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**Working Paper**

## Market-Based Redispatch in Zonal Electricity Markets: The Preconditions for and Consequence of Inc-Dec Gaming

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# Market-Based Redispatch in Zonal Electricity Markets

## The Preconditions for and Consequence of Inc-Dec Gaming

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**Abstract** – In zonal electricity markets such as Europe’s, system operators rely on out-of-the-market measures to relieve network congestion within bidding zones. One such measure is “redispatching” power plants, i.e. increasing the output of a station downstream of the congestion while lowering production of an upstream plant. Traditionally, generators have often been legally obliged to participate in redispatch and were subsequently compensated for costs incurred. In recent years numerous proposals have been made to organize redispatch through voluntary markets, including one by the European Commission. In this paper, we introduce a simple graphical game-theoretical model of a locational redispatch market within a one-zone electricity market. We solve the model explicitly by determining optimal bidding strategies and the Nash equilibrium. We show that market parties anticipate the redispatch market and bid strategically in the zonal market – this is the so-called increase-decrease game. As a result, grid congestion is aggravated, producers extract windfall profits, financial markets are distorted, and perverse investment incentives emerge. Despite claims to the contrary, we show that such gaming is possible absent any market power, i.e. under perfect competition. At the root of the problem is an inconsistent setup of power markets: combining a zonal with a locational market yields undue arbitrage opportunities that rational firms exploit. We conclude that such inconsistent market design should be avoided.

This paper builds on research undertaken with Consentec, Connect Energy Economics, Ecofys, Fraunhofer ISI and Stiftung Umweltenergierecht in the project “Untersuchung zur Beschaffung von Redispatch” for the Federal German Ministry of Economic Affairs and Energy (No. 055/17). Project findings are published as Neon & Consentec (2018, 2019), Connect Energy Economics (2018), and Consentec et al. (2019). This paper does not constitute a project deliverable. We thank Kristin Walter, Nils Saniter, Christoph Maurer, Bernd Tersteegen, Marco Nicolosi, Barbara Burstedde, Markus Graebig, Eva Schmid, Frauke Thies, Simeon Hagspiel, Samuel Glisman, Mike Hogan, Anselm Eicke, Tarun Khanna, Christoph Neumann, Catrin Jung-Draschil, Bernhard Hasche, Fabio Genoese, Charles Payement, Fabian Joas, Gerard Doorman, Philip Baker, Julia Radecke, Joseph Hefe, Christian Winzer, Rebecca Lordan-Perret, and SCCER CREST and Strommarkttreffen seminar participants for inspiring discussions and helpful comments.

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# 1 Introduction

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**Zonal electricity markets.** European wholesale markets for electricity are organized geographically into so-called “bidding zones”. Within bidding zones, all generation and load is cleared at a uniform price and the system operator guarantees free trade between market parties. Within-zone transmission constraints are initially ignored for purposes of pricing in the spot market; this has been called the “illusion of the copper plate”. If the desired dispatch cannot be accommodated physically by the existing electricity grid, the system operator relieves congestion using measures outside of the wholesale market. These out-of-the-market operations are often called “congestion management” (Hirth & Glismann, 2018, provide an overview). Congestion management includes several instruments such as switching operations in the power grid, adjusting the tap position of phase-shift transformers, curtailing renewable energy, and “redispatch”. Redispatching power plants (or loads) means ordering plants upstream of the constraint to reduce output while asking plants downstream of the constraint to ramp up. Redispatch can be organized through regulatory obligations or competitive procurement.

**Mandatory redispatch.** In central European countries, mandatory redispatch prevails. Here, generators are legally obliged to participate in redispatch. Small, renewables-based, and combined heat and power generators are sometimes exempted, as are loads and small-scale electricity storage. Redispatched parties are compensated for costs and forgone profits in order to achieve profit neutrality and economic indifference. Germany is among the countries that applies mandatory redispatch. Mandatory redispatch is problematic because true costs are unknown to the regulator and because it does not provide any investment incentive.

**Market-based redispatch.** An alternative is to conduct redispatch through a voluntary market. That is, system operators procure upward and downward redispatch in competitive auctions separate from the wholesale electricity market. Generators and loads bid their price at which they would be ramped up or down to relieve congestion.

**Nodal pricing.** The European “zonal spot plus redispatch” electricity market design stands in contrast to US “locational marginal pricing” (nodal pricing) markets, where grid constraints are accounted for in the initial security constrained economic dispatch. In nodal pricing systems, there is no need for redispatch. However, locational marginal pricing applies to the transmission grid only – installing a separate market to relieve *distribution* grid constraints would be comparable to redispatch markets.

**Increased network congestion.** Across Europe, pressure on transmission and distribution grids has increased in recent years, expanding the need for redispatching services. This trend is expected to continue. The pressure on the grid is due to a combination of factors including the rapid expansion of renewable energy sources, in particular wind power; the integration of electricity markets across national borders; the restructuring of historically integrated utilities that had ensured a close geographic match of consumption and generation, and, in Germany’s case, the phase-out of nuclear power. These factors tend to increase the distances between generation and demand, contributing to increased redispatching. Figure 1 shows the increase

in Germany's redispatch volumes and cost. 15 TWh of downward redispatch correspond to 2.5% of the country's electricity consumption.

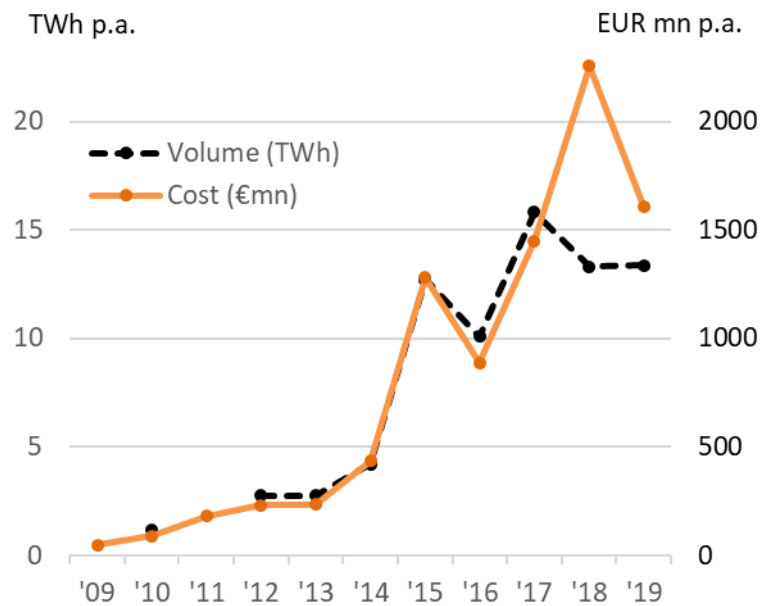


Figure 1. Increasing congestion management volumes (downward redispatch only, includes renewables curtailment) and costs in Germany. Authors' calculations based on data from Bundesnetzagentur.<sup>1</sup>

**Rationale for redispatch markets.** Against this background, several stakeholders have proposed to change procurement of redispatch resources and turn from obligations with cost-compensation to voluntary markets. The main reason for this is to make loads available as redispatch resources. Consumers and storage operators are difficult to integrate into mandatory redispatch because their opportunity costs are difficult to observe: while cost parameters of thermal plants can be reasonably estimated from observed behavior, in the case of hydroelectricity, storage and, demand response, the information asymmetry is much more severe. Estimating the water value of a hydroelectricity plant is very challenging. Making consumers indifferent with respect to being redispatched would require compensating them with their willingness to pay for electricity, which is private information. For those technologies, markets could provide the incentives to participate, ultimately leading to lower costs for rate payers. Some also believe voluntary redispatch markets could provide an incentive for investors to build power plants in regions that lack generation capacity and facilitate redispatch across national borders within the EU. Finally, advocates argue (and we agree) that as a matter of principle voluntary markets are preferred to regulatory obligations.

<sup>1</sup> [https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen\\_Institutionen/Versorgungssicherheit/Netz\\_Systemsicherheit/Netz\\_Systemsicherheit.html](https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit.html)

**Policy proposals.** These proposals for market-based procurement of redispatch services stem from European legislation and national research and pilot projects as well as first commercial implementations.

- The most prominent proposal emerged from the revised European Union’s Electricity Market Regulation which was first proposed by the European Commission as part of the “Clean Energy for All Europeans” legislative package in late 2016. Article 13 of the Electricity Market Regulation ([Regulation \(EU\) 2019/943](#)) mandates that “resources that are redispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms” unless certain derogations apply.<sup>2</sup> This proposal has been among the most contentious of the legislative package.
- In Germany, a large-scale research project called SINTEG provides the framework for several pilot projects for market-based congestion management. These include the projects Enera, C/sells, Windnode, NEW 4.0 and Designnetz.
- The Netherlands is using a market called GOPACS (Grid Operators Platform for Congestion Solutions). The Dutch system operator expects to procure a significant share of its 2019 redispatch volume with this approach.<sup>3</sup>
- Other research pilots, stakeholder initiatives and business cases include the markets Nodes AS, DA/RE, Flexrouter, Smart Nord, HeatFlex, Smile, and United Grid. See Radecke et al. (2019) for a descriptive overview.

**Many names.** These procurement mechanisms are sometimes labelled “markets for local flexibility”, “smart markets”, “market-based redispatch”, “inc-dec markets”, among other things. For convenience, we call all the above proposals “redispatch markets” regardless of the specific terminology used. In their cleanest form (and as we will model them in this paper), redispatch markets are based on voluntary participation, energy-only payments, unrestricted bidding, and free price formation based on marginal clearing prices. Actual proposals and existing mechanism despite their name often resemble mandatory redispatch more closely than such free markets: they often combine pay-as-bid pricing with tight regulation that compels producers to bid marginal costs. Other incentive mechanisms rely on longer term capacity payments, in contrast to the “energy-only redispatch markets” that we study here.

**Inc-dec strategy.** The purpose of this paper is to discuss the relationship between zonal power markets and locational redispatch markets and explain why the interaction of these makes voluntary redispatch markets untenable. We show that a two-stage electricity market where the two stages have a different geographical granularity offers 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

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<sup>2</sup> One of the exemptions from the EU Electricity Market Regulation’s obligation to introduce market-based redispatch specifically refers to the case of predictable congestion and the strategic bidding to be expected from such a situation (i.e. inc-dec gaming): “Non-market-based redispatching of generation, energy storage and demand response may only be used where: [...] d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion [...]”

<sup>3</sup> <https://gopacs.eu/nl/veelgestelde-vragen/>

than the zonal market. They therefore offer higher prices on the zonal market to price themselves out of the market. Conversely, producers in surplus regions will anticipate profits from being downward-redispached. To achieve this, they place low bids on the zonal market to 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. They are also known as increase-decrease (inc-dec) gaming.<sup>4</sup>

**Consequences.** Such strategic bidding has problematic side effects: it exacerbates congestion, creates windfall profits, distorts financial markets, and gives rise to perverse investment incentives.

**Contribution of this paper.** This paper contributes to the literature by providing a simple, intuitive example of a one-zone wholesale market with a locational redispatch market to demonstrate the incentives for inc-dec gaming and identify its consequences. Using this model, we show the incentives introduced by redispatch markets, identify optimal bidding strategies, determine Nash-equilibria and corresponding prices, and discuss implications. We do all this without mathematics or numerical modeling. By illustrating the intuition behind the inc-dec gaming, we aim to communicate to a broader academic and policy audience why redispatch markets should be avoided. Next, we discuss the pre-conditions for gaming, including the predictability of congestion and the finding that market power is *not* a necessary condition for gaming to occur. We then discuss factors that could aggravate the incentives for gaming further. Finally, we evaluate suggestions to prevent gaming.

**Conclusions.** We conclude that current proposals for redispatch markets within zonal wholesale markets that remunerate energy should not be adopted. The negative side effects are likely to be severe. Regulatory mitigation strategies seem little promising and are likely to entail costly side effects.

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<sup>4</sup> The term “inc-dec” refers to the strategy that generators first increase and then decrease sales of power (Sarfati et al. 2018), and also to the California redispatch market where upward bids were called “incrementals” and downward bids “decrementals” (Stoft 1998). Most academic literature uses the term inc-dec “*gaming*” to describe the behavior of firms. This stems from game theory, the branch of economics that studies strategic interactions. However, “gaming” also carries the connotation of the strategy to be illegal and/or complicated to exercise. Both are likely not the case, which is the reason we favor “inc-dec (bidding) strategy” (although we do use the term gaming to connect to the literature). One might also describe the behavior as “arbitrage trading”, “carry trade”, “optimization between two markets”, “pricing in opportunity costs” or one might even argue that firms “save flexibility for redispatch”.

## 2 Literature Review

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**Historical cases of inc-dec.** Several markets have suffered in the past from inc-dec gaming. Due to the negative impacts of the bidding strategy, policy makers have typically responded with changes to the market design or regulatory intervention. Two cases have drawn particular attention in the literature: California and Great Britain.

**California.** California liberalized its electricity market in 1996-98, introducing a zonal wholesale market with two bidding zones. Within-zone network congestion was managed with market-based redispatch (although that term was not used), incentivizing market parties to engage in the inc-dec game. As early as 1999, the Federal Energy Regulatory Commission warned that “the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced.” Gaming contributed to the energy crisis of 2000/01 during which the state suffered from a series of rolling blackouts. Inc-dec gaming and high redispatch costs were key factors in moving to nodal pricing, being introduced in 2009 (Cramton 2019). Similar gaming had already caused ERCOT to do the same. Hogan (1999), Harvey & Hogan (2001), Alaywan et al. (2004), Brunekreeft et al. (2005), and CAISO (2005) provide analyses of the California case.

**Britain.** Another case of inc-dec bidding occurred at the Scottish-English border, after an expansion of wind power in Scotland has led to increasing congestion. In 2012, the British regulator introduced the so-called Transmission Constraint License Condition to prevent further gaming by penalizing bids that result in “excessive benefits”, which has been in place ever since. The Condition requires generators to bid marginal cost and prevents them from factoring in locational rents. To us, this seems nearly equivalent to mandatory redispatch with cost compensation. Ofgem (2012, 2016, 2018) and Konstantinidis & Strbac (2015) provide accounts of this case.

**State of the theoretical literature.** We are aware of a few theoretical papers on the interplay between zonal spot and locational redispatch markets and the emergence of the inc-dec game. Knops et al. (2001) and De Vries & Hakvoort (2002) discuss congestion management methods in the context of limited interconnector capacity and conclude that redispatching and counter-trading are susceptible to strategic manipulation. Yet the discussion of possible strategies remains focused on market-power and misreporting of costs rather than the inc-dec game. Inderst and Wambach (2007) discuss congestion management approaches for the German electricity system and point out that there are strategic incentives under market-based redispatch for generators in the scarcity region to withhold supply from the spot market to benefit from higher prices in the redispatch market, thereby aggravating congestion. They do not discuss the case of underbidding in the oversupply region, which makes them conclude the wholesale price always increases as a result of the strategic actions (in the Appendix of this paper, we show the wholesale price can also decrease). Dijk & Willems (2011) and Ruderer & Zottl (2012) find distorted investment signals for generation and transmission capacity under zonal pricing with a redispatch market. The most elaborate discussion of the inc-dec game we know of comes from Pär Holmberg and his co-authors. Holmberg & Lazarczyk (2015) point



out that inc-dec gaming is an arbitrage strategy that cannot be eliminated by improving competition in the market. They point out that zonal pricing combined with a market based redispatch gives arbitrage opportunities to producers. More recently and with new co-authors (Hesamzadeh et al. 2018 and Sarfati et al. 2019), Holmberg comes to similar conclusions. He finds that “the inc-dec game is not due to the lack of competition, it is due to the misrepresentation of transmission constraints in the day-ahead market.” These papers are methodologically sound and draw reasonable conclusions. Yet, being highly technical in nature, they have failed to attract notice by policy makers.

**Recent policy discussion in Europe.** In a policy-oriented report, Connect Energy Economics (2018) discusses various ways of implementing market-based redispatch, e.g. installing a dedicated market platform or using existing platforms such as the intraday market or procurement auctions for balancing energy. The authors conclude that inc-dec gaming is present in any of these forms. In contrast to these findings, Grimm et al. (2018) argue that assuming competitive markets “implies that we abstract from any inc-dec games” (footnote 8), which we believe to be an incorrect inference. More recently, Cramton (2019) underlines the arbitrage possibilities between zonal and redispatch markets, noting that in this case “the arbitrage is harmful as it artificially exacerbates the binding transmission constraint”. He reasons that “zonal pricing, ignoring intrazonal transmission constraints, is fundamentally inconsistent with the pricing when constraints are respected”, yet suggests market-based redispatch as second-best option when nodal pricing is impossible and congestion is not structural. Brunekreeft et al. (2020) assess gaming incentives on the load side, concluding that gaming incentives for loads are structurally the same as for generators but differences arise from tariff structures, outside options and transaction costs for gaming. This paper adds to the literature by providing a simple graphical model to demonstrate the incentives for and consequences of inc-dec gaming to a non-technical audience.

## 3 Model Setup and Benchmark Designs

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In this section, we outline the physical setup of our model and two benchmark electricity market designs, nodal pricing and zonal pricing with mandatory redispatch.

### 3.1 Physical Setup of the Model

**Network and market.** We create a simple model—very loosely modeled on Germany—to illustrate inc-dec gaming. It is an isolated power system comprising two nodes, the export-constrained North ( $N$ ) and the import-constrained South ( $S$ ). These two nodes are connected through a single transmission line rated at 30 GW. The zonal market is uniform. We abstract from transmission losses and voltage limits and study a 1-hour snapshot of the market. Figure 2 displays the network topology.

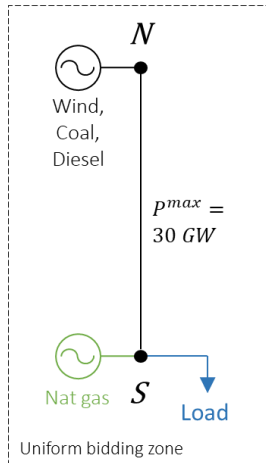


Figure 2. The simple network topology.

**Demand and supply.** In our model, the Northern node has three generation sources: wind power (20 GW), coal-fired power plants (20 GW), and diesel peakers (5 GW). We abstract from ramping, start-up, or minimum load constraints. As there is no load in the North, the direction of electricity flow will always be southbound. The Southern node connects loads (50 GW), which are assumed to be perfectly price inelastic, and natural gas-fired power plants (25 GW). Variable costs are assumed to vary in steps of 1 GW, in the increasing order wind, coal, natural gas, diesel. In total, 70 GW of generation capacity is available, hence capacity is abundant both on a system level and, given the transmission line capacity of 30 GW, on a nodal level. Figure 3 shows the supply stack of the system.

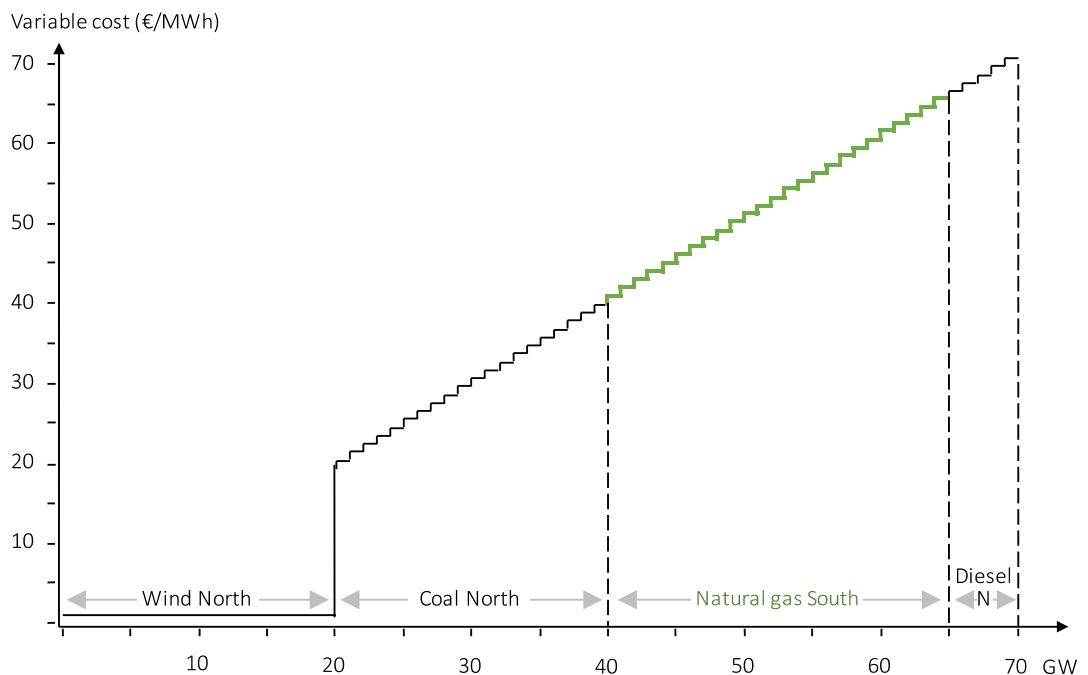


Figure 3. Variable costs ordered by size (merit order). Capacity connected to the South is depicted in bold green.

**Actors and information.** We assume profit-maximizing firms and full information, i.e. perfect foresight and the absence of information asymmetries. Firms do not collude and act as price takers, i.e. everyone behaves competitively. You may think of supply as 1 GW generator blocks owned by independent firms, without any firm being a pivotal supplier.

## 3.2 Nodal Pricing

**Locational marginal pricing.** Nodal pricing is a single-stage locational marginal pricing system without redispatch. Figure 4 displays supply and residual demand curves for the two nodes. The supply curves correspond to variable costs of power plants. As is common practice, we represent demand and network constraints as residual demand curves for each node. In the South, residual demand is thus local demand minus supply from North. In the North, it is the part of Southern demand that transmission lines allow to be served from the North, minus Southern supply. Price inelastic demand in the South is 50 GW, which can be either supplied locally or through (transmission-constrained) generation from the North.

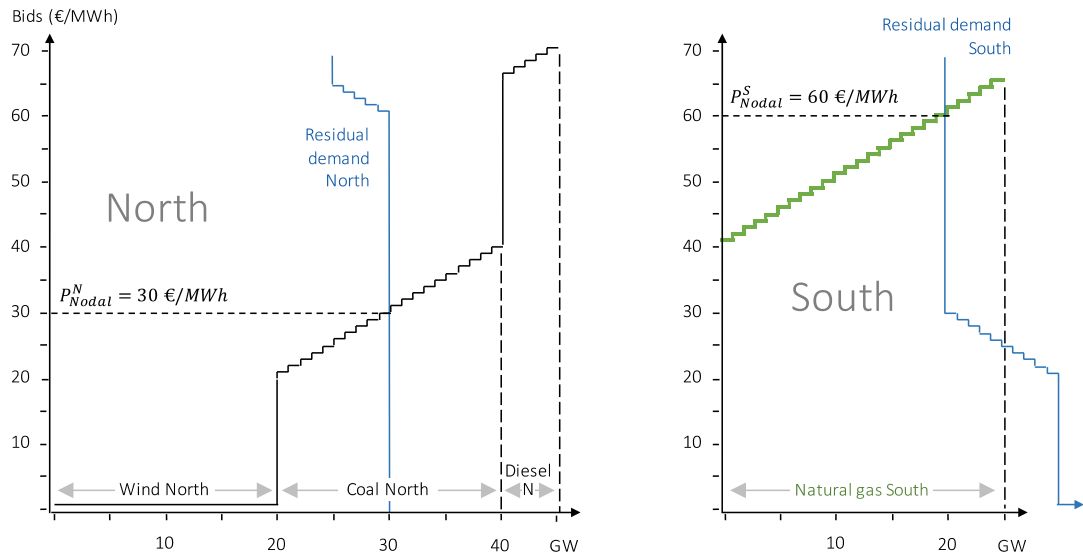


Figure 4. Variable costs ordered by size (merit order). Capacity connected to the South is bold green.

**Market outcome.** Table 1 shows the outcome of the nodal pricing markets. Absent market power, it is profit-maximizing for generators to bid variable cost, hence the market is incentive compatible. The dispatch corresponds to the security-constrained economic dispatch, i.e. the transmission-constrained cost minimum. The line is used at full capacity. The clearing prices are EUR 30 per MWh in the North and EUR 60 per MWh in the South. The system operators captures a congestion rent of EUR 900,000.

Table 1. Market result of the nodal pricing market.

	North	South
Price (locational)	30 €/MWh	60 €/MWh
Dispatch	20 GW wind 10 GW coal	20 GW natural gas
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Congestion rent	EUR 900,000	

### 3.3 Mandatory Redispatch with Cost Compensation

**Zonal separated from redispatch.** As the second benchmark market design, we study a one-zone (uniform) electricity market with mandatory provision of redispatch with cost compensation (also called “regulatory”, “administrative” or “cost-based” redispatch). In this setup, zonal markets and redispatch are two separate, consecutive processes. First, the wholesale market clears at a zonal level, resulting in a uniform price of electricity. For this purpose, transmission constraints are initially ignored. If the resulting dispatch can be accommodated by the grid, there is no need for redispatching. If the zonal market dispatch violates network constraints (as it will in our example), the system operator issues redispatch orders to the generators. Though generators are legally obliged to participate in redispatch, they are compensated for all costs occurred and profits forgone. This setup reflects several central European markets as of today, including Germany and Austria.

#### 3.3.1 Zonal Market

**Zonal market.** Figure 5 displays the zonal market equilibrium. Absent market power, it is profit-maximizing for generators to bid variable cost – the zonal market is incentive compatible. All production and consumption is cleared at a uniform price of EUR 50 per MWh. All power stations with variable costs at or below this price are dispatched, which includes 20 GW wind and 20 GW coal capacity in the North. This results in a line flow of 40 GW, which is physically infeasible.

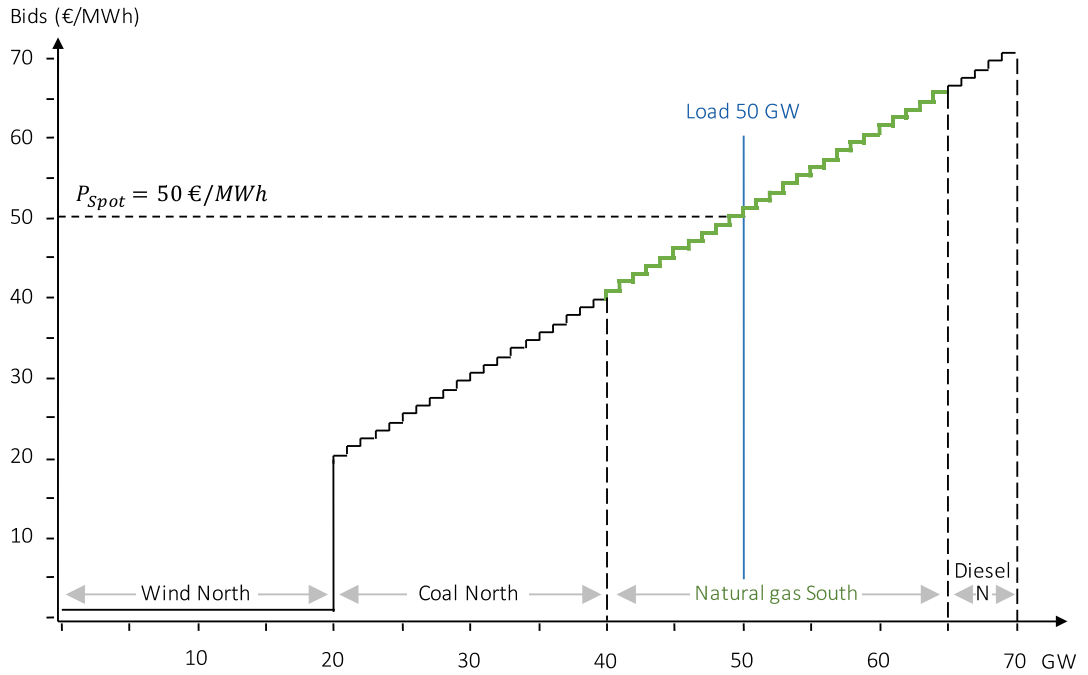


Figure 5. Zonal market equilibrium in a mandatory redispatch with cost compensation setting.

### 3.3.2 Redispatch and Compensation

**Redispatch process.** Following zonal market clearance, the system operator redispatches resources to avoid line overload. Minimizing net redispatch costs, the system operator orders the most expensive 10 GW of coal capacity to redispatch downwards (lowering generation) while the cheapest idling 10 GW natural gas capacity to redispatch upwards (raising generation).<sup>5</sup> We assume the system operator possesses perfect knowledge of costs. In a meshed network, load flow sensitivities need to be accounted for, which we avoid here due to the linear network topology.

**Compensation.** All redispatched resources are reimbursed for costs incurred and profits forgone relative to the zonal market equilibrium. This follows the logic of §13a of Germany's Energy Industry Act that says that the composition should be such that being redispatched "does not favor nor disfavor the market party economically". In the case of upward dispatch, the generator is paid its variable costs. In the case of downward dispatch, generators can keep zonal revenues but have to surrender avoided variable cost. In the above example, total redispatch costs amount to EUR 200,000. Figure 6 and Table 2 show redispatch outcomes.

<sup>5</sup> The terminology "(upward/downward) redispatch" can be found in Germany and EU texts as well as parts of the American literature while "constrained on/off plants" is more common in the UK context.

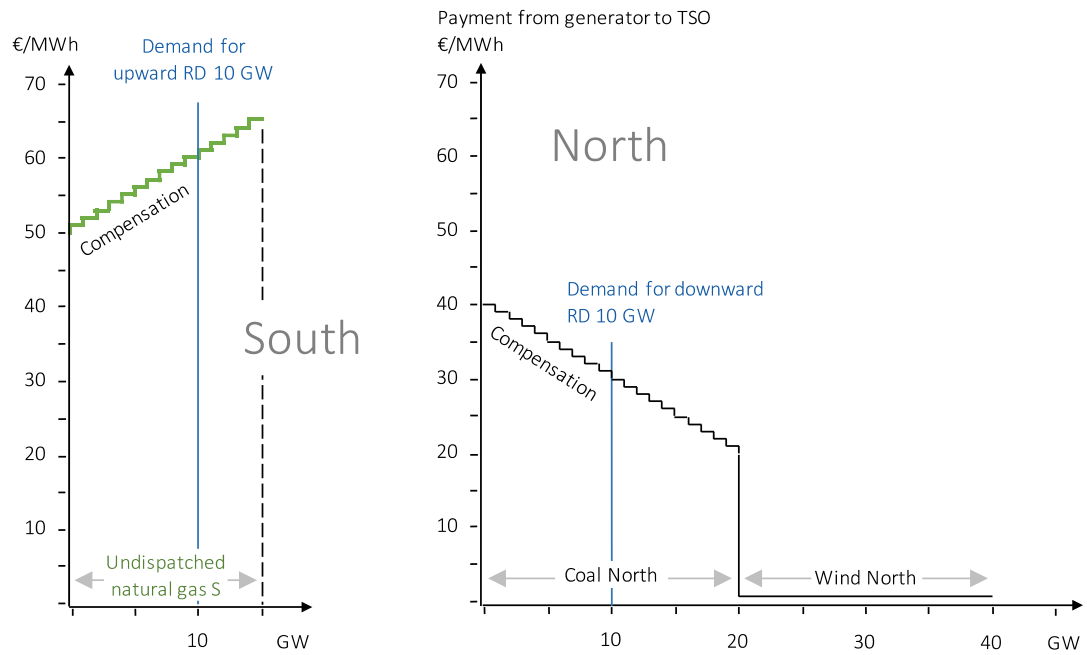


Figure 6. Mandatory redispatch with cost compensation.

Table 2. Outcome of mandatory redispatch.

	North	South
"Price"	Asset-specific	Asset-specific
Redispatch	10 GW coal ↓	10 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 200,000	

**Comparison to nodal pricing.** The physical dispatch is identical to nodal pricing, but the financials differ. Instead of collecting congestion revenue as income, the system operator incurs net costs, which are passed on to consumers. Southern generators earn less and Northerners more than under nodal pricing. So zonal markets with mandatory redispatch lead to a different distributive outcome than nodal pricing.

## 4 Inc-Dec Gaming in Redispatch Markets

After discussing two benchmark market designs, we now turn to redispatch markets. Here, a zonal electricity market is combined with locational tenders for redispatch. We first introduce the design of such a market and then derive the market equilibrium for two distinct cases, with and without anticipation.

### 4.1 Setup of the Redispatch Market

**Two-tier market design.** The power market comprises a one-zone power market that is followed by a nodal redispatch market. Hence, there are two separate markets for electricity that clear for every market time unit. Both markets are energy-only markets, i.e. remuneration is solely based on energy delivered.

**Redispatch market.** If the dispatch resulting from the zonal market can be accommodated by the grid, nothing else happens and the redispatch market is not invoked. If the zonal market dispatch implies a congested network, however, the system operator redispatches generation to resolve the congestion. Redispatch resources are procured through competitive auctions based on voluntary participation by market actors and free bids. This redispatch market is locational, i.e. it has a nodal resolution – effectively it is a separate auction for each node of the transmission network. In our example, the system operator buys energy in the South and sells energy in the North, or, more precisely, buys the Northern generators out of their contracts to produce. We assume marginal pricing (as opposed to pay-as-bid) in both market stages.<sup>6</sup> The assumption of consecutive markets seems plausible because redispatch requirements can only be determined once the zonal market equilibrium is known. For simplicity, we also assume bidding is constrained to integers (whole Euro amounts). Table 3 summarizes the market setup.

Table 3. Setup of the redispatch market.

	Zonal market	Redispatch market
Market time unit	1 hour	1 hour
Sequence	1 <sup>st</sup>	2 <sup>nd</sup> (after zonal gate closure, but before real time)
Geographic granularity	Zonal / uniform (1 price)	Nodal (2 prices)
Pricing rule	Marginal pricing	Marginal pricing

<sup>6</sup> In the case of pay-as-bid in the redispatch market, bidding behavior would be different, but the underlying incentives would remain the same. In a pay-as-bid market, market actors would try to bid as close as possible to the last accepted bid – prices thus largely converge to the unique clearing price, yet with some inefficiencies remaining (Kahn, 2001). See section 7.3 for a discussion of pay-as bid.

## 4.2 Redispatch Markets without Anticipation

**No-anticipation.** In this section, we discuss a redispatch market that is *not* anticipated by firms when placing bids on the zonal market. It will turn out that the outcome is not a Nash equilibrium.

**Solution strategy.** As markets are sequential and we assume no anticipation, the markets can be solved sequentially by forward induction. We start solving the zonal market and proceed with the redispatch market.

### 4.2.1 Zonal Market

**Zonal market.** If market parties do not anticipate the redispatch markets, bids and market outcomes on the zonal market are identical to mandatory redispatch (section 3.3.1), resulting in congestion that must be resolved with redispatching.

### 4.2.2 Redispatch Market

**South.** Because of the physical infeasibility of the zonal market results, the system operator invokes redispatch auctions. Figure 7 and Table 4 summarize the market equilibrium. In the South, all plants that are not yet dispatched offer upward redispatching. There is no market power as no supplier is pivotal, hence all suppliers bid variable costs. As the cheapest 10 GW of natural gas capacity are already dispatched, the bid curve starts at EUR 51 per MWh. The system operator has a demand of 10 GW for upward redispatch. The market clears at a price of EUR 60 per MWh.

**North.** In the North, power plants are willing to pay the system operator to be redispatched downwards because that saves cost for fuel. The producers in the North essentially buy back energy. It is helpful to think of their bids as a willingness to pay (demand) curve and the system operator's redispatch quantity as the supply curve. The competitive equilibrium price is EUR 30 per MWh. As a result, the system operator buys 10 GW in the South at a price of EUR 60 per MWh and receives EUR 30 per MWh for the 10 GW it sells in the North, resulting in net costs of EUR 30 per MWh or EUR 300,000.



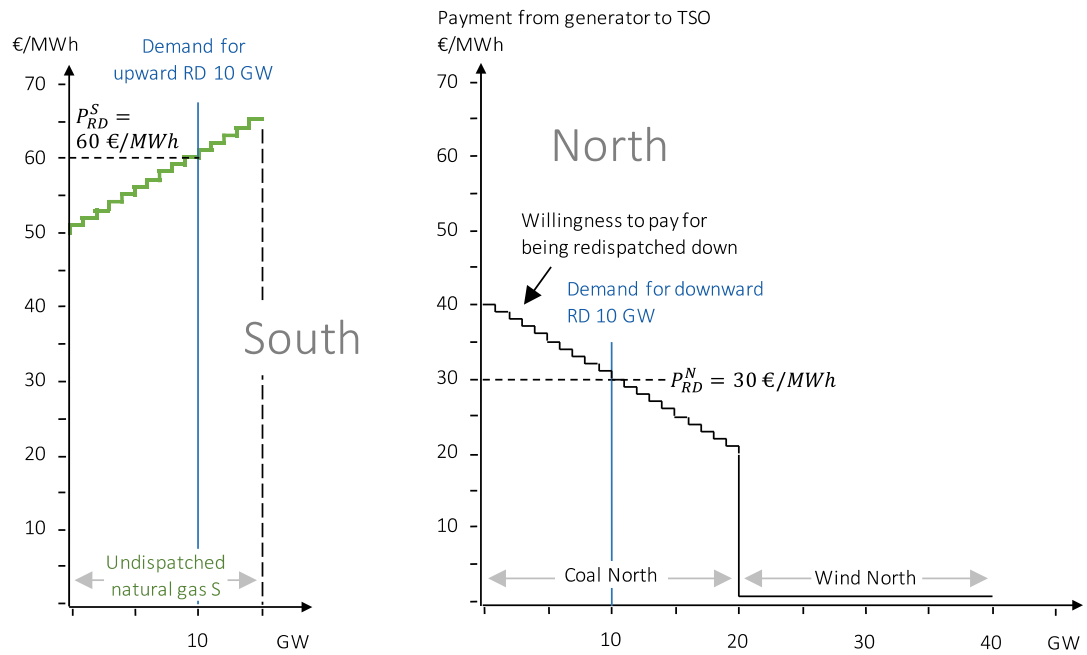


Figure 7. Redispatch market equilibria (without anticipation).

Table 4. Market result of the redispatch market (without anticipation).

	North	South
Price (locational)	30 €/MWh	60 €/MWh
Redispatch	10 GW coal ↓	10 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 30 per MWh = EUR 300,000	

**Price setting rules.** The prices on the redispatch market resemble those under nodal pricing. We assert that prices on redispatch markets, as a general rule, are identical to locational marginal pricing. In this sense introducing a redispatch market means introducing nodal pricing “through the back door” (on this observation, see also Neon & Consentec 2018).

**No Nash equilibrium.** We believe this outcome is what proponents of redispatch markets have in mind. The zonal market works properly and undisturbed, while the additional redispatch market resembles nodal pricing in terms of equilibrium prices and incentives. However, the crucial assumption behind this outcome is that generators *do not anticipate the redispatch market* when submitting bids to the zonal market. However, such ignorance is incompatible with rational behavior. Some generators in the South sell at a price of EUR 50 per MWh – if they had waited for the redispatch market, they could have earned EUR 60 per MWh. Similar

incentives exist in the North, as we show subsequently. Therefore, the outcome described in this section is not a Nash equilibrium and hence cannot be a stable market outcome.

## 4.3 Redispatch Markets with Anticipation

**Anticipation.** We now assume that generators can and do anticipate the redispatch market outcomes when placing bids on the zonal market. In other words, generators factor in that there is a second market in which they can sell – or buy back – electricity when deciding on their bidding strategy at the first stage.

**Solution strategy.** We start by assuming redispatch market prices, then solve for equilibrium strategies using backward induction, and finally, check that the assumed prices emerge through forward induction, i.e. that expectations are confirmed. As a starting point, we use the above clearing prices of EUR 60 and 30 per MWh, respectively.

### 4.3.1 Zonal Market

**Bidding strategy in the South.** When bidding into the zonal power market, generators in the South anticipate that they will be able to earn EUR 60 per MWh on the redispatch market. This opportunity cost sets a floor on their willingness to sell: cheap natural gas-fired power plants with variable costs below EUR 60 per MWh will *not* bid variable costs but instead overbid at EUR 60 per MWh. More expensive plants will continue to bid variable cost. The redispatch market essentially puts a floor on zonal offers. The zonal market is no longer incentive compatible for all firms.

**Bidding strategy in the North.** In the North, generators anticipate that they will be able to by themselves out of their delivery contracts for EUR 30 per MWh. Any zonal revenue above that will earn them a margin, independently of their own costs because, in the end, they will not produce. Essentially, these producers have the option to trade electricity between the two market stages. Consequently, the more expensive coal and diesel plants with variable costs above EUR 30 per MWh issue bids of EUR 30 – they underbid. The redispatch market effectively puts a ceiling on zonal offers. The cheaper wind and coal plants bid variable costs.

**Zonal market equilibrium.** Table 5 and Figure 8 display bid curves and the resulting zonal market equilibrium. The zonal market clears at a price EUR 60 per MWh. All power stations with variable costs below this price are dispatched, which includes *all* generation in the North, including expensive diesel peakers. 5 GW of generation capacity from the South is dispatched. Because 20 GW of natural gas capacity had bid identical prices, the identity of dispatched plants is undetermined; we assume it is randomly drawn. At first glance, this may not look like an equilibrium, but it is: all bidders with bids of 60 €/MWh are indifferent between being dispatched in the zonal market or not, because if they are not, they will earn the same price later in the redispatch market. The zonal dispatch results in a line flow of 45 GW, hence the dispatch is physically infeasible. Note that the line overload has increased compared to the case without anticipation.

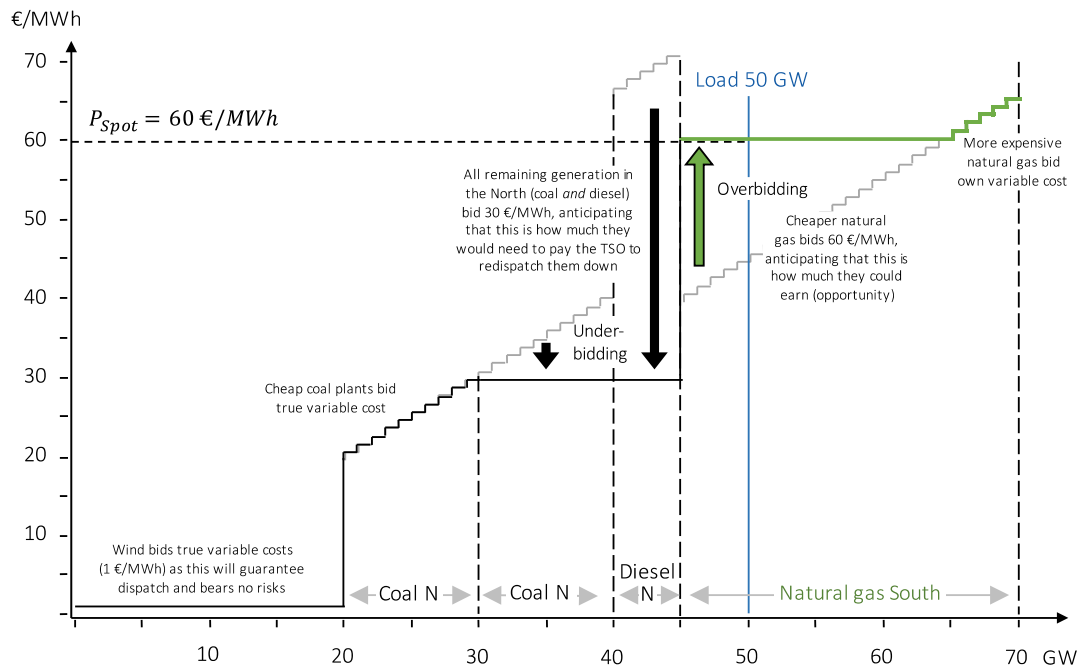


Figure 8. Zonal market equilibrium with anticipation of redispatch markets.

Table 5. Market result of the zonal market (with anticipation)

	North	South
Price (zonal)	60 €/MWh	
Dispatch	20 GW wind 20 GW coal 5 GW diesel	5 GW natural gas
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	45 GW (infeasible)	
Congestion rent	-	

**Nodal prices determine zonal prices.** In this specific example, the zonal market price is identical to the Southern redispatch market's price and hence higher than in the zonal price under mandatory redispatch. But this is not a general rule: in the Appendix, we present an otherwise identical example with load reduced to 40 GW in which the zonal price will be identical to the Northern redispatch price and thereby lower than under mandatory redispatch. When the line is congested, zonal prices seem to be determined as either one of the nodal prices (North or South). Which of the nodal prices sets the zonal market price depends on whether generation in the cheaper node (ignoring transmission constraints) is sufficient to cover total zonal load. If the line is not congested, both nodal prices and the zonal price are identical.

### 4.3.2 Redispatch Market

**Redispatch market.** Because of the physical infeasibility of the zonal market results, the system operator has to buy 15 GW of redispatch services. Given the redispatch market is the last market stage, there is no benefit to bidding anything but variable cost. Figure 9 and Table 6 present the market equilibrium.

**Clearing prices.** In the South, there is 20 GW of total supply available for upward redispatch and the demand for upward redispatch is 15 GW. Because the identity of the winning bidders in the zonal market had been undetermined hence randomly chosen, different patterns of the supply curve could emerge. However, there is a unique clearing price of EUR 60 per MWh. In the North, the clearing price is EUR 30 per MWh.

**An equilibrium.** This market outcome is a Nash equilibrium: All expectations, in particular the assumed prices on the redispatch market, turn out to be correct. No firm has an incentive to adjust its strategy.

**Gaming in the North.** Power stations in the export-constrained North underbid, increasing their output just to later decrease it in the redispatch market. These resources uneconomically schedule production in the zonal market, which is then undone in redispatch. This bidding strategies is what is often called the “increase-decrease game”. Of course, physical output is not really increased and decreased over time; it is only schedules that change over time. You could say that Northern generators engage in carry trade, selling electricity at a high price to buy it back later at a lower price. In a sense, the Northern generators engage in “asset-backed short selling” – the generator can deliver the initial zonal transaction physically but never intends to.

**Gaming in the South.** In the import-constrained South, generators engage in what you might call “dec-inc” gaming: they overbid, decreasing their scheduled output just to later increase it. The Southern generators optimize between two markets, selling their output where they earn the highest price. Essentially, both Northern and Southern generators earn profits from arbitrage between the two market stages. However, in this case arbitrage trade does not make prices converge: essentially it creates its own demand by increasing the need for redispatch. The exploitation of this arbitrage opportunity does not require market power nor collusion. Recall that in our model, all three markets are perfectly competitive.

**Consequences of gaming.** While gaming has no impact on the final physical dispatch, it has important consequences otherwise: line overload is magnified, and generators extract wind-fall profits. These and further implications we discuss in detail in the following section.

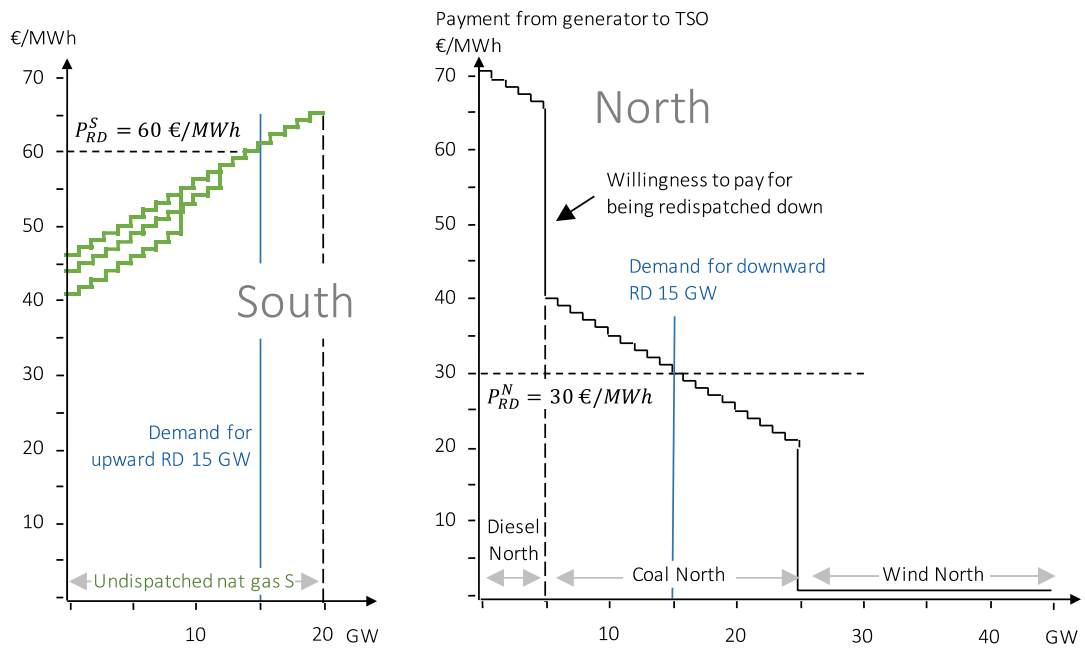


Figure 9. Redispatch market equilibria (with anticipation).

Table 6. Market result of the redispatch market (with anticipation).

	North	South
Price (locational)	30 €/MWh	60 €/MWh
Redispatch	10 GW coal + 5 GW diesel ↓	15 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 30 per MWh = EUR 450,000	

## 4.4 Clearing Prices in Comparison

**Clearing prices.** Table 7 summarizes the market-clearing prices across the three Nash equilibrium market designs. Mandatory redispatch can be understood as discriminatory pricing of first degree (individual prices for each producers), whereas nodal pricing and redispatch markets yield identical prices for producers connected to the same node. Only the redispatch market has two different parallel prices, a zonal and a locational price. This is the root of the incentives for strategic bidding behavior in the setting.

Table 7. Market-clearing prices.

€/MWh	Nodal pricing	Mandatory redispatch	Redispatch market
Zonal (uniform) price	-	50	60
Locational price North	30	-	30
Locational price South	60	-	60

## 4.5 No Market Power Needed

**Defining market power.** In economic theory, actors are said to have market power if they can influence the market-clearing price with their production decisions. In regulatory practice, the European Commission assumes markets are subject to market power if any individual suppliers has a market share of greater than 40%.<sup>7</sup> In electricity markets, market power is often assessed by determining if any individual generator is pivotal, i.e. required to supply demand.

**No market power.** By any of these definitions, market power is absent from our model. At all times, generators behave as atomistic price-takers, both the zonal as well as the redispatch markets. Firms do not collude, either, neither through explicit nor tacit agreements. This is a core result our model demonstrates: the inc-dec bidding strategy does not require any market power.

## 4.6 Predicting Network Congestion

### 4.6.1 Risk and Bidding Under Uncertainty

**The risk of gaming.** Absent perfect foresight, gaming carries a risk. If firms anticipate redispatch prices incorrectly, strategic bidding may result in losses or forgone profits. To see the risk they are facing, consider the above example. If, in contrast to expectations, congestion does not materialize, the Northern diesel generators who underbid in the zonal market actually have to produce at a loss. Some of the Southern generators do not produce despite the price being above variable cost, and hence forgo profit.

**Bidding under uncertainty.** For risk-averse actors, uncertainty will impact the optimal bidding strategy. In the example of diesel plants, optimal risk-adjusted bids will likely fall somewhere in between the predicted redispatch price and variable cost. The higher uncertainty and the more risk-averse actors, the closer prices will follow variable cost and, hence, the less gaming will occur.

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<sup>7</sup> [http://ec.europa.eu/competition/antitrust/procedures\\_102\\_en.html](http://ec.europa.eu/competition/antitrust/procedures_102_en.html)

#### 4.6.2 Producers Can Predict Congestion

**Prediction possible.** Whether congestion can be predicted with reasonable accuracy will depend on the nature of congestion. If congestion is structural,<sup>8</sup> correct anticipation of redispatch will be the norm, rather than the exception. The German transmission grid can be regarded as structurally congested.

**Network models.** A load flow model is likely the best tool to predict congestion. These models are widely available, inexpensive, and can be calibrated using historic redispatch data. Researchers maintain European load flow models, including open source models such as ELMOD or PyPSA<sup>9</sup>. Commercial software to solve load flow models is a standard product and readily available. These models should be able to forecast grid congestion accurately, and hour-by-hour clearing of electricity markets should give analysis plenty of opportunity to calibrate and learn. Even today in the absence of redispatch markets, consultancy companies are offering forecasts of grid congestion to German market participants, mostly to predict renewable energy curtailment.<sup>10</sup>

#### 4.6.3 Econometric Prediction

**Regression model.** Even absent a network model, one can even predict congestion using simple econometrics. As a proof of concept, we set up a regression model to predict hour-by-hour redispatch in Germany using regressors such as renewable generation forecasts, load forecasts, and lagged redispatch. Table 8 summarizes the model specification and data sources. All data used are in hourly granularity and taken from public sources. Using data from 2015-18, we estimate the model using OLS, yielding an adjusted  $R^2$  of 48%. Even with quite limited resources and a straightforward regression model, we can predict hour-by-hour redispatch volumes well. Detailed results can be found in the Appendix.

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<sup>8</sup> In the sense of the [Electricity Market Regulation](#), where grid congestion is considered structural if it does not only occur sporadically but “is predictable, is geographically stable over time, and is frequently reoccurring under normal power system conditions”. According to the German TSOs and approved by the regulatory authority BNetzA, congestion is structural within the German bidding zone (see [50Hertz et al. 2019](#)).

<sup>9</sup> A list of open power market models is available at [https://wiki.openmod-initiative.org/wiki/Open\\_Models](https://wiki.openmod-initiative.org/wiki/Open_Models)

<sup>10</sup> Meteomatics EinsMan Forecasts (see <http://meteomatics.com/display/NEWS/2017/02/07/Portfolio-individual+EISMAN-Forecasts>), UBIMET EinsMan Prognose (see <https://www.ubimet.com/en/services/einsman-solutions/> as well as <https://patents.google.com/patent/DE102017101265A1/en>).

Table 8. Congestion regression model specification

	Variables	Data Sources
<b>Dependent variable</b>	Redispatch volume (MW) as the sum of up and downward redispatch.	Own calculation based on Netztransparenz.de
<b>Independent variables</b>	Solar generation forecast in each German control area (MW)	ENTSO-E Transparency Platform
	Wind generation forecast in each German control area (MW)	ENTSO-E Transparency Platform
	Load forecast in each German control area and in CH, FR, AT (MW)	ENTSO-E Transparency Platform
	EU ETS Emission Allowance Prices (EUA)	EIKON Data Service
	24h lagged redispatch volume	Own calculation based on Netztransparenz.de
	Year dummies	-

**Machine learning models.** Staudt et al. (2018) and Staudt (2019) use an artificial neural network to predict congestion of an individual line. Using three years of data, they reach a precision of 70%. van der Lugt et al. (2020) provide similar findings, using a range of machine learning models. Like ours, these methods are purely statistical in the sense that it does not use information about the network topology. This underlines that congestion can be anticipated by market participants.

## 5 Implications and Consequences

In our model, the final physical dispatch of power plants is identical across designs,<sup>11</sup> as is the sum of producer and consumer surplus. However, there are broader welfare implications,

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<sup>11</sup> This is driven by our assumptions, of course. We assumed no information asymmetries between the system operator and the generators; such information asymmetries will tend to reduce the efficiency of mandatory redispatch. We also assumed no start-up and ramping constraints, which would turn timing and gate closure into relevant factors. Finally, we assumed perfect competition. Unabated locational market power will tend to impact nodal pricing and redispatch markets adversely.



which we will discuss in this section: network congestion is amplified, producers extract wind-fall profits, financial markets are distorted, and perverse investment incentives emerge.

## 5.1 Congestion is Exacerbated

**Making congestion worse.** The existence – or more precisely, the anticipation – of a redispatch market leads market parties to submit zonal market bids that *increase* the level of congestion. In our example, the line overload increased from 10 GW (mandatory redispatch) to 15 GW (Table 9). Thus, a larger quantity must be redispatched to satisfy the transmission constraint, inflating congestion costs.

Table 9. Redispatch volume

	Nodal pricing	Mandatory redispatch	Redispatch market
Redispatch volume	0 GW	10 GW	15 GW

**Systematic pattern.** This finding is not an artefact of the example but a systematic pattern. Parties located in scarcity regions are incentivized to withhold capacity from the zonal market by means of overbidding to then benefit from high prices for upward redispatch. By doing so they intensify scarcity, aggravating congestion. Similarly, generators in oversupply regions are incentivized to underbid and overproduce, further amplifying congestion. Consentec et al. (2019) use a load flow model calibrated to 2030 to estimate that market-based redispatch might increase redispatch volumes as much as six-fold.

**Operational challenges.** Large-scale redispatch might bring operational challenges. System operators get a systematically biased picture of actual system conditions by studying the zonal market outcome. Since a redispatch market can only be opened *after* gate closure of any zonal trading (see also Section 6.5), system operators will need to implement large volumes of re-dispatch quickly, which is challenging and may jeopardize operational security.

**Aggravating, not creating congestion.** While producers benefit from exacerbating congestion, there is no incentive to *create* congestion in an otherwise uncongested situation, because then the redispatch price would not rise above the zonal price in the competitive setting we study.

## 5.2 Windfall Profits

**Rents.** Inc-dec bids are a means to inflate profits, and so they do. Table 10 summarizes the distribution of rents among consumers and producers for the single hour that we study. There are two channels through which consumers pay for electricity: the wholesale price (1), and congestion rents/cost (2), the sum of which is total consumer expenditure (3). Since final physical dispatch is identical across market designs, variable generation costs must also be identical

(4), hence generators' profit differs (5). In this example, redispatch markets increases producer profits by 50% compared to mandatory redispatch.<sup>12</sup>

Table 10. Rent distribution and costs for the single hour modeled (EUR).

	Nodal pricing	Mandatory redispatch	Redispatch market
Wholesale costs for consumers (1)	3 000 000	2 500 000	3 000 000
Congestion cost (2)	-900 000 (congestion rent)	200 000 (redispatch cost)	450 000 (redispatch cost)
Total expenditure/revenue (3=1+2)	2 100 000	2 700 000	3 450 000
Variable generation cost (4)	1 285 000	1 285 000	1 285 000
Total Producer rents (5=3-4)	815 000	1 415 000	2 165 000
- of which Northern generators	625 000	1 370 000	1 975 000
- of which Southern generators	190 000	45 000	190 000

## 5.3 Financial Markets

**Loss of underlying.** Under mandatory redispatch, the zonal market price determines generator profit. Naturally, it serves as the underlying for forwards and futures traded on financial markets. With the emergence of redispatch markets, the zonal price might no longer be suited as underlying for forward contracts for two reasons. First, the zonal price itself becomes influenced by strategic bids, and second, it no longer captures the main sources of revenue.

**Zonal price influenced by strategic bids.** As we show in our example, in times of congestion, the zonal price converges to either one of the nodal prices. All consumption and generation are cleared at that nodal price. The zonal price therefore no longer results from the zonal supply and demand balance (zonal merit order) but from the interplay of local supply, demand, congestion and the strategic bids of market actors. It therefore becomes harder to predict.

**Redispatch markets relevant for revenues.** Generators who expect to earn a higher (nodal) price on the redispatch market than the zonal price will not be willing to hedge at the expected zonal price. Financial contracts based on zonal prices become poor hedging tools. Regulators have addressed this issue in most nodal pricing systems by introducing trading hubs and financial transmission rights, both of which are absent from all proposals for redispatch markets that we are aware of.

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<sup>12</sup> Recall that we have modeled a single hour. If you multiply these numbers by 8760 hours per year to get to annualized values, redispatch markets increases profits by EUR 7bn.

## 5.4 Investment Incentives

**A rationale for redispatch markets.** One argument in favor of market-based redispatch is that it might attract new entrants. This could be those existing assets that are not incorporated in mandatory redispatch, such as consumers. Alternatively, this could also be investment in new power generation capacity. The hope is, of course, to attract investment at locations where it makes sense from a grid perspective: generation in scarcity regions and consumption in over-supply regions. At first glance, this expectation seems warranted: the equilibrium prices on redispatch markets, as we have shown, resemble locational marginal prices. So, if redispatch markets are comparable to nodal pricing as a credible investment signal, one might expect a local investment response. However, market-based redispatch creates perverse investment incentives.

**Perverse investment incentives.** Figure 10 displays the producer rents of a power plant in the undersupplied South as a function of variable costs and across market designs. Figure 11 shows the equivalent for the oversupplied North. Rents are important in a dynamic context as they provide investment (or disinvestment) incentives to power plants. In our model, nodal pricing delivers undistorted locational prices and hence “gets the producer rents right”. It incentivizes (only) the kind of plants that are needed at the respective locations given grid constraints. Compared to this, both mandatory redispatch and redispatch markets create distorted incentives; however, the source and direction of distortion is different.

**Erased locational incentives under mandatory RD.** Mandatory redispatch results in lower prices in the South and higher prices in the North compared to nodal pricing. Consequently, investment incentives are biased towards too much investment North and too little South. Essentially, by applying a uniform price, this market design erases locational investment incentives.

**Aggravated overinvestment in the North under market-based RD.** Redispatch markets, in contrast, create a different pattern of distortion. In the South, rents are identical to nodal pricing. In the North, however, the arbitrage opportunity implies that it may be profitable to invest in assets that have the sole (or main) purpose to be redispatched down. Despite the fact that plants with variable costs above EUR 30 per MWh will not produce, these plants do earn a profit from selling at the zonal market and being subsequently redispatched. Redispatch markets thus encourage investments where they are not needed and above the level that would be incentivized by mandatory redispatch. In different words, redispatch markets cause dynamic inefficiency.

## South

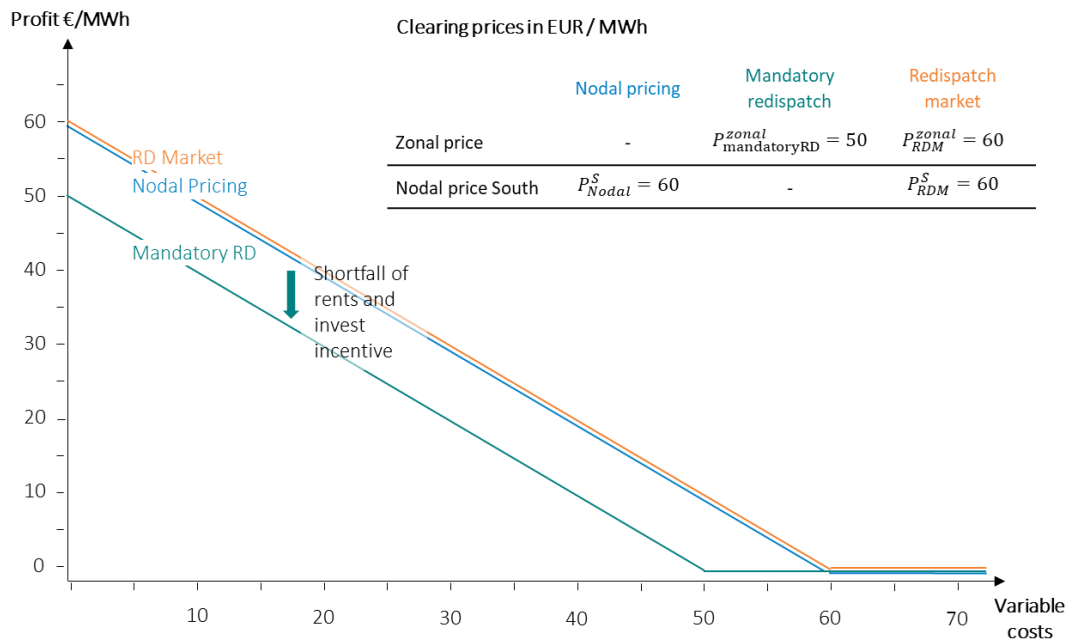


Figure 10. Generator profits in the South. The figure shows generator profits as a function of variable cost for the single hour we study. In the undersupplied region, rents on a redispatch market equal rents under nodal pricing.

## North

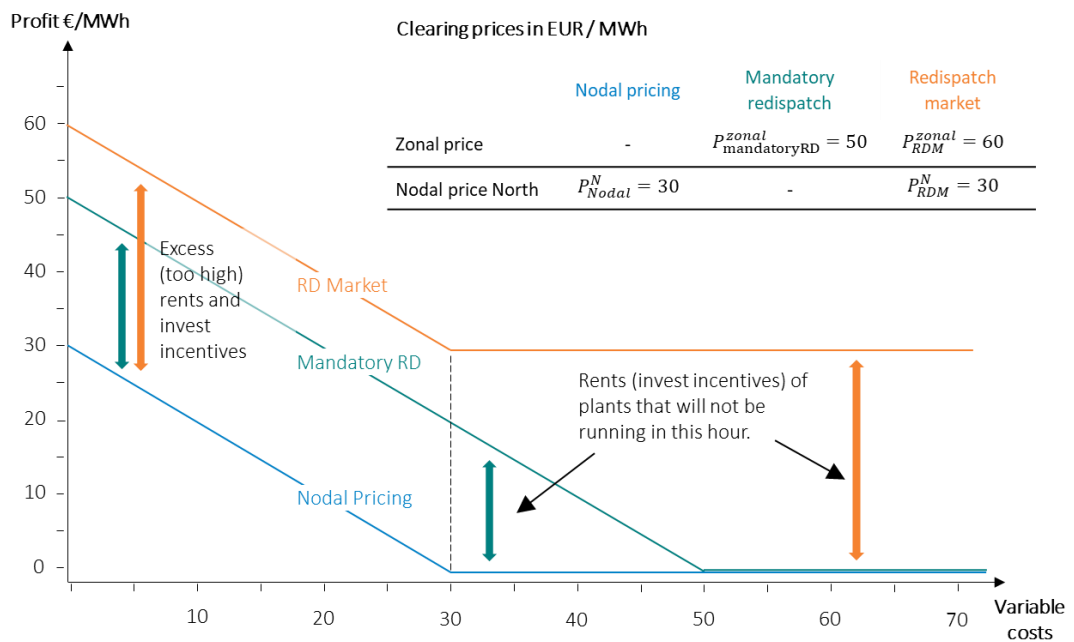


Figure 11. Producer rents in the North. The figure shows generator profits as a function of variable cost for the single hour we study. In the oversupplied region, redispatch markets systematically provide over-incentives for generation investments.

**Ghost plants.** The additional profit of generators in already oversupplied regions under market-based redispatch is especially problematic as it creates a perverse incentive to build additional capacity in the wrong place, which adds to network overload. The rents encourage investors to install low fixed-cost / high variable-cost generation – think of mothballed plants or retired ship engines – that have the sole purpose to engage in inc-dec gaming. Such “ghost generators” would be a profitable investment as long as the per-hour fixed costs are smaller than the arbitrage earned per hour. Variable costs do not matter, as these plants will never generate power.

**Ghost consumers.** The same perverse incentive exists on the load side in the South. Investors are encouraged to connect loads for the sole purpose to engage in gaming. Such “ghost loads” might be mothballed industrial consumers, loads that underutilize their grid connection, or even dedicated electricity-consuming devices such as large water heaters. They will never physically consume electricity, hence volumetric taxes and fees levied on consumption are not an issue.

**Network over-investment.** Grid operators and regulators might also face misleading investment signals. The increased volume of redispatch as a consequence of gaming might be taken as a signal of investment needs. This could trigger overinvestments in networks.

## 6 More Gaming

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Our model does not capture all possibilities to game a redispatch market. In this section we discuss five ways of how firms can extract additional rents: exploiting market power, participation of loads in gaming, pure financial arbitrage, a riskless gaming strategy that can be deployed if a firm holds assets on both sides of the constraint, and riskless gaming if redispatch and zonal markets run in parallel.

### 6.1 Effects of Market Power

**An example with locational market power.** Up to this point, we have assumed competitive markets. Now consider the case of market power. To this end, we assume only 20 GW (instead of 25 GW) of natural gas-fired power generation to be installed in the South – the 5 GW of plants with highest marginal cost disappear. We also assume that electricity demand becomes perfectly price elastic at a backstop price of EUR 10,000 per MWh, but that no other mechanism is in place to mitigate market power. All other assumptions remain.

**Outcomes.** Some outcomes remain unchanged while others will differ dramatically.

- Under mandatory redispatch, nothing changes: the zonal market equilibrium as well as redispatch remains the same.
- Under nodal pricing nothing changes in the North, while in the South all generators become pivotal, as overall capacity is just sufficient to supply load. Generators will be able to increase the price to EUR 10,000 per MWh in the South.
- Similarly, in redispatch markets, nothing changes in the Northern redispatch market, while in the Southern market generators will be able to increase the price to backstop levels. Consequently, they will also bid that amount into the zonal market. Hence, the zonal market clearing price increases from EUR 60 to EUR 10,000 per MWh. This yields windfall profits not only for Southern but also for Northern power plants.

Inc-dec bidding does not require any market power, but locational market power will have more severe consequences under redispatch markets than under mandatory redispatch.

**Mandatory redispatch as regulation.** Harvey & Hogan (2001), among others, have argued that zonal and nodal pricing are equivalent in the possibility of firms to exercise locational market power. This is indeed correct for redispatch markets, but not for mandatory redispatch. Essentially, mandatory redispatch is a form of cost-plus regulation that addresses locational market power.

## 6.2 Demand Participation

**Demand participation.** In our model, we assumed demand to be exogenous and perfectly price inelastic. In fact, consumers can engage in gaming, too.

**North.** Consider an industrial load connected to the North whose true willingness to pay is EUR 200 per MWh. Anticipating a price on the local redispatch market of EUR 30, the load will place a bid of that amount, effectively “withholding demand” on the zonal market. This will further exacerbate congestion, increasing the need to redispatch. On the redispatch market, the load will be able to buy electricity for EUR 30 per MWh.

**South.** Now consider an industrial load connected to the South whose willingness to pay is zero, say, because the facility is closed during holidays. There is no incentive to strategic bidding since zonal and redispatch price coincide. However, it is straightforward to construct a different example (see Appendix) where the Southern redispatch price rises above the zonal price. In that situation, there is an incentive for arbitrage: the load would “pretend to produce”, buying low-cost electricity on the zonal market and sell it back to the system operator at a higher price at a later stage. This aggravates congestion, too.

## 6.3 Financial Arbitrage

**Pure financial arbitrage.** Our model describes what could be described as “asset-backed arbitrage”: generators do not plan to fulfil their zonal market schedules physically, but they could

if necessary. In principle, one does not need to own physical assets to game the market. Any financial trader could take positions on the zonal market to close them on the redispatch market. Traded volumes could become infinitely large. However, such purely financial arbitrage trading could be prevented relatively easily through regulation that makes it a requirement to be able to physically fulfill any schedule.

**Shades of grey.** There may be shades of grey between purely financial and asset-backed bidding strategies. Assets under maintenance could be used by traders to justify short selling. In the case of wind and solar energy, gaming could be justified by the margin of error in production forecasts. Such strategies would make the outcomes of the above model more severe.

## 6.4 Riskless Arbitrage with Multiple Assets

**Reporting strategic schedules.** In our above model, gaming works through market transactions, e.g. selling and buying back. However, there are even easier ways of obtaining windfall profits from redispatch markets if a single firm controls plants on both sides of the constraint. After markets close, generators have to report to the system operator which power plants they plan to operate to fulfill their market-based and over-the-counter production obligations.<sup>13</sup> They can use these schedules to engage in the inc-dec strategy.

**Zero-risk gaming with two assets.** Consider a firm that owns both a low variable cost plant in the South as well as the high variable cost plant in the North. Initially, the firm would submit schedules indicating only the Northern plant to produce. If the network is congested, the firm behaves as in our model above, essentially earning income for shifting production from the Northern to the Southern facility. If there is *no* congestion, however, the firm simply fulfills its contract obligation using the Southern plant. So, unlike in our model, this type of inc-dec gaming is not subject to price risk.

## 6.5 Riskless Arbitrage with Parallel Markets

**Parallel redispatch and zonal markets.** In our model, we have assumed that the redispatch market to open after zonal market clearing. If, in contrast, both markets operate in parallel, risk-free gaming is possible: market parties can simply buy cheap on one and sell expensive on the other market. This does not lead to price convergence, because by aggravating congestion gaming creates its own demand.

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<sup>13</sup> In the EU, such obligatory reporting of plant-specific production schedules is established in a process called Generation and Load Data Provision Methodology (GLDPM), which is regulated by Article 16 of Regulation (EU) 2015/1222. In Germany, the GLDPM builds on a process called KWEP that was confirmed in decision number BK6-13-200 of the regulator BNetzA. See [https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1\\_GZ/BK6-GZ/2013/BK6-13-200/BK6-13-200\\_Beschluss\\_.html](https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1_GZ/BK6-GZ/2013/BK6-13-200/BK6-13-200_Beschluss_.html)

## 7 Mitigating Gaming through Regulation

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Preventing inc-dec bidding is not trivial. In this section we discuss five approaches that had been proposed: competition and transparency, competition law, pay-as-bid pricing, mandatory redispatch as a backstop, and regulating the redispatch market. Drawing on Neon & Consentec (2019), we show that these mitigation strategies seem little promising and/or are likely to entail costly side effects.

### 7.1 Transparency

**Transparency not a cure.** Given the importance of anticipation for actors engaging in the inc-dec strategy, it becomes clear that inc-dec gaming cannot be avoided by increasing transparency to the market. A recent report by European DSO organizations and ENTSO-E (CEDEC et al., 2019) claims that “being as transparent as possible will reduce the possibilities for gaming”. In this paper (Section 4.3), we show that specifically the full transparency case of perfect anticipation yields the maximum amount of gaming, and therefore show that transparency is not a viable strategy to prevent the inc-dec strategy.

**Removing transparency.** Going in the opposite direction, Schuster et al. (2019) propose to limit the available information about network congestion as a strategy to prevent inc-dec. This essentially means removing market transparency regarding network congestion. We find this to be neither doable nor desirable. First, congestion can be forecast using public weather variables together with historic redispatch data, as we show in Section 4.6. Furthermore, actors who are frequently called up for redispatch also observe their own redispatch pattern and correlate this to public data, making it impossible to completely remove market knowledge about congestion. Second, even if it were possible to achieve complete ignorance about congestion, the very investment signals that redispatch markets are supposed to provide would no longer materialize. Removing transparency is thus neither achievable nor desirable.

### 7.2 Competition Law

**Competition law.** Inc-dec gaming does not require market power nor collusion. Therefore, it seems unlikely that this bidding strategy violates competition law or market manipulation legislation (see also Stiftung Umweltenergierecht, 2019). It is also unlikely to violate connection agreements. It is a legitimate, rational strategy that essentially means simply to price in opportunity costs.

**Pricing in opportunity costs.** The redispatch market is comparable to the balancing market in the sense that both markets represent opportunity costs that rational firms factor in when bidding on the zonal market. A firm that expects to earn EUR  $X$  per MWh on the balancing market will be unwilling to sell electricity below that price on the zonal market, regardless of



its own variable cost. Similarly, anticipating a redispatch market, agents “withhold capacity” from the zonal market in the same way they “withhold capacity” to supply the balancing market. In both cases, this seems to be a valid and lawful optimization strategy across markets rather than abusive behavior or market manipulation. The only difference is that in the case of redispatch markets, the market design does not incentivize a system optimal choice but instead one that amplifies the initial problem (congestion).

**Preventing gaming.** Being legitimate behavior, inc-dec bidding cannot be simply penalized, even if it can be detected.

## 7.3 Pricing Rules in the Redispatch Market

**Pay-as-bid.** Many proposed and existing redispatch markets use the pay-as-bid pricing rule. This stands in contrast to our model where we assumed marginal pricing (pay-as-cleared). Under perfect foresight both pricing rules yield identical outcomes. Under pay-as-bid, infra-marginal bidders will simply bid the variable cost of the marginal plant, instead of their own variable costs. Under imperfect information market participants would try to forecast the clearing price and set bids close to that price. As a means to prevent inc-dec gaming, pay-as-bid pricing is ineffective.

**Constraint to bid the same in both markets.** A constraint that could, at a first glance, be thought of as curbing inc-dec gaming is that the regulator imposes on market parties to bid the same price into both the zonal and the redispatch market. Even though our example above allowed producers to bid independently in each market, our results do not depend on that assumption. Market parties can bid exactly the same in both markets without changing the market outcome (quantities, clearing prices, profits). Imagine in the redispatch markets (with anticipation, Figure 9) producers do not bid their marginal cost but instead bid exactly the same as they have bid into the zonal market (Figure 8). This would still result in the same redispatch market equilibrium. It is therefore not possible to curb inc-dec gaming by imposing such a constraint.

## 7.4 Mandatory Redispatch as Backstop

**Markets for some.** Many proposals for redispatch markets suggest leaving mandatory redispatch with cost compensation in place for those actors that are obliged to participate (typically large conventional plants) while introducing voluntary markets for all other actors, in particular loads. Based on initial economic intuition, this proposal appears to strictly improve welfare: producers will only participate if they can receive a net benefit. Furthermore, the system operator can use mandatory redispatch as a backstop for markets.

**Inc-dec gaming prevails.** However, this line of thinking neglects gaming. Even if it is only loads that face an incentive to game (recall 6.2), their strategic bidding will aggravate congestion. Again, the fallacy is to assume that zonal market results remain unaffected by introducing

redispatch markets. They will not. The small-scale plants and loads that can participate face an incentive to adjust their zonal market behavior to incorporate opportunities on the redispatch market, exacerbating congestion.

## 7.5 Regulating the Redispatch Market

**Stopping gaming through regulation.** To avoid the incentives for overbidding and underbidding on the zonal market, one would need to remove any predictable profit opportunity on the redispatch market. One way to do this is to require a pay-as-bid rule with monitored bids that correspond to marginal costs. This would then resemble mandatory redispatch in all aspects but the name.

# 8 Conclusions

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**Strategic bidding.** In this paper, we study hybrid electricity markets that combine a zonal power market with a nodal redispatch market. In the first stage intrazonal transmission constraints are ignored, but in the second they are not. We show that if firms – generators, storages, loads, and financial traders – can anticipate the outcome of the redispatch market, they will factor in this profit opportunity, distorting their zonal market bids. The incentive to do so derives from inconsistent pricing between the two market stages.

**The consequences of inc-dec gaming.** Such inc-dec gaming has a number of problematic consequences. In particular, it:

- aggravates congestion and hence increases redispatch volumes and congestion costs,
- creates windfall profits and redistributes rents from rate payers,
- causes financial markets to decouple from zonal markets, and
- creates perverse investment incentives.

**Inconsistent market design.** Despite claims to the contrary, it is *not* market power that drives inc-dec gaming. The model developed in this paper assumes competitive behavior, yet gaming is the dominant strategy. At the root of the problem is inconsistent market design: combining a regional with a locational market yields undue arbitrage opportunities that rational firms exploit. This is a general phenomenon in a power market that comprises two stages that have different spatial granularity. This applies also to, say, a distribution-level flexibility market located within a transmission-level nodal market.

**Mitigating gaming.** Inc-dec gaming is difficult to mitigate. Not relying on market power, is unlikely to violate general competition law. Using pay-as-bid pricing in redispatch markets will not stop gaming. Introducing redispatch markets for new actors (say, consumers) while keeping existing mandatory redispatch in place will do damage, too. Price regulation has high

informational requirements and, even if those are overcome, takes away the very incentive redispatch markets are meant to provide.

**A bad type of nodal pricing.** If congestion is predictable, introducing redispatch markets *de facto* means introducing nodal pricing – but a dysfunctional and costly type of nodal pricing: a proper institutional framework is missing (central dispatch, adequate market oversight, financial transmission rights, and more), and arbitrage trade allows market parties to extract windfall profits.

**Consistent policy options.** We conclude from this analysis that electricity market design must be consistent, and energy-based redispatch markets within zonal wholesale markets are not. We see three options: First, stick to bidding zones and relieve congestion within the zones through mandatory redispatch with cost compensation. Mandatory redispatch does not offer profit opportunities, and hence the spot market is not distorted. However, this comes at the cost of lacking locational incentives. Second, introduce full-fledged locational marginal pricing, including all the institutional changes associated with a well-functioning nodal market. Third, explore voluntary redispatch schemes that reduce arbitrage opportunities to the utmost degree possible. One option could be longer-term contracts with capacity payments. Market parties would offer their redispatch services for, say, a month or a year and would receive a fixed compensation. Payments must be designed such that actual delivery of energy (or reduction of output) does not provide profits.

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## Appendix: Reduced Load

The following figures depict the Nash equilibrium in zonal and redispatch markets with anticipation if the level of load is reduced to 40 GW. At this level, the zonal price converges to the nodal price of the Northern node. Whether the zonal price converges to the (lower) Northern or (higher) Southern RDM price thus depends on parameters. Changes are highlighted.

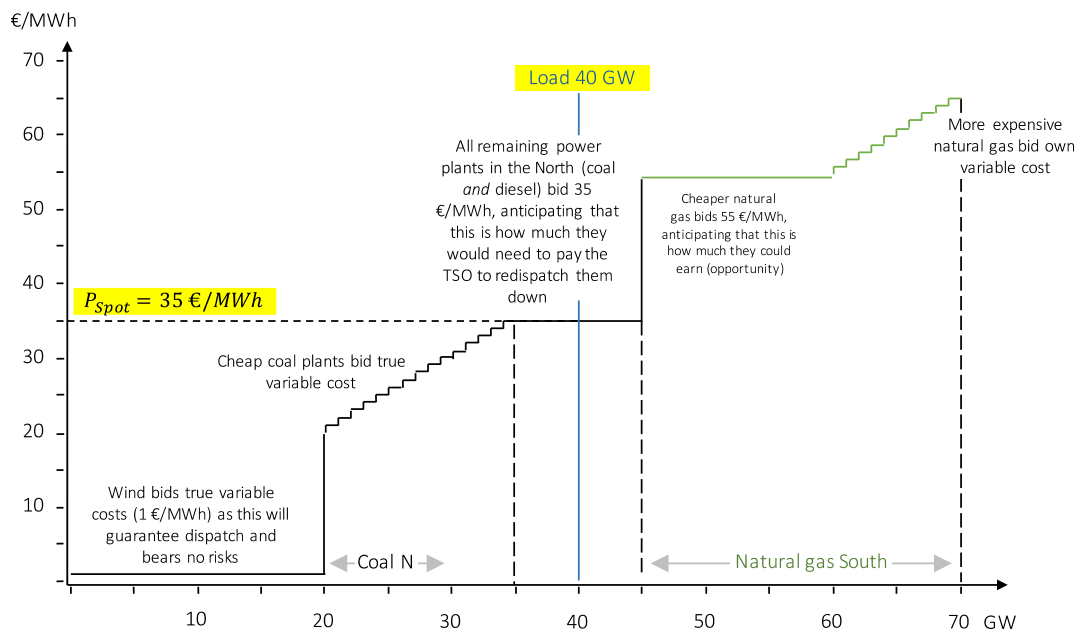


Figure 12. Zonal market equilibrium (with anticipation).

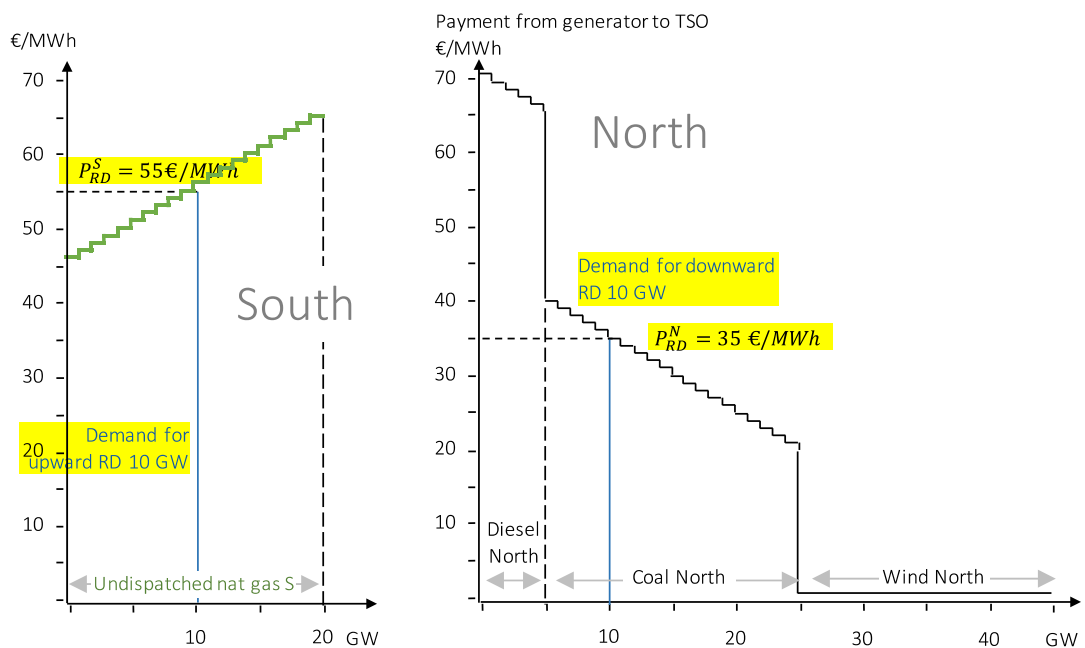


Figure 13. Redispatch market equilibria (with anticipation).

## Appendix: Regression Results

**Coefficients.** We report our coefficient estimates in Table 11. Of the 23 regressors, all but three are statistically significant at the 5% level. Usually, the German grid is congested between the Northeast and the Southwest, especially in high wind / high load situations. Most signs are as expected: generation in the North or East, such as offshore wind or 50 Hertz onshore wind, tends to increase redispatch volume, while generation in the Southwest (Transnet) reduces redispatch. Electricity consumption in the Southwest (Transnet) as well as South of German borders tend to increase redispatch. The other two control areas (Amprion and TenneT) often lie on both side of the bottleneck, hence the small or insignificant impact of load and generation. Only one coefficient comes at a surprise: we had expected load in the 50 Hertz area to reduce redispatch, but the coefficient is positive. The size of certain coefficients is economically significant. For example, the estimate of 50 Hertz wind onshore implies a marginal curtailment rate of 5.5% (half of 11%, since our dependent variable is the sum of up and down redispatch).

Table 11. Coefficient estimate

Variable	Expectation	Coefficient	p-value
<i>North / Northeast (upstream of constraint)</i>			
Tennet Wind offshore	+	0.05	0.00
50 Hertz Wind offshore	+	0.76	0.00
50 Hertz Solar	+	-0.04	0.07
50 Hertz Wind onshore	+	0.11	0.00
50 Hertz Load	-	0.02	0.04
<i>South / Southwest (downstream of constraint)</i>			
Transnet Solar	-	-0.13	0.00
Transnet Wind onshore	-	-0.35	0.00
Transnet Load	+	0.14	0.00
Load CH	+	0.16	0.00
Load FR	+	0.01	0.00
Load AT	+	0.17	0.00
<i>Cross-cutting</i>			
Amprion Solar	0	-0.03	0.24
Amprion Wind onshore	0	-0.11	0.00
Amprion Load	0	0.00	0.79
TenneT Solar	0	0.10	0.00
TenneT Wind onshore	0	0.11	0.00
TenneT Load	0	-0.10	0.00
<i>Year dummies</i>			



Variable	Expectation	Coefficient	p-value
2016	0	-429.95	0.00
2017	0	-153.07	0.00
2018	0	-829.49	0.00
<i>Other variables</i>			
EUA price	0	49.97	0.00
Redispatch(t-24)	+	0.28	0.00
Constant	0	-2456.64	0.00

**Robustness.** Below, we list the results of another model specification that includes all forecasts squared without changing results qualitatively. Table 12 shows results for a regression (in addition to that in section 4.6.3) that adds squared terms of all wind, solar and load time series. Using this specification,  $R^2$  and adjusted  $R^2$  both increase to 51%. The coefficients can, however, no longer be interpreted as intuitively as in the simple OLS regression, as the actual direction of the effect of an exogenous variable can only be determined by the joint effect of the linear and squared terms.

Table 12: Results for redispatch regression with squared terms

Variable	Coefficient	p-value
<i>North / Northeast (upstream of constraint)</i>		
50 Hertz Solar	-0.22	0.00
50 Hertz Solar Squared	3.0E-05	0.00
50 Hertz Load	0.24	0.00
50 Hertz Load Squared	-1.3E-05	0.00
50 Hertz Wind offshore	-0.60	0.00
50 Hertz Wind offshore Squared	2.1E-03	0.00
50 Hertz Wind onshore	0.10	0.00
50 Hertz Wind onshore Squared	1.6E-06	0.15
Tennet Wind offshore	-0.08	0.02
Tennet Wind offshore Squared	3.6E-05	0.00
<i>South / Southwest (downstream of constraint)</i>		
Load AT	-0.28	0.00
Load AT Squared	3.1E-05	0.00
Load CH	-0.12	0.37
Load CH Squared	1.6E-05	0.08
Load FR	-0.08	0.00
Load FR Squared	8.2E-07	0.00
Transnet Load	0.36	0.00
Transnet Load Squared	-1.5E-05	0.01
Transnet Solar	-0.13	0.12
Transnet Solar Squared	1.0E-05	0.62
Transnet Wind onshore	0.07	0.57
Transnet Wind onshore Squared	-3.5E-04	0.00
<i>Cross-cutting</i>		
Amprion Load	-0.13	0.02
Amprion Load Squared	3.5E-06	0.01
Amprion Solar	-0.05	0.43

Variable	Coefficient	p-value
Amprion Solar Squared	6.6E-07	0.94
Amprion Wind onshore	0.13	0.00
Amprion Wind onshore Squared	-4.5E-05	0.00
Tennet Load	-0.02	0.61
Tennet Load Squared	-1.5E-06	0.23
Tennet Solar	0.16	0.00
Tennet Solar Squared	-2.6E-06	0.61
Tennet Wind onshore	0.09	0.00
Tennet Wind onshore Squared	2.5E-06	0.01
<i>Year dummies</i>		
2016	-387.85	0.00
2017	-223.69	0.00
2018	-940.72	0.00
<i>Other variables</i>		
EUA price	45.11	0.00
Redispatch(t-24)	0.26	0.00
Constant	1851.78	0.00