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THE EUROPEAN ELECTRICITY MARKET, ITS INEFFICIENCIES, AND THE ASSESSMENT OF POSSIBLE IMPROVEMENTS

Master's thesis completed in order to obtain the degree of Master of Science in Electromechanical Engineering by Vassen Joanne

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Abstract

The objective of this paper is to discuss the European electricity market design. Indeed, there is a heated debate ongoing concerning the need of a refiguration of the latter, fueled by growing inefficiencies: the electricity pricing in the European market is based on a model of large bidding zones, meaning that wholesale markets are cleared as if there was no internal network congestion. However, neglecting the latter, the zonal market clearing may result in infeasible power flows within those bidding zones. This causes issues that are taken care of, generally with the mean of redispatching, which consists in a change in production and consumption patterns at either side of a grid bottleneck to change the flow and relieve congestion. At the early days of market coupling, those congestions were rare and without any bigger consequences. However, with the energy transition and a mismatch between grid and generation expansion, congestion has increased significantly, and pressure on congestion management is increasing.

For this paper, a literature review-based approach was adopted to address the question whether adjustments in the zonal market could be sufficient, or if a fundamental change in the latter is required.

Three potential options addressing these zonal inefficiencies are presented and analyzed. The aim is to offer a non-biased overview of advantages and disadvantages of each of these options. Two of the options, both consisting in an integral change in the design of the bidding zones (a reconfiguration of bidding zones and a switch to nodal systems) were found to be too disruptive, difficult or time-consuming to implement. A third option analyzed the approach of a market-based redispatch instead of a regulated one. Indeed, this option together with strategic grid reinforcement seems like a cost-efficient and feasible solution, however accompanied by strategic bidding risks which would need to be addressed with the right mitigation strategies.

Nomenclature

- ACER: Agency for the Cooperation of Energy Regulators
- CACM: Capacity Allocation and Congestion Management
- CCR: Capacity Calculation Region
- CEE: Central Eastern Europe
- CEP: Clean Energy Package
- CWE: Central Western Europe
- DA: Day-Ahead
- DSO: Distribution System Operator
- D-2CF: D-2 Congestion Forecast
- EEX: European Energy Exchange
- FB: Flow-Based
- FBMC: Flow-Based Market Coupling
- FRM: Flow Reliability Margin
- ID: Intra-Day
- IEA: International Energy Agency
- LTA: Long-Term Allocations
- LTTR: Long-Term Transmission Right
- LMP: Locational Marginal Pricing
- IRP: Interim Coupling Project
- MCO: Market Coupling Operator
- MRC: Multi-Regional Coupling
- NTC: Net Transfer Capacity
- OTC: Over The Counter
- PCR: Price Coupling Regions
- PX: Power exchange
- SDAC: Single Day-Ahead Coupling
- SIDC: Single Intra-Day Coupling
- TSO: Transmission System Operator
- TMC: Trilateral Market Coupling
- 4MMC: 4M Market Coupling
- IGM: Individual Grid Model
- CGM: Common Grid Model
- CNE: Critical Network Element
- RAM: Remaining Available Margin
- PTDF: Power Transfer Distribution Factor

- PUN: Prezzo Unico Nazionale
- NRAO: Non-Costly Remedial Action

Introduction

The European Union is striving for the completion of a liberalized, single electricity market. The proposed market design is known as the 'European target model', based on a model of large bidding zones.

In zonal pricing systems, wholesale markets are cleared as if the network were free of internal network congestion. Only trade between bidding zones is accounted for, limited by cross-zonal transmission capacity. As a result, a uniform market clearing price is obtained within each pricing zone. However, neglecting internal congestion, the zonal market clearing may result in infeasible power flows within zones. Therefore, once the market is cleared, Transmission System Operators (TSOs) take care of intra-zonal congestion in their respective areas via remedial actions. Most commonly, redispatch is used to this aim, which consists in a change in production and consumption patterns at either side of a grid bottleneck to change the flow and relieve congestion.

When Europe started coupling their markets, congestion caused by network constraints was infrequent and the need to redispatch power plants was rare. However, physical congestion has been growing in the last years. This can be explained by the fact that electricity demand and generation, as well as the amount of installed renewable and decentralized capacity, are growing at a much faster pace than the grid can be reinforced. The increasing grid congestion invokes numerous inefficiencies on EU level. High congestion costs, under-utilized cross-zonal capacities or poor price signals are some of the main issues that need to be tackled. Relying on grid expansion alone would be too costly and time-consuming. Therefore, market operators are seeking alternative ways to address the congestion issues.

One way of doing so is by improving the efficiency of cross-border capacity allocation. As it is the transmission network that constitutes the limitation for cross-border trades, capacity allocation should have a substantial impact on market performances. To this aim, Flow Based Market Coupling (FBMC) has been introduced for Central Western Europe (CWE) in 2015, and has been extended to the Core European Region in June 2022. Until then, the Net Transfer Capacity (NTC)-based approach was applied to couple European electricity markets. FBMC is considered being one of the cornerstones of the European target model: compared to NTC, FBMC achieves a better representation of physical constraints of the electricity grid, leads to a more efficient use of transmission capacity, ultimately leading to increased welfare and price convergence. Even though it is estimated that FBMC has a positive effect on congestion management, FBMC still corresponds to a simplified version of the grid and overloading probably occurs.

For this reason, further improvements or alternative changes should be implemented to address congestion. This article presents three different options which are currently being discussed by system operators to take up the challenge, each with its own advantages and challenges.

First, the paper addresses the question whether a market-based redispatch could be a feasible option to overcome issues. Today, most European countries adapted a regulated redispatching, where most plants are obliged to participate. However, a voluntary, market-based approach may open the market for a wider variety of technologies, increase transparency and ultimately lead to lower congestion management costs. However, market-based redispatch has persistently been discarded in most European countries. This is driven by the fact that the coexistence of a zonal market with a local redispatch incentivizes strategic bidding behavior. Market participants have the possibility to strategically bid in the zonal market to create congestion, with the goal of being paid for solving this very congestion in the redispatch market. Naturally, congestion is aggravated, and windfall profits created. However, the article shows that mitigation methods exist.

Secondly, the possibility of a reconfiguration of European bidding zones is analyzed. Currently, most bidding zone borders align with national borders. However, this turned out not to be the best solution. Indeed, the increase of zonal inefficiencies can for a large part be attributed to the current zonal configuration. Therefore, this paper analyses the possibility to recut bidding zones in a m manner that structural congestion is taken care of by the market, instead of relying on out-of-market redispatching measures. This ultimately would lead to smaller bidding zones. However, smaller bidding zones raise liquidity concerns and increase price volatility, which increases the risk of unfavorable market outcomes.

The last solution proposed by this paper is the implementation of a nodal pricing system in EU markets, where an individual electricity price is computed at every single node. In contrast to the zonal market clearing, all relevant transmission constraints are accounted for in the initial dispatch, and no redispatch is required. The market is cleared in a single stage, and no arbitrage incentive is offered.

Nodal pricing has some clear advantages over zonal pricing. Indeed, nodal prices offer better price signals to the participant and improve the efficiency of network use, ultimately leading to cost savings. Despite its advantages, nodal pricing has persistently been discarded by European stakeholders as a result of a combination of different factors.

This paper offers an objective analysis of the pros and cons of each of those approaches. The aim is to give an overview of possible solutions to overcome zonal inefficiencies assess whether there is enough room for improvement in the zonal market, or if more radical measures need to be taken.

To understand why the current zonal configuration is under a lot of pressure, it is important to first understand how energy markets work in general, and how they are organized in Europe. Therefore, chapter 1 explains how electricity networks are organized in general. The chapter emphasizes the importance of a balanced transportation network. Details are given on how the liberalized European market is organized.

Chapter 2 puts the focus on the actual coupling of zonal markets. Later, a detailed explanation of the zonal wholesale market clearing is given in chapter 3. It aims to highlight the fact that in zonal markets, trade is limited by inter-zonal capacities, and that its calculation is of great importance. Finally, a comparison of the cross-border capacity calculations is provided; bringing out why FBMC is the preferred method.

The remainder of the chapter discusses how the internal grid bottlenecks resulting from the zonal market clearing are treated.

The reminder of the paper discusses the above-mentioned growing zonal inefficiencies more in detail (chapter 5), before proceeding with the analysis of the aforementioned three potential mitigation methods.

1 Electricity networks

The modern world has become unthinkable without electricity, which is increasingly being integrated into almost every aspect of human life. Even though the ancient Greeks knew about electricity around 1000 BC, people still knew very little about it until around 250 years ago [1]. In that timeframe, countless scientists have performed experiments in electricity, one of whom was Benjamin Franklin, who is considered being one of the main pioneers in electricity [2]. Since then, people have put tremendous efforts into integrating electricity into their everyday life. As a result, the modern human being has become ever more dependent on a steady electricity supply: Electricity not only provides light, cools and heats buildings, but is also part of today's culture and lifestyle, let it be in the form of kitchen aid devices, computers, and many other gadgets without which modern lifestyle has become unthinkable.

To provide a reliable electricity supply, electricity needs to be generated and transported to the end-consumer. This requires the existence of a balanced electricity grid. Grid operators must ensure that the grid frequency remains stable, in Europe this frequency is set at 50 Hz with a tolerance of ca. 0.05 Hz, 24 hours a day, 7 days a week [3], [4]. This is achieved by making sure that the amount of electricity injected into the system equals the amount of electricity consumed by the system.

However, neither demand nor supply are stable. A higher demand than supply results in a drop of the grid frequency due to the lacking power. As not all producers can operate at lowered frequency, some of them have to unplug from the grid if the frequency drops below a certain threshold. This, however, leads to a further decrease in frequency and a higher number of producers have to unplug: The electricity grid suffers a cascade failure, which can lead to a potential blackout. Conversely, if the supply outpaces demand, the grid frequency increases, and a similar cascade failure occurs [3], [4]. The network needs therefore to be constantly monitored and balanced.

However, balancing has become an increasingly challenging task, as both consumption and production habits are facing radical changes. Global energy consumption is increasing, and the energy supply mix is changing, with renewables becoming an increasingly prominent part of the mix.

When renewable energy sources were not yet part of the energy mix, production could instantly be adapted, which facilitated balancing: Generally, non-renewable plants such as coal or nuclear plants produce on demand and the production volume is independent of any external conditions. Renewable sources, on the other hand, require a lot more monitoring and intervention to maintain stability. Renewables are increasing and are predicted to further do so: according to a report by the International Energy Agency (IEA), renewable power capacity is set to expand by 50% between 2019 and 2024, led by solar PV [5]. The increased share of renewable energy in the modern energy mix complexifies the grid balancing given that many renewable sources are characterized by a strongly intermittent, weather-dependent and non-dispatchable nature. One part of the solution of keeping the grid balanced despite the partially uncontrollable energy mix is electricity storage. However, electricity cannot easily be stored on a large scale or over a long period of time.

To obtain a balanced grid, the electricity generated should at every moment equal the electricity consumed. Does that mean that, whenever I switch on my TV or lightning, the nearest power generation plant instantly has to produce more in order to keep the grid balanced? Luckily, no – This would not only be impossible due to the sharp variability of demand and renewables, but also due to the fact that even classical power stations can be very inflexible, fail suddenly or take a significant amount of time for the run up. Therefore, to allow a constant supply whilst continuously changing generation and consumption, power trades should encompass a large number of producers, consumers, and storage operators, working together with the common aim to allow for a reliable energy supply [4]. The manner in which this is organized in practice will be described in subsequent chapters.

1.1 Power trading

Power trading with free competition, as we know it today, is still very young: Initially, Europe's electricity trading sector was monopolized. Back then, vertically integrated companies were, aside of being responsible for producing electricity, also in charge of transmitting and distributing it to all end users in a certain area. Additionally, the same companies had to provide balancing services and ensure the reliability and security of the electrical network.
Figure 1 represents a simplified scheme of the vertically integrated electricity sector.

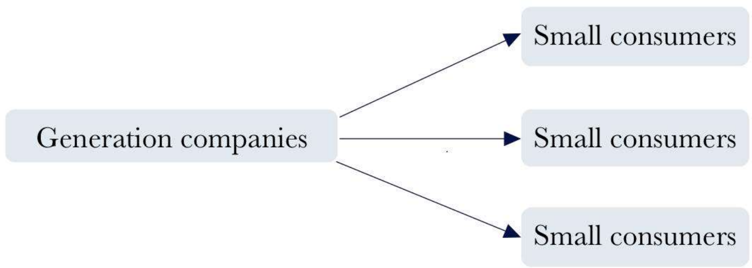

Figure 1: Simplified scheme of the monopolized electricity sector
Adapted from [4], [6], [7].

The vertically integrated market was characterized by a low market liquidity and low market competition. The companies were able to determine themselves their electricity prices and the integration of new market participants was almost impossible [6], [7].

With the publication of the first Energy Package in 1996, the European electricity sector gradually started to shift towards a liberalized, competitive system. The purpose was to create a single market for all EU states, with the aim of reducing grid costs and increasing the security of supply by allowing an electricity trade between a large number of market participants, including producers, consumers and retailers. Monopolies were broken up and the initially vertically integrated market was unbundled, meaning that the tasks of generating, transmitting and distributing electricity were separated. With the liberalization of the markets, electricity supply became more efficient [6]–[8].

However, the liberalization and unbundling did not happen overnight, and is still not completed to this day. The next section gives a more throughout understanding on how the unbundled, modern market is organized.

1.2 Wholesale and retail markets

To understand how the market is organized, it is important to first differentiate between the retail and the wholesale market. A simplified scheme of their functioning and interaction is given in Figure 2.

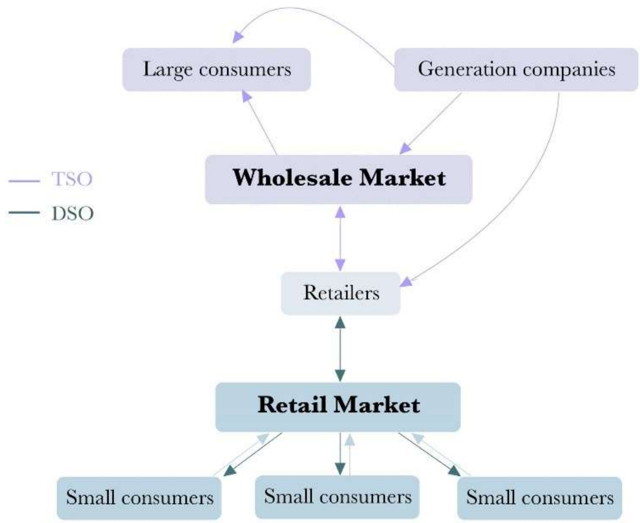

Figure 2: Simplified scheme of the liberalized electricity market
Adapted from [4], [6], [7].

On the retail market, individual consumers buy their electricity at a fixed price per unit of energy from retailers. To this aim, each retail company keeps a portfolio of its individual customers. The companies estimate and buy, either on the wholesale market or directly from the producer, the aggregated amount of energy needed to supply their customers. Of course, an estimation never corresponds to the actual production in real-time: individual imbalances are constantly summed up and corrected by buying or selling electricity via ancillary services.

On Figure 2, the arrow connecting the small consumer to the retail market goes both ways. This reflects the fact that certain individual households or companies are powered by renewable sources, in particular solar panels. At certain times, a solar panel can produce more electricity than what is actually consumed. Since it is difficult to store the surplus of energy, it is fed back into the electricity grid. However, if the panel produces too much electricity without warning, there is a risk of frequency voltage disturbance and transmission line overload. This may result in blackouts and damage to the infrastructure [9], [10].

Even though the retail market has some impact on system stability, it is the wholesale market that has the main influence and responsibility for keeping the grid balanced. In short, the wholesale market is a centralized platform where huge volumes of energy are traded at a variable market price. A large number of market participants are involved, such as generation companies, retailers and large consumers that wish to buy the energy directly on the wholesale market instead of passing through a retail company. Market participants can exchange the power in a transparent manner, according to the price they are willing to pay or receive, and according to the available capacity of the grid network [6]. Most of the time, exchanges are organized through auctions where sellers and buyers submit their bids and offers, on the basis of which the demand is matched with the available production. The location for the trade is offered by market operators that also have some additional roles such as balance scheme management or imbalance settlement. The market operation is supervised by market regulators, investigating market abuses [4]. In reality, however, the wholesale market is even more complex, and organized on different time horizons. Section 1.3 provides a more detailed explanation of how the wholesale market is organized.

It is important to understand that the electricity traded on the market must also be physically transported. This requires an adapted transfer capacity, stemming from a strong and flexible transportation grid. To minimize losses while ensuring security, the grid is divided into a high- and a low voltage grid. The high-voltage grid is used for transmission across long distances, generally in remote areas, reserved for the wholesale market trades. It is maintained and built by Transmission System Operators (TSOs), responsible for maintaining the balance between production and consumption of the grid. In most European countries, the high-voltage grid is

operated by one single TSO. In Belgium, the high-volte grid is managed by Elia at a voltage between 30 kV and 380 kV [11].
For trades on the retail market, low-voltage lines are used. Entities that operate on the retail market are called Distribution System Operators (DSOs). They are installed close to the end-users and are used for transmission across smaller distances [4].

TSOs and DSOs need to cooperate to ensure grid security. Especially since a large part of renewable energy is connected at the distribution network level, an optimized coordination and cooperation between TSOs and DSOs is required.

As mentioned before, it is primarily the wholesale market that ensures system stability. Consequently, the remainder of this article focuses on the wholesale market, which can be simply called the "market" for the rest of this document. The next section examines in greater detail how the market is organized.

1.3 Power trading on the wholesale market

The wholesale market is organized into different levels of time, depending on how far in advance to real-time the energy is bought: The market is divided in Future Markets, Day-Ahead (DA) markets, Intra-Day (ID) markets and Balancing Markets.

Figure 3 represents a scheme of the wholesale market timeline.

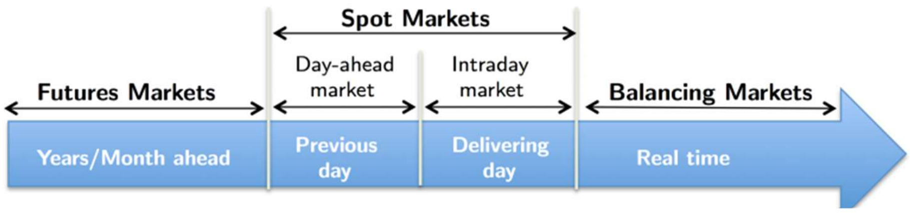

Figure 3: Wholesale market timeline
From [4]

The reason for this division of the wholesale market is the necessity to maintain constant consumption equal to production. As a reminder, electricity storage is helpful when it comes to

balancing. However, the storage is limited and can only be used to adjust small imbalances in real-time. For this reason, TSOs should know in advance how the real-time situation looks like, so that there is enough time to plan and adapt production. A question that arises is the following: How can TSOs know in advance what is the state of the grid at a certain moment in the future [4], [6], [8]?
To secure the instantaneous balance between generation and consumption, market participants need to have enough room to constantly correct their estimation errors. This is achieved by organizing the market on different levels.

The DA market is the main reference market, whereas Future Markets offer a hedging tool, and the ID and Balancing Markets are adjustment markets. The next section provides a short explanation of each of these market time horizons.

1.3.1 Future Markets

Months or even years before the delivery date, Future Markets take place, where large quantities of power for future delivery are traded. The price of that power corresponds to today's expectation of future spot prices.
Forward Markets are instruments to reduce the risk of unfavorable future market outcomes. To be more exact, their purpose is to allow market participants to protect themselves (or 'hedge') from the unpredictable volatility of spot prices (that's why long-term contracts are also referred to as hedging contracts). Forward Markets are indispensable for an overall efficient investment behavior on the market, as they provide efficient opportunities for risk management, risk transfer and risk sharing [7], [8], [12].

In Belgium, Forward Markets are traded on ICE Endex or European Energy Exchange (EEX) [7], [8], [12].

1.3.2 Spot Markets

In contrast to Future Markets, Spot Markets reflect the current physical balance of the market, and transactions are planned for immediate or close-to immediate deliveries. The Spot Market is divided into the Day-Ahead (DA) and the Intra-Day (ID) market.

The most important market is the DA market, where an auction occurs the day before delivery, in other words on day *d-1*, for the 24h of the next day *d*, the delivery-day. The DA auction is fixed gate: submissions of supply and demand bids are closed at pre-specified times. In Belgium, bids are submitted during a 15-minutes period.

The DA market is characterized by a uniform clearing price, cleared once a day around 1PM. Figure 4 shows how, by balancing the aggregated sell and buy bid curves, the day-ahead clearing price is determined. All the bids that are below this price are approved, and the associated participants can produce or consume the energy offered or demanded.

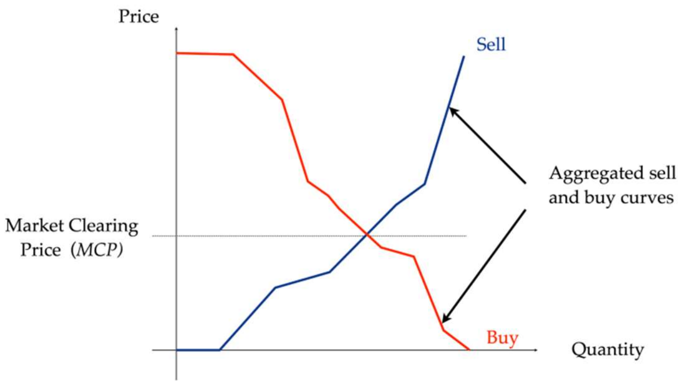

Figure 4: DA market clearing price determination
From [6]

Thanks to the fact that DA predictions are based on information that is close to real-time, they are generally accurate. Nevertheless, it is important to keep in mind that they are based on estimations for the coming day, taking into account weather forecasts, information on power plants and events that may have an impact on power consumption. Therefore, the DA forecast is never 100% accurate. To keep the grid balanced despite those estimation errors, the Intra-Day (ID) market opens only after the DA market has been cleared.

It is the ID market that allows the participants to correct the DA estimation errors until right before the actual delivery happens. In contrast to the DA market, different formats of this market exist depending on the location. In Belgium, the ID market is a continuous time auction with a 15-minutes resolution. This means that orders can be continuously submitted and are stored. At any possible time, whenever two bids match, deals can be approved. Prices are set based on a first-come, first-served principle [6]–[8].
Due to the fact that renewables generally update their forecast up to delivery date, the possibility offered by the zonal model to continuously trade on the ID market is especially valuable to match flexible resources with renewables. Therefore, the zonal market design with continuous ID trading is characterized by a high flexibility, that eases the introduction of work for new technologies, such as demand response and energy storage [13].

In Belgium, it is EPEX Spot Belgium that organizes the Spot Markets [7].

1.3.3 Balancing Markets

Despite the balancing mechanism offered by the ID market, there will always remain some imbalances in the real world. Due to the fact that production and consumption can never be forecasted at 100%, a deviation of some market agents from what was agreed in previous markets could lead to disturbances in the network frequency. If these disturbances exceed a certain threshold, ancillary services that restore balance must be purchased by the responsible participants. Therefore, for the grid to be balanced in real time, the market operators constantly monitor the grid frequency and the level of imbalance. It is interesting to mention that Balancing Markets are becoming increasingly important, linked to the fact that the variability in production and consumption increases from year to year, reinforcing price volatility.

In Belgium, TSO Elia handles this final imbalance by mobilizing reserve products [6]–[8].

1.4 Over the Counter (OTC) trading and Power exchanges (PX)

In the European electricity sector, two main trading options are available: Over the Counter (OTC) and Power exchanges (PX).

PX are trading platforms that seek to attain market liquidity and transparent energy trading. Their goal is to calculate the energy prices in the best possible way and to efficiently implement cross-border electricity allocations. They set up an auction that allows traders to submit their bids anonymously, but trading prices and volumes are then made public to the market. Trading in the Spot Market usually is organized by one or more PX per member state. In Europe, the two main PX are EPEX Spot (for Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland and the United Kingdom) and NordPool (for Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Norway, Sweden and the United Kingdom).
OTC markets, on the other hand, are used for bilateral contracts between counterparties without involving PX. In contrast to PX markets, the deal is not made public for the market, and trading prices and volumes are only known to the respective counterparties. As mentioned in section 1.2, retail companies and large consumers can buy their electricity directly from the generation companies instead of passing through a market. Those deals generally are OTC deals. Another use is in Future Markets. Even though Spot Markets can be organized through OTCs, they have a bigger gate closure time than PX, and are therefore less interesting for short term trading [12], [14].

2 European market coupling

Historically, the European market was organized on a national level, where every country was supposed to maintain itself without any outside aid. Cross-border trading was costly and its importance remained marginal. Interconnections between national markets were in the first place built for security and backup, and the overall market was characterized by illiquidity. With the increasing amount of renewable energy in the mix and the increasing fluctuations in use and demand patterns, cross-border electricity trading became more important and the European states started to strive for optimizing solutions. As a result, some European states decided in 2006 to promote effective competition and electricity trading by coupling individual electricity market zones (referred to as 'bidding zones').

The current zonal configuration is shown in Figure 5. In zonal market designs, the wholesale market is cleared assuming there is no congestion inside a bidding zone, leading to one uniform electricity price per market zone. How this is done in practice will be detailed in section 3.

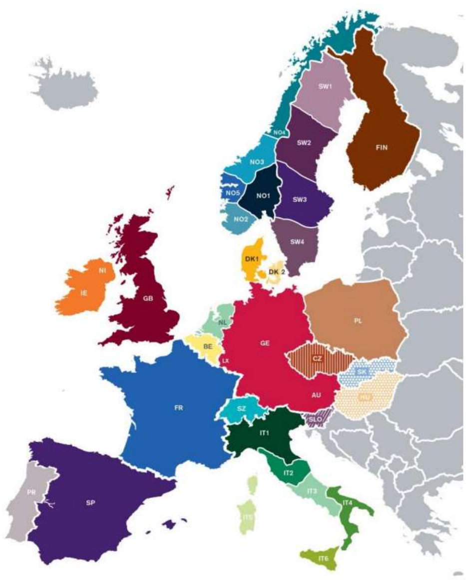

Figure 5: Current European bidding zone configuration
From [24]

As will be seen later in this paper, a zonal electricity pricing system is not the only design option.

The Figure shows that the market zones largely overlap with national borders. The reason for that is the will of keeping some autonomy and avoiding unmanageable disruptions when transitioning from the nationally organized market to a coupled one. As will be seen later in this paper, this turned out not to be the best solution.

Market coupling is intended to harmonize trading rules across market zones that are interconnected through a common system that is based on an algorithm. The algorithm aims at allocating electricity in the most efficient way possible through the coupled zones, so as to reduce cross-border price differences and promoting effective competition throughout Europe. Today, the market coupling algorithm in use is called Euphemia [15]–[17].

Market coupling systems exist in both ID and DA markets, but the latter is the main reference market, and therefore the main topic of this paper. Europe has achieved to couple the DA market of most of its countries (by the time of writing, European DA markets are coupled across 23 countries [18]).

The coupling has already proven that, compared to the unbundled market, trading efficiency is improved and market competition, liquidity, and robustness are increased. Additionally, due to the close interconnection of neighboring zones, generation sources can be used more efficiently and the countries can provide mutual assistance through the complementary nature of their consumption and production profiles, resulting in a more secure supply. This last point is especially important for the integration of renewable energy into the energy mix, and hence for the transition towards a carbon neutral system. To understand this, it is important to know that one main limitations of renewable sources is their intermittent and location dependent production pattern, and that renewables can’t easily be stored in big quantities. Therefore, to make consistent and efficient use of renewable resources, structured cross-border trading is crucial, so that surplus generation can be transported to regions with lower electricity production [15]–[17].

Due to the many advantages of the coupled market that has been achieved already, the states are further striving for the completion of one single, liberalized European market, referred to as the ‘European target model’. Reaching the ultimate goal for Europe doesn’t happen overnight, but requires a step-by-step approach, which must take several years [15]–[17].

Appendix 1 provides some background on Europe’s journey towards reaching their DA and ID target models of a single, liberalized market. The next section focusses on the fundamental working principle of the European market coupling.

3 The working principle of zonal pricing systems

This section aims at giving a more detailed description of how Europe couples its DA markets. In zonal systems, two different stages are required to determine the final power plant dispatch.

In the first stage, the wholesale market is cleared as if there was no congestion inside a zone, and only cross-zonal exchanges are accounted for. In other words, all injection points – or 'nodes'[1] - within a zone are grouped and replaced by an equivalent node to clear the market. As a result, electricity is priced uniformly within each pricing zone, and diverging prices between zones are indicators for any scarcity in transmission capacity.

The zonal aggregation corresponds to strong simplification of the grid, and could potentially lead to intra-zonal congestion. Therefore, once the market is cleared, TSOs take care of intra-zonal congestions in the second stage via remedial actions.

Section 3.1 and 3.2 give a more detailed explanation on how those stages are carried out in practice.

3.1 First stage: wholesale market clearing

As mentioned above, in a zonal market clearing, all the injections points – or 'nodes' – within a zone are grouped and replaced by an equivalent node to clear the market. This is illustrated in Figure 6. Internal grid congestions are neglected, and a uniform electricity price per zone is obtained.

[1] Those nodes can be, for example, generators or loads.

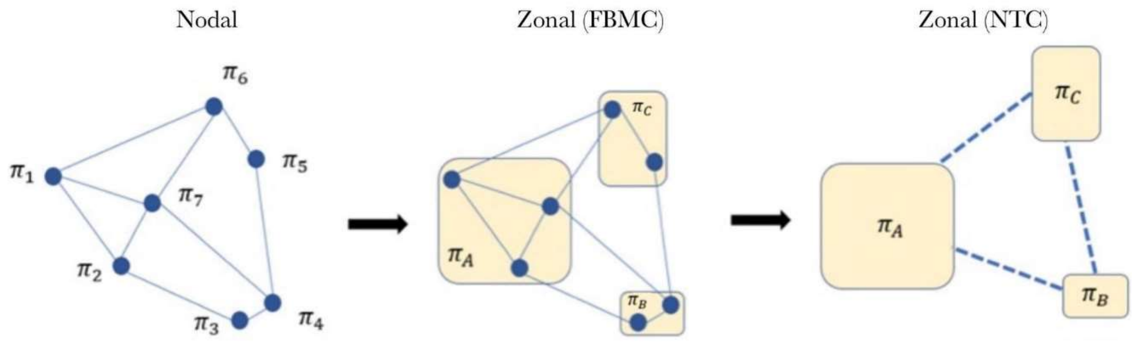

Figure 6: Illustration of zonal aggregation of injection points
Adapted from [30]

Only cross-border electricity trades are accounted for in the market clearing. Those trades are limited by the available cross-border capacity, and need thus be to computed before clearing the market [18] [19].

In a simplified way, all participating TSOs individually estimate the available transfer capacities for cross-border exchanges of their respective zones. As will be seen later, two different methods are used to this aim: Net Transfer Capacity and Flow-Based Market Coupling.

Based on this, Power exchanges (PX) set up auctions where traders submit their producer and consumer offer. Participants bid for the *electricity* they want to purchase - the price of the cross-border capacity is implicitly taken into account in the electricity price (which is why the auction is referred to as an implicit[2] one).

---

[2] *Remark:* Back when the market was organized on a national basis, it was purely based on explicit auctions where cross-border capacity and electricity were bought separately on different markets. In other words, the desired

Based on these auctions, the shared price coupling algorithm Euphemia matches zonal supply and demand and determines, while taking into account capacity limits of the network elements, the market outcome that maximizes social welfare[3]. The ideal market outcome is subject to market clearing conditions, i.e.

$$Zonal\ generation\ + Net\ zonal\ import\ =\ Zonal\ consumption$$

The algorithm calculates market prices and interconnector flows for the different participants across Europe in a fair and transparent matter. Throughout all above-mentioned steps, the capacity is constantly monitored by the TSOs and/or Market Coupling Operators (MCO) [14], [16], [19]. As a reminder, all of this happens the day before the actual delivery happens. After the DA market is cleared, continuous ID trading and balancing takes place.

3.1.1 The importance of capacity calculation

It has been mentioned several times that the zonal dispatch is limited by the transmission capacity. Therefore, a correct cross-border capacity calculation is crucial for the market coupling to work efficiently: By underestimating the available capacity, the grid is not used to its full potential, whereas an overestimation could lead to severe security issues. This can be explained by the fact that the transfer of electricity takes place in power lines and other equipment that have physical limitations and therefore can't support an infinite amount of energy. Not respecting those limitations can lead to overload, which can lead to grid damage or even worse to blackouts.

amount of cross-border capacity first had to be reserved before using it to transport the purchased electricity. However, the coupled market uses implicit auctions, merging the two previously separate markets into a single unified one – That's why the coupled market can also be referred to as an integrated market.

[3] The sum of consumer surplus, producer surplus and congestion rent is referred to as the social welfare.

Additionally, as will be seen later, zonal inefficiencies are increasing, resulting from an increasing need of redispatching activities. Optimizing capacity allocation improves grid usage, which will ultimately reduce intra-zonal congestion.

Therefore, for the coupling of markets to increase economic efficiency and reduce the need for redispatching activities, the cross-border transmission capacity has to be calculated properly. However, this computation is not as straightforward as one might think. The fundamental difficulty stems from the fact that the energy injected into the network flows following Kirchhoff's law, which claims that electricity naturally follows the least resistant path, instead of directly from seller to buyer. Put differently, commercial flows (i.e., shortest path between producer and consumer) differ from the physical flows (the actual power flow, which generally spreads out throughout the network, according to Kirchhoff's law) in the grid [17], [20].

Put differently, the capacity between two zones cannot be fully allocated to trades between those two zones, as some of the capacity will be used by parallel flows and loop flows[4], stemming from trades between other zones. This is illustrated in Figure 8, where a commercial

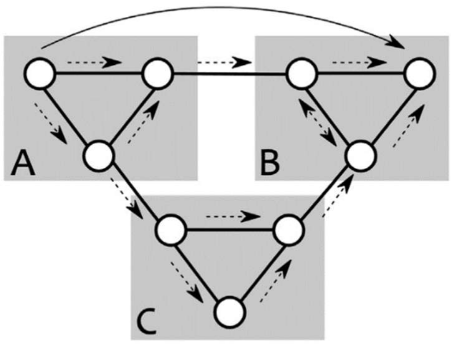

Figure 8: A commercial transaction between zone A and B causes physical flows through other parts of the grid.
From [20]

[4] Loop flows refer to flows that occur when an energy transaction within one bidding zone creates parallel flows in neighboring areas.

transaction between two nodes in two different zones A and B causes physical flows through other parts of the grid [20].

In Europe, two different main methods are used to calculate cross-border capacities: The Net Transfer Capacity (NTC) and the Flow-Based (FB) method. The following sections provides a brief explanation of both methods without getting into details, but rather by highlighting their differences. The aim is to show why the FB method is generally preferred for DA markets.

a) Net Transfer Capacity (NTC)

In the NTC method, every TSO approximates *ex ante* of the market clearing one import-, and one export capacity value for every border of their respective bidding zone. Those values are fixed before the actual market clearing takes place, and the capacity allocated to one border is independent of the capacity allocated to another border. This is illustrated in Figure 9, showing that only one equivalent cross-border link is considered.

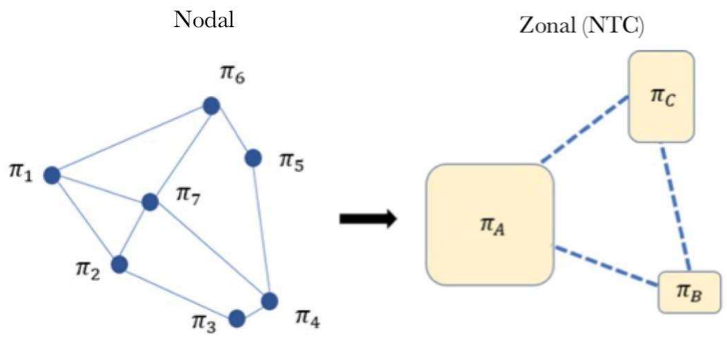

Figure 9: In the NTC method, only one equivalent node per zone is considered, and only one cross-border link connecting the market zones is considered. Adapted from [30]

One advantage of this method is that the market clearing algorithm is rather simple. However, the method is criticized for being inflexible and for leading to non-optimized network uses.

Firstly, as the offered capacities need to be independent from each other, a low-capacity utilization on one border does not allow an increase on another border. However, in the real world, flows within a coupled area are often highly related and interdependent, as shown in the previous section. Therefore, NTC does not correctly represent the physical nature of the grid and strongly simplifies the link between commercial and physical flows. The method disregards Kirchhoff's laws.

Secondly, due to the fact that the capacities are fixed before the market clearing takes place, they can't take into account the actual market needs. To be more exact, the calculation is based on a forecast of the grid at the moment of delivery, made 2 days before delivery, referred to as the D-2 Congestion Forecast (D-2CF). As these values are purely based on strong assumptions of the future market outcome, they need to be rather conservative to avoid overloading, and the full potential of a line is not exploited [17], [20].

For the above reasons, some European countries started implementing a more efficient and flexible method, replacing the Net Transfer Capacity (NTC) calculation with the Flow-Based Market Coupling (FB, or FBMC). Both methods share the same goal of computing the available capacity for future cross-border exchanges based on assumptions about the state of the grid, but differ in terms of methodology, effectiveness and other criteria, as discussed in the next section.

b) Flow-Based Market Coupling (FBMC)

FBMC aims at combining the zonal approach with an improved physical representation of the grid. In contrast to the NTC method where the output is a fixed import and export value per border, the FB method considers the available capacity of every single element that is relevant for cross-zonal trading (no matter if it is inter- or intra-zonal), referred to as Critical Network Elements (CNE) [21]. This is illustrated in Figure 10, showing that, in contrast to the NTC method, all critical lines are accounted for.

However, as the zonal approach is retained, grid constraints need to be simplified. In contrast to the NTC, capacity allocation happens partly ex ante, partly during the market clearing.

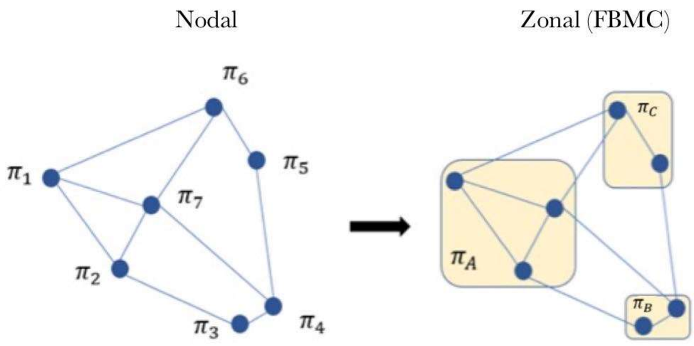

Figure 10: In the FBMC method, only one equivalent node per zone is considered, but all critical lines are taken into account
Adapted from [30]

To be exact, TSOs determine one day before market clearing, for every CNE belonging to their zone, two different parameters: the Remaining Available Margin (RAM) and a matrix of Power Transfer Distribution Factors (PTDF).

The Remaining Available Margin (RAM) describes the available capacity for cross-zonal capacity exchanges. It is calculated in the following way:

$$RAM = F_{max} - FRM - F_{0,Core} - C_{N-1}$$

Where F_{max} is the maximal thermal loading of the CNE, representing its physical limitation. As the calculation is performed the day before delivery using prediction data, a certain Flow Reliability Margin (FRM) has to be subtracted from this amount, reflecting the uncertainty. $F_{0,Core}$ represents the part of the capacity reserved for internal flows and loop flows. The last term C_{N-1} adds an additional security based on the N-1 methodology, stating that if a network element, such as a power line or a transformer, should fail (i.e., occurrence of any contingency), grid security should still be guaranteed [22], [23].

The Power Transfer Distribution Factors (PTDF) describe the sensitivity of the element for a certain cross-zonal trading. For every possible trade, the PTDFs of every element have to be computed, indicating the variation of power flow through that element due to the trade. PTDFs are the result of an analysis of the grid model (prediction of load and output profiles, and of the connection between the nodes in the network), and depend on physical parameters, such as reactance and susceptance, of the element [17].

The methodology to calculate those parameters is complex: the difficulty mainly stems from the fact that the DA market outcome has to be known in order to determine the parameters (RAM and PTDFs), which are required themselves to clear the DA market. To tackle the issue, the computation of the parameters is based on the D-2CF, which are then used in the DA market clearing algorithm [23].

In contrast to NTC, FBMC includes simplified Kirchhoff constraints, and therefore accounts for the strong interconnection between the markets. The final constraints are linked, and the method acknowledges that an exchange between two zones can impact numerous other network elements. Additionally, the capacity allocation takes place partially before, and partially during the market clearing, and can therefore take account of actual market needs. As a result, larger capacities are made available to the market, which increases welfare and price convergence and allows for a more flexible utilization, which is highly valued by market participants. It is worth mentioning that the performance of the methodology is also influenced by the zonal configuration: the smaller the zone, the better the representation of the physical characteristics, the better the result [23]. Therefore, some market participants are currently considering a zonal reconfiguration (more on that later).

To avoid grid security issues, FBMC includes qualification and verification processes, and requires a step-by-step approach to determine the final domain. Put simply, the stages are as follows:

1^st^ step: Initial RAM and PTDF values are computed for every CNE. In order not to take account of every single element, a filtering is applied by only taking relevant elements that have a maximum PTDF of minimum 5% [19].

2^nd^ step**:** The intermediate FB domain is computed by expanding the domain using Non-Costly Remedial Actions (NRAO) trying to increase the RAM of the most limiting CNEs. Remedial actions are any measures applied by TSOs to maintain operational security, mainly used to redirect the flow. Examples of Non-Costly Remedial Actions (NRAO), are phase shifters or topological modifications [19].

<u>3th step</u>**:** Based on the intermediate domain, the adjustment for the minimum RAM is performed.
The main reason why a minimum amount of capacity is mandatorily reserved for cross-zonal exchanges stems from the fact that, as will be seen later, the current bidding zone configuration increasingly leads to significant internal bottlenecks. To limit intra-zonal congestion costs, some TSOs lowered the capacities available for cross-border exchanges, which, however, decreases welfare. Therefore, Europe's Clean Energy Package (CEP) has set the minimum 70% target (also referred to as the min Ram target or CEP70 process) – stating that at least 70% of thermal capacity has to be reserved for cross-zonal trading. The resting 30% is attributed to FRM, internal and loop flows[19].
Additionally, by offering larger cross-border capacities to the market, renewable energy integration is enhanced and cross-border competition is increased.
Finally, the Long-Term Allocations (LTA) stemming from Future Market contracts are included into the domain. After individual validation, with the possibility of reducing the RAM or adding CNEs, the final domain is computed.

Rem: It is important to mention that the CEP70 process is subject to different values according to national action plans and derogations. For example, Belgium can make a derogation of only having to offer 60% to cross-border exchanges due to the very high loop flows coming from Germany [19].

It is obvious that taking into account every single CNE instead of allocating fixed values per border complicates the market clearing algorithm. However, it better represents the physical nature of the grid, and the network is automatically used for more useful exchanges compared to NTC. The flow-based method increases exchange potential on borders where they are the most useful, while taking account of physical grid constraints, thereby resulting in increased welfare and price convergence.

Further details on the differences between the methods can be found in the Appendix 2.

3.1.2 Methodology used in European DA Markets

Until 2015, NTC was used for the whole European DA market. However, due to the above reasons, CWE states decided on May 20th 2015 to introduce flow-based market coupling (FBMC) to their internal borders. The CWE region is composed of Belgium, France, the Netherlands, Luxembourg and Germany, as shown in dark blue in Figure 11. Before go-live in this region, the FBMC methodology has been tested with parallel runs during two years, which have proven that the method increases welfare, price convergence, stability and robustness [20].

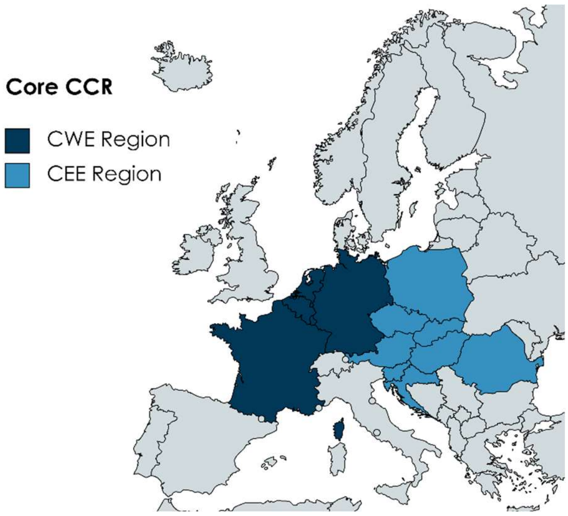

Figure 11: Core CCR region, with the CWE region in dark blue, and the CEE region in light blue

Because of the numerous advantages the method brings, the European Union Agency for the Cooperation of Energy Regulators (ACER) decided end 2016 to launch the so-called Core FBMC project. The latter promotes the extension of FBMC to the Central Eastern Europe (CEE), establishing the Core Capacity Calculation Region (CCR) in the framework of SDAC.

Figure 11 shows the Core CCR, that encompasses, in addition to CWE region (colored in dark blue), the countries Poland, Czech Republic, Slovakia, Hungary, Austria, Slovenia, Croatia and Romania (colored in light blue).

Since the 8th of June 2022, the FBMC has successfully been extended to the Core region (composed of, as a reminder, the CWE and CEE region) [24].

It has already been proven that the FBMC brings advantages in terms of price convergence and welfare. However, the switch also comes with major challenges: the implementation of the mechanism requires standardizes operating rules, shared by all system operators in Europe, and calls for a good coordination among TSOs. Instead of a direct border-per border coordination such as in ATC, FBMC requires a regional coordination between all TSOs.

3.2 Second stage: Internal grid congestion management

In the first stage, the zonal wholesale market was cleared without properly accounting for internal congestion. The NTC method corresponds to a strong simplification of the grid, often leading to intra-zonal congestion. Even though the physical representation of FBMC is more exact than of the NTC, CNEs are decided before the actual market clearing takes place, and overloading may still occur.

In both cases, the market outcome potentially results in internal grid congestions. This has to be taken care of with the help of measures outside of the wholesale market (referred to as 'congestion management').

The congestion management is performed by TSOs and market participants with the help of remedial actions. Several non-costly actions[5] are used to this aim. However, if non-costly

[5] Such as an adjustment of the tab position of a phase shifter, switching operations in the power grid, as has been explained earlier.

options are not available or reach their limits, costly actions are used. One such costly congestion management measure is referred to as “redispatch”.

Redispatch consists in a redirection or change in production and consumption patterns at either side of a grid bottleneck to relieve congestion. Most commonly, the generator output downstream of the congested line is increased, whereas the production upstream of the congestion is reduced [25].

Redispatch can either be organized on a mandatory- or on a market-based level.
In a large part of Central Europe, redispatch is organized on a mandatory level. In that case, the owner of the redispatch resources is paid the redispatch prices to compensate for the incurred cost to achieve profit neutrality. Mandatory redispatch is therefore also sometimes referred to as cost-based, or regulatory redispatch[26].

However, with the Electricity Market regulation recast in 2016, the European Commission suggested that a system of voluntary participation in markets may be preferable to the regulated approach [27]. This topic will be assessed in section 5.

Even though in recent years, redispatch quality has been significantly developed and improved, redispatching costs have been increasing significantly, as will be discussed in the next section.

4 Pressure on European markets

To summarize what has been said in previous chapters, in zonal designs, the market is cleared neglecting intra-zonal congestion. Cross-zonal trades are limited by cross-zonal transmission capacities (computed with NTC or FBMC), and a uniform market clearing price is obtained within each pricing zone. Price differences between zones are indicative of the limited cross-border transmission capacity.

The zonal aggregation corresponds to a strong simplification of the actual grid, and implies a loss of information. This potentially leads to infeasible power flows within zones, which requires correction. Therefore, once the market is cleared, TSOs take care of intra-zonal congestions in their respective areas via redispatch: consumers and producers contributing to the congestion are demanded to adapt after the DA market clearing to cancel grid bottlenecks.

When Europe started coupling its markets, congestion was a rare event. The need for redispatching measures was infrequent and considered irrelevant. However, in many states, congestion has been increasing significantly, and the need for redispatching services has grown. This trend is driven by a combination of factors. The growing need of congestion management is partly due to the fact that consumption and production have been growing faster than the transmission capacity. Additionally, the important uptake of renewable generation in remote locations, along with the shut-down of numerous flexible, centrally located plants (such as nuclear or coal plants), increases the distance between consumers and producers, further increasing the pressure on the electricity grid [28].

As a result, congestion and redispatch costs have become more important than initially anticipated. Figure 12 shows the 10-year evolution (from 2009 to 2019) of Germany’s downward redispatch volume and cost. Germany is an interesting example, as the shut-down of its nuclear plants further contributed to a growing need of redispatching measures.

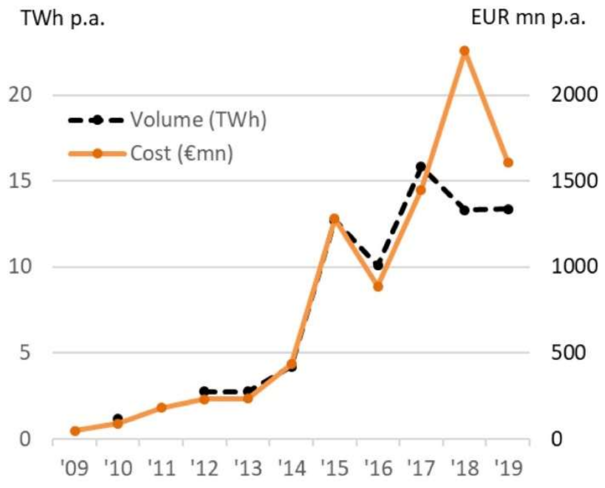

Figure 12: 10-year evolution of Germany's congestion management volumes and cost
From: [26]

One can see that the need for redispatch and the associated costs have increased significantly in the past few years. To have an order of magnitude, Germany's total energy consumption in 2019 was 600 TWh. This means that the volume that has been re-dispatched downward in 2017 corresponded to roughly 2.5% of Germany's total energy consumption [29].

4.1 Main inefficiencies on EU level

The increasing grid congestion invokes numerous inefficiencies on EU level. High congestion costs, under-utilized cross-zonal capacities or poor price signals are some of the main issues that need to be tackled. Those inefficiencies are closely related, as explained below.

For instance, TSOs are likely to reduce cross-zonal interconnector capacities made available to the market, to reduce the need of costly out-of-market measures. As a result, grid capacity is not used efficiently (however, as mentioned in section 3.1.1.b, the CEP70 has been introduced to oblige TSOs to provide enough cross-border transmission capacity).

Ineffective price signals are also a direct result of increasing redispatching need: The cost of remedial actions is partly paid by the end-consumer in the form of grid charges – therefore, high redispatch requirements lead to inefficient price signals to the consumer. This negatively impacts the development of energy storage and investment decisions. [30]

To tackle those inefficacies, the need for redispatching measures must be reduced. Relying solely on network expansions would be too costly and time-consuming. Therefore, it is the market configuration itself that needs to be adapted accordingly. How and whether to reconfigure is subject to a heated debate.

Different congestion mitigation options are currently being discussed by European stakeholders. This article aims at giving an objective assessment of ways to address congestion issues, each with their own advantages and challenges:

1. Market-based dispatch
2. Bidding zone reconfiguration
3. Nodal electricity pricing system

The first option, namely the market-based redispatch, is viewed by many stakeholders as being the most cost-efficient and most feasible option. The rationale of introducing a market-based redispatch would be to integrate flexibilities and loads more easily as compared to a mandatory redispatching. Flexibilities are believed to be key in further integrating renewables, ultimately relieving network congestion. However, the voluntary market is rejected by numerous stakeholders as it offers incentives for structural bidding.

Some market participants argue that simply improving the zonal market without fundamentally changing the zonal configuration is not a long-term solution. Therefore, option 2 analyses potential benefits and drawbacks of a of bidding zone reconfiguration. The aim is to relieve intra-zonal grid bottlenecks by aligning zonal borders with physical congestion patterns. The market clearing algorithm is believed to account more efficiently for actual congestion, as less redispatching measures would be required.

Option 3 takes this idea one step further by proposing a nodal pricing system. Nodal pricing defines, as opposed to the zonal design where nodes are aggregated into zones, a clearing price for each individual node. All transmission constraints are accounted for in the initial economic dispatch algorithm, and no potentially problematic redispatch would be required.

The reminder of this paper aims at providing a critical and objective assessment of the three options.

5 Option 1: Market-based redispatch

As a reminder, redispatch is a powerful congestion management instrument, where market actors change their production and consumption patterns on either side of a grid bottleneck to relieve intra-zonal congestion stemming from the market clearing.

In a large part of Central Europe, redispatch is organized on a mandatory level. In that case, TSOs centrally plan and command redispatch activities, and force market participants to adjust their position accordingly. Knowledge and power are centralized, and system management is untransparent. Except for some renewable generators, combined heat and power plants or small-scale storages, most production facilities are obliged to participate. To obtain profit neutrality, the owner of the redispatch resource is paid the redispatch prices to compensate for the cost incurred or profits forgone.

Most European countries implemented mandatory redispatch. It is however problematic on several levels: first, it can be difficult to observe the actual redispatch cost. Secondly, it does not allow for flexibilities, loads, consumers and storage operators (such as hydro-electricity storages) to participate. This is because their opportunity costs can be varying in time and location, and depend on operational preferences. Therefore, those costs are challenging to observe, and therefore difficult to integrate into a cost-based structure. This is especially problematic, as loads and flexibilities are considered to be crucial for a further integration of renewables [26].

To allow for a better integration of flexibilities, market operators propose to turn from obligatory mechanisms to a market-based, voluntary redispatch, as is the case already in the U.K. and in the Nordic countries [25].

5.1 What is a redispatch market and what are its advantages?

The redispatch market happens after zonal gate closure, but before real time, and has, contrary to the wholesale market, a nodal resolution. Competitive auctions are organized, where producers and loads submit the prices at which they would be ramped up or down to relieve congestions. In other words, actions are dispatched on the basis of freely offered prices from participants by choice – Their decision-making is based on price signals linked to the necessity of redispatch [25].

One main argument in favor of the market mechanism is that it brings flexibility into the system and allows for a higher variety of different technologies to be included. Inclusion is especially facilitated for demand-response and other technologies that could not be part of the mandatory redispatch as their opportunity costs are difficult to anticipate [31].

In addition, market-based procurement of congestion management is organized following competitive auctions, implying that knowledge and power are no longer centralized to the TSO, and that the system is becoming transparent. The management and operation of the system no longer appear as a "black box", and the variety of different technologies is revealed – this way, the redispatch is open to the most efficient and cheapest technologies at any time, and the most cost-effective solution can be identified.

As a result, the need for further network investment to support the connection of new loads, renewable energy generation and storage plants would be significantly reduced, ultimately leading to financial benefits. Additionally, the increase of flexibility would facilitate the integration of renewables into the grid, ultimately benefiting the environment.

However, despite those advantages, policy-makers in most of European markets decided to implement a mandatory redispatch that requires a central planning, as explained in the next section.

5.2 Risks associated with the market-based redispatch

The main concerns about the market-based redispatch is that it offers gaming, strategic bidding, and arbitrage opportunities to the market participant.

Firstly, the nodal resolution of redispatch markets increases the risk market power abuses [27]. Market power refers to the ability to manipulate prices above competitive levels. The European Commission assumes that markets are subject to market power if an individual participant holds a share of at least 40 % [32].

Secondly, the two-staged market with a different spatial granularity offers gaming incentives to participants. The most prominent one is referred to as 'increase-decrease (inc-dec) gaming'. Even though inc-dec gaming is aggravated in the case of market power, it does not require it [26].
Inc-dec gaming is an arbitrage strategy where market participants anticipate congestion and deliberately buy themselves out of the spot market to gain larger profits in the redispatch market. Concretely, producers in surplus regions expect to profit from a downward redispatch (in other words, if they have to reduce their production to remove congestion) by bidding low to enter the zonal market, and later buying the energy back on the redispatch market at a lower price. Conversely, producers in scarcity regions will anticipate that a higher profit can be gained on the redispatch bidding for higher prices.

5.3 Consequences of inc-dec gaming

By assuming perfect conditions (no information asymmetry, perfect market competition, no ramping or start-up constraint), the final physical redispatch is unlikely to change with or without strategic bidding, only the schedules change over time. However, although gaming has no impact on the physical output, line overloads are amplified, ultimately leading to increased grid congestion cost, increases windfall profits and misleading investment incentives.

5.3.1 Exacerbated network congestion

As has been mentioned in the previous section, participants in scarcity regions are incentivized to retain capacity from the wholesale market to take advantage of being upward redispatched, conversely, participants in surplus regions systematically overproduce. Put differently, inc-dec gamers strategically bid in the zonal market to create congestion, with the goal of being paid for solving this very congestion in the redispatch market. Thus, to still satisfy network limits, redispatch volumes increase. As a result, not only congestion costs are intensified, but large-scale redispatch is also accompanied by operational challenges: since the market is opened shortly before delivery, large volumes have to be exchanged quickly, which could endanger system security [26].

5.3.2 Windfall profits

Generators' profits differ significantly compared to what would have been obtained in a mandatory redispatch [26].

5.3.3 Misleading investment incentives

Due to the fact that generators gain additional profits in oversupplied regions, the market-based redispatch encourages investments in the wrong places, further contributing to network overload. Additionally, large-scale redispatch volumes, resulting from the market-based redispatch, may offer misleading investment signals to grid investors, which potentially results in network overinvestments [26].

5.3.4 Loss of underlying for Forward markets

Spot price risks are hedged using Forward markets. Those contracts are based on assumptions and predictions based on zonal market prices. However, with redispatch markets, Future contracts may become poor hedging tools. Zonal prices may no longer be suited as underlying for Forward contracts, as they no longer result from a zonal supply and demand balance, but are influenced by strategic bidding [26].

5.4 Cause of inc-dec gaming

Most of the time, the source of strategic bidding is anticipatable congestion. Whether congestion can be predicted depends on the available information on capacity and on the nature of the congestion. If congestion is structural[6], a correct anticipation of the redispatch is standard as participants already have information on the potential success of their strategic bidding. Different methods, such as load flow models, econometrics and statistics allow participant to predict congestion and forecast grid bottlenecks [26].

Reducing structural congestion is not done easily. It can be done either by reinforcing the grid structure appropriately, or by reconfiguring bidding zones, both of which are complicated tasks [31]. Therefore, alternative measures and control mechanisms have been introduced to mitigate the impacts of strategic bidding on the market.

5.5 Mitigating measures of inc-dec gaming

Despite the risks associated with inc-dec gaming, redispatching market are widely considered as being a cost- and time-effective innovation required for the EU to achieve its climate targets. Therefore, instead of rejecting the market base approach because of the potential abuse, numerous stakeholders prefer addressing the strategic bidding concerns by seeking for new, or enforcing already existing mitigating solutions. Some stakeholders believe that appropriately

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[6] A good example of structural congestion is in German bidding zones

designed, controlled and monitored flexibility markets should avoid inc-dec incentives [31]. Others argue that most mitigating approaches seem unpromising and expensive [26].

It is common practice to introduce observatory methods (market monitoring) to detect gaming and impose penalties. In addition, mitigation method can be introduced: gaming incentives can be reduced by either increasing the associated risk (by, for instance, introducing randomized activations), or by reducing the expected benefits.

5.5.1 Enhancing competition

The risk of market-power abuses can be reduced by enhancing market competition. This can be done by either imposing a minimum amount of competing market participants, or by imposing and enforcing legislations (such as competition law) [31]. Even though those strategies have proven successful, they are not able to avoid strategic bidding.
Indeed, inc-dec gaming is exacerbated by poor market competition. However, as long as generators can anticipate the redispatch market outcome, inc-dec gaming remains possible, even in perfect competition conditions. Therefore, legislation that is focusing on market competition cannot prevent market abuses. [26]

5.5.2 Reference price levels

To reduce strategic bidding incentives, a reference price level can be established. By comparing the reference to bids, prices that are suspicious of gaming can be detected. Bids that significantly deviate from the reference level would be dismissed and/or face a fine.

To give an example, Norway implemented a regulatory framework that selects suspicious bids: if bids on the wholesale market seem suspicious of strategic bidding because they exceed the marginal cost by a significant amount, they should be ignored (or even penalized if this happens repeatedly) [31]. However, it is important to keep in mind that those price regulatory methods require precise information: in case of information asymmetry, inc-dec gaming is not prevented [26].

5.5.3 Hybrid approach

The main concerns about the market-based redispatch stem from large generators. Therefore, a hybrid model could reduce inc-dec gaming significantly. The idea is to combine a regulated approach for large-scale plants, and a market-based approach for small-scale generators and loads that are less prone to inc-dec gaming. However, the hybrid approach would not perfectly circumvent gaming as small-scale plants and loads are also capable of gaming.

5.6 Conclusion

Due to the increasing amount of decentralized generation plants and the further electrification of the energy system, market actors are currently facing a rapidly growing pressure on redispatch activities. Therefore, there is a predominant view that a new way of system management has to be introduced , focusing on implementing the flexibilities the market has to offer.

Instead of a centralized and regulated re-dispatching, as currently implemented by most states, the European electricity market could be organized as a combination of a zonal pricing market and a spatially granulated redispatch market. Compared to the regulated approach, it has been shown that this would enhance market competition, liquidity and overall system efficiency. As a result, grid reinforcement requirements would be more limited, and the integration of new technologies and flexibilities could be facilitated.

While this approach, due to its numerous benefits, is backed by the Electricity Market Regulation Directive, the potential strategic bidding incentives offered by two-staged market has pushed most European countries to apply a regulated form of redispatch [26].
Indeed, such market abuses have to be considered as they can have negative impacts and

severe side-effects. In particular, they aggravate congestion, create windfall profits and misleading investment incentives. Long-term contracts become poor hedging tools, ultimately leading to increased power generation costs. Even though the risk of strategic bidding is to be taken seriously, mitigation measures exist that can partially overcome the risks, allowing for the benefits of redispatch markets to reign.

Combining the market-based redispatch with strategic grid reinforcement seems like a cost-effective solution to congestion. Numerous countries are already using the market-based approach and have proven to be successful, having introduced a series of measures to avoid gaming.

6 Option 2: Bidding zone reconfiguration

Numerous stakeholders believe that a market-based redispatch is not sufficient to deal with the increasing pressure on the European network. This chapter analyses potential benefits and disadvantages of a bidding zone reconfiguration.

To a large extent, the increase of zonal inefficiencies can be attributed to the current zonal configuration: as pointed out earlier, the geographical scope of most bidding zones corresponded to national borders. The reason for that is the will of keeping some autonomy and avoiding unmanageable disruptions when Europe started transitioning from the nationally organized market to a coupled one. However, this configuration turned out not to be the best solution, as national borders do not necessarily align with physical grid constraints, leading to numerous inefficiencies, such as high redispatch costs and under-utilized transmission capacities. Market participants believe that smaller bidding zones that align with congestion patterns could enhance congestion management and improves price signals.

The Capacity Allocation and Congestion Management (CACM) guideline (consisting of network codes describing the European target model) prescribes that bidding zones should be designed in a manner that enhances a well-functioning market, and ensure efficient congestion management. Therefore, some countries chose a common bidding zone (such as Germany and Luxembourg), and some other decided to have several bidding zones (such as Norway, Sweden, Denmark and Italy), see Figure 5. These inefficiencies triggered the idea of a further recutting of bidding zones.

6.1 CACM bidding zones

The current bidding zone configuration is referred to as ‘status quo’: relatively large and stable bidding zones that often run along national borders. However, based on the bidding zone concept in the Guideline Capacity Allocation and Congestion Management (CACM), so-called ‘CACM bidding zones’ have been introduced [33].

CACM bidding zones is a system prototype that is characterized by smaller zones cut along permanent and significant bottlenecks. CACM bidding zones can be updated every five years to adapt to changing congestion pattern.
The market functioning would be the same as under the status quo: Wholesale markets are cleared, and out-of-market measures are used for congestion management. However, the number of necessary interventions is likely to be lower compared to the status quo. Grid operation and trading is also carried out similarly to status quo, but the smaller zones and their imbalances require a greater cooperation between TSOs and PXs [33].

Until today, the CACM bidding zone-model remains a theoretical concept. However, as a switch to smaller bidding zones may a have significant positive influence on European market efficiency, an increasing number of stakeholders is discussing the possibility of actually reconfiguring the zonal design.

Changing the configuration of bidding zones is politically sensitive, and potential impacts need to be analyzed thoroughly. Therefore, the efficiency of the current bidding zone configuration and the potential impact of a reconfiguration is assessed every three years in a bidding zone review [34]. The next sections provide an overview of the review's main conclusions.

6.2 Benefits of CACM bidding zones

Smaller bidding zones that are consistent with grid bottlenecks could drive a more effective use of the grid in the short-term. Spot markets consider a more detailed grid model, which results in an earlier congestion management in the market sequence. In other words, the market-based dispatch is more consistent with the physical reality, and the redispatch need for CACM zones tends to be less important. As a result, congestion costs would be reduced, cross-border capacities used more efficiently, and better price signals offered to market actors [33].

Additionally, the locational differentiation may act as price signals to market actors.

However, some downsides exist, that can pose major problems, as specified in the next section.

6.3 Criteria against smaller bidding zones

The main concerns regarding a size reducing of bidding zones it that it potentially raises liquidity concerns, increases price volatility and investment risks [30], [34].

6.3.1 Reduced market liquidity

Market liquidity is the degree to which assets (here electricity) can be quickly sold and bought without impacting significantly the underlying price. This translates into high levels of trading activities with many counterparties and sufficient product variety, a close bid-ask spread[7], proper spot price setting and low transaction fees [34], [35] [36] . Naturally, the smaller the zone, the higher the risk of poor liquidity.

In their bidding zone report of 2018, stakeholders shared a common view on a negative influence of a bidding zone reconfiguration on market liquidity. Several bidding zone split scenarios have been modelled, all of which resulted in lowered liquidity on Future, ID and DA trading.

6.3.2 Price volatility in the spot market and risk hedging

Smaller bidding zones tend to deteriorate the stability of short-term prices, as cross-zonal transfer capacities are more restricted. This naturally leads to a higher risk of zonal price fluctuations in spot market prices, and exposes participants to a higher risk of unfavorable market outcomes.

Spot price volatility risks can be hedged with the help of Future Markets. However, Future Markets that offer risk management tools against real-time uncertainty for market participants

[7] The bid-ask spread is the difference between the maximum price at which the market wants to buy and the minimum price at which the market wants to sell [36].

are themselves considerably affected by the size of bidding zones. Given the fact that Future markets purely rely on predictions of Spot Market outcomes, risk hedging is complicated in smaller bidding zones due to the more limited liquidity [30], [34].

6.3.3 Risk associated with periodic recutting

As has been mentioned earlier, CACM bidding zones should be in accordance with physical congestion patterns. However, as those patterns could themselves be constantly changing, the zones are reconfigured every five years if needed. Defining new bidding zones is however a very time-consuming process. This is partly due to the required analysis and planning, but also a result of oppositions of some countries to reconfigurate their zones, or TSOs that are not always in favor of implementing such significant structural changes.

Considering that flow patterns are constantly changing, the new designs may potentially be outdated by the time of implementation, which would be very disruptive and increase investment uncertainty.

6.4 Resistance to zonal split

Naturally, when recutting bidding zones, different prices could potentially apply to the new zones. In other words, energy would have a different value within countries. How would a zone characterized by an uneven production and consumption patterns react to sudden price differences within the zone? Let's take Germany as an example. Germany is characterized by a windy, energy producing north, and an energy-hungry south [37]. Inevitably, large volumes of electricity are transported from north to south, congesting power lines. By splitting the north from the south of the country, price differences would appear, which would naturally create injustices and thereof social resistance. However, mitigating solutions exist. Italy for instance, where the DA market is divided into six zones, introduced the PUN (Prezzo Unico Nazionale). Italian consumers buy electricity at PUN price, representing the national weighted average of the zonal sales prices of electricity for each hour and for each day [38].

6.5 Conclusion of bidding zone report

The bidding zone report provides mixed results, and no complete picture be drawn. On one hand, a bidding zone split improves spot price formation, while promoting efficient congestion management. On the other hand, price volatility and market liquidity, and with it hedge opportunities are worsened when increasing the amount of bidding zones.

As none of the alternative scenarios performed better than the status quo, no conclusive decision could be made. However, one can conclude that defining new, adequate bidding zones is a very challenging and complex task, and getting approval to change zones is tedious [30], [34].

7 Option 3: Transition to nodal Pricing in the European Electricity Market

The previous section discussed the advantages and disadvantages of a bidding zone reconfiguration. Despite the probable positive impact on congestion management, a reconfiguration seems like a challenging task. Indeed, given the cost and time required to continuously adjust bidding zones, policy makers and market actors frequently discuss the possibility of adopting nodal pricing in the EU.
In nodal pricing, also referred to Locational Marginal Pricing (LMP), every individual feed-in or extraction point – or 'node', is a separate bidding zone. All relevant transmission constraints are accounted for in the market clearing, and no redispatch is required. In other words, the market is cleared in a single stage. As a result, an individual price is computed per node, representing the locational value of energy (i.e., not only reflecting the cost of energy, but also the cost of delivering it).

Nodal pricing has been implemented in numerous electricity markets all over the world: New-Zealand was, in 1997, the first country to implement the nodal pricing system, and Pennsylvania-New Jersey-Maryland followed shortly after in 1998. Since then, numerous countries, among which several U.S. states, Russia, Argentina, Chile, Mexico followed the trend [28], [39].

There have been several debates and research regarding the use and potential impacts of nodal pricing in Europe to deal with the growing inefficiencies, partly stemming from the current bidding zone configuration. Academic literature claims that nodal pricing is theoretically the most optimal pricing system for electricity markets and networks. Indeed, a switch to nodal pricing would potentially improve local price signal and use the network more efficiently [39]. Nevertheless, nodal pricing has persistently been discarded in Europe.

The purpose of this chapter is to provide an unbiased and objective overview and critical assessment of concerns and arguments regarding nodal pricing systems. In order to do so, it is important to first understand how nodal markets are organized.

7.1 Organization of Nodal Pricing

Figure 14 illustrates the difference between the nodal and zonal grid representation.

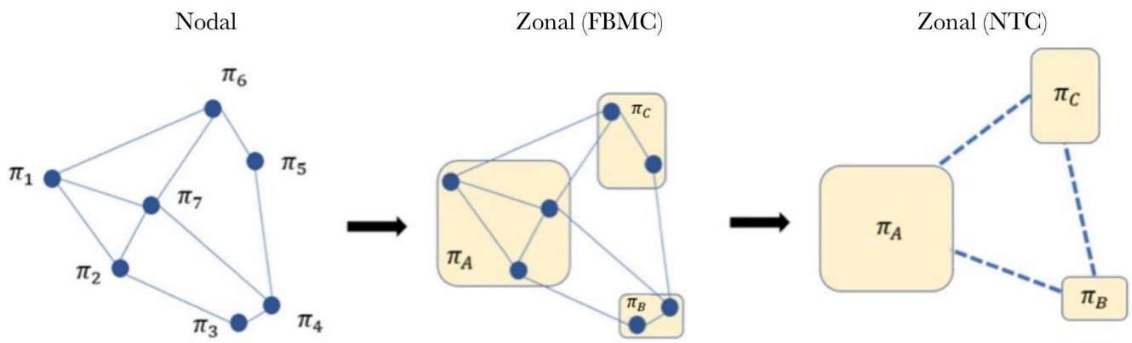

Figure 14: From nodal to zonal grid representation
Adapted from [30]*Figure 14*

By comparing the models, one remarks that the zonal design corresponds to a strongly simplified representation of the actual grid: All nodes within a certain zone are aggregated and modelled as an equivalent node in the zonal market clearing algorithm. Obviously, the zonal aggregation implies a loss of information (less in the case of FBMC then NTC), which is why out-of-market measures have to be taken to align with the physical limitations of the grid.

On the other hand, this disaggregated nodal view allows for a finer geographical resolution and therefore a high level of accuracy in terms of physics.
To make the nodal pricing possible, market participants submit offers for the generation and demand at the various network nodes to the auction platform. Based on these bids, a market clearing algorithm determines the most cost-efficient power plant use, taking into account all grid restrictions. This optimization is usually carried out by an Independent System Operator

(ISO), which bundles some of the functions that are executed in zonal systems by PXs, grid operators and plant operators [28].

In contrast to zonal markets, the nodal dispatch is centralized: producers submit detailed cost data to the ISO that decides for the dispatch. In zonal markets, producers submit less detailed information and rely and self-dispatch [40].

The nodal market clearing algorithm computes a separate price per node. Nodal prices are calculated as the marginal benefit or cost for the overall system, if one extra MWh is fed into this node, taking into account all grid restrictions[8] – That's where Locational Marginal Pricing (LMP) got its name from [33]. Those prices are a direct reflection of current grid restrictions, as they automatically account for any scarcity in power and limit of any transmission constraint [39]. The market clearing algorithm accounts for any transmission constraint, meaning that no congestion management is required.

At each node, the producer is paid according to where its node is located. If there is free transmission capacity between individual nodes, the price in nodal systems will converge to the same level - similar to prices of bidding zones with sufficient cross-border capacity.
Again, the transmission capacity between two nodes is not necessarily determined only by the direct connection line, as electricity flows through other parts of the network. Nodal prices start diverging when the capacity utilization reaches the capacity limits. Diverging nodal prices indicates congestion in the transmission system [33].

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[8] If an additional feed-in at a certain node would relieve the grid and thus make it possible to use power plant more cost-effectively elsewhere in the grid, the electricity price at that specific node would be particularly high, indicating the high grid value of power feed-in [33].

Rem: Nodal systems directly account for every transmission element. By resolving energy needs and network infrastructure simultaneously, commercial transactions are automatically correctly translated into physical flows. From a congestion management point of view, FBMC represents a smooth transition between NTC and nodal prices (as represented in Figure 14) [23].

7.2 Nodal pricing in U.S. markets

Initially, the U.S. states were based on a zonal design. Like Europe today, they have started to realize the limitations of the zonal method and therefore seek for ways to improve it. Their main concerns were the growing need for redispatch measures in real time, in addition to the increasing difficulty to predict inter-zonal congestion. As is currently the case in Europe, they first considered a reconfiguration of the bid areas. However, due to the complicated and tedious process of getting approval to change zones, they decided to implement a drastic transition to nodal instead [39].

The switch to a nodal pricing brought significant operational cost savings and other economic benefits to the US. For instance, the one-time implementation costs when transitioning towards a nodal pricing system have recovered within one year of operation thanks to significant operational cost savings [41]. However, in Europe this may take longer, which can be explained by a higher system variety [42].

Taking the success in U.S. markets as an example, there have been several studies concerning the implementation of nodal pricing in Europe. In the following, zonal and nodal pricing systems are compared against numerous criteria.

7.3 Price signals as incentive tools for consumers and producers

Grid bottlenecks mean that the economic value of electricity is not the same in all places, leading to potential differences in nodal prices. To illustrate this, the Figure 15 shows Texas nodal electricity prices on a given day. Texas assigns prices to around 12000 different nodes [30].

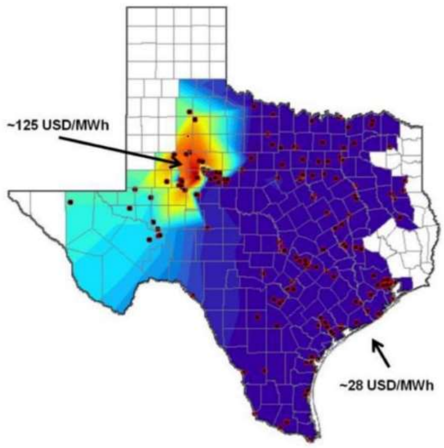

Figure 15: Nodal Prices in Texas
Source: [30]

One can see that a large part of the country has a uniform electricity price of around 28 USD/MWD, but differs tremendously in the North-West region of the country, where the price gets up to almost 5 times higher [33].

The locational differences in nodal prices directly reflect network constraints and give consumers and producers the right incentive to operate and trade energy taking the constraints into account.

7.4 Price signals as investment incentive tools

Similarly, differentiated prices offer incentives to investors. Obviously, nodal pricing offers significantly better price signals to the market participant and investor then the zonal signals.

However, the effectiveness of local price signals offered by the Nodal Pricing can be questioned, as will be explained in this section.

In nodal systems, power plant investors tend to direct their investments to areas where electricity has a high market value (and hence is scarce), whereas investments by electricity consumers are directed to regions with a low market value (hence where electricity is abundant) [39]. However, this also means that an existing efficient plant in a region with a low market value has a lower incentive to run than an inefficient plant in an area where the market value is high [42].

Nevertheless, it is claimed that the impact of nodal prices on guiding investors to scarcity regions should not be overstated. Investment decisions generally have an impact over a long period of time. Therefore, it is not today's price that acts as an investment incentive, but the expectations about future prices. Thus, for the investment incentive to be effective, the price signals have to be predictable and credible, otherwise the investor is not likely to incorporate them into his decisions [33].

In a nodal system, unanticipated new generation, load and grid changes have a stronger impact on the nodal prices than when those impacts are diffused over a larger zone. Uncertainties on future returns from future investments are therefore increased.
The market participants carry the risk in nodal pricing, whereas the risk is socialized among end users in the zonal design. Yet, some claim it's reasonable to assign the risk to the market participants only. Generally, they have better forecast opportunities and are better informed than the end users. Put differently, the risk is attributed to those who can manage them best. [28].

On the other hand, the status quo does not offer locally differentiated wholesale prices acting as investment incentives. Even though zonal prices do not offer such incentives (except potentially by redispatching markets, but to a lesser degree), alternative incentive tools can be implemented in all designs. For instance, grid connection- or grid usage charges may be spatially different, which can act as an investment incentive. However, those charges can increase the risk of market competition, and the determination of efficient and non-discriminatory charges is a major challenge. Therefore, grid charges are not everywhere used. Similarly, RE support schemes may act as incentives to invest in grid-supportive locations. For instance, wind-prone locations can be offered a higher subsidy to avoid local RE construction agglomerations that are accompanied with high system integration costs [33].

7.4.1 TSO perspective

As opposed to zonal prices, locally differentiated prices do not offer grid investment incentives to TSOs. Under zonal pricing, there is an incentive to invest in network to reduce intra-zonal congestion and the corresponding costs. However, there is a lack of such incentive in nodal systems, as an investment in the grid would not reduce costs or increase profits [42].

7.5 Market liquidity and the impact on price hedging

The discussion about a bidding zone size reduction has shown that smaller bidding zones have a tendency to increase market liquidity and price volatility, while decreasing the efficiency of risk hedging.

Similar conclusions can be drawn for the reconfiguration of bidding zones: if local prices differentiate too much, market-based risks could arise. The volatility of nodal short-term prices can also increase uncertainty in trading activities. In order to counter that, long-term contracts can be used in zonal markets to hedge against this price volatility – However, hedging is more complex in nodal pricing due to poor nodal market liquidity: because of the small-scale division of the market area, the number of trading parties at each node is low. Liquidities are predicted to decrease in forward markets when switching to a nodal model, and only few potential partners are available for risk hedging at each node [9] [28], [41].

To overcome this problem, hedging transactions in the form of Financial Transmission Rights (FTRs) are organized between trading hubs (typically liquid)[10]. FTRs are hedging tools used in nodal markets for the short- and medium-term (up to three years). They play an important role stabilizing cash flows of existing assets in nodal pricing systems. The owner of FTR is paid the price difference between two pre-defined nodes, offering a better price certainty to the participant when delivering energy to the grid.
To hedge the risk related to the price difference of node and hub, participants can trade locational hedging contracts with each other, or buy FTRs between node and hub [33] [28].

7.6 Efficiency of network use

In zonal pricing systems, the efficiency of grid use depends mainly of the redispatch quality. As mentioned above, redispatch is not necessarily inefficient. However, it is currently sub-optimal: Grid congestion is avoided, but may require expensive, last-minute corrections. However, section 5 showed that optimization is possible and in development, which however would offer gaming-incentives.

On the other hand, in nodal pricing, a precise spatial control of generation and flexibilities takes place at every single stage of the market [39]. The centralized DA market ensures it makes technically feasible and optimal dispatch. Obviously, the efficiency depends on how well the algorithmic complexity is mastered. This is a similar challenge to the optimization of the redispatch in the zonal design [33].

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[9] However, data shows that liquidity did not decrease in US markets when transitioning towards nodal [42].

[10] Trading hubs include a subset of nodes over which the weighted average nodal price is calculated. It can be interpreted as a combination of numerous nodes into a single virtual node, making the FTR trading actually zonal.

Thanks to the fact that the market is not two-staged, nodal pricing systems do not favor flows within zones over cross-zonal changes any more. As a reminder, TSOs are interested in keeping redispatch costs as low as possible. To limit intra-zonal congestions, partly so they don't have to support loop flows, some TSOs lowered the capacities made available for cross-border exchanges. To circumvent this, CEP70 target has been introduced to guarantee that sufficient cross-zonal trade capacity is made available [42].

It is worth mentioning that some stakeholders point out that nodal pricing fails to harness the flexibility offered by grid topological changes. It has also been pointed out that the zonal electricity market relies on topological changes (NRAOs) to relieve network congestion. The automated nodal grid management however could result in fewer use of NRAOs, and introducing topological changes seems to be rather complicated in the nodal market clearing algorithm. This could potentially reduce static efficiency. On the other hand, it is important to keep in mind that, as the nodal pricing already optimizes dispatch, it is less dependent on such topological changes than the zonal market, where a large part of NRAOs is used to correct the DA market outcome [28].

7.7 Barrier to unlock flexibilities in centralized markets

It has been pointed out previously that European zonal markets can be referred to as 'decentralized' markets: Operators are allowed to use self-dispatch, where actors determine their dispatch positions themselves in the form of bids and continuous ID trading. Due to the fact that renewable energies generally update their forecast up to delivery date because of their weather dependent profile, the possibility offered by the zonal model to continuously trade on the ID market is especially valuable to match flexible resources with renewables [13], [43]. Therefore, one main advantage of the zonal market design is the flexibilities, that eases the introduction of work for new technologies, such as demand response and energy storage.

Conversely, nodal markets use a central unit commitment. Obviously, one main advantage with a centralized day-ahead market is that it makes sure that the dispatch is technically feasible and optimal. However, the central characteristic may be a barrier to the participation of demand-response and storage in the wholesale market, as centralized markets are characterized by a poor flexibility. Continuous ID trading is not recommended under nodal pricing, as the ID trades would depart from the position cleared in DA, and ISOs would constantly need to confirm that the trade does not exceed grid limitations. This ultimately leads to a hindered integration of flexible resources that are crucial for the integration of renewables, on various levels [43]. However, specific bidding formats are being introduced and improved to overcome this barrier, which could strengthen the integration of flexibilities [22], [13], [42].

7.8 Market competition and market power

Competitive electricity pricing is indispensable for a well-functioning, statically efficient market. Particular attention should be paid to eventual market power abuses. Generally speaking, the risk of market power increases with spatial granularity, as strategically located participants potentially have a bigger influence on wholesale prices.

For this reason, numerous stakeholders fear that the disaggregated nodal electricity prices may be a barrier to market competitiveness: Indeed, the risk of market power in wholesale markets is relatively low in status quo, rising above the CACM bidding zones up to nodal pricing.

If the network is congested in a nodal pricing system, the ownership of generation capacity concentrates to one or a collection of nodes. Price setter opportunities are thus given, and could potentially result in market power abuses.

To partially overcome this problem, U.S. markets have introduced power mitigation mechanisms, aiming at detecting and evaluating potential abuses prior to market clearing. For instance, bids from actors could be restricted with the help of price-caps that are considered being strategically located. Nevertheless, although mitigating options were introduced to partly overcome this problem, the risk of market power abuse stays a main argument against nodal pricing [28].

However, it is important to remember that not only node-based pricing systems risk market abuse, as all designs present structural weaknesses and the risk of market power abuse [28]. Even though zonal pricing does not suffer from a significant risk of market power abuse in the spot market, a risk of local market power exists in the redispatch. This, however, is exacerbated by arbitrage strategies offered by market-based redispatch. On the contrary, nodal pricing does, in theory, not allow for inc-dec gaming, and market power abuses directly affect wholesale prices [28].

On one hand, some argue that the impact of market power abuse has more severe impacts when it is performed in the spot market such as in nodal pricing systems, others argue that monitoring the abuses may be easier in the nodal market that in the zonal redispatch market [44].

As a conclusion, one can say that all systems thus basically have the problem of local market power: In nodal pricing, market power occurs in the spot market, and in zonal markets, it occurs in the redispatch market. To minimize the abuse, price regulation of bids in the spot and/or redispatch market is used [33].

7.9 Resistance towards diverging prices within a country

Nodal pricing has some clear advantages compared to zonal in terms of grid usage, the incentives given by economic signals and other theoretical aspects. However, social impacts should not be neglected.

Firstly, the locational price differentiations are deemed to be socially undesirable. Similarly to what has been discussed in the context of a potential German bidding zone split, participants may be resistant against price differences within a nation. Especially around demand centers, electricity prices increase, and at nodes in remote areas, where electricity injection increases the flow on lines with binding network constraints, electricity prices are low. This obviously risks resistance from the consumer side, especially those consuming on demand centers. However, regulatory mitigating options exist. To hedge against the differences in economic values inside the country, FTRs can be bought to hedge against price differences in two different nodes.

A same kind of resistance can stem from generators, especially those generating in remote locations. Due to the locational constraints, renewable energies, more specifically wind-farms, are the most often affected (which can be tamed thanks to renewable support for instance).

7.10 Conclusion

Nodal pricing is an alternative to zonal designs that could narrow the gap between physics and markets. Indeed, nodal designs have, compared to the zonal pricing design, some clear advantages. The transitioning would likely come with significant economic benefits, mainly thanks improved price signals and optimized generator scheduling. Nodal prices are also accompanied by some risks or inefficiencies, but, in most cases, mitigation methods can be implemented.
Despite better performances on numerous levels, European stakeholders continuously rejected a nodal pricing system in Europe. One main reason is that the transition towards a nodal pricing system in Europe would require tremendous changes in the market: current arrangements in cross-border trading would need to be developed, implying significant IT and procedural changes and induce high costs. Another main argument European stakeholders hold against nodal pricing is the centralized dispatch. In centralized markets, participants can not choose how they deliver the committed energy at the agreed location, and no continuous trading on ID markets is possible. Due to the fact that renewables generally update their forecast up to delivery date, the possibility offered by the zonal model to continuously trade on the ID market is especially valuable to match flexible resources with renewables.

8 Final conclusion and discussion

As a result of the increasing number of decentralized resources and the delay in grid expansions, the current European market design is questioned. Indeed, the zonal aggregation corresponds to a strong simplification of the actual grid, and pressure on congestion management is increasing.

The implementation of FBMC in the Core region is likely to positively impact market efficiency. Indeed, its implementation in CWE has proven better price convergence and increased welfare. In addition, thanks to the fact that the capacity allocation takes partly place during the market clearing, actual market needs can be taken into account, and internal grid congestions are likely to be smaller. The extension on Core is likely to bring further benefits. However, as the flow-based methodology has only been implemented for a few months in the Core region by the time of writing, no closing remarks can be made. Nevertheless, even though the improved capacity calculation method can slightly slow down the increasing zonal inefficiencies, FBMC will not be able to stop it.

Therefore, this article assesses three mitigation options currently in discussion: redispatch markets, a reconfiguration of bidding zones, and a radical switch to a nodal system.

A first option, a radical switch to a nodal system is the most extreme option. Nodal pricing is from a theoretical perspective superior to zonal pricing: the right price incentives are offered to consumers and producers, the network is used more efficiently, and welfare is ultimately increased. However, even though nodal pricing is theoretically more performant, implementing a nodal design in Europe would be highly disruptive and costly. Additionally, nodal pricing systems represent a barrier to unlock flexibility, and they don't allow for continuous ID trading. Therefore, nodal pricing does not seem like a viable option for zonal markets.

A second option that this paper assesses is a reconfiguration of bidding zones. However, no conclusive results could be drawn. On one hand, a bidding zone split improves spot price formation, while promoting efficient congestion management. On the other hand, price volatility and market liquidity, and with it hedge opportunities, are worsened when increasing the amount of bidding zones. Additionally, reconfiguring bidding zones has proven to be a very time-consuming process. Considering that flow patterns are constantly changing, the new designs may potentially be outdated by the time of implementation. Therefore, a bidding zone split may be a possible solution, but is not likely to happen anytime soon.

A third option related to redispatching markets seems like a viable solution. The rationale of introducing a market-based redispatch would be to integrate flexibilities and loads more easily as compared to a mandatory redispatching. Flexibilities are believed to be crucial to further integrate renewables, ultimately relieving network congestion. However, the voluntary market is rejected by numerous stakeholders as it offers incentives for strategic bidding which would bring a whole new set of issues that have to be taken seriously. Mitigation measures exist that can partially overcome these risks, allowing for the benefits of redispatch markets to reign.

To conclude, one can say that the zonal design offers enough room for improvement, and a fundamental change in the zonal configuration is not required to solve congestion problems. I believe that the best suited approach to provide a cost-effective solution is to organize redispatch on a voluntary basis, together with strategic grid reinforcement and further implementation of FBMC. Moreover, the implementation of mitigation methods to avoid inc-deck bidding are crucial to the success of such a system.

9 Annex 1: History of SDAC and SIDC

9.1 Single Day-Ahead Coupling (SDAC)

This section provides a brief overview of Europe's key cornerstones towards the completion of the European DA target model of a single, liberalized market. To reach the model, the Single Day-Ahead Coupling (SDAC) has been launched, which is a project for creating a single integrated pan cross-zonal DA electricity market.

The first wave of SDAC started in November 2006: Belgium, France and the Netherlands integrated their DA market, forming the first transnational merger called the Trilateral Market Coupling (TMC).
Four years later, in November 2010, Luxembourg and Germany joined this group, thereby creating the Central Western European (CWE) region, colored in dark blue in Figure 16.

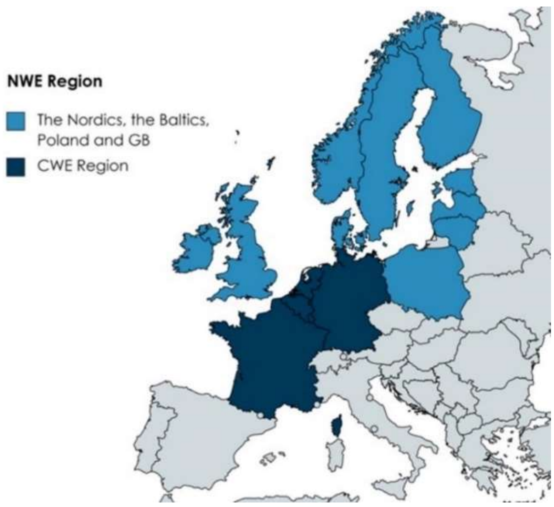

Figure 16: NWE Region, with the CWE region in dark blue, and the other countries completing NWE in light blue

The first initiative of pan-European Price Coupling Regions (PCR) emerged in February 2014 in North-Western Europe (NWE). NWE covers CWE (dark blue in Figure 16) in addition to the UK and Ireland, the Scandinavian and Baltic Countries, as well as Finland and Poland (light blue Figure 16) [14], [16], [19].

PCR is a coupling project led by European PX. It is considered as being a key step towards the goal of a harmonized, coupled energy market. The project's aim is to further increase market liquidity, efficiency and social welfare by implementing a single electricity price calculation method for all PCR parties.

To this aim, PCR developed a price coupling algorithm called Euphemia, which is to this day in use. Euphemia calculates market electricity prices and interconnector flows of the different participants in a fair and transparent matter, while taking into account capacity limits of the network elements. The uniform algorithm leads to increased market transparency and order, as well as to a more robust operation [14], [16].
The project region was extended in May 2014, when Spain and Portugal joined the PCR. In February 2015, Italy, Austria and Slovenia also connected to PCR, forming the Multi-Regional Coupling (MRC).

In the following years, Bulgaria, Croatia, Greece and Ireland completed the MRC region. However, as a consequence of Brexit, the UK was decoupled in 2021. On Figure 17**,** the current

MRC configuration is shown in blue. Today, these countries cover 85% of the total European electricity consumption.

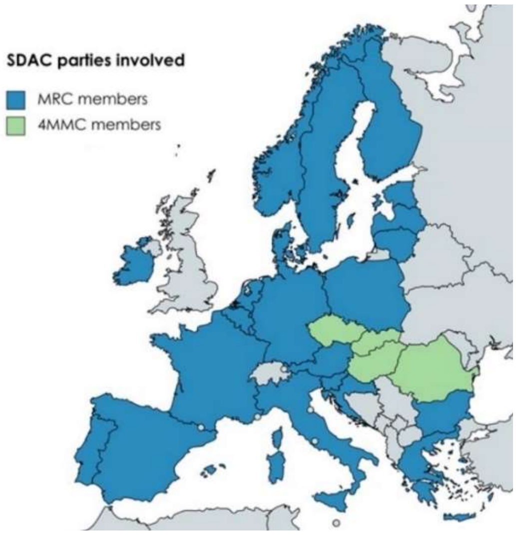

Figure 17: SDAC parties currently involved (blue), parties that will be involved in the future (green)

In parallel to the MRC, Hungary, Slovakia and the Czech Republic were coupled together, by creating the 4M Market Coupling (4MMC) project, colored in green Figure 17**.** In June 2021, the Interim Coupling Project (IRP) coupled the MRC to the 4MMC region and thereby finalizing the SDAC, whose ultimate goal is to create a single pan European cross border DA market [14], [16], [19] .

9.2 Single Intra-Day Coupling (SIDC)

As already mentioned, it is the DA market that mainly interests us. However, with the increasing amount of renewable energy in the mix, it is worth mentioning that the ID market is becoming increasingly important. This is due to the fact that the intermittent nature of renewables makes it harder to predict the state on the next day. Consequently, it is becoming more difficult to keep the grid balanced without relying on balancing mechanisms.

For this reason, being able to balance until right before delivery is becoming increasingly important for the overall grid stability and performance. Therefore, progress has also been made on the coupling of the ID market: The Single Intra-Day Coupling (SIDC), aims at, similarly to the SDAC, creating a single European cross-zonal market, but on ID level. European market participants work together to make the ID more efficient by continuously trading energy across borders [16].

10 Annex 2: Flow-based Market Coupling vs. Net Transfer Capacity

In cross-border capacity calculation methodology, two main methods are used: the Net Transfer Capacity (NTC) and the Flow-Based (FB) method.

Initially, the CWE region used the NTC method for its DA capacity calculation because of its simple operation. However, due to the numerous advantages, it has been replaced by the FB method, and is further used for the DA capacity calculation for the Core region.

However, the NTC method is still commonly used for other capacity calculations, as for example the Future Markets. Therefore, it is interesting to understand how both calculation methods work.

The following section give a brief explanation on both methods without getting into details, emphasizing on their differences. The aim is to show why the FB method is overall the preferred method.

10.1 Net Transfer Capacity (NTC)

In the NTC method, every TSO calculates one import-, and one export capacity value for every border of their respective bidding zone. The TSOs perform the calculation separately, each following their individual calculation methodologies – resulting in potentially different results for different TSOs. To ensure operational security, results are harmonized by taking the minimum of the two values that neighboring countries have computed. The values are calculated based on a prediction of load and generation, grid status and the status of other countries, represented by a grid model (based on the N-1 criterion: capacity needs to be feasible even if there is an unplanned outage).

Let's for example consider the capacity on the Belgian-German border. The following table takes an example of NTCs computed by Belgian and German TSOs. The first and second rows represents Belgian and German results, respectively, while each of them is using their own, individual methodology.

	BE → GE	GE → BE
Belgian NTC value	1500 MW	1800 MW
German NTC value	1200 MW	2000 MW

Table 1: Example of NTC values for Belgium and Germany

For the export from Belgium to Germany, Belgium computed a capacity of 1500 MW, and Germany a capacity of 1200 MW. The harmonized and final NTC value takes the smallest value, i.e., in this case 1200 MW. The same principle can be applied to the import capacity from Germany to Belgium, where Belgium and Germany obtained capacities of 1800 MW and 2000 MW, respectively. The harmonized NTC value equals the minimum of both the values, i.e., 1800 MW.

It is important to mention that the final capacities that are offered to the market are fixed and independent of activities on the other lines. In other words, all of the resulting NTCs need to be simultaneously feasible.
To illustrate this, let’s have a look on Figure 18, representing a 2D example of a NTC capacity domain for the exchanges from Belgium to France and Germany. The domain defines a space of allowed cross-zonal exchanges, colored in blue in Figure 18.

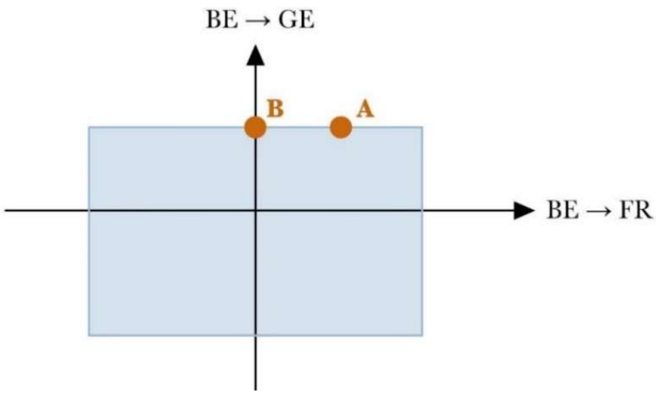

Figure 18: 2D example of a NTC capacity domain

Remark: It is important to mention that, to make the graph visible, a 2D example has been taken, representing the transaction to two bidding zones.

One can see that the NTC limitations create a fixed rectangle, where the horizontal and vertical lines represent import and export capacity values for the respective borders. In this example, the vertical sides represent the exchange limits between bidding zone Belgium and France, and the horizontal lines represent the capacity limits between Belgium and Germany. By taking the example given in Table 1, the upper line would correspond to 1200 MW, and the lower line to -1800 MW.

Let's for example consider the market result A on Figure 18. from a Belgian point of view, some of the export capacity to France is used, while the export capacity to Germany is fully employed. By moving the point to the left, a market outcome where the Belgian-French lines are relieved compared to the previous situation is considered.

In the real physical world, decreasing the import from Belgium to France would probably have an impact on different lines, and could increase the bilateral capacity between Germany and Belgium. However, when looking at the market result B, one can see that, even if no exchange with France happens, the export limit to Germany still is not affected.

Therefore, the rectangle-shaped NTC domain does not represent correctly the actual physical flows. In reality, bidding zone borders are strongly connected and dependent on each other. In other words, the flows are not always direct and bilateral and a lot of transit flows take place. For example, an electricity flow from Germany to France is not always direct, but can also follow a path through Belgium and the Netherlands, which of course has an influence on the remaining capacity of the latter. Therefore, the NTC method does not reflect how the physical flow goes through the network grid. This method can thus not reflect how market participants are interested in the capacity.

10.2 Flow-Based (FB)

Compared to the NTC method, the FB method is a more advanced method to calculate the capacity. In contrast to the NTC, its calculation is performed centrally, using coordinated and harmonized tools, taking account of the complex flows that occur in the physical world. The output is not, as for the NTC method, a fixed import and export value per border, but a list of Critical Network Elements (CNE) – i.e., elements such as power lines that are relevant for cross-zonal trading. For every CNE, RAM and a matrix of PTDFs coefficients are computed.
As a reminder, the RAM is the remaining capacity available for cross-border trading, and the PTDFs contain a linear relationship between the net exchange positions and flows through CNEs [20]. In other words, they describe the change of power flow of a certain element resulting from a given power flow between two bidding zones. A matrix containing all possible combinations of trading and the respective PTDFs for every CNE is computed.
Let's illustrate this with an example: A flow of 1 MW from Germany to France, and three different CNEs a, directly connecting Germany to France; b, connecting Germany to Belgium; and finally, c, linking Belgium to France, are considered, as shown on Figure 19.

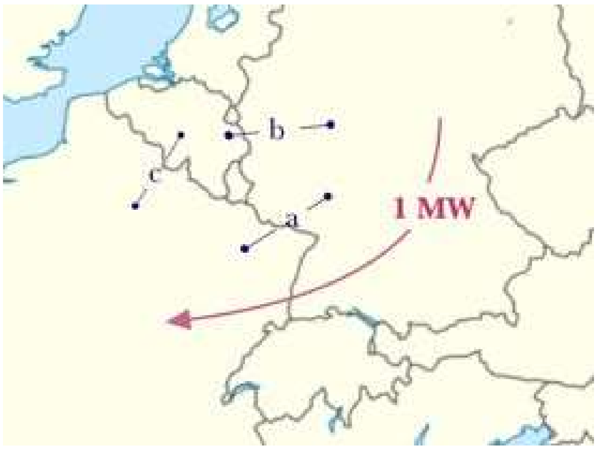

Figure 19: Representation of the CNEs a, b and c, that are affected by the power flow from Germany to France

The PTDF and RAM values for each of those CNEs are given in Table 2. The flow, that actually goes through a certain network element, is obtained by multiplying the total power flow (of 1MW on that case) by the respective PTDF value. When doing so, one can conclude that 0.55 MW flow through element a, 0.20 MW through element b, and 0.15 MW through element c. The highest flow goes through a, the element that directly links the two countries that are exchanging power. It is important to keep in mind that this example only shows three out of a large number of CNEs actually affected.

CNEC	**PTDF GE → FR**	**RAM**
a (GE-FR)	0.55	800 MW
b (GE-BE)	0.20	1000 MW
c (GE-NL)	0.15	1300 MW

Table 2: Example of NTC values for Belgium and Germany

To determine if a certain flow is feasible, it has to be compared to the RAM value of the element in question. For example, one can conclude that element a is not overloaded, as it has to support a flow of 0.55 MW, which is significantly smaller than its RAM of 800 MW.

To highlight the differences and advantages compared to the NTC method, a 2D example of a FB

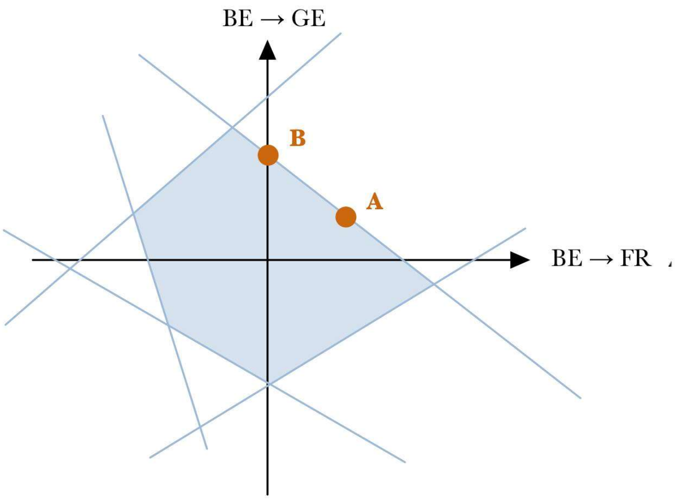

Figure 20: 2D example of a FB capacity domain

capacity domain between the two same bidding zones as in section 10.1 is given in Figure 20. Whereas the NTC limits are import and export capacities for each border, the FB limit lines are CNECs. For each line, the distance from the origin is proportional to its RAM, and the inclination to its PTDF value.

Let's consider the market clearing point A. Again, there is a transaction between Belgium and France, as well as between Belgium and Germany, and there is no possibility to export more. However, by decreasing the export to France, some elements could be unloaded, resulting in a spare RAM that could be used for increasing the export to Germany (clearing point B).

This is the main advantage of the FB method: It correctly represents the physical flows and links final constraints with each other. The results take into account the interdependency and the calculation is not limited to bilateral exchanges. Additionally, the method allows for a more flexible utilization during market coupling and capacity allocation. Besides the flexibility benefit, the capacity allocated in the FB domain is generally higher than for the NTC method.

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