt with the interaction between the electricity grid and the electricity market in general and the procurement of redispatch in particular. Its aim was to examine organizational forms of congestion management that are located at different points in the spectrum between a fully regulatory and a largely market-based organization. This document is the final report of the overall project. It summarizes the findings from the individual work packages and serves to develop policy recommendations.

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Summary

Context. When proposing the Electricity Market Regulation recast in 2016, the EU Commission suggested to make market-based redispatch obligatory for all member states. This, as well as the ongoing debate on market-based congestion management triggered by academics and stakeholders, motivated this study. The study primarily discusses competitive procurement of redispatch. In essence, the question is whether a system of voluntary participation in redispatch based on price incentives is preferable to the current German approach of mandatory participation with reimbursement of costs, sometimes referred to as cost-based redispatch.

Integrating loads. A central disadvantage of regulatory cost-based redispatch is the difficulty of making demand-side resources available for redispatch. Integrating loads into cost-based redispatch would require network operators to assess each consumer's individual willingness to pay for electricity in order to calculate their compensation, which will often be impossible. If loads were available for redispatch, this could reduce the costs for redispatch and enhance economic efficiency. Market-based redispatch solves this problem, as market participants determine their own remuneration in the form of bids and thus have an incentive to participate. Also first principles of economic policy make a voluntary system preferable to obligations.

Problems of market-based redispatch. In this study, however, we identify two fundamental problems of market-based redispatch: Impact on the electricity market due to strategic bidding (inc-dec gaming) and locational market power. These problems must be conceptually separated, but are mutually reinforcing.

Impact on electricity market. The coexistence of a zonal electricity market with a necessarily local redispatch market offers market participants arbitrage opportunities and incentives for strategic bidding behavior. In scarcity regions, producers will anticipate that higher profits can be generated by selling their production on the redispatch market rather than the zonal market. They therefore offer higher prices on the zonal electricity market to price themselves out of the market. Conversely, producers in surplus regions will anticipate profits from being downward-redispatched. To achieve this, they place low bids on the electricity market and thus push themselves into the market. On the redispatch market, they buy the energy back at a price below the zonal price and thus meet their delivery obligation. One can understand these strategies as an optimization between two markets or as arbitrage trading. As a consequence, the introduction of a redispatch market has an impact on the zonal electricity market, as it changes the rational bidding behavior of market parties on that market. This has severe negative side effects: It aggravates network congestion, as supply decreases in already scarce regions while it increases in surplus regions. In network simulations for the year 2030, strategic bidding increases the required redispatch volume to approx. 300-700% of the volume for cost-based redispatch. Moreover, this bidding strategy leads to windfall profits at the expense of final consumers and to perverse investment incentives, stimulating generation investments in export-constrained regions. The costs for redispatch in the simulations increase approximately

threefold due to inc-dec gaming. Loads are also subject to analogous incentives for strategic bidding behavior.

Regulatory mitigation. This bidding strategy does not constitute a violation of competition law or balancing responsibility. Addressing strategic bidding through targeted regulatory action we deem difficult. The coexistence of zonal and local markets results in an incentive structure that systematically rewards problem-exacerbating rather than system-stabilizing behavior. This fundamental problem cannot be solved easily. Any effective form of regulatory containment requires a high level of regulatory knowledge, especially with regard to the individual willingness of consumers to pay for electricity. Essentially, for effective regulatory mitigation of inc-dec gaming one would need to have the same amount of information that is necessary to integrate loads into cost-based redispatch. It would therefore be inconsistent to believe that regulatory monitoring of the redispatch market would overcome the disadvantages of cost-based redispatch.

Market power. The bidding behavior described above neither requires market power nor collusion, i.e. explicit or tacit agreements among market parties. However, a redispatch market is also subject to significant local market power, because the effectiveness of redispatch in relieving congestion greatly differs between network nodes. Loads or generators at certain network nodes which are particularly favorably located in terms of impact on a certain congestion thus hold a high degree of market power. Abuse of market power is a problem in its own right with known consequences such as capacity withholding and inflated prices. Quantitative assessments suggest that this problem is likely to be significant. It also increases incentives for inc-dec gaming.

Recommendations. When weighing up the advantages and disadvantages of market-based redispatch, we see more risk than chance. We therefore advise against introducing market-based redispatch. This recommendation applies regardless of the specific procurement mechanism (dedicated procurement platform, use of balancing energy, use of the intraday market, etc.). Although the focus of our analyses is on the transmission grid, the problems described also occur in the distribution grid and are therefore also relevant for markets for local flexibility. To integrate loads in redispatch, we recommend assessing capacity-based payments, that is, voluntary participation without compensation for the activation of redispatch resources. In addition, we recommend examining locational investment incentives, e.g. location-specific grid usage charges, deep connection charges, and locational incentives provided by support schemes for renewable energy.

Table of contents

List of figures

List of abbreviations

TFEU	Treaty on the Functioning of the European Union
BNetzA	German Federal Network Agency
CACM	Guideline on Capacity Allocation and Congestion Management
DC	Direct current
RE	Renewable energy
RES	Renewable energy sources
ENLAG	Energy Line Expansion Act, Germany
EnWG	Energy Industry Act, Germany
FERC	Federal Energy Regulatory Commission, USA
GW	Gigawatt
GWB	Act against Restraints of Competition, Germany
inc-dec	Inc-dec behavior (from *increase-decrease*). Behavior of market participants to price the opportunity costs from the redispatch market into the bids on the spot market
CHP	Combined heat and power cogeneration
LMP	Locational marginal pricing
MW	Megawatt
MWh	Megawatt hour
PJM	Regional transmission system operator in the east of the USA
RD	Redispatch
RDM	Redispatch market
TCLC	Transmission Constraint License Condition, regulation by the British regulator Ofgem prohibiting excessive bids
TWh	Terawatt hour
TWh/a	Terawatt hour per year
TSO	Transmission system operator

1 The discussion about market-based redispatch

Redispatch in Germany's electricity market design. A core idea of the German electricity market design "Electricity Market 2.0" (Strommarkt 2.0) is the separation between market and grid. The large, liquid, and uniform bidding zone forms stable and resilient price signals; government intervention in price formation is minimized. The management of domestic grid congestion takes place outside the market. As part of redispatch for conventional power plants and feed-in management for renewables, network operators instruct generation and storage facilities to increase or decrease generation in order to change electricity flows in the network to avoid overloading network elements. Participation in redispatch is mandatory for most generation and storage facilities. They are subsequently compensated for costs incurred and profits foregone and are thus economically neutral towards redispatch provision.

Increasing grid load. In recent years, the redispatch volume has risen sharply, mainly due to increasing congestion in the transmission network. Due to the integration of the European electricity markets, the nuclear phase-out, the further expansion of renewable energies (RE) and delays in grid expansion, a further increase in redispatch can be expected in the coming years. In the longer term, the growth in electric mobility and heat pumps could also lead to significant congestion in distribution networks. Against this background, it is in principle desirable to include further resources, in particular loads, to redispatch. However, this is difficult to imagine in a cost-based redispatch setting, because the incurred costs of load curtailment, e.g. due to loss of production, can hardly be estimated. It would also be desirable if the grid situation was to play a role in decisions on the location of power plant and load investments. Cost-based redispatch, which is not intended to provide incentives, cannot fulfil this function either.

This report. For this reason, various actors have proposed a market-based redispatch in recent years. Since 2017 we have been dealing with this topic as part of the BMWi project "Beschaffung von Redispatch" (procurement of redispatch). This text is the final report of the project resulting from Work Package 7, "Evaluation and Recommendations".

1.1 Current developments of German grid congestion

Last few years. The need for measures by network operators in Germany to relieve grid congestion has risen sharply up to 2015 in particular and has fluctuated at a high level ever since.

These measures include instructing power plants to adjust their planned (and marketed) production schedule by the grid operators.[1] Costs and lost profits shall be reimbursed to the plant operator. Accordingly, the costs for these measures have also risen significantly in recent years. The following Figure 1 shows the development of redispatch volumes and costs over the past years. In 2018, the costs for redispatch and feed-in management of renewables, including the costs for maintaining the so-called grid reserve (Netzreserve), amounted to almost EUR 1.5 billion. In 2017, costs also reached EUR 1.5 billion. In 2018, around 4 % of electricity generation[2] in Germany was affected by redispatch measures.

Causes. Several developments are responsible for the increasing redispatch volume in recent years. On the one hand, the expansion of RES generation - with a noticeable regional concentration in northern Germany - and the simultaneous shut-down of conventional generation capacity, especially in southern Germany, in particular due to the progressing phase-out of nuclear energy, is responsible. This leads to an increase in north-south electricity transport through Germany. However, the existing transmission network does not always provide sufficient transport capacity because the network expansion is lagging behind schedules. As a result, generation facilities in the northern half of Germany have to reduce production while generation facilities in the south have to increase production. On the other hand, cross-border electricity exchange has intensified. This concerns Germany's exchange with its neighboring countries as well as – Due to its geographical location - also transit through Germany. This is an additional challenge for the German transmission grid. The fact that renewable energy plants are often connected to the distribution grid means leads congestions in distribution grids as well if there is high local concentration of renewable energy plants, and large quantities of renewable energy generation need to be transported into the transmission grid. Also in such situations grid operators have to change production schedules of generation facilities, in this case of renewable energy plants.

[1] More precisely, a distinction must be made between redispatch and feed-in management for these measures: Due to the European rules on priority dispatch of renewable energy and CHP plants, these plants have so far been regulated separately as so-called "feed-in management". Feed-in management is only permissible in exceptional cases. The network operator instructed change of production schedules of generation from all other (conventional) power plants is called redispatch. For the sake of a simpler presentation, in this report we will generally refer only to redispatch, but mean it to include also feed-in management. In addition, the amendment to the "Netzausbaubeschleunigungsgesetz" (NABEG, Network Expansion Acceleration Act) now stipulates that RE and CHP plants will also be formally integrated into redispatch with effect from 1.10.2021. Their fundamental feed-in priority is to be safeguarded by the fact that they are only re-dispatched instead of conventional plants if the use of conventional plants to relieve the grid would be many times more expensive.

[2] Electricity generation in Germany: approx. 530 TWh; redispatch (sum of power reduction and power increase): approx. 16 TWh; feed-in management: approx. 5 TWh; accordingly, 21 TWh of 530 TWh are affected by redispatch.

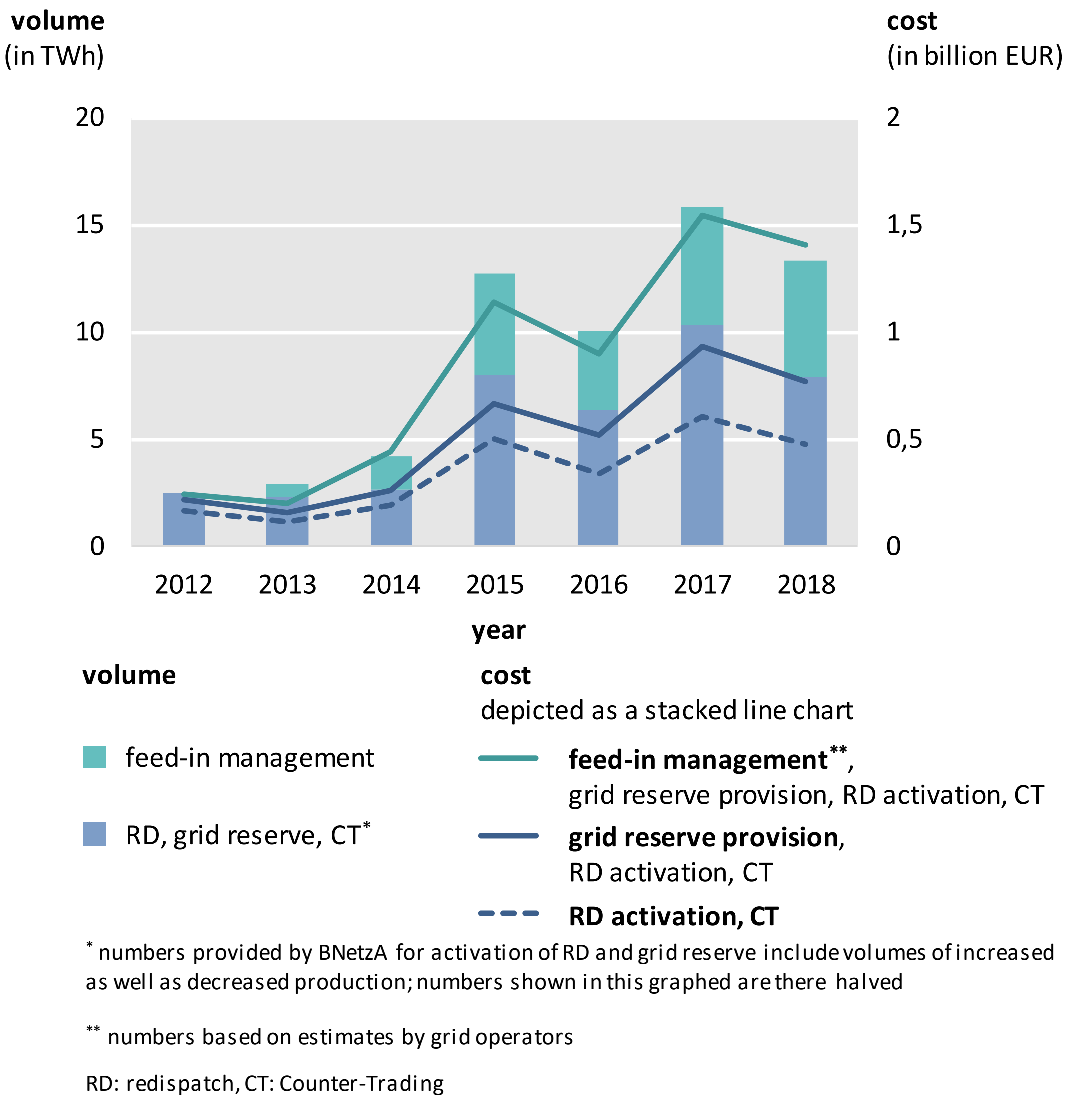

Figure 1: Development of redispatch volume and costs between 2012 and 2018
Source: Own calculation based on the reports on grid and system security measures BNetzA (2016a), BNetzA (2017), BNetzA (2019) and the monitoring reports BNetzA (2015) and BNetzA (2016b)

1.2 German Grid Congestion in the Coming Years

The years to come. The developments that have led to the rise in redispatch in recent years are likely to continue in the coming years. A decline in redispatch volumes and costs is therefore not to be expected for the time being. On the contrary, there could even be a temporary further increase. However, it is not possible to make reliable statements in this regard because redispatch volume depends heavily on the renewable feed-in conditions (in particular wind), progress of network expansion and other factors.

Generation mix. The North-South transport demand in Germany will continue to increase in the coming years. On the one hand, the expansion of renewable electricity production is continuing. The share of RE electricity generation in gross electricity consumption is expected to rise from around 39 % in 2018 to 65 % in 2030. Assuming a constant electricity consumption, the annual RE electricity generation will have to be increased by another 160 TWh to 390 TWh/a. Due to the relatively low full load hours of renewable generation compared to conventional generation technologies, the generation capacity connected to the grid will increase significantly and is likely to be in the order of 200 GW, depending on the technology mix. At the same time, the completion of the phase-out of nuclear power by the end of 2022 will eliminate around 10 GW of generation capacity - just over half of it in southern Germany. Due to the phasing out of coal-fired power generation and may be also due to market conditions, there will be further shutdowns. Depending on the location of the power plant, these can have both a congestion relieving and a congestion reinforcing effect.

European market integration. The cross-border exchange of electricity, which is limited by the physical transmission capacities available in the electricity grid, is also likely to intensify in the coming years and thus increase the need for redispatch. The recently adopted European Electricity Market Regulation[3] stipulates that in future at least 70 % of the physical transport capacities of critical grid elements must be made available for electricity trading. However, lines are not only loaded by cross-border exchange, but also by intra-zonal exchange. The past practice of reducing cross-border trading capacity to accommodate loop flows (electricity flows resulting from transactions internal to bidding zones but occurring in other bidding zones) and internal flows (electricity flows resulting from transactions internal to bidding zones and occurring in the same bidding zone) will no longer be permitted in the future. It can therefore be expected that in future there will be congestion on a regular basis as a sum of flows from cross-border and intra-zonal exchanges. These must be eliminated redispatch (including cross-border redispatch).

Delay in grid expansion. Higher transport requirements, especially for the transmission grid, would not be a problem if the corresponding expansion of the electricity grids to meet demand took place at the same time. However, the expansion of the transmission grid is being delayed. To illustrate the delays in grid expansion, following Figure 2 shows the network operators' monitoring of the expected commissioning date of the expansion projects in accordance with the Energy Line Expansion Act (EnLAG) at various points in the past. The figure shows the total length of new/amplified circuit kilometers expected to be put into operation by a certain point in time in the future.

The evaluation illustrates the delays: While in 2013 the transmission system operators still expected that by the end of 2019 almost all of the 1,800 kilometers of electricity circuits would have been built, the grid operators now (Q1/2019) assume that by the end of 2019 not even half of these lines will already be in operation. It should be noted that the expansion measures according to EnLAG represent only the smaller part of the planned expansion projects in the

[3] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

German transmission grid. In addition, there are about 5,900 kilometers of electricity circuits to be built according to the Bundesbedarfplan (federal demand plan). Almost 300 km of this have been realized to date. In particular, the commissioning of the planned direct current (DC) lines would significantly ease the congestion situation in the transmission grid. Currently, the transmission system operators estimate their commissioning for the years 2025 and 2023 (Ultranet). However, all projects are still at a rather early planning stage, so that delays in the further approval process cannot be ruled out.

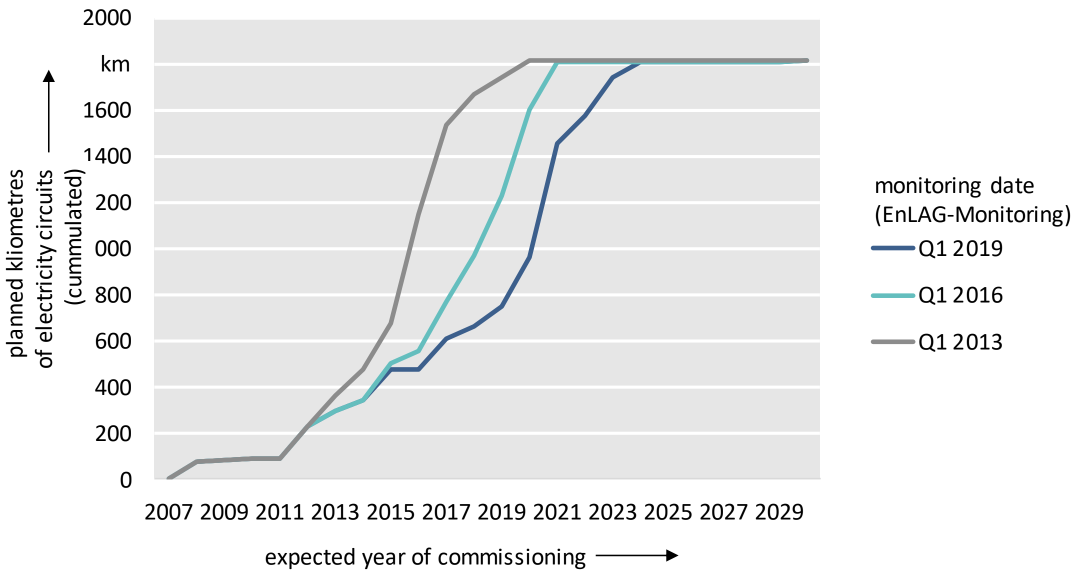

Figure 2: Development of the transmission system operators' monitoring of commissioning times of network extensions according to EnLAG in the course of time at
Source: own evaluations on the basis of BNetzA (2013), BNetzA (2016c), BNetzA (2019b)

Positive developments with regard to future redispatch requirements. The aforementioned points suggest a redispatch demand that may continue to rise, but at least is not sustainably declining. However, there are also developments and measures that should have a reducing effect on the demand for redispatch. These include efforts to improve coordination of cross-border redispatch. Last but not least, the amended European Electricity Market Regulation makes this mandatory by requiring transmission system operators to make their redispatch potential available to each other. The integration of feed-in management, i.e. congestion management by RE and CHP plants, into the regular redispatch will also improve the efficiency of redispatch in the future. In addition, measures to optimize the existing networks (e.g. thermal rating of overhead lines, reactive network operation management with grid boosters, phase shifters and ad hoc measures) help to increase the transport capacity of the transmission network in the short term. In addition, various measures are taken within the framework of renewable energy support to achieve a locational allocation of new investments that also takes account of grid requirements (e.g. the distribution grid component "Verteilernetzkomponente" or the quantity cap for wind plants in surplus regions"Netzausbaugebiet").

Findings from quantitative analyses. The quantitative simulations carried out in this project for the reference year 2030 indicate that a substantial demand for redispatch can also be expected in the medium term. Calculations in which a quantity-optimized redispatch is modeled result in a redispatch volume of approx. 20 TWh. However, the figures naturally depend heavily on assumptions about network expansion and the implementation of other network technology measures (e.g. reactive network operation management such as grid boosters or additional domestic phase shifters). Thus, it cannot be ruled out that the redispatch requirement will also be significantly lower.

1.3 Redispatch in the German "Electricity Market 2.0"

Energiewende. For the electricity sector, the *Energiewende* represents the most fundamental transformation for decades, possibly since electrification. Four trends deserve special mention: wind and solar energy are the new cornerstones of electricity generation, which will soon cover half of Germany's electricity demand. As variable generation technologies, they present new challenges to the electricity market and grid. A number of new generation, storage and consumption technologies have been established or are in the process of being established, including battery storage and electro mobility. The digitalization of the energy industry means better controllability, even for small systems. After all, the emerging energy landscape is characterized by a multitude of new players, including prosumers, aggregators, electricity traders and virtual power plants.

Signals for flexibility. Against the background of energy system transformation, electricity prices play a central role as signals, especially for flexibility options. This concerns their use as well as investment and innovation.

Electricity market 2.0. The German electricity market design is constructed around the core idea of enabling price signals that provide incentives for the development, investment and deployment of flexibility technologies in order to integrate large quantities of renewable energies and ensure a cost-effective security of supply. The large, liquid, uniform bidding zone serves to form stable and resilient price signals while minimizing state intervention in price formation. This requires the fiction of a congestion-free market area, i.e. the separation of market and network. The management of grid congestion lies outside the market sphere; the market should function unaffected by possible grid congestion. However, the side-effect is that that the market does not provide any locational incentives.

Redispatch today. The current redispatch system can be described as an "administrative/regulatory redispatch with cost reimbursement" (hereinafter referred to as "cost-based redispatch"). We always mean to include feed-in management (i.e. congestion management of renewables and CHP) as well. As part of redispatch, transmission system operators instruct generation facilities and storage facilities to increase or decrease generation in order to change electricity flows in the grid to avoid overloading network elements. Participation in redispatch is mandatory for most generators; generators under 10 MW are excluded so far, in future only small plants under 100 kW will be excluded. Operators are subsequently compensated for costs incurred and lost profits and are thus financially indifferent to redispatch provision. The aim of making operators financially indifferent to redispatch provision is to avoid strategic bidding behavior and other feedback from congestion management to the electricity market.

1.4 CHALLENGES OF COST-BASED REDISPATCH

Cost-based redispatch faces four key challenges:

- Complex implementation of compensation rules
- Lack of incentive to participate in redispatch
- Cross-border redispatch does not yet work to the desired extent
- No locational steering of investments

Compensation rules. The principle for compensating power plant and storage operators for participating in redispatch is clear: they should be compensated for costs incurred and lost profits so that they are economically indifferent. At first glance, this scheme seems easy to implement by determining the cost of fuel and CO_2-certificates. Lost profits can be determined by contribution margins based on the electricity price. In detail, however, the determination is highly complex, especially with regard to the wear and tear due to the operation of the plant, opportunity costs from intraday trading, and costs associated with the establishment of operational readiness or the postponement of maintenance work. In the case of storage power plants, the value of the stored energy is also determined. The industry guide for determining remuneration (BDEW 2018) alone comprises almost 50 pages. It is difficult to imagine how such standardized compensation rules could be applied to electricity consumers, because the costs incurred as a result of load curtailment, e.g. due to loss of production, would differ greatly from facility to facility, but also on the time dimension e.g. from hour to hour. The information asymmetry between plant operators and grid operators is even more pronounced with load entities than with generators and storage facilities.

Lack of incentive to participate. The core idea of cost-based redispatch is to make plants indifferent with regard to their redispatch participation. Conversely, this means that system operators have no incentive to participate in redispatch. With reference to restrictions on heat generation from CHP plants or to obligations under balancing contracts and other technical restrictions, power plants can avoid or reduce being re-dispatched, which results for example in a very low utilization of CHP plants for redispatch. Other generating plants which are in principle obliged to participate in redispatch could also have an incentive to withdraw at least partially from redispatch participation by reporting technically justified non-availabilities, e.g. to avoid a higher number of start-ups and shut-downs which limit the plant's lifetime or cause costs which are difficult to assess and therefore possibly not reimbursable. Against this background, it is also relevant that transmission system operators currently have no incentive to comprehensively examine these notifications from plant operators. Above all, the lack of incentive means, however, that no installations that are not legally obliged to participate in redispatch will do so. As already mentioned, this applies in particular to loads. This means that in a cost-based redispatch, not all facilities that would be suitable in principle are available for redispatch.

Integration of loads. The integration of loads in redispatch has two sides. In the surplus region, it is about "usage before curtailment", i.e. increasing electricity consumption to avoid having to curtail production e.g. from renewables. In the scarcity region, it is a question of interruptible loads. To the best of our knowledge, there are no comprehensive analyses that allow a statement to be made on the benefits of load integration that go beyond individual situations or individual (distribution) grid areas but quantify nationwide potential savings for both the transmission and distribution grid. However, such studies are necessary for a robust cost-benefit analysis. Quantitative analyses carried out by us as part of this project indicate that the cost savings that can be achieved by including loads in redispatch in the German transmission grid are comparatively low[4].

Cross-border redispatch. In contrast to the electricity market in the day-ahead and intraday sectors, which are strongly influenced by European regulations, grid congestion has so far mostly been dealt with on the basis of national regulations and the responsibility of the national TSOs. In Germany, for example, TSOs have a legally secured right of access only to power plants connected to the grid in Germany. The use of foreign power plants for redispatch purposes is only possible through voluntary cooperation with neighboring TSOs. Access to those power plants is therefore not secured. At the same time, the incentives for TSOs to make cross-border redispatch potential available to neighboring TSOs are low. This applies in particular if the TSO expects that it might need the potential for its own purposes at a later stage or that not enabling access to the redispatch resource might reduce its own congestion costs. Cross-border redispatch has therefore so far only been carried out to a very limited extent, e.g. in the TSC transmission network operator cooperation. In theory, there is even the possibility that redispatch measures by neighboring transmission system operators may mutually reinforce or weaken each other.

International coordination desirable. From a system-wide international point of view, a cross-border coordination of redispatch is highly desirable. Particularly in the case of congestion occurring close to the border, planned cross-border redispatch operations could significantly reduce volumes and costs. Increasingly, there are also situations in which it is not possible to guarantee system security with national redispatch potentials alone. Of high practical relevance for Germany are situations in which strong wind power generation is accompanied by high market-based exports to the south and west and a high load. This combination of factors regularly leads to inner-German grid congestion and is also relevant for the dimensioning of the grid reserve. Since in such a situation, however, the German power plants are already largely producing, foreign plants must be started up in order to carry out redispatch. In the past, plants abroad were therefore contracted under the roof of the grid reserve in order to make secured redispatch capacity available. The need for redispatch will probably increase due to the new rules for calculating cross-border trade capacities in the amended Electricity Market Regulation. Thus, the grid reserve approach no longer seems sufficient. The Electricity Market Regulation requires transmission system operators to make their redispatch potential available to each other. In future, the coordination of redispatch measures, from requirement

[4] See report on Work Package 6 of the project, section 3.4 "Estimates of the benefits of developing additional redispatch potentials".

assessment to deployment decisions, will also be coordinated by regional security coordinators (RSCs). Market-based redispatch, i.e. the existence of voluntary bids, would fundamentally simplify cross-border coordination.

Lack of incentive to invest. Because participation in redispatch does not enable profits, redispatch cannot provide locational steering of investments. Redispatch therefore has no locational steering effect of generation, storage or load investments. This concerns new investments as well as maintenance investments and also the maintenance of the operational readiness of unprofitable production plants. Existing power plants that should be decommissioned for economic reasons but are necessary as a redispatch resource due to their location in the electricity grid are currently kept operational within the framework of the grid reserve (Netzreserve) because redispatch itself cannot act as an incentive. Also, since this market design yields no regional investment incentives, the necessary network expansion, at least in theory, is greater than the economic optimum.

Estimation. Of the problems of cost-based redispatch, the lack of locational steering and the difficulty of integrating loads and decentralized storage appear to be the most fundamental. To the best of our knowledge, however, there has so far been a lack of comprehensive and reliable analyses of how high the overall - and not just case-specific - cost savings in congestion management would be if loads were integrated. Our analyses point to a limited potential for cost savings in the transmission grid by 2030.

1.5 MARKET-BASED REDISPATCH

Against the background of increased volumes and prices of redispatch and the conceptual problems of cost-based redispatch, various suggestions for a market-based procurement of redispatch have been made in recent years.

Definition: Market-based redispatch. According to our definition, a market-based redispatch must meet two criteria: (a) participation by market participants is voluntary and (b) compensation is made for the activation and is provided on the basis of bids from these same market participants. Systems with pure capacity payments therefore do not fall under this definition.

Goals. In essence, a market-based procurement of redispatch should address the problems mentioned above, i.e. on the one hand it should provide incentives to participate in redispatch and thus win loads and decentralized generators and storage facilities for redispatch, improve participation of CHP and facilitate cross-border redispatch. On the other hand, it is hoped that these locational incentives could bring about locational steering of investments.

Suggestions and concepts. The recently adopted EU Electricity Market Regulation stipulates market-based redispatch as the rule, albeit with far-reaching exceptions. In addition, various distribution network operators, electricity exchanges, associations and scientists, in particular from Germany, have developed proposals on redispatch markets in the distribution network, including the terms "smart markets" or "flexibility markets". It has occasionally been pointed out that many European countries follow market-based approaches, including the UK, the Netherlands, Italy and Scandinavian countries. Various projects of the German Smart Energy

Showcases (SINTEG) program have developed concepts for "flexibility markets" and "flexibility platforms". These often serve to integrate loads into congestion management at the distribution network level; some of them can be described as market-based redispatch in the above sense.

Problems of market-based redispatch. In the following two chapters, we will dive in detail into the fundamental problems of market-based congestion management. These include in particular:

- Feedback to the electricity market in the form of so-called inc-dec gaming
- The potential for abuse of local market power
- The fact that redispatch markets also set wrong locational investment signals (in addition to correct ones)

We then weigh up advantages and disadvantages in Chapter 4.

2 Feedback effects on the electricity market: inc-dec

A central finding of the project is that redispatch markets have feedback effects on the electricity market, i.e. they influence bidding behavior on the electricity market. Two effects can be distinguished here: firstly, changes caused by local market power, which we will discuss in the next section. Second, changes that occur without market power. These will be discussed below.

2.1 Incentive structure from market-based redispatch

Nodal. The sensitivity of a power plant (or load) on the flow on an overloaded grid element depends on its location in the grid. The different effectiveness is usually indicated in the form of load flow sensitivities. It is quite possible that the effectiveness of two generation units connected to neighboring nodes may differ by a factor of two - i.e. twice as much change in generation would be needed at the neighboring node to resolve the same congestion. Due to the widely varying load flow sensitivities, a redispatch market is always nodal, regardless of its concrete design. On the redispatch market, different prices can therefore form at each individual network node, reflecting the value of energy used to remove congestion at the respective node (so-called nodal prices). This also applies to local flexibility markets in the distribution network, whereby in such markets this would lead to an even finer geographical resolution of prices.

Incentive to adjust the bidding strategy. A redispatch market within a zonal electricity market therefore means the co-existence of two market levels with different spatial resolution, zonal and nodal. In this new system, market players - producers, consumers and storage operators - have the opportunity to select the market, where they want to buy or sell, i.e. they optimize between two markets. They can also buy on one market and sell on the other, i.e. arbitrage. This leads to a change in the rational bidding strategy on the zonal electricity market. The reason for this bid adjustment on the zonal market is the additional revenue opportunity on the redispatch market.

Pricing-in opportunity costs. Opportunity costs created by alternative marketplaces are a sensible and legitimate component of marginal costs in incentive-compatible market designs. Such consideration of opportunity costs takes place in a comparable form in the interaction between spot market and balancing market or the spot market bids by storage power plants (opportunity of future water use). Actors therefore behave in an incentive-compatible way of the newly created incentive system if, after the introduction of a redispatch-market, they take the opportunity costs from that market into account in their bids on the zonal spot market.

Timing of redispatch market. We assume here that the redispatch market clears after the zonal electricity market. In the current redispatch in Germany, redispatch is a parallel process that starts before day-ahead and takes place until shortly before real-time. However, we do not consider this to be feasible with market-based redispatch, since such a temporal parallelism would permit even further-reaching, risk-free strategies leading to aggravated congestion on the electricity market. In the following, we will therefore look at a redispatch market that is cleared after the zonal electricity market closes. However, the incentives described also apply to a redispatch market conducted in parallel with the zonal electricity market.

Incentives. In essence, a redispatch market provides the following incentives: producers in scarcity regions anticipate that (higher) profits can be generated by marketing their production on the redispatch market instead of the zonal electricity market. They therefore bid higher prices on the zonal electricity market and thus price themselves out of that market in order to be available for the subsequent redispatch market. One can understand these strategies as an optimization between two markets. Conversely, producers in surplus regions anticipate profits from being downward-redispatched. To make this possible, they place low bids on the electricity market and thus push themselves into the market. They can offer at this price as they can buy themselves out of their delivery obligation on the subsequent redispatch market. In principle, they buy back the electricity that was previously sold at high prices on the electricity market at a lower price on the redispatch market. One can understand this strategy as arbitrage trading. Since the schedules of these plants are first increased on the electricity market and then reduced on the redispatch market, the scientific literature also speaks of the "increase-decrease" or "inc-dec" strategy.

Aggravated congestion. This incentive system is problematic because it *aggravates* network congestion on the zonal market: in scarce regions, a reduction of production is encouraged, and in surplus regions an increase in production - exactly the opposite of what would be useful for the system. The introduction of a redispatch market therefore increases the need for redispatch.

Inc-dec also by consumers. Analogous to producers, loads (consumers) can also implement inc-dec bidding strategies. Those in the surplus region initially reduce their demand, while those in the scarcity region initially increase it. Via the redispatch market, they then either get significantly cheaper electricity or can "return" the unneeded electricity to the TSO at higher prices, in both cases making a profit while aggravating congestion on the zonal electricity market.

2.2 THE INC-DEC STRATEGY GRAPHICALLY EXPLAINED

This section explains inc-dec using a simple graphical model based on Hirth & Schlecht (2019). This is for illustration and understanding only; quantitative results of a calibrated network model of Europe follow in section 2.5.

The model. The aim is to represent a nodal redispatch market within a zonal electricity market in a model as simple as possible. In the model, a redispatch market (RDM) follows after the closure of the zonal electricity market. Both market segments are characterized by voluntary participation, uniform pricing (as opposed to pay-as-bid)[5] and the absence of market power. The market consists of a single uniform price zone with two nodes - an over-supplied "North" and an under-supplied "South" - connected by a 30 GW line. All load is connected to the southern node. To keep the example tractable, we assume that load is inflexible and does not exhibit inc-dec behavior. The majority of generation - wind, coal and diesel - is located in the north, gas-fired power plants in the south. We model a single hour and refrain from uncertainty and information asymmetry. Figure 3 and Figure 4 show the model. Since there are only two nodes in this example, the sensitivity of all individual power plants at the northern node and at the southern node to the single line is the same.

Cost terminology. To define the various cost concepts, we use the term "generation costs" for the fundamental costs incurred from generation (e.g. fuel and CO_2-certificates for power plants or the willingness to pay for electricity consumers). We use the term "marginal costs" on the other hand to mean all costs taken into account in the bids, including opportunity costs from selling at alternative markets. The bids based on marginal cost for the zonal market thus include the opportunity costs from the subsequent redispatch market. Since the redispatch market is the last opened marketplace before the delivery date, the players have no opportunity costs from other markets at the close of trading of redispatch. In this case, the marginal costs correspond to generation costs.

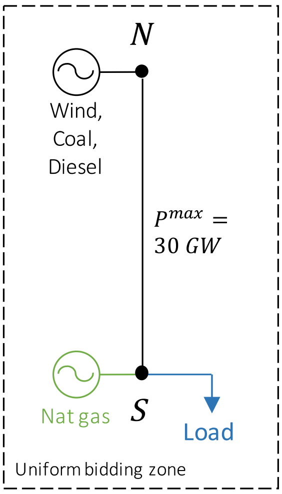

Figure 3: Network structure

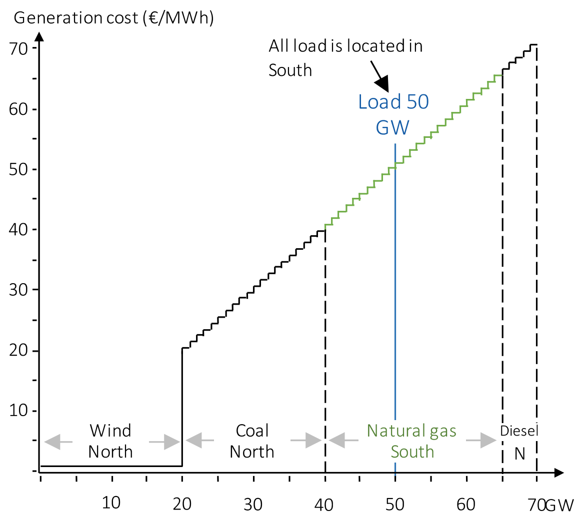

Figure 4: Supply and demand

[5] In the case of pay-as-bid on the RDM, bidding behavior changes, but the basic incentive mechanisms examined and described here remain unchanged. In a market with free bids and pay-as-bid, players would try to place their bids as close as possible to the price of the last accepted bid - so prices converge to the uniform clearing price even for pay-as-bid. Pay-as-bid must not be confused with bidding mere costs. Our assumption of uniform pricing is therefore a good approximation also for bidding strategies under a pay-as-bid regime.

Cost-based redispatch. On the electricity market, all producers offer their marginal costs, which in this case correspond to the generation costs. There are no opportunity costs from redispatch, as cost-based redispatch is designed to leave players financially indifferent. This results in an equilibrium price of EUR 50 per MWh. This implies a flow on the line of 40 GW and thus exceeds the line capacity of 30 GW - redispatch is necessary. The grid operator selects the 10 GW coal-fired power plants with the highest generation costs and instructs them to ramp down. In the south, on the other hand, the 10 GW cheapest gas-fired power plants not yet in operation will be ramped up (Figure 5).

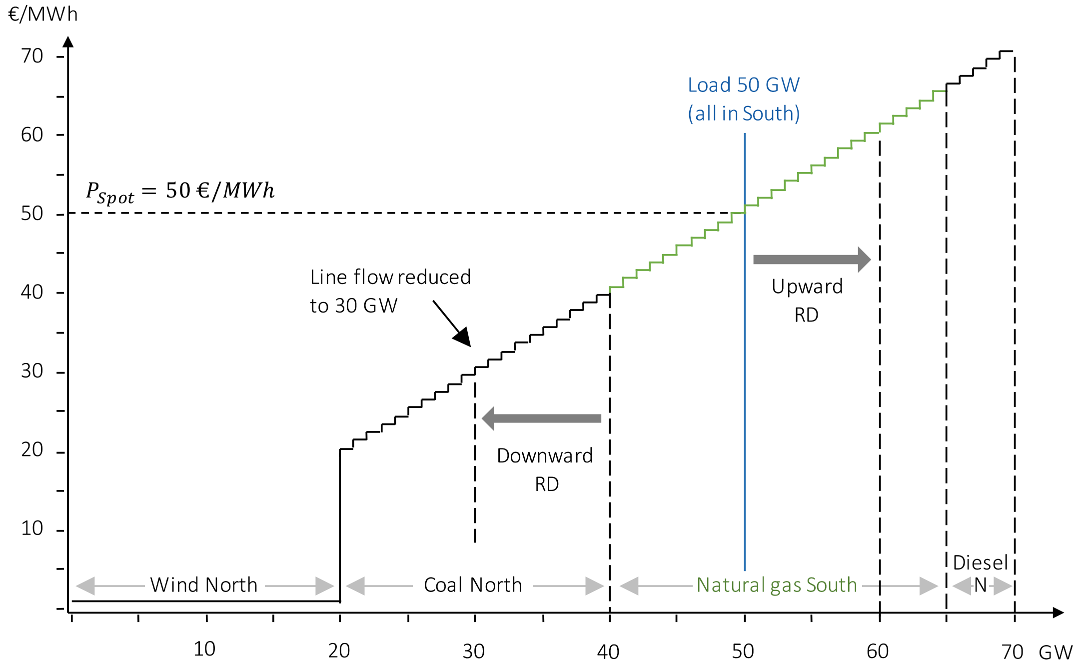

Figure 5: Cost-based redispatch

RDM without anticipation. Now we assume the administrative, cost-based redispatch will be replaced by a voluntary redispatch market. For the time being, we assume that the RDM will not be anticipated and that bids on the electricity market will therefore continue to correspond to generation costs. After gate closure on the zonal electricity market, the grid operator opens two procurement auctions: 10 GW additional generation in the south and 10 GW down-regulation in the north. In a way, the network operator buys 10 GW in the south and sells the same amount in the north. The equilibrium price of the RDM is EUR 60 per MWh in the south and EUR 30 per MWh in the north (Figure 6). Although the same units are used as for cost-based redispatch, the redispatch costs increase because all providers in the redispatch now receive the uniform marginal price instead of a pure reimbursement. Local rents are created both in the north and in the south (which in the long term could encourage the construction of new power plants in both locations, i.e. both in the scarcity and in the surplus region). One problem with this solution is that it does not represent a Nash equilibrium, as the bidding strategies of some power plants are not optimal. They do not take opportunity costs from the redispatch market into account in their bids. This can be seen most clearly in the gas-fired power plants in the south. Some power plants have sold electricity at EUR 50 per MWh (on the electricity market), others at EUR 60 (on the redispatch market). For the former, the strategy shown is not rational. Rather, they would prefer to sell their production on the redispatch market at a higher price. They can do this by taking the opportunity of the redispatch market into account in their bid.

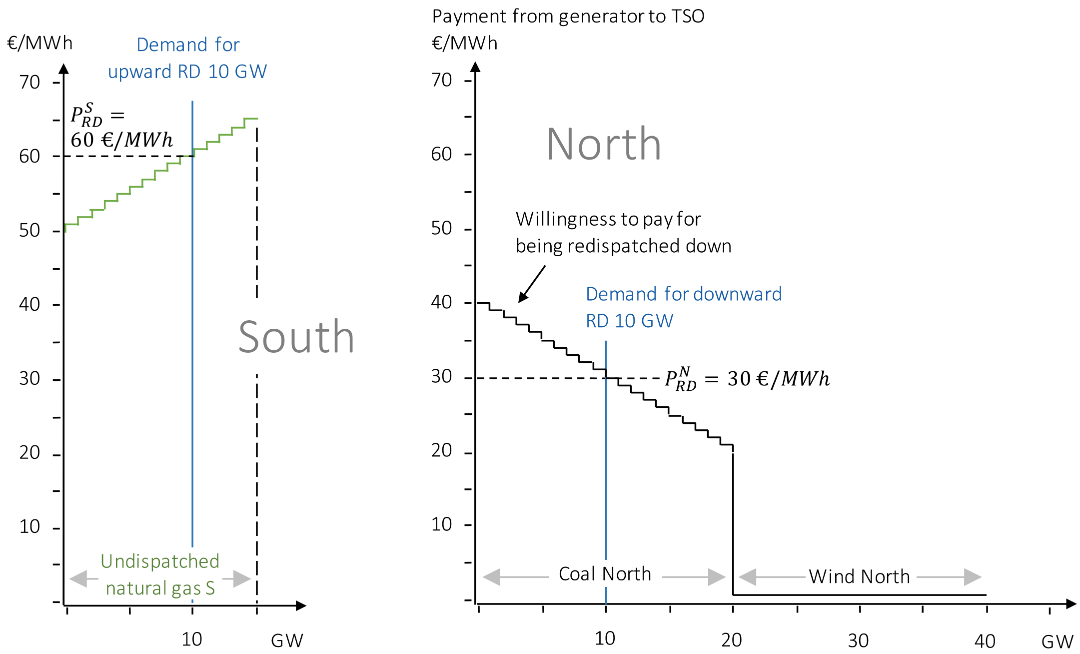

Figure 6: Redispatch market without anticipation

RDM with anticipation. Rational market actors anticipate the redispatch market and adjust their bidding strategy on the electricity market by taking the new opportunity into account (Figure 7). The bids are strategic to the extent that they contain the opportunity costs from the subsequent market level. In the south, all gas-fired power plants offer at least EUR 60 per MWh. Although some of their generation costs are below this level, it is the opportunity costs that determine the bidding strategy: As the power plants have the possibility to sell later at EUR 60 per MWh, they will not sell before at a lower price. Therefore, they are pricing themselves out of the electricity market and are de facto holding back capacity, because only then can they be ramped up on the redispatch market. In other words, power plants optimize between two markets and prefer to sell in the high-price market segment. In the north, the opposite happens: expensive coal and diesel power plants anticipate that they can buy back electricity from the grid operator on the RDM for EUR 30 per MWh, i.e. pay the grid operator this amount so that they do not have to produce the electricity. They offer EUR 30 per MWh in the electricity market, even if their generation costs are far higher. They are praising themselves into the market, because only then can they participate in redispatch. This strategy can be understood as arbitrage trading: buying cheaply on the redispatch market in order to sell for a higher price on the electricity market (just that the electricity market is the first market). In Hirth & Schlecht (2019) we show that this is a Nash equilibrium.

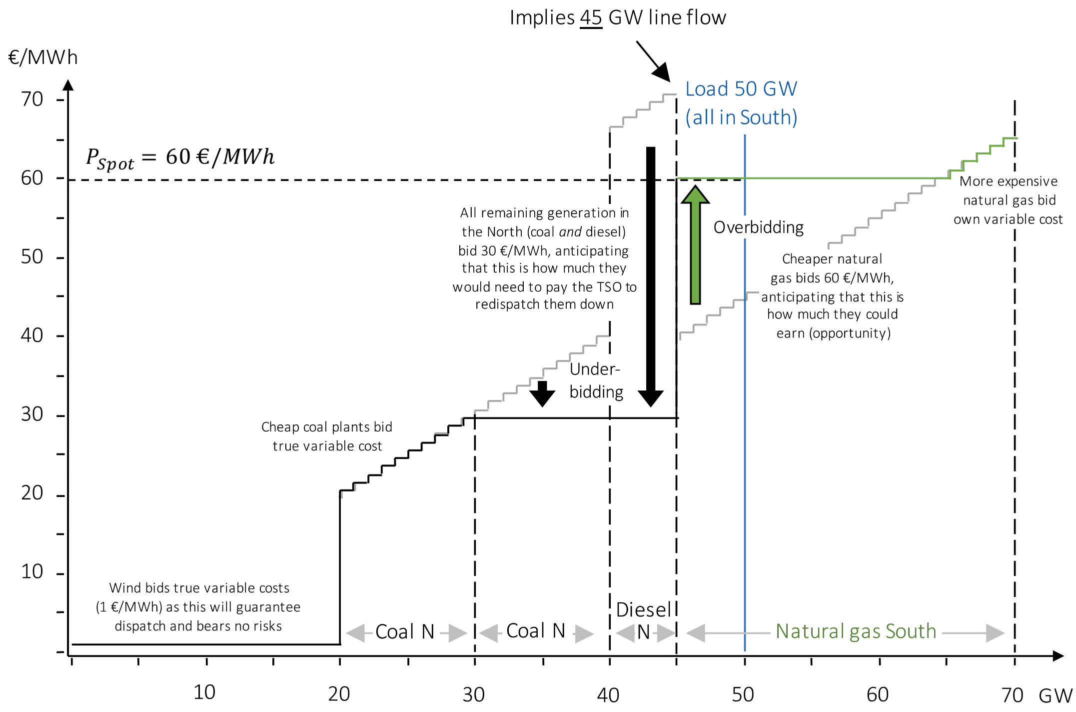

Figure 7: Optimal spot bidding strategy anticipating the RDM

2.3 Consequences of the Inconsistent Incentive System

Four problems. The final physical dispatch for cost-based and market-based redispatch is identical despite inc-dec.[6] However, strategic bidding behavior has four relevant problematic consequences: increased congestion, windfall profits, effects on financial markets, and perverse investment incentives.

Congestion-aggravating behavior. By anticipating the redispatch market (consideration of the opportunity costs in the offered marginal costs), the optimal spot-bids from market players change in such a way that congestion is systematically intensified. In this example, the redispatch volume increases from 10 GW to 15 GW.

[6] Even if the stylized model in all considered variants (cost-based redispatch as well as market redispatch with and without anticipation) results in the same final power plant dispatch (after redispatch), a changed dispatch would be expected in reality for various reasons. On the one hand, changes result from timing problems. If the redispatch market is carried out at an early point in time, the power plant deployment is frozen at an early point in time and can then no longer be optimized on the intraday market. If the redispatch market is only carried out at a late stage, however, for technical reasons not all power plants will be available - the final use of the power plant would therefore change. Other possible changes result from potential local market power and differences in the group of participants (e.g. with regard to power plants in neighboring countries) in the spot and redispatch market as well as from the partly counter-intuitive incentives triggered by market-based redispatch.

Windfall profits. Market players also earn significant additional rents ("windfall profits"). In the model, the redispatch costs increase from 200,000 EUR to 450,000 EUR compared to cost-based redispatch; costs that are currently passed on to consumers via grid charges and the increase of which would therefore primarily come at the expense of consumers. In addition, the spot price will rise from EUR 50 to EUR 60. Consumers pay almost 30 % more in total, the revenues of producers increase by 50 %.

Financial markets. Markets for futures and forwards are fundamental for hedging the risks of generators, distributors and consumers. The financial products traded there are based on the spot electricity price. The spot price is the underlying for almost all hedging products. When a redispatch market was introduced, it would replace the zonal electricity market as the most relevant source of revenue and costs for many producers and consumers. Hedging on the basis of the zonal electricity market is therefore no longer possible. Products such as financial transmission rights, which are known from nodal pricing systems, would have to be introduced to cover the basic risk. It is not to be expected that liquid trading in financial products based on nodal prices of the RDM as underlying would develop, as there are too few players at each individual node who could provide the necessary liquidity.

Perverse investment incentives. The increase in the rents of plants in the South creates desired investment incentives. At the same time, however, the redispatch market creates perverse incentives for investments in generation in the North. In the North, too, the rents of down-graded investments are rising systematically when redispatch markets are introduced and are further increased by the arbitrage opportunities. It would even be conceivable that, in order to be able to participate in redispatch in the North, it may make sense to build additional plants there at the lowest possible investment costs (and probably very high generation costs) or to keep existing plants in operation that are no longer economically viable. They may never generate electricity themselves, but earn rents for doing nothing as part of redispatch. When engaging in arbitrage trade between the two market levels, the plants' own generation costs are even irrelevant.

Inconsistent market design. These four problems show the systematic inconsistency of two market levels with different geographic resolution. Any analysis of redispatch markets must therefore take feedback effects into account. The zonal electricity market is *not* independent of the subsequent redispatch market.

2.4 Prerequisites for inc-dec Incentives

This section discusses the prerequisites for inc-dec gaming to occur. It also clarifies that market power is not a prerequisite for pricing in opportunity costs from the redispatch market.

Anticipation. Inc-dec gaming is not risk-free for market actors. Diesel power plants serve as an example for this in our model: If, contrary to expectations, the grid was uncongested, these power plants would have to accept negative contribution margins. Market players must therefore be able to forecast local prices on the redispatch market with some amount of certainty. It is sufficient to correctly anticipate whether the price on the redispatch market is below or above the zonal price. This is unlikely to be the case, for example, if congestion occurs only sporadically. However, we are of the opinion that in a bidding zone with structural congestion such as the German one, the anticipation of congestion with sufficient accuracy is possible. Data availability is high - also thanks to the EU Transparency Regulation - and the analytical capabilities of trading departments and consulting firms are significant. Even if network and redispatch data were not published, each activation provides the respective market players with an opportunity for learning patterns of redispatch.

Structural congestion ensures predictability. In view of the structural congestion in the German network, a situation with a sporadically occurring redispatch market is rather unlikely - especially if players with inc-dec strategies increase congestion. In 2018, redispatch took place[7] in over 6,500 hours (75%) of the year, which is a useful proxy for when a redispatch market would have taken place. At the same time, high rents on the redispatch market can be obtained especially in situations where the need for redispatch is particularly high. These situations are particularly easy to anticipate.

Risk of wrong prediction: North. If a redispatch market takes place, the risk for flexibility providers with an inc-dec strategy lies primarily in an incorrect assessment of the direction of the price difference between the zonal and local markets. For example, if the actual price on the redispatch market in the north is higher than the zonal market price, the diesel player from the example above (assuming it would not foresee the situation and still play the inc-dec strategy) could not make a profit from the difference between the local price and the zonal price, but would have to buy back the energy sold to the zonal market at the unexpectedly higher local price. However, the risk is limited to the difference between the local and zonal price and does not mean the player would have to produce at his own very high generation costs. If the bidder has only estimated the extent of the price difference but not its direction incorrectly, the inc-dec strategy remains advantageous, albeit not to the extent hoped for.

Risk of wrong prediction: South. The same applies to power plants in the south, which also run the risk of misjudging the "larger-smaller ratio" of local and zonal prices. In theory, they could "price themselves out of the zonal market" in anticipation of a high local price, and may then later find that the actual local price is below the zonal price. Even then, however, their risk is limited to the difference between local and zonal prices and does not mean that they cannot market their production at all. If the local price is lower than expected, but still above the zonal price, the inc-dec strategy remains advantageous. A clear risk limitation is that the rational strategy on the redispatch market is to bid at generation costs. As long as these are lower than the local price, the players in the redispatch market would get activated for ramping up.

No market power or collusion necessary. As our model shows, pricing-in opportunity costs from the redispatch market (i.e. inc-dec behavior) does not require a dominant market position. It is a strategy that is feasible even for atomistically small actors. Although market players temporarily deviate from the pure generation cost bids on the spot market by also pricing-in opportunity costs from the redispatch market, they all offer their generation costs finally on

[7] Own evaluations based on data from www.netztransparenz.de (data retrieved on 5.7.2019).

the redispatch market (since there are no further opportunity costs from subsequent markets any more). Market power therefore is not a prerequisite to inc-dec gaming. Conversely, this of course means that additional redispatch providers do not prevent inc-dec, as we outline in more detail also in the following Section 2.5. If, however, (local) market power exists, which is likely to be the norm, a number of problems are exacerbated (more on this in Chapter 3). Just like inc-dec gaming does not require a dominant market position, it also does not require collusion among market players.

2.5 ADDITIONAL REDISPATCH SUPPLY DOES NOT PREVENT INC-DEC

Additional redispatch resources do not prevent inc-dec. Since the inc-dec strategy can be understood as an arbitrage trade, it is reasonable to assume that the price difference between the redispatch market and the electricity market will disappear due to the integration of additional redispatch supply. Additional providers would lower the price and lead to the redispatch price converging to the zonal spot price in the long term. However, this consideration is wrong, as we will show below. It is helpful to distinguish what is meant by "additional supply" in the redispatch market. We differentiate three cases.

Additional inc-dec players. The narrowest (and "static") definition of additional supply is the additional supply on the redispatch market caused by the inc-dec incentives themselves. These are existing generators or loads that adjust their zonal bid due to the opportunity costs from redispatch in such a way that they are now available as an "additional supply" on the redispatch market. It seems that capacity available for redispatch has increased to the extent that, without their strategic bidding behavior, the capacity available for redispatch would have been smaller. However, these additional players on the redispatch market have exacerbated the network congestion on the zonal market to the *same extent* that they are now increasing supply on the redispatch market. The additional supply thus creates its own additional demand. The marginal redispatch power plant will remain unchanged and so will the price on the redispatch market. The inc-dec strategy is therefore arbitrage trading without price convergence. This becomes clear in the example in Section 2.2: Inc-dec bids increase transport demand; redispatch supply and demand each increase by exactly 5 GW. The additional providers on the redispatch market have increased the redispatch demand on the zonal electricity market to the same extent as their new redispatch supply. Due to the synchronization of supply and demand, prices on both redispatch markets (North and South) remain unchanged at EUR 60 per MWh and EUR 30 per MWh respectively.

Integration of existing resources into redispatch. A somewhat broader (but still "static") definition of additional resources for redispatch also includes resources that already exist but have not yet been used for redispatch. This includes loads or storages that are not currently integrated in the cost-based redispatch. In the zonal electricity market, however, such resources are already active participants. These additional potentials therefore do not alter the existence of congestion. Congestion arise as a result of the planned dispatch based on the trading on the zonal market. However, trading on the zonal market does not change simply because additional redispatch potential is tapped. Congestion therefore remains and must continue to be remedied by redispatch. Inc-dec incentives thus remain in place. It is true, however, that such additional resources shift the price on the redispatch market in the direction of the zonal electricity price. For example, if new suppliers integrated into redispatch in the South have generation costs above the zonal price but below the original redispatch price, their additional redispatch supply could lower the price on the redispatch market and thus narrow the gap to the zonal price. The same applies to loads whose willingness to pay is above the zonal price but below the redispatch price. However, the price reduction in the redispatch market only occurs to the extent that the underlying cost structures and the number of providers allow, and never leads to an adjustment of the redispatch prices to the zonal market. If the resources newly integrated into redispatch were viable at the zonal price, congestion would not have existed in the first place.

New investments in the scarcity region. The broadest (and "dynamic") definition of additional offering in redispatch includes resources that have only been invested in due to incentives from the redispatch market. These are investments which only become profitable through the additional contribution margins from the redispatch market, i.e. which would not have been profitable on zonal revenue alone. They would not exist without the redispatch market. If such investments were to bring prices on the local redispatch markets down to the level of the zonal price and congestion would disappear, investors would have made a mistake. The hoped-for additional rents from the redispatch market would then not materialize and the investment would thus be in deficit; this is therefore not a long-term economic equilibrium. A partial alignment is conceivable in which the congestion on the zonal market persist and the redispatch price approaches the zonal price but does not fully reach its level. Complete alignment would also be impossible against the background of different resource availabilities (wind speeds, solar radiation, real estate prices) at different locations, which are already the reason for production cost divergence across locations initially.

New investments in the surplus region. Even more problematic, however, is the fact that the investment incentives of a redispatch market in part themselves exacerbate congestion. As explained in section 2.3 introduction of the redispatch market also systematically increases profits of power plants in the surplus region ('north'). Such new investment incentives for congestion aggravating plants in surplus regions could also lead to delayed dis-investment of otherwise unprofitable old power plants in surplus regions, as the additional profits from redispatch markets could make them remain financially viable – despite the fact that they are congestion aggravating. These additional rents represent an investment incentive in regions that already cause congestion on the zonal market due to excessive local electricity supply. Therefore, this does not lead to a reduction but to an increase in congestion.

Redispatch markets do not make congestion disappear. In summary, no form of 'additional supply' leads to the disappearance of inc-dec incentives, as congestion in the zonal market remains. At best, the profitability of inc-dec can be reduced, but it cannot be eliminated. Congestion and inc-dec incentives could even reinforce each other due to the perverse investment incentives of redispatch markets in surplus regions.

2.6 QUANTIFICATION IN A NETWORK MODEL

Aim of quantification. The findings from the conceptual considerations on the impact of inc-dec are clear. Inc-dec bidding strategies that result from an inconsistent incentive system due to the coexistence of a zonal electricity market and a local redispatch market have problematic consequences: Congestion is exacerbated, redispatch costs and volumes increase as a result, rents shift between market participants / consumers and windfall profits as well as perverse investment incentives arise. The results of the (zonal) electricity market, whose prices are supposed to guide efficient use of and investment in generation and other flexibility options as well as trigger innovation, are also distorted. Using a stylized example of two nodes, the basic mechanisms were graphically worked out. However, this does not answer the question of the magnitude of the impact on the electricity market and redispatch volumes and costs if inc-dec strategies were applied as a result of a redispatch market in the German transmission grid. In this project, extensive model-based simulations were carried out on the basis of a European electricity market model and a high-resolution European transmission grid model in connection with methods for load flow and redispatch simulation.

Simulation approach. The method chosen for the quantitative analyses is based on the fact that inc-dec is an economically rational bidding strategy of market players, which also - as already explained above - leads to a Nash equilibrium. This is the case at least if one disregards use of market power, as we have done for this part of the analysis (for implications of the abuse of market power, see Chapter 3).

In summary, inc-dec gaming on the zonal electricity market is that a player - whether generator or consumer and whether 'in front of' or 'behind' the congestion - aligns its bidding strategy on the preceding zonal market with the expected local market price, which is revealed on the subsequent redispatch market at the network node of the respective player.[8] Under the assumptions of the absence of (the use of) market power, the rational strategy on the subsequent redispatch market is for all market participant to bid their respective marginal generation costs (for consumers: their reservation price, i.e. their willingness to pay for the physical supply of electricity for the respective point in time).[9]

In order to analyze the effects of inc-dec gaming, we first simulate the zonal European electricity market. We use a state-of-the-art electricity market model (equilibrium model) developed by Consentec. This simulation is carried out in two versions (see Figure 8 below). One version is the usual approach in electricity market simulations for most applications: loads and power plants "bid" with their respective reservation prices or marginal generation costs.

[8] Thus, for a large number of players, the rational strategy is to bid exactly the local market price. For some operators with particularly high or low marginal generation costs who cannot expect to benefit from an inc-dec strategy, however, the rational strategy is to bid their marginal generation costs. This is also reflected in our model calculations.

[9] This applies under the assumption that a *uniform pricing/pay-as-cleared rule* applies in the redispatch market (cf. the assumptions for the stylized example in Section 2.2).

This version represents a zonal market without inc-dec gaming (base scenario). In a second version, flexible loads and power plants instead bid the site-specific expected local market price (inc-dec scenario). The local market prices for the inc-dec scenario are determined in an pre-calculation step using a nodal pricing algorithm on the basis of marginal generation costs and a nodal grid model.

The two versions of the electricity market simulation are each followed by a redispatch simulation. In both redispatch simulations, the change in generation / consumption schedules of power plants, flexible consumers and active grid elements is determined in such a way that all congestions in the German transmission grid including interconnectors are solved at minimum costs. The difference between a cost-based, regulated redispatch and a redispatch market in this modelling stage is in the redispatch simulation itself (in both cases bids are cost-based), but rather in the evaluation of the simulation results with regard to redispatch costs[10]and market rents of the different market participants: In the case of cost-based redispatch, changes in the production schedule are "settled" on a cost basis, i.e. based on marginal generation costs and reservation prices assumed in the redispatch simulation as input data. There are no rents for redispatched market players. Simulating a redispatch market settlement takes place at the local market price (nodal price). Redispatch costs are ceteris paribus higher because, for example, power plants that are upward regulated are usually being paid a local market price that is above their marginal generation costs, which would be paid in cost-based redispatch. In return, the flexibility providers on the redispatch market generate rents.

[10] Since inc-dec gaming is the focus of the analyses presented here, both calculated version are based on basically the same redispatch potential. For both version, for example, we have assumed that flexible loads are available for redispatch, i.e. also for the cost-based version. A main disadvantage of cost-based redispatch is, however, it that such "new" redispatch potentials are unlikely to be integrated in cost-based redispatch. In addition to the incentive for inc-dec gaming, the availability of this potential for redispatch would therefore be a further difference between market-based and cost-based redispatch. In order to be able to identify effects as clearly as possible, this aspect is examined quantitatively in a separate calculation. In the report on work package 6 of this project (Section 3.4 of the report on WP 6), these calculation are described in detail.

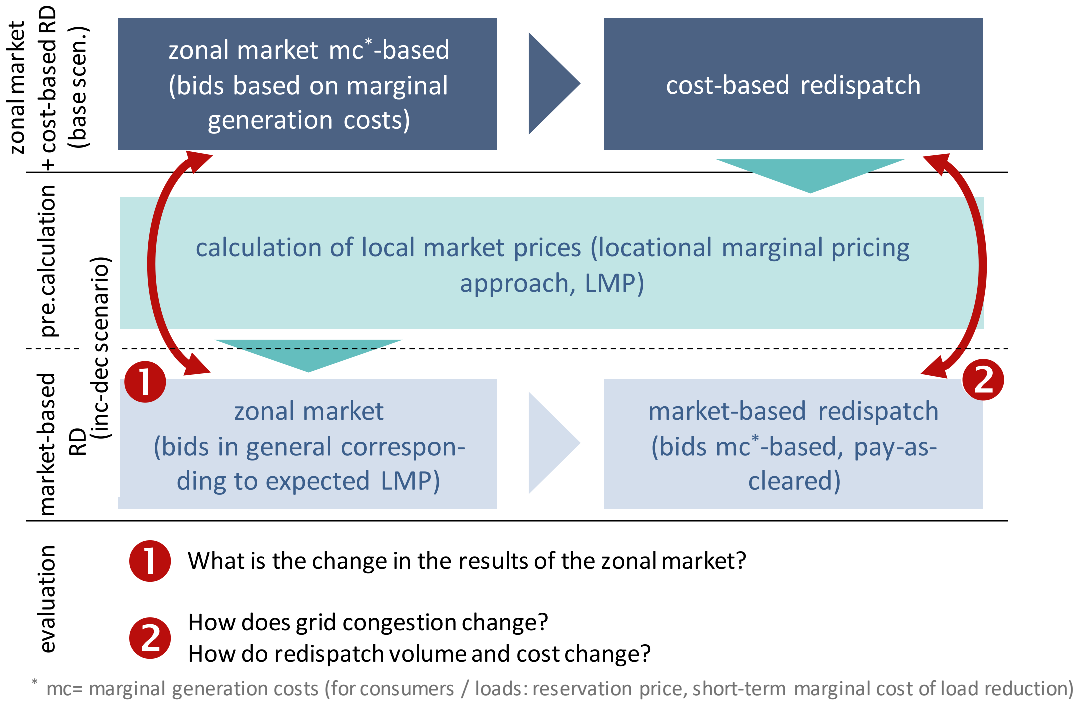

Figure 8: Simulation approach to assess the impact of inc-dec gaming

By comparing the results of the two runs of a sequence of the electricity market model and redispatch simulation, essential questions regarding inc-dec gaming can be answered: How does the result on the zonal market change when incentives are given to players to apply inc-dec gaming? How does this change network congestion and how do redispatch volumes and costs change?

Assumptions on fundamentals of the energy system. The quantitative analyses are carried out for a scenario of the energy systems' fundamentals that reflect a possible situation in 2030. We have aligned the assumptions regarding the most important fundamentals, which are required inputs for the simulation, as far as possible to current policy decision and the state of discussion: In Germany, for example, we have assumed an expansion of electricity generation from renewable energies that will meet a target of 65 % renewables by 2030. As far as conventional power plant capacities are concerned, we have based our calculations on a scenario that is basically in line with a phase out of coal-fired power generation by 2038. The development of electricity demand in Germany follows the grid development plan 2019 (Netzentwicklungsplan). Fuel and CO_2 certificate prices are based on the World Energy Outlook, power plant capacities outside Germany are based on scenarios of the European transmission system operators. The state of grid expansion in Germany reflects the legal requirements under the Bundesbedarfsplangesetz (as of July 2018). For the allocation of cross-border capacity in the electricity market modell, we implemented the Clean Energy Package requirements, in particular the application of a flow-based capacity calculation model in the so-called CORE capacity calculation region, to which Germany also belongs. The requirement that at least 70 % of the physical transmission capacity of critical network elements must be made available for electricity trading is reflected in the models.

Further assumption: Inc-dec only with "real" flexibilities, no short sales included in simulations. For the interpretation of the results, another detail of the simulation assumptions is important: We have assumed that the application of inc-dec gaming is only possible to the extent that all bids simulated for the zonal market are actually physically backed. This can be explained using the case of the diesel power plants in the north from the stylized example above: In the case of inc-dec, for example, these plants bid on the zonal market at the local market price and with a quantity that corresponds to their physically maximum available generation capacity (here: 5 GW). This allows them to benefit from arbitrage - selling energy at a higher zonal price and later fulfilling their supply obligation by buying the energy at the lower local market price - as far as their physical generation capacity allows. However, since they do not intend to produce the energy sold on the zonal market with their power plant, it would general also be possible that they would sell more than their physical capacity on the zonal market and buy back the correspondingly higher quantity at the local market. This is only possible because, as a constituting feature of inc-dec, they create the demand for decreasing power on the local market themselves. Therefore, this type of "short selling" is ultimately not limited in quantity. However, we assume that - unlike a physically covered inc-dec bids (cf. Section 2.7) - such short sales would at least be sanctionable by, for example, using corresponding regulations in balancing group contracts, because bids on the zonal market would not be physically covered. This is not allowed according to our interpretation of today's balancing group contracts. Hence, we limit the volume of inc-dec bids in our simulations to the physically available capacities of the respective player. In case of renewable energy plants and (flexible) loads, we limit the inc-dec bids to the available renewable energy supply or the load at the specific point in time. In reality, however, (limited) circumvention possibilities are likely to exist with regard to this restriction on RES plants and loads, for example by players increasing their potential for inc-dec gaming through higher RES or load forecasts. It may be difficult to prove abusive behavior. In this respect, this assumption of our simulation leads to a rather conservative estimation of the potential for the application of inc-dec gaming.

Significant impact of inc-dec on the zonal electricity market. Inc-dec bidding changes the bidding curve on the zonal market (see Figure 4 and Figure 7 for the stylized example above). This changes which bis are accepted at the zonal market - and thus the schedules of power plants and flexible consumers - and it changes the prices on the zonal market. The extent of the change in prices depends heavily on the merit order and local market prices and is difficult to predict[11].. Due to the inc-dec strategy, prices in the zonal market are neither systematically higher nor systematically lower.

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[11] In section 2.4 'predictability' was mentioned as a condition for inc-dec. However, this refers to congestion and local prices (and thus the optimal bidding strategy). Being able to predict zonal prices is not a prerequisite for the application of inc-dec gaming - just as it is not a prerequisite for an optimal bidding strategies in a zonal market without inc-dec incentives.

As a quantitative measure for the impact of inc-dec gaming, we compared the marketing of generation assets and the procurement of electrical energy to cover demand on the zonal market as a result of the base scenario and the inc-dec scenario. The sum of the absolute amounts of the change in electricity marketed/procured on the zonal market was evaluated per modelled plant / consumer and per hour. The comparison is intended to show what impact a redispatch market has on the zonal market as a result of inc-dec gaming / bidding behavior. For the simulated year 2030, the inc-dec bidding results in a change in marketing decisions on the zonal market summing up to 570 TWh. The greatest share of this is from marketing decisions of power plants (540 TWh) and, in addition to German plants, also concerns plants from other countries that are included in the redispatch market and therefore also have incentives for an inc-dec bidding strategy. The marketing of German power plants will change by 192 TWh[12]. In applying inc-dec gaming, 79 TWh of generation, which would not be marketed in a situation with cost-based instead inc-dec-based bids, are additionally marketed and 113 TWh of generation assets, that would be marketed in a situation with cost-based bids, are not marketed at the zonal market due to inc-dec gaming.[13]

These figures clearly show that the introduction of market-based redispatch in addition to a zonal market would lead to very significant distortions in the zonal market. The result - market clearing / accepted bids - of the zonal market would differ greatly from the actually desired result, which is one that would result if all bidders on the zonal market were to bid on the basis of their marginal generation costs.

Huge increase in redispatch volume and costs as a result of inc-dec gaming. The changed marketing decisions in the zonal market also change the congestion situation, which is a result of the (preliminary) power plant generation schedules due the zonal market result. The theoretical considerations above have shown: All changes in the dispatch schedules in a situation with inc-dec gaming have a unidirectional impact on congestion: congestion increases. In view of the massive change in the dispatch based in the zonal market result as a consequence of inc-dec gaming as described above, it is also to be expected that the extent of the congestion and consequently the redispatch volume and costs will increase significantly.

The amount of redispatch needed to solve grid congestion increases dramatically in our simulations as a result of inc-dec gaming. The redispatch volume increases from around 44 TWh to 306 TWh (cf. text box below). Under the assumptions made, redispatch markets would therefore increase the redispatch demand by about a factor of 7. The redispatch costs would rise to around EUR 3,5 billion, EUR 2,4 billion more than in the case of cost-based redispatch. The increase in redispatch costs with a factor of slightly above 3 very substantial.

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[12] For comparison: The gross electricity consumption in this scenario amounts to approx. 556 TWh in Germany for the year 2030 or approx. 3,241 TWh in the entire modelling area.

[13] The difference can be explained on the one hand by a change in demand (in particular flexible loads shift some of their electricity purchases to the redispatch market) and on the other hand by foreign power plants, which market in sum more as a consequence of inc-dec gaming.

Post-optimization of the zonal market on the redispatch market. The redispatch volume calculated at 44 TWh for the base scenario (cost-based redispatch) is - may ab surprisingly - comparatively high. Two aspects in particular need to be taken into account to understand this results: On the one hand, a strictly cost-minimizing redispatch simulation as carried out here, usually results in a "post-optimization" of the zonal market result. This means that redispatch measures are also carried out in redispatch optimization which do not (exclusively) serve to solve congestion, but have a positive effect with regard to the objective function of the optimization, i. e. cost minimization (which is equivalent to welfare maximization). This leads to significantly lower specific costs per MWh of redispatch due to increasing volumes at lower overall costs. The potential for such a post-optimization arises because in the redispatch simulation it is necessary to strictly stick to the zonal merit order (to do so is a constituent feature of a zonal market). In simple words: The redispatch simulation can "skip" power plants in the merit order if it can thereby enable additional, welfare-enhancing electricity trading without violating grid restrictions. This is possible because the redispatch simulation "sees" the technical impact of an additional feed-in more detailed compared to the zonal market. In a zonal market, by definition , any feed-in, irrespective of its location within the zone, has the same grid impact (implemented by the so-called GSK, *Generation Shift Key*). In a redispatch simulation the impact is differentiated network node by network node. Eventhough if the effect of post-optimization cannot be clearly separated from other effects, we have estimated it in a sensitivity analysis: The effect can account for about half of the calculated redispatch volume. The second aspect to be considered is that, in contrast to calculations that would be carried out, for example, within the framework of the network development plan, the assumed energy market fundamentals lead to a higher redispatch requirement simply because the assumed network expansion status (here: line extensions in accordance with the Bundesbedarfsplan as of July 2018), do not reflect the recently changed, more demanding political requirements. These include in particular the regulation of the Clean Energy Package on minimum trading capacities, the increase in renewable energy expansion targets by 2030 and the phasing out of coal-fired electricity generation by 2038.

To illustrate the effects, the following figure compares the congestion situation in the German transmission grid before redispatch and the necessary redispatch in the base scenario and in the inc-dec scenario for an exemplary hour from the simulation year 2030. The selected hour is typical for the simulation year with regard to the location of congestion and units used for redispatch.

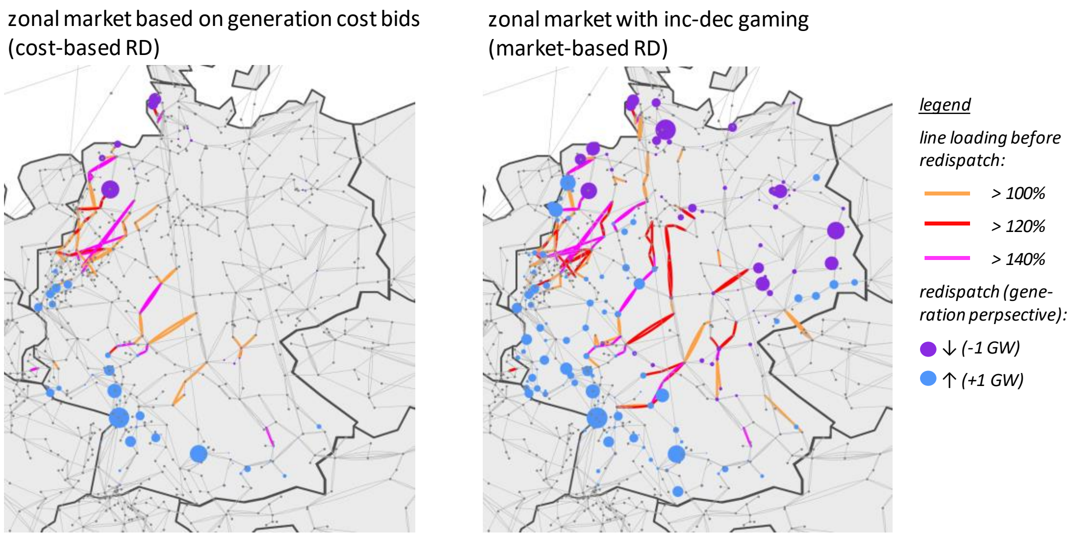

Figure 9: Line loading in the German transmission grid before redispatch and necessary redispatch for solving congestion for an exemplary hour

On the one hand, the clear increase in congestion is obvious: Not only is the number of overloaded transmission lines increasing (in the picture on the right, significantly more lines are colored, which marks a load higher than 100 % in the (n-1) -contingency calculations). The lines already congested in the base case (left) are also more heavily congested (shown by the changed coloration in the right picture, cf. color scale in the legend). The colored circles represent the necessary redispatch measures. Blue circles indicate an increase in generation (or load reduction), violet circles a decrease in generation (or load increase). The surface area of the circles corresponds to the amount of redispatch (in terms of MW). For reasons of reducing complexity of the figure, redispatch measures carried out outside Germany are not shown; however, they are taking place. It can clearly be seen that the amount of the redispatch is increasing significantly. Expressed in figures, the redispatch volume increases from 19 GWh to 56 GWh (factor 3) in this hour. Costs increase from EUR 506,000 to EUR 2,079,000 (factor 4).

Risk aversion reduces the impact, but the impact of inc-dec gaming is still very significant. The analyses presented so far have assumed that network congestion and local market prices are perfectly predictable by the market players. The application of inc-dec gaming is then risk-free for the players. Even if, as explained above, we assume that such a forecast would be possible with sufficient accuracy in view of a transmission grid with structural congestion such as the one in Germany, it cannot be assumed in reality that it is perfectly possible to anticipate. Players then run a risk of loss through inc-dec gaming. In the stylized example from above, for example, the diesel power plants in the north run the risk of underestimating the local price. The actual local price could then be higher than the expected price, possibly even higher than the zonal market price. The player would then not make a profit from the difference between the local price and the zonal price, but would have to buy back the energy sold at the zonal price at the unexpectedly higher local price.

Sensitivity analysis. In an additional analysis, we have examined the impact of risk aversion in the application of inc-dec gaming on the impact of these strategies. For this analysis, we have assumed that players only apply inc-dec gaming if the expected LMP has a specified required minimum deviation from the zonal market price. The following diagram shows how redispatch volume and costs in the case of "risk-averse inc-dec" compare to volume and costs in the base case cost-based redispatch - i.e. without flexible consumers and without inc-dec gaming.

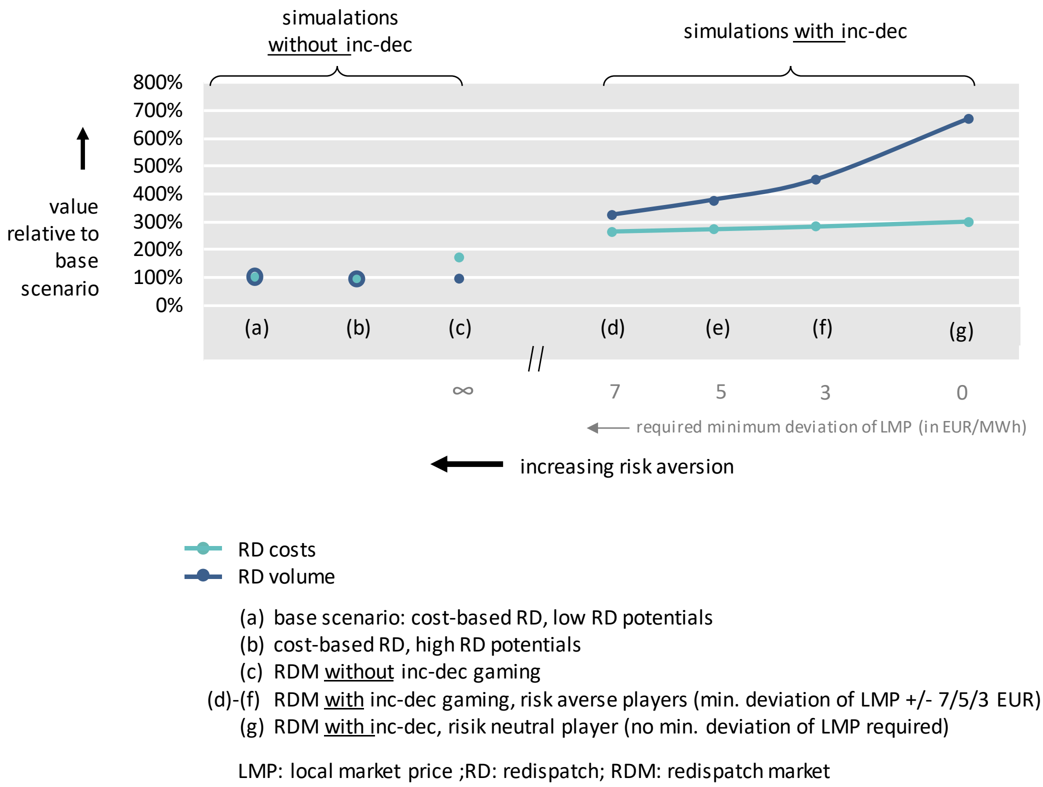

Figure 10: Redispatch volume and costs if inc-dec is only applied by the players that expect a certain minimum deviation of the LMP from the zonal price in the respective hour and at the respective network node; the case without inc-dec gaming corresponds to an "infinitely" high minimum deviation (∞).

This additional analysis show that risk-averse behavior limits the increase in redispatch volume and costs as a result of inc-dec gaming. But even with a comparatively high required "safety margin" of 7 EUR/MWh, the increase in redispatch costs and volumes is still very substantial with a factor of about 3. Redispatch costs decrease significantly less than volumes as the "safety margin" increases. The reason is that due the "safety margin" inc-dec gaming is primarily avoided in situations in which possible rents from inc-dec are rather low, especially in relation to the necessary changes in marketing (volume). Thus, as risk aversion increases, inc-dec is first reduced in situations that have comparatively little impact on overall costs. However, inc-dec strategies will continue to be implemented in the event of high possible extra rents and thus large effects on the redispatch costs. This leads to the different curves of the volume and cost curves.

In addition, the figure shows that the introduction of a redispatch market generally leads to a rent shift towards the players redispatched. This leads to an increase in redispatch costs. This is due to the fact that "price discrimination" between redispatched units is not possible in a redispatch market, unlike in cost-based redispatch. In cost-based redispatch, price discrimination occurs as a result of the fact that each redispatch power plant is paid its individual cost. Two power plants would therefore be remunerated differently, even if they are located at the same node. In a redispatch market, settlement is based on nodal prices. As a result, power plants that are located “ahead of the congestion” only pay the lower nodal price to the TSO instead of their marginal costs. Conversely, the TSO pays power plants located "behind” the congested line a nodal price that is higher than the marginal cost (windfall profits).

2.7 LEGAL ASSESSMENT

Competition law. Competition law firstly prohibits agreements between firms and collusive practices which aim at or result in the prevention, distortion or restriction of competition (prohibition of cartels, Art. 101 TFEU, § 1 GWB). Secondly, dominant firms are prohibited from abusing their market position in their favor (prohibition of market power abuse, Art. 102 TFEU, §§ 19, 29 GWB). However, the implementation of inc-dec strategies does not require collusion between companies, but can also be operated by a single market player and therefore the prohibition of cartels is not relevant. It should also be noted that this strategy does not require market power, but can be implemented by an atomistically small player. All market players behave in a competitive manner, so the prohibition of abuse is not relevant either. Regardless of this, it is of course possible for individual companies to hold a (regional) dominant position on the redispatch market and to abuse it. The abusiveness lies in the pricing-in (on the zonal electricity market) of opportunity costs from the redispatch market, which have been raised by the exploitation of market power market on to the redispatch market. At this point, however, the key point is another, namely that inc-dec bidding strategies can also be implemented without violating competition law.

Pricing in opportunity costs. Although market players in the inc-dec strategy deviate with their electricity market bids from their pure generation costs (or loads from their pure willingness to pay for electricity), this can be fully explained by the fact that they price in the opportunity costs arising from the redispatch market and that generation costs plus opportunity costs represent the marginal costs of the plant. This can be clearly seen in the model in Section 2.2 from the example of gas-fired power plants in the south. These bid EUR 60 per MWh on the electricity market, not because this corresponds to their own physical generation costs, but because they are the revenue opportunities on the subsequent redispatch market - i.e. opportunity costs. This is comparable to the pricing of opportunity costs on the balancing energy market: a hypothetical power plant, which expects EUR 100 per MWh for a four-hour commitment period from the provision of positive balancing power and work, will not be prepared to market its power for this period on the electricity market at a lower price. This behavior is common and generally accepted. In 2009, the German Federal Cartel Office (Bundeskartellamt) clarified in the proceedings against *RWE* and *E.ON in* connection with the pricing in of emission certificates allocated free of charge that the pricing in of opportunity costs is generally in line with competition law. Thus, an infringement of the prohibition of abuse would only be observed if (in addition to the existence of market power) the opportunity from the redispatch market were raised even further by the exercise of market power, and then priced into the electricity market bids. Inc-dec bidding strategies that work without the use of market power are not subject to competition law objections. A more detailed legal evaluation of inc-dec bidding strategies conducted as part of this project by Stiftung Umweltenergierecht (2019) can be found in the accompanying material to this project.

Balancing responsibility. Inc-dec bids are also possible if balancing obligations (of balancing responsible parties, BRPs) are maintained, as is the case in all examples shown above. This means that no balancing responsibilities are violated. If redispatch markets are designed in such a way that schedules can be submitted which are not physically or commercially covered and which can still be changed at a later stage, this allows for even lower-risk variants of inc-dec for the actor - but for the purposes of this study we only consider variants of inc-dec which are covered by trading transactions without breaching balancing obligations.

Inc-dec is legal. Since inc-dec bids can be carried out without breaching competition law and balancing responsibility, they are legal under the current legal situation. In other words, even if inc-dec bids were identified, they cannot not be sanctioned at the moment in the form described above. Although inc-dec bids are not illegal today, a corresponding regulation of bids would at least theoretically be conceivable; we will discuss this in the following.

2.8 REGULATORY CONTAINMENT OF INC-DEC

Four approaches. We have come to the conclusion that a containment of the newly created incentive system is hardly possible in a sensible way - at least not without significantly limiting the hoped-for benefits of redispatch markets. We would like to explain this in the following. In essence, four approaches to preventing inc-dec incentives are proposed in the discussion:

- Making it more difficult to anticipate congestion
- Limiting the redispatch market to loads and keeping the existing redispatch as a fallback option
- Regulating bids on the redispatch market
- Regulating bids on the electricity market

Making anticipation more difficult. To price in the opportunity from the redispatch market (inc-dec), it is necessary to anticipate network congestion. Schuster et al. (2019) propose to prevent strategic behavior by "limiting the available technical information on network congestion" (p. 78). Even if this were possible - obligations under European law such as the

Transparency Directive speak against it - market players have the opportunity to improve their forecasting models at every redispatch call-up. The most important variables to forecast congestion in Germany are also public anyway, namely wind and solar infeed as well as temperature to estimate load. Such data can therefore not be restricted anyway. Moreover, transparency has its purpose, for example in preventing insider trading and market manipulation. If it were possible to create complete uncertainty about future network congestion, redispatch markets would also have no investment effect whatsoever. We therefore do not consider the restriction of information to be a sensible strategy to contain inc-dec bids.

Limitation to loads. Many proposals envisage retaining the mandatory cost-based redispatch for power plants and additionally introducing a voluntary flex market only for loads. The current cost-based redispatch thus remains as a fallback option. This would mitigate the consequences of inc-dec by excluding a large number of producers from the market (those which would stay in the cost-based redispatch). The fallback option could also cap prices and thus mitigate incentives. However, the market design would continue to provide incentives for congestion-exacerbating behavior with regard to the loads still subject to the voluntary market redispatch. In addition, it is difficult to justify a restriction to certain groups of actors and it is not easy to distinguish between them, for example in the case of industrial own production. We consider a redispatch market only for loads to be less harmful than a general one, but also see inc-dec as a fundamental problem here.

Regulation of RDM bids. Although inc-dec bids are not illegal today, a corresponding regulation of bids would at least theoretically be conceivable. In principle, two variants of such regulation are possible. One option would be to regulate the redispatch market to such an extent that no profit opportunities arise from it and to leave the electricity market unregulated instead. Such a regulation of the redispatch market would be conceivable via a pay-as-bid remuneration in conjunction with the obligation to always bid at marginal cost there so that no contribution margins are generated. We do not consider this approach to be very promising because it is difficult to check this requirement for loads, where the fundamental problem is that it is hard to estimate the true willingness to pay. Furthermore, this regulation, if successful, would prevent all rents and thus also incentives and would in fact be a return to cost-based redispatch.

Regulation of electricity market bids. Another possibility for regulation would be an obligation to require all electricity market participants to bid their own generation costs or willingness to pay on the electricity market - or to register schedules, which would result on the basis of generation cost bids/willingness to pay on the electricity market, and forbidding market participants to include opportunity costs from the redispatch market in such bids. However, this too is likely to be difficult to monitor, especially in the case of loads. Considerations on the introduction of a redispatch market are based, among other things, on the recognition that a regulated determination of the flexibility costs of loads is hardly possible. In addition, bids on the electricity market are currently portfolio bids which do not distinguish between individual power plants, making monitoring even more difficult.

Economically questionable. Even if bid monitoring were successful, it would have questionable economic consequences. In particular, cheap generators - who are already in the money on the electricity market - would be denied a local rent, while more expensive generators - who are out of the money on the electricity market - are likely to generate a local rent. This becomes clear in the case of the gas-fired power plants in the south from the model in Section 2.2. In the case of perfect regulation, power plants whose generation costs are higher than the price on the electricity market are likely to participate in the redispatch market and generate contribution margins there. Power stations with lower generation costs on the same site would be prohibited from doing so and would therefore not be entitled to the local rent. Ultimately, such an approach would treat installations differently depending on whether their short-term generation costs on the electricity market are already covered or not. This would result in perverse incentives, e.g. with regard to investments in congestion areas: There would be an incentive to invest more into generators with high generation costs. Economically and legally, such discrimination is difficult to justify. Therefore, the detection and sanctioning of inc-dec bids seems questionable.

Containment also means reducing benefits. Most approaches to curbing inc-dec incentives aim at reducing rents in order to reduce incentives for congestion-aggravating behavior. But this also undermines the fundamental idea of market-based redispatch, which is supposed to generate incentives: Without contribution margins, there is no incentive to participate in the redispatch market. Effectively one would then have returned to cost-based redispatch of today. This is also made clear by an example. Suppose an investment in storage is lucrative on the basis of high redispatch prices. In operation, however, the storage facility is already "in the money" on the electricity market. If the storage facility were now prevented from earning the higher rent on the redispatch market, since it is already "in the money" on the electricity market, it would not be able to refinance its investment. In anticipation of this, it would never be built.

All market forms are affected. In work package 4 of the project (Connect Energy Economics 2018), alternative forms of market-based redispatch were presented, such as procurement via a separate platform, the intraday market or the balancing energy market. In principle, these can be classified along the "regulation - market" axis (Figure 11). The more market-based the procurement is, i.e. the less regulated redispatch bids are, the more the benefits in terms of incentive effect become apparent. At the same time, however, the incentive for inc-dec strategies is also increasing. These are independent of the concrete design form or procurement platform.

Inc-dec difficult to identify even ex-post. One suggestion in the discussion is to introduce redispatch markets step-by-step and empirically observe the inc-dec strategies that arise in the process. This is not feasible, as even ex post identification of such strategies is difficult and usually not possible without any doubt.

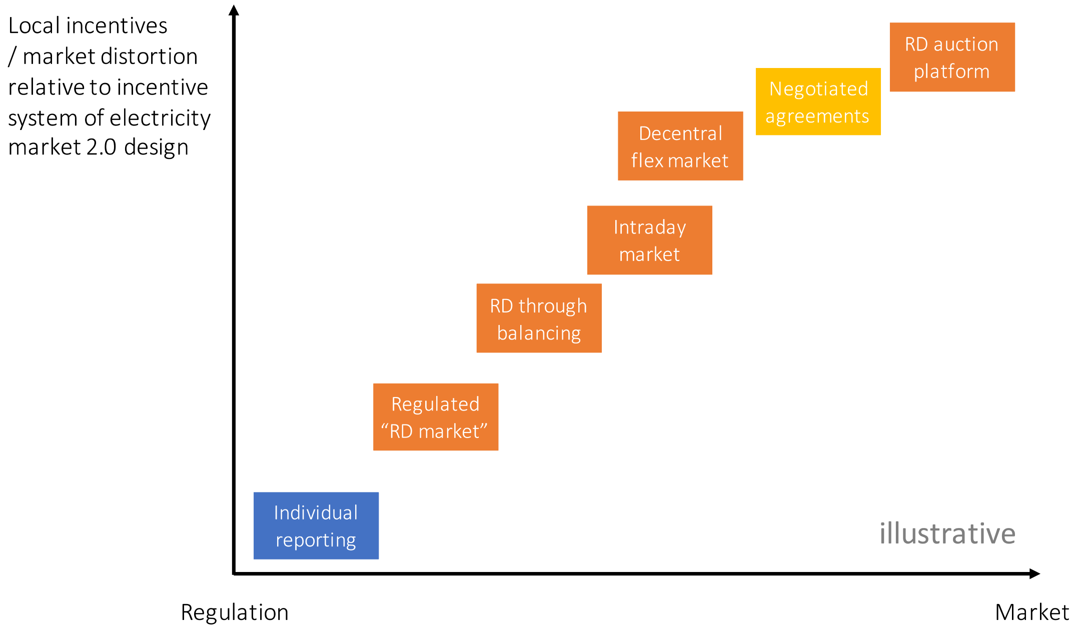

Figure 11: Different concepts for the competitive procurement of redispatch
Source: Connect Energy Economics (2018)

2.9 Scientific literature and historical examples

Theoretical literature. In the (game) theoretical economic literature strategic bids for profit maximization on a redispatch market embedded in a zonal electricity market are called "increase-decrease game" or "inc-dec gaming", where gaming relates to game theory. In addition to the fundamental works of Harvey and Hogan (2000a, 2000b), the more recent contributions of Pär Holmberg with various co-authors (Holmberg & Lazarczyk 2015, Hesamzadeh et al. 2018, Sarfati et al. 2018) particularly noteworthy. Based on different analytical and numerical models, these come to similar conclusions as we do. In addition, there is extensive literature on specific historical cases of inc-dec strategies, such as those that occurred in the USA in the former zonal markets of California (CAISO), New England (ISO-NE), Texas (ERCOT) or PJM. The examples became particularly well-known in California and Great Britain.

California. The Californian electricity market was liberalized in 1996-98. A zonal wholesale market with two bidding zones was introduced. Network congestion within the zones were resolved with the help of market-based redispatch (under a different name). As a consequence, market players applied inc-dec bidding strategies on a large scale, including energy trader Enron, who was later involved in various fraud scandals. Back in 1999, the Federal Energy Regulatory Commission (FERC) warned that "the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced". In the years 2000 and 2001 the state experienced a serious energy crisis with large-scale power outages. The reasons for this are complex, but strategic bidding contributed to the crisis. For example, producers exploited the so-called "Miguel Constraint" in southern California and generated additional monthly profits of approximately USD 3-4 million through inc-dec strategies (Hobbs

2009, Neuhoff et al. 2011). As a consequence, California introduced Nodal Pricing in 2009. Comparable experience, albeit without major supply crises, had already prompted the states in New England to introduce nodal pricing. The strategic bidding of market players was a major reason for the introduction of a nodal electricity market in California and other North American electricity markets. The Californian case is documented in Hogan (1999), Harvey & Hogan (2001), Alaywan et al. (2004), Brunekreeft et al. (2005) und CAISO (2005).

Great Britain. Between England and Scotland in the course of the 2000s increasing grid congestion appeared, among other things, due to the expansion of wind energy in the north; an important grid congestion is known as the "Cheviot Boundary". In Great Britain, grid congestion is primarily solved within the framework of the Balancing Mechanism, a mechanism for joint procurement of balancing energy and redispatch in competitive auctions on the basis of pay-as-bid settlement rules. Around 2010, inc-dec strategies appeared on a larger scale. UK regulator Ofgem estimated the cost of inc-dec strategies and the use of market power to be up to GBP 125 million in 2010. In particular, operators of Scottish coal-fired and gas-fired power plants were suspected of deliberately forcing grid congestion through strategic bids on the day-ahead market in order to exploit them in the balancing mechanism. But also the revenues of Scottish wind power operators within the Balancing Mechanism from successful bids to reduce their generation in some cases significantly exceeded the lost revenues from originally planned electricity sales. Ofgem responded to this circumstance by introducing the Transmission Constraint License Condition (TCLC) in 2012, which prohibits "excessive" bids. The legal basis for this has already been laid down in the Energy Act (2010). The introduction of TCLC had a significant impact on the balancing mechanism. After the introduction of regulation, for example, the average bids of wind power operators to reduce their generation between 2012 and 2016 decreased by about 70 % (Ofgem 2016). This effect cannot, however, be attributed exclusively to the introduction of TCLC. Other circumstances such as increased competition, closure of thermal power plants in the congestion region (export congestion), grid expansion and improvements in system management will also have had an impact. Compliance with TCLC is monitored by Ofgem and there is a risk of severe penalties for non-compliance. Since the introduction of that regulation, however, only one infringement has been punished. In 2014, a Scottish hydro operator was unable to justify her bids under the Balancing Mechanism to reduce generation. Due to its positive effect, but also due to delays in network expansion, the regulation has been extended several times since then and is still in force today for an indefinite period. In our understanding, regulation in fact forces the bidder to bid her own marginal costs plus a small surcharge and is therefore quite similar to cost-based redispatch. Ofgem (2009, 2012, 2016, 2018) und Konstantinidis & Strbac (2015) document the case.

Interconnector Denmark-Germany. Another example of a congestion management arrangement that in principle yields inc-dec incentives can be found at the Danish-German border. In 2017, both countries agreed on a minimum trading capacity that would increase over time, which was further increased by Tennet's commitment to the European Commission in 2018. In order to avoid physical congestion of the network, it was agreed that TSOs would counterbalance trade flows by counter-trading where necessary. While TenneT uses the continuous intraday market (usually for up-ramping), EnerginetDK (usually for down-ramping) uses bids from the Nordic balancing market within the framework of Special Regulation, whereby individual bids for congestion management outside the merit order are called up and remunerated at the bid price (pay-as-bid). This offers incentives for Danish loads not to cover their electricity needs on the day-ahead market but to wait for a more favorable price in the Special Regulation of the balancing energy market. Such "demand restraint" would exacerbate congestion; it is nothing else than an inc-dec strategy. In the current monitoring report on the agreement (EnerginetDK & TenneT 2019), the TSOs involved confirm that such behavior occurs and that some market players buy significantly less electricity on the day-ahead market than they need in some hours of Special Regulation. However, this behavior is not consistent and systematic as it is difficult to predict congestion with certainty. At the same time, however, the TSOs also stress that they have no way of investigating whether production units have also implemented an analogous strategy (oversupply on the day-ahead market and ramping-down production through Special Regulation). From our point of view, the experience with this single interconnector cannot be generalized. The implementation of inc-dec strategies requires investments in analysis and forecasting capabilities. It is quite possible that this is not worthwhile if the expected profits are insignificant due to the small market size. In a large market such as a nationwide market-based redispatch, the majority of market players are likely to pursue inc-dec strategies. At the same time, the German-Danish example seems to confirm that predictability is crucial to the emergence of inc-dec strategies.

3 Market power

Regardless of and in addition to incentives for inc-dec gaming, redispatch markets may be subject to (local) market power. The considerations in section 3.1 illustrate by means of a simple example that in nodal markets there is in principle a higher market concentration, since the location of units plays a significant role in this. We also used our simulation models to examine the potential for market power abuse by assessing the owner structure of modelled units and then quantifying their potential to exercise market power. The simulation approach is explained in detail in Section 3.2. The results are also presented and explained there.

3.1 Market power and redispatch markets

What's meant. By market power we mean situations in which players can behave to a significant extent independently of their competitors. In the event of high market concentration, they are given the opportunity to raise market prices above the competitive level, e.g. through withholding capacity or price mark-ups. Whether market power is actually exercised depends on other factors, including how strong the incentive to exercise market power is, in particular the extent to which they could increase their profits by exercising market power.

Competition control. Competition control can restrict the exercise of market power. However, this is always associated at least with expenditure and in practice usually not completely possible. In this respect, a low market concentration already represents a "value in itself".

Measuring market power and market concentration. Measuring market concentration is not a new task and not limited to electricity markets. Competition authorities are addressing the issue of appropriate methods for measuring market concentration in a wide variety of markets. Therefore, different indicators to measure market concentration are established. These include the Herfindahl-Hirschman Index (HHI), which is calculated on the basis of the market shares of the players active in the market, and various indicators such as the *Pivotal Supplier Index* (PSI) or the *Residual Supplier Index* (RSI), which are intended to measure how necessary a particular player is to satisfy market demand. The German competition authority Bundeskartellamt has dealt extensively with such and other indicators, e.g. in the sector inquiry on electricity generation and electricity wholesale markets. In addition to the indicators that are particularly relevant in competition supervision, game theoretical models also play a role, for example so-called agent-based simulation models which attempt to explicitly model actor structures and strategies for exercising market power.

Fundamental challenges in nodal electricity markets. Market power is a particular challenge in nodal electricity markets, of which redispatch markets are one form. On the one hand, measuring market concentration is challenging as the definition of the relevant market is highly dynamic over time and not unambiguous. At the same time, the strategies for exercising market power in nodal markets are often more complex than in zonal markets. On the other hand, market power is a particularly relevant issue here, since - depending on the network situation/constellation - the relevant market is comparatively small and therefore also smaller players can achieve a high market power potential.

Market definition in nodal markets. It is obvious that a single node - i.e. the comparison of the generation and load located a particular node - is not a suitable market definition. Units at other nodes can usually also cover the load at one node and are therefore competitors for the units at that node. However, in a meshed transmission grid, there are close interactions. For example, units at two different nodes may not be able to compete with their full capacity with the considered unit at the same time because the available transport capacity to the considered node is limited. Related to redispatch markets a very fundamental question also arises: Which market to cover which demand is considered? Typically, in the context of electricity markets, it is a market where generators offer capacity to cover a consumption load.[14] In redispatch markets, however, a different view of "demand" is also conceivable, namely that of the network operator's demand for available capacity to resolve congestion. This obviously at least influences the application of concentration measures.

Systematically higher market power potential in redispatch markets. In redispatch markets, the market power potential is systematically higher than in zonal markets for various reasons. One reason for the systematically higher market power potential is the fact that the network operator's demand for capacity that can solve congestion is completely price-inelastic in contrast to the demand for electricity on the electricity market. While in electricity market analysis often price-inelastic demand is assumed, the demand in fact actually is increasingly price-elastic, at least in the case of significant price fluctuations / price spikes. This limits the incentives to exercise market power. In fulfilling its system responsibility, however, the network operator has no choice but to satisfy its demand for congestion-relieving capacity completely with the capacities offered to it in the event of a congestion. It is not possible for the network operator to adjust its demand if suppliers charge very high prices for their capacity.[15]

Another reason for the systematically higher market power potential is the fact that, although for a certain congestion, a large number of suppliers can often offer capacity that can solve the congestion, it isa characteristic of meshed grids that a unit’s sensitivity on a congestions, i. e. the effectiveness to solve a congestion, to a large extent depends on its exact locations in the network, i.e. on its network connection point and its relative position to the overloaded line. In general it can said, that the closer a unit is located to the overloaded line, the greater its potential to solve the congestion.

In AC-networks this is described by the so-called load flow sensitivity. The load flow sensitivity indicates how the flow on a given line changes in relation to the change in feed-in at a given node. The load flow sensitivity ranges between +100 % and -100 %. A value of +50 % means,

[14] Already here, new questions will arise in the future, since the consumption load can no longer be assumed to be fixed in view of the increasing activation of load flexibilities, as is often still the case today with the application of market concentration measures.

[15] Onlyif the offered capacity is too little, the network operator has further possibilities to intervene.

for example, that for a 1 MW reduction in the load on a line, the feed-in at the respective node must be reduced by 2 MW. The load flow sensitivity is a system property that depends only on the network topology and the electrical properties of the network as well as the location of nodes and lines under consideration.

As an example, the following figure shows the load flow sensitivities for five power plants larger than 100 MW, which have the highest sensitivity for solving the congestion of a particular line representing a typical congestion in the recent past in the German transmission grid (line Gießen Nord - Großkrotzenburg, markes with a red circle in the figure).

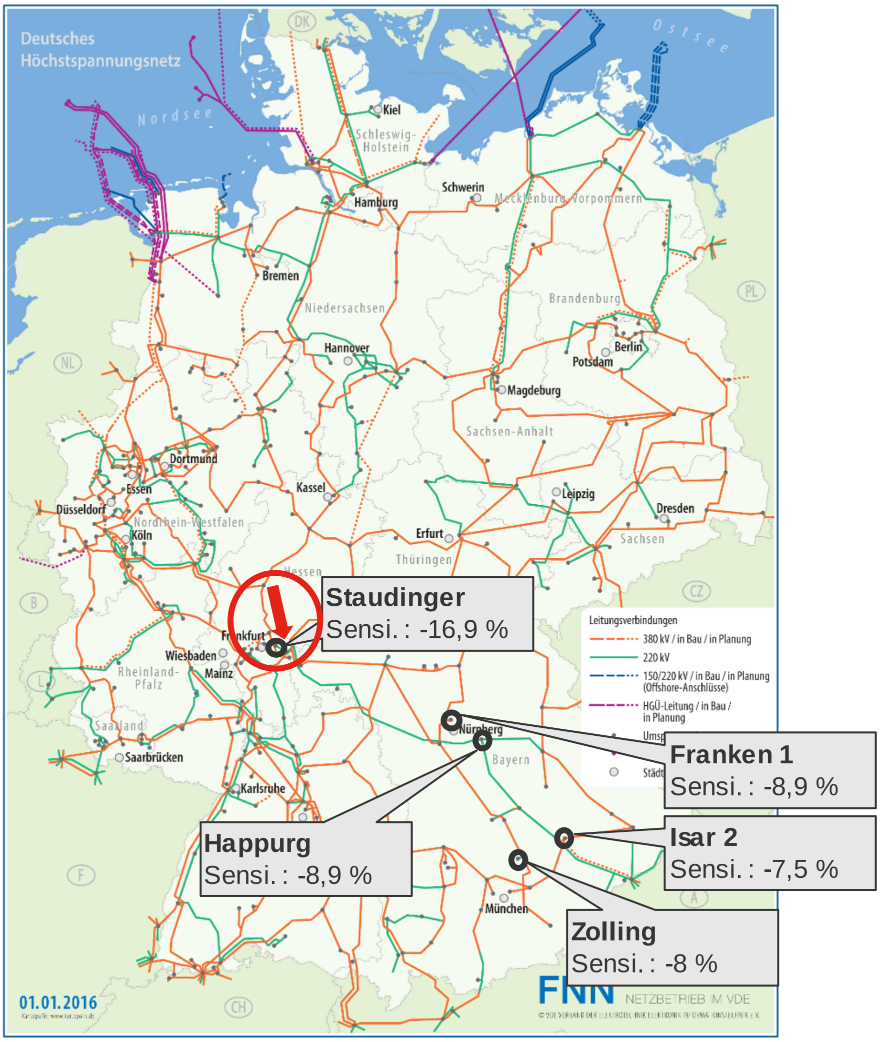

Figure 12: Load flow sensitivity of the five most sensitive power plant for the line Giessen/Nord - Großkrotzenburg; the line is a congestion in the German transmission grid typical today

The power plant “Staudinger” has a sensitivity of -17 %, i.e. an increase in output of the power plant of 1 MW leads to a 0.17 MW reduction in the load on the congested line. Conversely, this means that a relief of 1 MW requires an increase in output of 5.9 MW at the Staudings plant. The second most effective power plants (Happurg and Franken 1) already have almost half the sensitivity. A relief of 1 MW for the line would already require an increase in capacity of 11.1 MW. The fifth most effective power plant would require an increase in output of 13.3

MW in order to achieve a comparable effect in terms of congestion relief. Even among the five most effective power plants, the load flow sensitivity already varies by a factor of 2. Other power plants at other network nodes have significantly lower load flow sensitivities. What is remarkable is the fact that in this case the three most effective power plants are also completely or at least partly owned by the same owner, Uniper SE in this case. This leads to a significant increase in market concentration, as the possibilities for meeting the network operator's demand vary greatly from location to location. For this reason, power plants with a "favorable" location to the congestion (high sensitivity) are in effective competition with only a few power plants at other nodes.

3.2 Quantitative analyses

Aim of the analyses. As explained, measuring market concentration in nodal markets is a particular challenge. However, the task of this project is not to develop exact indicators for determining the market concentration in redispatch markets - this is necessary when such markets are actually introduced, but has not yet been conclusively resolved either in practice or in academic literature. The aim is rather an quantitative classification based on an empirical basis of the extent to which redispatch markets lead to a high market concentration compared to the status quo and incentives to exercise market power.

The Potential to change nodal prices. Since this project is not concerned with the development of exact market concentration measures, we have developed an indicator that is only relevant for our simualtions, but is comparatively easy to implement and suitable for showing the market power potential in redispatch markets. As an indicator we measure the ability of market players to influence nodal prices. The developed indicator is based on the observation that strategies of the market players - insofar as they are concerned with the exercise of market power - are aimed in particular at influencing nodal prices in a manner favorable to their own profits. This can be done in two ways:

1. Increase local prices through withholding capacity or price mark-ups in order to increase the contribution margin from the marketing of energy at the local price or revenues from flexibility "behind the congestion" to relieve the congestion. A power plant "behind the congestion" (i. e. in a scarcity region) solves the congestion if it increases its output, and thus receives a payment from the network operator on the redispatch market at the local market price for the increased output. This strategy also occurs in nodal pricing systems.

2. Reduce local prices by expanding supply or underbidding in order to increase revenues from flexibility that solves a congestion "ahead the congestion". A power plant "ahead of the congestion" has a positive effect on the congestion when it reduces its output. It pays the network operator a price equal to the local price for the reduction. It is advantageous for this player if the local price is as low as possible in this case. This strategy is a specific feature of redispatch markets.

These strategies can also be interpreted as follows: Market players have - in addition to inc-dec gaming - have an interest in behavior that reinforces congestion.

Simulationapproach. The following illustration shows the methodological implemented in this project for the investigations on market power.

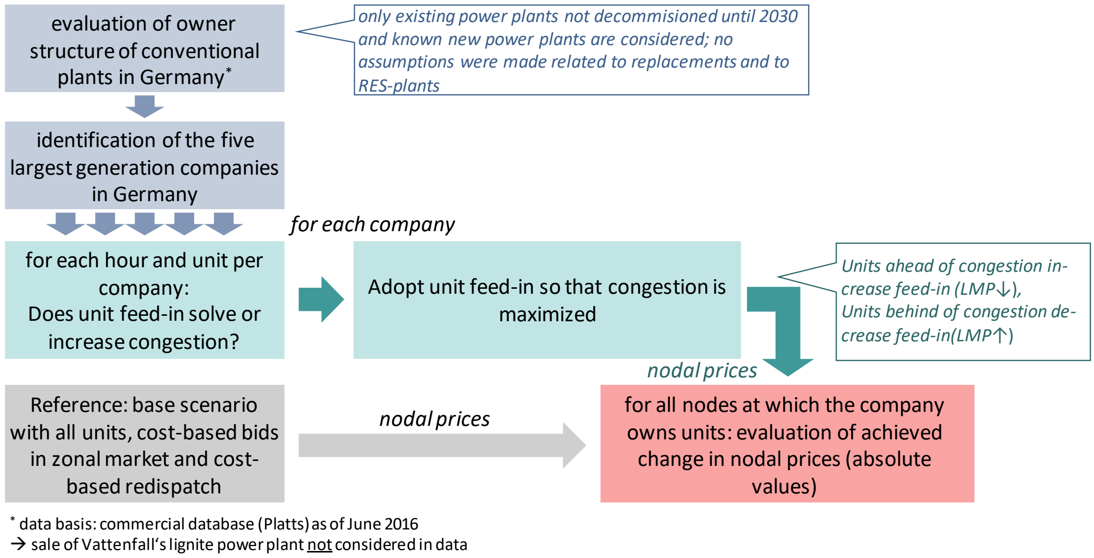

Figure 13: Overview of the simulation approach used for quantitative analyses on market power incentives in redispatch markets

The analyses were applied to the scenario already used section 2.6. The analysis was carried out as an example for the five largest generation companies in Germany for the scenario year 2030.

We evaluated data from a commercial database on the ownership structure of conventional power plants in Germany. Only existing power plants not decommissioned by 2030 or known new power plants were considered. This way, the five largest generation companies in Germany according to this definition were identified for the year under review, 2030 (see Figure 14).

For each of the five companies, the following strategy was implemented and its impact analyzed. For each hour and each power plant of the company, it is first checked on the basis of the base scenario (bids based on marginal generation costs in the zonal market, no exercise of market power, cost-based redispatch) whether the power plant feed-in increases or decreases a congestion. Then the feed-in of the power plants in the redispatch market (!) is changed in such a way that it has a maximum effect an increasing congestion - and thus with respect to local market prices, a maximum impact in a positive direction from the point of view of the company. A power plant ahead of the congestion would increase its feed-in (and thus maximally lower the local price), a power plant behind the congestion would withhold its output (and thus maximize the local market price). Considering this change in the feed-in of the considered companies' units nodal prices are then determined again and compared with the nodal prices from the base scenario.

In this way, we can determine for each company which maximum change in the nodal prices they can achieve in their favor by adjusting capacity in the redispatch market. The achieved change in nodal prices is weighted with the generation capacity of the respective company at the respective node. This can be interpreted as an indicator of the company's incentive to exercise market power. It should be noted that the modelled strategy of maximizing the congestion exaggerates the effect of the exercise of market power, since the company itself could no longer benefit from the strategy with this strategy. If the company has held back/increased its capacity on the redispatch market to the maximum, it would then have changed the price in a positive direction at most, but it would no longer be able to market capacity at this price. The optimal quantity adjustment from the point of view of the company is therefore smaller than the maximum adjustment quantity. The selected maximum quantity, however, represents a clearly defined point that makes it possible to carry out comparative observations without having to use very complex, game theoretical agent-based models to illustrate the strategies. The selected indicator of the capacity-weighted nodal price change also reflects an agent-related perspective and expresses the incentives for the exercise of market power from the company's perspective. This does not allow any direct conclusions to be drawn as to which efficiency losses and rent shifts would result from the exercise of market power. However, this is not the aim of the investigations in this section either.

Results. The following figure shows the result of the evaluation of the ownership structure according to the assumed development of the conventional generation capacity for the year 2030 in Germany. The largest company (here referred to as "A") has a generation capacity of a good 7.5 GW, or 15 % of the total installed conventional generation capacity, while the fifth largest player "E" has a share of around 3 % with less than 2 GW.

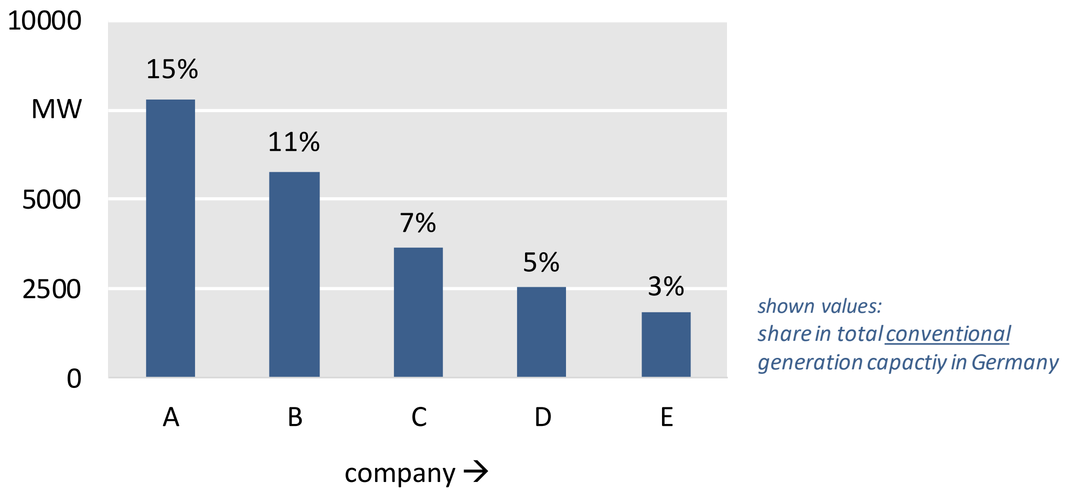

Figure 14: Generation capacity of the five largest generation companies in Germany in the year under review 2030

The result of modelling the congestion maximizing bidding strategy as described above is shown in Figure 15. The change in nodal prices that can be achieved by the different companies on average over the year and the minimum nodal price change achieved in 500 or 100 hours are shown. The grey bars in the background indicate that in a few hours (< 100) even higher nodal price changes are possible. However, we deliberately refrained from showing the maximum, since this - due to its dependence on the network nodes under consideration - does not represent a stable value.

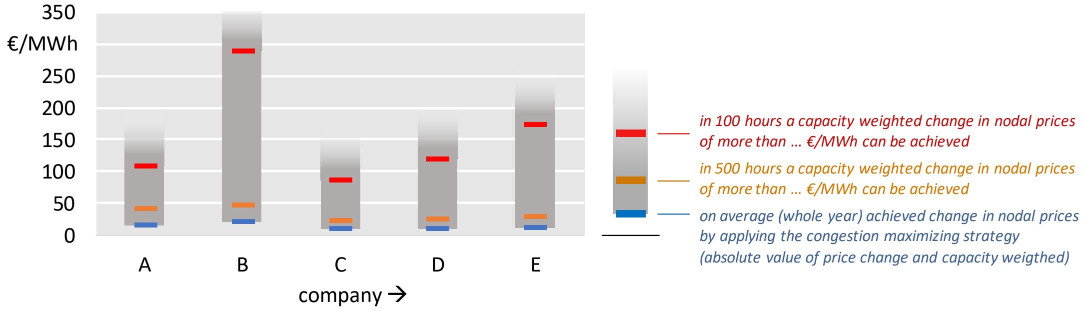

Figure 15: Achievable change of nodal prices for the benefit of the companies through capacity adjustment in redispatch markets

It is shown that, on average, the companies can achieve changes in nodal prices in the order of 15 to 20 EUR/MWh. However, it should be emphasized that they can bring about a very large price change (up to 50 EUR/MWh or 300 EUR/MWh) in a smaller number of hours (500 or 100). This suggests that there are very strong incentives to exercise market power during these hours, which are likely to be characterized by a particularly high congestion in the transmission grid..

In order to be a better grasp for the magnitudes of the numerical values, a "reference" was also determined. For this purpose we evaluated the maximum price change the companies could achieve without a redispatch market, i.e. if they applied a strategy of maximum capacity withholding on the zonal market. We have also simulated such a strategy and calculated the resulting change in zonal prices according to the same scheme. The following figure additionally shows the minimum change in the zonal price achieved in 500 hours due to a maximum withholding of capacity by the company.

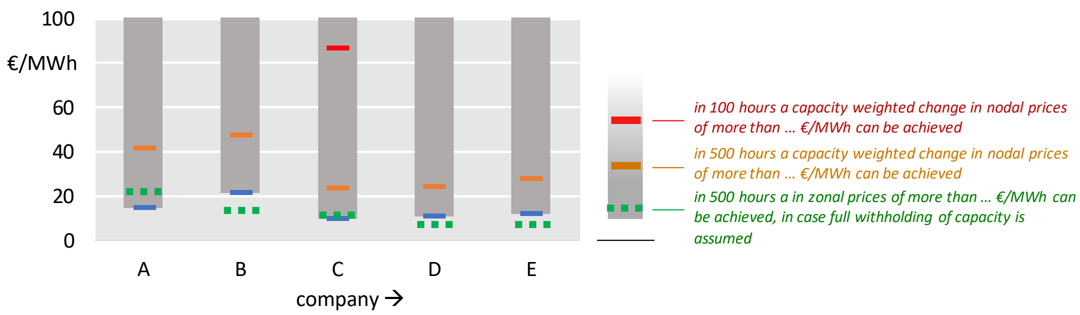

Figure 16: Maximum achievable change of the zonal price compared to the maximum achievable change in nodal prices in case of a redispatch market.

This comparison allows a better “feeling” for the determined numbers. In comparison, this analysis shows that the incentive to exercise market power in redispatch markets is obviously significantly higher than in a zonal market: The same company can use a comparable strategy (maximum capacity adjustment) to change the prices in the redispatch market relevant to its revenues many times (factor 2 to 4) more strongly in a positive direction than in the zonal market. By way of illustration, company B is considered. It can achieve an increase in the zonal market price of at least 14 EUR/MWh in 500 hours by fully withholding capacity on the zonal market. If a redispatch market were introduced, its strategy would not be based on the zonal market price but on the local market price. Our simulation shows that, based on the local market price at the location of his power plants, he can achieve a price change of more than 47 EUR/MWh instead of a price change of 14 EUR/MWh through a strategy of capacity adjustment. This makes it clear that from the point of view of the same company with the same strategy (capacity adjustment), the potential to influence prices - and thus the incentive to do so - can increase significantly through the introduction of a redispatch market. The reason for this is that, depending on the location of the power plants, in particular in relation to the grid congestion, the competition to which the player is exposed changes significantly: If, in the zonal market, it is still in full competition with all other producers in the bidding zone and limited competition with producers in neighboring zones (due to limited cross-border trading capacity), competition in the redispatch market is significantly restricted, since the possibilities for solving congestion are very strongly dependent on location (see the explanations in Section 3.1 on the basis of a Figure 12).

4 Market-based redispatch: Conclusions

This chapter weighs the advantages and disadvantages of market-based redispatch. Among the advantages, the integration of loads into redispatch stands out. In addition to the aforementioned disadvantages of inc-dec strategies and market power, perverse investment signals must also be mentioned. Finally, we discuss specificities of redispatch in distribution networks and discuss redispatch on the basis of capacity payments instead of energy payments.

4.1 Advantages

Participation incentives. In contrast to cost-based redispatch, market-based redispatch enables participants to generate positive contribution margins from redispatch and thus provides an incentive to participate. This is true both in scarcity regions (ramped up power plants not only get their own costs reimbursed, but a price set by the marginal power plant) and in surplus regions (ramped down power plants do not have to surrender their own saved costs completely, but only those of the marginal ramped down power plant). This effect is particularly relevant for the participation of loads in redispatch, since loads could not be integrated into the regulatory redispatch without such voluntary incentives, as regulatory cost determination is hardly possible for them. We consider this to be the fundamental advantage of market-based redispatch.

Investment incentives. The possibility of generating contribution margins in redispatch creates regionally differentiated investment incentives. There is an additional incentive to invest in generation in scarce regions and in loads in surplus regions. This is desirable. Unfortunately, a redispatch market also offers counter-productive, undesirable investment incentives: the additional rents also make generation investments in surplus regions and loads in scarce regions more attractive. Whether such a market as a whole leads to investments that are better or worse distributed for grid purposes than a zonal electricity market without locational steering is unclear.

Quantification of benefits of load integration. In this project, we also examine the benefits of loads as additional potential for eliminating congestion in the transmission grid. The results show that these benefits are rather limited overall. The potential in terms of the maximum available flexible power is probably comparatively high. However, this potential (e.g. from heat pumps or electric mobility that can be used flexibly within certain limits) is on the one hand distributed nationwide and in this respect only a certain proportion of the total output can be used advantageously in terms of network technology. On the other hand, the time availability is also limited and often shorter than the duration of congestion to be remedied, e.g. due to passing wind fronts. Under the assumptions made in the calculations, the savings potential in the regulatory redispatch is just over EUR 60 million in annual redispatch costs. The redispatch volume is reduced by about 1.3 TWh. The results indicate that the benefits of including loads are rather limited to few situations with a particularly high need for redispatch. Our calculations do not allow any conclusions to be drawn about the benefits of load flexibility for eliminating congestion in the distribution networks. A higher benefit is conceivable here on a case-by-case basis. However, to date there is no systematic quantitative investigation for distribution grids.

4.2 Drawbacks

Higher redispatch costs. Even if one assumes that neither inc-dec strategies nor market power occur, market-based redispatch leads to significantly increased redispatch costs. In our simulations of a German redispatch market (see Section 2.5), the redispatch costs would roughly double in a case without inc-dec, since not only the costs are reimbursed, but rents can be earned from the redispatch market. As a result, the costs for redispatch increase. This is the flip side of the participation and investment incentive. Higher redispatch costs are reflected in higher network charges for consumers. If the incentives created were all system-friendly, increased costs could be justified. However, this is not the case, as will be shown below.

Perverse investment incentives. The possibility of generating (additional) contribution margins in redispatch strengthens or creates investment incentives. If the additional contribution margins were only to accrue in the case of system-friendly power plants, these would be sensible and desirable. Even without inc-dec or market power, market-based redispatch, in contrast to nodal pricing systems, however, also creates perverse investment incentives. Speaking in the example from section 2.2: While the increased contribution margins for power plants in the south are useful, as they attract investment in this region, power plants in the north also generate additional contribution margins. This is particularly the case for power plants which, due to their high generation costs, do not generate in the final power plant dispatch because they are ramped-down by redispatch. There is therefore an increased incentive to invest in precisely such unneeded power plants or to delay disinvestments. Inverse (false) investment incentives exist for the choice of location of load entities. Perverse investment incentives occur even if inc-dec is completely prevented by regulation.

Inconsistent market design. As discussed in Chapter 2, market-based redispatch additionally leads to feedback on the zonal electricity market (inc-dec), which leads to an increase in congestion, an increase in redispatch volumes, aggravated perverse investment incentives and windfall profits. Model-based quantification has shown that these effects are significant in their magnitude. Since the inc-dec bids responsible for this are the optimal bidding strategy of rational actors who react to incentives, we regard market-based redispatch in zonal electricity markets as an essentially inconsistent market design.

Market power. As explained in Chapter 3 market-based redispatch is also subject to market power problems. Since a market-based redispatch is necessarily nodal, the market area is small, so there are few actors that can meet the demand for redispatch. Therefore, it can be assumed that market players would either exploit their potential for market power to raise prices above the competitive level or that a stringent control of market power must be implemented. In comparison to nodal pricing systems, market-based redispatch also offers another way of exploiting market power: the possibility of depressing the price on the redispatch market in surplus regions in order to have to pay the network operator less (or even get a payment) when being ramped down.

Interaction of inc-dec strategies and market power. While market power and inc-dec alone separately already represent significant problems of market-based redispatch, there is further problem potential in the combination. The possibility of exploiting local market power on the redispatch market not only increases existing congestion (as part of the inc-dec incentive system), but also increases opportunity costs from the redispatch market through market power, thereby creating new congestion. In addition, the price level on the zonal electricity market would also be influenced by locational market power, since the players would price the expected price level on the redispatch market into their bids on the zonal market as opportunity costs.

Effects on network expansion. Market-based redispatch could also have an impact on network expansion planning, which would potentially remove network expansion from the optimum. However, it is unclear in which direction these effects will go. The significantly increased costs for redispatch could suggest to the network operator and regulator that the expansion requirement is greater than it would be economically optimal. On the other hand, it would also be conceivable that a market-based redispatch would be seen as a sensible alternative to network expansion, thereby reducing the willingness to expand the network.

RES targets. With market-based redispatch, it is no longer possible to regulate the feed-in priority of renewable energies or a switch-off sequence in redispatch, as it is currently envisaged since the amendment of the Network Expansion Acceleration Act, as renewable energies would also bid on the redispatch market with their marginal costs (including lost subsidies). This could make it more difficult to achieve the targets on the share of RES in electricity generation.

4.3 INC-DEC GAMING IN DISTRIBUTION NETWORKS

Theoretical concerns still apply . The findings regarding inc-dec have so far been illustrated primarily with examples from the transmission grid. Nevertheless, the considerations can in principle be applied to congestion in the distribution network as well. The inc-dec incentive problem arises from the inconsistency of the spatial resolution of two market stages. It is irrelevant for the general effects whether the higher spatial resolution of the second market stage (redispatch market or flexibility market) results from grid congestion in the transmission or distribution grid.

Differences between transmission and distribution networks. Even though the general effects and incentive structures are identical, there are differences between transmission and distribution networks with regard to the assessment of market-based congestion management:

The problems of both cost-based and market-based redispatch seem to weigh more heavily in the distribution network.

Integration of load may be more relevant. A considerable part of the expansion requirements and congestion in distribution networks will probably also be load-induced in the future. One of the reasons for this is the expansion of sector coupling, e.g. in the form of e-mobility, whose charging infrastructure has high connected loads / installed capacities. It has already been pointed out in detail that there are considerable difficulties, e.g. due to information asymmetries, in integrating loads into the cost-based dispatch. Obviously, it would just be the grid-friendly dispatch of these "new" loads that would be suitable to avoid the need for network expansion (or to solve congestion) as this expansion demand is primarily caused by them. Their integration into congestion management could therefore be particularly relevant. To the best of our knowledge, however, there is no comprehensive cost-benefit analysis today that goes beyond individual case studies as far as the grid-friendly dispatch of such flexibilities is concerned. We can therefore only assume that the inclusion of loads in congestion management in the distribution network would be more relevant than in the transmission network and that, as a consequence, the problems of doing so in cost-based redispatch would weigh more heavily.

Market power appears to be an even more relevant issue in distribution networks. As in the transmission network, market-based redispatch is also prone to local market power in the distribution network. Market power and collusive behavior of players is likely to be even more critical in distribution networks than in transmission networks. The reason for this is that the influence of individual units on congestion is sometimes significantly higher in distribution grids than in transmission grids due to the less (or not at all) meshed grid structure. At the same time, the number of units that influence congestion is generally much smaller. This also increases the potential for collusive behavior among several players to the detriment of other network customers (higher congestion management costs).

Incomplete unbundling in distribution networks. Another problem is that some distribution system operators are not subject to unbundling rules to the same extent as transmission system operators. Power plant operators could use knowledge about grid congestion from distribution grid operation to generate increased profits from redispatch markets.

4.4 Redispatch based on capacity payments

Idea. Market-based redispatch based on activation payments is subject to inc-dec strategies and market power problems, as shown. Voluntary redispatch based on capacity payments, on the other hand, would at least significantly reduce the incentives for inc-dec strategies. We will briefly outline such a system in the following. Flexible consumers give network operators the right to access existing flexibility on a voluntary basis. The network operator's right of access is limited, e.g. with regard to the number of allowed activations in a certain period of time. The right to activate does not go hand in hand with the requirement to maintain a certain flexibility, the network operator only has the right to use the flexibility if it is available. [16] In return for granting access rights, consumers receive a lump sum payment for capacity, possibly also in the form of a general reduction in network charges. The decisive factor is that the remuneration is independent of the activation of flexibility by the network operator. The amount of the remuneration can be determined ex ante in the sense of an offer ("Who is willing to provide their flexibility at this price?") by the network operator or can also be market-based, e.g. in the form of tenders. This concept could be seen as a further development of the provisions currently laid down in §14a EnWG, particularly in connection with a consideration in the form of reduced network charges.

Intention. The intention of this concept is to integrate loads into congestion management while at the same avoiding inc-dec incentives as far as possible. The latter is achieved by the fact that the remuneration for participation in congestion management is not paid by activation but is fixed in advance. Unlike other instruments discussed in Chapter 5 this instrument primarily aims at providing flexibility for network operators in operational network operation and not at local investments incentives.

Disadvantages and problems. The extent to which this approach avoids inc-dec gaming depends on certain conditions. Incentives for inc-dec gaming are likely to be significantly reduced if the flexibility provider incurs costs when the network operator uses the flexibility. In contrast to inc-dec, the bidder then has no incentive to provoke the activation of their flexibility by the network operator through his bidding behavior, as this only incurs costs for him, but he does not receive any activation-related remuneration. This applies at least from a static point of view. In a dynamic perspective, i.e. in the long term, there could be an incentive to initially increase congestions in order to later increase the network operator's demand for flexibility that solves congestion and thus profit in the future from an increased willingness to pay on the part of the network operator due to higher demand. However, these incentives are likely to decrease significantly, especially in the case of longer contract terms (e.g. in the range of several months), as uncertainties about the success of this strategy increase significantly.

Load reduction vs. load increase. The assumption that the flexibility provider incurs costs as a result of the activation is generally given for load reduction potentials, but not necessarily for potentials to increase the load. If the flexibility offered to the network operator was to increase load, inc-dec would still create incentives: A consumer in the north, whose load has a

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[16] This means that load and generation reduction are particularly suitable for such flexibility products. If activation is carried out rarely enough and if there is a basic incentive to operate the units (in the case of power plants, revenue incentive, in case of loads an incentive to demand electricity, in particular if the offer of flexibility is not possible free of charge, but is linked, for example, to considerable network charges which exceed the flexibility payment), only limited incentives for changes in behavior on the part of the supplier to maximize their own revenues would be to be expected from such a regulation. The question of the availability of flexibility providers for load or generation increases, on the other hand, would be much more difficult to prove. In this respect, a moral hazard problem could exist here in such a way that providers offer flexibility products without actually enabling the fulfilment of requirements.

positive effect on congestion, could have an incentive not to procure at the zonal market in order to have his load increased by the network operator and to have the energy supplied free of charge by the network operator.

Time variable costs. For loads with opportunity costs that are highly time-variable - this is likely to be the case with some industrial loads, for example, depending on the fixed contract term for the flexibility product - this instrument also appears to be unsuitable. If these consumers are not well able to assess ex ante whether the network operator's activation of their flexibility is more likely to take place at times of high or low own costs through load reduction, offering flexibility to them is likely to only be an option in the case of high capacity payments. From the network operator's point of view, the high costs will often exceed the benefits. Alternatively, it is conceivable that flexibility providers could be allowed to reject the activation by the network operation under certain conditions, which in turn could create incentives to offer flexibility that is de facto non-existent.

Evaluation. For a certain part of the load flexibility, this concept appears to be suitable in principle to integrate these loads in congestion management without creating inc-dec incentives at the same time. Which loads actually fall into this segment and which benefits their integration into congestion management could actually have, should therefore be analyzed in more detail, as should the question of which product specification (e.g. with regard to contract terms) inc-dec incentives should be avoided as far as possible. The behavior at negative electricity prices should also be examined more closely.

5 Alternative local incentives

Grid over-investment. A large bidding zone with cost-based redispatch does not provide locational steering of investments within the zone. New and maintenance investments in generation, storage and loads are therefore not directed towards grid-friendly locations, but carried out completely independently of grid congestion. Because qua market design the zonal market does not allow for a trade-off between network expansion and steering of investments to grid-friendly locations, it requires a degree of network expansion exceeding the economic optimum.

Delay in network expansion. Although these considerations apply in theory, in practice the opposite problem is likely to prevail at present: delays in network expansion. The length of time it takes to expand the transmission network can lead to network congestion lasting for years. Above all, the "dry spell" between the final nuclear phase-out and the completion of the DC lines in Germany is likely to be marked by significant grid congestion beyond the economic optimum. However, this is also an argument for the locational steering of investments. In both the theoretical-long-term and practical-medium-term time frames, one should therefore consider locational steering of investments in power plants, loads and storage facilities.

Relation between market and grid. In work package 2 of the project we dealt with the relation between market and grid as well as different instruments of locational pricing and steering. The corresponding report on the interaction of market and grid in the electricity system has been published as Neon & Consentec (2018). For the overall project “Beschaffung von Redispatch”, however, these questions only represented a marginal aspect; the following discussion is therefore by no means conclusive.

Instruments of locational steering. On the one hand, locational steering signals can arise from the electricity market itself if it has a geographical resolution. This is the case with small price zones and nodal pricing (Figure 17). On the other hand, additional instruments outside the electricity market can have a steering effect. Such incentive systems include, in particular, deep grid connection charges as well as locally differentiated grid usage charges, RES promotion or capacity mechanisms. These instruments can be combined both with each other and with a locally resolved electricity market.

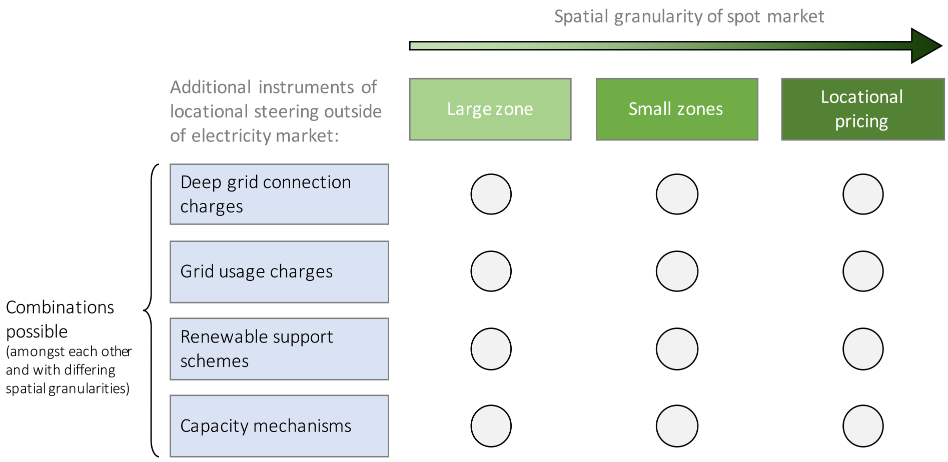

Figure 17: Basic options for locational steering in the electricity market

5.1 LOCATIONAL INCENTIVES FROM THE ELECTRICITY MARKET

One approach to locational incentives is to give the electricity market itself a higher geographical resolution. This can be done through smaller bidding zones or nodal pricing.

5.1.1 Bidding zone division

Concept. One could, for example, divide the current German-Luxembourg bidding zone into two to six small bidding zones and, for example, re-configure the zones every few years. This would roughly correspond to the model of the EU Regulation establishing a guideline for Capacity Allocation and Congestion Management (CACM Regulation).

Intention. The following problems are addressed by the system:

- In the case of structural, persistent network congestion, bidding zones can be divided so that congestion between the bidding zones are already taken into account in the market result. This leads to lower redispatch volumes and costs and different electricity prices in the individual zones.
- This also creates local investment incentives at the level of bidding zones.

Disadvantages and problems. The following problems arise:

- Zone boundaries are static in the short term. However, congestion is often dynamic and varies at the physical level depending on season and time of day. On this time scale, however, small bidding zones are fixed and cannot take this into account. They are therefore better suited for countries with a more linear network topology (and thus natural congestion boundaries at stable points) than those with a strongly meshed network topology with seasonal and/or time-of-day changing congestion boundaries.

- There is still a need for redispatch within the price zones. There is also no locational steering of investments within zones.
- The stability and credibility of prices is limited by the risk of regulatory zone changes. Unlike market risks, this regulatory risk cannot be hedged. This poses a threat to efficient local investment or even investment in general.

Classification. In terms of its advantages and disadvantages, the concept of small price zones lies between a large zone and nodal pricing. The exact location between these two prototypes depends on the number of zones. However, the regulatory risk of zonal reconfiguration applies only to this concept, which is why we particularly advise against a regular bidding zone reconfiguration.

5.1.2 Nodal pricing

Concept. In this system, typically known as nodal pricing or locational marginal pricing, physical trading with electrical energy takes place across all market levels on the basis of high-resolution (nodal) prices.[17] In comparison to the market designs discussed so far, nodal pricing no longer considers the market and the network separately, but optimizes them integrally in a single step. An independent system operator, who is also responsible for network operations management, centrally determines the optimal use of power plants to avoid network congestion in accordance with the defined optimization function on the basis of bids from market participants that are based on units (so-called central dispatch[18]). In the course of the different market levels (e.g. day-ahead, intraday, balancing) the stakes and prices are adjusted on the basis of the latest information available. The role of network expansion in a system with nodal prices is shifting. While network expansion in zonal markets is absolutely necessary to cover the load, in nodal systems it becomes an option alongside locational steering. Since liquid long-term trading with electrical energy, e.g. for hedging transactions, is hardly possible within the limited nodes, hedging transactions are preferably concluded at liquid hubs that combine several nodes and on the basis of financial transmission rights between hubs or nodes. The report on nodal and zonal electricity price systems in comparison (Consentec & Neon 2018) summarizes a large number of pros and cons.

Intention. The following problems are addressed by nodal pricing:

- Congestion is handled market-based and without regulatory coercive measures. Redispatch is no longer necessary.

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[17] In many cases, this is done only for generators. Consumers in many existing nodal markets such as California (CAISO) are assigned to zones and pay only the average price in that zone.

[18] In contrast, the model used in Germany and most European countries is the so-called self-dispatch. The market participants only submit bids for their entire portfolio and independently allocate the quantities of energy sold to the units to be produced. In contrast to central dispatch, the optimization of the operation mode of the plant fleet and the consideration of its technical characteristics are carried out decentrally on the basis of individual scheduling by the operators and not by a central algorithm.

- The use of market mechanisms based on voluntary bids increases the efficiency of the final dispatch.
- At the same time, all flexibility options are given the opportunity to participate in congestion management (which is done as part of the electricity market under nodal pricing). An integration of (large) loads and storages is possible.
- The locally resolved prices send signals to the market participants for the locational steering of investment/disinvestment decisions.
- Consistent price signals across all market stages avoid incentives for inc-dec strategies.

Disadvantages and problems.

- With nodal pricing, local market power can be problematic. Intensive market surveillance and competition surveillance measures are therefore necessary to prevent the abuse of market power. It can be difficult to distinguish between the abusive exercise of market power and the desired profit to incentivize entrepreneurial activity. Both an unpunished exercise of market power and an unjustified skimming of returns can weaken the effectiveness of local price signals as well as the acceptance of the system.
- In particular, a problem could be that intensive market surveillance will suppress scarcity prices. The consequence of such regulation would be a so-called missing money problem, i.e. a lack of sufficient investment incentives. In real markets in the past this has often been decisive for the introduction of capacity mechanisms.
- It is unclear whether local prices have sufficient credibility to signal investment decisions. In addition to the actions of the market participants, local prices are influenced to a considerable extent by network expansion decisions of the regulated network operators, who follow different economic objectives.

Evaluation. A statically efficient use of power plants can be expected, but this will also be accompanied by intensive market monitoring and centralization of trading. It is questionable whether dynamic efficiency can be guaranteed for investments in load and generation. At the very least, there is a threat of the need for state protection of investments, which would reduce the value of local price signals for investment steering. The fundamental differences make it difficult to evaluate nodal pricing compared to zonal market designs. The comparison to market-based redispatch, on the other hand, is simpler: Nodal pricing does not provide an incentive for strategic inc-dec bids. Unlike market-based redispatch it also offers functioning financial trade through financial transmission rights. In this way, nodal pricing avoids two fundamental problems of market-based redispatch; other problems, especially local market power, remain. If a market design is to offer incentives with a high temporal and spatial resolution, which are determined by voluntary bids from market players, then nodal pricing seems to be the only viable way. This statement should not be misunderstood as a recommendation. A well-founded decision on a market design should carefully weigh up the extensive advantages and disadvantages and take into account the framework conditions of the electricity system (Consentec & Neon 2018).

5.2 Instruments outside the electricity market

Another approach to local incentives is to leave the zonal electricity market unaffected and provide incentives outside of it, such as grid charges, RES support schemes or capacity payments. These instruments must, of course, be differentiated locally in order to have a locational steering effect. These options all avoid incentives for inc-dec bids. However, they do have their own problems: they are largely determined by administration and usually not, or only slightly, variable over time. Furthermore, although they tend to reduce the need for redispatch, unlike nodal pricing they do not replace operational congestion management.

5.2.1 Deep grid connection fees

Concept. In the case of deep connection charges, power plants and loads bear the costs for the grid expansion caused by them a one-off payment when obtaining the grid connection[19]. These charges should take into account the total additional costs caused by the connection to the grid. A number of European countries, especially in Central and Eastern Europe, apply deep grid connection charges. If new facilities contribute to grid relief, grid connection charges are theoretically conceivable as payments from the system operator to the entity requesting a connection, but to our knowledge no such system with "system benefit payments" exists.

Intention. Such a model aims at influencing the locational decision in the case of new placements of loads or investment into generators.

- In this case, a locally differentiated price signal is generated by the grid connection fee.
- In contrast to other locally differentiated prices, there are no credibility problems because the amount of the connection fee is fixed at the time of the investment and is not changed thereafter.

Disadvantages and problems. However, this design also gives rise to various problems.

- The price signal only reflects the estimated costs or benefits of the newly connected system at the time of the investment and is therefore purely static. It therefore does not take into account the fact that the cost and benefit effects of generators can change dynamically over time.
- The grid connection fee generates a price signal that only affects investment decisions, not power plant usage decisions. Congestion can therefore continue to occur during operation.
- If the first grid connection at a given location has to pay for the line capacity and it would subsequently be cheaper for the next, nobody wants to be a "first mover" and

[19] Payments can also be spread over longer periods of time as long as the amount of the fee to be paid / received with connection is fixed and does not change depending on the use of the system. If changes are permitted, the model moves closer to the model of locally differentiated grid usage charges discussed later.

each player first waits to see whether others will invest before him. In reality, however, such effects would be smoothed by averaging the charges.

- The local price signals are calculated in a model on the basis of centrally determined assumptions: These do not correspond to the real scarcities and cost parameters - especially since a forecast of cost and benefit effects over the useful life of the plant is necessary. Also, it opens room for lobbying to influence the model or the assumptions.
- It is not possible to determine deep grid connection charges "exactly", since the technical effect of a single source or sink on the grid cannot be assessed on its own. This makes assumptions and parameterization decisions necessary. There is a risk of a lack of transparency in the modelling and of feared or actual disadvantage or preference of individual actors. In the context of unbundling, this was the main argument against the introduction of deep connection fees in most Western European markets.

Evaluation. The high credibility speaks for deep network connection fees as an instrument of investment steering. The difficulty in determining the level of charges in a non-discriminatory and transparent manner, on the other hand, is considerable. We therefore consider this option problematic in many respects, but worth considering.

5.2.2 Grid usage charges

Concept. Another way of implementing local signals is to levy locally differentiated network charges for consumers and producers. These would be charged as a premium/discount on-withdrawn or fed-in energy (EUR/MWh) or as an annual capacity payment (EUR/MW). The network usage fees could be determined model-based and per transmission network node, developed on the basis of forecasts for the development of the power system. It would be possible, for example, to fix them for a duration of 1-5 years in advance. A similar approach is used in the UK and Sweden.

Intention. Locally differentiated grid usage fees pursue two main objectives:

- There are locational price signals for the use of power plants and investments similar to locational market prices (but only regarding the locational dimension, not the temporal).
- At the same time, the definition for longer periods protects market players from the risks of volatility of local price signals. The hope is therefore to achieve credible and thus effective locational price signals.

Disadvantages and problems. The following problems arise:

- The fees are unlikely to be time-varying at all or only to a limited extent. This they "blur" the locational price signals.
- In hours without congestion, energy produced at different locations is a homogeneous commodity (apart from grid losses). With locational grid usage charges, it would, however be priced differently and thus inefficiently. During these hours the instrument has a distorting effect.

- The locational price signals are determined in a model based on assumptions: This does not correspond to the real scarcities and cost parameters. It is necessary to forecast for the duration of grid usage fees (1-5 years). There is also the possibility of lobbying the model or assumptions.

Evaluation. The advantages and disadvantages are similar to those of connection charges. In addition, however, the dispatch in uncongested hours is inefficient. In addition, there is interaction with other policy objectives, such as the avoidance of further regressive distribution effects through a disproportionate burden on low-income households or incentives to save energy. Nevertheless, we consider grid utilization fees to be a worthwhile instrument for locational steering.

Time-varying grid charges. In addition to the variant of locally differentiated grid charges discussed above, a temporal differentiation and - as a consequence - the introduction of temporally variable retail prices are also discussed, especially for distribution networks. [20] To incentivize network-friendly behavior with such an instrument appears to be particularly useful if the network problems addressed are caused by the consumption behavior not of individual network users but of the collective of network users within a distribution network. Possible effects are, for example, influencing the simultaneous peak load in a network or the consumption structure in general, e.g. by shifting consumption over time. Less suitable, on the other hand, are time-varying grid charges for targeted load control for individual subnetworks or network elements, such as the case of redispatch in the transmission network.

5.2.3 Support systems for renewable energies

Concept. This approach aims at the internalization of grid effects in the promotion of renewable energies. The idea is that the subsidy paid out not only depends on the cost structures/bids of the facilities, but also on the grid situation in the connection region/at the connection point. In Mexico, for example, such a system is implemented through locally differentiated surcharges/discounts on the subsidies. In Germany, there are quantity restrictions in regions labelled as “grid expansion area” (Netzausbaugebiet). The calculation of such measures is done in a similar fashion as for locally differentiated grid usage charges. The German “reference yield model” (Referenzertragsmodell) for the allocation of wind energy subsidy premiums is also effectively an instrument of regional investment steering.

Intention. The intended effects are similar to those of regionally differentiated grid utilization charges, but are limited to renewable energy.

- Similar to grid connection charges, the system is very credible from the investor's point of view.

[20] See Consentec, Regulatorische Bewertung von Maßnahmenvorschlägen zur Erschließung netzdienlicher Flexibilität, Studie im Auftrag der dena, 2019.

- One advantage is that no reform of the grid charge is necessary for implementation. It should be much easier to implement a limited change to the RES promotion regime in legal and administrative terms.

Disadvantages and problems. At the same time, specific problems arise:

- The model implements local prices that are actually technology-specific. This leads to inefficiencies in the choice of technology between different flexibility options such as renewable and conventional generation, load flexibility and storage. If, for example, a grid congestion could be relieved cost-effectively by a storage investment that would serve the grid, a renewable energy support system could not provide any incentives for this.
- The forecasting of cost and benefit effects over the lifetime of the plants is similarly problematic as with grid connection fees.
- The incentives apply only to subsidized RES installations. If there will be more non-subsidized plants in the future, they will no longer be subject to control.
- At the same time, due to the lack of technology neutrality and thus limited options for responding to network problems, the effectiveness with regard to congestion relief is lower than with general mechanisms. In particular, such a mechanism alone cannot completely rule out local security of supply problems.

Evaluation. This option is attractive due to the reduced legislative complexity and the prominent position of renewable energies. On the other hand, it does not provide an incentive for conventional power plants, storage facilities or loads.

5.2.4 Capacity mechanisms

Concept. This concept complements the electricity market with a local tender for new investments in generation capacity. This could also be described as a nodal capacity mechanism. In the case of renewables, this concept obviously has considerable overlaps with the previously discussed approaches for locational steering within support mechanisms for renewables.

Intention. The aim of the capacity mechanisms is to address local supply shortages resulting from grid congestion that cannot be covered by existing plants. If local tenders are used not only as an emergency measure and last resort, but are systematically weighed against grid expansion measures, there is at least the theoretical possibility of coordinating generation investments and grid expansion and thus avoiding unnecessary grid expansion. For example, local tenders in regions with a generation shortage could be used to specifically remedy grid congestion.

Disadvantages and problems. However, the following problems arise:

- A government body, such as the regulator, must define the nature and technical specification of the capacity to be tendered. Due to the incentive structures for regulators, which are typically risk-averse, there is a danger of an overestimation of demand and an inefficient choice of technology because the risk-averse approach tends to be sceptical of innovation and often leads to over-investment.

- Due to local barriers to entry (e.g. limited availability of power plant sites), there is a significant risk of market power and thus excessive costs. If the local capacity market is defined in very small local terms, there may be only one or a few suppliers with suitable locations, so that tender prices above the competitive level could be expected due to the market power of these suppliers.
- The coordination with network development mentioned above is likely to be rather difficult in practice, especially over longer periods of time. Calls for tenders for generation assets may be issued in order to solve short-term security of supply problems. At the same time, however, the expansion of the grid is being pursued, which may ultimately result in an inefficient combination of generation and grid expansion.
- Depending on its design and credibility, a local capacity tender, as well as other forms of a capacity market, can lead to a reduction in investments based on the energy-only market due to a deterioration of prices.

Evaluation. In view of the problems listed above, local capacity tenders to us seem to be the last resort at best. It should also be considered to keep subsidized installations in reserve and not letting them participate in the electricity market in order to avoid negative effects on the energy-only market.

5.2.5 Fundamental problems of the additional instruments

Incentive mechanisms installed in addition to and outside the electricity market have a number of advantages: They can be designed to be credible and are then effective as an investment signal. In practice it’s also relevant that they can be implemented without a fundamental transformation of the electricity market itself. However, these instruments also have a number of common drawbacks, which are discussed below.

Time-invariant. The local incentives of the additional instruments are generally not variable over time and therefore do not provide dynamic incentives for system-friendly operation of the assets. After the investment decision, capacity mechanisms and grid connection fees do not provide any incentive to operate the assets in a way that is useful for the network. Although grid usage fees and surcharges on RES support provide an incentive, this is generally time-invariant. The grid situation, on the other hand, changes dynamically from hour to hour. Figure 18 illustrates the optimal incentive as a difference in the value of electricity between two locations. Time-invariant instruments set an incentive at best that is correct on average over the year, but is either too high or too low in every single hour - or even works in the wrong direction. Although these instruments may therefore be suitable as investment incentives, they cannot be an operational alternative to redispatch.

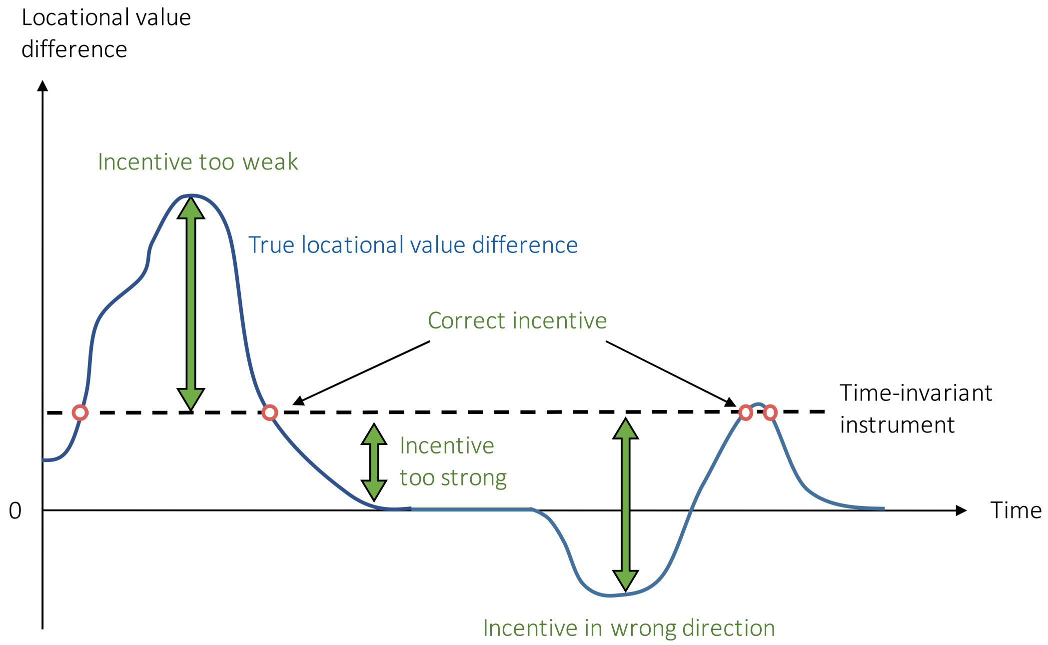

Figure 18: Additional instruments offer little or no time-varying incentive
Source: Eicke et al. (in publication)

Energy or capacity. These instruments can be specified in the form of payments for capacity (EUR/kW) or energy (EUR/MWh). A capacity payment implies a stronger incentive for technologies with low utilization hours, an energy payment a stronger incentive for base load technologies. The "capacity or energy" decision is therefore technologically discriminatory.

Administrative calculation. The level of incentives is not determined by supply and demand by market players. Rather, it must be calculated administratively. This also gives rise to two problems that have already been discussed:

- The local price signals are determined in a model based on assumptions: This does not correspond to the real scarcities and cost parameters - forecasts are necessary for the duration of grid usage fees (1-5 years).
- There is also the possibility of lobbying the model or assumptions.

Duration of the commitment. There is a trade-off with regard to the duration of the fixation of the incentive: a long-term fixed incentive (in extreme cases only a single once-off charge for the investment decision) means a credible investment signal - but must be fixed decades in advance (at least if counting the full operational time period of the asset). On the other hand, a short-term (e.g. annual) changeable incentive better reflects the actual network situation - but is less effective at influencing investment decisions.

6 Recommendations

Summary. The focus of the present study is the question of how redispatch should be procured, in particular if market-based procurement is advised. Our recommendations are based on theoretical considerations and numerical simulations.

Do not introduce market-based redispatch. In the current and foreseeable German situation, we advise against introducing a market-based redispatch based on energy or activation payments. In the German transmission grid, network congestion is significant and relatively easy to anticipate. In such a situation, we believe the emergence of inc-dec gaming on a large scale is likely. The consequences would be an increase in redispatch volume and cost, windfall profits for market participants at the expense of electricity customers, an undermining of the financial electricity markets that is essential for risk hedging, and perverse investment incentives. In our quantitative studies, strategic behavior increases the redispatch volume to up to 700% of the volume under cost-based redispatch. In addition, market players are likely to exercise the significant market power, which tends to exacerbate the problems mentioned and requires appropriate regulatory responses. In addition, market power constitutes a problem of its own right. Against this background, we advise against the introduction of market-based redispatch in the transmission network and recommend keeping administrative redispatch with cost reimbursement which is mandatory for most generation and storage facilities.

Variants. There is no variant of implementation of market-based redispatch (dedicated procurement platform, use of balancing energy, use of the intraday market, etc.) that we can recommend. The "less market-based" redispatch is organized, i.e. the stronger cost-based regulatory intervention, the fewer the incentives for inc-dec gaming and market power abuse. However, a stronger intervention also reduces the benefits. In addition, perverse investment incentives would remain even with perfect regulation.

In principle, this also applies to distribution networks. In principle, the arguments made apply also to market-based congestion management in distribution networks - often referred to as "flexibility markets". Here, too, there are inherent design incentives for strategic bids on the spot market and (local) market power is likely to exist frequently. However, the effects at the distribution grid level were not quantitatively investigated in this project.

The price of not introducing market-based redispatch. We advise against market-based redispatch, but this comes at a price. With administrative redispatch, it is likely to be very difficult to incorporate significant amounts of demand-side flexibility into congestion management. For this reason, we recommend an in-depth examination of further options to relieve grid congestion.

Redispatch based on capacity payments. Redispatch on the basis of longer-term capacity prices, in contrast to payments for each activation, reduces the incentives for congestion-aggravating behavior. For the integration of (certain) loads into redispatch, such capacity payments seem conceivable. Possibly, Germany's ordinance concerning interruptible loads (AbLaV) could be integrated into redispatch. A regulation based on Germany's § 14a EnWG seems possible for distribution grids. Main challenges are pricing and product definition, e.g. in specifying the depth, duration and frequency of activation. We recommend a detailed analysis of the potential, design options and advantages and disadvantages of such an approach.

Locational incentives. In addition, we recommend the systematic evaluation of instruments that provide locational investment incentives. A certain level of locational incentives seems desirable for large bidding zones such as the German one, at least in this phase of the *Energiewende* with its dynamic transformation and delays in grid expansion. In general, these instruments do not provide an incentive for congestion-aggravating behavior or abuse of local market power. We recommend an in-depth investigation of such instruments for the German context. Possible instruments include grid connection and grid usage fees as well as renewable energy support schemes.

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