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The inc-dec game and how to mitigate it

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Abstract

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JEL Classification C72, D47, L94

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The inc-dec game and how to mitigate it[1]

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The power exchange and the real-time markets used by the system operator differ in how system constraints are managed. This can result in regulatory arbitrage, which can increase consumer costs, increase the risk of power outages and distort investment incentives. This paper uses a game-theoretical approach to study these problems and proposes various measures to reduce them. For example, zones and grid tariffs can be adjusted. Moreover, regulations of real-time markets can improve, and transmission system operators can implement measures to increase the capacity of the existing grid.

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Introduction

Most of the physical electric-power trade occurs the day before delivery, in the day-ahead market. The European day-ahead market neglects several details in the power system, which are then considered in real-time when electricity is delivered. Hence, real-time prices can differ from day-ahead prices. The inc-dec game is an arbitrage strategy where market participants exploit such price differences. If price differences are predictable, the arbitrage volumes can be large, which could be costly for the system operator. Large arbitrage volumes could also stress the system's real-time operation, potentially increasing the risk of blackouts. Moreover, distorted price signals mean that investments will be inefficient.

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The electricity-market reforms in the US, where more details are now considered already in the day-ahead market, have partly been motivated by a need to reduce the inc-dec game. However, in Europe, it has, mainly for political reasons, been challenging to introduce regional differences in day-ahead prices within a country. This paper studies inc-dec games, related arbitrage games, and measures that mitigate such games. It is well known that considering more details in the day-ahead market will reduce inc-dec gaming. The paper encourages such measures but will mainly focus on measures that do not increase regional price differences in the day-ahead market, such as regulations of real-time markets, network tariffs and procurement of ancillary services.

Most EU countries are part of the Single Day-ahead Coupling (SDAC), the integrated European electricity market. Norway, which belongs to the European Economic Area (EEA) but not to the EU, is also part of the integrated market. The integrated European electricity market is divided into zones. Most countries have one zone per country. However, Denmark, Italy, Norway, and Sweden are divided into 2-6 zones. Germany and Luxembourg have a mutual single zone. Similarly, Ireland and Northern Ireland have a mutual single zone, the Single Electricity Market (SEM). In the EU, the delivery period is one hour long, but it will be shortened to 15 minutes. EU has a single day-ahead price in each zone for each delivery period. This market design is called zonal pricing. The classical zonal day-ahead market neglects congestion inside the zones. EU has an intra-day market between the day-ahead and real-time markets. It essentially considers the same constraints as the day-ahead market. Most of our analysis will neglect the intra-day market. After Brexit, Great Britain (GB) is no longer part of SDAC. The design is still similar to the electricity market in the EU, and GB has a single zone.[3] However, a difference is that delivery periods in GB are half an hour long.

When electricity is delivered, the system operator needs to consider many details. The system operator uses various real-time markets to accomplish this task. Production needs to equal consumption roughly every second to avoid a system collapse. Maintaining this constraint without overloading transmission lines between zones is, in this paper, referred to as balancing of the system. The system operator procures such services in the *balancing market*.[4] Balancing prices are uniform inside zones, but balancing prices can differ between zones. If consumption or the output of solar- and wind power fluctuates, then balancing prices could differ during a delivery period.

We refer to other power-system constraints, not managed by the balancing market, as non-balancing constraints. Maintaining such constraints in real-time is referred to as non-balancing operations. The voltage must be within acceptable bounds at each node of the transmission network, and no transmission line inside a zone should be overloaded. Moreover, non-balancing operations ensure that generation units have sufficient inertia (rotational energy) to make the power system robust to short-term disturbances.[5] A non-

[3] The UK government is conducting a Review of Electricity Market Arrangements (REMA), which may result in additional zones.

[4] European balancing markets have different reserves that operate at various time scales. The primary reserve, Frequency Containment Reserve (FCR), stabilises the system within 10-60 seconds. The secondary reserve, automatic Frequency Restoration Reserve (aFRR), has resources activated within 5-7.5 minutes. The tertiary reserve, the manual Frequency Restoration Reserve (mFRR), is activated within 12.5-15 minutes. In Sweden, the balancing price is set by mFRR. The energy price is the same for all reserves that pay for delivered energy. There are sometimes additional payments when a unit commits to being available or when the unit is activated.

[5] If there is a brief energy shortage in the power system, it can be drawn from the rotational energy in generators and turbines. Reducing this energy will slow down their rotation and reduce the power-system frequency. In Europe, synchronous generators are designed to rotate at a speed corresponding to 50 Hz, i.e. in sync with the power-system frequency. Various problems can occur if generators and

balancing operation increases production in plants that provide the needed service and decreases production in plants that do not provide it. Non-balancing operations do not influence the balance of the system.

A non-balancing operation that relieves congestion inside a zone by buying and selling electricity at different nodes of the zone is called redispatch. A redispatch often implies that prices will differ for nodes in the same zone. We refer to them as nodal redispatch prices.[6] Typically, the nodal redispatch price would be higher in a node where the system operator buys electricity and lower in a node where the system operator sells electricity. The day-ahead market has a single price in each zone, so having different nodal redispatch prices inside a zone means that at least one price will differ from the day-ahead price of the zone. Predictable differences between the nodal redispatch prices and the day-ahead price can lead to regulatory arbitrage, such as the inc-dec game.

Countertrading is related to redispatch. Countertrading is when the system operator relieves congestion in an inter-zonal line/cable by buying electricity in one zone and selling it in another. This could be done in either the intraday market or in the real-time market. Countertrading could also be used if the system operator wants to increase the cross-zonal transmission capacity in the market, e.g. if the realised transmission capacity is larger than expected. In this case, the system operator would get positive revenue from the countertrading operation, which may explain Estonia's statistics in Table 1.

Article 16 (8) of the Electricity Regulation (EU) 2019/943 partly drives the countertrading volumes. The article says system operators should offer at least 70% of the available cross-country capacity to the day-ahead market. The EU Agency for the Cooperation of Energy Regulators (ACER) encourages countries that have minor difficulties with meeting this target to use countertrading, i.e. to offer 70% of the transmission capacity in the day-ahead market and to use countertrading in the intraday or real-time market to reduce the transmission capacity. Exaggerated transmission capacities in the day-ahead market will also introduce arbitrage opportunities, which we will study.

1.1 Non-balancing operations in Europe

Table 1 shows statistics for non-balancing operations in the EU, Norway, and Great Britain.[7] Relative to the demand level, the volume and cost of non-balancing operations are high in several large countries with a single zone, such as GB, Germany, Poland, and Spain. Redispatch costs are extremely high in Ireland. A problem with Ireland is that it has limited possibilities to trade power with other markets. Also, the share of Variable Renewable

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turbines deviate too much from that frequency. For example, vibrations, mechanical stress, and overheating can cause damage to generators and turbines. Hence, they are disconnected from the grid before this happens. Such disconnections would reduce the power frequency further, and there is a risk that a domino effect of disconnected generation units will lead to a power system collapse. More inertia in the generators and turbines makes the system more robust to imbalances; more energy can be drawn from these rotational masses without slowing them down too much so that they can stay connected to the grid. Similarly, temporary excess energy in the power system can be stored as rotational energy. Increasing this energy means that generators rotate faster, increasing frequency. The frequency increment is smaller if the power system has more inertia.

[6] In Sweden and several other countries, redispatched units would be paid as bid, so prices may differ for market participants providing the same service. However, the intuition is still the same. Also, in theory, all pay-as-bid compensations would be at the market price in a perfectly competitive market if all market participants are fully informed, so that there is no uncertainty.

[7] The data is based on statistics reported by the Agency for the Cooperation of Energy Regulators (ACER, 2020;2023). The statistics are for short-run non-balancing operations that are reactive and that have a specific purpose. EU refers to them as remedial actions.

Electricity (VRE) is nearly 40% (International Energy Agency, 2023). The consequence is that curtailment rates are high in Ireland, around 10% of the VRE production is curtailed (International Energy Agency, 2024). [8]

Italy has had high redispatch costs, but the costs were drastically reduced in 2022, even if prices in the European power exchange increased to extreme levels that year. According to the International Energy Agency (2023), Italy's curtailment rate fell from around 4% in 2020 to 1.6% in 2022, despite a marginal increase in wind and solar energy production. This improvement was achieved through several measures to increase power flow in the existing grid.

Key steps included implementing new network components at critical locations and using old components more efficiently. [9] Moreover, Italy increased the use of dynamic line rating and topology management.[10] Additionally, Italy has invested in software to improve the prognoses of the system operator, making balancing and non-balancing operations more timely and efficient. Italy's zonal design was updated in 2021. In addition, lower non-balancing volumes reduced arbitrage opportunities and inc-dec gaming, further contributing to the reduction in non-balancing volumes and redispatch costs, creating a positive feedback loop.

Denmark, Finland, Sweden[11] and the Baltic countries had no exceptions from the 70% rule in 2022. To comply, they sometimes resorted to countertrading, partly explaining why countertrading is relatively high in these countries (see Table 1). A significant amount of power is countertraded at the Danish-German border, with Germany bearing the costs due to the internal grid issues limiting cross-country flow.

Most other EU countries have been granted exceptions from the 70% rule, which partly explains their lower levels of countertrading. While part of SDAC, Norway has postponed the implementation of the 70% rule. According to ACER, there is no countertrading in Norway, which is quite different from Denmark, Finland and Sweden. In the Netherlands, a large part of the cost for non-balancing operations can be attributed to other actions, which in their case are contracts for ramping, according to ACER (2021).

In 2022, 87% of the non-balancing operations in the EU were due to congested transmission lines, 10% were due to voltage issues in transmission lines, 1% were due to other problems in transmission lines, and 2% were due to issues at the distribution level (ACER, 2023). The need for congestion management involving renewable energy technologies, mainly in the form of curtailment, is growing steadily. Non-balancing operations involving renewable technologies have grown from 3.3% of the total volume in 2020 to 7.5% in 2021 and 17.1% in 2022 (ACER, 2023).

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[8] Spain has almost the same share of VRE, but only 2% of the VRE production is curtailed in Spain (International Energy Agency, 2023).
[9] For example, network components that can control the voltage were implemented.
[10] Dynamic line rating means that the transmission capacity is adjusted depending on the ambient temperature. If it is cold outdoors, more power can be transported through a transmission line without overheating it. Topology management is when the system operator changes the flow through the grid by changing its topology, i.e. by opening and closing switches or by using network components to reroute power flows. Topology management can sometimes relieve congestion or make the power system more robust to disturbances and faults in the grid.
[11] The Swedish system operator did apply for several exceptions from the 70% rule in 2022 (Holmberg and Tangerås, 2023b), but ACER (2022) turned down the application. The view of ACER is that the problems in Sweden are relatively small and that they can be managed by countertrading. During 2022, Svenska Kraftnät procured resources suitable for countertrading.

Table 1: Statistics for non-balancing operations in the EU and Norway. GB is also added to the table but note that the statistics of GB are for 2019, the last year that GB reported to the Agency for the Cooperation of Energy Regulators (ACER).

Country	Volume 2022 per unit demand (%)	Total costs 2022 (MEUR)	Total costs 2021 (MEUR)	Total costs 2020 (MEUR)	Re-dispatch cost 2022 (%)	Counter-trading cost 2022 (%)	Cost of other actions 2022 (%)	Cost per unit of demand 2022 (EUR/MWh)
Austria	0.17	20	16	141	100			0.33
Belgium	0.05	7	8	2	47	53	0	0.09
Bulgaria	0.00	0		0				0.00
Croatia	0.03	0	0	0				0.00
Czechia	0.00	0	0	0				0.00
Denmark		1	0			100	0	0.02
Estonia	0.10	-2	0	0		100		-0.24
Finland	0.00	7	3	1	24	76	0	0.09
France	0.34	171	34	8	14	86	0	0.39
Germany	5.64	2808	1850	1339	87	13	0	5.82
Greece	0.01	0	0	0				0.00
Hungary	0.00	0	0	0				0.00
Ireland		612			92	8		19.05
Italy	0.11	63	1055	1470	95	5		0.22
Latvia	0.02	0.3		4		100		0.04
Lithuania	0.04	2	1	1		100	0	0.14
Luxemb.	0.00	0						0.00
Netherl.	0.87	389	337	79	43		57	3.87
Norway	0.89	51	21	10	100			0.39
Poland	6.41	397	213	76	100	0	0	2.30
Portugal	0.00	0	0	0	100			0.00
Romania	0.00	0			100	0	0	0.00
Slovakia	0.00	0						0.00
Slovenia	0.00	0	0	0				0.00
Spain	2.95	599		435	74	26	0	2.45
Sweden	0.27	39	7	1	15	85	0	0.29
EU	1.87	5164	3978	3133	81	15	4	1.94
GB – 2019	6.23	429			100	0	0	1.89

1.2 The inc-dec game

The classical inc-dec game is played by producers facing export constraints inside their zone. Due to local excess supply, they encounter a low nodal redispatch price in real-time when the constraint is considered. However, in the day-ahead market, which neglects the export constraint, they often face a zonal price higher than their nodal redispatch price. This price difference allows them to make an arbitrage profit. Producers in the export-constrained node are incentivised to sell as much power as possible in the day-ahead market and then buy back any power they do not wish to produce during redispatch.

For export-constrained producers with high costs, it becomes profitable to offer power below marginal cost in the day-ahead market and then to buy back the power at an even lower price in the redispatch market. Similarly, an export-constrained wind power producer can exaggerate its output in the day-ahead market and subsequently buy back the shortfall at a lower nodal redispatch price.

Producers do not need market power to make an arbitrage profit (Holmberg and Lazarczyk, 2015; Hirth and Schlecht, 2019). A small producer can sell power in the day-ahead market at a given day-ahead price and buy back power at a lower given nodal redispatch price. However, if producers in export-constrained nodes have market power, they can push down their nodal redispatch price to buy back power at an even lower price. Hence, inc-dec game profits can increase due to local market power. Pavlovic et al. (2021) argue that inc-dec gaming would be a significantly smaller problem in practice, if local market power was not an issue.

In some countries, such as Sweden, only flexible units that can be activated within 15 minutes can participate in the real-time market. Still, most of the production in an export-constrained node can engage in the inc-dec game, as most plants, including many wind-power plants, can shut down quickly and are flexible regarding output reductions. In GB, all production, including inflexible production, can participate in the real-time market. [12]

Flexible and import-constrained production facing a high nodal redispatch price in real-time can reduce their output to zero in the day-ahead market and offer all their capacity to the non-balancing market. This strategy is sometimes referred to as *off-and-then-on-again supply gaming*. Issues with off-and-then-on-again supply gaming can be exacerbated if producers in import-constrained nodes use local market power to push up the nodal redispatch price.

The classical inc-dec game and the related off-and-then-on-again supply game occur as the transmission capacity within a zone is exaggerated; the day-ahead market assumes that the transmission capacity is unbounded within a zone. Related arbitrage games can occur if system operators would report an exaggerated cross-zonal capacity to the day-ahead market.

Flexible consumers who face an import constraint inside their zone can also play an inc-dec game. Because of local excess demand, they will face a high nodal redispatch price in real-time when the import constraint is considered. This nodal redispatch price is often above the day-ahead price, which does not consider the import constraint. Hence, flexible consumers in import-constrained nodes have incentives to buy as much power as possible in the day-ahead market and to sell back, in the redispatch, what they do not need. Related arbitrage issues occur for consumers that pay a low fixed price for consumption, because of regulations or long-term contracts, and that can sell demand reductions, for example, in the real-time market, at a significantly higher price. In this case, consumers have incentives to exaggerate demand bought at a low price and then offer the extra power as a demand reduction in real-time. Kleit (2019) describes in detail how some consumers in the US have exploited this.

Inc-dec games by flexible consumers have historically been less problematic. One reason is that most consumption units are small and either cannot participate in the real-time market or choose not to due to administrative costs. However, this is changing as aggregators can now represent multiple small consumption units in the real-time market. Moreover, the electricity-intensive industry is becoming more flexible. Consequently, inc-dec games by consumers

[12] Inflexible production is allowed to trade in the real-time market of GB, as the system operator sometimes redispatch units hours ahead of delivery.

will likely become an increasing problem. This paper will consider an example where consumers use arbitrage strategies, but its primary focus will be arbitrage games played by producers.

1.3 Inc-dec games by low-capability units

The underlying problem of the inc-dec game is that the power system has a binding maximum constraint on production in the export-constrained node, which the day-ahead market does not consider. More generally, this can be seen as a maximum constraint on the volume of low-capability power, where such low-capability power is either located incorrectly or lacks technical characteristics that are critical for the system's needs.

This insight leads us to understand that inc-dec games can occur whenever there is a binding maximum constraint on the volume of low-capability power, which is not considered by the day-ahead market. If there is an inc-dec game, low-capability power with high costs will exaggerate their output in the day-ahead market (offer it below marginal cost) and then repurchase it at a lower price in real-time.

Inc-dec games can occur due to heterogeneities in the provision of inertia or voltage control. Such differences can give different prices for the units in the market where non-balancing services are traded; units with fewer capabilities will get a lower price. When this price falls below the day-ahead price, such units are incentivised to sell as much power as possible in the day-head market and repurchase the excess they do not want to produce in the market for non-balancing services.

Technologies with low technical capabilities, such as solar and wind power plants, are often bad at providing inertia and voltage control.[13] Another example includes large plants. The challenge with big plants, which have a high-power output or consume a lot of power, is that they can destabilise the system. If such a plant were suddenly disconnected from the grid due to a fault, it could cause a substantial disturbance. [14] Therefore, the system's need for inertia increases when a large plant runs at full capacity. Sometimes system operators make redispatches where big plants reduce their output, making the system more robust.

If consumption, the output of wind and solar power, and the balancing price, are relatively constant during the delivery period, then the inc-dec game would typically not be driven by balancing operations. But if ramping is needed and predictable, there could also be an inc-dec game involving the balancing market. Ramping within a delivery hour is neglected in the day-ahead market, where it is sufficient to balance supply and demand on average during each hour. This simplification means it can be profitable for inflexible production, which cannot ramp up quickly, to sell at a (relatively) high price in the day-ahead market. The

[13] Many solar and wind power plants use power electronics that are grid-following, which do not control the voltage. Modern solar and wind power plants sometimes have power electronics that are grid-forming, which control the voltage (Lin et al., 2020). Wind power plants are asynchronous and do not rotate in sync with the grid frequency. For this reason, they cannot provide conventional inertia. But the rotational energy of asynchronous wind-power plants could be used to provide synthetic inertia (RISE, 2021; Holmberg & Tangerås, 2023a). Solar power plants do not have any rotating energy. They would need a battery or a supercapacitor to provide synthetic inertia.

[14] Inertia is mainly a concern in small synchronous areas, such as Ireland (including Northern Ireland), Great Britain, and the Nordic countries (excluding Iceland and Jutland). In these relatively small areas, it becomes a significant disturbance when a large power plant, above 1000 MW, trips. Such an incident is less of a concern in Continental Europe (including Jutland), which has more power plants and more total rotational energy in the power system. The different synchronous areas in Europe are connected by HVDC links, which allow frequencies to differ at the two ends of the cable.

balancing market needs to keep supply and demand in balance every second. Hence, there will be a low balancing price (below the day-ahead price) when demand is low during the delivery hour. Inflexible production is repurchased at this low price (it is assumed that it can ramp down quickly). Thus, inflexible production could make an arbitrage profit from the difference in the day-ahead price and the low-demand balancing price. This profit can drive an inc-dec game.

1.4 Problems with the inc-dec game

One problem with the inc-dec game is that arbitrageurs can profit substantially at the expense of the system operator and consumers. Moreover, this arbitrage game distorts price signals. Typically, low-capability production that is less useful for the system, because it is in the wrong location or cannot provide non-balancing or ramping services, can earn excessive profits. In scenarios when the classical inc-dec is prevalent, a low-capability plant achieves a weakly higher profit than a high-capability plant with the same marginal cost. Hence, frequent inc-dec games incentivise producers to invest in locations and technologies that are less beneficial for the overall system (Dijk and Willems, 2011). In the long term, this will increase the need for non-balancing services or reduce the supply.

A related problem is that the inc-dec game tends to push the day-ahead schedule, which reflects the production plan implied by the day-ahead clearing, away from a schedule that would be feasible in real time, where non-balancing constraints and ramping are considered. Hence, inc-dec games increase the volumes traded in real-time. If producers refrained from playing the inc-dec game and offered power at marginal cost in the day-ahead market, the day-ahead dispatch would be closer to a feasible real-time dispatch.

An unexpected need for large volumes of balancing and non-balancing services could increase the risk of rolling blackouts or brownouts. In general, the system operator has fewer alternatives in real-time than the day ahead, as some production needs a long time to ramp up. Thus, market power and inefficiencies are larger concerns in the real-time market compared to the day-ahead market. In practice, welfare would be higher if the day-ahead dispatch were closer to a feasible real-time dispatch.

1.5 Empirical observations of inc-dec games

10-25 years ago, the US faced significant challenges with the inc-dec game. Enron made the game infamous during the California energy crisis in 2000-2001 (Alaywan et al., 2004; Hobbs, 2009; Neuhoff et al., 2011). Before this, instances of the inc-dec game were observed at PJM (Hogan, 1999).[15] At that time, deregulated electricity markets in the US had zonal pricing in the day-ahead market, similar to those in Europe. However, by now, all deregulated electricity markets in the US have moved to a nodal-pricing design. This shift roughly means that each city has a local electricity price in the day-ahead market.[16] This

[15] PJM was originally the joint electricity market of Pennsylvania, New Jersey, and Maryland. Now, the market also serves all or parts of Delaware, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, Virginia, West Virginia and the District of Columbia.

[16] Singapore and some markets in the US have nodal pricing for producers and zonal pricing for consumers, who pay an average of the nodal prices in the zone (Ahlqvist et al., 2022). This market design is referred to as Generator Nodal pricing (GNP). Italy has a related design with small zones for producers, whereas consumers pay an average of the zonal prices (Holmberg and Tangerås, 2021). However, in 2025 the small zones in Italy will apply to both consumers and producers. Different prices for producers and consumers at the same location can give rise to arbitrage opportunities, especially for an agent that is both buying and selling electricity. Italy and countries with the GNP design have introduced regulations that mitigate this type of arbitrage (Holmberg and Tangerås, 2021).

nodal-pricing design incorporates more details of the power system in the day-ahead market, thereby narrowing price differences between day-ahead and real-time markets. These market reforms were largely motivated by a need to mitigate the inc-dec game, which is now less of a problem. Day-ahead electricity markets in US would normally not consider voltage levels in the grid. It is possible that inc-dec gaming could still occur with respect to voltage constraints.

Now, it is mainly Europe that has problems with the inc-dec game.[17] There are several reasons why the problems have increased in Europe. Power flows have increased, have changed paths, and are transported a longer distance due to increased market integration, which the EU encourages. Moreover, the green energy transition has implied that old power plants have closed down and been replaced by new renewable energy at new locations. It takes a long time to adjust the power system to the new flows, so it is more congested now. Thomassen et al. (2024) show with simulations that an uncoordinated deployment of renewables will massively increase the need for redispatch in the EU by 2040, unless the market design changes. A stressed power system is a particular problem for countries, e.g. GB, which have accelerated their energy transition by allowing renewable power to connect to the grid in advance of the completion of the wider transmission reinforcement works (Newbery and Biggar, 2024). The green energy transition has also increased the need for non-balancing and ramping services or reduced the supply. These changes have increased the incentives to play an inc-dec game with non-balancing and ramping services.

The introduction of local flexibility markets has also increased arbitrage opportunities (Beckstedde et al., 2023; Cramton, 2022; Jahns et al., 2023). These markets are mainly used by local grid owners to manage congestion and voltage levels in low- and medium-voltage distribution networks. Inc-dec games can occur due to technical constraints in both transmission and local distribution networks, but Bjørndalen (2020) argue that they should be less likely in distribution networks.[18] We will not specifically discuss flexibility markets in this paper.

Inc-dec gaming is mainly a problem for countries where compensations for non-balancing operations are determined by the market, such as Finland, GB, Italy, Netherlands, and Sweden. This is different in Austria and Germany, where the redispatch is cost-based; the provider of a non-balancing service gets a regulated payment based on the estimated cost of providing the service.

Inc-dec gaming became a noticeable problem in Great Britain after the electricity market in England and Wales became fully integrated with Scotland in 2005. At that time, the Cheviot Boundary between Scotland and England became a critical congestion point in the GB electricity system. Production in Scotland was often export-constrained (Neuhoff et al., 2011; Hirth and Schlecht, 2019). Ofgem (2011) estimates that market-power-related gaming of the constraint at the Cheviot Boundary increased redispatch costs by £106-£115 million, whereas

[17] There are also problems outside Europe. The electricity market in Ontario uses zonal pricing and has similar issues with arbitrage games (Brown, 2023). Australia has regional pricing, which is related to but different from zonal pricing (Biggar and Hesamzadeh, 2014). Hence, arbitrage games played in Australia often differ from those in the EU.

[18] There are several reasons why it is more difficult to play an inc-dec game in a distribution network (Bjørndalen, 2020). The behaviour of a Distribution System Operator (DSO) is difficult to predict; the practices of one DSO can completely differ from the practices of a neighbouring DSO. Lead times for grid reinforcements are typically lower at the distribution level. The consequences of overloading a line or component are normally less severe in distribution networks. Moreover, the redispatch volumes are typically much smaller at the distribution level. This limits the potential profit per transaction of inc-dec bidding.

inc-dec gaming increased costs by £19-36 million. Graf (2024) finds that the redispatch volumes peaked during the pandemic.

In 2020, 18% of the wind power production in Scotland was curtailed (Newbery and Biggar, 2024). Bloomberg has studied inc-dec games played by a set of wind-power farms that are routinely curtailed, who can make a profit from exaggerating their wind-power output in the day-ahead market. The exaggeration increases the chance that they will be curtailed, and they can make an inc-dec profit from not producing power that they couldn't have produced anyway (Intini and Waterson, 2023). Bloomberg estimates that this inc-dec game of wind-power plants has increased consumer costs by about £100 million per year.[19] This is about 0.5% of the electricity production cost in the UK, valued at the day-ahead price.

In 2023, Ofgem issued a £24-million fine to the owner of the South Humber Bank combined cycle gas turbine, a 1400 MW unit, which allegedly acted strategically when the system operator needed the unit to reduce its output. Bloomberg also reports that off-and-then-on-again supply gaming is prevalent in GB.[20] National Grid (2022) discusses similar issues.

In Italy, Graf et al. (2024) estimate that the cost of redispatch actions averaged approximately 15% of the total cost of energy consumption valued at the day-ahead price for the years 2017 and 2018. Bloomberg estimates that Italian producers earned about €800 million annually due to redispatch premiums.[21] The premiums tend to be high on Sundays and holidays when energy demand typically reaches its lowest levels. The reason is that the relative share of conventional power production, which is better at providing system services, is typically lower when demand is low. Hence, redispatch costs exploded in Italy during the COVID lockdown, when demand was low for an extended period. Graf et al. (2021a) estimate that the redispatch cost increased by 79% relative to previous years, even if average day-ahead prices decreased by 45%. The redispatch cost is also high when demand is high. During peak demand hours in 2017 and 2018, the total cost (including the redispatch cost) of providing electricity was 40% higher than would be the case in a competitive and efficient market (Graf et al., 2024).

Hirth et al. (2019) discuss arbitrage games at the German-Danish border. Danish and German system operators have a joint agreement to report a high cross-border transmission capacity to the day-ahead market, even if it is not feasible to transport all of that power in real-time, so that countertrading is needed to relieve the transmission line. Hirth et al. (2019) also estimate that, due to inc-dec gaming, redispatch volumes in Germany would increase by 300-700% if Germany introduced a market-based redispatch.

Norway used to have problems with inc-dec gaming, especially during periods of high-water flows combined with grid maintenance, faults in the power system, or very low consumption.

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[19] Bloomberg makes this claim in the article ”Wind Farms Are Overstating Their Output — And Consumers Are Paying For It”, published on February 1, 2024.

[20] This problem is discussed in the article ”Consumers Foot the Bill for Traders Manipulating UK Power Market”, published on March 23, 2023. In GB, the off-and-then-on-again supply gaming is exacerbated by the fact that plants with slow ramping can take part in the real-time market. Some plants need to cool down for several hours before they can run again. According to the article, critical plants report that they will shut down several hours before they are needed. This forces the system operator to buy expensive power from them in the non-balancing market for several hours, so that they stay online until needed.

[21] Bloomberg discusses redispatch issues with the Italian market, including off-and-on-again supply games, in the article ”How Power Companies Profited from Italy's Covid Lockdown”. The article was published on November 10, 2023.

1.6 Mitigating the inc-dec game

Day-ahead markets with 24 prices per day and zone have a high resolution with fine granularity in the time dimension. Output would rarely be ramped up by more than 5% during a delivery period. Hence, volumes related to ramping arbitrage can be at most 5% of the output. The problem will decrease even further when the EU shortens the length of the delivery periods from one hour to 15 minutes. Potential drawbacks of having a fine granularity in the time dimension are that it becomes more complicated and costly to clear the day-ahead electricity market. Transaction costs will increase, reducing liquidity in intra-day markets and for forward contracts associated with a single delivery period (in case such forward contracts would be traded).

Similarly, the inc-dec game would be mitigated if the day-ahead market had a fine granularity in the spatial dimension, so that the day-ahead market becomes more similar to the real-time market. Countries with several zones typically have lower volumes of non-balancing operations and fewer arbitrage opportunities. Italy was an exception in the past, but the costs have now been drastically reduced to a level similar to other countries with multiple zones. Large countries like Germany, Poland, Spain, and GB would likely also benefit from introducing more zones. An alternative is to introduce dispatch-hubs, proposed by two system operators, Elia in Belgium and 50Hz in Germany (Elia Group, 2019), and studied by Schlecht and Hirth (2021). The idea is that tiny zones should be introduced at a few critical locations and may only apply to producers (Holmberg and Tangerås, 2022). This is also related to the Pole of limited production zones that were previously used in Italy (Graf and Wolak, 2024), which limited the total production in a small area due to local transmission constraints. Adding zones has many benefits, but it is likely to worsen liquidity in forward markets, make investments in production and consumption riskier, and result in redistributive effects that are sometimes hard to accept politically. This trade-off is further discussed by Ahlqvist et al. (2022), Eicke and Schittekatte (2022) and Pollitt (2023).

Adding zones will often decrease inc-dec game problems. But this paper focuses on alternatives, such as suitable network tariffs, market regulations, and procurement arrangements. The effect of such measures is derived from a game-theoretical analysis. Section 2 considers a simple network, a power system with a single zone and two nodes. More generally, the model has two types of production technologies, with high and low capabilities, and the system has a maximum constraint on the output of low-capability power. We assume that producers are tiny and without market power. Production is flexible and predictable. Demand is inelastic and without uncertainties. We solve for an equilibrium (a subgame perfect Nash equilibrium), where each producer maximises its profit, given strategies chosen by competitors.

According to the theoretical model, the inc-dec game poses more significant challenges than an off-and-then-on-again supply game (Conclusion 2-3). If an inc-dec game is played, every consumer would gain from a switch to nodal pricing (Conclusion 2). Exaggerating cross-zonal transmission capacities in the day-ahead market increases the countertraded volumes. In theory, the negative effects of increased countertrading are small, as long as the exaggeration is small (Conclusion 1). However, large exaggerations/understatements have worse effects and can give rise to inc-dec gaming.

The analysis suggests that various interventions can be used to reduce arbitrage incentives. One such method is that the system operator procures high-capability production before the day-ahead market opens (Conclusion 4). The system operator would not lose anything from this, as redispatch costs would be reduced. Moreover, network tariffs can be used to reduce arbitrage opportunities. To some extent, local network tariffs can compensate for the lack of nodal pricing in the day-ahead market (Conclusion 6). Mandating that only flexible production can sell power in the real-time market would reduce inc-dec gaming, but increase welfare losses, at least in the short run (Conclusion 5). Flexible consumers that are active in the real-time market reduce inc-dec gaming, at least if consumers are not allowed to exaggerate their demand in the day-ahead market (Conclusion 7).

Further, the paper proposes regulatory changes to reduce the exploitation of arbitrage opportunities. Bid and offer prices to the real-time market should be fixed throughout the day, except for short-run energy storage and demand reduction (Recommendation 1). Market-based compensations for non-balancing operations have many advantages. However, there should be exceptions for individual units during delivery hours when they have excessive market power or excessive arbitrage opportunities. In such exceptions, compensations could be regulated (Recommendation 3). To avoid gaming, baseline regulations should be used when compensating Variable Renewable Energy (VRE) and demand response (Recommendation 2).

The paper briefly discusses the organisation of the intra-day market. A problem with continuous matching of orders in European intra-day markets is that there is less time to consider constraints in the transmission network, compared to the day-ahead market. Differences in how network constraints are considered can make prices inconsistent, which can potentially give incentives to arbitrage gaming. If arbitrage games in the intra-day market are an issue, then it would be better to avoid continuous intra-day trading and instead have frequent intra-day auctions that consider the same network constraints as the day-ahead market.

Arbitrage games would be mitigated if the power grids were upgraded in Europe. As Italy demonstrates, many small and quick investments can sometimes make a significant impact. Flow-based zonal pricing, which is used in the day-ahead market of several EU countries, means that the grid is used more efficiently. This can potentially reduce arbitrage opportunities. However, if the available network capacity is systematically larger day ahead than intra day, then other types of arbitrages could occur.

To expedite the energy transition, it is likely a beneficial idea to quickly connect new production and load to the grid, even if it will take a few years to increase the grid capacity so that the new units can run at full speed at any time. However, it is not a good idea to pay such units market-based compensation when they are curtailed, because it will encourage them to play arbitrage games. A better alternative may be to adopt the proposal of the transmission operator in Ireland and Northern Ireland. Eirgrid (2022) suggests that new units should be quickly connected, but that access should be non-firm for up to five years. Hence, new units will be curtailed first in case the grid is congested, and the new units may not be compensated for being curtailed. Similarly, one could argue that exceptions from the 70% rule should be allowed if it can be shown that recent investments have made it more difficult to follow the 70% rule. If the 70% rule is too firm, it may slow down the European energy transition and investments in cross-border capacity.

2 Analysis

2.1 Assumptions

In the analysis, we will consider a simple two-node example. Assume that the transmission capacity between the two nodes is given by T. The exporting node is denoted by E and the importing node is denoted by I. We make an exception in Section 2.11, but otherwise, we will assume that consumers are inelastic, i.e. consumption is independent of the price. Demand in the two nodes is denoted by d_E and d_I, respectively. We assume that $d_I > T$ to ensure that at least some local power will be produced in the importing node. Consumers buy electricity in the day-ahead market and do not participate in the real-time market, which is only open to flexible resources.

The total production capacity in node E is denoted by Q_E, and the total production capacity in the importing node is Q_I. We will assume that monitoring and the market design are such that producers cannot sell more than their capacity in the day-ahead market. This is difficult to monitor for intermittent renewables, for which the maximum output depends on the weather. We will discuss this issue further in Section 2.12.
Production is assumed to be flexible; ramping costs and times are negligible. Moreover, it is assumed that marginal costs are strictly increasing with respect to output in both nodes. We assume that participants do not have market power and that they are perfectly informed about demand and costs. Each producer has a negligible capacity, and there is a large number of producers. An individual producer cannot influence prices in the day-ahead or real-time markets but can choose how much to trade in each market, at given prices.[22]

The two nodes are inside the same zone, but we will make exceptions in Sections 2.4 and 2.5, which consider nodal pricing. We consider classical zonal pricing, so the day-ahead market neglects the transmission constraint T between the two nodes. The day-ahead market assumes that electricity can flow freely between the two nodes. Hence, the day-ahead market is cleared at the zonal price p_z, at which total supply equals total demand. The power flow from the exporting to the importing node implied by the day-ahead clearing is denoted by F_D. We assume that the marginal cost of producing d_I-T in the importing node, which we denote by MC_I, is higher than that of producing $d_E + T$ in the exporting node, which we denote by MC_E. This assumption will imply that $F_D > T$ in equilibrium, so that the transmission line is congested.

We solve for a subgame perfect Nash equilibrium (SPNE).[23] Hence, each producer acts to maximise its profit, given the strategies of competitors. Moreover, producers are sequentially rational in an SPNE. Whatever happens in the day-ahead market, a producer will try to maximise its profit in real-time.

In real-time, we will (for simplicity) assume that demand is the same as predicted the day before. Hence, no balancing operations are needed. However, adjustments are required in the transmission flow implied by the day-ahead market. Otherwise, the transmission line would be overloaded when electricity is delivered. The system operator relieves the congested

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[22] A recent paper by Ehrhart et al. (2022) develops a more advanced model of the inc-dec game that considers market power and imperfect information with respect to costs and demand.

[23] Similar to Holmberg and Lazarczyk (2015), there is a continuum of infinitesimally small producers. Each producer chooses its offer in order to maximize its individual payoff. Hence, the paper calculates equilibria for a continuum of agents. This Nash-equilibrium concept was first introduced by Aumann (1964).

transmission line by making a redispatch. Hence, it buys power from producers in the import node to increase their output and sells power to producers in the export node to decrease their output. We assume that the system operator acts in order to maximise the social welfare that is implied by the bids and offers in the real-time market. Hence, if the real-time market is perfectly competitive, the system operator will maximise social welfare. [24]

We will assume that the redispatch is market-based, so that the real-time market will have a nodal redispatch price in the export node, p_E, and a nodal redispatch price in the import node, p_I. For simplicity, we assume that the nodal redispatch price is set by the marginal offer in the node. In practice, several redispatch markets apply pay-as-bid pricing. However, this difference does not matter under our assumptions, where producers are assumed to be perfectly informed and without market power (Holmberg and Lazarczyk, 2015).

After the redispatch market has been cleared, each producer produces in accordance with its obligations, i.e., sales in the day-ahead market plus sales in the real-time market. The total production in node E is denoted by q_E, and the total output in node I is denoted by q_I. We assume that the net cost of the redispatch is covered by a tariff paid by the market participants. All participants are minor, so each participant can neglect the impact its decisions have on the tariff payments. We will assume that all consumers in both nodes will pay a strictly positive tariff if the redispatch cost is strictly positive. Apart from this assumption, our conclusions will not depend on how the tariff is distributed among consumers and producers.

The transmission constraint introduces a maximum demand for power, $d_E + T$, in the export-constrained node, which is considered in real time. More generally, the analysis also applies to technical constraints on voltage control, stability or ramping, when the system has production with two types of technical capabilities, high and low, and there is a binding maximum constraint at $d_E + T$ on the output of low capability production. Production in the export-constrained node corresponds to low-capability power and production in the import-constrained node corresponds to high-capability power. However, the analysis only applies to one constraint at a time. The analysis does not consider cases where there are several binding system constraints on transmission, inertia, voltage control or ramping that bind at the same time.

2.2 Equilibrium in the real-time market

We neglect the market power of producers. Irrespective of what happened in the day-ahead market, it is sequentially rational for producers to offer power at marginal cost. Production is flexible. It can be ramped up and down without delay or cost. Hence, dispatched production will be socially optimal in real-time, whatever happened in the day-ahead market. The socially optimal production in node E is $q_E = d_E + T$, and the socially optimal output in node I is $q_I = d_I - T$. Nodal redispatch prices are exogenously determined by the marginal cost of producing the outputs q_E and q_I, respectively, in the two nodes. Hence, $p_I = MC_I$ and $p_E = MC_E$, where $p_E < p_I$.

2.3 Equilibrium offers in the day-ahead market

It is somewhat more complicated for electricity sold in the day-ahead market, because producers have the opportunity to sell (or buy) electricity in the real-time market, which introduces an opportunity cost. The day-ahead market is assumed to be competitive. A producer will either offer at its marginal cost or its (marginal) opportunity cost.

[24] In a two-node system, it would be equivalent to assume that the system operator minimizes the redispatch volume, under the constraint that the transmission line should not be overloaded.

First, consider producers in the import-constrained node. Producers with a marginal cost below p_I can choose to sell electricity at p_I in the real-time market, so p_I is their (marginal) opportunity cost, and they will offer to sell electricity at p_I in the day-ahead market. We know from the previous subsection that q_I is the volume of power in the importing node that has a marginal cost below p_I, and this volume will be offered at (and not below) p_I. Producers with a marginal cost above p_I do not have the option to sell power in the real-time market and will simply offer their power at marginal cost in the day-ahead market. In summary, in the import-constrained node of the day-ahead market, no producer will offer power below p_I and q_I units will be offered at p_I. This is illustrated in the right part of Figure 1.[25]

In the day-ahead market, producers in the export-constrained node that have a marginal cost below p_E will offer to sell their production at marginal cost. It follows from the previous subsection that q_E units will be offered below p_E. Producers with a higher marginal cost have the possibility to buy back power at the nodal redispatch price p_E, so this becomes their (marginal) opportunity cost, and they offer electricity at p_E in the day-ahead market. Hence, the export-constrained node's production capacity (Q_E) will be offered at $p_\mathrm{E} < p_\mathrm{I}$, or lower. This is illustrated in the left part of Figure 1.

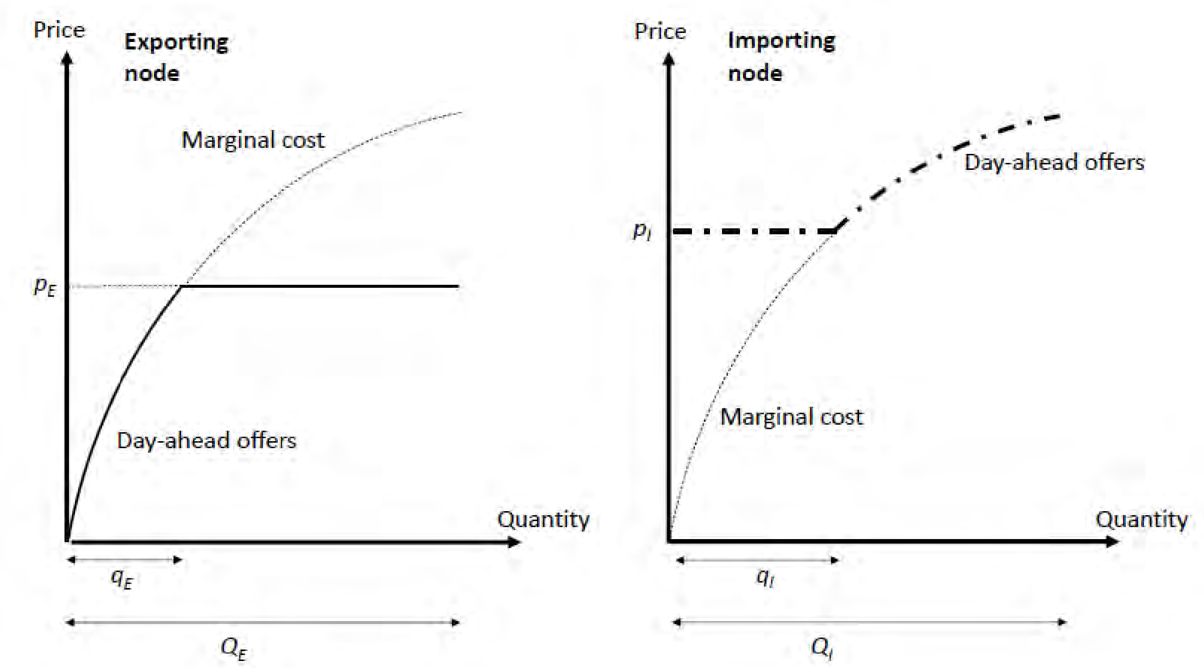

Figure 1: Day-ahead offers in the export-constrained node (left) and the import-constrained node (right).

2.4 Nodal pricing in the day-ahead market

Before analysing zonal pricing, we will – as a benchmark – look at nodal pricing, where the transmission constraint is considered already in the day-ahead market. Note that the equilibrium offers in the real-time and day-ahead markets that we derived in the previous subsections do not depend on to what extent the day-ahead market considers the transmission constraint T. Hence, those results also apply when we have nodal pricing in the day-ahead market, so that the transmission constraint T is fully considered. Hence, we get socially optimal production in node E and socially optimal output in node I already in the day-ahead market. Similar to the real-time market, nodal day-ahead prices are given by p_I and p_E. No

[25] There are multiple equilibria of offers, but it can be shown that all of them give the same market outcome in terms of prices and volumes.

adjustments are needed in real-time. The redispatched volume is zero. This outcome is efficient. It is also efficient in the long run (investments will be efficient), as all production is paid the marginal value of additional output in its node. The equilibrium is illustrated in Figure 2.

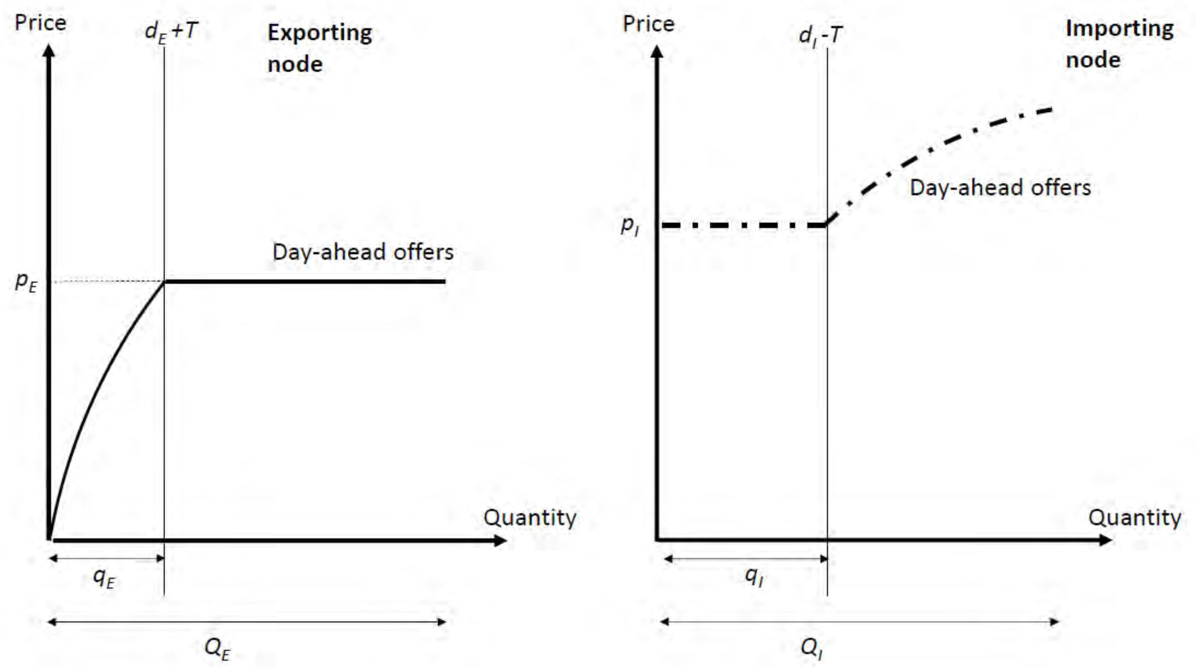

Figure 2: Equilibrium offers in a day-ahead market with nodal pricing.

2.5 Exaggerated transmission capacity in the day-ahead market

As mentioned in the introduction, Danish and German system operators have a joint agreement to report a high cross-border transmission capacity to the day-ahead market, even if it is only feasible to transport some of that power in real time. Hence, countertrading is often needed to relieve the transmission line. In our model, the exaggerated transmission capacity will be countertraded in the real-time market.
To consider this issue, we will consider the nodal pricing model, but with an exaggerated transmission capacity $T+\Delta T$ between the two nodes in the day-ahead market. In this subsection, we will think of the two nodes as being two different zones, so that the transmission line is cross-zonal. One of the nodes could represent Denmark, and the other could represent Germany. Offers to the day-ahead market will be the same as outlined in Section 2.3. Hence, as illustrated in Figure 3, the exaggeration does not affect the day-ahead prices in theory, at least not if the transmission capacity is exaggerated by a small positive amount. The reason is that offers on the margin are flat in the day-ahead market, if more power would be accepted from the exporting node/zone and less from the importing node/zone. In our model, the only consequence of the exaggeration is that the countertraded volume of the system operator increases by ΔT. In real-time, it has to buy power in the importing node/zone and sell the same amount in the exporting node/zone, so that the transmission line can be relieved. In each node/zone, the day-ahead and real-time prices are the same. Hence, (in theory) there will not be any arbitrage profits. The outcome is the same as with nodal pricing in the previous subsection, except that some dispatch decisions are postponed to the real-time market. In practice, such a postponement could lead to welfare losses or the exercise of local market power, but this is not captured by the model.

There would be a difference if the transmission capacity were exaggerated by a large amount, so that one of the following happens: 1) The reported transmission capacity plus demand in the exporting node is larger than the production capacity in the exporting node. This case corresponds to the zonal market that is analysed in Section 2.6. 2) The reported transmission capacity is larger than demand in the import-constrained node, which means that the day-ahead price will be p_E in both nodes. This case corresponds to the zonal market that is analysed in Section 2.7.

Conclusion 1: *Exaggerating the day-ahead transmission capacity between two zones by a small positive amount ΔT does not affect prices or pay-offs in our model. But the two zones are essentially merged into one zone if ΔT is large.*

Figure 3: The equilibrium in a day-ahead market with two nodes/zones, where the cross-zonal transmission capacity between the two nodes has been exaggerated by ΔT.

2.6 The inc-dec game in a zonal market

Now, we will consider a zonal market where the two nodes are in the same zone. To get an inc-dec game, we need to assume that the production capacity in node *E*, Q_E, is less than the total demand d_E+d_I in the market. In this case, we have $Q_E + q_I \geq q_E + q_I = d_E+d_I > Q_E$, so the zonal day-ahead price is set by the offers at p_I in the importing node. Hence, it follows from Section 2.3 that all production capacity in the exporting node is offered at p_E (or lower) and sold at the price p_I. Production with a marginal cost above p_E will offer power (below marginal cost) at p_E and buy back power at the price $p_E < p_I$ in the real-time market. Hence, per unit of capacity, each plant in the exporting node will earn $p_I - p_E > 0$ extra relative to the payoff in a nodal market, as in Section 2.4, where all accepted production in the exporting node would be paid the marginal price p_E of the node and rejected bids wouldn't be paid anything. This is an arbitrage profit (the inc-dec game). There is no arbitrage profit for producers in the importing node. Some producers will sell power in the day-ahead market, and some in the real-time market. But all output in this node will be sold at the price p_I. The inc-dec game is illustrated in Figure *4*, where the offers in the exporting and importing nodes have been aggregated into a zonal supply curve.

A consequence of the inc-dec game is that production units with a marginal cost below p_E will get the same payoff irrespective of the location. The payoff for plants with a marginal cost above p_E will be higher in the exporting node, even if they do not produce anything. Hence, the inc-dec game distorts investment signals. It makes investing more profitable in the export-constrained than in the import-constrained node, even if it is the import-constrained node that lacks production capacity. Hence, investments will become inefficient.

In the considered example, all producers are perfectly informed, and production is fully flexible. In practice, large redispatch volumes can be costly and inefficient. Large and unexpected real-time adjustments could also increase the risk that there will be rolling blackouts or brownouts.

Another consequence of the inc-dec game is that it is the most expensive node that sets the zonal day-ahead price. Hence, consumers in both nodes pay at least as much as under nodal pricing. The redispatch cost is strictly positive, so the tariff is strictly positive for consumers in both nodes. Hence, all consumers would benefit from a switch from zonal pricing to nodal pricing if an inc-dec game is played. This is especially true for consumers in the export-constrained node, who gets a significantly lower day-ahead price under nodal pricing.

Conclusion 2: *If an inc-dec game is played in a zonal market, then investments are inefficient, and every consumer would strictly benefit from a switch to nodal pricing.*

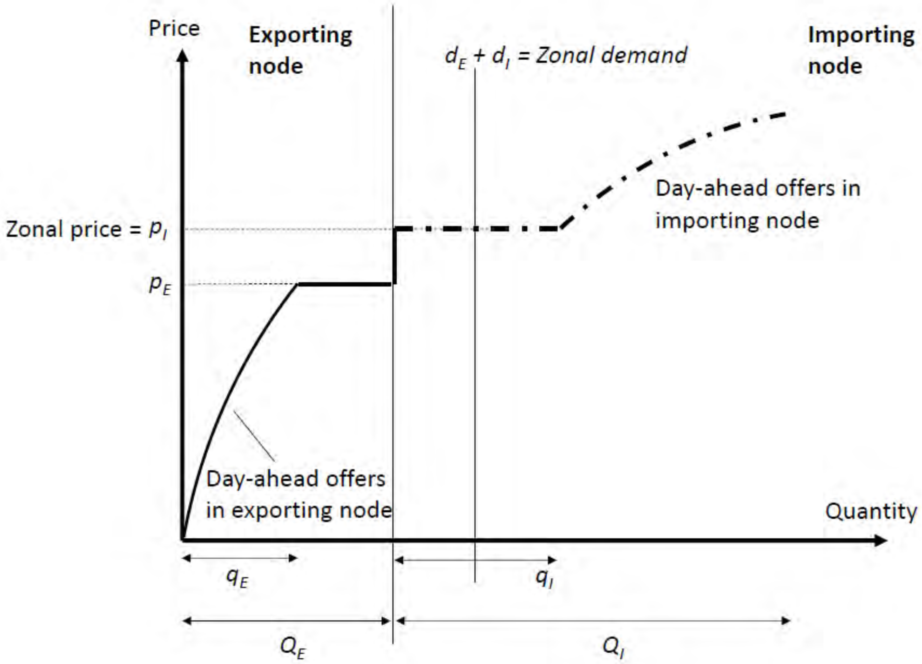

Figure 4: Equilibrium in the day-ahead market for an inc-dec game.

2.7 Off-and-then-on-again supply gaming

Now, we consider the other case where the production capacity in node E, Q_E, is larger than the total demand d_E+d_I in the market. It follows from our assumptions that $q_I= d_I-T>0$, so that $q_E = d_E+d_I -q_I< d_E+d_I$. Hence, the day-ahead price will be set by an offer in the export-constrained node's output range (q_E,Q_E). Output in that range is offered at (and not below) p_E, so the zonal day-ahead price is p_E. This is the same as the nodal redispatch price in this node, so there are no arbitrage rents in the node. For the import-constrained node, all production is offered at p_I, or higher, so no production in the import-constrained node is accepted in the day-ahead market. This node's production is sold in the real-time market at $p_I =MC_I$. This corresponds to the "off-and-then-on-again" supply game that has been observed in practice. The equilibrium is illustrated in Figure 5.

Under our assumptions, the payment to producers is the same as under nodal pricing. Hence, the outcome is efficient, also in the long run. The total payment from consumers is also the same as under nodal pricing. But according to our assumptions on the network tariff, each consumer will pay part of the redispatch cost. Hence, consumers in the exporting node will also pay part of the high nodal redispatch price in the importing node.

Conclusion 3: *If an off-and-then-on-again supply game is played in a zonal market, then investments into production are efficient. Consumers in the import-constrained node would prefer zonal pricing, whereas consumers in the export-constrained node would benefit from nodal pricing.*

In our theoretical analysis, off-and-then-on-again supply gaming is not harmful, as there are no inefficiencies. However, in practice, a problem with off-and-then-on-again supply gaming is that the redispatch volumes increase relative to the case where producers offer at marginal cost in the day-ahead market. In particular, this is a problem when there is imperfect information about redispatch volumes. Inefficiencies occur when less production can be activated in real-time compared to the day before delivery. Moreover, the off-and-then-on-again supply game is a problem if production in the import-constrained node can exercise market power in the real-time market.

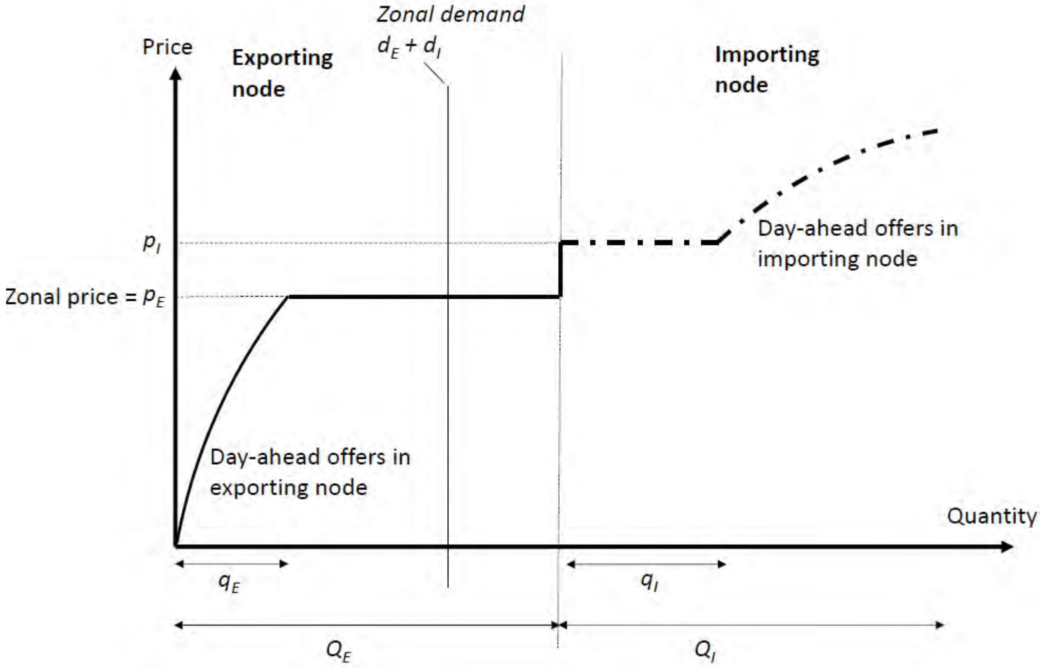

Figure 5: Equilibrium in the day-ahead market for an off-and-then-on-again supply game.

2.8 Procuring production in the import-constrained node

A measure to mitigate the inc-dec game is if the system operator procures production in the import-constrained node before the day-ahead market opens. It can procure a volume Δq in that node, which is then committed to produce and sell electricity in the day-ahead market. Δq might be less than q_I, but we assume that $Q_E + \Delta q$ is larger than total demand $d_E + d_I$ in the market, so that the export-constrained node sets the day-ahead price. Production in the import-constrained node has the opportunity to sell power at p_I in the real-time market. Hence, the system operator needs to pay $p_I - p_E$ per unit of energy as compensation to the procured units, otherwise they wouldn't give up the opportunity to sell in the real-time market. The system operator saves the same amount on the reduced redispatch volume, so it does not lose anything. The equilibrium is illustrated in Figure 6.

The outcome is essentially the same as under Off-and-then-on-again supply gaming in Section 2.7, but the redispatched volume is reduced. Moreover, the risk of getting an inc-dec game is reduced.

Conclusion 4: *The system operator can reduce redispatched volumes and the risk of an inc-dec game, if it procures production in import-constrained nodes before the day-ahead market opens. The system operator saves the same amount on the reduced redispatch volume, so it does not lose anything.*

Similarly, a system operator could procure production with high technical capabilities before the day-ahead market opens. Such procurements have, for example, been performed by the Swedish system operator, Svenska Kraftnät. Instead of procuring such services as a non-balancing operation in the real-time market, Svenska Kraftnät signed long-term contracts with a nuclear power reactor (Ringhals 1) and a combined heat and power plant (Rya) in the Summer of 2020 and 2021, respectively. These long-term contracts may have reduced inc-dec opportunities.

An alternative would be to compensate high-cost production in the export-constrained node for not selling power in the day-ahead market.[26] This would also reduce the redispatch volumes. The profit of the compensated producers would be the same. The system operator would not lose any money to the compensated producers as the paid compensation would equal what it saves on the reduced redispatch volumes. However, a problem with this type of agreement is that it reduces the production capacity offered to the day-ahead market by export-constrained producers. This increases the risk that the offered volume in the export-constrained node will be less than total demand, so that an inc-dec game could be played.

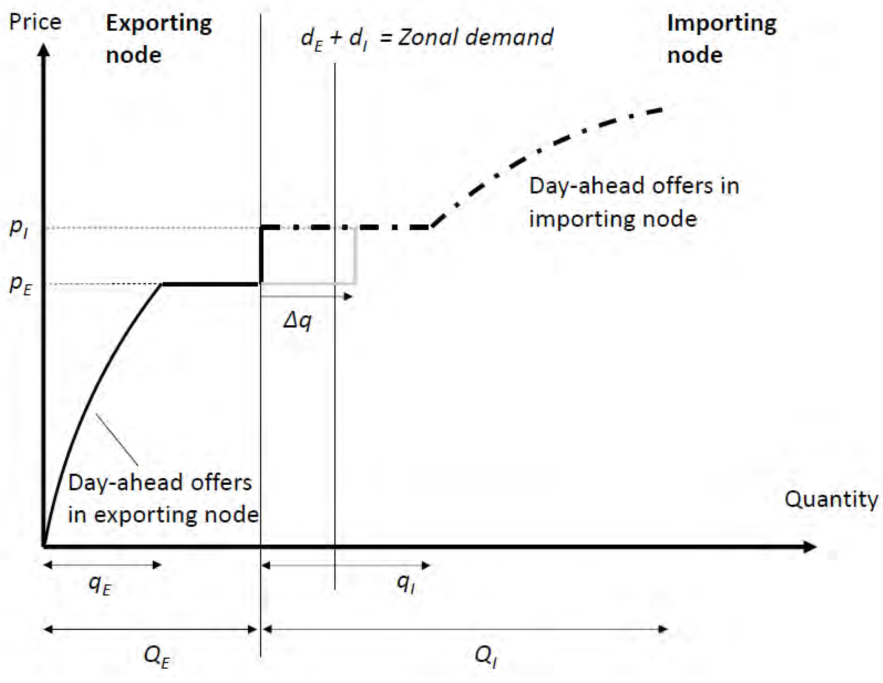

Figure 6: Procuring a sufficiently large volume Δq in the import-constrained node changes an inc-dec game to an off-and-then-on-again supply game.

[26] A few years ago, Svenska kraftnät made a somewhat related non-frequency-ancillary-service agreement with a 1450-MW-nuclear-power plant in Sweden, Oskarshamn 3. The agreement was that Oskarshamn 3 should reduce its output by 100 MW and be compensated for this, when the Nordic power system was lacking rotational energy (inertia). The agreement with Oskarshamn 3 is no longer needed after the Nordic countries started to procure synthetic inertia to the Fast Frequency Reserve (FFR). In Finland, the 1650-MW-nuclear-power-reactor Olkiluoto 3 needs to pay for a 300-MW reserve. The output of the reactor is capped at 1300 MW whenever the reserve is unavailable.

2.9 Only allow offers from flexible production in real-time market

Flexibility is not crucial for our results if it is assumed that inflexible production is allowed to trade power in the real-time market, as in GB. As long as there are no uncertainties, inflexible production can decide how much to produce the day before delivery and then sell it in the market where the price is highest. If it decides not to produce, it can still play an inc-dec game, where it first sells the power in the day-ahead market, and then buys it back in the real-time market.

However, inflexibility would make a difference if inflexible production would not be allowed to sell power in the real-time market, which is the case in Sweden. This means that inflexible production in the import-constrained node no longer has the opportunity to sell power at p_I in the real-time market. They have to sell their power in the day-ahead market. Thus, all inflexible production in the importing node will offer at marginal cost in the day-ahead market, including production with a marginal cost below p_I.

Let Δq_1 be the volume of inflexible power in the import-constrained node that has a marginal cost below p_E and let Δq_2 be the volume of inflexible power in the import-constrained node that has a marginal cost between p_E and p_I. Hence, the volume of zonal day-ahead offers below p_E will increase by Δq_1, and the volume of day-ahead offers below p_I will increase by $\Delta q_1 + \Delta q_2$. This will reduce redispatch volumes and also reduce the risk that an inc-dec game is played, as illustrated in Figure 7. On the other hand, such a restriction may result in welfare losses. The problem is that the volume Δq_2 of inflexible production in the import-constrained node with marginal costs in the range (p_E, p_I) will not be dispatched if the day-ahead price is set by the export-constrained node. From a welfare perspective, it would be efficient to dispatch these units. We assume that all power is flexible with regard to output reductions. Hence, the Swedish flexibility constraint would not change offers in the export-constrained node.

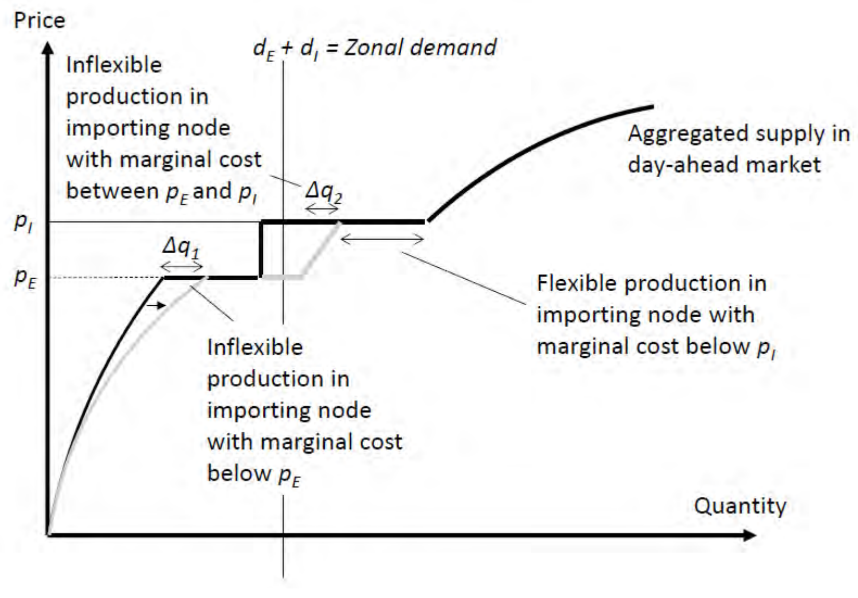

Figure 7: Preventing inflexible production from selling power in the real-time market will increase the supply of low offers in the day-ahead market, reducing the risk of inc-dec gaming. Note that the grey curves include offers from inflexible production in the import-constrained node, so some offers from the import-constrained node are now in the left part of the aggregated supply curve in the day-ahead market.

Conclusion 5: *The system operator can reduce redispatch volumes and the risk of inc-dec games, if inflexible production is not allowed to sell power in the real-time market. But such a constraint introduces welfare losses.*

2.10 Local network tariffs

Instead of arranging a procurement, the network owner could give production in import-constrained nodes a fixed-rate compensation Δp per unit of energy produced (irrespective of the market in which the energy is sold). The compensation could, for example, be part of the tariff structure. This would reduce the marginal cost of production in import-constrained nodes by Δp. The nodal redispatch price in the import-constrained node, p_I, will also go down by Δp, (if we assume that Δp is small so that we still have $p_I > p_E$). This will reduce the difference $p_I - p_E$ by Δp, which is driving the inc-dec game and the off-and-then-on-again supply game. This is illustrated in Figure 8. Hence, the revenues from those games and the incentives to play them are reduced. The network owner will lose $\Delta p q_I$ due to the fixed-rate payment. However, the system operator will save the same amount from a reduced redispatch cost. In many EU countries, the system operator owns the transmission grid. If so, its net cost from the fixed-rate compensation is zero.

Similarly, rents from arbitrage games would be reduced if production in export-constrained nodes paid a fixed-rate per unit of energy produced, increasing the marginal cost of production in that node. To some extent, local network tariffs can compensate for the lack of nodal pricing.

In particular, network tariffs with peak-coincident capacity charges should effectively reduce arbitrage games. When the transmission line is congested, consumers in the import-constrained and producers in the export-constrained node, who contribute to the congestion, should pay a steep tariff that is proportional to the withdrawn and injected energy, respectively (Schittekatte and Meeus, 2018). The tariff should be symmetric (Pérez-Arriaga et al., 2017), so producers in the import-constrained and consumers in the export-constrained node, who relieve the congestion, should be compensated for this; they should be paid a steep tariff that is proportional to the injected and withdrawn energy, respectively.

Conclusion 6: *The owner of the transmission grid can mitigate the inc-dec game and the off-and-then-on-again supply game, if it gives production in import-constrained nodes a fixed-rate compensation and if production in export-constrained nodes pays a fixed-rate per unit of energy produced.*

GB, Norway and Sweden have local network tariffs in the transmission grid (Eicke et al., 2020), which should mitigate arbitrage gaming somewhat.

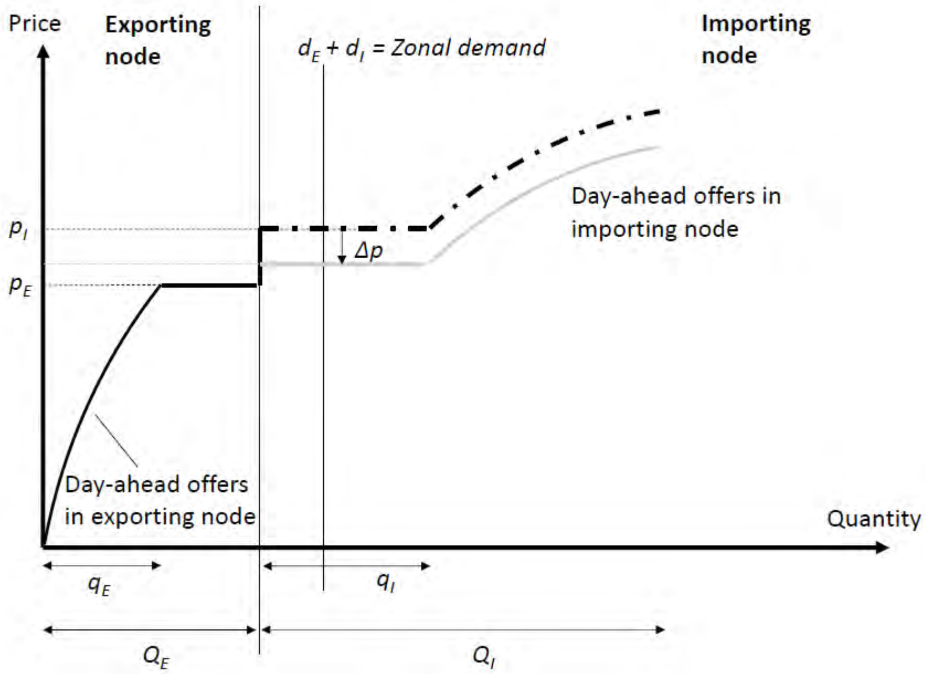

Figure 8: Paying production in the import-constrained node with a fixed-rate compensation Δp per unit of energy produced reduces the rents from an inc-dec game or an off-and-then-on-again supply game.

2.11 Flexible consumption

This subsection will consider consumers that are flexible and active in the real-time market. We still assume that demand is inelastic up to a reservation price, which is supposed to be high and above p_I. Moreover, we assume that consumers are small and without market power. Hence, the outcome in the real-time market will not change, but offers to the day-ahead market will change.

Consumers in the two nodes will buy d_I and d_E, respectively, as long as the price is below the reservation price. Analogous to our assumption for producers, we assume that monitoring and the market design are such that consumers cannot buy more than these demand levels in the day-ahead market. But in practice, it can be difficult for an outsider to estimate how much electricity a consumer needs during a specific hour. We will discuss this issue further in Section 2.14.

In the redispatch, flexible consumers in the export-constrained node will be able to trade at the price p_E. Hence, consumers will buy all of their consumption d_E in the day-ahead market, as long as the zonal price is below p_E, and they will not purchase anything at zonal prices above p_E. Analogously, consumers in the import-constrained node will buy all of their consumption d_I in the day-ahead market, as long as the zonal price is below p_I, and they will not purchase anything at zonal prices above p_I. This is illustrated in Figure 9.

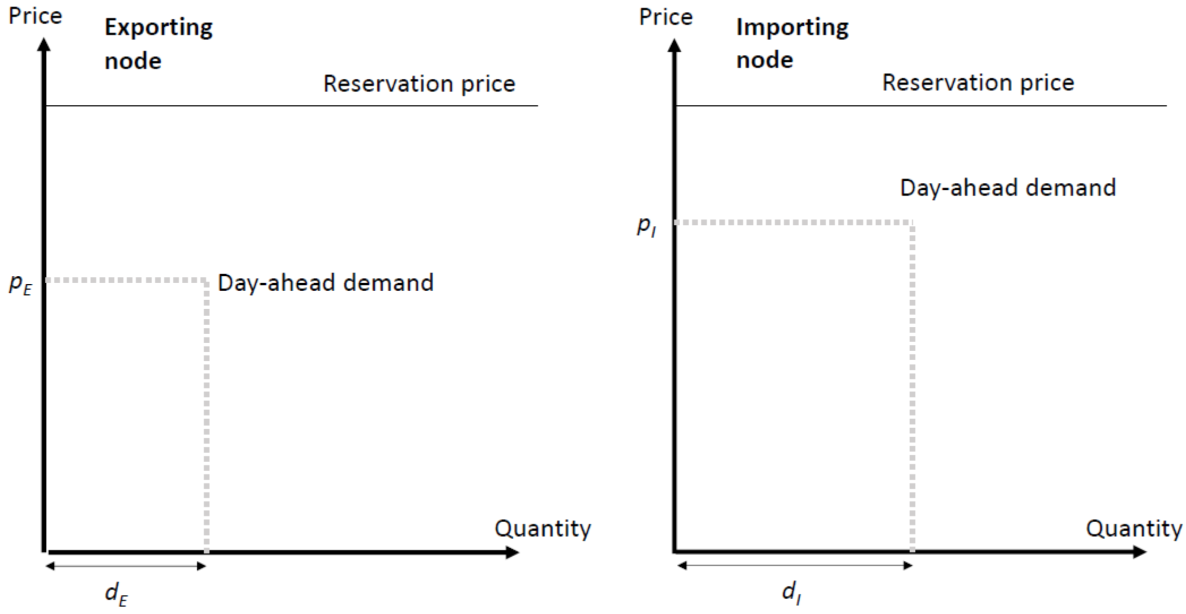

Figure 9: Day-ahead bids in the export-constrained node (left) and the import-constrained node (right).

In Figure 10, we aggregate the day-ahead bids into a zonal demand curve and add the aggregated day-ahead supply curve. The figure illustrates that the zonal day-ahead price can become lower with flexible demand, even if the reservation price of consumers is above p_I. The reason is that flexible consumers in the export-constrained node have the opportunity to buy power in the real-time market, making them less willing to pay a high price in the day-ahead market. In the example, consumers in the import-constrained node will buy all of their power at the zonal day-ahead price $p_{E,}$ and producers in the import-constrained node will sell all of their power at p_I in the real-time market. The price difference gives a redispatch cost. In the export-constrained node, all power is traded at p_E. The rent of the producers is the same as under nodal pricing. The total cost of consumers is also the same, but consumers in the export-constrained node will pay more than under nodal pricing, as they will pay part of the redispatch cost.

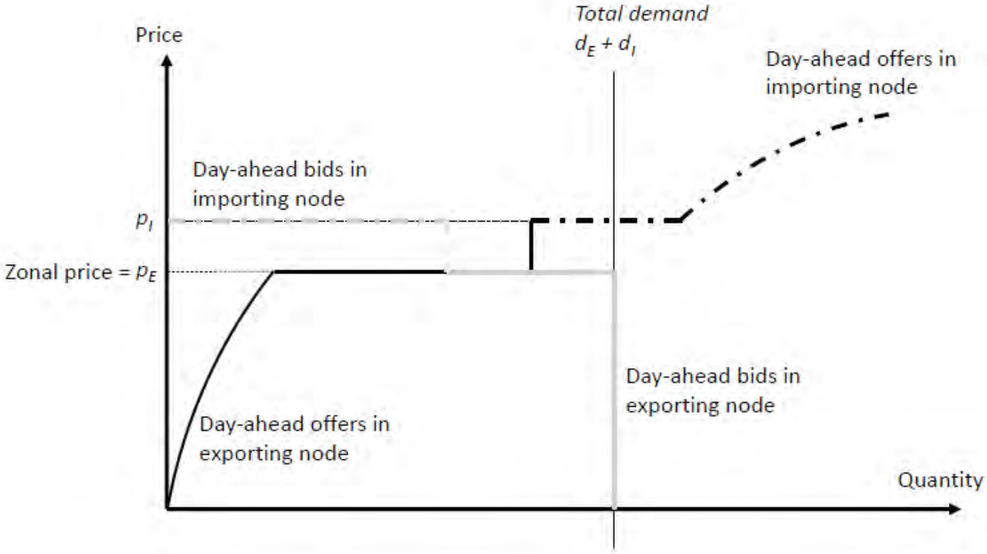

Figure 10: Equilibrium in the day-ahead market when demand is flexible.

Conclusion 7: *Flexible consumption contributes to lower day-ahead prices and reduces the risk of inc-dec games, as long as a consumer cannot buy more power in the day-ahead market than it needs.*

2.12 Regulation of offers and compensations

Some countries regulate offers and compensations for providers of non-balancing operations. Great Britain has introduced the Transmission Constraint Licence Condition (TCLC) Act, which intends to prevent generators from exploiting periods of transmission constraint (Ofgem, 2012). The act was amended in 2017. Now, it applies to general exploitation of system constraints. In principle, it could also apply to situations where there is a shortage of inertia, ramping services, or voltage-control services. Producers have been fined for violating the act.

Similarly, the Netherlands has introduced related regulations (Nodes et al., 2019). Regulatory intervention, penalties and zone splitting are proposed as threats to limit gaming.

Local shortage of power, and accordingly, the potential to play the inc-dec game or exercise market power in the real-time market, tends to vary during the day. Therefore, if offer prices are fixed for each unit over the entire day, it becomes more challenging to play an inc-dec game and exercise market power in the real-time market. At the very least, inc-dec gaming should be smoother across the day, and result in less extreme inc-dec volumes at sensitive hours, e.g. when demand is high, or the output of low-capability power is high.

Each unit's reported marginal cost curve, as implied by the offers and bids, should be fixed for the entire day. However, the reference point, i.e., the scheduled output of the unit, should be allowed to change during the day. In addition, redispatched units should be compensated for start-up costs and ramping costs. Offers related to these costs should also be fixed during the whole day. Requiring offer prices to be fixed during the entire day should be fairly non-restrictive for most production plants, for which the marginal cost and opportunity cost do not change much during the day.[27] However, exceptions should be made for batteries, other short-run energy storages, and demand reduction, as their opportunity cost can vary significantly during a single day. Variable Renewable Energy (VRE) should be allowed to change the production capacity during the day.

Recommendation 1: *For each unit, bid and offer prices to the real-time market should be fixed during the day. Exceptions should be made for short-run energy storage and demand reduction.*

Compensation for providers of non-balancing services is cost-based in Austria and Germany. As shown in Section 2.5, playing the inc-dec game with a production unit involves selling power below marginal cost in the day-ahead market and then buying it back at an even lower price in the redispatch market. This strategy is challenging if the compensation in the redispatch market is cost-based. However, it can be difficult for a regulator to fully observe the production costs of a plant. In particular, it can be challenging to observe whether a wind-power or a solar-power plant has sufficient wind or sunlight to produce what was sold in the day-ahead market. Under a cost-based regulation, the owner of a plant should (in principle) pay a very high price for not having to produce electricity that it is not capable of producing. But in practice, it can be very difficult for the regulator to differentiate between output that was curtailed and output that would not have been produced anyway, i.e. a faked curtailment.

[27] If non-balancing volumes are large and offers are fixed during the entire day, it may be better to compensate accepted offers in accordance with a market price. Currently, accepted offers in GB and Sweden are paid as bid.

There is a similar problem for demand response, where it is difficult for the regulator to distinguish between actual demand reductions and reductions that are faked by exaggerated day-ahead volumes. Some markets use a baseline regulation, where demand reductions are imputed from historical data or other observable variables (Holmberg and Tangerås, 2022; Valarezo et al., 2021). A similar regulation could be used when compensating for the curtailment of solar- and wind power.

Recommendation 2: *If the redispatch is cost-based, baseline regulations should be used when compensating demand response and curtailed solar- and wind power in the real-time market.*

There are other issues with cost-based regulations. For example, Wolak (2003) notes that unless properly monitored and regulated, producers can, through transactions with affiliate companies, make accounted fuel costs and other input costs correspond to whatever level they would like to bid.

Moreover, there is a risk that market participants prefer not to take part in real-time markets, or that they do not invest in capabilities of relevance to real-time markets, if they have little to gain from such participation and such investments. To avoid underinvestment, cost-based regulations need to be sufficiently generous, so that market participants get a fair return on their participation in the real-time markets. In the US, cost-based regulations often add 10% on top of the estimated cost (Graf et al., 2021b).

In several electricity markets in the US, cost-based regulations are introduced at locations and points of time when competition is inferior (Graf et al., 2021b). An automatic local market power mitigation process means that lengthy legal battles can be avoided. An advantage of having market-based bidding most of the time is that offers and bids submitted under competitive conditions can be used to regulate offers under non-competitive conditions (Graf et al., 2021b).

Norway has a related regulation specified in the Norwegian Regulation on System Responsibility (FOS). When it is evident that pricing in the real-time market is not economically efficient, the system operator, Statnett, has the right to disregard bids and instead pay accepted offers in accordance with the prevailing price in the day-ahead market, which reduces gaming opportunities (Bjørndalen, 2020). During particularly stressed system conditions, i.e. due to maintenance, planned outages or operational disturbances, the Norwegian system operator has the authority to curtail production without paying any compensation.[28]

Recommendation 3: *European real-time markets should mainly be market-based. However, a regulated compensation can be used at occasions when a unit is likely to have excessive local market power or has strong incentives to play an arbitrage game.*

The regulated compensation could for example be the prevailing zonal day-ahead price or some average of the unit's bids/offers that were made during non-problematic market conditions, whichever is preferred by the unit.

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[28] Here is a detailed guideline of how the Norwegian regulations work in practice: www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/retningslinjer-for-systemansvaret/

2.13 Unit-based bidding

Bids and offers are unit based in the real-time market. This means that when a system operator accepts an offer in the real-time market, then it knows the exact location of where this power is going to be dispatched. This information is crucial when the system operator needs to relieve congestion in local transmission lines and when it needs to control the voltage in local nodes.

Bids and offers in the day-ahead market and intra-day market are portfolio based in most EU countries. Each market participant says how much it is willing to sell or buy in each zone, but it does not need to specify how much it plans to produce or consume in each unit. Italy and Spain are exceptions that have (at least partly) unit-based bids in day-ahead and intra-day markets. One advantage of this is that it becomes easier for system operators to make a prognosis of redispatch volumes. Also, it is easier to monitor a market if bids are unit based. Another potential advantage is that the system operator could, if the power exchange would allow it, use day-ahead and intra-day markets to procure power at critical locations or to procure critical high capability production. Similarly, the system operator could make sure that units that are at particularly bad locations or that have a particularly low technical capability would be dispatched to a less extent at the power exchange. This would reduce the need for non-balancing operations in real time. But there are also potential disadvantages with unit-based bids, which are discussed by Ahlqvist et al. (2022). For example, unit-based bids could reduce intra-day trading or increase transactions costs.

A compromise could perhaps be that bids are unit based for units that the system operator finds to be particularly critical, or particularly unfavourable, and portfolio based for other units. Moreover, the system operator's possibilities to influence dispatch decisions of critical units could be limited to particularly stressed system conditions. This would be some sort of compromise between electricity markets in the EU and US.

2.14 Improving power system quality

In the long run, the most effective way to mitigate inc-dec games and issues with local market power is to improve the overall quality of the power system, so that the power system is less constrained. Italy has shown that many small and quick measures can make a significant difference. Moreover, a more efficient market design makes a difference. EU countries that are part of the Core Capacity Calculation Region (Core CCR) apply flow-based zonal pricing.[29] This method allows system operators to consider critical network constraints inside a zone while still maintaining a single day-ahead price per zone. Moreover, flow-based zonal pricing means that critical network constraints will be managed by a coordinated effort of the system operators. This means that the network will be utilised more efficiently, which could potentially reduce arbitrage opportunities, inc-dec gaming and the exercise of local market power. Simulations by Sarfati and Holmberg (2020) illustrate this. However, it is somewhat uncertain how this works in practice, as it is less certain that the network is utilised more efficiently in the intra-day and real-time markets. Improved market integration, including harmonisation of European real-time markets, will make it easier for system operators to manage the various power-system constraints and to enhance market competitiveness. Similar integration should also be introduced for non-balancing services.

[29] Thirteen EU countries are part of Core CRR: Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxemburg, the Netherlands, Poland, Romania, Slovakia and Slovenia. The implementation of flow-based zonal pricing in the Nordic countries has been delayed until the autumn of 2024.

Intra-day markets that allow for continuous matching of orders have problems to consider network constraints in detail (Neuhoff et al., 2016; Ehrenmann et al., 2019; Ahlqvist et al., 2022; Graf et al., 2024). Pricing in the day-ahead and intra-day markets would be inconsistent if the day-ahead market considers intra-zonal congestion in one way, and the intra-day market considers this congestion in another way. This can potentially lead to arbitrage games. To avoid this problem, intra-day markets should be organised as a discrete number of auctions, where each auction applies the same congestion management method (e.g. flow-based zonal pricing) as the day-ahead market. The auctions can be frequent, e.g. every 5-10 minutes, as long as there is enough time to consider network constraints in detail. Other advantages of discrete auctions are that they reduce transaction costs, increase liquidity (during the auction) and reduce algorithmic trading (Ahlqvist et al., 2022; Graf et al., 2024).[30]

Recommendation 4: *Intra-day markets should be organised as a discrete number of frequent auctions, where each auction applies the same congestion management method (e.g. flow-based method) as the day-ahead market.*

Massive investments in battery storage in many European markets should also contribute to less stressed power systems and less arbitrage gaming. Similarly, games of units with low capabilities would be less of a problem if the system operator required units to have specific capabilities, for example regarding voltage control, ability to disconnect quickly and not having a too large capacity. This will also reduce rents from inc-dec gaming.

To prevent inc-dec games, owners of transmission networks should be careful not to connect new production and consumption units that will significantly worsen congestion or the quality of the power system. This partly explains why redispatch volumes are relatively small in France, where network capacity has to be available before new generators can be connected to the grid (Pavlovic et al., 2021). But being too careful would slow down the energy transition. A better way may be to follow the proposal of the transmission system operator in Ireland. Eirgrid (2022) suggests that new units should be quickly connected, but that access will be non-firm for up to five years. Hence, new units will be curtailed first in case the grid is congested, and they may not be compensated for it.

The 70% rule on cross-country transmission lines will become firm from 2026. No exceptions will be granted after that. However, a strict 70% rule may slow down the transition by slowing down investments, including new cross-country lines, especially if such investments would make it more difficult to follow the 70 % rule. Perhaps a country should, also after 2026, be allowed to get exceptions from the 70% rule, if it can be shown that the cross-country problems are caused by new investments.

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[30] Algorithmic trading increases the costs of operating the intra-day market and encourages partly inefficient rent-seeking activities. In general, rent-seeking is inefficient if resources are used to contest wealth instead of creating wealth (Tullock, 1967). For example, an agent that invests in the fastest computer and algorithm can make a considerable amount of money in a market with continuous trading, simply by responding a microsecond quicker than competitors to public information, see Budish et al. (2015). This opportunity can motivate agents to make costly investments in speedy technologies to make rents at the expense of other traders, even if the social value of bringing information one microsecond earlier to the intra-day market is likely negligible.

3 Conclusions

European wholesale electricity markets have partly inconsistent pricing. Day-ahead markets neglect details of the power system, such as transmission capacities of small lines, voltage control and the stability of the power system. These details are crucial and must be considered in real-time when power is delivered. As day-ahead and real-time markets consider different constraints, prices will be different, and these price differences can sometimes be predictable. Predictable price differences encourage market participants to engage in arbitrage strategies, where they try to buy electricity at a low price, sell it at a higher price, and profit from the difference.

These arbitrage games have several issues. One problem is that the day-ahead dispatch is pushed away from a feasible real-time dispatch, necessitating a larger volume of adjustments in real time. We refer to these adjustments as non-balancing operations. Fewer alternatives are available on short notice in real-time. Hence, the real-time market is often less competitive and less efficient compared to the day-ahead market. Managing a large volume of non-balancing operations in real-time is challenging, particularly, if the volume is unpredictable. This increases the risk of blackouts or brownouts.

Moreover, arbitrage rents distort price signals. It is mainly production units that are less useful for the system that benefit from the arbitrage opportunities. Thus, producers get increased incentives to invest in units that are less useful for the system.

In the paper, we focus on two types of arbitrage strategies. The inc-dec game implies that low-capability production that is not needed – because of wrong location or a low technical capability – sells power at a high price in the day-ahead market, which does not consider the capability in detail, and then repurchases it at a low price in real-time. The second strategy, termed the off-and-then-on-again supply game, implies that high-capability production that is needed – because of a good location or a high technical capability – does not sell power in the day-ahead market and instead offers it in the real-time market, which considers more details and pays a higher premium for high-capability production.

In the analysis, we consider a simple model with two nodes connected by a single transmission line. Producers are assumed to lack market power but can play arbitrage games. We show that the inc-dec game is more problematic than the off-and-then-on-again supply game, at least in competitive markets, where producers lack market power. All consumers would benefit from nodal pricing if an inc-dec game is played.

We show that the following would reduce inc-dec gaming: 1) The system operator can procure high-capability production that commits to selling power in the day-ahead market. 2) Not allowing inflexible production to take part in the real-time market, would force inflexible high-capability production to sell in the day-ahead market. 3) The network owner can pay a fixed-rate compensation per unit of energy for high capability production, as part of the network tariff. 4) Flexible consumers that are active in the real-time market reduce inc-dec gaming, as long as they do not exaggerate their demand in the day-ahead market.

The paper also studies the effect of system operators reporting an exaggerated cross-zonal transmission capacity to the day-ahead market, which is then countertraded in the intra-day or real-time market. This is encouraged by the EU:s 70% rule for cross-county transmission capacity and has been implemented at the Danish-German border. In theory, such a measure would not have any effect on the day-ahead prices, at least not if the capacity is exaggerated by a small amount. But if the transmission capacity is exaggerated by a large amount, then this would be akin to a merger of the zones.

The paper advocates that compensations for non-balancing operations should primarily be market-based. Still, a temporary cost-based regulation could be applied for a unit on occasions when the unit is likely to have excessive local market power or strong incentives to play an arbitrage game. Moreover, offer prices to the real-time market should be fixed during the day. Exceptions can be made for short-run energy storage and demand reduction.

Frequent auctions in the intra-day market, instead of continuous trading, should reduce arbitrage opportunities and make trading more efficient.

If Europe increased the network capacity, used dynamic line rating, added network components that control the voltage and flows or invested in more energy storage, so that the existing grid could be utilised more efficiently, then arbitrage games would be less of a problem. Similarly, games of units with low technical capabilities would be less of a problem if the system operator required units to have specific capabilities, such as voltage control, being able to disconnect quickly and not having a too large capacity.

To speed up the energy transition, it may be necessary to connect new units to the grid before firm access can be guaranteed. If so, the system operator should be allowed to temporarily curtail such units without compensation during a transitionary period. Similarly, one could argue that EU should allow for temporary exceptions from the 70% rule if new investments make it difficult to follow the rule. In particular there should be exceptions for countries that invest in new cross-country capacity.

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