Balancing and redispatch: the next stepping stones in European electricity market integration

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Keywords: electricity market, market design, ancillary services, balancing, redispatch, agent-based modelling, reinforcement learning, optimization, energy policy, strategic bidding

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To my grandfather.
For teaching me to read, to love books
and for all the endless kindness.
I wish you were here.

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Right now is one of the most exciting times to work in the field of energy. Hardly any other field has been developing so fast, in so many ways and so little time, from technology to regulation and policy. The research world has more responsibility than ever to drive innovation, provide sound analysis and develop solutions for all stakeholders, consumers, energy companies, network operators and policymakers - particularly at a time when the sense of urgency to ensure a more sustainable future is finally sinking in across the world.

The electricity sector at the nexus of grid, market and regulation poses numerous challenges while answers are much less straightforward than one might expect (or hope for). Similarly, I have found myself sitting at my own nexus, writing a PhD at TU Delft and working at AIT in Austria, which has been a tough balancing act all of its own, with its own set of challenges and exciting experiences.

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Ksenia Poplavskaya *Vienna, June 5, 2021*

Summary

Balancing and redispatch are essential services for the security and stability of the electricity network. Balancing refers to continuously maintaining a balance between supply and demand by activating flexible resources. Redispatch refers to changing the dispatch of generators to remedy network congestion. The need for flexibility resources for balancing and congestion management is ever more pressing due to several policy, market and technological aspects. First, the integration of renewable energy sources, supported and promoted by EU decarbonization policy, reduced the controllability of supply and produced forecasting challenges. Second, the decommissioning of (uneconomic) conventional generation requires new flexibility from other technologies. Third, decentralization has led to the emergence of small-scale technologies and new actors such as aggregators that have been placed on the same level with conventional generation by the Clean Energy for all Europeans Package of 2018-2019. These, however, have not yet been (fully) integrated into ancillary service provision.

The European Union's Clean Energy Package requires market-based procurement of the two ancillary services. The balancing market has been undergoing substantial market design changes, in particular since the adoption of the Electricity Balancing Guideline in 2017. The Guideline prescribes a set of new market rules and sets the path for balancing market harmonization and integration to be implemented by the end of 2024. This creates an impetus for investigating the upcoming changes. Most balancing markets are highly concentrated and suffer from market inefficiencies, which translates into higher costs for consumers. The market-based approach to redispatch, in turn, has been widely debated, mainly due to concerns about possible strategic bidding. Similarly, the issue of redispatch requires surgent attention since redispatch and frequent congestion in general affect wholesale market prices and market integration. Countries like Germany face congestion over 75% of the time, costing over a billion euros annually. Yet, only a small group of conventional power plants tends to be involved in the provision of redispatch services. So far, the topic of redispatch has been barely addressed in research due to a low degree of transparency and varying degrees of congestion among different EU countries. Now that more countries are expected to face growing congestion challenges, extending beyond the transmission network to the distribution network, efficient procurement of redispatch from a broader pool of providers is gaining importance.

In this time of fast-paced, massive transformation that is the energy transition, the electricity system and network are becoming more vulnerable to disturbances, requiring more flexibility. This makes it crucial to inform system operators, regulators and policymakers how the availability of flexibility can be increased and system

services can be procured more efficiently, i.e. in a way that better aligns actor incentives with policy objectives. In this dissertation, we test the hypothesis that the efficiency of procurement can be improved with the help of market design adjustments. Thus, the author explores the following main question:

How can market design changes help transmission system operators procure balancing and redispatch services in a more economically efficient manner?

The answer to the main research question is subdivided into two parts: the first one studying a well-defined and well-established balancing market and the second one, building upon the analysis produced in the former, addresses issues related to redispatch. For this, market modelling was combined with analytical and empirical approaches to study the procurement of the two services.

In the first part, the first step was the development of a framework for identifying the design variables for the balancing market. Improvements to market design can facilitate the diversification of supply and thereby intensify competition. Empirical studies of three neighboring EU countries with advanced balancing markets, Austria, Germany and the Netherlands, were used to illustrate the use of the framework and assess the alignment of their market designs in the requirements set out in the European Balancing Guideline. As part of the qualitative analysis, special attention was paid to the impacts of changes in market design and the overall regulatory framework on the entry of new market actors and the participation of new distributed energy resources. The assessment framework aided the conceptualization of a model and provided useful lessons for the prioritization of market design changes. Secondly, the relations among the key players in the balancing market, aggregators, incumbent suppliers and balance responsible parties were analyzed based on five possible interaction models between them. These were contrasted with the existing practice in the three countries to determine how the participation of aggregators in the balancing market can be better enabled.

The insights from the assessment framework were combined with the analysis of the interrelated bidding strategies of balancing service providers acting in several markets using theoretical bidding calculus. Together, they formed the foundation for an agent-based simulation model of the balancing market developed in this dissertation, Elba-ABM. As in other complex systems, system and market rules affect actor behavior by creating new incentives and strategies that ultimately influence the market performance. Elba-ABM's focus was on the feedback loops between market design and balancing service providers, which are represented as profit-maximizing agents with the aid of reinforcement learning algorithms . This allowed us to analyze their evolving bidding strategies and estimate the potential for strategic bidding under different market designs. It helped us understand the market impacts of the new balancing market rules mandated by the European Balancing Guideline. These rules include, among others, the introduction of a standalone balancing energy market (as opposed to a combined market for balancing capacity and energy

far ahead of real time), application of the marginal pricing rule (as opposed to commonly used pay-as-bid pricing) and allowing voluntary bids (balancing energy bids not previously committed in the balancing capacity market). Model results show that the new rules are conducive to improving market efficiency and reducing the risk of strategic bidding. We show that procuring balancing energy in a separate auction close to real time increases market efficiency. The introduction of voluntary bids has the largest potential of curbing strategic bidding behavior as long as they are submitted by new market participants and are not simply used by the incumbents as 'second-chance' bids. The market performance improved when marginal pricing was applied as compared to pay-as-bid pricing. Yet, the pricing rule needs to be addressed after implementing the other changes and increasing competition levels to avoid price shocks. Together, these design variables are likely to incentivize balancing service providers to bid more competitively.

This modelling study revealed the complexity of the balancing market, such as the fact that there are four auctions per product (capacity and energy, upward and downward regulation), which the balancing service providers need to optimize jointly. Agent-based modelling was shown to be a highly flexible tool for modeling these multiple marketplaces and their market design variables and for simulating actor strategies and portfolios. Reinforcement learning, in turn, helped us to realistically model learning agents who respond dynamically to changing market conditions and actions of their competitors. Interdependent bidding strategies in the four auctions required the development of a new collaborative reinforcement learning algorithm that accounted for these links. The modelling of this highly complex market, however, also revealed limitations of the approach, most notably the need to limit the number of learning agents in the model to reduce their interference with each other.

The second part of this research concerned the procurement of redispatch. In contrast to balancing, the EU's approach to redispatching is less harmonized and its design more open for discussion. The differences and similarities between redispatch and balancing, which sometimes make use of the same resources, and recent regulatory developments formed the starting point of an analysis of ways in which redispatch could be efficiently procured in a market-based setup while minimizing conflicts between the two services. Country case studies from Germany, France and the Netherlands illustrated three different approaches to redispatch procurement, which formed the basis of three possible models of balancing and redispatch procurement: 1) market-based balancing and cost-based redispatch; 2) a common market for balancing and redispatch and 3) two separate markets for the two services. The results showed the tradeoffs in terms of allocative efficiency, resource availability, susceptibility to strategic bidding and ease of implementation for all approaches. We showed that these tradeoffs are minimized if the two services are procured in two separate markets. Cost-based redispatch does not create an incentive for flexibility providers to participate thus leading to higher market concentration by definition. Market participation can be improved by implementing

standardized, technology-agnostic prequalification procedures for providers of redispatch services. The risk of strategic bidding can – at least to an extent – be mitigated by addressing structural and predictable congestion before introducing market-based redispatch.

In the final stage, we moved away from the prevailing dichotomy of "cost-based redispatch vs. redispatch market". Instead, we considered a broader perspective by analyzing the ways in which congestion – the reason for redispatch – affects overall electricity market integration and efficiency. This led to the formulation and analysis of a new method that enables the integration of preventive redispatch into the day-ahead market coupling method in order to increase the available cross-border transmission capacity. To assess the method's overall benefits, we implemented a multi-step optimization process. An optimization approach was chosen for this case to limit the already high degree of complexity of the model, considering the need to model the market, the transmission network and the multi-step method of flow-based market coupling. Combined with the use of small-scale example networks, the optimization approach allowed us to maintain tractability of the results and gain understanding of the fundamental links between flow-based market coupling and redispatch. As a result, we showed how so-called 'integrated redispatch' can help to increase cross-border exchanges by freeing valuable capacity on the interconnectors for more cost-efficient generators. This can lead to overall economic efficiency gains leading to lower total system costs. This method can also help alleviate the risk of strategic bidding since the generation units that are used for redispatch participate in the day-ahead market on par with other market participants and therefore cannot bid differently for redispatch.

This dissertation contributes to the content as well as the methodological side of electricity system analysis. From the content point of view, it advances the understanding of electricity market design, the growing market complexity and interdependencies between electricity marketplaces, in particular in the context of less studied ancillary services, balancing and redispatch. The assessment framework that was developed in this dissertation allows to systematically analyze market design and serves as a basis for roadmap development and for simulation. The author of this dissertation synthesized the existing body of research on bidding strategies in short-term electricity markets and built upon it to obtain new insights into the implications of policy changes for bidding behavior in the balancing and other markets. In particular, the author assessed different market designs with respect to their susceptibility to strategic bidding and proposed improvements of balancing markets that preempt non-competitive practices. Furthermore, this dissertation clarifies the relations and differences between balancing and redispatch and proposes measures for improving the efficiency of redispatch procurement in Europe. It presents a method combining redispatch with flow-based market coupling using multi-step optimization. By improving the efficiency of redispatch, this method contributes to European market integration by increasing cross-border exchanges.

From the methodological perspective, this dissertation is a big step forward in the development of tools for market analysis. Different methodological approaches, agent-based modelling, machine learning and optimization are used to answer questions about market design and market efficiency. In particular, the novel combination of agent-based modelling and reinforcement learning applied to the study of balancing markets has opened new opportunities for a detailed and complex analysis of market design and strategic bidding. In addition, this dissertation contributes to the development of optimization models for flow-based market coupling and redispatch.

The agent-based model, Elba-ABM, has been demonstrated to be a potent tool for studying of effects of the design of interrelated markets on the bidding behavior of market actors, anticipating the upcoming regulatory change. Finally, this dissertation illustrates the value of machine learning as an enhancement of ABM, in particular in modelling strategic bidding behavior. Of particular methodological value is the novel collaborative machine learning algorithm that simulates the interrelations between bidding strategies in the balancing capacity and balancing energy markets. In this way, with this dissertation, we contribute to the development of methods for market design analysis in order to identify ways of procuring balancing and redispatch more efficiently.

This dissertation concludes with a number of policy recommendations. In order to generate long-lasting efficiency gains from market design improvements, the broader market and policy context should be considered to avoid improving certain elements to the detriment of others. As much as it is crucial to identify the features of the target market design, it is no less crucial to focus on the pathway towards it and understand how individual design variables can be prioritized. Such prioritization should be achieved systematically considering possible links and effects between individual design variables and tested e.g., using Elba-ABM, prior to actual implementation. Concerning balancing markets, this dissertation demonstrates that the balancing market defined in the EU Regulation of Electricity Balancing leads to overall efficiency gains. It requires, among others, the application of marginal pricing, which can reduce weighted average prices by as much as 30-40%, and the introduction of a standalone balancing energy market clearing close to real time, which leads to an about 10% average weighted price decrease. Yet, more new entrants are needed to obtain competitive prices. In other words, market adjustments alone are not sufficient to bring about expected efficiency gains as long as the market itself is not fully open to all types of potential participants. Allowing voluntary bids in the balancing market was shown to dramatically decrease balancing energy costs not just by substituting competition in the merit order but by inducing a more competitive behavior from strategic bidders. The latter were shown to deviate from their true costs about 15% of all hours on average as compared to almost 50% of all hours when voluntary bids were not allowed. Concerning redispatch, in order to provide "efficient economic signals to the market participants and TSOs involved", market-based redispatch is most likely to attract flexibility

resources without leading to excessive system costs as long as structural congestion is tackled first. Improved TSO forecasting of congestion and TSO-TSO coordination of redispatching coupled with preventive redispatch will likely help reduce the cost of congestion to the market. This dissertation demonstrates how by combining redispatch and day-ahead market clearing not only can socio-economic welfare be maximized but activation of units for redispatch can help increase the volume of available capacity for cross-border trade.

To sum up, market harmonization and network integration are developing rapidly in the EU, creating new challenges for the electricity system. This dissertation addresses key issues that system operators, regulators, policymakers and market participants face in the electricity markets today and provides practical recommendations as to how market design can be improved and what other measures are required to ensure economic efficiency. The developed tools provide new means of decision support for energy system stakeholders. They can be easily adapted to answer multiple questions related to the effects of market design changes. A good example of the practical applicability of Elba-ABM is the recent project conducted by the author for the Swedish transmission system operator, Svenska kraftnät. The author adjusted Elba-ABM to the Swedish balancing market design to investigate the potential of strategic behavior under the planned design adjustments. This study does not only contribute to improving network stability through market design but, by helping reduce system costs, contributes to the overall economic welfare and the achievement of EU policy goals. Finally, it provides the scientific community with the insights and methodological know-how, in particular in the field of agent-based modelling and machine learning, for the study of numerous future questions in the area of electricity market design, bidder incentives and market integration. The issues analyzed in this dissertation will probably remain key elements of the European energy reform agenda for years to come. It is my hope that this dissertation will serve as a valuable stepping stone on the path towards a more efficient electricity system and market.

Samenvatting

Balancering en redispatch zijn essentiële diensten voor de veiligheid en stabiliteit van het elektriciteitsnet. Balanceren verwijst naar het continu handhaven van een evenwicht tussen vraag en aanbod door het activeren van flexibele middelen. Redispatch verwijst naar het wijzigen van de inzet van generatoren om netwerkcongestie te verhelpen. De behoefte aan flexibiliteitsmiddelen voor balancering en congestiemanagement wordt steeds urgenter vanwege verschillende beleids-, markt- en technologische aspecten. Ten eerste verminderde de integratie van hernieuwbare energiebronnen, ondersteund en bevorderd door het CO_2-reductiebeleid van de EU, de regelbaarheid van het aanbod en leidde het tot problemen met de voorspelbaarheid. Ten tweede vereist de ontmanteling van (onrendabele) conventionele opwekking nieuwe flexibiliteit van andere technologieën. Ten derde heeft decentralisatie geleid tot de opkomst van kleinschalige technologieën en nieuwe actoren, zoals aggregatoren, die door het wetgevingspakket *Clean energy for all Europeans* van 2018-2019 op hetzelfde niveau zijn geplaatst als conventionele opwekking. Deze zijn echter nog niet (volledig) geïntegreerd in de ondersteunende dienstverlening.

Het *Clean Energy Package* van de Europese Unie vereist openbare aanbesteding van de twee ondersteunende diensten. De onbalansmarkt heeft substantiële veranderingen in het marktontwerp ondergaan, met name sinds de goedkeuring van de elektriciteitsbalanceringsrichtlijn in 2017. De richtlijn schrijft een reeks nieuwe marktregels voor en bepaalt het pad naar harmonisatie en integratie van de onbalanssystemen eind 2024. Dit is aanleiding om de aanstaande wijzigingen te onderzoeken. De meeste onbalansmarkten zijn sterk geconcentreerd en lijden onder marktinefficiënties, wat zich vertaalt in hogere kosten voor consumenten. Een marktgebaseerde benadering van redispatch, aan de andere kant, is omstreden, voornamelijk vanwege bezorgdheid over mogelijke strategische biedingen. Het onderwerp redispatch vereist echter evenzeer urgente aandacht, gezien het effect van redispatch, en van frequente congestie in het algemeen, op groothandelsmarktprijzen en marktintegratie. Landen als Duitsland hebben meer dan 75% van de tijd te maken met congestie, wat jaarlijks meer dan een miljard euro kost. Toch is vaak slechts een kleine groep conventionele energiecentrales betrokken bij de levering van redispatchdiensten. Tot dusver is het onderwerp redispatch in onderzoek nauwelijks aan de orde gekomen vanwege de lage mate van transparantie en de verschillende mate van congestie in EU-landen. Nu de verwachting is dat meer landen met toenemende congestie te maken zullen krijgen, niet alleen van het transmissienetwerk maar ook van het distributienetwerk, wordt het steeds belangrijker om redispatchdiensten bij een bredere pool van leveranciers in te kopen.

In deze tijd van snelle, massale transformatie, de energietransitie, worden het elektriciteitssysteem en het netwerk kwetsbaarder voor storingen, waardoor meer flexibiliteit nodig is. Dit maakt het cruciaal om systeembeheerders, regelgevers en beleidsmakers te informeren over hoe de beschikbaarheid van flexibiliteit kan worden vergroot en systeemdiensten efficiënter kunnen worden ingekocht, d.w.z. op een manier die prikkels aan actoren beter afstemt op beleidsdoelen. In dit proefschrift testen we de hypothese dat de efficiëntie van de inkoop kan worden verbeterd met behulp van aanpassingen aan het marktontwerp. Daarom onderzoekt de auteur de volgende hoofdvraag:

Hoe kunnen veranderingen in het marktontwerp transmissiesysteembeheerders helpen om op een economisch efficiëntere manier balancerings- en redispatchdiensten in te kopen?

Het antwoord op de hoofdonderzoeksvraag is onderverdeeld in twee delen: in het eerste wordt een welomschreven en gevestigde onbalansmarkt geanalyseerd en in het tweede, dat voortbouwt op de analyse in het eerste deel, behandelt kwesties die verband houden met redispatch. Marktmodellen zijn gecombineerd met analytische en empirische benaderingen om de aanbesteding van de twee diensten te onderzoeken.

In het eerste deel is de eerste stap de ontwikkeling van een raamwerk voor het identificeren van de ontwerpvariabelen voor de onbalansmarkt. Verbeteringen in het marktontwerp kunnen de diversificatie van het aanbod vergemakkelijken en daardoor de concurrentie versterken. Empirische studies van drie aangrenzende EU-landen met geavanceerde onbalansmarkten, Oostenrijk, Duitsland en Nederland, zijn gebruikt om de toepassing van het raamwerk te illustreren en om aanpassingen van hun marktontwerpen met betrekking tot de eisen van de Europese Balanceringsrichtlijn te analyseren. Als onderdeel van de kwalitatieve analyse is speciale aandacht besteed aan de impact van veranderingen in het marktontwerp en het algemene regelgevingskader op de toetreding van nieuwe marktspelers en de deelname van nieuwe gedistribueerde energiebronnen. Het beoordelingskader ondersteunde de modelconceptualisatie en leverde nuttige lessen op voor het prioriteren van individuele veranderingen in het marktontwerp. Ten tweede zijn de relaties tussen de belangrijkste spelers op de onbalansmarkt, aggregatoren, gevestigde leveranciers en balansverantwoordelijken geanalyseerd op basis van vijf mogelijke interactiemodellen tussen hen. Deze werden vergeleken met de bestaande praktijk in de drie landen om te bepalen hoe de deelname van aggregatoren aan de onbalansmarkt beter mogelijk kon worden gemaakt.

De inzichten van het beoordelingskader zijn gecombineerd met een analyse van de onderling gerelateerde biedstrategieën van aanbieders van balanceringsdiensten die actief zijn in meerdere markten met behulp van een theoretische biedcalculus. Samen vormden ze de basis voor een agent-gebaseerd simulatiemodel van de onbalansmarkt, ontwikkeld in dit proefschrift, Elba-ABM. Net als in andere complexe

systemen, beïnvloeden systeem- en marktregels het gedrag van actoren door nieuwe prikkels en strategieën te creëren die uiteindelijk de marktprestaties beïnvloeden. De focus van Elba-ABM lag op de feedbackloops tussen het marktontwerp en de aanbieders van balanceringsdiensten, die gemodelleerd zijn als winstmaximaliserende agenten met behulp van reinforcement learning. Hierdoor konden we hun evoluerende biedstrategieën analyseren en het potentieel voor strategisch biedgedrag onder verschillende marktontwerpen inschatten. Het hielp ons om inzicht te krijgen in wat voor soort marktimpact de nieuwe regels voor de onbalansmarkt, opgelegd door de Europese Balanceringsrichtlijn, zouden kunnen hebben. Deze regels omvatten onder meer de introductie van een stand-alone balanceringsenergiemarkt (in tegenstelling tot een gecombineerde markt voor balanceringscapaciteit en -energie die ver voor realtime sluit), de toepassing van de marginale prijsregel (in tegenstelling tot het veelgebruikte pay-as- bid pricing) en het toestaan van vrijwillige biedingen (biedingen voor balanceringsenergie die niet eerder waren gecontracteerd in de markt balanceringscapaciteit). Modelresultaten laten zien dat de nieuwe regels bevorderlijk zijn voor het verbeteren van de marktefficiëntie en het verminderen van het risico van strategisch bieden. We laten zien dat het inkopen van balanceringsenergie in een aparte veiling dichtbij realtime de marktefficiëntie verhoogt. De introductie van vrijwillige biedingen heeft het grootste potentieel om strategisch biedgedrag te beteugelen, zolang deze worden ingediend door nieuwe marktdeelnemers en ze niet simpelweg door de gevestigde aanbieders worden gebruikt als 'tweede kans'-biedingen. Betere marktprestaties werden waargenomen als marginale prijzen werden toegepast in vergelijking met pay-as-bid prijzen. Toch moet de prijsregel worden aangepakt nadat de andere wijzigingen geïmplementeerd zijn en het concurrentieniveau verhoogd is om prijsschokken te voorkomen. Samen vormen deze ontwerpvariabelen waarschijnlijk een stimulans voor aanbieders van balanceringsdiensten om concurrerender te worden.

Deze modelstudie bracht de complexiteit van de onbalansmarkt aan het licht, zoals het feit dat er vier veilingen per product zijn (capaciteit en energie, op- en neerwaartse regulering), die de aanbieders van balanceringsdiensten gezamenlijk moeten optimaliseren. Agent-gebaseerde modellering bleek een zeer flexibele tool te zijn voor het modelleren van deze meerdere marktplaatsen en marktontwerpvariabelen en het simuleren van actorstrategieën en portefeuilles. Reinforcement learning heeft ons op zijn beurt geholpen om op een realistische manier leeragenten te modelleren die dynamisch reageren op veranderende marktomstandigheden en acties van hun concurrenten. Onderling afhankelijke biedstrategieën in de vier veilingen vereisten de ontwikkeling van een nieuw collaboratief algoritme voor reinforcement learning dat rekening hield met deze relaties. Het modelleren van deze zeer complexe markt bracht echter ook de beperkingen van de aanpak aan het licht, met name de noodzaak om het aantal leeragenten in het model te beperken om hun interferentie met elkaar te verminderen.

Het tweede deel van dit onderzoek betrof de inkoop van redispatch. In tegenstelling tot balancering is de EU-benadering van redispatching minder geharmoniseerd en is de opzet ervan meer open voor discussie. De verschillen en overeenkomsten tussen redispatch en balancering, die soms gebruik maken van dezelfde middelen, en recente ontwikkelingen op het gebied van regelgeving vormden het startpunt van een analyse van manieren waarop redispatch efficiënt kon worden gecontracteerd in een marktconforme structuur terwijl de conflicten tussen beide tot een minimum konden worden beperkt. Landencasestudies van Duitsland, Frankrijk en Nederland illustreerden drie verschillende benaderingen voor het contracteren van redispatching die de basis vormden van drie mogelijke modellen voor het contracteren van balanceringsdiensten en redispatching: 1) marktgebaseerde balancering en kostengebaseerde redispatch; 2) een gemeenschappelijke markt voor balancering en redispatch en 3) twee afzonderlijke markten voor de twee diensten. De resultaten illustreerden de afwegingen tussen allocatieve efficiëntie, beschikbaarheid van hulpbronnen, gevoeligheid voor strategische biedingen en eenvoud van implementatie voor de verschillende benaderingen. We hebben aangetoond dat deze afwegingen tot een minimum worden beperkt als de twee diensten op twee afzonderlijke markten worden ingekocht. Kostengebaseerde redispatch creëert geen prikkel voor flexibiliteitsaanbieders om deel te nemen en leidt dus per definitie tot een hogere marktconcentratie. De marktdeelname kan worden verbeterd door gestandaardiseerde, technologie-agnostische prekwalificatieprocedures te implementeren voor aanbieders van redispatchdiensten. Het risico van strategisch bieden kan -– althans tot op zekere hoogte – worden beperkt door structurele en voorspelbare congestie te managen voordat marktgebaseerde redispatch wordt ingevoerd.

In de laatste fase zijn we afgestapt van de heersende dichotomie van "op kosten gebaseerde redispatch versus redispatchmarkt". In plaats daarvan hebben we een breder perspectief bekeken door te analyseren op welke manieren congestie -– de oorzaak van redispatch -– de algehele integratie en efficiëntie van elektriciteitsmarkten beïnvloedt. Dit leidde tot de formulering en analyse van een nieuwe methode die het mogelijk maakt om preventieve redispatch te integreren in de day-ahead marktkoppeling om zo de beschikbare grensoverschrijdende transportcapaciteit te vergroten. Om de voordelen van de methode te beoordelen hebben we een optimalisatieproces in meerdere stappen geïmplementeerd. Voor deze case werd gekozen voor een optimaliseringsbenadering om de hoge modelleringscomplexiteit te beperken, rekening houdend met de noodzaak om de markt, het transmissienetwerk en de methode van flow-based marktkoppeling te modelleren. In combinatie met het gebruik van kleinschalige voorbeeldnetwerken konden we hierdoor de resultaten traceerbaar houden en inzicht krijgen in de fundamentele verbanden tussen flow-based marktkoppeling en redispatch. Als resultaat hebben we laten zien hoe zogenaamde ‘geïntegreerde redispatch’ kan helpen om grensoverschrijdende stromen te vergroten door waardevolle capaciteit op de interconnectoren vrij te maken voor meer kostenefficiënte generatoren. Dit kan leiden tot algemene economische efficiëntieverbeteringen die leiden tot lagere

totale systeemkosten. Deze methode kan ook helpen het risico van strategisch bieden te verminderen, aangezien de productie-eenheden die voor redispatch worden gebruikt op gelijke voet met andere marktdeelnemers deelnemen aan de dagvooruitmarkt en daarom niet anders kunnen bieden op redispatch.

Dit proefschrift draagt zowel bij aan de inhoud als de methodologische kant van elektriciteitssysteemanalyse. Inhoudelijk gezien bevordert het ons begrip van het ontwerp van de elektriciteitsmarkt, de toenemende marktcomplexiteit en de onderlinge afhankelijkheden tussen elektriciteitsmarktplaatsen, met name in de context van de minder bestudeerde ondersteunende diensten, balancering en redispatching. Het beoordelingskader dat in dit proefschrift is ontwikkeld maakt het mogelijk om marktontwerp systematisch te analyseren en dient als basis voor de ontwikkeling van een roadmap en voor simulatie. De auteur van dit proefschrift bracht het bestaande onderzoek naar biedstrategieën op korte termijnelektriciteitsmarkten samen en bouwde daarop voort om nieuwe inzichten te verkrijgen in de implicaties van beleidswijzigingen op biedgedrag in de onbalans- en andere markten. In het bijzonder heeft de auteur verschillende marktontwerpen beoordeeld met betrekking tot hun gevoeligheid voor strategische biedingen en om verbeteringen van onbalansmarkten voor te stellen die concurrerentieondermijnende praktijken voorkomen. Verder verduidelijkt dit proefschrift de relaties en verschillen tussen balancering en redispatch en stelt het maatregelen voor om de efficiëntie van het contracteren van redispatchdiensten in Europa te verbeteren. Het presenteert een methode die redispatch combineert met flow-based marktkoppeling met behulp van optimalisatie in meerdere stappen. Door het verbeteren van de efficiëntie van redispatching draagt deze methode bij aan de Europese marktintegratie door meer grensoverschrijdende uitwisselingen.

Vanuit methodologisch perspectief is dit proefschrift een grote stap voorwaarts in de ontwikkeling van tools voor marktanalyse. Verschillende methodologische benaderingen, agent-gebaseerde modellering, machine learning en optimalisatie zijn gebruikt om vragen over marktontwerp en marktefficiëntie te beantwoorden. Met name de nieuwe combinatie van agentgebaseerde modellering en reinforcement learning, toegepast op de studie van onbalansmarkten, heeft nieuwe mogelijkheden geopend voor een gedetailleerde en complexe analyse van marktontwerp en strategische biedingen. Daarnaast draagt dit proefschrift bij aan de ontwikkeling van optimalisatiemodellen voor flow-based marktkoppeling en redispatch. Het agent-gebaseerd model, Elba-ABM, heeft zich een krachtig instrument betoond is voor het bestuderen van de effecten van het ontwerp van dergelijke onderling verbonden markten op het biedgedrag van marktpartijen, in anticipatie op de aanstaande wijzigingen in de regelgeving. Ten slotte illustreert dit proefschrift de waarde van machine learning als een verrijking van ABM, in het bijzonder bij het modelleren van strategisch biedgedrag. Van bijzondere methodologische waarde is het nieuwe collaboratieve machine learning-algoritme dat de onderlinge relaties simuleert tussen biedstrategieën in de markten voor balanceringscapaciteit en -energie. Op deze manier dragen we met dit proefschrift bij aan het begrip van het ontwerp van

de elektriciteitsmarkt en aan de ontwikkeling van methoden voor marktontwerpanalyse om manieren te identificeren om balancering en redispatch efficiënter te verkrijgen.

Dit proefschrift wordt afgesloten met een aantal beleidsaanbevelingen. Om langdurige efficiëntiewinst te genereren door het aanpassen van het marktontwerp, moet de bredere markt- en beleidscontext meegewogen worden om te voorkomen dat verbeteringen van een element ten koste gaan van andere. Hoe belangrijk het ook is om het gewenste marktontwerp te identificeren, het is niet minder cruciaal om te focussen op de weg ernaartoe en inzicht te verkrijgen in het prioriteren van individuele ontwerpvariabelen. Deze prioritering moet systematisch worden bereikt, rekening houdend met mogelijke verbanden en effecten tussen individuele ontwerpvariabelen, en moet worden getest, bijvoorbeeld met behulp van Elba-ABM, voordat tot implementatie overgegaan wordt.

Met betrekking tot onbalansmarkten toont deze dissertatie aan de het marktontwerp zoals gedefinieerd in de Europese Balanceringsrichtlijn tot een algemene verbetering van de efficiëntie leidt. Hij vereist onder meer de toepassing van de marginale prijsregel, wat tot een reductie van de gewogen gemiddelde prijzen van maar liefst 30-40% kan leiden, en de introductie van een zelfstandige markt voor balanceringsenergie die bijna in realtime wordt gecleard, wat leidt tot een prijsdaling van gemiddeld ongeveer 10%. Toch zijn er meer nieuwkomers nodig om concurrerende prijzen te verkrijgen. Met andere woorden, marktaanpassingen alleen zijn niet voldoende om de verwachte efficiëntiewinst te bewerkstelligen, zolang de markt zelf niet volledig openstaat voor alle soorten potentiële deelnemers. Het toestaan van vrijwillige biedingen op de balanceringsmarkt bleek de kosten voor balanceringsenergie drastisch te verlagen, niet alleen door de concurrenten in de merit-order te vervangen, maar ook door meer competitief gedrag van strategische bieders teweeg te brengen. Deze laatsten bleken gemiddeld ongeveer 15% van alle uren af te wijken van hun werkelijke kosten, vergeleken met bijna 50% van alle uren wanneer vrijwillige biedingen niet waren toegestaan.

Wat betreft redispatch: om "efficiënte economische signalen te geven aan de betrokken marktdeelnemers en TSO's", zal marktgebaseerde redispatch hoogstwaarschijnlijk flexibiliteitsmiddelen aantrekken zonder dat dit leidt tot buitensporige systeemkosten, zolang structurele congestie eerst wordt aangepakt. Verbeterde TSO-prognoses van congestie en TSO-TSO-coördinatie van redispatching in combinatie met preventieve redispatch zullen waarschijnlijk helpen om de kosten van congestie voor de markt te verlagen. Dit proefschrift laat zien hoe door de combinatie van redispatch en day-ahead marktclearing niet alleen de sociaaleconomische welvaart kan worden gemaximaliseerd, maar dat activering van eenheden voor redispatch kan helpen het volume van de beschikbare capaciteit voor grensoverschrijdende handel te vergroten.

Kortom, marktharmonisatie en netwerkintegratie ontwikkelen zich snel in de EU, waardoor nieuwe uitdagingen voor het elektriciteitssysteem ontstaan. Dit proefschrift behandelt cruciale uitdagingen waarmee systeembeheerders, regelgevers, beleidsmakers en marktdeelnemers op dit moment op de elektriciteitsmarkten worden geconfronteerd en geeft praktische aanbevelingen voor het verbeteren van het marktontwerp en andere maatregelen om de economische efficiëntie te waarborgen. De ontwikkelde tools bieden nieuwe manieren om de besluitvorming door stakeholders in het energiesysteem te ondersteunen. Ze kunnen gemakkelijk worden aangepast om verschillende vragen te beantwoorden die verband houden met de effecten van veranderingen in het marktontwerp. Een goed voorbeeld van de praktische toepasbaarheid van Elba-ABM is een recente project van de auteur voor de Zweedse transmissiesysteembeheerder, Svenska kraftnät. De auteur heeft Elba-ABM aangepast aan het ontwerp van de Zweedse onbalansmarkt om de invloed van geplande aanpassingen van de markt op het potentieel voor strategisch gedrag te onderzoeken. Deze studie draagt niet alleen bij aan betere stabiliteit van het netwerk door middel van marktontwerp, maar draagt, door de systeemkosten te helpen verlagen, bij tot de algehele economische welvaart en de verwezenlijking van EU-beleidsdoelstellingen. Ten slotte voorziet hij de wetenschappelijke gemeenschap van de inzichten en methodologische knowhow, in het bijzonder op het gebied van agent-gebaseerde modellering en machine learning, voor de studie van talrijke toekomstige vragen op het gebied van het ontwerp van de elektriciteitsmarkt, marktprikkels en marktintegratie. De kwesties die in dit proefschrift worden geanalyseerd, zullen waarschijnlijk de komende jaren hoog op de Europese energieagenda blijven staan. Ik hoop dat dit proefschrift zal dienen als een waardevolle opstap naar een efficiënter elektriciteitssysteem en een efficiëntere elektriciteitsmarkt.

List of abbreviations

aFRR	automatic frequency restoration reserve
AGGR	aggregator
ATC	available transfer capacity
ACER	Agency for Cooperation of European Regulators
BC	balancing capacity
BE	balancing energy
BRP	balance responsible party
BSP	balancing service provider
CACM	Capacity Allocation and Congestion Management
CCGT	combined-cycle gas turbine
CEP	Clean Energy for All Europeans Package
CNE	critical network element
DA	day-ahead
DER	distributed energy resources
DR	demand response
DSO	distribution network operator
Elba-ABM	Agent-Based Model of Electricity balancing
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FBMC	flow-based market coupling
FCR	frequency containment reserve
GCT	gate closure time
GL EB	Regulation establishing a guideline on electricity balancing
GOT	gate opening time
GSK	generation shift key
I-AGGR	independent aggregator
ICT	information and communication technology
ID	intraday
IRD	integrated redispatch
LTN	long-term nomination
MCP	marginal clearing price
mFRR	manual frequency restoration reserve
MP	marginal pricing
NEX	net exchange
NRA	national regulatory authority
NTC	net transfer capacity
PaB	pay-as-bid
PTDF	power transfer distribution factor
RA	remedial action
RAM	remaining available margin
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	renewable energy sources
RL	reinforcement learning
RR	replacement reserve

S	supplier
SD	system dynamics
SDAC	single day-ahead market coupling
TSO	transmission system operator
VPP	virtual power plant
vRES	variable renewable energy sources

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1 Introduction

1.1. Motivation

It is a common observation that the electricity sector is undergoing a revolution driven by massive integration of renewables and emergence of new technologies, actors and business models. However, the transformation of the electricity sector is in fact more akin to a gradual shifting of two tectonic plates: the established practices of the incumbent actors and the political and legislative processes. This fundamental shift has been uprooting and replacing long-established practices. It has led to the entry of numerous new market actors, spurred innovation at an unprecedented degree and produced an increasing number of short-term marketplaces, including ancillary service markets – to name a few.

Short-term flexibility has become one of the most sought-after commodities by market actors looking to maximize profits and consumers looking to reduce their electricity bills. Network operators have been among the forefront of adopters, as they seek to manage new challenges, such as massive integration of variable renewables (vRES) complicating the predictability of power supply or early decommissioning of conventional generation.

The network stability can no longer be taken for granted, pushing the issue of securing sufficient flexibility for ancillary services[1] from a wide range of sources to the foreground of European and national regulatory agendas and development plans [1]–[3]. The focus of this dissertation is on the procurement of two ancillary services: balancing (the service used for frequency support) and redispatch (the service used for congestion management). These services have become essential not only for

[1] Ancillary services are the services used by network operators for maintaining and restoring system stability and security of supply. They include frequency stability (also called system balancing), congestion management, voltage control, black start, etc.

secure network operation but also have an impact on the functioning of the electricity market and the implementation of the Internal Electricity Market in the EU. Availability of flexibility resources is now crucial. This in turn creates new questions about how to procure and value flexibility in a way that promotes access and competition, ensures cost efficiency and prevents distortive incentives for flexibility providers. In order to facilitate the ongoing transformation of the system, a revised market design is needed [4], [5] – one less influenced by large centralized generators than past designs [6], [7]. The first answers have been given through the adoption of the EU Network Codes and the Clean Energy for All Europeans Package. A final answer, however, is far from straightforward – especially given the growing market complexity, interconnection (interdependence) of national networks and markets combined with different stakeholder interests and priorities.

Since the devil is in the detail, this dissertation strives to analyze in detail the ingredients of an efficient market design and associated incentives and bidding strategies of market actors. How can the participation of all types of providers, including small-scale distributed energy resources, in the balancing markets be stimulated? What are the crucial market design variables and their effect on bidding strategies and market efficiency? What can redispatch procurement 'learn' from the balancing markets? How can redispatch contribute to European market integration? These questions are at the core of this dissertation. It uses analytical methods and cutting-edge model-based tools to investigate market participation, design and efficiency. As balancing and redispatching are embedded in the greater electricity market and regulatory landscape, special attention is paid to these temporal and contextual market interdependencies and the relevant regulatory framework.

1.2. Background: evolution of electricity markets and ancillary service provision

If a parallel can be drawn between the human life and the evolution of electricity markets in Europe, the wholesale electricity markets as of the early 2020s are entering their adulthood. The wholesale electricity markets have outgrown the publicly owned, vertically integrated utilities that used to combine all aspects of electricity generation, transport and delivery to the final consumer. The birth of European electricity markets was a result of two main processes, market liberalization and unbundling, which took place in the early 2000s (formalized in the *First and Second Energy Packages* adopted in 1996 and 2003, respectively[2], as is

[2] These Packages include a number of legislative documents, including the most important ones for this discussion:
Directive 96/92/EC of the European Parliament and the Council of 19 December 1996 concerning common rules for the internal market in electricity. (OJ L 27, 30.1.1997, p. 20-29).
Directive 2003/54/EC of the European Parliament and the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC. (OJ L 176, 15.7.2003, p. 37-56)

illustrated in Figure 1.1). A consequence of the former was the introduction of competition on the supply side and the latter resulted in the splitting of electricity supply and transmission. Electricity transmission and distribution remained within the regulated domain, as power networks are natural monopolies. These regulatory changes were accompanied by cross-border cooperation and the implementation of the European Internal Electricity Market; short-term (day-ahead) electricity exchanges that turned electricity into a commodity akin to other energy carriers and financial products.

Electricity has an inherent link to its transportation system, the electricity grid. As electricity cannot be stored economically, properties such as availability to change output or consumption at a short notice, ramp rate (i.e. a unit's activation profile) and duration of activation have value in and of themselves. This is commonly referred to as 'flexibility'. Flexibility has been gaining value, among others, due to the following factors:

1) European countries decided to pursue their commitments to reduce CO_2 emissions by stimulating renewable energy sources (RES);
2) the merit-order effect, that causes near-zero marginal-cost RES to push conventional generation out of the merit order, as a result of which the amount of flexibility, such as system inertia and ramping capacity [2], diminishes.

The second wave of electricity sector transformation was brought about by the EU's *Third Energy Package* in 2009. For the first time, this recognized explicitly the increasing value of flexibility as a result of the increasing share of vRES getting connected to the grid. It also directly addressed and promoted smaller market players and new technologies, recognizing them as potential contributors to system flexibility in the future. It recognized a potential in aggregation of so-called distributed energy resources (DER), such as battery storage, photovoltaic systems, heat pumps or electric vehicles, that were becoming amenable to aggregation and, thus, market participation, thanks to rapid developments in control, management and automation systems. In addition to the forward and day-ahead markets, it became possible to trade in the intraday markets since as early as 2004 in some countries.

The transition from the planned economy of vertically integrated utilities, where transmission and generation could be seamlessly coordinated, to unbundling and competitive markets led, among others, to the establishment of the national balancing markets in the 2010s. These differed significantly in terms of technical requirements and overall market design. Most countries up until recently relied on large conventional generators to provide balancing services, in some cases on a mandatory basis. As the balancing market is going through its experimenting

Regulation (EC) No 1228/2003 of the European Parliament and the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity (OJ L 176, 15.7.2003, p. 1-10).

teenage years, many of the national balancing markets have started to allow a broader spectrum of participants, in part facilitated by aggregators.

The emerging questions about DER and vRES integration and market harmonization provided the impetus for the development of the *EU Network Codes*, which tackle the technical aspects of grid and market operation and which were gradually adopted between the years 2015 and 2018. This is the period when energy system stakeholders recognized that the stability of the network could no longer be taken for granted and therefore the emergence of new technologies and the flexibilization of demand required novel solutions. In this way, the European Network of Transmission System Operators for Electricity (ENTSO-E) and the Agency for Cooperation of European Regulators (ACER) made significant steps towards the harmonization of the European energy sector; Network Codes and Guidelines were finalized as EU regulations and gradually implemented into the national frameworks.

The two most important regulations for this discussion are:

1) *European guideline for electricity balancing (GL EB)* – primarily concerned with the balancing market that established the so-called 'standard balancing products'[3] and
2) *Capacity Allocation and Congestion Management Regulation (CACM).*

In parallel, continuing market integration has led to the development of more advanced cross-border network capacity calculation methodologies; the ultimate goal being greater market integration and creation of benefits to consumers. In 2015, the available transfer capacity (ATC) approach was substituted by a more efficient flow-based market coupling (FBMC) in the countries of Central Western Europe that enabled day-ahead and – since 2018 – also intraday market coupling. FBMC is expected to be implemented in the rest of the region in the coming years in order to optimize the use of interconnector capacity [8].

[3] This dissertation uses standard definitions for all the notions related to balancing and congestion management, as specified in the EU regulatory documents, Network Codes and the Clean Energy Package. Standard balancing products include 1) frequency containment reserve (FCR), automatic and manual frequency restoration reserve (aFRR and mFRR) and (in some countries) replacement reserves (RR).

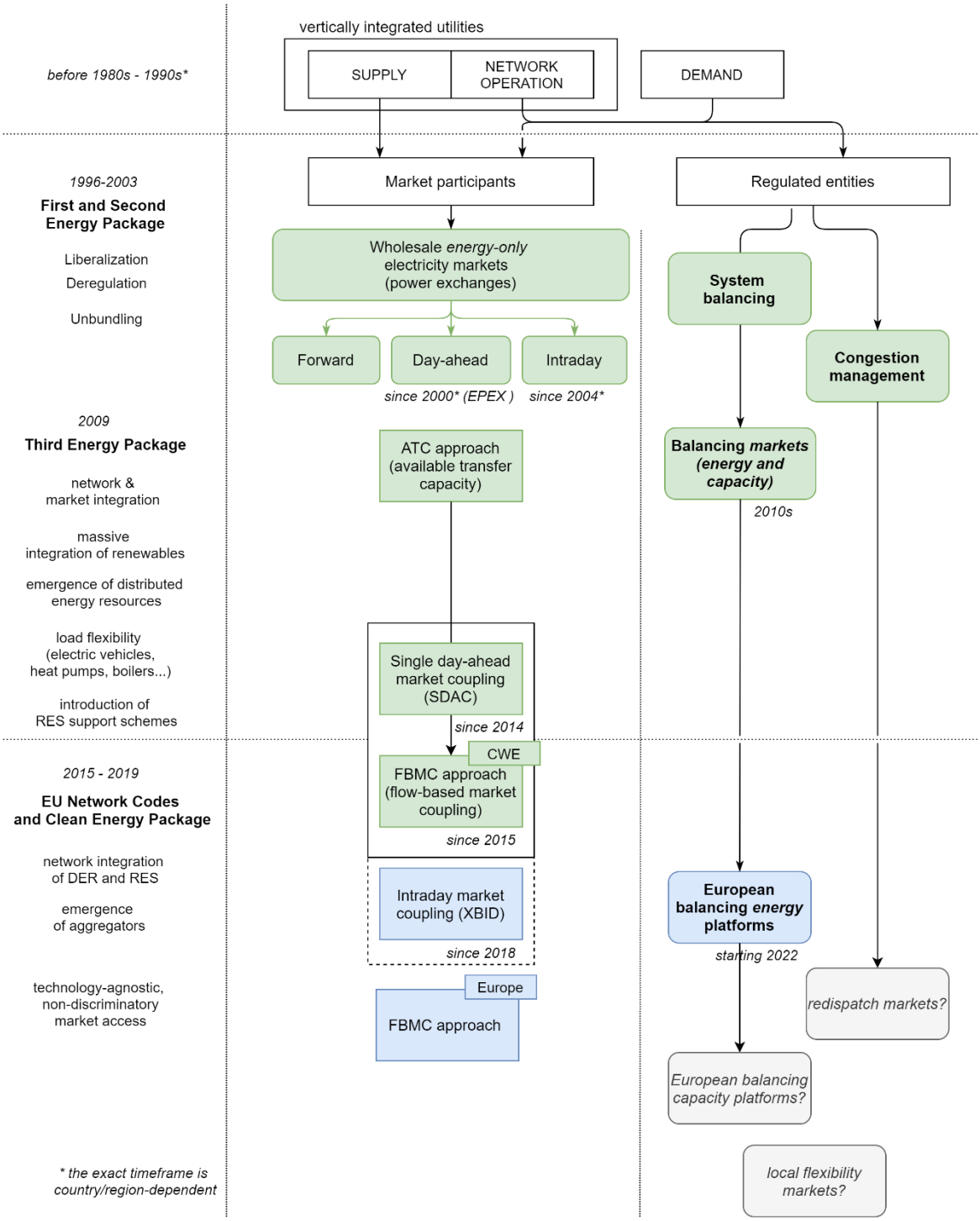

Figure 1.1. Evolution of electricity markets, main regulatory documents and main drivers.

The current wave of changes was spurred by the most ambitious legislative package so far, the *Clean Energy for all Europeans Package (CEP*[4]*)*, adopted in 2018-19. For the first time, the CEP put the consumer at the very center of the energy transition. Its crucial features are:

1) a strong adherence to the principle of technology neutrality and a so-called 'level playing field', meant to put all technologies and market actors on an equal footing [9],
2) a pronounced preference for a market-based approach to the procurement of ancillary services,
3) an obligation on Member States to provide access to all marketplaces for all types of generation or load, irrespective of technology, size, etc.

Point 2 above combined with the challenges facing network operation open the discussion about the design of future marketplaces for flexibility. Although congestion itself is not a new phenomenon, redispatch is still in its infancy, compared to the 'adult' wholesale electricity markets and 'teenage' balancing markets. In particular, it remains to be seen whether market-based redispatch will be universally adopted and if the emerging local flexibility market projects will take hold in Europe.

In sum, a number of steps have been taken at the EU level towards system integration, in order to improve economic efficiency and competition and reduce system costs [5]. Market design adaptations and integration, however, are slow, gradual processes. When it comes to the procurement of ancillary services, considerable differences among EU Member States still exist – as a recent survey conducted by ENTSO-E [10] attests to. In addition, the growing complexity of the market creates new challenges for profit-maximizing market participants as well as network operators. The latter are playing an increasingly important role not only in system operation but also in the European market integration efforts. For these reasons, a study of the procurement of ancillary services, balancing and redispatch, it is important to account for all the aspects of electricity market functioning. In particular, behavioral aspects of market participants influence the market performance irrespective of the traded product, as has been emphasized in [11]. An investigation is urgently needed to identify ways of securing the flexibility potential, increasing market efficiency and designing measures to mitigate market power in ancillary service markets. Such an analysis of market design requires a three-fold approach – learning from the past as well as from the best practices in other markets, studying the interdependencies between marketplaces and addressing the three main driving forces of market design, 1) policy and regulation, 2) changing stakeholder behavior and 3) the physics of electricity production and transportation.

[4] This package presents a compendium of communications, directives and regulations that was proposed by the European Commission substituted the Third Energy Package: http://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:52016DC0860

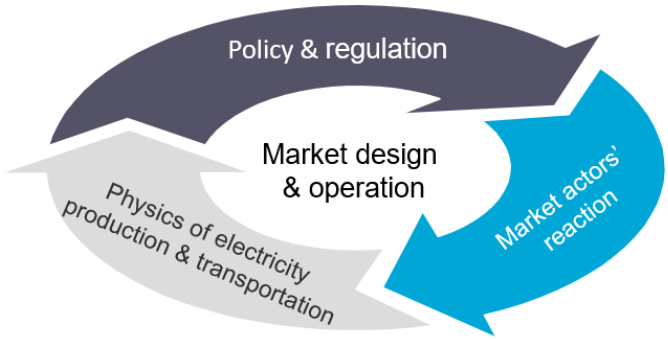

Figure 1.2. Driving forces of market design and operation.

Multiple feedback loops exist between these elements e.g., rapid and far-reaching regulatory changes alter the behavior of market participants or network challenges, which creates impetus for the changes in the regulation (Figure 1.2). These increase the complexity of system and market operation. Of particular concern is inefficient market design as it exposes markets to the risk of producing higher system costs and reduced social welfare due to low competition or susceptibility to strategic bidding.

Finally, it is an essential task of research to provide a disinterested perspective into the measures for improving market design and the overall efficiency of ancillary service procurement. It is particularly important since different electricity system stakeholders pursue different, potentially competing, interests and priorities whereas different countries in Europe have very distinct energy mixes and different pathways of market development. Without a well-researched and tested toolbox of improvements, European efforts risk inefficiencies and ad-hoc interventions in the market with detrimental results for consumers and the system at large.

1.3. Problem description and research objectives

The two main responsibilities of transmission system operators (TSOs) are 1) safeguarding operational system security by compensating real-time imbalances between generation and consumption and 2) providing transfer capacity to transport electricity from supply to demand. The former is achieved through system balancing whereas the TSO uses a number of remedial actions[5], including redispatch, for the latter. TSOs are challenged by technical constraints such as limited possibilities for

[5] Redispatch or the change of plant dispatch after the market clearing belongs to so-called 'costly remedial actions'. To alleviate congestion, the TSO can also recur to 'non-costly remedial actions', such as changing the tap position of phase-shifting transformers. Finally, some countries, such as Italy and the Nordic region, use splitting of the bidding zones within individual countries, resulting in different market prices. The reader is invited to see further details about the fundamentals of congestion management in Chapters 7 and 8 of this dissertation.

grid reinforcement and the rapid system transformation due to the integration of vRES and distributed resources. At the same time, they need to conform with the overall policy objectives as well as with the existing regulatory framework, which requires cost-efficient and market-based procurement of ancillary services, at least since the adoption of the EU Network Codes and the CEP.

For the following reasons, now is a crucial moment in time to analyze the two ancillary services:

- there is growing pressure on the grid to offset increasing residual load volatility with large volumes of fast-reacting balancing resources;
- the planned substantial balancing market design changes and integration in 2017-2022;
- the increasing magnitude and frequency of internal and cross-border congestion is requiring higher volumes of redispatch;
- the progressing European electricity market integration and the intensifying cooperation in the area of congestion management;
- the fact that the costs of redispatch and balancing are fully or partially socialized among all grid users increases the social relevance.

Considering the above, the main research question that is addressed is:

How can market design changes help transmission system operators procure balancing and redispatch services in a more economically efficient manner?

With market design, we refer to all the rules and mechanisms that guide and structure the behavior of market participants. This not only includes the configuration of the marketplace but also the regulatory and technical requirements placed upon the participants. The last point is particularly relevant for ancillary services as the units providing them are subject to technical prequalification, including requirements to the communication infrastructure and the speed and duration of activation. Among the objectives of research on market design, researchers and policy-makers cite the inclusion of all technologically capable participants [12], creation of the "right" incentives [13] and accounting for "policy-relevant tradeoffs with practical consequences" [14]. Regulation often faces a so-called 'pacing problem' i.e., being unable to keep pace with the technological innovation. As a result, existing market rules may not be designed in a way that different, especially new technologies or new market entrants, can comply with. Once different actors can enter the market, it is important to ensure that the incentives created by market design are aligned with socio-political objectives, such as maximization of economic efficiency and welfare. Finally, in complex multi-stakeholder systems, such as the electricity sector, market actors, policymakers but also different Member States pursue different interests and priorities and it is *de facto* impossible to accommodate all of them to the same extent, making tradeoffs inevitable.

European balancing markets have been characterized by high degrees of concentration, resulting from strict technical prequalification requirements and market rules originally designed with large power plants in mind. This made them prone to strategic bidding, which is defined as a kind of behavior when a market actor exploits market vulnerabilities or inefficiencies by placing non-competitive bids. One of the ways to deal with market power and strategic behavior is by expanding the pool of available resources whereas another way is to improve market design. Our analysis of these two aspects starts out with determining the measures that can contribute to making the balancing market more friendly towards all types of providers, including in particular distributed energy resources (DER) and aggregators as main enablers of DER. This helps to understand and structure the market design space with its high degree of complexity and numerous design options. The focus is then shifted towards strategic behavior and, using a simulation model of the balancing market, the author analyzed ways to mitigate market power – even in the absence of new market actors, such as DERs. The complex market structure, interdependencies with other marketplaces and heterogeneous bidders with different strategies make the potential of qualitative analysis limited. While useful to set the foundation for a more detailed analysis, it is complemented with market modelling and simulation to answer the posed research question.

Redispatch has become a challenge in European electricity networks more recently than balancing, since some national grids could no longer efficiently accommodate the growing shares of variable RES. This issue is growing in complexity due to cross-border electricity market and grid integration, which created additional effects such as loop flows on neighboring countries, turning redispatch into a pan-European issue. In contrast, the solution to congestion is highly localized i.e., only a few assets close to the congestion point can solve it efficiently. This creates concerns about inherent market power of redispatch providers and influences the procurement method. Considering that redispatch, unlike balancing, has generally no markets to speak of, valuable lessons can be learned by comparing the design of the two services. Following that, we analyze the ways in which the procurement methods of the two services affect the bidding behavior. Finally, we propose a method for the procurement of resources for redispatch that allows to both reduce overall system costs and contribute to electricity market integration by increasing cross-border flows.

Although there is a long history of electricity market design analysis, the attention was centered largely on wholesale electricity markets (see Figure 1.1). Balancing markets have only more recently been receiving increasing scientific attention, especially in the past five years (Figure 1.3) but most of it is centered on profit-maximizing actor strategies (e.g. [15]; [16], [17]; [18]; [19]) as opposed to the market design perspective. National design differences caused most research to be focused on individual countries, especially Germany (e.g. [19]–[21]). Due to its recency, little research was focused on the issue of harmonization of balancing markets. There is no adequate analysis of the potential effects of the planned market

design changes, as per GL EB, especially given the propensity towards strategic behavior. In this context, ABM coupled with machine learning for modelling complex bidding strategies is a new but particularly promising method for simulating the effects of policy changes (see also Section 1.4). Furthermore, there is an insufficient body of recent research concerning congestion management and redispatch (Figure 1.3) that takes the most recent state of regulation and market integration into account.

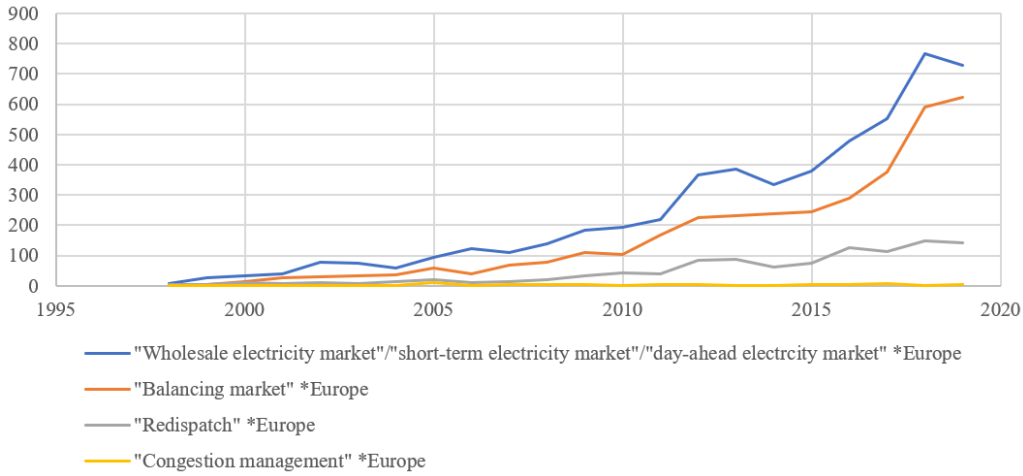

Figure 1.3. Number of publications by search term in text. Based on Google Scholar as of August 2020.

Rather than providing a clear and detailed pathway, the European Balancing Guideline and the Network Code on Capacity Allocation and Congestion Management set the general direction with regard to balancing and congestion management. Their implementation depends on the methodologies that the TSOs propose and that need to be approved by the national regulatory authorities (NRAs) and/or ACER. While many questions remain about feasible and cost-efficient solutions and while these solutions are subject to intense debate[6], many of their provisions are expected to be implemented in the upcoming years. This creates a special impetus for investigating the implications of the upcoming regulatory changes, in particular their effects on the bidding strategies of market actors, market harmonization and overall market and system efficiency.

Given the knowledge gaps described above, the intention of this dissertation is to tackle the complexity of regulation-actor-grid interaction (Figure 1.2) by answering

[6] Some prime examples of the recent debates originate in Germany, e.g. concerning the viability of market-based redispatch (see Chapter 7 for more detail) and whether bidders in the balancing market should be awarded based on the capacity price alone (see Chapter 6 for further details), which even led to a court case.

the following sub-questions:

1. *How can balancing market design be improved to stimulate the entry of new participants and technologies?*

2. *What are the main factors that influence the bidding strategies in the balancing capacity and energy markets?*

3. *What is the effect of changes to balancing energy market design on strategic bidding and market efficiency?*

4. *How are flexibility providers' interrelated bidding strategies in the balancing market affected by the introduction of voluntary bids?*

5. *How can the combined efficiency of balancing and redispatch procurement be improved considering links and potential conflicts between them?*

6. *How can redispatching be used to maximize cross-border exchanges in a flow-based market coupling regime?*

In the first part of this research (questions 1-4), we study different aspects of balancing market design. **Research question 1** is motivated by the need to find ways to effectively integrate all kinds of providers, including small-scale DER, into balancing markets since securing sufficient flexibility potential is one of the main challenges for a TSO. We analyze measures that can be undertaken to expand the pool of balancing resources and the governance issues that new market entrants face. These markets differ significantly from country to country and from product to product. With the adoption of the GL EB, the vision of product-wise harmonized European balancing markets has been created. To understand how, in these changing complex conditions, balancing markets can be made more amendable to the participation of different technologies, in particular DER, it is necessary to first structure the design space. We show in what ways market participation is contingent on market access requirements, contractual relations among actors involved and the auction design itself [7]. These are the main focus areas of **research question 1.**

Research question 2 zooms in on the ways in which the auction design determines the incentives and, ergo, the strategies of market participants. They are also affected by the existence of related marketplaces and the opportunity costs of not trading there in favor of the balancing market. The effects of market rules and interactions with other short-term markets are studied using theoretical bidding calculus.

The analytical framework elaborated under research question 1 and the theoretical analysis of bidding strategies in the interrelated markets studied under research question 2 provide the foundation for the development of an agent-based model, Elba-ABM (agent-based model of Electricity Balancing), which is used to study the

complex bidding strategies of balancing service providers (BSPs) and to answer **research questions 3 and 4**. In particular, we analyze the planned changes of the balancing market design prescribed by the GL EB, in particular the introduction of a standalone balancing energy market and of voluntary bids as those were identified as important drivers of market efficiency. Using machine learning, we are able to provide an insight into the effect these changes might have on the potential for strategic bidding.

In the second part of this research (questions 5-6), we focus on the approaches to the procurement of redispatch. The procurement of balancing services constitutes a maturing market, thus, by answering the previous research questions, useful lessons can be drawn from them in order to analyze the current and future procurement of redispatch. At the same time, the author seeks to clarify some of the confusion related to redispatch, some of it stemming from its apparent similarity to balancing. In **research question 5,** we compare the two services and analyze the implications the different procurement methods for redispatch might have on actors' incentives. As redispatch and its consequences are no longer an issue of individual states, we dedicate the last **research question 6** to the issue of market integration and how efficient redispatch procurement can contribute to it. For this, Central Western Europe was chosen as a region with a high level of integration thanks to the use of a so-called flow-based market coupling approach.

The next paragraphs briefly describe the content of each chapter of this dissertation in relation to the research questions:

1. *How can balancing market design be improved to stimulate the entry of new participants and technologies?*

In **Chapter 2**, we provide recommendations for improving balancing market rules that would facilitate expansion of the pool of BSPs. The developed assessment framework helps us to 1) facilitate comparability of different market designs 2) evaluate their alignment with GL EB's prescriptions and 3) determine the pathway from the current to the desired state/design by prioritizing different design variables. It also serves the purpose of laying the groundwork for the model in Chapters 5 and 6.

In **Chapter 3**, we analyze market access requirements for aggregators as key enablers of DER to participate in the balancing market using case studies from Austria, Germany and the Netherlands. An integral part of this discussion is the governance, i.e. the definition of the roles of different participants, suppliers, aggregators and balance responsible parties (BRPs)[7], their relations and respective

[7] In broad terms, the BRP is responsible for the balance within its portfolio that may include generation, loads or both and for issuing regular schedules of planned generation and consumption. The main goal of a BRP consists in avoiding imbalance charges that are routinely applied by the TSOs and correspond to a BRP's schedule deviations in a given imbalance settlement period.

responsibilities. It sheds light on the relevance of the requirements placed on portfolios and BSPs' relations with other market participants using several analytical models of actor cooperation.

2. *What are the main factors influencing the bidding strategies in the balancing capacity and energy markets?*

In **Chapter 4**, the effects of incentives, cost structures and bidding strategies of market actors, given their involvement in related markets, are analyzed. Indeed, balancing markets do not exist in isolation; by participating in them, BSPs face opportunity costs meaning their actions in one market will depend on their actions in other markets. Understandably, changing market design variables (for instance, the pricing mechanism) will influence the incentive structures of market participants and, consequently, their bidding behavior. The outcome of this research is the improved understanding of the cost structures of BSPs in the balancing markets and how upcoming regulatory changes alter their optimal bidding strategies. This analysis helps to define agent strategies in the subsequent model-based studies.

3. *What is the effect of the design changes of the balancing energy market on strategic bidding and market efficiency?*

In **Chapter 5**, we focus on the modelling of balancing *energy* procurement and compare the efficiency gains from the introduction of a standalone short-term balancing energy market as opposed to a common balancing capacity and energy market. The most important design variables identified in Chapter 2 are simulated using scenarios with different actor numbers, portfolios and bidding strategies. Machine learning techniques are implemented to evaluate the exposure of different market design to strategic bidding. It is deployed to explore the feedback loop between the changes of market design, resulting bidding strategies and their effect on market performance. It further compares the market clearing with pay-as-bid versus marginal pricing rules. The results are contrasted based on the agents' profits, market prices and system costs and valuable insights are derived about the effect of upcoming design changes.

4. *How are flexibility providers' interrelated bidding strategies in the balancing market affected by the introduction of voluntary bids?*

In **Chapter 6**, we further expand Elba-ABM to include a detailed model of the balancing *capacity* market and develop a collaborative machine learning algorithm that takes the bidding strategies in the two markets and their positive and negative directions into account. The chapter analyzes the introduction of voluntary bids i.e., bids not previously awarded in the balancing capacity markets, as one of the key measures to increase market competitiveness. It investigates the effect of such on both markets and reveals the complex interdependencies between market design, competition levels, repeated auctions and bidder strategies. Finally, it analyzes the

policy implications of the planned changes.

5. *How can the combined efficiency of balancing and redispatch procurement be improved considering links and potential conflicts between them?*

In **Chapter 7**, the fundamental links and possible conflicts between the two services potentially competing for the same short-term flexibility are analyzed. Country studies from Germany, France and the Netherlands as well as the recent relevant EU regulation help to assess different procurement options and their effect on the behavior of market participants. It provides some solutions to how their joint efficiency can be improved, considering the planned introduction of EU balancing energy platforms. Since there is no fully-fledged or harmonized redispatch market, first steps are taken to open the discussion of the optimal procurement of redispatch.

6. *How can redispatching be used to maximize cross-border exchanges in a flow-based market coupling regime?*

In **Chapter 8**, we get away from the common market-based versus cost-based dichotomy discussed in Chapter 7 by placing the discussion of redispatch procurement in the broader context of integrated electricity markets. Using an optimization approach, we demonstrate the efficiency gains that can be achieved through integrating redispatch in the day-ahead market coupling as a way to facilitate cross-border exchanges and reduce redispatch costs.

1.4. Approach and methodology

This dissertation combines qualitative analytical and quantitative model-based approaches. The former is used to develop a market analysis framework and interaction models between actors and/or markets. The latter is deployed to analyze complex interactions and quantify the effects of different design variables and approaches to ancillary service procurement.

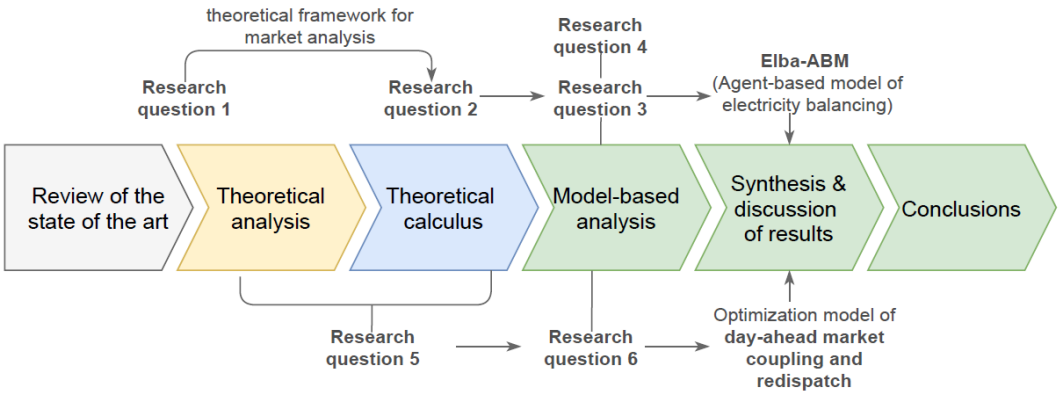

Figure 1.4. General research approach used in this dissertation.

The general approach follows the steps illustrated in the diagram in Figure 1.4 below. It includes two consecutive parts, the first one focused on balancing and the second one, building upon the analysis of the first tier, - on the procurement of redispatch (see Figure 1.4).

The first step consists in laying the groundwork for market analysis and mapping the relevant design space for the simulation models. The author develops a framework that provides a typology of the major market design variables in the EU. It is based on an empirical analysis of selected balancing markets, including current regulatory and policy developments on the national and supranational levels. The author compares the designs in the case studies to the requirements set in the GL EB and proposes a way to prioritize design variables in order to make market design more efficient and avoid possible negative effects, such as one variable neutralizing the effect of another one. The outcomes of the qualitative analysis are the theoretical framework for market analysis (Research question 1, Chapter 2) and the theoretical models of actor interaction in the balancing market (Chapter 3). The effect of the market design on the bidding strategies of market participants is first analyzed with the help of theoretical calculus (Research question 2, Chapter 4) and subsequently with an agent-based model of a balancing market. The model, called Elba-ABM, is developed by the author (Research question 3, Chapter 5 and research question 4, Chapter 6). The intention of the model is not to be as numerically precise as possible or in re-creating reality; rather, it is designed as a stylized model of reality that is capable of capturing the essential market dynamics, making it possible to analyze agent behavior with a high level of definition, such as hour-to-hour changes in the bidding behavior over an entire year.

Building upon the insights from the balancing market analysis, the second part of the research in this dissertation is extended to the analysis of redispatch; first, from the point of view of its relations with balancing and their joint efficiency (Research question 5, Chapter 7) and, second, from the perspective of the overall market and system efficiency (Research question 6, Chapter 8). Since the discussion on an efficient procurement of redispatch services is still very much in its infancy, an optimization approach is used to evaluate the overall system efficiency. The author decided against using an agent-based approach at this stage since the combined simulation of actors, the market and the grid would have been too complex to ensure that we can trace the dependencies in the model and obtain generalizable results. Optimization is then the first necessary step to understand the interactions between flow-based market coupling and redispatch and to propose measures to improve redispatch procurement as part of the market integration process. Strategic behavior in redispatch is briefly addressed for the sake of completeness but is out of the scope of this dissertation.

This combined approach is envisaged to provide insight into the functioning of the balancing market, possible coordination of redispatch with balancing and other short-term markets and a comprehensive support tool for decision-making.

1.4.1. Methodological approaches to modeling electricity markets

Electricity markets are characterized by dynamic behavior and heterogeneous participants with different goals and interests that are connected by a complex network of relations. Thus they are a prime example of a complex adaptive system [22]. In such systems, the overall results do not depend on the behavior of the participants alone. In such systems, the overall results are a function of the complex interactions between the behavior of market participants, which, in the case of electricity markets, is shaped by market relations, technical constraints and opportunities, regulation and social aspects [23], [24]. A variety of methods have been used for market analysis, such as optimization, game theory, system dynamics and agent-based modelling. Each of them has their distinct benefits and limitations, causing their suitability to depend on the type of the research question at hand. A brief discussion of each serves highlights under which conditions each method is more appropriate.

Optimization has been commonly used to identify the profit-maximizing strategies of participants in one or several markets. Total market or system costs can also be minimized using optimization. This approach is appropriate for competitive markets, such as the day-ahead market [25], given the assumption of perfect competition and information of market participants. It has been shown to be a useful tool for testing new approaches to system or market operation. However, questions contradicting the assumption mentioned above, such as the possibility of strategic non-competitive bidding, or details of market design cannot be reliably studied using this approach.

System dynamics (SD) is also used for simulating electricity markets. It does not allow direct representation of individual agents and their differences but is rather based on causal relations between variables and feedback loops [26]. It is also possible to use SD to model dynamic processes, however, it is more difficult to incorporate learning effects into such a model as agents are only present in the aggregate [23]. As far as the methodology is concerned, the decision of the type of modeling approach is therefore also linked to the question of how significant the weight of individual action is for the overall outcome.

Game theory can be used to obtain an insight in the theoretically optimal bidding strategies of market actors. For instance, as the authors in [27] show, game theory can be used to give a regulator an idea of how far the theoretical outcome is different from the empirical evidence and recognize trends. It assumes perfectly rational actors and is primarily concerned with finding the equilibrium strategy for the players involved. On the other hand, due to its mathematical complexity, it is notoriously difficult to handle real world complexity, such as heterogenous actors, multiple-unit portfolios and multi-stage games, using game theoretical approaches. Game theory does, however, provide an excellent basis for model-based analysis and agent

calibration that in part underpins the work presented for this dissertation.

Agent-based modeling (ABM) is well-suited for providing a more true-to-life representation of complex adaptive systems, according to [22]. Several types of markets have been simulated using ABM, including markets for commodities, financial assets and stocks as well as electricity markets (e.g. [28], [29]). In the context of electricity markets, ABM has been successfully implemented to study strategic bidding (e.g. [19], [30]), market power and various aspects of market design [31]. A comprehensive literature survey of ABM applied in the area of electricity markets can be found in [32]. Researchers in [33] and [34] provide an extensive overview of ABM efforts and the areas in the investigation of electricity markets.

ABM is an efficient tool for capturing market complexity and actor heterogeneity. When used for electricity markets, it can be employed to reflect the fact that agents are involved in a continuous interaction process, characterized by multiple bidding rounds, as compared to game-theoretical analyses of one-off games. The agents' pursuit of their goals is "encoded" in their behavior, which simulates decision-making processes that differ among the heterogenous agents. This is a particular advantage vis-à-vis the top-down SD approach when trying to understand the impact of market rules on real-life behavior. An additional advantage of ABM is the flexible formulation, which makes it amenable to combinations with other approaches e.g., machine learning. In this way, an agent-based approach makes it possible to account for the behavior of multiple actors and their reactions to market opportunities and incentives [26] as well as effects of policy changes considering adaptive behaviors of participants [11], [35].

1.4.2. Modelling methods used in this dissertation

Given the arguments presented in Sub-section 1.4.1 and the research questions stated in Section 1.2, ABM was chosen for the study of the balancing market while optimization is used for the analysis of redispatch and the day-ahead market coupling. The methods are described in detail in Chapters 5-6 and Chapter 8, respectively.

Optimization-based approaches, which are often based on assumptions of perfect competition and foresight, are commonly used in a normative manner e.g., to establish a benchmark for ideal performance or to calculate optimal technology investments. While they provide a fair approximation of the performance of competitive, liquid markets, such as day-ahead electricity markets, these assumptions can significantly distort the results of analysis of oligopolistic markets (such as balancing power markets, see Chapters 2 and 5 for more details). Other methods need to be used to adequately address questions that concern the behavior of actors in the presence of imperfect competition and a market design that is too complex to analyze with game theory. For this type of questions, the author of this

dissertation chose agent-based modeling, based on the arguments in Sub-section 1.4.1.

In Elba-ABM, a discrete single-sided auction is implemented in great detail (see class structure of Elba-ABM in Appendix A), simulating the participation of BSPs in the balancing market using different biding strategies. It allows to trace the evolution of agent behavior given changes in regulation and market design. Oligopolistic markets, like most balancing markets, are prone to strategic bidding behavior. Learning agents that adjust their strategies based on experience were introduced to assess the effect of the most important market design variables that were identified under research question 1 on bidding behavior. Elba-ABM was complemented with reinforcement learning algorithms to explore ways in which the balancing market design can be adapted to better align actors' incentives with the overall system objectives and to derive corresponding policy implications.

Balancing markets are characterized by a complex structure that includes markets for capacity and energy in positive and negative directions i.e., for upward and downward regulation. This creates additional challenges for formulating the reinforcement learning algorithm that represents the interdependencies between these four products. For the first time, a collaborative machine learning algorithm is developed in this dissertation that models interdependent bidding strategies of a market actor in the positive and negative balancing capacity and energy markets. This provides valuable insights in the strategy dependencies in different marketplaces driven by the market design such as the use of different pricing rules and the introduction of voluntary bids, as per the European Balancing Guideline. To the author's knowledge, this is also the first application of machine learning to strategic behavior in multiple interdependent markets.

Optimization is used for the second tier of this research, the analysis of cross-border congestion management, for two reasons. First, because there are no well-established redispatch markets yet (see also Section 1.2), their analysis requires a different approach that is less focused on individual design variables and more on the overall market performance. Specifically, when a market still needs to be designed, optimization helps compare different options under ideal circumstances. Studying such issues as strategic bidding then is a deviation from the optimum and is a second level of analysis that was deemed out of scope of this dissertation. As pointed out earlier, optimization is also useful to limit model complexity in comparison to ABM. In this dissertation it is used in order to identify a cost-efficient approach to redispatch and day-ahead market combined. A series of multi-step optimization models was developed to model the three stages of market coupling, the Base Case, the day-ahead market coupling itself and the *ex post* redispatch. The approach allows to accommodate different grid resolutions, to flexibly model both the power grid and the market and to combine the two in each optimization step. The business-as-usual approach used in zonal markets with flow-based market coupling is contrasted with the outcome of the nodal market and the proposed

approach integrating preventive redispatch into the market coupling process. The author, however, recognizes that the issue of strategic bidding in redispatch should be analyzed in more detail in the future and the work presented in Chapter 8 opens the potential for future research on congestion management using ABM.

For a more detailed discussion of the modelling methods used in this dissertation, the reader is referred to Chapters 5, 6 and 8.

1.5. Scientific contribution

The contributions of this dissertation cover both content-related and methodological aspects.

1.5.1. Content-related contributions

a) **Design and performance of ancillary service markets:** This dissertation advances the overall understanding of electricity market design, its evolution as well as related energy policy and regulation. Its discussion is placed in the broader European context considering its past, present and to-be-implemented regulation. This dissertation helps to make sense of the growing market complexity and interdependencies between different established and emerging marketplaces. An assessment framework is proposed with regard to balancing market design in order to evaluate its alignment with the latest state of regulation, facilitate roadmap development and serve as a basis for simulation. Additionally, the assessment framework can be used for the analysis of further ancillary service markets and provides a significant help in future modelling of electricity markets. Furthermore, the modelling tools developed in this dissertation enable the study of the elements of efficient ancillary service markets, balancing and redispatch, their relations and ways of improving overall system and market efficiency. The results have been translated into specific policy recommendations.

b) **Bidding strategies in interrelated markets:** This dissertation synthesizes the existing body of research on bidding strategies in short-term electricity markets and builds upon it to obtain new insights into the implications of policy changes for biddings behavior in the balancing market. This analysis is enabled by advanced modelling and simulation techniques that allowed, among others, to emulate strategic bidding behavior, identify potential implications and risks of design changes. This work advances the discussion of bidding incentives and interrelations between bidding strategies in sequential marketplaces, namely the balancing capacity market, the day-ahead market and the balancing energy market. It improves the understanding and

implications of complex actor interactions and their consequences for energy sector regulation and market efficiency and proposes concrete measures to improve balancing markets by preempting non-competitive practices.

c) **Redispatch in the context of European market integration:** As compared to balancing, redispatch has received limited scientific attention due to its lower relevance in the past and current lack of data and transparency. This dissertation clarifies the relations and differences between balancing and redispatch and proposes measures for improving the efficiency of redispatch procurement in Europe, given both its growing system relevance and ongoing debate on the subject. To the author's knowledge, this is the first model-based analysis of redispatch in the context of flow-based market coupling. A novel method is proposed that combines redispatch with flow-based market coupling using multi-step optimization. We demonstrate how units used for redispatch can contribute to increasing cross-border exchanges. Thus, besides improving the efficiency of redispatch, for the first time, it contributes to European market integration.

1.5.2. Methodological contributions

a) **Purpose-specific detailed models of ancillary service provision:** In this dissertation, different methodological approaches, agent-based modelling, machine learning and optimization are used to answer questions about market design and market efficiency. It is demonstrated how different methods can help solve different research questions depending, for instance, on whether the research question concerns fundamental market design choices or the details of incentives that affect strategic behavior. Careful consideration should be given to the type of the problem or research question at hand. Electricity market optimization remains an important tool for studying market operation and its impact on suppliers and consumers. It is also useful for understanding the potential of a new approach. This dissertation contributes to the development of optimization techniques for modelling flow-based market coupling and redispatch. However, some of the assumptions made in optimization create limitations for its applicability to more specific questions regarding market design and actor behavior e.g., strategic bidding. For these questions, agent-based modelling is more appropriate and therefore used in this dissertation. This dissertation is also one of the very few research endeavors that combines ABM with machine-learning to study balancing markets.

b) **Development of optimization models for redispatch and flow-based market coupling:** This work contributes to the development of novel approaches to study flow-based market coupling together with different approaches to redispatch. To the authors knowledge, it is the

first study combining the optimization of both market coupling and redispatch. The use of multi-step optimization is demonstrated for the study of ways to maximize the efficiency of redispatching in combination with day-ahead market coupling.

c) **New applications of agent-based modelling:** This dissertation applies ABM to simulate and analyze the behavior of market actors in response to market design choices. Building upon the existing know-how in agent-based modeling of electricity markets, this dissertation presents a Python-based model, called Elba-ABM, to study how particular market design choices may affect the bidding behavior of market actors and the performance of interrelated markets. The modeled market designs anticipate upcoming regulatory changes in the EU.

d) **Novel algorithms using reinforcement learning:** The learning algorithms developed in this dissertation allow to model bidding behavior in electricity balancing markets. This dissertation illustrates the value of machine learning as an enhancement of ABM, in particular in modelling strategic bidding behavior. It is achieved by incorporating learning agents into the market environment consisting of interrelated balancing capacity and balancing energy markets. Of particular methodological value is the novel collaborative machine learning algorithm developed to model the interrelations of bidding strategies in the balancing capacity and balancing energy markets.

This dissertation addresses the issues that system operators, regulators, policymakers and market participants face in the electricity markets today. The developed tools support decision making by energy system stakeholders. It also provides the scientific community with insights and methodology for studying the numerous open questions in the area of electricity market design, bidding incentives and market integration. The broader implications of this research for electricity markets and policy are discussed in Chapter 9. The outcomes of the empirical and analytical studies as well as from the simulation results are translated into concrete recommendations for the improvement of market efficiency, actor involvement and promoting EU policy objectives are summarized in Chapter 10.

2

How can balancing market design be improved to stimulate the entry of new participants and technologies?[8]

Thanks to new technological advancements and EU policy impulse, distributed energy resources (DER) are poised to become a viable alternative to conventional generation for the provision of balancing services to transmission system operators. In this paper we show that the design variables that may affect DER access to and participation in the organized balancing market include different features of auction configuration as well as a number of formal, administrative and technical aspects of market design. These, however, do not necessarily encourage DER integration. Using a comparative case study of the balancing markets in Austria, Germany and the Netherlands, we determine the extent to which a given market design effectively facilitates DER participation. To structure this analysis the authors designed an assessment framework providing a comprehensive tool for decision-makers for the assessment of balancing markets in Europe vis-à-vis DER participation. Results show that flexible pooling conditions, higher bidding frequency and product resolution together with the authorization of non-precontracted bids, among others, can significantly ease DER integration in the market. Achievement of EU policy goals requires further adjustments of market design, these, however, need to consider the enhancing and neutralizing effects of individual design variables.

[8] This chapter has been published as Poplavskaya, K., De Vries, L., Distributed energy resources and the organized balancing market: A symbiosis yet? Case of three European balancing markets. Energy Policy, 2019. 126: 264–276.

2.1. Introduction

The increasing availability and decreasing costs of distributed energy resources (DER) raise the question of how these resources can effectively contribute to achieving such policy goals as consumer empowerment and market efficiency. DER refer to small-scale units, including variable renewable energy resources (vRES), wind turbines and photovoltaics, and other distributed generation as well as storage and demand response connected to the distribution network.

The main task of the transmission system operator (TSO) is to preserve balance between energy supply and demand at all times. In the synchronous area of Continental Europe, the TSO maintains stable frequency levels at 50 Hz by regulating energy infeed or withdrawal. Under the current electricity market deregulation provisions, balancing services preferably have to be procured in a market-based way [36]. In the balancing auction, the TSO acts as a single buyer and procures capacity to guarantee that enough reserves are committed and activates balancing energy in case of actual frequency deviations. The three standard balancing products [37] (Art. 2(28)) include frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR), which are activated successively and differ according to the speed and duration of activation. These can be deployed either to increase generation or reduce load if the system is undersupplied or vice versa if the system is oversupplied. Balancing service providers (BSPs) are then remunerated either for capacity alone or for capacity and energy delivered.

In the evolving power system, the available capacity of traditional BSPs, conventional generators, has been dwindling [38] while more vRES with limited predictability have been integrated in the energy system, which increases the complexity of system balancing. Furthermore, balancing markets are often not fully liberalized and highly concentrated [39]–[41]. Thanks to technological advances, new actors and emerging DER capable of balancing service provision can help to boost competition, reduce overall balancing costs, and provide the needed flexibility for efficient vRES integration. Creating appropriate incentives for all market participants remains a challenge and requires a careful rethink of current market design.

In the view of the described developments, we set an objective to address the question of whether current balancing market rules sufficiently facilitate the adoption of DER for system balancing, as encouraged by the EU policy and regulation, and the ways in which market design can be improved.

To provide a comprehensive answer to this question we first describe the general principles of the balancing market in the EU and identify all market design variables relevant for DER integration in Section 2.3. These feed into an assessment framework, which structures the evaluation for a specific balancing market to deepen the understanding of the requirements placed on balancing resources as well as its

alignment with the EU policy objectives and regulatory framework[9]. A comparative analysis of the balancing markets in Austria, Germany and the Netherlands is used for the case study presented in Section 2.4. In Section 2.5 we analyze the results of the case study focusing on the way the suggested adjustments can lead to a greater integration of DER and improve the functioning of the balancing market from the point of view of non-discrimination and economic efficiency. We then sum up the lessons learned from the case study identifying positive developments and potential barriers for DER. Finally, in Section 2.6 we review the key differences in the balancing markets in the three countries and provide overall conclusions and policy implications.

2.2. Literature review

Large differences in national balancing market designs are still observed among EU countries, as was shown in a survey by the European Network of Transmission System Operators for Electricity [42]. This heterogeneity stems from their historical developments, generation mixes and cross-border interconnections. In the face of these differences, the question of an optimal balancing market design has been raised in previous research (e.g. [13], [43]–[45] and [46]). Van der Veen in [47] provided a comprehensive and systematic overview of available design variables in the balancing market. Building upon it, the authors in [13] discussed the tradeoffs and synergies among the identified performance criteria and the uncertainty associated with the choice of design settings. In their work, researchers [48] pioneered the assessment of the balancing market from the point of view of access facilitation for distributed sources of flexibility. The authors proposed a modular framework and identified some barriers to entry for DER and existing best practices, focusing mainly on the integration of electric vehicles for FCR and aFRR. The modules included rules toward the aggregation of DERs, rules defining the products on the market and the payment scheme of grid services [48].

On the other hand, the future significance of DER has been widely recognized. Researchers, EU policy-makers, the industry and EU-funded projects call for creating such conditions so as to enable system operators and market actors to extract maximum value from DER for system services and market participation (e.g. [49]–[51]). The recently adopted Commission Regulation establishing a guideline on electricity balancing (GL EB) emphasizes market-based procurement of balancing services without "undue barriers to entry for new entrants" [37] (Art. 3.1 (e)). It explicitly refers to enabling aggregated DER, including vRES and storage facilities to participate in ancillary service provision (Art. 3.1 (f, g)). The Clean Energy for All

9 This paper presents the state of regulation as of beginning of 2018. The ongoing changes in the European and national regulatory landscapes outpace their documentation; these changes, however, do not fundamentally affect the results of the analysis presented in this work.

Europeans Package[10] issued by the European Commission in November 2016 echoes many of the provisions in the GL EB with respect to the balancing market, sets customers as the centerpiece and encourages aggregation.

While technologically feasible, the economic viability of DER depends on costs, consumer acceptance, range of provided services as well as on the current market rules and regulatory regime. There is an indication that progressive introduction of small-scale balancing resources may be sufficient to meet the overall demand for balancing reserves [52]. Yet, a number of studies found that today's short-term market design, still largely tailored to traditional power plants, puts the participation of DER at a competitive disadvantage due to constraining requirements (e.g. [53]; [48]). Research reveals that entry barriers for DER can be manifested in a number of ways such as formal restrictions of certain groups of providers, administrative restrictions, obscure procedures or restrictive technical requirements. At a later stage, if DER are prequalified to enter the balancing market, their participation and profitability can be affected not only by the auction configuration but also by applicable remuneration rules, tariffs and network charges, as discussed by [54]. Most research therefore addressed only some aspects deterring market integration of DER. Design variables such as minimum bid size, contracting periods or product symmetry [48], [55] have received a lot of attention while others – not less relevant – seem to have been overlooked. The latter include, for instance, product resolution and the authorization of bids not precontracted during the procurement of balancing capacity, as will be discussed below.

2.3. Assessment framework

We build upon the existing research to provide a structured qualitative evaluation of the degree of DER integration in the balancing market that takes both market design and regulatory developments into account to provide EU-relevant recommendations for market design improvement. We continue the work of Borne et al. (2018) and other researchers and present a complete set of design variables related to both market access and the market configuration specifically relevant for DER participation in Table 2.1. In the proposed framework, we include all standard balancing products as well as analyze how each design variable was addressed in the EU regulatory framework. The framework can be applied to any EU country and will help us to decompose the design of a balancing market and identify specific inefficiencies as well as ways of improving it. It is meant to aid decision-makers to comprehensively evaluate the level of DER integration, to determine how amenable a given balancing market design is to DER participation, or to which extent it is aligned with the EU prescriptions. The latter is particularly important in the light of ongoing balancing market integration and the harmonization of rules being a major

[10] This package presents a compendium of communications, directives and regulations proposed by the European Commission and meant to substitute – upon its adoption – the current Third Energy Package: http://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:52016DC0860.

policy goal.

The aspects covered in the framework are related to market access from the formal, administrative and technical points of view and to the configuration of the balancing auction having an effect on market participation and revenue generation. These are structured into the requirements (Table 2.1, first column) subdivided into specific design variables (second column), selected through a comprehensive overview of the conditions placed on participants in market environments in a number of European countries. It is based on the work conducted by [42], [47], [46] as well as on the pertinent regulation, network codes, BSP agreements and the insights described in the previous section. Options presented (third column) are the ones currently applicable in EU countries (based on Ocker et al. (2016), ENTSO-E (2017) and national network codes). These are contrasted with the respective requirements set out in the current regulatory framework at the EU level (fourth column).

In the following, we describe the identified groups of design variables used in Table 2.1 and the associated options.

Market access

Formal access requirements: This aspect refers to explicitly specified obligations or restrictions of certain BSPs for market entry. Here, we review whether the principle of non-discrimination or a level playing field is formally observed.

1. *Explicit restrictions for certain types of service providers* – Such restrictions can be based on size or type of technology or connection level. Besides, if load participation is allowed, it can still be restricted to certain load types, such as big industrial loads.
2. *vRES access to the balancing market* – In many EU balancing markets vRES are not allowed to participate due to their intermittency and only moderate predictability. In some countries, e.g. in Belgium, more lenient rules are applied to vRES [56] while in some countries such participation, though not prohibited, is still in test phase, e.g. Germany [57][11].
3. *Capacity provision* – Power plants of over a specific size may be obliged to provide balancing services.
4. *Specific products for DER* – As opposed to standard products, these products are meant to extract value from a specific type of technology or provider, e.g. demand response.

Administrative aspects: These are concerned with the ways DER are organized, operated and with the actors affecting their participation. General constraints for most of DER are the need for aggregation or pooling due to their relatively small individual capacities. DER willing to participate in the balancing market may also be constrained by other market participants, suppliers and balance responsible parties

[11] After the publication of this article the test phase for the participation of wind generation in the balancing market was prolonged until the end of 2019, after which the pilot phase ended making wind generation subject to general prequalification requirements.

(BRPs) who may limit DERs' choice of an aggregator or may impose additional charges on DER owners or operators [58].

5. *Pooling* – Regulation may explicitly allow or prohibit joint use of DER. Whether pooling is allowed or not affects the possibility for BSPs to extend technical capabilities of individual units or integrate different types of reserve units in their portfolio.
6. *Approach to prequalification* – BSPs' portfolios are obliged to pass technical requirements for balancing service provision by either prequalifying each unit separately (unit-based) or the portfolio as a whole (portfolio-based).
7. *Explicit portfolio requirements* – Restrictions may, for instance, apply to the number of units, mixing different types of components in the same portfolio (RES, conventional, flexible loads, storage, etc.).
8. *Additional agreements* – Art. 2(15) of COM(2016) 864 defines "independent aggregator" as "an aggregator that is not affiliated to a supplier or any other market participant" [59]. A requirement to obtain authorization of other market participants may restrict independent aggregator's actions and ability to participate in the balancing market. Such consent may have to be obtained from a consumer's supplier or from a BRP, entity responsible for submitting generation and/or consumption schedules to the TSO and settling portfolio imbalances.

Technical prequalification criteria: The inherent feature of the balancing market is that its rules and requirements are to a large extent mandated by the technical characteristics of the power system. Upon reserving balancing capacity, TSOs procure it from prequalified BSPs. In other words, the balancing market is not universally accessible; instead, it is restricted to those BSPs that pass the prequalification process. These technical requirements are described in TSO framework documents and to some extent in the national network codes and relate to, among others:

9. *Activation speed & duration* – This variable determines how fast and for how long a committed balancing resource shall provide a balancing service.
10. *Ramp rate* – It refers to the minimum power gradient or the rate at which the output or consumption of a unit or a pool can be increased or reduced until full activation.

Auction configuration

This group of variables encompasses both the requirements placed on the bids for different balancing products and the temporal characteristics of the marketplace that BSPs face upon market entry. These characteristics do not only vary from country to country but are also often different for each balancing product in the same country. They have implications for both the possibility to participate in the market and for the bid formulation.

Bid-related requirements:

11. *Minimum bid size* – The minimum acceptable bid to participate in the balancing market.
12. *Bid symmetry* – Deviations from the required frequency value can be positive or upward (in case of oversupply or overestimated demand) and negative or downward (for instance, in case of insufficient generation due to forecast errors or excess demand). Two types of adjustment, upward and downward, are therefore required for each of the three products. In some balancing markets, only symmetrical bids are accepted, while in others it is possible to submit asymmetric bids, i.e. separate bids for upward or downward regulation.
13. *Procurement of capacity & energy* – If reserve capacity and balancing energy are procured jointly, it implies that the energy bid is already specified together with the capacity bid while the opposite is true for split procurement.
14. *Energy bid adjustment* – Some regulatory frameworks may allow BSPs to adjust their submitted energy bids, including after the gate closure of the bidding period.
15. *Non-precontracted energy bids* – Precontracted energy bids are bids that were submitted and awarded during capacity reservation. If non-precontracted (also called "free" or "voluntary" bids) are allowed, those BSPs that did not participate in the capacity reservation stage still have a chance to submit their bids for balancing energy.

Time-related characteristics:

16. *Frequency of bidding: capacity* – This variable determines how often bids for capacity are called and thus the duration of reservation, a period during which balancing capacity should be kept continuously available. In case the frequency of bidding is lower than the frequency of activation, the price stays the same in each activation period.
17. *Frequency of bidding: energy* – This variable can either equal the frequency of capacity bidding in case of joint procurement of capacity and energy or differ in case split procurement.
18. *Frequency of market clearing: capacity* – This variable determines how often a merit order of capacity bids is built and is normally the same as bidding frequency for capacity.
19. *Frequency of market clearing & activation: energy* – It is either equal to the frequency of bidding for energy or has a higher time resolution if the merit order for balancing energy is built more frequently.
20. *Product resolution* – This variable refers to the timeframe of sub-products traded within the same bidding period, for example, separate auctions can be held for different timeframes for upward and downward regulation (e.g. delivery of balancing energy in 4-hour blocks).

Remuneration:

21. *Pricing rule* – This refers to the way awarded capacity and energy bids are remunerated, whether through a fixed payment, according to the bid price (pay-as-bid) or according to the highest awarded bid in the merit order (so-called marginal or uniform pricing).
22. *Special support schemes for balancing service provision* – This includes considerations of whether special conditions are applicable only to certain types of providers such as reduced network tariffs or incentive payments, and whether DER can profit from them on par with other providers.

Thus, the proposed assessment framework (Table 2.1) includes all variables that can affect specifically DER integration in the balancing market and allows to assess how the current design choices impact their ability to participate in the market versus an incumbent BSP or how it is aligned with the EU policy objectives. It is furthermore a tool allowing a comparative analysis of balancing regimes in the EU with a specific focus on the participation of new technologies and actors. Its application is demonstrated in Section 2.4 and contributes to the study of market design and related incentives.

Table 2.1. Assessment framework

	GROUP	VARIABLE	EXAMPLES OF OPTIONS	SPECIFICATION IN THE EU NETWORK CODES OR OTHER EU LEGISLATION
MARKET ACESS	**Formal access requirements**	1. Explicit restrictions for certain types of service providers	Participation restricted according to e.g. size, technology, connection level, demand side / No restrictions	Non-discriminatory approach to all providers, including vRES, demand side, storage and any kind of aggregated facilities (GL EB, Arts. 3.1, 5 & 18.4)
		2. vRES access to the balancing market	Allowed / not allowed	
		3. Capacity provision	Mandatory / voluntary	Market-based procurement (GL EB, Art. 3.1(e))
		4. Specific products for DER	Yes / no	TSOs should justify why standard products are not sufficient and specific products will not create market distortions (GL EB, Art. 26)
	Administrative aspects:	5. Pooling	Allowed / not allowed	Should be allowed (GL EB, Art. 18.4)
		6. Approach to prequalification	Unit-based / pool-based	Defined in the national regulation
		7. Explicit portfolio requirements	Restrictions apply / No restrictions	
		8. Additional agreements	Obligatory / not obligatory	No obligation to see a customer's supplier's agreement; independent aggregation should be allowed (COM(2016) 864, Art. 13)
	Technical prequalification criteria	9. Activation speed & duration	The set and the extent of the applicable requirements varies greatly depending on the country in question and is determined by the TSO	For FCR as soon as possible; for aFRR activation in maximum 30 seconds (further specifications in Arts. 154.7 and Art. 158.1d of the System Operation Guideline)
		10. Ramp rate		Defined by the TSO

AUCTION CONFIGURATION	**Bid-related requirements**	11. Minimum bid size	300 kW – 50 MW	Defined in the national regulation
		12. Bid symmetry	Symmetrical bidding / Asymmetric bidding	Asymmetric at least for secondary and tertiary reserve (GL EB, Art. 32.3 and COM(2016) 861, Art. 5.9)
		13. Procurement of capacity & energy	Split/joint capacity & energy bids	Split (GL EB, Art. 16.6): no pre-determination of the energy price in the capacity contract
		14. Energy bid adjustment	Allowed / not allowed	Shall not be allowed after balancing energy gate closure time (GL EB, Art. 24.3)
		15. Non-precontracted energy bids	Allowed / not allowed	Allowed for BSPs that passed the prequalification (GL EB, Art. 16.5) and not discriminated against (GL EB, Art. 16.7)
	Time-related characteristics	16. Frequency of bidding - capacity	Once a year – once every 15 minutes	"The contracting should be performed for not longer than one day before the provision of the balancing capacity and the contracting period shall have a maximum period of one day" (COM(2016) 861, Art. 5.9)
		17. Frequency of bidding - energy	Once a year – once every 15 min	"Market participants shall be allowed to bid as close to real time as possible" (COM(2016) 861, Art. 5.5)
		18. Frequency of market clearing – capacity	Once a year – once every 15 min	Defined in the national regulation
		19. Frequency of market clearing & activation - energy	1 hour – 15 min	As close as possible to real time, within the limits of feasibility and "not before the intraday cross-zonal gate closure time" (GL EB, Art. 24.2)
		20. Product resolution	1 hour – 1 year	Defined in the national regulation
	Remuneration	21. Pricing rule (remuneration of awarded bids)	Regulated price / Pay-as-bid / Marginal pricing	Marginal pricing to be applied to the procurement of energy bids for FRR (GL EB, Art. 30 (1a)) unless all TSOs determine that a different pricing methodology is more efficient (GL EB, Art. 30.5).

	22. Special support schemes for balancing service provision	Not applied / Applied only for e.g. only certain voltage levels; only for certain types of providers	Defined in the national regulation

2.4. Comparative study of balancing market regimes in Austria, Germany and the Netherlands

In this section, we apply the framework to the balancing markets of three neighbouring EU countries, Austria, Germany and the Netherlands. All the three countries are characterized by well-developed and quickly evolving organized balancing markets for all balancing products in contrast to a number of EU countries where mandatory provision of balancing services is still applied to at least some balancing products [60]. The bids are activated according to the merit order, i.e. the cheapest bids are activated first, in line with the GL EB. National regulators have eased market access for flexible DER, for example by revising the prequalification criteria and bid requirements, which facilitated the entry of aggregated DER onto the balancing market, as will be shown in Section 2.5.

The three countries apply a so-called 'balancing group model', under which BRPs carry responsibility for the imbalances of their portfolio of generation and/or demand. TSOs take a reactive approach to system balancing addressing only the remaining imbalances. Each supplier or consumer must be part of a BRP portfolio either directly or through an intermediary. As of January 2018, for FCR, aFRR and mFRR, 7, 13 and 14 BSPs in Austria, 24, 37 and 52 BSPs in Germany and ca. 4, 10 and 10[12] BSPs in the Netherlands, respectively, have been prequalified to participate in the balancing market. The basis for the market design overview are the relevant national laws, decisions of the regulator, TSO websites as well as TSO-BSP and BSP-BRP agreements applicable in the three countries.

2.4.1. Market access

An overview of the aspects related to formal requirements, aggregation and prequalification in the three countries is presented in Table 2.2. Design choices that are aligned with the EU regulatory framework, as described in Table 2.1, fourth column, in this and subsequent tables are marked in green; those not regulated or not aligned are left unmarked.

[12] Numbers according to the correspondence with the Dutch TSO. The exact number is not publicly available.

Table 2.2. Design choices in the countries of study related to the market access of DER.

Formal access requirements	Austria	Germany	Netherlands
Explicit restrictions for certain types of service providers	No restrictions	No restrictions	No restrictions
vRES access to the balancing market	Yes for wind (only FRR)	Yes for wind (in pilot phase)	Yes
Capacity provision	Mainly voluntary	Voluntary	Mainly voluntary
Specific products for DER	No	Yes (interruptible loads)	No
Pooling conditions			
Pooling	Allowed	Allowed	Allowed
Approach to prequalification	Pool-based	Pool-based	Unit-based for FCR, pool-based for aFRR & mFRR
Explicit portfolio requirements	One reserve pool can contain several reserve groups of max. 1,000 technical units	No restrictions according to pool size or technology	No specific pooling restrictions for aFRR or mFRR
Additional agreements	Notification and coordination with BRP's necessary; Supplier's agreement needed if he and aggregator belong to different balancing portfolios	Coordination with the BRP for the produced imbalances	BRP's notification and agreement required; currently no independent aggregators for balancing products
Technical prequalification criteria			
Activation speed & duration	FCR: reaction time of a few secs, full activation within max 30 secs for at least half an hour; aFRR: within a few secs; full activation within 5 min; mFRR: within 10 min. for 15 min.	FCR: reaction in a few secs, full activation within 30 secs for minimum 15 min.; aFRR: reaction in maximum 30 secs; full activation within 5 min; mFRR: reaction in maximum 5 min.; full	FCR: 50% activated in 15 secs; full activation within 30 secs; aFRR: response in 30 seconds, full activation within maximum 15 min.; mFRR: activation within 15 min.

		activation within 15 min.	
Ramp rate	2% of rated output/min (for aFRR)	Minimum 2% of rated output (for FCR); for FRR – upon agreement with the TSO	Minimum 7% of the volume of the bid per minute for aFRR and mFRR

Table 2.2. shows that in all three countries load participation is allowed using the same market mechanism as generation. On the face of it, the level playing field is guaranteed to the renewables although the participation of vRES is not yet considered fully viable in Germany and is tested in a pilot phase for wind parks [57]. Apart from standard balancing products, Germany employs specific products, immediately interruptible and quickly interruptible loads, to procure services from large industrial loads. The capacity provision is mandatory in Austria for power plants bigger than 5 MW only in case of failure to procure sufficient capacity after third call while an obligation to provide balancing in the Netherlands applies to power plants bigger than 60 MW in case of a failure to procure sufficient capacity.

While all the countries allow pooling, the conditions applicable to aggregators vary with regard to notification and consent of other market participants, BRPs and suppliers.

It is individual TSOs' prerogative to define the exact technical prequalification criteria, whose fulfillment in case of DER is strongly linked to the pooling conditions applied in a given country. Pooling eases the compliance with the prequalification requirements, including the requirement to withhold capacity, for instance, for a weeks' time, as units are not obliged to reserve a given capacity individually but can rather "share the burden". A slower ramping time of one unit can be compensated by a faster time of another unit in the same pool. Separate technical units in a pool can be substituted by others in a way that does not affect service provision. Besides, in case energy reserves have been exhausted they can be replenished and substituted by other reserves in the meantime as the regulation cannot be deactivated.

2.4.2. Auction configuration

The configuration of the balancing auction affects the possibility and incentives for DER to participate in the market. Table 2.3 provides an overview of the design choices in the three countries for the three balancing products, FCR, aFRR[13] and mFRR[14], respectively, as of January 2018. Notably, for the provision of FCR only reserved capacity is remunerated while for aFRR and mFRR both capacity and energy

[13] Until 2016, aFRR was referred to as "regulating power" while mFRR as "reserve power" in the Netherlands. In the Germany-speaking countries, aFRR is called "secondary control" while mFRR is called "tertiary control".

[14] In the Netherlands, mFRR includes 1) schedule-activated reserves (balancing energy only no capacity bidding) and 2) directly activated mFRR ("emergency power"), a specific balancing product for which capacity is procured on a yearly and quarterly basis.

bids have to be submitted. Table 2.3 reveals differences in design choices not only on the country level but also on the product basis. These variables are subject to regular changes; for instance, the frequency of bidding and minimum bid sizes have been progressively reduced over the last years.

Table 2.3. Auction configuration for the procurement of the three balancing products in Austria, Germany and the Netherlands.

FCR Bid-related requirements	Austria	Germany	Netherlands
Minimum bid size	1 MW (1-MW increments)	1 MW (1-MW increments)	1 MW (1-MW increments)
Bid symmetry	symmetrical	symmetrical	symmetrical
Timing-related characteristics			
Frequency of bidding - capacity	Once a week	Once a week	Once a week
Frequency of market clearing – capacity	Once a week	Once a week	Once a week
Product resolution	weekly[15]	weekly	weekly

aFRR Bid-related requirements	Austria	Germany	Netherlands
Minimum bid size	5 MW (1-MW increments)	5 MW (1-MW increments)	min. 4 MW - max. 200 MW (1-MW increments)
Bid symmetry	asymmetric	asymmetric	asymmetric
Procurement of capacity & energy	Joint capacity & energy bids	Joint capacity & energy bid	split
Energy bid adjustment	no	no	no
Non-precontracted energy bids	no	no	yes
Time-related characteristics			
Frequency of bidding - capacity	Once a week	Once a week	Yearly and monthly
Frequency of bidding - energy	Once a week	Once a week	Every 15 min
Frequency of market clearing – capacity	Once a week	Once a week	Once a year & once a quarter

[15] Please note that since the time of writing of this article, the bidding frequency in the German and Austrian FCR markets was changed to daily.

Frequency of market clearing & activation - energy	Every 15 min	Every 15 min	Every 15 min
Product resolution	12 hours (peak & off-peak for upward and downward)[16]	12 hours (peak & off-peak for upward and downward)	15 min

mFRR Bid-related requirements	Austria	Germany	Netherlands
Minimum bid size	1 MW to 50 MW for the first bid and further bids between 5 MW and 50 MW (1-MW increments)	5 MW (1-MW increments)	4 MW to 200 MW (1-MW increments)
Bid symmetry	asymmetric	asymmetric	asymmetric
Procurement of capacity & energy	joint capacity & energy bids	joint capacity & energy bids	split
Energy bid adjustment	yes (possible D-1 from 11:00 till 15:00)	no	no
Non-precontracted energy bids	no	no	yes
Timing-related characteristics			
Frequency of bidding - capacity	Once a week and once a day	Once a day	no capacity reservation
Frequency of bidding - - energy	Once a week and once a day	Once a day	Every 15 min
Frequency of market clearing – capacity	Once a week and once a day	Once a day	n/a
Frequency of market clearing & activation - energy	Once per 15 min	Once per 15 min	Once per 15 min
Number of auctions	4 hours (12 separate auctions in total per day (separate for upward and downward))	4 hours (12 separate auctions in total per day (separate for upward and downward))	1

[16] Please note that after the time of writing this article, the production resolution in the German and Austrian aFRR markets was changed to 6 4-hour products (per direction).

Renumeration	Austria	Germany	Netherlands
Pricing rule (remuneration of awarded bids: pay-as-bid (PaB) vs. marginal pricing (MP))	FCR: PaB for capacity; aFRR and mFRR: PaB for capacity and energy	FCR: PaB for capacity; aFRR and mFRR: PaB for capacity and energy	All: PaB for capacity; aFRR: MP for energy; mFRR: MP for energy
Special support schemes for balancing service provision	Reduced network usage fees or exemptions for some types of BSPs	Flexibility premiums for existing and flexibility allowances for new biogas plants	no

German and Austrian TSOs procure capacity and energy simultaneously, meaning that both prices must be included in the bid although it is the capacity bid alone that determines which BSPs enter the merit order. In contrast, in the Netherlands, the balancing capacity and balancing energy markets are operated separately from each other.

Another specificity of the Dutch market is that it allows so-called non-precontracted energy bids. Unlike precontracted bids, these bids are only remunerated only for the activation of balancing energy. All the received bids form the same merit order [61]. Finally, unlike its Austrian and German counterparts, the Dutch TSO does not foresee a capacity reservation stage for mFRR since this product is very rarely activated in the Netherlands.

The timeline of procurement and activation of balancing resources is illustrated in Figure 2.1. Timing of FCR, aFRR and mFRR (capacity (C) and energy (E)) procurement in the balancing markets in Austria, Germany and the Netherlands.. It shows the market sequences for all the balancing products, bidding periods, number of auctions in each period and market clearing times. Adjusting energy bids is only allowed for mFRR bids in Austria, in the TSO's effort to reduce balancing energy prices. The bids can be reduced for upward regulation and increased for downward regulation. Currently, the bidding frequency in Austria and Germany for aFRR (which they procure jointly since June 2016) is weekly but it is planned to be changed to daily with six 4-hour products to align with mFRR starting from July 2018 [62]. The contracting period of aFRR capacity in the Dutch balancing market is expected to be reduced to one month in 2018.

It is noteworthy that balancing energy prices cannot be changed for a whole week for FCR and aFRR in Austria and Germany and also for weekly mFRR in Austria. So even though the frequency of energy activation is the same in all the three countries, in Austria and Germany the same energy bids are used to build a merit order in each 15-minute period of a product (one week, 12 hours or 4 hours). In contrast, only balancing capacity prices are submitted in the Netherlands in the first stage while different balancing energy prices can be submitted for any 15-minute period,

minimum one hour prior to activation (Figure 2.1. Timing of FCR, aFRR and mFRR (capacity (C) and energy (E)) procurement in the balancing markets in Austria, Germany and the Netherlands.). The awarded BSPs in the Dutch market are under obligation to bid their total precontracted volume in the balancing energy market. In case of failure to do so, the TSO places bids for them [61].

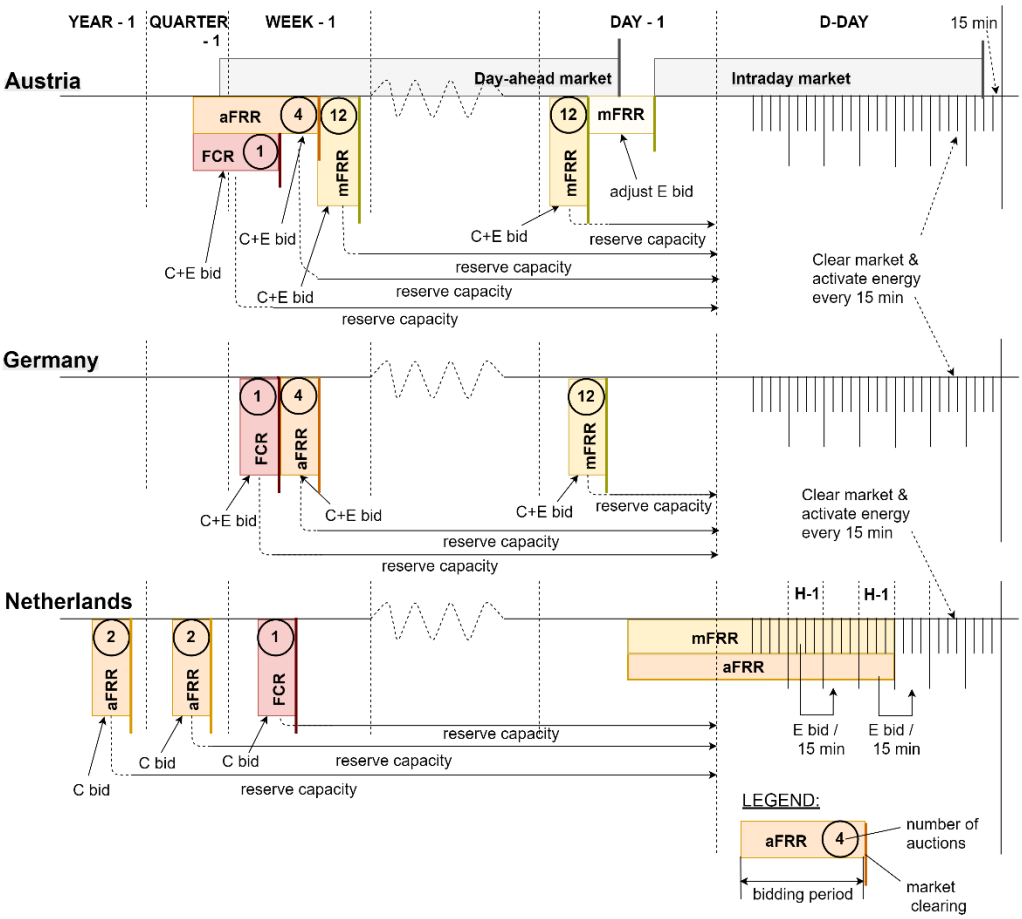

Figure 2.1. Timing of FCR, aFRR and mFRR (capacity (C) and energy (E)) procurement in the balancing markets in Austria, Germany and the Netherlands.

For FCR, only one auction takes place (encircled numbers in Figure 2.1). As explained in Section 2.2, the number of auctions is linked to product resolution within the same bidding period. In Austria and Germany separate auctions are held for peak and off-peak periods as well as for upward and downward regulation for aFRR. For mFRR, six separate 4-hour-block auctions are held. No distinction between different time periods is made in the Dutch market.

Support schemes to certain groups of service providers are sometimes used to encourage participation in the balancing market. Following this logic, in Austria, market participants are offered reduced network usage fees if they provide balancing services. Units at the low-voltage level, however, are excluded from this provision [63]. Furthermore, storage systems acting both as generators and consumers depending on their operation mode must pay system losses charges twice, in charging and discharging modes. Pumped hydro storage plants are the only storage systems so far exempted from such double charges. In contrast, in Germany, only biogas power plants are offered so-called flexibility premiums or allowances for services including balancing, pursuant to German Renewable Energy Acts [64] which led to a surge of biogas BSPs providing downward regulation[17].

2.5. Analysis: Balancing market design for DER

The introduction of market mechanisms to procure balancing services was meant to provide equal opportunities to all balancing-capable actors, increase market efficiency and minimize the cost of balancing procurement. The challenge is to create the right incentives for market participants, given the large set of market access and auction configuration variables (Table 2.1). Having applied our framework to the case of the Austrian, German and Dutch balancing markets, in this section we analyze the effect of individual variables on DER integration and on the performance of the balancing market. We review how different measures for the adaptation of the market design can contribute to non-discrimination and economic efficiency in the balancing market. With respect to economic efficiency we focus on price efficiency, i.e. how well costs are reflected in market prices, and utilization efficiency, i.e. whether the cheapest providers are used for balancing, following the performance criteria identified in [47, p. 57].

2.5.1. Non-discrimination

In countries where the provision of balancing services remains mandatory, large generation units are called on to restore system frequency. In contrast, Austria, Germany and the Netherlands procure balancing products in a market-based way. An organized market opens up opportunities for DER, including flexible loads, if they have not been excluded by formal restrictions on market entry. The adequacy of product characteristics and requirements for DER participation is often defined historically rather than justified by technical restrictions.

All three countries formally observe the non-discrimination principle and an EU policy goal by providing unrestricted access to all types of providers, guided only by the considerations of economic efficiency, but the interpretations vary slightly. For instance, the Netherlands is technology-neutral in granting both same rights and same responsibilities to all BSPs, including balance responsibility of all market participants, in contrast to Austria and Germany where vRES that are subsidized are

[17] https://www.vdi-nachrichten.com/Technik-Wirtschaft/Preisverfall-Regelleistung (in German)

not fully balance responsible. Yet, considering the low bidding frequency for reserve capacity and the low liquidity of the intraday market in the Netherlands, the market effectively favors traditional BSPs at the cost of vRES and other DER. In this regard, an efficient intraday market can significantly facilitate the participation of DER, especially vRES, by allowing them to adjust their forecasts closer to real time.

Specific balancing products are not ruled out but must be justified, according to the EU legislation. Two products, immediately interruptible and quickly interruptible loads, are used in Germany, arguably to help big industrial interruptible loads provide balancing services. The bid sizes are still rather large, 5 MW, excluding potential smaller-scale, commercial and residential providers. If interruptible loads are in the end only rarely activated through this additional mechanism, the question arises of whether they should be dispensed with in favor of standardized products with democratized entry conditions for all types of loads. Current regulation in the three countries provides BSPs with sufficient freedom to determine the components and their number in the pool. This allows potential market participants to provide both downward and upward regulation and to accommodate technical constraints of DER better by, for example, aggregating different technologies.

Market actors in Austria and Germany are authorized to bundle resources from several balancing groups in a single portfolio. This is particularly beneficial for DER aggregators because it allows them to substantially expand their portfolio and improve their business case while lowering transaction costs. Independent aggregators in Austria and in Germany need to ensure that energy injections and withdrawals are duly notified and coordinated with the involved BRPs. In these countries, this approach has already been exploited by a number of independent aggregators [65]. Yet, an obligation to obtain an explicit BRP authorization may become an obstacle for aggregators since BRPs may not want to risk increasing their portfolio imbalances by accepting balancing responsibility for aggregators of DER. In the Netherlands, as long as aggregators do not take on the role of BRPs themselves, their entry into the market will remain limited [65]. Nor are Dutch aggregators currently allowed to pool resources from different balancing portfolios, unlike their German and Austrian counterparts, which can also significantly limit the pool size and consequently its flexibility potential.

Prequalification criteria are dictated by the technical system requirements and can be adapted less readily. Yet, there are no criteria described in Section 2.4 that inherently discriminate against DER, thanks to flexible pooling conditions which generally do not limit the size of the balancing pool or the involved technologies. The provision of reserve capacity requires stable power output throughout the ramping and activation periods. In cases in which the flexibility potential depends on usage patterns, such as thermal storage or e-mobility, the maximum available capacity will be reduced. DER technically can provide all product types along with regulation in both directions, depending on the technology or their combination. In the countries of study, DER are allowed to prequalify for aFRR and mFRR in aggregate, which significantly eases fulfillment of ramping and minimum capacity

requirements. Yet, the prequalification for FCR is still unit-based in the Netherlands. Consequently, balancing provision from single batteries, one of the main candidates for FCR provision among DER, remains economically unfeasible due to their inability to maintain the required output over an extended period of time, such as a week, while avoiding depletion [66]. As prequalification criteria are stipulated by individual TSOs, additional hurdles remain for BSPs willing to participate in several European balancing markets.

Finally, market design specifics may produce other disincentives that are not immediately observable. Similar to the prequalification criteria, the application of support schemes for BSPs is a prerogative of individual states. Although favorable network tariffs can theoretically motivate market actors to provide balancing services, such incentives are artificial and can produce distortionary effects if not extended to all types of BSPs. Since DER can provide the required services in a way similar to conventional technologies, a revision of applicable grid tariffs and other support schemes is needed to ensure that DER can profit from these on par with other providers. On the other hand, flexibility premiums granted to biogas plants in Germany did encourage their wider use for balancing yet raise the question of why such an incentive is not applied to other technologies. Overall, any type of subsidization to a lesser or greater extent insulates its recipients from market signals and thus runs contrary the goal of higher market efficiency.

2.5.2. Economic efficiency

Bid-related requirements and market efficiency

DER can improve price and utilization efficiency of the balancing market can be improved in a number of ways. The size of the bids has a direct effect on competition in the balancing market since its volume is much smaller than that of the wholesale spot market, so even providers with relatively small bids may influence the market outcome [46]. Allowing more participants helps to increase market liquidity and price efficiency. For market entry, the minimum bid size becomes less relevant, yet not unimportant, if pooling is unrestricted. The minimum bids for aFRR and mFRR (4-5 MW in Germany and the Netherlands) still require aggregators to have a large pool of small-scale providers to comply. Currently, only Austria offers a possibility to place a single 1 MW bid for mFRR. The German TSOs introduced special exceptions for smaller-scale BSPs allowing them to place single bids under 5 MW for aFRR since July 2018 [62].

The requirement of symmetrical bidding can be a barrier for DER as some of these resources are only economically capable of downward regulation, for instance vRES and demand response. Symmetrical bidding in the three countries is required only for FCR. For the other two products asymmetric bidding is allowed in all three countries. This is in line with the regulatory requirements and can help increase utilization efficiency of available balancing resources.

Another way to extract value from DER would be to uncouple capacity and energy bids, which are currently required to be submitted jointly when balancing capacity is contracted in Austria and Germany. Joint bid submission implies that the energy price is locked in for the whole period of reservation (Figure 2.1) and may therefore not adequately reflect the value of the energy at the actual time of activation. The requirement of joint capacity and energy bids may lead to a further distortion: since the bids are selected based on the capacity price alone, a BSP may be tempted to submit a very low capacity bid in combination with a very high energy bid. A low capacity bid then acts a "door keeper" ensuring a BSP's place in the merit order for balancing energy allowing them to potentially obtain windfall profits during the activation stage. Balancing energy bids then virtually sponsor artificially low capacity bids leading to inefficient prices and resource allocation. For this reason, balancing energy prices of thousands of euros per MWh are not uncommon in Austria and Germany.

In this context, non-precontracted energy bids can boost price efficiency. Already introduced in the Dutch balancing market, such bids set a *de facto* cap on balancing energy bids of precontracted BSPs since they run a higher risk of not being called if they bid too high. Besides, DER-aggregating BSPs often cannot participate in the capacity reservation stage due to forecasting challenges farther from real time. Non-precontracted bids allow them to generate profits through balancing energy activation. Such bids are also called for in the GL EB (Table 2.1). Yet, the need for them may fall away in the future if the frequency of bidding increases and competition levels are no longer a concern.

Time-related requirements, service remuneration and market efficiency

Adjustment of timing characteristics (Figure 2.1) can significantly increase utilization efficiency in the balancing market by allowing cheaper distributed BSPs to participate. The auction frequencies in the three markets for most products are not yet aligned with the aspiration to increase the bidding frequency for all products to daily, as stipulated in the GL EB (Table 2.1). Longer contracting periods can be beneficial for awarded BSPs, allowing them to enjoy a long period of guaranteed profits from reserved capacity. However, this also creates more uncertainty since these profits are lost if the bid was not selected and the waiting time for the next bidding opportunity is considerable. Moreover, smaller providers or vRES are likely to face difficulties to ensure that their pool is constantly available for a longer period of time, making it more difficult for them to participate. For instance, the bidding frequency for FCR and especially for aFRR in the Netherlands remains remarkably low, making it impossible even for aggregated DER to provide balancing capacity. DER-aggregating BSPs can therefore only participate through non-precontracted energy bids. The planned introduction of daily auctions for aFRR in Austria and Germany in 2018 is likely to boost the entry of new participants, liquidity, competition and price efficiency as a result.

The product resolution, as defined by the period of time during which a product may be activated, directly affects the participation of DER. In the Austrian and German balancing markets, the shortest product block is 4 hours for mFRR. According to its recent decision, the German regulator intends to reduce current 12-hour blocks for aFRR to 4 hours [62]. A higher temporal granularity substantially improves the opportunity for DER to bid their capacity and subsequently increase market liquidity. A BSP then has to guarantee the availability of bid capacity for a few hours instead of a whole day or for even longer contracting periods, which reduces forecasting risks. A further reduction to 1-hour or smaller blocks would accommodate the technical capabilities of small-scale DER even better but is not yet feasible from the point of view of information processing and effort involved in clearing 96 auctions per day (total for aFRR and mFRR) [62]. The fact that product resolution is not directly covered in the EU regulatory documents and therefore not harmonized may potentially affect cross-border procurement and lead to information asymmetries and trade distortions.

Concerning remuneration, the best pricing methodology has been subject of debate (e.g. [43], [44], [67], [68]). The application of marginal pricing is required by the GL EB (Table 2.1). It has been argued that pay-as-bid pricing hinders effective price formation [60] and affects small-scale providers particularly negatively as compared to marginal pricing [69]. Under pay-as-bid pricing, large BSPs in a concentrated balancing market are likely to bid close to the expected marginal price rather than their true costs [70]. In contrast, smaller BSPs, being price-takers, may be compelled to bid closer to their marginal costs and only manage to cover those under the pay-as-bid rule. Since bidding is voluntary, prequalified small-scale BSPs might not be encouraged to bid regularly into the balancing market but only in situations when expected balancing prices and therefore profit margins are high. Such sporadic bidding, however, reduces utilization efficiency and competition levels in the market. Marginal pricing may reduce information asymmetries between more and less experienced BSPs and stimulate DER investments over a longer term. Yet, it may also produce the opposite effect if market concentration is high, which is why the Austrian and German regulators have not introduced marginal pricing thus far. Other measures, such as increasing the bidding frequency, should take precedence in order to improve competition levels first.

Lessons learned

The main lessons learned from this comparative study are summarized in Table 2.4. Current rules do not sufficiently facilitate the use of DER for balancing. In the countries of study, most positive developments are related to the formal and administrative criteria for market entry and prequalification of DER. More obstacles remain in the area of actual market participation due to the auction configuration and the role of applicable support schemes. The case studies can give stakeholders in other markets in the EU insights as to which concrete elements of market design can either improve or complicate the position of DER in balancing markets.

Table 2.4. Lessons learned from the Austrian (AT), German (DE) and Dutch (NL) balancing markets.

Positive features	Potential barriers
Market access	
Formal access requirements	
Market-based procurement of all balancing products (all)	
Technology-neutral, non-discriminatory approach to market participation (all)	
Administrative aspects	
Independent aggregation allowed (AT, DE)	Limited independent aggregation (NL)
Extensive pooling options (pool-based prequalification, pooling across balancing portfolios, etc.) (all)	Explicit agreement between an aggregator and a BRP needed for providers of aFRR and mFRR (NL)
Technical prequalification criteria	
Criteria possible to fulfil thanks to pooling conditions (all)	Heterogeneous prequalification criteria in the three countries
De facto no minimum unit capacity requirement for prequalification (all)	
Auction-configuration: Bid-related requirements	
	Minimum bid size still high for DER to comply for aFRR and mFRR (all)
Non-precontracted bidders allowed to participate (NL)	Participation of non-precontracted capacities is not allowed (AT, DE)
Split capacity and energy bids and markets (NL)	Joint capacity and energy bidding (AT, DE)
High product resolution of several hours for aFRR and mFRR (AT, DE)	Gate closure time far ahead of real time (D-1) (all)
Auction-configuration: Time-related characteristics	
Daily auctions for mFRR (DE, AT)	Weekly auctions for balancing capacity for FCR (all)
Planned daily auctions for aFRR (AT, DE)	Very low frequency of capacity bidding for aFRR (NL)
Remuneration	
Level playing field for all providers in terms of remuneration (NL)	Pay-as-bid pricing rule for aFRR and mFRR balancing energy (AT, DE)
	Reduced fees or exemptions for some balancing providers (AT) and support schemes for a specific technology type (premiums) (DE)

The analysis in this section notably points to links between different market design variables. We argue that, in order to achieve a tangible improvement of the balancing market design, adjustments need to be implemented stepwise observing these links, as illustrated in Figure 2.2. It shows the all the design variables[18] included in our assessment framework (as presented in Table 2.1) ranked according to the level of priority. In order to ensure optimal integration of DER into the balancing market, as the first step, formal access requirements should not preclude DER participation. Once these no longer represent a barrier for DER, two critical design variables, flexible pooling conditions and separate capacity and energy markets, need to be addressed in the second step as the largest number of other variables is dependent on them. For instance, extended pooling options help to fulfil technical prequalification requirements, to reach the required minimum bid size as well as comply with longer contracting periods and bid symmetry requirements. Splitting balancing capacity and balancing energy markets is necessary before introducing non-precontracted bids and reducing the frequency of energy bidding. In the next market design step, increasing product resolution, frequency of bidding and authorizing non-precontracted bids can all help to achieve higher competition levels and, subsequently, justifying the introduction of marginal pricing. Once this is accomplished, it should be critically assessed if support schemes for balancing service provision are still necessary.

2.6. Conclusions and policy implications

The extent to which DER can contribute to the efficient functioning of the balancing market, among others, greatly depends on the market access criteria and auction configuration, which includes design variables related to the bids, timing and remuneration. The formal acceptance of new balancing resources does not guarantee their *de facto* entry as the actual rules can still be too restrictive or incentives insufficient. We developed an assessment framework which presents the most complete overview of balancing market design choices for DER thus far. Its application was illustrated with the help of a comparative analysis of the Austrian, German and Dutch balancing markets. It allowed us to systemically analyze the impact of current design choices on the performance of the balancing market with respect to non-discrimination and economic efficiency. The framework can aid decision-makers in harmonizing the currently fragmented balancing market designs and improving them to facilitate the contribution of DER to system balancing.

Key differences between balancing markets among the countries of study include the administrative requirements placed on DER and their aggregators as well as aspects of auction configuration. The minimum bid sizes that TSOs allow range from 1 to 5 MW, which is fairly restrictive for DER. Large differences were observed in product resolution, which is substantially higher in the German and Austrian markets

[18] For the sake of a better overview variables under "formal access requirements" and "technical prequalification criteria" were represented as clusters in the diagram (Figure 2.2).

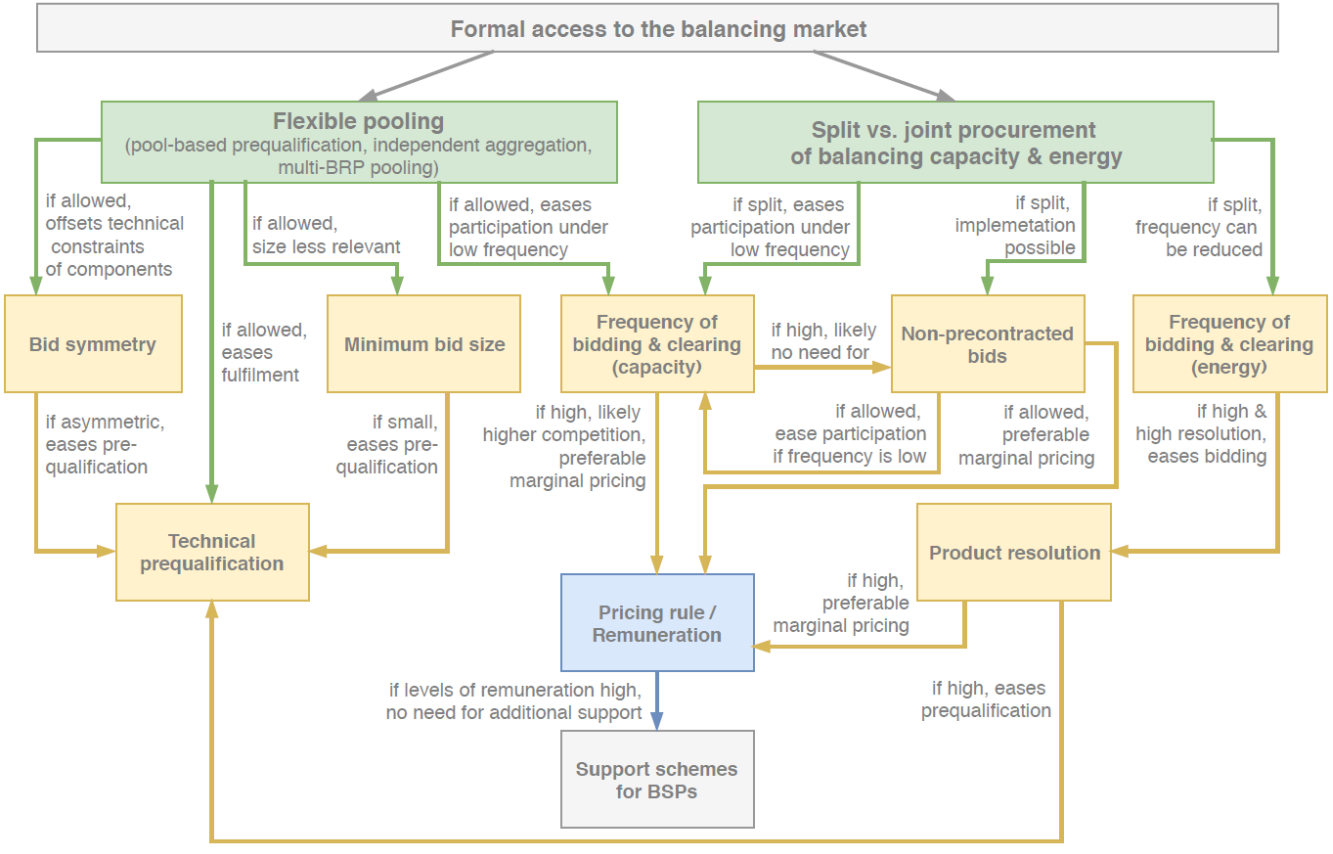

Figure 2.2. Links between balancing market design variables organized according to priority with which they should be addressed.

than in the Netherlands. Similarly, the countries apply different bidding frequencies ranging from one year to one day for the procurement of balancing capacity. The Dutch market is the only one in which balancing energy is procured separately from balancing capacity and in which non-precontracted bids are allowed. Finally, the three countries apply different pricing rules to the remuneration of activated balancing energy, namely pay-as-bid in the German and Austrian markets and uniform pricing in the Dutch market.

We conclude that for an efficient utilization of DER more changes to the auction configuration are needed while the support schemes for the resources contributing to system balancing need to be streamlined. Providing extensive pooling options (Table 2.4) such as independent aggregation and pool-based prequalification can significantly improve the potential contribution of DER. In this regard, care should be taken when determining the conditions for the participation of aggregators and the agreements they need to conclude with other market participants. In those markets where the bidding frequency remains low, non-precontracted bids, as in the Dutch market, may significantly facilitate access to DER. Since DER may face much higher forecasting challenges compared to conventional BSPs, the market design can be improved by increasing the frequency of bidding together with applying a higher product resolution, following the examples of Germany and Austria.

Recent EU regulatory documents [37] cover almost all crucial design variables related to DER participation in the balancing market. Yet, product resolution was not addressed and, while aggregation was encouraged, specific roles and responsibilities or pooling options remain to be defined.

An important implication of this analysis is that adjustments to the balancing market design need to be considered in aggregate since different design variables can enhance or neutralize each other's effects. We identified multiple relations between different balancing market design variables and showed that formal access criteria have to be addressed in the first place, followed by the pooling requirements and the introduction of split markets for the procurement of balancing capacity and energy. Only once several adaptations related to the auction configuration have been implemented, can the pricing rule be changed to marginal to ensure optimal market performance. Finally, the need for special support schemes for BSPs is questionable and should be critically assessed once the market design has been improved.

As a potential enhancement of our framework, it can be tailored to different DER types or augmented by a quantitative analysis of variable combinations and the identified differences in the balancing market design on market performance. A second line of research regarding the market integration of DER should concern the role of network tariffs along with exploration of ways to streamline TSO-DSO interaction to lower the barriers for DER deployment.

3

A (not so) independent aggregator in the balancing market: theory, policy and reality check[19]

The aggregator has been touted as the key enabler of active engagement of distributed energy resources and promises to contribute to greater economic efficiency in the European balancing markets by providing cheap sources of flexibility. This paper presents an empirical analysis of how aggregators organize themselves in relation to other market participants given the rules of the balancing market and the impact thereof on their participation. We reviewed how market design influences their choices by comparing three countries, Austria, Germany and the Netherlands, in the light of the goals set by the EU. Despite the EU policy drive to integrate aggregators, the participation of independent aggregators in the balancing market is so far limited. Relaxing the agreement requirements, allowing pool-based prequalification and standardizing compensation mechanisms unlocks more possible business models for the aggregator and may help create synergies among aggregators, suppliers and balance responsible parties.

[19] This chapter has been published as Poplavskaya K., De Vries, L., A (not so) Independent Aggregator in the Balancing Market: Theory, Policy and Reality Check. Proceedings of the 15th International Conference on the European Energy Market, 2018.

3.1. Introduction

The aggregator has been touted as the key actor to unlock flexibility from distributed energy resources (DER) and promises to contribute to greater economic efficiency in European balancing markets. Since balancing markets are often characterized by high market concentration, strategic behavior and high price volatility (e.g. [40], [68], [71]), aggregators' participation promises to boost competition levels and reduce balancing costs as a result. Although independent aggregators have already been entering energy markets both in the EU and elsewhere, their involvement has so far been limited. One of the reasons for this could lie in the balancing market design while the conditions for their participation differ across countries. Several researchers studied possible business models for aggregators in the Nordic market [72] and a few other European countries in project BestRES [73] but found that either not all models were allowed by existing regulation or improvements were needed.

We take this analysis further by analyzing how the participation of aggregators and their benefits to the balancing market depend not only on their number, the technologies they include in their portfolio but also on their level of independence. Their contribution is directly linked to their relations with other market actors (suppliers and balance responsible parties, BRPs) as emphasized in [58]. Market design affects these relations and, as a consequence, their degree of independence and choice of business models. This paper therefore investigates the question of how aggregators organize themselves in response to different market designs.

3.2. Methodology

To this purpose, we investigate the role of an aggregator from three different perspectives. First, we review the EU policy goals and the relevant regulatory documents such as the Clean Energy for All Europeans Package and the recently adopted Regulation establishing a guideline on electricity balancing (GL EB), identifying the main aspects of market design affecting aggregators. As a second step, we identify six potential setups, i.e. ways in which the relations among aggregators, suppliers and BRPs may be structured. With the help of these we then study the empirical evidence from three European countries, Austria, Germany and the Netherlands, which were selected as all of them apply the BRP model to system balancing and aggregators already participate in the balancing market. Finally, we determine which of the setups are currently applied as well as the way the main relevant aspects of market design affect the aggregator's incentives and choices of a setup and formulate policy recommendations to overcome existing restrictions.

3.3. Policy Perspective

At the EU level, efforts have been made to boost consumer engagement, non-

discrimination and market transparency through the drafting of a comprehensive Clean Energy for All Europeans Package. The GL EB further strives to increase competition levels in the balancing market and ensure operational security in the most price-efficient way. An aggregator can become instrumental in contributing to these goals and is encouraged in the EU regulatory framework.

Notably, the recently proposed Directive on common rules for an internal market for electricity introduced two separate definitions for an "aggregator" and an "independent aggregator" [59]. The former is defined as "a market participant that combines multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market", while an independent aggregator is defined as one "that is not affiliated to a supplier or any other market participant" ([59], Art. 2 (14-15)). Recent EU regulation thus strives to create enabling conditions for independent aggregators to participate in the national markets.

These definitions do not preclude market actors from assuming more functions beyond their core activities and deciding what kind of resources on the supply and/or demand side will be included in their portfolio. Depending on a portfolio and market design, these activities can range from the participation in the wholesale markets, balancing market, other ancillary services or electricity supply of end users. According to the definition, the aggregator does not necessarily supply end consumers with electricity. They can also operate a so-called virtual power plant (VPP), which bundles small generation units for market participation. Besides, Article 4 of the Proposal for a Regulation on the internal market for electricity mandates everyone to be accountable for the imbalances they produce, either by acting as a BRP themselves or delegating these functions to a BRP [12]. That said, a market participant, a supplier or an aggregator, may or may not perform the functions of a BRP.

In the proposed EU regulation, pursuant to Articles 13 and 17 (3a) [59], independent aggregators are not obliged to seek the authorization of their customers' supplier or any other market participant. The Member States are required to adapt the regulatory framework by clearly defining roles and responsibilities, data exchange procedures and freeing aggregators from the obligation to compensate suppliers or generators ([59], Art. 17 (3b-d)). Financial compensation is permitted only provided that "one market participant induces imbalances to another market participant resulting in a financial cost" ([59], Art. 17.4). According to the GL EB, balancing energy bids can be assigned to several BRPs, for instance, the BRP of a supplier and the BRP of an aggregator. These have to calculate and exchange the corresponding incurred costs of imbalances ([37], Art. 18, 4(d)).

Therefore, the recent EU regulation highlights two main market design aspects that can affect the aggregator's incentive to participate in the balancing market and their choice of a business model, namely:

- Agreement requirements: Requirement to obtain an authorization of a BRP or a supplier is imposed in some EU countries and can effectively hinder the market entry of aggregators [74].
- Additional charges placed on aggregators: Such charges may include high administrative or network fees, risk or other premiums required to compensate a customer's supplier or the BRP.

3.4. Theoretical Perspective

The question of how the relations with other market participants are structured is relevant since new market participants do not only transform the market landscape but also affect the roles and activities of the existing stakeholders in the sector. In line with the definitions in Section 3.3, the relationship between aggregators, suppliers and BRPs can be structured in a number of ways. This is based on whether an existing supplier takes over the functions of an aggregator or if an aggregator is a standalone independent actor; whether a supplier or an independent aggregator assume the functions of a BRP and whether an aggregator can pool resources from multiple supplier or BRP portfolios. The decision tree used to identify possible setups is illustrated in Figure 3.1.

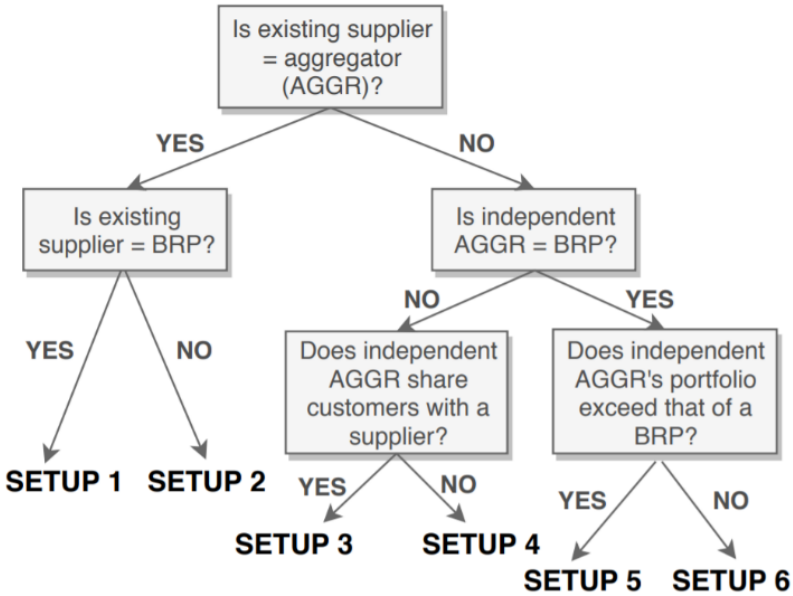

Figure 3.1. Decision tree used to identify possible interrelational setups between aggregators, suppliers and BRPs

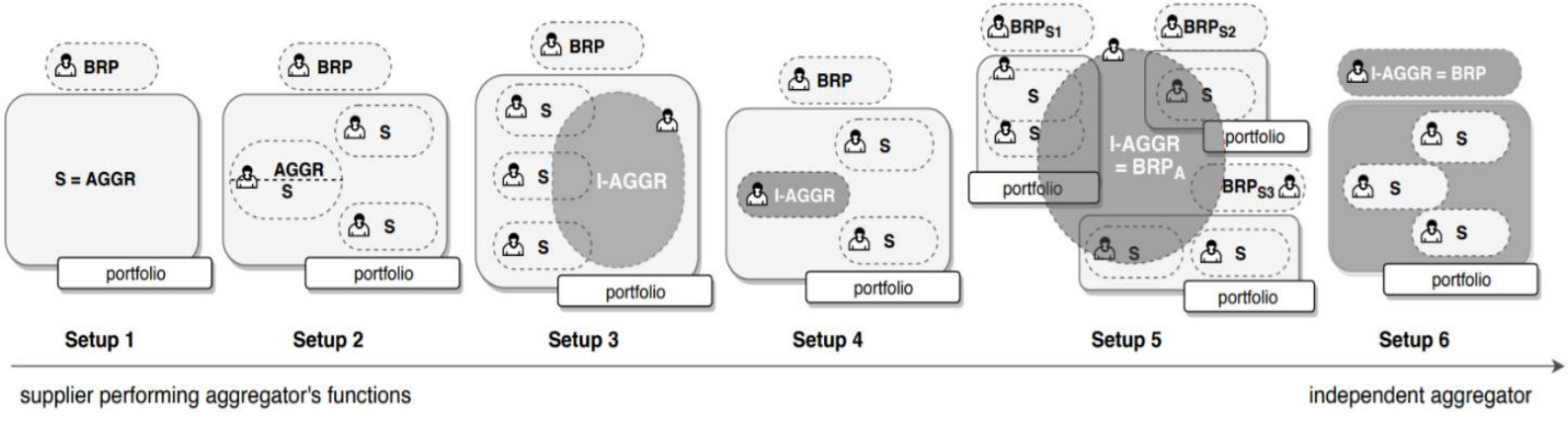

Figure 3.2. Possible interrelational setups among aggregators (AGGR)/ independent aggregators (I-AGGR), suppliers (S) and BRPs.

Based on these variables, six theoretically possible setups were defined in [58] and will be briefly explained below. The setups, as is illustrated in Figure 3.2 are ordered according to the degree of independence and flexibility with which an aggregator can choose a portfolio and the scope of his activities from the supplier-aggregator setup to the most independent aggregator setup. Figure 3.2 shows a spectrum of options: the functions of market participants are fluid and can evolve in the future and definitions may start overlapping because of an increasing number of common features. As a result, the relationship among different market parties can become more competitive or more symbiotic.

In Setups 1 and 2, the role of an aggregator can be taken up by a supplier as an extension of their business model, taking profit of their sector expertise and the existing customer base. It is common for a big supplier to form their own balancing portfolio of generation units and consumers (Setup 1) or for a daughter company to join the portfolio of the parent company (Setup 2). Such a supplier-aggregator can pool supply-side and demand-side resources to provide an array of services, including balancing, and realize economies of scale.

Under Setups 3, 4, 5 and 6, an aggregator is an independent third-party actor, as per definition in the Clean Energy Package [59]. An independent aggregator could potentially target several customer groups, thus building a more flexible portfolio, and combine a number of functions. Following this logic, a company pooling resources across energy systems or a sector-external company linking telecommunications with energy services for data management could be well-positioned to perform the role of an aggregator under Setups 3, 4, 5 and 6. Another possible actor, a local energy community, introduced in the Clean Energy Package, could be operated by an independent aggregator (Setup 6) and provide local system services along with balancing services ([59], Art. 16). However, the business case largely depends on the applicable grid tariffs and taxes.

From the point of view of cost allocation, an aggregator can have a double-edged-sword effect. On the one hand, an aggregator with flexible DER can assist the BRP in optimizing their portfolio and hedging against imbalance costs (Setups 2, 3, 4, 5). On the other hand, if an aggregator's portfolio includes a lot of variable renewables or small loads, it can turn out more difficult to avoid imbalances and an aggregator can potentially aggravate the balancing position of associated suppliers (Setup 3) and BRPs (Setups 3, 4, 5). In particular, the participation of an independent start-up aggregator can be challenging both from the point of view of customer acquisition and from a substantial investment, particularly into a reliable and advanced ICT infrastructure. Inappropriate cost allocation can result in creating value for certain parties, aggregators and their customers, while negatively affecting the rest of the players as balancing costs are at least partially socialized through system charges [75]. In contrast, applying to perform the tasks of a BRP (possible in Setups 1, 5 and 6), an aggregator would bear all the costs of imbalances. This requires a contract with a TSO and more prerequisites to fulfill in return for a better overview and control

of the available portfolio resources.

An aggregator's portfolio can be part of a BRP's portfolio (Setups 2, 3, 4) or draw their resources across several BRP portfolios (Setup 5). Such setups foresee an ex-post imbalance calculation with the involved BRP(s), which raises complexity from the point of view of financial transactions and compensation. In order to perform their tasks efficiently, an aggregator needs a robust enough DER portfolio. If an aggregator is restricted to one specific BRP portfolio, they may not have a sufficiently big pool of resources and subsequently their potential might be limited (Setups 2, 3 and 4). Notably, Setup 5 foresees an option for an aggregator to act outside a single balancing portfolio and to cooperate with several suppliers' BRPs, benefitting from a bigger, more flexible portfolio. The main challenge under this setup consists in defining proper arrangements for the imbalance settlement among the actors involved.

Finally, one of the main yardsticks of an efficient market is successful mitigation of market power. In case an incumbent supplier providing balancing services decides to assume the role of an aggregator, the issue of market concentration in the balancing market remains unsolved although the goal of greater customer involvement in the market can be accomplished nevertheless. Even when a new independent aggregator enters the market and achieves a dominating position with a vast flexibility portfolio, as would be possible in Setups 5 and 6, the competition levels can deteriorate. These setups echo the idea of a centralized aggregator described in [75].

The described benefits of aggregation and potential tradeoffs were matched with the analyzed setups in Table 3.1.

Table 3.1. Overview of benefits and main concerns linked to the identified setup.

Setup	**Benefits**	**Potential risks / disadvantages**
Setup 1 S = AGGR = BRP	Economies of scale, portfolio diversification, new services (e.g. spot and balancing markets)	No contribution to increasing competition in the balancing market
Setup 2 S = AGGR ≠ BRP	More services, minimization of imbalance costs through a "flexibility buffer" from DER	No contribution to increasing competition in the balancing market
Setup 3 I-AGGR ≠ S ≠ BRP	Customer engagement, activation of the demand side; new services	Possible difficulty for an aggregator to achieve a marketable portfolio size; potential conflicts of interest with the supplier or BRP due to

		increasing imbalance volumes; potentially, higher complexity
Setup 4 I-AGGR ≠ S ≠ BRP; $BRP_S \neq BRP_A$	Potentially higher competition levels in the balancing market; innovation; potentially: optimization of a BRP's portfolio	Possible difficulty for an aggregator to achieve a marketable portfolio size; potentially higher imbalance costs for the BRP
Setup 5 I-AGGR ≠ S ≠ $BRP_{S1,S2,Sn}$, AGGR = BRP_A or AGGR ≠ BRP_A	Flexible portfolio composition; contribution to competition in the balancing market; innovation; economies of scale possible	High costs of portfolio optimization for the aggregator; high complexity as financial compensation with suppliers or BRPs necessary.
Setup 6 I-AGGR ≠ S = BRP_A	High flexibility in portfolio composition; more services; suitable for a Local Energy Community ([59], Art. 2(7))	Cost of BRP portfolio management Potentially, exertion of market power in case of a big centralized aggregator [75]

3.5. Reality check

Given EU policy goals and prescriptions for the participants' roles and the associated market design, it is important to evaluate how aggregators organize themselves locally. This section deals with the setups applicable in the countries of study, the reasons for aggregators' choices and implications thereof. We further discuss constraints aggregators face due to market design. As pointed out in the previous sections, the aggregator's freedom and attractiveness of the business case depends on such market-design-related factors as the possibility to pool units from different BRP portfolios, agreements required with other market participants and applicable charges, which are approached differently in individual countries. This means that while some setups maybe allowed, these restrictions make their choice *de facto* unattractive for an aggregator. This will help us to understand whether national market designs allow aggregators to develop their full potential in the balancing market.

3.5.1. Austria

In Austria, all of the described configurations can be implemented and do not run into regulatory barriers [58]. It is the aggregator's prerogative to choose the setup they deem most optimal. Five aggregators (out of which three are independent) have been prequalified to participate in the balancing market.

The relations between the independent aggregator and other market participants as well as compensation mechanisms are not stipulated in the market design rules, thus the specific conditions vary from one agreement to another. Furthermore, the Austrian regulator does not place any restrictions on the composition of the pool and does not specify who is allowed to perform the role of an aggregator. Cross-BRP pooling is allowed in Austria, which gives an independent aggregator more flexibility in setting up his DER portfolio (Table 3.1).

The example of currently active aggregators shows that pooling of small generation facilities is more practicable than demand response (DR). Only two aggregators in the electricity market included industrial DR in their portfolios. Thus, the goal of greater consumer engagement has been fulfilled only marginally. Another specificity of the Austrian market is that only those RES that do not obtain their revenues under a support scheme are allowed to generate additional revenues through the participation in the balancing market.

In the balancing market, an aggregator is under obligation to coordinate his activities with the respective BRP(s). Besides, the supplier's consent is obligatory if the independent aggregator and supplier belong to different BRP portfolios (case of Setup 5). An aggregator therefore has an incentive to form an own balancing group that avoids potential conflicts of interest with other market participants as well as the need to carry out financial adjustments with the BRP or supplier or seek their consent. This explains why the aggregators in Austria prefer setups at the ends of the scale in Figure 3.2, under which either incumbent suppliers take over aggregation (Setups 1 and 2) or an independent aggregator concentrates all DER in one self-managed balancing portfolio (Setup 6), as the analysis in [58] showed.

3.5.2. Germany

Similar to the Austrian case, German market design does not limit market participants in the choice of a setup or the type of resources they include in the pool. In Germany, 8 independent aggregators have been prequalified to participate in the balancing market for one or several products with portfolios including a variety of DER, such as CHPs, industrial loads and power-to-heat, as well as vRES generation. Energy storage is gaining importance in aggregation activities [76] and has already been implemented by two German aggregators. RES providers under a market-based "direct sale" (Direktvermarktung) mechanism are allowed to generate additional profits from participation in the balancing market.

Demand response from industrial and commercial providers is much more actively used in the German context, which can be explained by the effort of the regulator, Bundesnetzagentur (BNetzA), to minimize the number and extent of contractual relations needed for consumers to carry out their activities in the balancing market either individually or with the help of a "third-party" aggregator. BNetzA, specifically addressed the "intermediate" setups where an aggregator is not at the same time a

supplier or a BRP (Setups 3, 4, 5) with reference to the provision of balancing products from final consumers[20] [77]. According to the decision, an end consumer shall notify his supplier of his intention to provide balancing services. A consumer's supplier yet cannot deny this right to a consumer or aggregator unless this has been explicitly stipulated in the supply contract. No obligation of notification or approval is foreseen with respect to the BRP as neither the end consumer nor their associated aggregator has a direct contract with them. Unless specified, an end consumer can provide balancing services through the BRP of the aggregator and the supplier's BRP is under obligation to "open their group" [77]. The German regulator thus attempted to overcome potential barriers to entry mentioned above making intermediate Setups 3, 4 and 5 more viable and their choice more common among German aggregators.

Concerning the compensation mechanisms between market participants, it has been argued that aggregators' activities cause a higher administrative effort for the BRP due to schedule adjustments and exchanges as well as higher risks for the suppliers of those customers whose units are used for the provision of balancing energy. Following the EU guidelines described in Section 3.3, BNetzA decided against applying additional charges in these respects. However, while no risk premiums are foreseen, suppliers can still charge customers and, consequently, aggregators disproportionately for schedule exchanges, which can arguably act as a *de facto* deterrent to their participation in the balancing market. For this reason, in Germany, it is more economically sensible for an aggregator to engage in electricity supply of end consumers to avoid conflicts of interest and possible barriers to entry.

3.5.3. The Netherlands

Similar to the other two markets, the Dutch market actors are offered extensive pooling options to participate in the balancing market. Yet, so far no aggregators are providing *standard* balancing products in the country. The only aggregator poised to do so is German Next Kraftwerke through a new partnership with Energie365[21]. Main reason for this lies in the fact that bidding in the Dutch balancing market is conducted through the BRP. This means that an explicit agreement of a BRP is required to allow an aggregator to submit their bids. Besides, for standard balancing products, aggregators so far cannot deliver services from portfolios of different BRPs (Setup 5), limiting their potential to contribute to system balancing.

As long as an aggregator cannot assume the role of the BRP themselves – and in so doing take sole responsibility for imbalances – they cannot participate in the balancing market without BRP intermediation, excluding Setups 3 and 4 from their options. Yet, the costs of management of a balancing portfolio are not trivial and

[20] Specifically, automatic frequency restoration control (aFRR) and manual frequency restoration reserve (mFRR)

[21] https://www.next-kraftwerke.com/news/next-kraftwerke-netherlands-virtual-power-plant

should be evaluated, whether a BRP role makes economic sense. Besides, assuming the role of a BRP, an independent aggregator has to ensure that the portfolio is properly dimensioned to avoid high imbalance volumes. Imbalance prices create a tangible risk for market participants, as these, unlike in Germany or Austria, are published very close to real time. As a result, Dutch aggregators mainly fulfil an ancillary function providing flexibility for BRP's portfolio optimization.

Notably, in contrast to standard balancing products, aggregators are active in the provision of so-called emergency power (Noodvermogen) with about 5 aggregators who are allowed to pool resources from different BRP portfolios for this purpose. Emergency power is a specific balancing product predominantly provided by large industrial consumers. The Dutch transmission system operator procures emergency power on a yearly and quarterly basis, which guarantees fixed revenue flow but at the same time if the aggregator was not chosen, the pool will be inactive for an entire year or quarter. The aggregator should have a bigger pool than stated in the contract with TenneT to ensure it has a flexibility buffer in case of non-delivery, which is heavily penalized by TenneT. This therefore limits the choice of a setup to Setups 5 and 6 where aggregators do not run into portfolio constraints.

These considerations make it easier for existing suppliers with established BRP relations to take up an additional aggregation function (Setups 1, 2) and make possibilities for independent aggregation beyond emergency power limited.

3.6. Results and conclusions

EU policy goal to encourage independent aggregation relies on the premise that their growing number can improve the performance of the balancing market by bringing more flexibility into the market, maximizing competition and ultimately reducing the cost of balancing. We showed that the relations among market participants, suppliers, aggregators and BRPs, can be set up in a number of ways and influence the modalities of aggregators' participation in the balancing market. All the identified setups (Figure 3.2), as shown in Table 3.1, involve tradeoffs; the extent to which they materialize and the aggregator's choice of a setup depends on market design in individual countries. It includes such key aspects as obligation to conclude agreements with other actors or compensation mechanisms in place. The case study of 3 EU countries shows how these are approached differently and are so far not entirely aligned with the recent EU regulation described in Section 3.3.

The specifics of market design in individual countries affect the freedom with which independent aggregators can choose the most optimal setup for themselves and realize their potential in the balancing market. While ever more aggregators have been sprouting in the German balancing market, their performance in the Dutch balancing market is negligent (except for emergency power). Required intermediation of other market actors, namely BRPs, in the Dutch balancing market,

reduces their incentive to participate. The incumbents, in turn, are in a better position to include aggregation into their activities as a promising business model (Setups 1 and 2). Stringent requirements to obtain other market actors' consent may either limit the range of services they can provide from flexible DER or the extent to which they are incentivized to engage suppliers' customers. In the countries where such contractual agreements are imposed on aggregators, there is an incentive for market participants to consolidate their activities by assuming multiple roles, common for Austrian aggregators. Assuming more functions for a single actor, i.e. choosing a setup at the extremes of the scale in Figure 3.2 (Setups 1 and 6), simplifies cost allocation and reduces conflicts of interest. It is however also linked to higher costs and does not necessarily contribute to maximizing competition in the balancing market. Relaxing applied agreement requirements, similar to the recent measures taken in Germany, unlocks the intermediate setups (Setups 3, 4 and 5) and helps create synergies among aggregators, suppliers and BRPs.

To fully exploit the potential of aggregation of flexibility, independent aggregators should be acknowledged and encouraged by explicitly allowing Setups 3, 4, 5 and 6. This would expand the range of business models available to them and therefore maximize their contribution to the balancing market. In particular, reliance on intermediate Setups 3 and 4 will lead to more symbiotic relations with other market actors while the choice of Setups 5 or 6 can foster competition among existing suppliers and new independent aggregators.

To improve the situation of aggregators in EU Member States, independent aggregators should be allowed to perform their tasks on par with the established market actors and given freedom to choose the most optimal setup. It is possible to unlock all possible setups by lifting agreement requirements to guarantee aggregators' actual independence and allowing pooling DER beyond a single BRP portfolio. Finally, uniform compensation mechanisms should ensure that aggregators are responsible for the produced imbalances but are not unduly disadvantaged by additional changes.

4

Interrelated balancing and wholesale electricity markets and their effect on bidder cost structure and strategies[22]

This study provides insights into the consequences of market actors' bidding strategies depending on market design changes, particularly the sequence and timing of different marketplaces. Balancing market bidding represents a complex decision problem for prequalified market participants as they could profit not only from reserving capacity but also from increasing or decreasing their output. At the same time, they face opportunity costs due to trading options in the wholesale markets. The bidding decisions are affected by the planned splitting of balancing capacity and balancing energy markets. Other factors that influence actors' strategies is the introduction of voluntary balancing energy bids and the gate closure time of the balancing capacity auction with respect to the day-ahead market. We investigate the impact of these changes by developing a theoretical bidding calculus for participants in multiple markets based on decision theory. We show that the sequence in which markets close and clear has an effect on market actors' cost structures and their incentive to bid their capacity in a given market using three market design options. The business-as-usual option with a joint market is compared to split balancing capacity and energy markets with clearing for balancing capacity

[22] This chapter has been published as Poplavskaya K., *et al.*, Impact of short-term market sequences on bidding behavior of market participants. Proceedings of the 3rd European Grid Service Markets Symposium, 2019.

before or after the closure of the day-ahead market. The possibility of submitting voluntary balancing energy bids is explicitly considered in the bid formulation.

We find that the effect of splitting balancing capacity and energy markets will be marginal unless the timing of balancing capacity market is also adjusted and voluntary bids are introduced. The procurement of balancing capacity day-ahead after the closure of the day-ahead market ensures that more expensive power plants with the lowest opportunity costs bid for balancing leading to an efficient market equilibrium. The effect of the introduction of voluntary bids is twofold. It will on the one hand reign in high balancing energy prices but also create higher opportunity costs and, ergo, higher balancing capacity prices as bidders will attempt to compensate for the foregone profits from balancing energy by bidding higher for balancing capacity in the next rounds in repeated auctions. Thereby the optimal bidding strategies of voluntary bidders and regular bidders using voluntary bids as a second chance to participate in the balancing energy market will differ.

4.1. Introduction

At present, European balancing markets are undergoing far-reaching reforms [37]. These auction-based markets need to cope efficiently with the changing system reality such as increasing volumes of variable renewable energy sources (vRES). On the other hand, new resources such as flexible loads and distributed generation are penetrating the system and the markets. Another important driver is the progressive integration of European electricity markets, which requires an adaptation of national marketplaces towards coordinated European marketplaces and a harmonized market design [37], [78], [79].

Market participants have a number of options to generate profits in liberalized electricity markets. They may trade energy at the spot markets, i.e. day-ahead (DA) market and intraday (ID) market, or offer flexibility in the balancing market to aid the transmission system operator (TSO) to keep generation and load in balance. From the perspective of market design, a crucial factor that determines the performance of balancing markets is the timing for the procurement of balancing capacity (BC) and balancing energy (BE). Timing changes in the spot markets have an effect on the balancing market and vice versa [13], [53]. The reason for this is that balancing service providers (BSPs) face tradeoffs when participating in the balancing markets or in the spot markets. Thus, the order of markets affects participants' cost structures and creates interdependencies between their strategies in different markets with regard to bid volumes and prices (e.g. [70], [80]).

In most European countries, BC and BE are procured jointly in a single auction ahead of the DA market[23] [42], [44]. A separate market for BE must be implemented in European balancing markets for automatically activated Frequency Restoration Reserve (aFRR) no later than 2021, pursuant to the EU Electricity Balancing Guideline (GL EB), the main EU regulation guiding the future balancing market design [37]. Furthermore, so-called voluntary BE bids must be introduced [37]. This implies that market participants who did not participate or were not awarded in the BC market may still submit BE bids without receiving remuneration for capacity. In this way, BSPs do not necessarily reserve their capacities in advance but aid system balancing on a more *ad hoc* basis, which is expected to improve market efficiency and boost competition [37].

Given the novelty of this regulatory change, to our knowledge, its implications have not yet been examined in the literature. Additionally, most balancing-market-related studies focused on BC reservation alone while the procurement of balancing energy was not investigated in its own right (e.g. [42], [46], [82]–[84]).To analyze the effect of the changes in the balancing market design on BSPs' bidding strategies, we pose three research questions in this study:

- What is the effect of splitting BC and BE markets on bidders' cost structures and bids in these markets?
- The GL EB only prescribes the temporal position of the BE market, yet the position of the BC market is not fixed. What effect does the position of the BC market with respect to the spot markets have on the cost structures of the bidders?
- What is the effect of the introduction of voluntary bids on BSPs' optimal bidding strategies in the balancing market?

In order to answer these questions, we contrast the presently most common balancing market design with several options for split BC and BE markets. We analyze the optimal bidding strategies that result from these options and discuss which option best fulfills the above-stated policy goals. We develop a theoretical bidding calculus for participants in multiple markets based on a decision-theoretical approach. We present a BSP's bidding calculus for each market design option and derive the profit maximizing bidding strategy.[24]

[23] One of the few exceptions to this rule is the Dutch balancing market design where BE is procured separately from BC. In the Nordic countries, in contrast, a BE-only product exists for mFRR, i.e., no BC is reserved in advance [81].

[24] Note that we do not apply a game-theoretical analysis. This would exceed the scope of this paper. For a game-theoretical model of the current Austrian-German and future harmonized European aFRR auction please refer to [27].

4.2. Market design and market actors' cost structures

The fundamental goal of each market is different: the DA market is the primary market for energy trade, the ID market serves as the final option for "last-minute" schedule adjustments, the BC market represents an option market for possible future activation, and the BE market is the actual physical contribution for stabilizing system frequency. The BE market and the ID market serve similar purposes, i.e., addressing system imbalances: in the ID market, market participants attempt to minimize deviations from their submitted schedules (e.g. due to an updated forecast from renewables or unforeseen changes in demand), while in the BE market, the TSO alleviates system imbalances by BE activation.

The availability of different marketplaces determines the number of trading options for market actors and consequently their prospects for profit. This is illustrated in Figure 4.1 and discussed in the following. Market actors can be characterized by two important factors. Firstly, not all wholesale market participants can place bids in the balancing market due to the technical prequalification required for market entry. Prequalified market participants, BSPs, must decide whether to sell their capacities on one of the spot markets, where only energy delivery is remunerated, or on the balancing market, where profits from both the reservation of BC and the delivery of BE can be generated.

Secondly, based on their short-term marginal costs, a distinction is made between inframarginal and extramarginal market participants. Inframarginal participants' variable costs are lower than the marginal price in a given market. In contrast, variable costs of extramarginal participants are higher (e.g. [43]). This characteristic determines in which markets actors can offer their available capacity profitably as well as their cost structures. Considering the high observed empirical balancing prices [85], a market actor with high variable costs, e.g. a gas-fired power plant, is likely to be extramarginal in the spot markets but inframarginal in the BE market (see also [86]). In contrast, a market actor operating coal-fired power plant, which is likely inframarginal in the DA market, must consider expected profits in different markets when formulating their trading decision ([43] [70], [86]). Finally, market actors with short-term flexibility (e.g. vRES) tend to bid in the ID market as they are most often not allowed to participate in the balancing market [87].

If the system is undersupplied, positive BE bids are required to increase generation (or reduce load) whereas in the case of undersupply negative BE bids are needed to lower generation levels (or increase load) in order to restore system balance. Following the merit-order in the positive and negative balancing market, bids are activated from the lowest to the highest bid. In the latter, a BSP generates savings by reducing its generation level, so in this market BE bids with the highest variable costs should be activated first. Figure 4.1 shows that the bids for the two regulation

types imply different cost structures, which may or may not include opportunity costs.

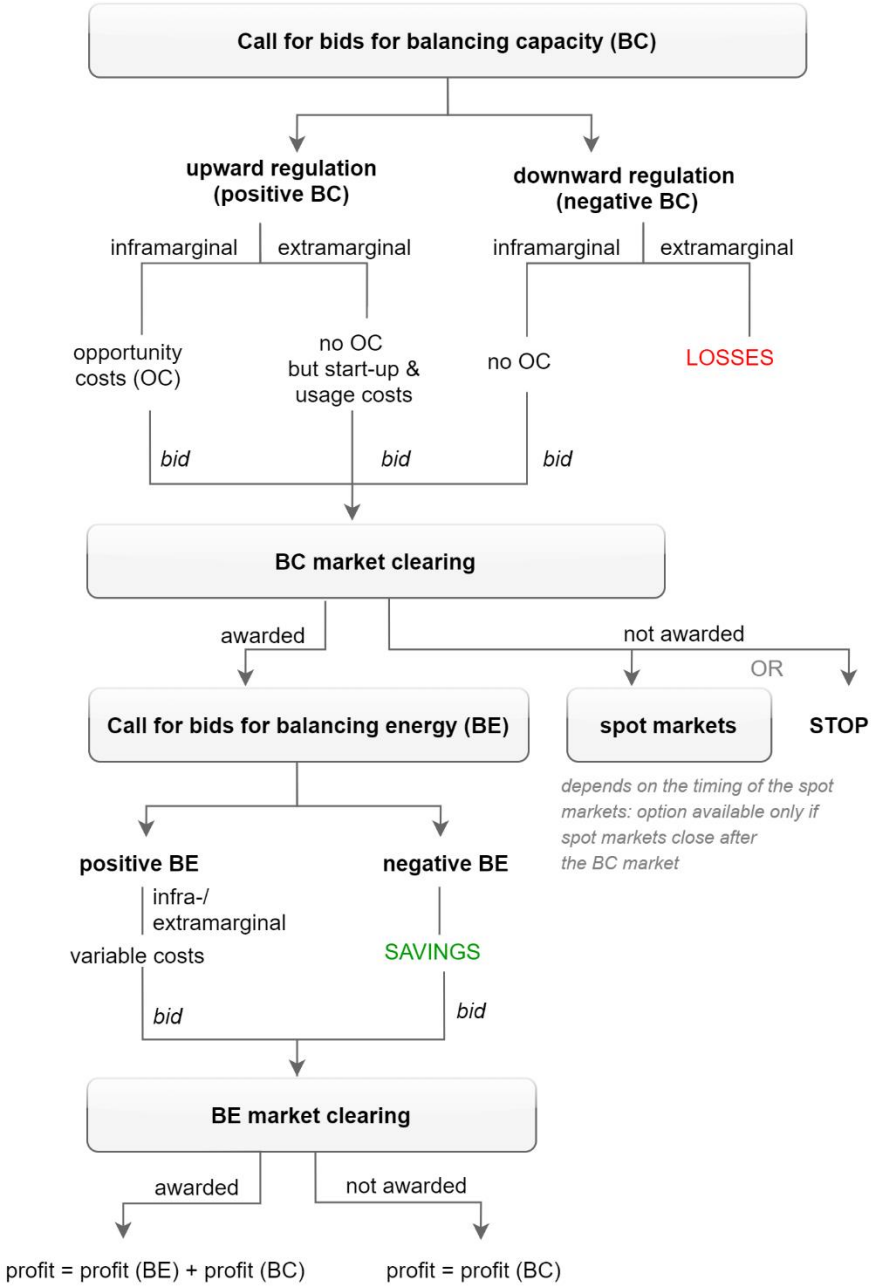

Figure 4.1. Trading options and associated costs for prequalified BSPs in the balancing market.

Unlike technology-related costs, opportunity costs are largely dependent on a market sequence applied and limit market actors' strategy space. Market sequence also plays a role in determining whether BSPs that were not awarded in the balancing market can still offer their capacity in one of the spot markets. Their order is defined by a number of timing-related design variables, such as:

- the bidding frequency, i.e. how often a specific auction takes place,
- the bidding period, i.e. the timeframe when the order book is open, starting with gate opening time (GOT) and ending at the gate closure time (GCT) when no bids can any longer be modified or any new bids submitted and
- the frequency of market clearing, i.e. how often the market operator builds a respective merit order and determines the market clearing price.

Depending on the frequency of bidding, BC can be reserved for potential activation for different periods of time so that the reservation period during which BE can be activated can vary from a year to an hour or even less [44], [87]. Unlike the DA market and the ID market, in the balancing market bidding and clearing times can differ. For instance, if bids for BC and BE are submitted only once a week, i.e., the capacity market is cleared once a week, the energy market may be cleared every 15 minutes based on real-time system imbalances. Currently, fifteen minutes is the shortest settlement period applied in the European markets [42]. In contrast, if the two markets, for BC and for BE, are split, the frequency of bidding of BC and BE are not identical.

The wholesale markets and the balancing market can be cleared either sequentially, a preferred way in the ENTSO-E area [42], [88], or simultaneously, for instance, as implemented in some US markets (e.g. PJM or CAISO). The markets are further characterized by different lead times, i.e., the time between GCT and bid execution, e.g. one day for the DA market and 60 to 5 minutes for the ID market (e.g. [89]) [e.g. 19]. Finally, the markets in a sequence can be more spread out with longer time periods in between respective bidding periods or positioned compactly within a short timeframe, e.g. a day.

4.2.1. Cost Structures

The underlying cost structures are crucial for the formulation of the bidding calculus. They consist of costs of capacity reservation (henceforth capacity costs) and costs of energy activation (henceforth calling costs).

Capacity Costs

Capacity costs include all costs of a BSP for reserving BC for the balancing market and are included in the BC bid in Euro/MW. For positive BC, the operator of an inframarginal power plant needs to consider opportunity costs. These arise due to sequential market clearing of the balancing and the spot markets so that the capacity

committed to the balancing market cannot be sold in these other markets during the reservation period. The opportunity costs are given by the margin between the relevant market price and the variable costs, multiplied by the length of the reservation period (Figure 4.1). For negative BC, inframarginal power plants do not face opportunity costs: all the produced energy is sold at a profit because the operator must run the plant on a certain minimum load. For the operator of an extramarginal power plant several cost components are included in the capacity costs, such as start-up costs, usage costs or maintenance costs when providing upward regulation (Figure 4.1). However, these cost components are highly dependent on a specific power plant and, thus, are not considered in our theoretical analysis.

Calling Costs

Calling costs are assigned to the BE bid in Euro/MWh. The TSO incurs these costs in case BE is called. For positive BE and both inframarginal and extramarginal power plants, these costs are equal to the variable costs of generation. For negative BE, these costs are actual savings (Figure 4.1). The reason is that BSPs are still remunerated with the relevant market price. Recall, if negative BE is needed, there is too much energy supplied to the power system. Thus, a BSP does not need to produce traded energy with her power plant and also saves costs by reducing the load level of her power plant. Therefore, a BSP may be willing to pay the TSO for the delivery of negative BE, where the maximum willingness to pay is determined by the variable costs of the BSP's power plant.

4.3. Analysis of market design options

4.3.1. Current design: Joint market for BC and BE

This option is most frequently used in the European balancing markets (cf. [42]). BC bids and BE bids are submitted in the same bidding period, while the joint market is cleared only for BC. The scoring rule, i.e. the determination of winning bids, comprises solely BC bids. The BE bids in the merit-order remain the same for the duration of the reservation period (from the GCT to real time). The GCT of the DA market and ID market take place after the GCT of the balancing market. Finally, the BE market is currently cleared every 15 minutes to one hour close to real time (Figure 4.2).

Figure 4.2. Joint market for BC and BE clearing before the DA market.

The BSP's objective is to maximize her (expected) profit, which depends on her capacity costs c and calling costs k. The BSP's probability of being accepted with her BC bid b_C is described by function $H(b_C)$, which has a negative derivative, $h(bc) \leq 0$. A BSP's probability of being called for the delivery of BE on the basis of her BE bid b_E, is described by function $G(b_E)$. Since the calling probability $G(b_E)$ decreases with b_E, its derivative is less or equal to zero, $g(b_E) \leq 0$. The probabilities $G(b_E)$ and $H(b_C)$ are based on BSPs' subjective beliefs. The reservation period in hours is denoted by d and a BSP's capacity offer by q (i.e., her prequalified capacity). For the purpose of this analysis, we assume that a BSP submits only one BC bid and only one BE bid. If a BSP is awarded, her expected profit is given by (see also [14])

$$\pi(b_C, b_E) = H(b_C) \cdot q \cdot [(b_C - c) + (b_E - k) \cdot d \cdot G(b_E)] \,. \tag{1}$$

The first-order conditions for the maximization of (1) with respect to both bids b_C and b_E lead to the following conditions for optimal BC and BE bids b_C^* and b_E^*:

$$b_C^* = c - (b_E^* - k) \cdot d \cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)}, \tag{2}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}. \tag{3}$$

The optimal BC bid b_C^* depends on the capacity costs c. The term $(b_E - k) \cdot d \cdot G(b_E^*)$ in (1) reflects the expected profit of the BE bid per megawatt (MW) $\pi(b_E^*)$. That is, the expected profit of the optimal BE bid b_E^* is considered in the calculation of the optimal BC bid b_C^*. Since the term $H(b_C^*)/h(b_C^*)$ is negative, its absolute value is added to c. In our model the price rule pay-as-bid (PaB) is applied, i.e., awarded BSPs are remunerated with the bid figures they submitted.[25] This markup is due to the PaB rule and corresponds to a markdown in sale auctions, which is called "bid-shading" [91]. The optimal BE bid b_E^* is independent of the optimal BP bid b_C^* because the BC bid must be accepted first before any profits can be generated with the BE

[25] The authors are aware that the GL EB foresees pay-as-cleared (uniform pricing) as price rule in the future, harmonized balancing markets. However, we decided to apply pay-as-bid in our analysis for three reasons. Firstly, the aim of this paper is the examination of effects on bidding strategies based on different market sequences, not based on different price rules. For an analysis of different price rules refer to [6], [90]. Secondly, GL EB allows using pay-as-bid in balancing markets if it is proven that its application leads to a higher efficiency than pay-as-cleared. Thirdly, the theoretical analysis is more complex and less intuitive with pay-as-cleared as a price rule (see [6], [26]), i.e. exceeding the scope of this paper.

bid. The calling costs k are the basis of the optimal BP bid, to which – due to the PaB rule – the absolute value of $G(b_E^*)/g(b_E^*)$ is added as a markup.

From a theoretical perspective, this market sequence ensures overall market efficiency, i.e., minimizing overall costs. The reason for this is that winner determination is based on the submitted BC bids: BSPs with the highest variable cost and, thus, lowest opportunity cost incorporated in the BC bid, are awarded for the balancing market. This yields the efficient allocation that BSPs with low variable cost are not selected in the balancing market but run continuously on the spot market, while BSPs with high variable costs are selected for the balancing market in which they are activated discontinuously (based on the system imbalance) [6], [43], [86].

Under the current design, the expected capacity costs c are given by

$$c = \max((p_{DA} - VC) + \varepsilon_{DA}; (p_{ID} - VC) + \varepsilon_{ID}) , \tag{4}$$

where VC denotes the costs of power generation p_{DA} denotes the (expected) price of the DA market, and p_{ID}denotes the (expected) price of the ID market. Note that BSPs form beliefs about future DA and/or ID market prices since those are not known at the time of BC bid submission. To capture this price uncertainty of BSPs, we use the variables ε_{DA} and ε_{ID}, which can be interpreted as risk premiums with regard to expected opportunity costs. According to (4), capacity costs represent the maximum of the price spread of the DA market and a BSP's variable cost and the price spread of the ID market and a BSP's variable costs.

The magnitude of BSPs' expected opportunity costs is affected by how big the temporal gap between the GCT of the balancing market and that of the spot markets is. The farther the time of bid submission is from real time, the less precisely the expected opportunity costs can be estimated. As a result, market participants are more likely to place BE bids as close as possible to the maximum expected spot market prices to reduce the extent of missing out on profits from the spot markets [92]. A greater uncertainty produces higher risk premiums ε_{DA} and ε_{ID} as well as a risk for market inefficiency due to a higher probability of a distorted assignment of BSPs to the spot markets and balancing market. The size of the risk-premium depends also on the volatility of the spot market prices, i.e., the higher the volatility of the prices, the higher are the BSPs' risk premiums [93].

Thus, information availability largely depends on the time horizon of the balancing market. According to GL EB, "the contracting should be performed for not longer than one day before the provision of the balancing capacity and the reservation period shall have a maximum period of one day" ([37], Art. 5.9). Frequent bidding opportunities make it easier to evaluate the options closer to real time. However, the compression of GCTs may also lead to liquidity issues, particularly for daily timeframes [94], and to a much higher price volatility [53], thus increasing the magnitude of risk premiums ε_{DA} and ε_{ID}.

4.3.2. Alternative market design options: Split markets for BC and BE

Split markets for BC and BE imply that the BE market is independent of the BC market and both market clearing times and bidding frequencies differ. Furthermore, an additional factor is modelled: voluntary BE bids. As a result of their introduction the bid components for existing BSPs change: an additional voluntary BE bid b_{VE} is added.

In our model, two distinct bidding options are considered. Firstly, if a BSP is awarded with the BC bid b_C, she submits her regular BE bid b_E, and if a BSP is not awarded with the BC bid, she can still submit her voluntary BE bid b_{VE}. Secondly, a BSP that did not participate in the BC market now also can still submit a voluntary BE bid (e.g. vRES plants that cannot reserve capacity upfront).

Note that in the first option the bidding strategy for the BC bid and the regular BE bid is not independent of the bidding strategy for the voluntary BE bid. The reasons for this is that bidders still have the chance to submit their voluntary BE bid if not awarded with the BC bid. This is not the case in the second bidding option: if a BSP did not participate in the BC market, she submits a voluntary BE bid exclusively. Further note that we assume that regular and voluntary BE bids form part of a single merit order.

Split BC and BE market with DA market cleared after BC market

In this design option capacity reservation takes place ahead of the DA market whereas the GCT of the DA market takes place prior to the opening of the market for BE, as is shown in Figure 4.3. Importantly, even if the BC and BE markets are formally split; bidders who commit their capacity in the first one will inevitably take the expected profit from the latter into account. In contrast to BC bids, different BE bids can be submitted each 15 minutes. The capacity costs correspond to (4).

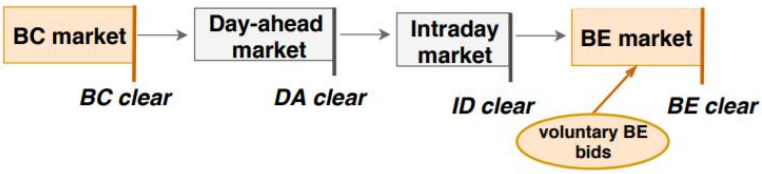

Figure 4.3. DA market cleared after BC market and before BE market.

If voluntary bids are allowed, an additional element is considered in the expected profit function as the BSP who participates in the BC market takes both options for BE bid submission, regular and voluntary, into account. The expected joint profit is given by

$$\pi(b_C, b_E, b_{VE}) = H(b_C) \cdot q \cdot [(b_C - c) + (b_E - k) \cdot d \cdot G(b_E)] + \\ + \big(1 - H(b_C)\big) \cdot G(b_{VE}) \cdot (b_{VE} - k) \cdot d \ . \tag{5}$$

The BSP is awarded with the BC bid b_C with probability $H(b_C)$ and, thus, generates profits with the BC bid and the regular BE bid, while with the probability $\big(1 - H(b_C)\big)$ a BSP is awarded with the voluntary BE bid b_{VE}. For maximizing (5), we compute the first-order conditions for the optimal BC bid b_C^*, regular BE bid b_E^* and voluntary BE bid b_{VE}^*, which lead to the following conditions:

$$b_C^* = c - (b_E^* - k) \cdot d \cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)} + (b_{VE}^* - k) \cdot d \cdot G(b_{VE}^*), \tag{6}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}, \tag{7}$$

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)} \ . \tag{8}$$

Compared to (2), the optimal BC bid in (6) includes an additional markup corresponding to the opportunity costs given by the expected profit of voluntary BE bid. The optimal voluntary BE bid has the same structure as the optimal BE bid: the basis are the calling costs k plus the absolute value of the markup.

If the BSP did not participate in the BC market and is then awarded with the voluntary energy bid, her expected profit is given by

$$\pi_{VE}(b_{VE}) = G(b_{VE}) \cdot (b_{VE} - k) \cdot d \cdot q \ . \tag{9}$$

Note that in the case of non-acceptance with the voluntary BE bid, a BSP does not generate a profit at all because the DA market and ID market already cleared. The first-order condition for maximizing (9) leads to the condition for the optimal the voluntary BE bid b_{VE}^*:

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)} \ . \tag{10}$$

Note that the voluntary BE bid is identical with the term in (8).

Split BC and BE market with DA market clearing before the BC market

In this option, BC is procured on a daily basis after the GCT of the DA market and BE is auctioned after the GCT of the ID market, as is illustrated in Figure 4.4.

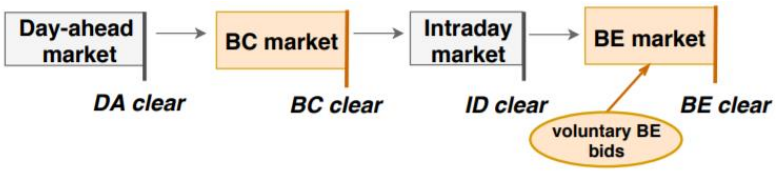

Figure 4.4. BC and BE markets clearing after the DA market.

The opportunity cost reflect the expected foregone profit of the ID market:

$$c = (p_{ID} - VC) + \varepsilon_{ID} \,. \tag{11}$$

For both bidding options, the expected profit function is identical as in (5) and (9) and the first-order conditions for the optimal bids are identical as in (6)-(8) and in (10).

In practice, a BSP with a portfolio of units can allocate different portfolio shares to each market depending on their variable costs and, thus, maximize profits. Given that BSPs have the chance to generate higher profits in the subsequent balancing market, the DA market price now incorporates balancing market opportunity cost. Depending on the extent of which the DA price is influenced by these opportunity costs, the higher the DA market price, the less attractive is the balancing market option, and vice versa.

Yet, both from a theoretical standpoint (e.g. [27], [86]) and confirmed by empirics [85], the balancing market offers higher profits, even as close as a day-ahead of delivery. Notably, in the BC market where capacities are reserved, BSPs do not face variable costs, unlike the DA market where participants incur costs for actual energy generation. Market participants, both those extramarginal in the DA market but also inframarginal, are thus incentivized to provide the maximum of their prequalified capacities as BC, potentially driving volumes away from the DA market.

Although technically feasible, this sequence is unpopular because of system security concerns, that is, if BC market is following the DA market, a supply shortage is more likely, endangering the system. The ultimate goal of system balancing consists in stabilizing frequency deviations, as a result, insufficient capacity available for activation would cause power outages. Therefore, safeguards such as a second auction or mandatory provision in case of danger to system stability must be in place. Another concern is that moving the balancing market so close to real time may affect market liquidity. This, however, should not necessarily be the case due to an offsetting effect of entry of renewables and distributed providers of flexibility into the market, which becomes possible thanks to shorter timeframes and improved forecasting.

4.3.3. Introduction of voluntary BE bids

If we set $G(b_E^*) = G(b_{VE}^*)$ for (8), (9) and (10), two interesting observations can be made: firstly, the optimal regular BE bid and the optimal voluntary BE bid are identical, and secondly, the term for the optimal BC bid reduces to $c - H(b_C^*)/h(b_C^*)$. However, is it reasonable for a BSP to assume the same calling probability beliefs for both the regular BE bid and the voluntary BE bid? We argue that this is not the case. Recall that in the market equilibrium those BSPs are awarded with BC bids who have the lowest opportunity costs and, thus, (relatively) high variable costs. If a BSP is not awarded with the BC bid, she gains the additional information that her variable costs are lower than all of the variable costs of the BSPs who were awarded with the BC bid, i.e. those BSPs who form the initial merit-order of BE bids. This means that a BSP who was not awarded with the BC bid learns that she will compete with relatively "expensive" competitors for the positions in the merit order of BE bids. A rational BSP will include this information when formulating her voluntary BE bid: she will include a higher markup $G(b_{VE}^*)/g(b_{VE}^*)$ on her variable cost basis k and, thus, submit a higher voluntary BE bid compared to the regular BE bid.

The actual magnitude of the markup is a trade-off between additional profits and the position in the BE bid merit order: if a BSP exaggerates her markup, the BE bids of BSPs who were initially awarded with the BC bid, might still be lower than the voluntary BE bid. This would then result in a high position in the BE merit-order and, consequently, the BSP would deliver BE in a reduced number of cases. An additional factor that may limit her markup is that a number of voluntary bids that did not take part in the BC market will be placed in the BE market. These can be vRES or small-scale producers whose bids will not necessarily have high variable costs and their additional volume is difficult to estimate. In other words, although BSPs that previously took part in the BC market obtain an information advantage, they do not get a similar advantage in the BE market as the bidding timeframe is the same for regular and voluntary bids and all the bidders are informed about the results of the BE market only *ex post*. Besides, according to the GL EB, no BE bids may be adjusted after the gate closure time of the BE market (Art. 24, [37]).

The empirical benefits of voluntary bids from the market perspective are illustrated by the experience from the Dutch market, where voluntary bids are already used. It shows that although the number of BC providers is very limited and they participate in the market repeatedly over an extended period of time, the balancing market still shows an efficient outcome as more BE providers take part in the market through voluntary bids (e.g. [26]). Furthermore, opportunistic or collusive behavior that can arise from repeated BC auctions with a limited number of participants can be mitigated with the help of voluntary bids that seem to "cap" unreasonably high BE bids. As a result, voluntary bids can increase market liquidity and allocative efficiency making sure that the most cost-efficient units are used for the service.

4.4. Conclusion

Historically determined features of the balancing market design do not always imply that the most optimal choices were made. With the help of bidding calculus, we showed that the sequence in which markets close and clear has an effect on market actors' cost structures and their optimal bidding strategies. An additional change is expected to be produced by the introduction of a standalone BE and voluntary bids, as mandated by the GL EB. We analyzed these effects by comparing three balancing market designs and studying the possibility of submitting voluntary balancing energy bids.

An important conclusion from this study is that the splitting of BC and BE markets alone does not change BSP's optimal bidding strategy unless the timing for the BC market is adjusted and voluntary bids are introduced. If these two aspects are disregarded, the effect splitting *per se* will be marginal. The reason for that is that BSPs will still consider their costs and profits from both markets and the same bidders awarded in the BC market would participate in the subsequent BE market. Conducting the auctions for balancing capacity close to the DA market or even after its closure is likely to improve market efficiency. The expected low availability of balancing resources is not a concern for as long as the expected profits in the BE market are higher than in the DA market.

Through voluntary bids, actors with short-term flexibility and low variable costs, e.g. new market entrants such as operators of renewables not participating in the BC market, in the future can also compete for profits in the BE market through voluntary bids. We show that their bidding strategy will differ from the one of incumbent BSPs that may use voluntary bids as a second chance to enter the merit order in the BE market. The introduction of voluntary bids in separate BE markets is likely reign in very high BE prices. A potential downside could be that the balancing market becomes so competitive that profit levels in the BE market as compared to the expected profits in the spot markets decrease to such an extent that it no longer appears profitable, driving capacities out of the balancing market.

The additional short-term trading option in the form of voluntary BE bids generates additional opportunity costs, which leads to even higher BC prices if BC reservation precedes the DA market. Especially if the BC market is situated far ahead of DA market, this can provoke substantial costs of capacity reservation borne by consumers. If the BC market, in turn, follows the DA market, BSPs that are both extra- and inframarginal in the DA market are motivated to participate in the BC market thanks to higher expected profits and absence of opportunity costs. This, as a result, can help offset higher opportunity costs from the introduction of voluntary bids, leading to a more efficient outcome of BC and BE markets.

5

Effect of market design on supplier bidding in the balancing energy market[26]

Market-based procurement of balancing services in Europe is prone to strategic bidding due to the relatively small market size and a limited number of providers. In the European Union, balancing markets are undergoing substantial regulatory changes driven the efforts to harmonize the market design and better align it with the goals of the energy transition. It is proposed to decouple the balancing energy (real-time) market from the (forward) balancing capacity market and the price of balancing energy will be based on the marginal bid. In this paper, the potential effects of these changes on market participants' strategies are analyzed using an agent-based model. This model compares the effects of a standalone balancing energy market with different pricing rules on economic efficiency with agents that apply naive, rule-based and reinforcement-learning strategies. The results indicate that the introduction of a standalone balancing energy market reduces the cost of balancing, even in a concentrated market with strategic bidders. Marginal pricing consistently leads to lower weighted average prices than pay-as-bid pricing, regardless of the level of competition. Nevertheless, in an oligopoly with actors bidding strategically, prices can deviate from the competitive benchmark by a factor of 4–5. This implies that the introduction of a standalone balancing energy market does not entirely solve the issue of strategic bidding, but helps dampen the prices, as compared to the balancing market prior to the design change.

[26] This chapter has been published as Poplavskaya K., *et al.*, Effect of market design on strategic bidding behavior: Model-based analysis of European electricity balancing markets. Applied Energy, 2020. 270: 115-130.

5.1. Introduction

To balance supply and demand, most European transmission system operators procure balancing services in a market-based way through a two-stage process, first reserving the necessary balancing capacity and then activating balancing energy when system deviations occur. However, market-based procurement is not necessarily efficient as the strict technical requirements limit the number of eligible balancing service providers (BSPs). Many European electricity balancing markets have design features that, along with market concentration, make them susceptible to gaming. With the help of an agent-based model (ABM) with artificial intelligence, we study opportunities for strategic behavior and assess whether expected balancing market design changes can improve its efficiency. As the EU intends to integrate growing shares of renewables into the European grids and markets, to harmonize balancing markets and facilitate cross-border procurement of balancing resources (cf. [95]), it is important to identify balancing market design features that facilitate market entry and increase robustness to strategic bidding. The first aspect has been addressed in detail in [7], while the second aspect requires quantification of the effects of bidding strategies under different market designs and is addressed in this paper using ABM.

To stabilize the system frequency, most European transmission system operators (TSOs) procure balancing services in a competitive, two-stage process. First the necessary balancing capacity is reserved; balancing energy is activated in real time, when actual system deviations occur. However, market-based procurement is not necessarily synonymous with efficient procurement [27], [96]. Due to strict technical requirements, the current number of eligible balancing service providers (BSPs, parties who sell balancing services to the TSO) is limited. As a result, balancing markets are highly concentrated, which opens up room for opportunistic behavior and market inefficiencies.

The need for greater market integration [97] and the wish to remediate market inefficiencies led to the recent adoption of several European regulations and network codes [9], [98]. Among them, the EU guideline on electricity balancing (GL EB, adopted in November 2017) defined the main features of harmonized European balancing markets [99]. Specifically, the balancing energy (BE) market is required to be decoupled from the balancing capacity (BC) market so that balancing energy bids are submitted in a separate auction close to real time. A review of balancing market design variables and their combinations is presented in [7]. The authors structured the design variables according to priority and showed that, in order to improve market access and performance, the splitting of the balancing capacity and energy markets is the necessary first step before addressing other design aspects as most other variables depend on it [7].

In order to analyze and study the expected behavior of market players under this

new design, in this work we simulate a standalone BE market (hereafter *"split BC-BE market"*) with the help of an ABM. To this end, we implement naïve and learning agents and compare their performance. The naive agents bid their true short-term variable costs. The learning agents that are designed to represent different levels of market power take decisions either according to a pre-determined rule or by using a fitted Q-iteration algorithm (a class of reinforcement learning algorithms) to identify their bidding strategies. We investigate the potential efficiency gains from introducing a separate balancing energy market, as compared to a market where balancing capacity and energy are procured jointly (hereafter *"joint BC-BE market"*) used today. For this, we analyze the bidding behavior, profits of BSPs, and the cost of balancing in the face of this regulatory transformation.

This work provides an analysis of regulatory changes spurred by the GL EB with a new approach to modelling the balancing market, namely ABM with agents that apply learning strategies. Unlike other ABM-based studies of the balancing market, we focus on the market for balancing energy that is mandated by the GL EB. Our approach allows to represent individual elements of market design and their combinations in great detail, including different types of actors and technologies. Reinforcement learning allows agents to adapt their market strategies, which we compare with predefined strategies and with empirical observations. The combination of a detailed agent-based market model with artificial intelligence in the agents provides a powerful tool for analyzing the impact of market design on strategic behavior.

To the authors' knowledge, this is the first model-based study of the upcoming introduction of a standalone balancing energy market and marginal pricing and their effects on the bidding strategies of market actors. The model provides a deeper insight into the implications of these changes, helps to make market design more robust against gaming and to estimate the extent to which the actions of a single or few bidders can affect market outcome. This analysis is particularly relevant for the EU's harmonization efforts and energy policy goals. This paper provides useful conclusions for regulators, TSOs and policymakers and provides them with specific recommendations for improving balancing market design and efficiency.

We structure the paper as follows: Section 5.2 reviews the state of the art of the balancing market analysis and the use of ABM for electricity market modelling. Section 5.3 describes the functioning of the balancing market and the bidding process along with the main building blocks of its design. Section 5.4 presents the agent-based model, Elba ABM, its main features, key assumptions, design choices and agent strategies. Section 5.5 describes the simulation setup and scenarios. Section 5.6 provides and analyses model results and Section 5.7 concludes the paper.

5.2. Literature review

5.2.1. Balancing market analysis

Balancing markets in Europe have generally been a rather lucrative commercialization option for flexible generation. As a result, most of the current body of research has been focused on issues related to the portfolio optimization for participation in balancing markets (e.g. [100]). As the European countries have been gradually easing market access rules to new flexibility sources, recent research has extensively addressed the potential of distributed energy technologies, such as battery storage [101], heat pumps [102] household photovoltaic and storage systems [103], as well as demand response [104] for frequency support.

The relevance of the balancing market as performing a key function in the European electricity market design has been widely acknowledged in the literature. Research has addressed market design improvements [7], [48], harmonization of market rules [105], [106] and strategic bidding behavior [90], [107], among others. The authors in [105] analyze possible future market design and argue for the use of asymmetric bidding in the balancing market and shortening the product length to enable the procurement of balancing reserves from renewables and other distributed energy resources. Positive effects of market integration and the possible cost savings that can be achieved with its help were addressed in [108]. Balancing market harmonization is however complicated by large national differences [42], [109], which makes it important to identify the elements of an efficient market design. Currently, balancing markets are characterized by high entry requirements and therefore low competition levels [110], [111]. Consequently, the conventional assumption that all participants behave competitively and bid their full available capacity at true costs seems rather unrealistic.

5.2.2. The use of agent-based modelling for the analysis of bidding strategies and electricity market design

Researchers widely use ABM to analyze the effects of policy and market design changes. As shown in [112] and [113], ABM is a suitable method for capturing balancing market complexity, including noncompetitive behavior. For instance, authors in [112] used ABM to model the imbalance settlement and studied the effects of imbalance pricing on market actors. Researchers in [114] investigated the effect of different options for market clearing of interconnected day-ahead and balancing markets using ABM. In [115], ABM was applied primarily to analyze the effect of increasing shares of vRES on electricity markets. Their model, MATREM, simulates the day-ahead and intraday markets as well as forward and bilateral markets and use complex agents able to interact with the user [115]. Researchers in [116] successfully combined agent-based modelling and optimization techniques to investigate the effect of demand response and storage systems in the electricity

market as alternative to the capacity market. German electricity market design was analyzed in [113]; the authors found that the introduction of a capacity market can help solve the generation adequacy issue and is a viable alternative to the energy-only market in the long term. Bidding strategies were the main focus of [117] where the authors compared bid pricing rules in the DA market and the effects of price volatility. In [118], ABM was used to optimize bidding strategies of generating companies in the DA market and showed the suitability of this approach for modeling complex systems and interactions within them.

In an ABM, it is possible to equip the agents with learning capability [23], [35]. For instance, Researchers in [119] and [32] developed PowerACE, an ABM that includes a spot and German balancing market. The authors in [32] provided a thorough assessment of several learning algorithms that can be integrated into ABM to represent agent behavior and showed that Q-learning produced better results than Erev-Roth type reinforcement learning. Since market participants do not have access to complete information, they are bound to behave strategically in the face of uncertainty (e.g. [120]), optimizing their decisions by factoring in the risk associated with imperfect information. In [121], a short-term electricity market is modeled to teste agents' learning strategies and attitudes to risk. The authors showed that agent bidding strategies can be improved through more risk-averse strategies. Researchers in [111] developed an agent-based model of the German balancing market to study the bidding behavior of market actors and the effect of attitude towards risk on their bidding strategies and showed that ABM is an appropriate tool to analyze the balancing market [111][27]. The way the same market design can provoke different outcomes due to different agents participating in it incorporating agents' expectations and uncertainty was demonstrated with the help of ABM in [122].

5.2.3. Agent-based modelling and learning for the analysis of regulatory changes in the balancing market

ABM has proven to be a useful tool to capture market dynamics and complexity and account for the behavior of multiple actors and their reactions to market opportunities and incentives [123]. It further allows to analyze the effects of policy and market design changes considering adaptive behavior of participants [11], [23]. The authors in [124] use empirical market data from Central Western Europe to emphasize that balancing market design has a direct effect on the strategies of flexibility providers. However, top-down optimization models cannot represent different bidding strategies and potential opportunistic behavior due to their intrinsic assumptions of perfect competition and foresight. Similarly, game theoretical approaches, while useful for identifying optimal strategies of market actors, lack flexibility in integrating multiple agents with different characteristics and strategies and do not scale up to include multiple players with a large number of decision

[27] In contrast, for highly competitive day-ahead markets fundamental optimization models have proven to yield better results [25].

variables (such as plants to dispatch). ABM allows for heterogeneity and a larger number of agents (e.g. [125]) and can help to understand and quantitatively assess the bidding behavior of the agents in repeated auctions. The relevance of the repeated nature of the balancing auction has been demonstrated e.g. in [126], [127]. ABM makes it possible to evaluate the effects of actors' decisions (e.g. [115]), in particular types of bidding behavior, on the price levels and behavior of others by providing the agents with learning capabilities [128]. It is particularly suitable for exploration based on incomplete information (actual strategies of market participants are not disclosed) and multiple observations (market outcomes) [129].

5.3. European balancing markets

European balancing markets are rooted in the physical grid requirements and the TSOs' obligation to maintain the energy balance within their control system in order to maintain the network frequency in the interconnected system. System imbalances are caused by stochastic processes, uncertainty associated with generation and load forecasts, plant or line outages and the behavior of market participants. Balancing markets consists of several institutional arrangements, as is shown in Figure 5.1.

Figure 5.1 illustrates that the balancing market for electricity is a key link between the physical power system and the markets. The process in the balancing market starts with the procurement auction for the reservation of balancing capacity (BC), the goal of which is to ensure sufficient balancing capacity available for potential activation. It is followed by the activation of balancing energy (BE) in real time to resolve system imbalances, using the pool of balancing resources that were contracted during the previous stage. Finally, after real time, the costs of imbalances are settled between the TSO and the BRPs under the "polluter-pays" principle. Resulting imbalance prices are based on the cost of provision of balancing energy (although the methodologies differ among EU countries).

The bottom of this figure represents the Physical Layer of the system. The imbalances between electricity generation and consumption are controlled by the TSO in real time. The Actor Layer shows the players: the TSO is in the middle between the balancing services providers (BSPs), who obtain their resources from suppliers on the left, and the balancing responsible parties (BRPs), who are the cause the imbalances, on the right. In contrast to day-ahead and intraday markets, only market participants whose assets pass a stringent prequalification process may act as BSPs.[28] BRPs aggregate market actors (providers and consumers of electricity) into portfolios to achieve scale economies (on the right side in the Actor Layer, Figure 5.1). BRPs submit planned load and generation schedules to the TSO day-ahead.

[28] More information on the limits of access to the balancing market can be found in [7] and the detailed requirements can be found in the GL EB [99] as well as national prequalification documents.

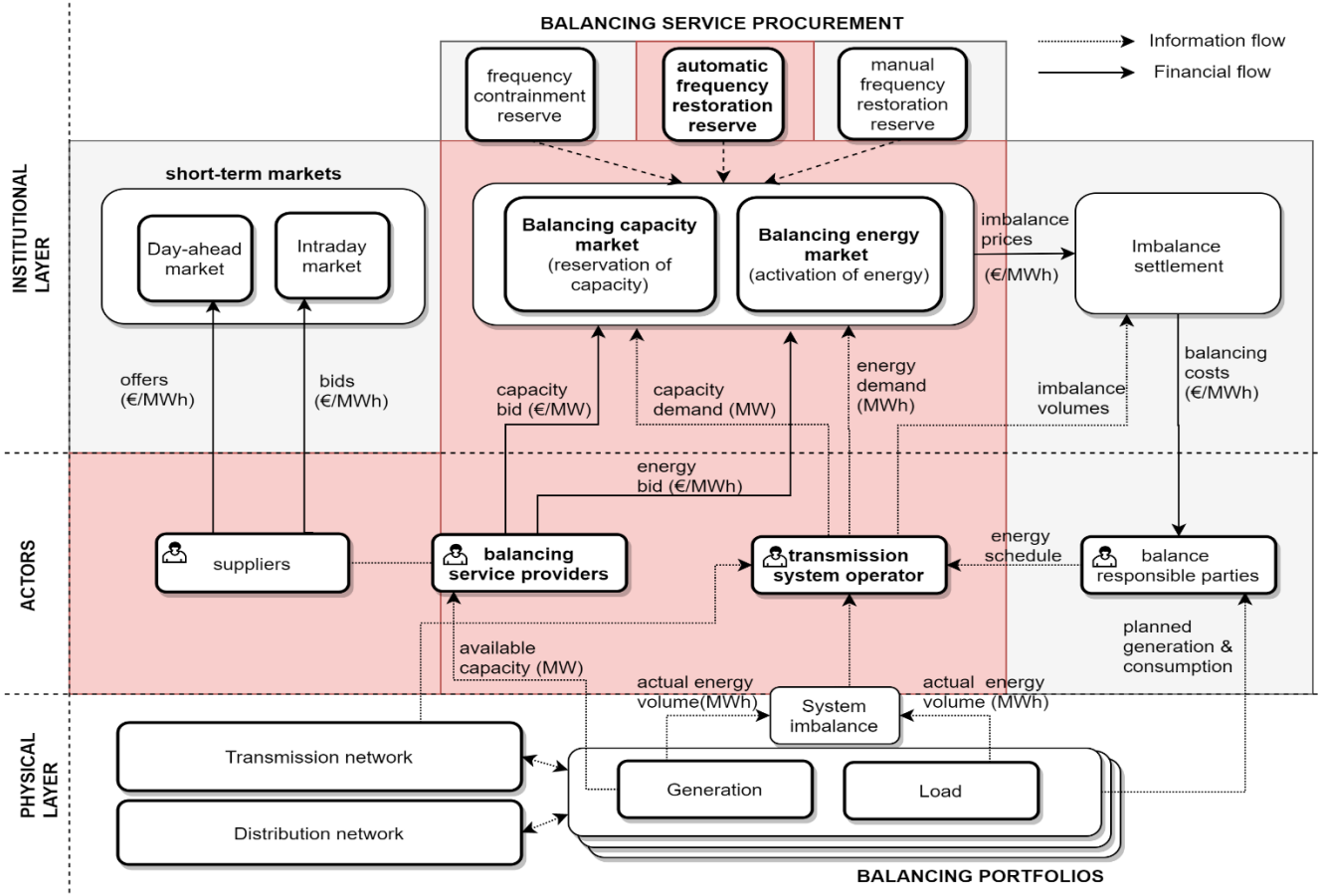

Figure 5.1. Overview of the organization of European electricity balancing markets and their relation to short-term electricity markets. The focus of the Elba-ABM model in this paper is marked in red.

The Institutional Layer shows how the TSO handles imbalances through balancing services that it purchases from balancing service providers (BSPs) before real time in the *balancing capacity market*. System imbalances are corrected in real time by activating the regulating capacity that was purchased from the BSPs in the *balancing energy market*. Deviations from the required network frequency value can be both negative and positive. If the system imbalance is negative, i.e. the system is short, generation output must be increased (or demand reduced), activating positive balancing energy. Conversely, negative balancing energy is activated in case the system is long, i.e. oversupplied, and generation must be reduced (or demand increased). BRPs need to compensate the TSO for deviations from their schedules, e.g. caused by forecast errors of renewable generators.

Unlike spot markets, balancing markets are single-sided, with the TSO acting as the single buyer. TSOs use separate auctions for procuring the standardized balancing products. The GL EB defines four standard balancing products: Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), manual Frequency Restoration Reserve (mFRR) (Figure 5.1, top), and Replacement Reserve (RR), which mainly differ according to their activation speed and duration of activation. The FCR is used to handle imbalances that are caused by so-called *"intra-dispatch interval variability"* [80], meaning that while demand changes continuously, schedules are submitted in discrete steps, most commonly of 15 min, and as a result there are continuous, small differences between supply and demand. We ignore this issue and focus on deviations between the actual and scheduled electricity generation or consumption per time interval, which are largely handled with aFRR (with mFRR and RR as backups). aFRR is used in all countries of the ENTSO-E area and has the highest trading volumes among the standard products (cf. [130]). In a series of interrelated electricity markets [131], the BC market is cleared before the day-ahead (DA) market (see also Figure 5.2, top.) This may occur from one year to one day ahead of delivery time, depending on the country and the balancing product. The required BC for each product is determined by the TSO, whereas the demand for BE depends on actual imbalances.

The bid structure of aFRR (automatic frequency response reserve) includes the BC volume in MW and the respective BC price in €/MW. Commonly, the price for activation of BE in €/MWh must be provided at the time of the BC auction and only BSPs whose capacity bids have been accepted are considered for providing balancing energy (Figure 5.1). A merit order based on the price of balancing capacity is created for clearing the BC auction, whereas another merit order is constructed afterwards for the BE market by ranking the energy bids (from the accepted balancing capacity providers). In the market for positive regulation, the bids are ranked from the lowest to the highest, while in the market for negative regulation, a descending merit order is built: if a BSP submits a positive bid, he/she is willing to pay the TSO for reducing his/her output whereas the TSO must remunerate the BSP that submitted a negative bid and was awarded.

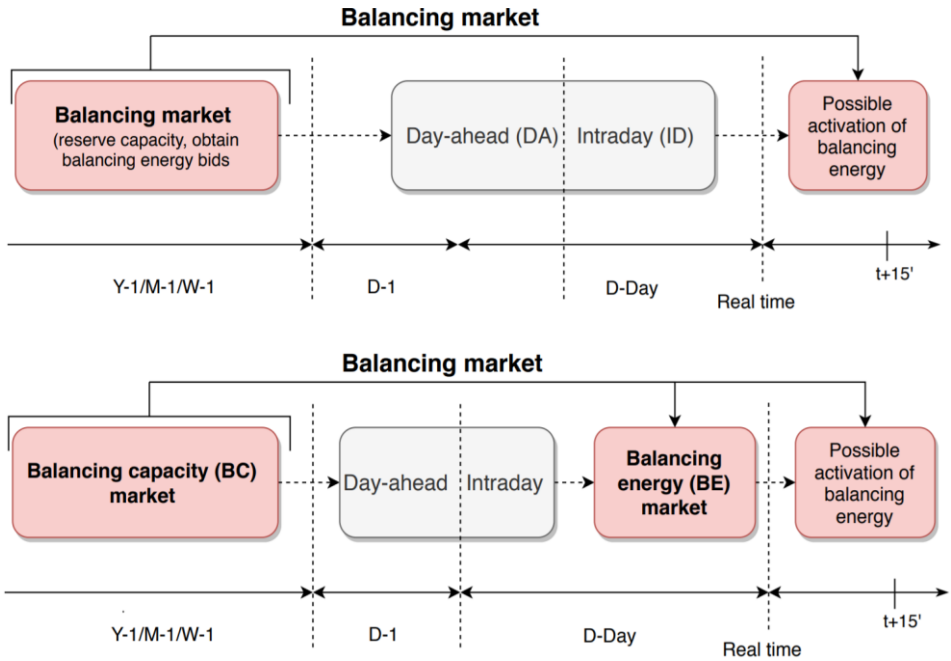

Figure 5.2. Top: Current temporal sequence of the balancing and spot markets. Bottom: the change in the balancing market sequence proposed by the GL EB.

Under the European electricity market unbundling provisions, balancing services must be procured in a market-based way [99]. Yet, large differences in national balancing market designs exist among the EU countries [42]. In some balancing markets, BSPs are still required to submit symmetric bids, i.e. the same volumes of positive and negative regulation must be supplied, while in others asymmetric bids are allowed. The service provision can be remunerated according to a pay-as-bid rule or to a marginal price rule. The former implies that each generator receives the price they bid while in the latter case each awarded bid receives the same market clearing price. Balancing products are distinguished by the period during which they should be available for activation ranging from a day to an hour [42].

5.4. Elba ABM: model overview

This section is divided into three parts. The first sub-section introduces Elba-ABM (Agent-Based Model of ELectricity BAlancing market) and its main functionalities. The second sub-section describes the modelled market design and the third sub-section describes the three types of bidding behavior that are modeled.

5.4.1. Model introduction

Elba-ABM is a bottom-up agent-based model that simulates balancing market mechanisms and bidding decisions of individual BSPs. The main intention of the model is to represent key design features of European balancing capacity and balancing energy markets. The model makes it possible to adjust these design features in order to evaluate their impact on the strategies of BSPs and, consequently, on the market outcome. We focus on the effects of different combinations of market design variables on market efficiency in the presence of competitive and strategic bidding strategies.

Two versions of the model were developed that represent joint and split BC-BE markets, as will be described in Section 5.4.2. The models represent the process of bid submission, the market clearing processes and the financial settlement process (using either marginal or pay-as-bid pricing). The model can simulate bids per generator as well as portfolio bidding with generators of different technologies. In the model, the BSPs determine their bids individually based on their marginal costs[29] and/or prior experience (modeled through rule-based or reinforcement-learning (RL) agents). These strategies will be described in detail in Section 5.4.3. We use representative balancing market data that is based on data from the Austrian aFRR market [132].

The authors are aware of the strong connection between the balancing market and other short-term markets. Although the day-ahead market is not modeled explicitly, it is taken into account through day-ahead prices that are given to the BSP agents as an opportunity value. Secondly, the capacity that BSPs can bid in the balancing market is limited because it typically needs to consist of spinning reserve or fast-start units. The model uses a scenario generation technique proposed in [133] for developing realistic and correlated data for simulating the market. This technique generates realistic system imbalance scenarios that correlate with day-ahead market prices. For every yearly simulation, the Elba-ABM framework generates a new scenario of imbalances and prices.

5.4.2. Joint versus split BC-BE markets

The model consists of a two-stage simulation, with the BC market setting the stage for the BE market. The bidding frequency for BC can be varied from once per year to daily. In the model version with a joint BC-BE market, the BE prices are set as part of the BC auction. In the split BC-BE market model, the BE market has either the same or a higher frequency. We implemented a frequency of once per hour. The time step for market clearing the BE market is set to 15 minutes, i.e. equal to the imbalance settlement period, so every hour, the BSPs offer their BE prices for the

[29] For the purpose of this analysis, we do not distinguish between variable costs and marginal costs and use the two terms interchangeably.

four 15-minute blocks of the delivery hour. Upward regulation and downward regulation are procured in two separate auctions (positive and negative markets, respectively). Each of the auctions can be cleared using a pay-as-bid (PaB) or marginal pricing (MP) rule.

The market clearing mechanism for the balancing market is the central element of the simulation model. The model procedures are summarized below and illustrated in Figure 5.3 and Figure 5.6. In the BC market, the TSO first announces the demand for balancing capacity; then, bidders submit BC bid volumes and prices based on their strategies; finally, the TSO awards bidders according to merit order results. In real time, when the awarded bidders participate in the BE market, the TSO determines imbalance volumes and clears the market per 15 minutes based on separate merit orders for +aFRR and –aFRR and then calculates and stores the results. Bidders obtain the market results *ex-post* and calculate their profits.

Joint BC-BE Market

In the joint BC-BE market, the agents' bids do not change throughout a model run: each time step with a positive imbalance, agents submit the same positive bid, the same goes for steps with a negative imbalance. For instance, if we assume a product resolution of one day, the same BE price ladder (supply function) is used for all 96 time intervals of 15 min. The marginal clearing price (MCP) for each 15-minute interval varies only because of differences in the demand for balancing energy. Thus, the BC market determines the frequency of change of BE prices. The model flow of the joint market is illustrated in Figure 5.3.

In the joint BC-BE market, the bid information must contain the BE prices for a given hour of the day. So, if, for instance, hourly products for BE are assumed, then a BSP may submit, once a day, up to 24 BE bids, one for each hour, with optionally different BE prices. In the example below, a bidder offers its balancing resources by 23:00 for each hour of the next day (Figure 5.5).

Split BC-BE Market

In the split BC-BE market, a new merit order for BE is built every 15 min. The BE bids submitted on an hourly basis, i.e. the gate closure time (GCT) is assumed to be one hour ahead of delivery. The MCP is again determined by the actual imbalance volume, but in this case, BSPs have more room to adjust their bid strategies to generate a higher reward, as information is updated with a high frequency. The model runs the BE market for the 96 intervals per day (15 min interval). The simulation flow is illustrated in Figure 5.4

By way of example, assume that the gate for BE bids opens at 22:00 (GOT) and closes an hour later at 23:00 (GCT). Within this period, bids are submitted for

potential activation between 00:00 and 01:00 of the next day. This means that the bidding period is from 22:00 to 23:00 whereas the delivery period is from 00:00 to 02:00. This is illustrated in Figure 5.6.

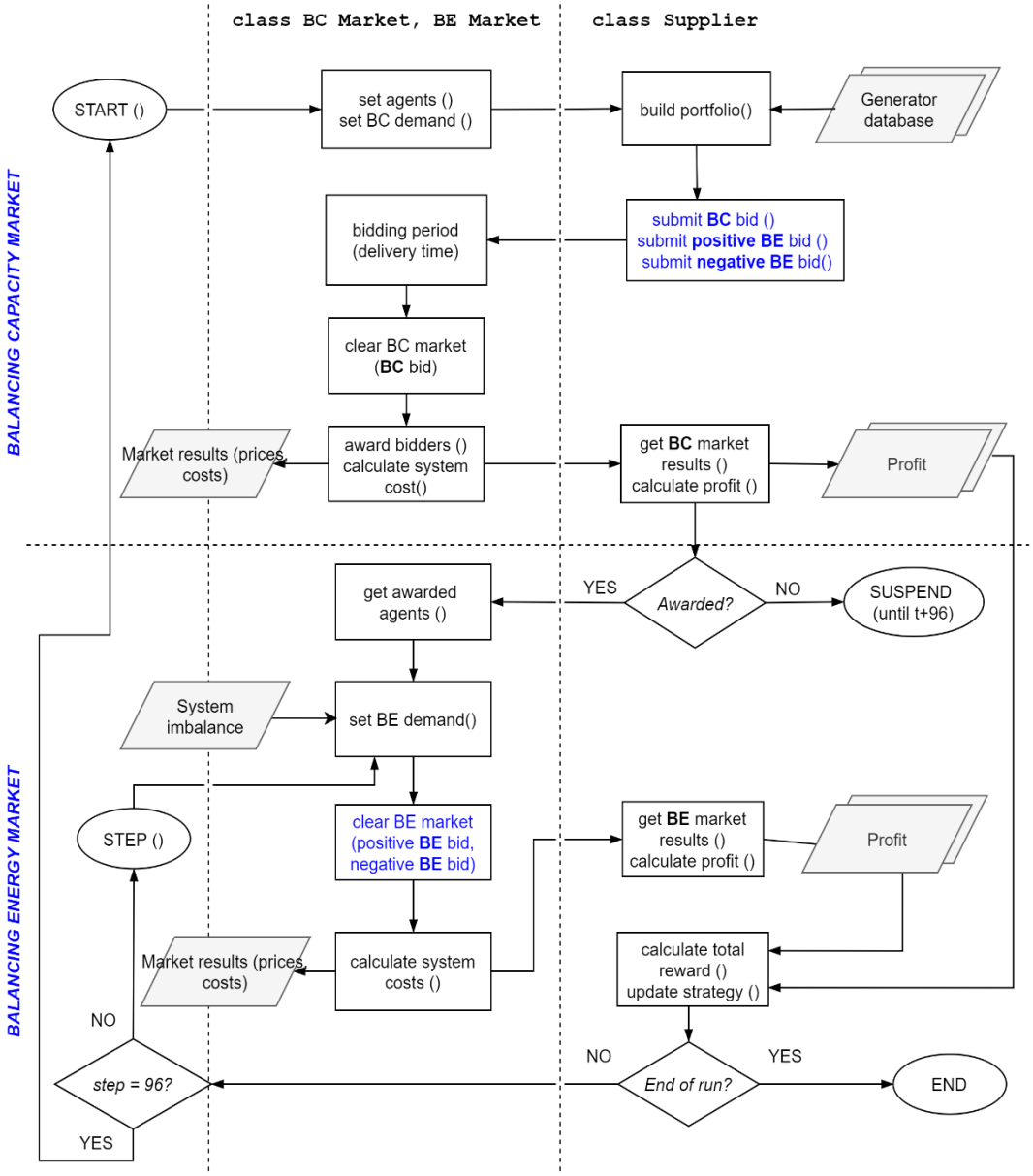

*Figure 5.3. General model structure diagram for a **joint** auction for balancing capacity and energy. The differences between the joint and split auction are marked in blue.*

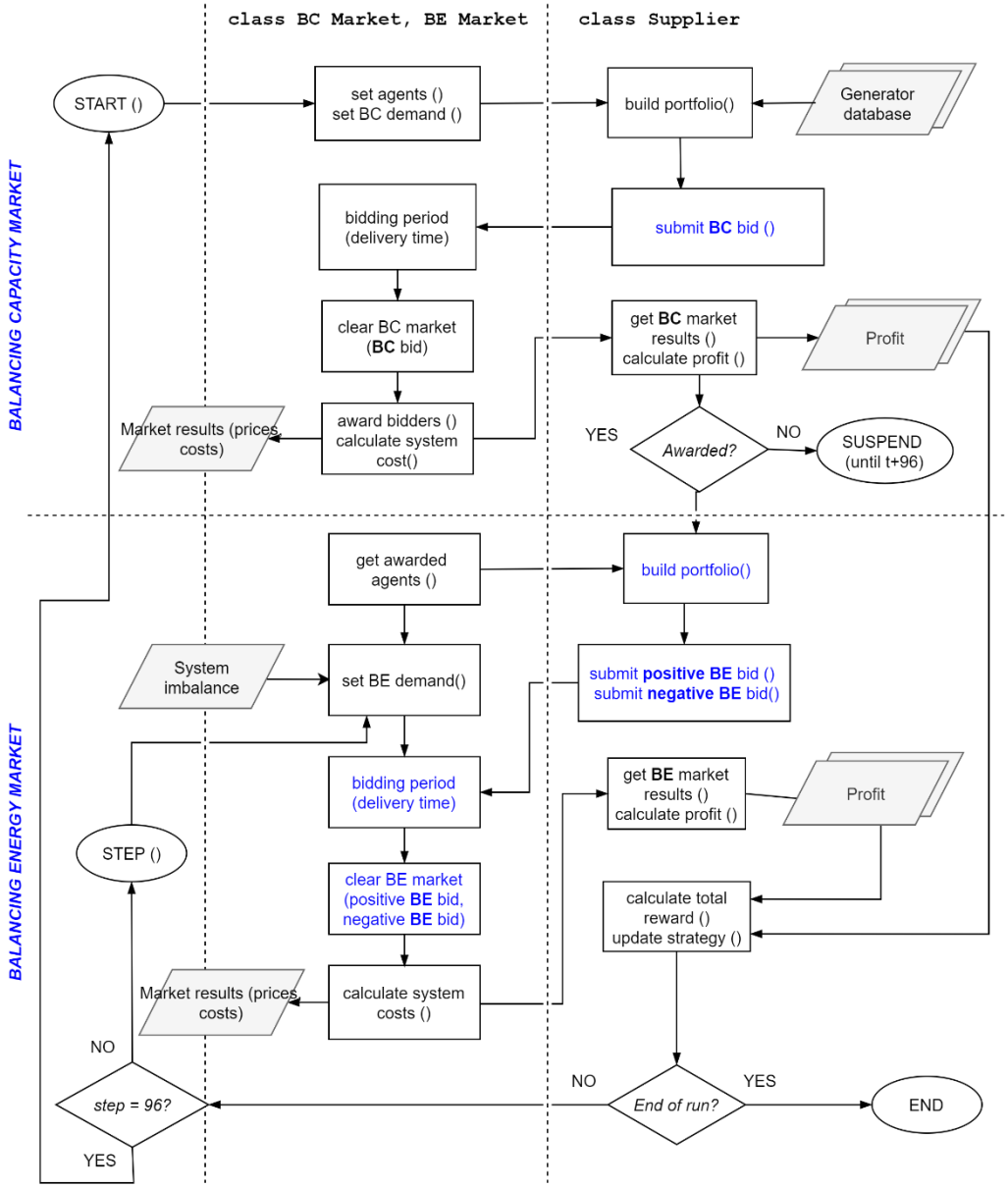

*Figure 5.4. General model structure diagram for a **split** balancing capacity and balancing energy auctions. The differences between the joint and split auction are marked in blue.*

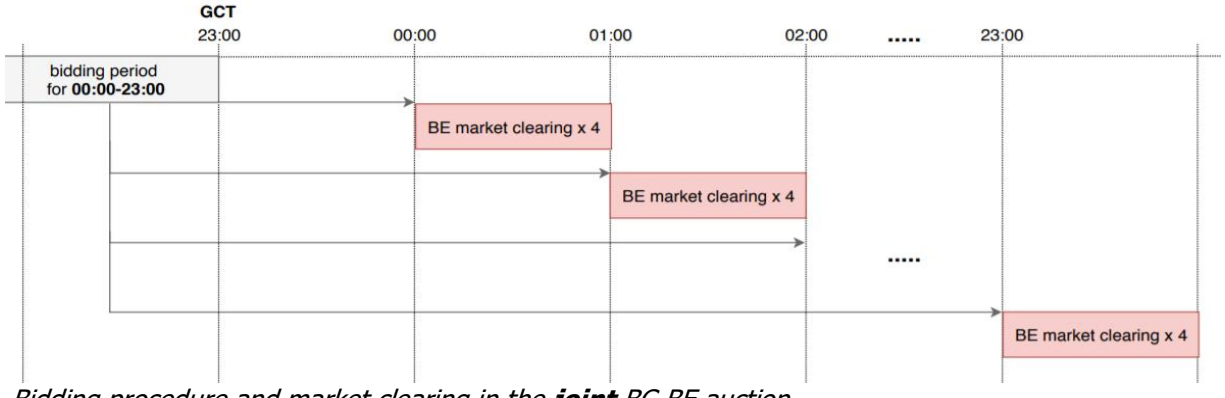

*Figure 5.5. Bidding procedure and market clearing in the **joint** BC-BE auction.*

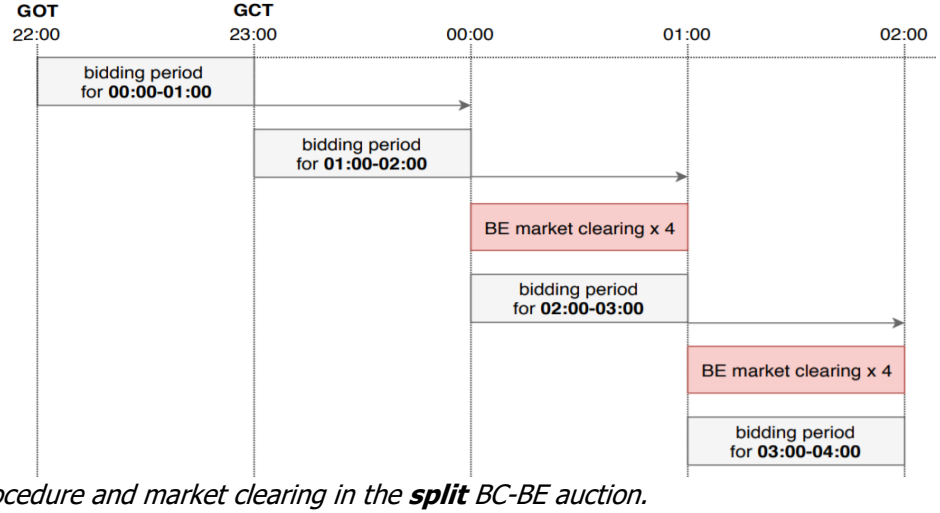

*Figure 5.6. Bidding procedure and market clearing in the **split** BC-BE auction.*

5.4.3. Agent definition

To simulate the bidding behavior of BSPs, we consider three types of agents: naïve ones, rule-based and reinforcement learning (RL) agents. Their strategies are briefly summarized in Table 5.1.

Table 5.1. Brief overview of agent bidding strategies.

	1. Naïve agents	**2. Rule-based agents**	**3. RL agents**
Bid	True costs, i.e. bid is equal to generator marginal costs	A markup or markdown is added to marginal costs, depending on whether a) the agent's bid was awarded at least once a) in the last 2 hours (split BC-BE market); b) in the same hour on the previous day (joint BC-BE market). The size of markup is higher in peak periods.	Optimal policy for each generator in portfolio is determined based on the agent's own state, the system state, and memory dataset; actions are taken to maximize reward (see Annex B)
Learning	no	no	yes
Memory	no	short-term	long-term

We use strategies 1 and 3 to compare the effects of market design changes under perfect competition and under strategic behavior whereas strategy 2 was introduced to calibrate RL agents' performance. The analysis is based on the following hypotheses.

- If BSPs bid their true variable costs, as would be expected in a competitive market according to neo-classical economic theory, it would not matter if BC and BE markets are joint or not. • In the market for downward regulation, if BSPs bid their true costs, they will offer to pay approximately their variable costs to the TSO in order to reduce generation output[30].
- As the number of market actors increases, the profits are expected to go down.

The performance of the agents is measured by their profits. Whereas in the BE market for + aFRR, the profit is calculated as revenue in a given delivery period

[30] The cost structures of the bidders in the +aFRR and -aFRR market are different due to the fact that in the former agents increase output when the system is short, incurring generation costs, and in the latter decrease output, potentially saving costs. Thus, their bidding strategies in the two markets will also be different [131].

minus the cost of producing additional energy, the calculation in the market for downward regulation (-aFRR) is less straightforward. We assume that the BE bidder participates in the DA market and receives a uniform market price for the volume sold in the DA market. In the -aFRR market, BSPs are theoretically willing to pay the TSO a price up to their variable costs[31] since these costs are avoided by not having to generate the energy that they sold in the DA market [134]. Therefore, in a true-cost bidding strategy, the bid price for reducing output is equal to a generator's variable cost. As a consequence, a BSP still generates a net profit, because he/she saves his/her variable costs for the volume he/she was downward regulated, even if a he/she submits a positive bid in the BE market, i.e. pays to the TSO to reduce his/her output. Even if the profit in the BE market is zero, the BSP still generates an overall profit from the DA market. If a bidder places a bid below his/her marginal costs and the bid is accepted, he/she increases his/her profit in the BE market for -aFRR. Finally, if a BSP submits a negative price, i.e. demands to be remunerated for reducing his/her output, he/she receives an additional payment from the TSO for the balancing service. Due to minimum-load requirements, however, the volume that he/she can regulate downward is smaller than the total volume that he/she sold in the DA market.

True-cost bidding agents

True-cost (i.e. variable cost) bidding is expected according to neoclassical economic theory in case of perfect competition, when each actor is a price-taker. This provides a benchmark for the analysis but does not necessarily represent realistic behavior in a balancing market. Observed prices in Austria regularly reach several thousands of euro per MWh, which clearly points to strategies that significantly deviate from marginal-cost bidding [132]. To simulate strategic behavior in the balancing market, two other approaches are implemented, as described below.

Rule-based bidding agents

Rule-based agents bid according to a predefined rule: their variable costs are marked up or down by a coefficient that is adjusted as the model proceeds, separately for the positive and negative BE market. An agent considers whether the bidding period corresponds to a peak (from 8 am to 4 pm) or to an off-peak period (the remaining hours and weekends). By default, the value of the coefficient is equal to 1.0; for true-cost bidding agents, this is how it stays throughout the model run.

In the split BC-BE market, the results of two previous hours are stored. The coefficient is increased in the positive market and decreased in the negative market by 5% in an off-peak period and by 10% in a peak period if the generator was

[31] According to game theory, optimal strategy for a BSP in the negative market would be to bid strictly negative. Yet in reality, the bidders' prices tend to be negative only in the first merit-order ranks and become positive and volatile very quickly [27].

awarded at least 25% of those times, i.e. at least once in an hour (see Appendix B for details). Conversely, generators for which the condition is not fulfilled gradually revert to true-cost bidding. In the joint BC-BE market, the rule-based agents follow the same strategy but due to a lower bidding granularity, consider the results of the previous day for the same hour.

The strategy of true-cost and rule-based agents includes an additional consideration of situations when the marginal costs of a BSP participating in the –aFRR market happen to be higher than the DA market price. If awarded in the BC market, such a generator needs to be scheduled in the DA market to be available for downward regulation. He/She then places a negative bid for balancing energy equal to his/her marginal costs, which means that in case of activation, the TSO must pay an amount of the bid.

Reinforcement learning agents

The learning agents use a reinforcement learning (RL) algorithm called fitted Q-iteration with which they adjust their bidding behavior to maximize their profit. The Q-iteration algorithm that has already been tested in many energy applications (e.g. [133], [135]) was chosen for its relative simplicity and good performance. For instance, [136] uses fitted Q-iteration to control seasonal storage systems in the context of electricity markets. It is important to note that more advanced approaches were tested, e.g. approaches based on deep learning [97], such as double Q-learning [137], however, they were not as successful as fitted Q-iteration.

As in all RL algorithms, the method considers that the agent and the BE market can be modelled via a Markov decision process: the agent modelled by a state-action pair where each state is controlled with a discrete set of actions and transitions from one state to another are based on a probability distribution (see Appendix B). In addition, when transitioning states, the agent receives a reward representing how good the action taken was. The reward is not deterministic but generated from a probability distribution. During the training, the RL agent continuously updates and improves its policy that outputs, for each state, the optimal action that maximizes the expected value of the cumulative sum of rewards. After each round, the agent's information about its respective profits is updated. As the decision in the positive and negative balancing markets are independent from each other, separate policies are determined.

State space

To define the state space of the positive (negative) RL agent, we consider the following variables:

- The four most recently activated volumes for both the positive and negative BE market. The definition of most recent naturally depends on the specific gate closure times and on the market structure under study.
- The four most recent prices in the positive (negative) market

- The day-ahead market price and the corresponding hour.

It is important to note that selecting the number of recent values for the variables of interest is a design choice. We opted for four as a tradeoff between computational complexity and method accuracy.

Action space
For the action space, we consider that, for each generator in its portfolio, each RL agent (BSP) bids its maximum available capacity at a variable price. Therefore, the action space is defined as a selection between a discrete set of prices for each of the agent generators.

For the RL agent in the positive market, the action space for each generator is modeled as fifty prices log-uniformly distributed between 1 and 10 times the variable cost of the generator, i.e. the RL agent has 50 actions per generator. Then, for the total action space, the RL agent considers the set of all possible combinations (with replacement) of the fifty individual actions (see Appendix B).

For the RL agent in the negative market, the action is space is similar. However, instead of the prices being discretized between 1 and 10 times the variable cost of each generator, they are discretized between 1 and −10 times the variable cost. The size of the action space scales similarly to the positive market.

The choices to select fifty values per generator and prices up to 10 times the variable cost are trade-offs between accuracy and computational cost.

Reward
The reward is the accumulated economic profit in the bidding period, e.g. for a balancing market with a four-hour product and market clearing of 15 minutes, the reward of a given state-action pair is the accumulated profit during the 16 market clearing steps.

Agent evaluation
After the initial training year (the exploration phase), the market performance is evaluated using a second simulated year (the exploitation phase). The agents' profit-maximizing bidding strategy is observed (see Appendix B for details).

5.4.4. Validation and sensitivity analysis

The market and the RL agent algorithms have been validated with multiple simplified scenarios to demonstrate that the agent's behavior is in line with what is expected from game theory (Bertrand competition). Bertrand competition implies competition on price and not on volume: as in this analysis, only those agents participate in the balancing energy market whose capacity was reserved in the previous market stage. Their capacity is therefore committed and cannot be changed in the balancing

energy market. Validation tests replicated the main assumptions of Bertrand competition [138], two actors offering an identical product, in our case electrical energy, at the same location, balancing energy market, and a constant demand, in our case system imbalances.

Other factors in Bertrand competition that influence bidder strategies and whether they can reach a Nash equilibrium are whether the two actors have the same marginal costs and whether the demand can be covered by either actor entirely. Results of validation tests with a constant imbalance, i.e. demand for BE, show that when both agents have the same marginal costs and the demand can be covered by either of them, both agents bid their true costs, as expected from theory [138]. If their marginal costs are different, the agent with lower costs is incentivized to bid just below the (estimated) costs of the more expensive agent. The simulation results correspond in this case as well: the RL agent with marginal costs of 40€/MWh converges on a bid of 48,3€/ MWh, slightly lower than the 50€/MWh bid of his/her true-cost bidding competitor, regardless of the pricing rule that is applied.

The situation is different if both agents are needed to cover the demand, ergo both of them have market power. In this case, the simulation results again correspond with theory and both agents bid high. Aside from total demand, other factors, such dynamic bidding, i.e. bidding in multiple consecutive runs, may cause agents to bid above their marginal costs due to learning effects from multiple rounds [86]. For instance, both reinforcement learning agents with the same marginal costs of 50€/MWh exploit multiple bidding rounds to develop very high bids and yet be awarded. As a result, they end up placing an average bid of 240 €/MWh despite limited demand. Our results are conservative with respect to price spikes because we consider a uniform imbalance within a 15-minute period. This excludes high but brief imbalances that may occur within the 15-minute periods.

In order to determine the best-performing RL strategy with respect to profit maximization, several configurations of the RL algorithm were tested, with regard to the number of choices when setting the bid price and the training time. Rule-based agents were used for the calibration of the RL agent. The results of sensitivity analyses showed that if RL agents could set the same maximum price in the positive/negative market of 500€/MWh/−500€/MWh, this produced poor results for the agents with cheap generation units due to the fact that the number of all available decisions is too broad for an agent to sufficiently test the performance of options closer to marginal costs. As a result, the RL agent is rarely awarded and has too little data about successful bids to take optimal decisions after training. Instead, the RL agent was set to be able to bid up to 10 times his/her marginal costs. Concerning training time, the RL agent is set up in such a way that it trains in the first year, whereas the following year it behaves optimally. Runs with two to five years were conducted and, since the performance of the RL agent didn't improve considerably with a greater number of training years, we used two-year simulations with one training year and one year when the RL agent behaves optimally.

5.5. Experiment design

In the model, reference data from the Austrian balancing market for aFRR was used [132]. Yet, the main goal of the study is not to imitate or make conclusions for this specific market. Rather, Elba-ABM is meant as a tool for testing different market results. The model is run for the split and joint BC-BE markets and market prices based on marginal bids (MP) or pay-as-bid (PaB). In each of these market designs, the following scenarios with regard to the agents were compared:

	baseline 3TC scenario				*3RL scenario*				*1RL_5TC scenario*				*6RL scenario*			
Descrip-tion	Baseline scenario with 3 true-cost bidding agents				An oligopolistic scenario with 3 reinforcement learning (RL) agents				Higher level of compete-tion with six agents*: 1 RL agent and 5 true-cost bidding agents				A higher level of competition with six agents: 6 RL agents			
BC-BE market	Split		Joint		Split		Joint		Split		Joint		Split		Joint	
Pricing rule	PaB	MP	PaB	MP	PaB	MP	PaB	MP	PaB	MP	PaB	MP	PaB	MP	PaB	MP

**This is a fair assumption for the number of participants as, according to the data of the Austrian TSO, the number of participants in a bidding round for aFRR varies between 5 and 10 BSPs [49].*

As a baseline, As a baseline, the *3TC scenario* generates the prices and balancing costs that would be expected under the assumption of perfect competition. To estimate the impact of strategic bidding in an oligopoly on the market outcome, *3RL scenario* is used. These results are compared with the scenarios with a higher number of market actors to observe whether the presence of a single strategic bidder can significantly affect market efficiency (*1RL_5TC scenario*) and whether a higher number of competitors in a market with learning actors alone *(6RL scenario)* can improve market efficiency.

In order to compare market designs, similar generation portfolios were used in all scenarios in order to exclude the influence of portfolio differences on simulation results. Each agent has a portfolio of four generators with variable costs between 10 and 15, 30 and 35, 50 and 55, 70 and 75€/MWh[32]. This ensures that the results are not affected by large cost differences among agents while at the same time a stepwise merit order function can be built. In reality, one of the main prequalification

[32] Assumptions about the costs of the generation technologies are based on the information provided in [41], [139].

requirements is a high speed of activation, which can be fulfilled only by few technologies such as hydropower, hard-coal and lignite, biomass, gas-fired power plants and CCGTs [23,47]. The variable costs of generation are approximated and assumed not to change for the period of simulation, so the different bid prices can occur only if an agent deviates from the true-cost bidding strategy. It is assumed that agents cannot split bid volumes but can bid differently for each generator in their portfolio. The exact configuration of agent portfolios is detailed in Appendix C.

For our study, a series of assumptions related to the balancing market are made:

- The frequency at which the BE market is cleared is once per 15 minutes.
- Within a quarter of an hour, normally both positive and negative imbalances occur. For simplicity, only the net imbalance over 15 minutes (i.e. either positive or negative) is used.
- International cooperation (e.g. imbalance netting) is not considered, i.e. all imbalances are assumed to be handled within the control area.
- The BC market is assumed not to influence agents' bidding strategies because the profit in the BC market is considered negligible.[33] This assumption is based on the fact that that BE bid is independent of the BC bid [27] as well as on empirical evidence that balancing capacity prices tend to be low. BSPs bid low to secure their participation in the balancing energy market; the high balancing energy prices that are observed in practice make up for that [27]. The focus is therefore on the BE market.
- As BSPs are able to bid only a share of their total capacity for upward or downward regulation, a BSP is assumed to bid 10% of its total capacity in the balancing market [23] whereas the remainder is assumed to be bid in the DA market. The volume in the BE market is equal to the entire volume that is accepted in the BC market. BSPs are obliged to bid the entire committed volume throughout the delivery period.
- Agents are assumed to submit the same bid volume for both positive and negative generation.[34]
- In order to specifically address the price levels and balancing costs under different market designs in the presence of learning agents, we use a single decision variable for the agents, their balancing energy price.[35]

Many European markets are still characterized by a fairly low bidding frequency for aFRR [42]. However, the GL EB requires balancing energy to be procured as close

[33] Interdependencies between BC and BE bids are disregarded in the current discussion and can be incorporates as a future step.

[34] Bids for +aFRR and –aFRR are submitted separately, so asymmetric bidding can be implemented easily in the model. For now, symmetric bidding is considered for simplification purposes. In practice, requirements for symmetric bidding are now considered unnecessarily restrictive with regard to the participation of new technologies, especially renewables and is expected to be substituted with asymmetric bidding, pursuant to the EBGL.

[35] It is important to note that the single decision variable and the exogenous day-ahead market prices, is not a limitation of the Elba-ABM framework. Instead, it is a design choice of the current study. The framework could in theory be used for more complex modeling, including multiple decision variables and interactions with other markets.

as possible to real time. Consequently, balancing capacity auctions are expected to take place on a daily basis [99]. To account for these expected adjustments and to ensure that the design of the joint BC-BE market is comparable to the split BC-BE market, we apply a daily bidding frequency for balancing capacity.

5.6. Simulation results and discussion: the effect of balancing market design on the bidding behavior

The results of the 16 simulations are presented in this section; the agents and their portfolios are shown in Appendix B. Since the rule-based agents were mainly used to calibrate the RL agent, the results with rule-based agents are not included in this section. A scenario with all true-cost bidding agents is used as a baseline. The resulting market efficiency is of each market design in different scenarios is assessed based on the total cost of balancing and the weighted average prices.

In *3TC scenario*, the weighted average of the price-setting bids for +aFRR is 39 €/MWh and 48€/MWh for –FRR in both the split and joint markets and under both pricing rules[36]. The total cost of balancing for upward and downward regulation are lower under the pay-as-bid rule because there are no infra-marginal rents (see Figure 5.7).

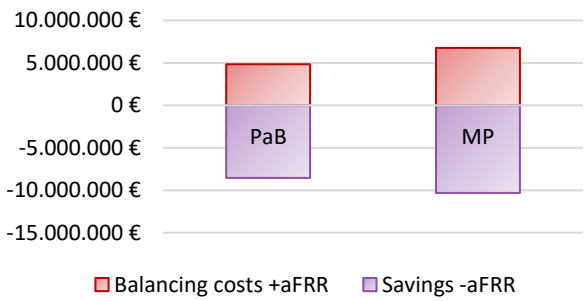

Figure 5.7. Yearly balancing costs for positive balancing energy and savings from negative balancing energy under PaB and MP rules in the baseline scenarios with three true-cost bidding agents.

5.6.1. Oligopolistic scenario

In *3RL scenario* with strategic bidders (with all RL agents), the agents deviate considerably from the competitive strategy, notwithstanding the fact that none of

[36] A positive price for –FRR indicates the willingness of a BSP to pay to the TSO for reducing their output.

them can cover the demand on their own. In the joint market with PaB pricing, the weighted average price of +aFRR is more than 7,5 times higher, at 294€/MWh, than the baseline, leading to a 3,5-increase in balancing costs. The weighted average price in the joint BC-BE market with marginal pricing also exceeds the weighted average price in the baseline, but less than the price in the scenario with the PaB rule, at 269€/MWh. For –aFRR, in turn, the weighted average marginal price falls to -73€/MW if PaB rule is applied and to -45€/MWh in case of MP, i.e. the agents make net profits from not producing and the TSO faces costs for downward regulation (Figure 5.8 and Figure 5.9).

In the joint market, BSPs that bid opportunistically cannot affect the market outcome *within* the delivery period. However, this also means that if high BE bids are accepted, they apply for the entire product duration. The maximum marginal price for +aFRR regularly exceeded 700€/MWh, whereas the maximum –FRR price reached -700€/MWh 10 times in a year, largely corresponding to the times of high demand for –aFRR. In the split market, *3RL scenario* also produced average prices that were higher than the competitive benchmark, but less so than in the joint market. If the PaB rule is applied, the weighted average prices are 269€/MWh for +aFRR and -64€/MWh for –aFRR. If marginal pricing is applied, the prices decrease further: 178€/MWh for +aFRR and at -23€/MWh for –aFRR. This reduces overall balancing costs compared to the joint BC-BE market, but it still exceeds the cost of balancing in the baseline scenario by a factor of 2 to 3 for upward regulation. The total costs of balancing per scenario and market design option are shown in Figure 5.10.

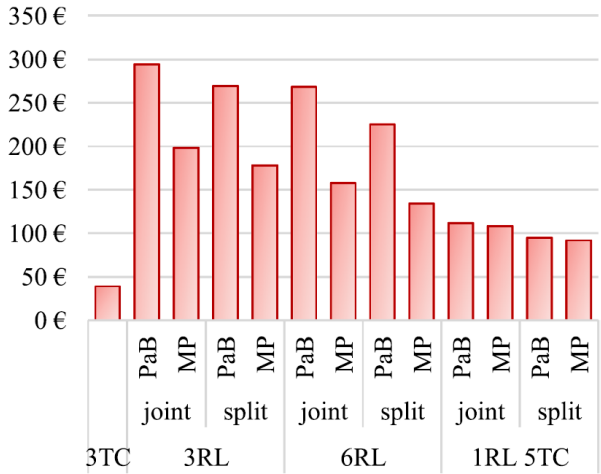

Figure 5.8. Weighted average prices for +aFRR in 5 scenarios in joint and split BC-BE markets under PaB and MP rules.

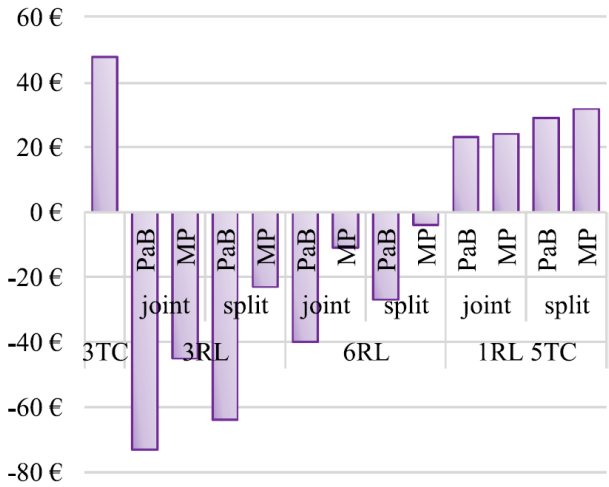

Figure 5.9. Weighted average prices for -aFRR in 5 scenarios in joint and split BC-BE markets under PaB and MP rules.

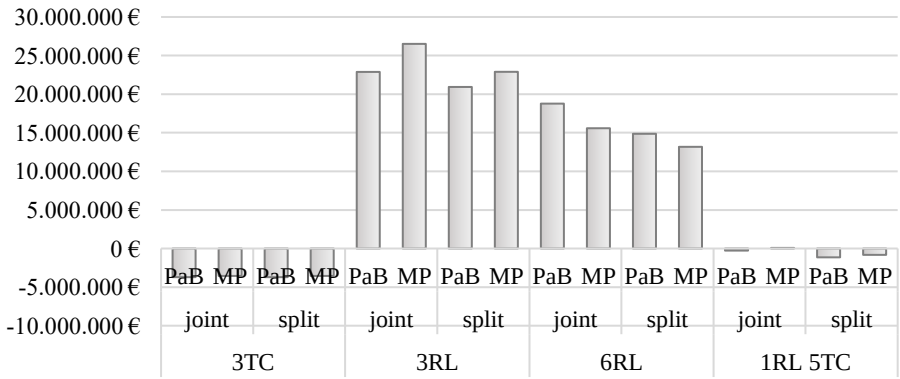

Figure 5.10. Net balancing costs for upward and downward regulation for each scenario and market design option (negative values indicate net savings).

5.6.2. Scenarios with a higher degree of competitiveness

The results of the *6RL scenario* show that a more competitive market with six actors does not inoculate the market from fairly high prices if all six agents follow a RL strategy, i.e. learn from their experience and adjust their strategies in repeated auctions. The deviation from the baseline is particularly large if the PaB rule is applied: the weighted average price for +aFRR reaches 268€/MWh in the joint BC-BE market and 225€/MWh in the split BE market while –aFRR prices are -40€/MWh and -27€/MWh, respectively. Notably, the impact of a greater number of learning

agents is greater for –aFRR, as is illustrated in Figure 5.9. The observed cost of balancing, as compared to the oligopolistic *3RL scenario,* is more modest, yet it is still ca. 2-4 times higher than the baseline for +aFRR whereas savings in the –aFRR market go down by 76% - 92%, depending on the pricing rule applied (Figure 5.10).

A scenario with all true-cost bidding agents and one RL agent, *1RL_5TC scenario*, was used to estimate the impact of a single learning agent on the market outcome. In this case, the RL agent is not able to deviate substantially from its marginal costs to increase its profit and does not affect the balancing costs significantly (Figure 5.10). Yet, the weighted average price for +aFRR and –aFRR deviates from the competitive outcome, 92-108€/MWh for +aFRR and 23-32€/MWh for –aFRR (Figure 5.8 and Figure 5.9), in particular in the times of scarcity when all bidders are necessary to restore system balance. Balancing cost deviations from the competitive benchmark are the lowest in this scenario, as expected. The observed increase in total balancing costs is substantially lower, compared to the other scenarios, between 17% and 73%, where the split BC-BE market with marginal pricing produces the most cost-efficient result, as shown in Figure 5.10.

The simulation results demonstrate that the balancing energy prices produced by Elba-ABM correspond to the prices observed in European balancing markets with the design modelled in *the joint BC-BE market* (e.g. in Germany and in Austria).[37] Previous research has demonstrated that the magnitude test is a useful approach to validate the results of agent-based models (cf. [69]). The real observed prices for balancing energy and the prices produced by the model both often deviate from marginal costs of the most expensive generation technologies, as is shown in Figure 5.8. These simulation results confirm the argument that in concentrated balancing markets, players are able to coordinate their bids [86] and *"orientate their bids towards previous market results"* [89]. They also show how a single strategic bidder in a fairly competitive market can still at times affect the market result (*1RL_5TC scenario*).

This implies that:

- Although a higher number of actors bidding competitively can dissuade their counterparts from bidding strategically by exposing them to a higher risk of not being awarded, the market is not immune to it, in particular in scarcity conditions However, a standalone BE market with marginal prices improves the incentive to place bids closer to marginal costs.
- Given these results as well as the fact that the need for larger balancing volumes is likely to grow to offset rapid integration of intermittent renewable generation, increasing the availability of balancing resources is essential. This can be achieved by easing prequalification conditions and facilitating cross-border procurement of balancing resources. The latter will in fact be

[37] Specifically, the model results were compared with the prices for aFRR in Austria (time series of years 2017 and 2018 [132]).

enabled through EU platforms for cross-border exchange of balancing energy that are planned to be implemented by mid-2023 [140].

As the costs of balancing are at least partially recovered through network tariffs paid by consumers, the presence of strategic bidding will affect social welfare to a greater or lesser extent depending on the cost recovery scheme applicable in a given state. For instance, while the costs of reserving aFRR capacity are distributed among all grid users in most EU countries, the costs from activation of aFRR balancing energy are mostly recovered from the BRPs whose actions led to system imbalances [42].

Overall, the simulations of the split BE market consistently demonstrate more efficient market results; in the presence of true-cost bidding agents they approximate the competitive results in the baseline. At the same time, the differences in weighted average prices under the two pricing rules were observed in all scenarios and points to a tangible positive effect of marginal pricing (see Figure 5.8 and Figure 5.9).

In case of portfolio bidding, we find that RL agents apply a different strategy to generators with low to medium variable costs than to more expensive generators in their portfolio. Cheaper generators tend to be offered close to the variable costs while generators with higher variable costs are bid in at high prices. Consequently, they are rarely activated (2%-10% of times in a year), but still allow RL agents obtain high profits during times of scarcity. Occasionally, they create price spikes of up to nine times the marginal cost of the most expensive generator.

A standalone BE market is likely to produce lower bid prices in the BE market for upward regulation and higher bid prices in the BE market for downward regulation. However, our experiments with learning agents show that also in the most efficient market design there is room for strategic behavior when the demand for balancing services is high. The effect of strategic bidding is significantly dampened if not all agents behave strategically, in particular if the uniform pricing rule is applied. The results consistently demonstrate a positive effect of the MP rule on the weighted average marginal prices in both positive and negative BE markets, especially if a standalone BE market is introduced pointing to the positive expected effect of the upcoming regulatory change. However, while the effects of these market design changes are significant, further measures to improve market access and competition are needed to make the balancing market robust against gaming.

5.7. Conclusions

We presented an agent-based model, Elba-ABM, to provide an insight into the effects of proposed changes to European balancing market design, in particular the introduction of a standalone balancing energy market and marginal-price settlement of energy bids, on strategic bidding in the balancing market. The agents are

modelled with realistic generation portfolios and learning agents are equipped with reinforcement learning (using a neural network) to identify opportunities for strategic behavior. Using Elba-ABM, we assessed the results with respect to the profits of agents, the weighted average prices of positive and negative balancing energy and the total cost of balancing.

Testing the robustness of the new market design with a standalone balancing energy market, we came to the following conclusions:

(1) A split (standalone) balancing energy market reduces balancing costs and weighted average prices, compared to a joint BC-BE market. It is particularly helpful in case of an oligopoly, even though it does not solve the issue of market power in case of high market concentration entirely. Concerns that were raised about the negative effects of more frequent opportunities for learning leading to gaming [62] in case of highly granular markets were not supported by the simulation results.
(2) Marginal pricing performs better than pay-as-bid, regardless of whether the BE market is standalone or not.
(3) The fact that in more competitive scenarios the results of the joint and split balancing capacity and energy markets do not substantially differ from each other confirms the expectation that in a more competitive market, its exact design is less relevant and the results of different market designs are more likely to converge. But as long as balancing markets remain concentrated, a standalone balancing energy market is preferred since (a) in a closed setting of an oligopoly, a standalone BE market reduces agents' ability to affect market outcome; (b) it can be combined with voluntary bids, which can help dampen balancing energy prices.
(4) The new market design choices are likely to improve market performance but more new entrants are needed to obtain competitive prices. Therefore, particular attention should be given to market access conditions, such as reduction of minimum bid size, aggregated and asymmetric bidding (as pointed out in [7]), along with market design adaptations, in view of many new types of flexibility providers that are emerging.

Our methodological contribution consists of a novel combination of agent-based modelling with reinforcement learning techniques. Elba-ABM represents a detailed model of the market and of the market actors. Their different characteristics, constraints and objectives, the absence of perfect foresight and perfect competition are reflected in the model. Reinforcement learning techniques make it possible to emulate strategic behavior in a market in which actors explore opportunities for increasing their profits. We will build on this approach in future work to test other market design variables, integrate intertemporal constraints and to apply agent-based modelling to more complex cases with interrelated markets. A second tier of research should address approaches to the recovery of balancing costs and their effect on social welfare together with an investigation of links between balancing costs, distribution of imbalance costs and network tariffs.

6

Making the most of short-term flexibility: is the new balancing market design up to par?[38]

Electricity balancing is one of the main demanders of short-term flexibility. To improve its integration, the recent regulation of the European Union introduces a common standalone balancing energy market. It allows actors that have not participated or not been awarded in the balancing capacity market to participate as voluntary bidders or 'second-chance' bidders. We investigate the effect of these changes on balancing market efficiency and on strategic behavior in particular, using a combination of agent-based modelling and reinforcement learning. This paper is the first to model agents' interdependent bidding strategies in the balancing capacity and energy markets with the help of two collaborative reinforcement learning algorithms. Results reveal considerable efficiency gains in the balancing energy market from the introduction of voluntary bids even in highly concentrated markets while offering a new value stream to providers of short-term flexibility. 'Second-chance' bidders further drive competition, reducing balancing energy costs. However, we warn that this design change is likely to shift some of the activation costs to the balancing capacity market where agents are prompted to bid more strategically in the view of lower profits from balancing energy. As it is unlikely that the balancing capacity market can be removed altogether, we recommend integrating European balancing capacity markets on par with balancing energy markets and easing prequalification requirements to ensure sufficient competition.

[38] This chapter has been published as Poplavskaya K., *et al.*, Making the most of short-term flexibility in the balancing market: Opportunities and challenges of voluntary bids in the new balancing market design. Energy Policy 2021 (under review).

6.1. Introduction

To improve the efficiency of balancing markets and increase competition, the European Union (EU) has adopted a guideline that proposes significant changes to the balancing market design. Using an agent-based model (ABM) with reinforcement learning (RL), we analyze the impact of these proposed market changes on bidder strategies and balancing market efficiency.

In order to maintain system frequency, European transmission system operators (TSOs) commonly procure balancing services through a two-stage process by first reserving the capacity in the balancing capacity market and then activating it as balancing energy when actual system imbalances occur. The need for new sources of short-term flexibility is growing as more conventional generation is being decommissioned and more variable renewables are coming online leading to rapid changes in residual load [2]. Market design can create incentives for the entry of participants with new forms of flexibility [7]. This is relevant for balancing markets, in which the number of balancing service providers (BSPs) has been fairly limited because of strict prequalification procedures and long procurement timeframes [7]. The concentrated nature of balancing markets has long raised concerns about the high risk of strategic bidding[39] and market power[40] (e.g. [142], [143]).

To improve the efficiency of balancing markets and increase competition, the EU guideline on electricity balancing (GL EB) introduced a common market for balancing energy, which, until now, was usually procured together with balancing capacity. A standalone balancing energy market allows a broader selection of BSPs to participate: besides bidders that were awarded in the balancing capacity market, other BSPs with flexibility available on a short notice may submit balancing energy bids as 'voluntary' bids [37]. Besides, BSPs whose capacity bids were not awarded may still use the standalone balancing energy market as a second opportunity to make a profit.

This study investigates the implications of the new balancing market design, in particular:

- its effect on actors' strategies in the markets for balancing capacity and balancing energy and
- whether or to which extent voluntary bids can help increase market efficiency.

[39] Any rational bidder follows a strategy in a market. In this context, however, under "strategic behavior" or "strategic bidding" we understand bidding to exploit market information and/or one's dominant market position in order to excessively profit from a given market.

[40] Market power is defined as "the ability to affect the market price" where "the effect must be profitable and the price must be moved away from the competitive level" [144, p. 318]. The study of market power is motivated by the repeated presence of unrealistically high prices for the balancing service at the times apparently unaffected by scarcities.

We inform decision-makers by analyzing the effects of regulatory changes on the pricing and availability of flexibility in the balancing capacity (BC) and balancing energy (BE) markets, on volume distribution among different marketplaces (balancing and day-ahead markets) and factors having an influence on this distribution. For this, we build upon the agent-based model of the BE market, Elba-ABM, introduced in [143] by 1) developing a detailed model of the BC market, 2) linking it to the exogenous day-ahead (DA) market, 3) introducing voluntary bids in the balancing energy market. The main methodological contribution of this paper consists in the development of a novel collaborative reinforcement learning algorithm to model linked bidder strategies in the BC and BE markets.

The rest of the paper is structured as follows: the key references on the balancing market design and bidding strategies of BSPs are summarized in Section 6.2. The model of the balancing market, Elba-ABM, and the enhancements implemented to study the research questions are introduced in Section 6.3. In Section 6.4, we present the simulation scenarios and analyze the simulation results. In Section 6.5, we discuss policy implications of the research results and provide conclusions.

6.2. Background and literature

In the European networks, to offset frequency deviations caused by plant outages, unplanned changes in demand or in the output from renewable generation in real time, the TSO uses a stepwise procedure activating first the fastest frequency containment reserves (FCR) and, for larger deviations, frequency restoration reserves (FRR). The latter are further subdivided into automatic (aFRR) and manual (mFRR)[41] reserves. Based on the sign of the imbalance, either upward (positive market) or downward (negative market) regulation is performed.

Balancing markets do not exist in isolation but are part of a sequence of short-term electricity markets. They provide alternatives for the commercialization of flexibility, hence the links between them motivate the bidding strategies of BSPs and should be considered if we are to derive meaningful conclusions for the balancing markets. These interdependencies were analyzed in [144], [142], [19]–[21]. For instance, Weidlich in [20] used ABM to study the connection between DA, balancing energy market and the CO2 market, [145] described the relation between the balancing market volumes and the efficient design of the intraday market. In his research, [19] focused on the bidding in three sequential balancing markets for balancing capacity while [53] explored further interdependencies between balancing and intraday markets.

From the market participants' perspective, the balancing market presents an additional trading option for their flexibility, as long as they are prequalified to

[41] Some EU countries such as France and Spain, also use replacement reserves (RR) to replenish the amount of the manual frequency restoration reserve [10].

participate [7]. The DA market is the largest market that provides market participants with robust price signals. It is particularly relevant for the BC market, commonly clearing ahead of the DA market, as it determines the actors' opportunity costs [131]. The gate closure times (GCTs) of different marketplaces also determine whether non-awarded bids can be submitted elsewhere. The bidder can use available market information to form price expectations and to exploit arbitrage opportunities. Several researchers have shown that, unlike largely competitive DA markets, balancing markets offer different options for strategic behavior, such as orientation of bid prices to the highest bid in pay-as-bid auctions rather than to one's actual costs [146]. Furthermore, market participants may have incentives to oversupply or undersupply the market, taking profit of intertemporal dependencies among sequential markets [131]. Using large data sets, [142] came to the conclusion that the German market design provides a possibility to exploit strategic opportunities between the DA and the balancing market. They further showed that pay-as-bid pricing intensifies the incentive from deviating from one's true costs. This result was also confirmed by [143].

The behavior of market participants has been further shown to be affected by other factors, including the repeated nature of balancing auctions, incomplete information, (low) competition levels and their portfolio structures [111]. Perceived risk and uncertainty, for instance, are linked to a low bidding frequency for balancing capacity, a low product resolution, i.e. the number of hours the bid should be available for potential activation, and the volatility of balancing energy prices [147], [148].

A look at historical prices makes the effect of market design changes on bidding strategies and therefore prices evident. A good examples of this illustrated in Figure 6.1. It shows price developments in the German positive and negative aFRR markets, respectively. In 2018, as a result of the adoption of the disputed 'mixed-price calculation' (in Ger. *Mischpreisverfahren*), the BC market experienced a large price hike (Figure 6.1, top) whereas a mirroring effect was produced for BE prices (Figure 6.1, bottom). The abrupt change in the bidding behavior was caused by the change of the scoring rule: instead of awarding the bidder based on the BC bid price alone, an additional weighing factor based on the BE bid price was introduced. Interestingly enough, the prices went back to 'normal' soon after the 'mixed-price calculation' method was abolished in mid-2019.

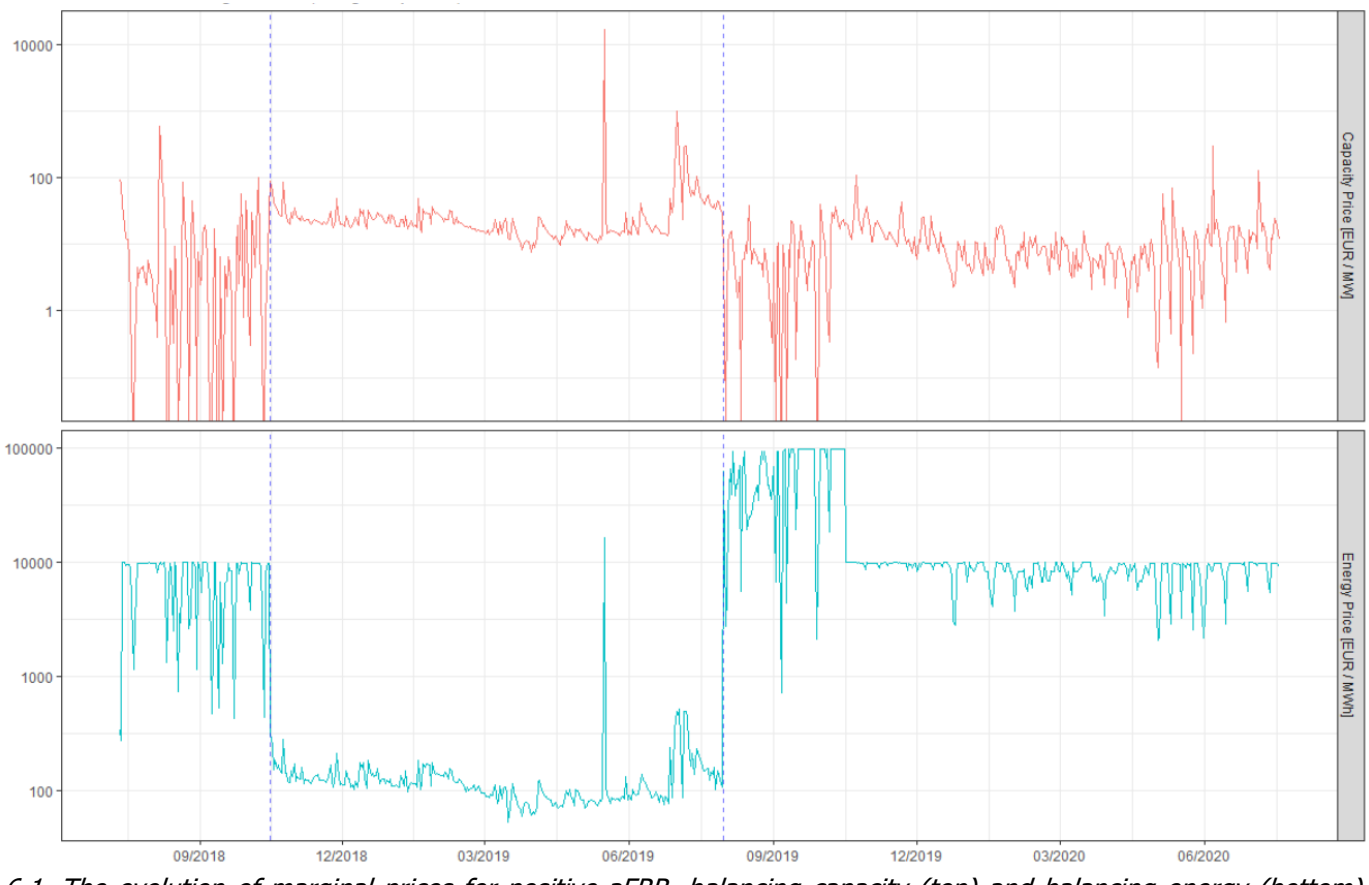

Figure 6.1. The evolution of marginal prices for positive aFRR, balancing capacity (top) and balancing energy (bottom) in Germany from end of 2018 to mid-2020. The period during which 'mixed price calculation' was in force is marked with dashed lines.

Although the number of bidders in the balancing market has increased in the last few years thanks to the entry new flexibility providers, such as aggregators[42], it is still much more limited as compared to the short-term electricity markets. The reasons for this include strict prequalification requirements, sometimes drafted only for specific technologies to fulfil; a thus far limited amount of short-term flexibility and a complex two-stage market structure. A modular approach to determining barriers to entry in European balancing markets was presented in [149]. The market structure has been addressed in great detail in [7], where the authors provided a framework for analyzing balancing market design and comparing it to the requirements introduced in the GL EB.

The implications of some of the upcoming design changes have been studied in [131] and in [143]. The authors in [143] demonstrated, among others, that the introduction of a standalone balancing energy market led to considerable efficiency gains in particular in combination with marginal pricing, yet was alone insufficient to protect the market from strategic bidding requiring additional adjustments [143]. Another arguably important market design adjustment is the introduction of voluntary bids in the BE market. [131] used theoretical bidding calculus to study the impact of market sequences on the optimal bidding strategies of BSPs and observed that voluntary bids can significantly alter bidder strategies by altering the regular BSP's price and competition expectations and dampening market power.

Due to their novelty, the effect of voluntary bids has not yet been modelled in research. Balancing markets have been subject of close scientific attention in the recent years, yet a large part of it was focused on optimizing bidding strategies i.e. on the perspective of individual participants and technologies [150]–[154]. From the perspective of the market itself, the research has been focused on national markets (e.g. Germany [145], [155], the Netherlands [156] or the Nordics [157]). To our knowledge there has not yet been a comprehensive model-based study of the new balancing market design, as prescribed by the GL EB.

This paper is intended to address the identified research gap and to contribute to the policy dialogue about the efficient balancing market design. It is pivotal for adequate system operation at the time when more sources of flexibility are becoming available from a wider range of technologies and providers (e.g. [158]), balancing procurement is getting internationalized and harmonized [159] and the task of system balancing is becoming more challenging [2].

This study contributes to the policy dialogue on efficient balancing market design through an innovative, powerful method to study the market and emulate agents' strategic behavior. To address the research questions posed in Section 6.1, we support our analysis with the results of an agent-based model, Elba-ABM, enhanced

[42] For an example of the list of prequalified BSPs, the reader is referred to the official webpage of the German TSOs, www.regelleistung.net.

with reinforcement learning. The latter is used to model agents bidding strategically based on the available market information and own experience. To the authors' knowledge, it is the first study that uses an agent-based model with learning agents to analyze the effect of voluntary bids on the strategies and the relation between the BC and BE markets. It is also the first to develop a collaborative machine-learning approach to modelling bidding strategies in interrelated markets. It allows us to draw valuable conclusions about the ways to make the most of short-term flexibility while keeping the prices close to competitive levels and inform decision-makers about possible caveats of market design changes.

6.3. Methodology

To answer the research questions posed in this study, we adapt the simulation framework of Elba-ABM, balancing energy market model developed in [143].

Agent-based modelling is a useful tool for modelling markets with low competition levels, such as the balancing market, as shown in [20], [111], [143]. We chose ABM in order to:

1) reflect all market design characteristics of the BC and BE markets and intertemporal links between them.
2) represent diverse portfolios and bidding strategies of market actors not bound by assumptions of perfect competition and foresight.

The *original* model focused on the representation of a balancing energy (BE) market alone. Its main goal was to study the effect of introducing a BE market with marginal pricing, independent of the BC market, as per the provisions of the GL EB. It was compared with the current balancing market design, where BSP submit BC and BE bids together (far) ahead of real time. Using Elba-ABM, bidding strategies of strategic and true-cost bidders were compared, given these design changes in terms of system costs and weighted average prices in the BE market. The BC market results were taken for granted, meaning that all bid capacity was assumed to be awarded, whereas BSPs could only compete on the BE price. The BE markets for upward and downward regulation were modelled and settled separately. The model did not consider the possibility of asymmetric bidding or the availability of voluntary bids. To illustrate the differences between the original and the new model, their characteristics are compared in a table in Appendix D.

In the *updated* Elba-ABM, a decision-making process with a larger scope is introduced as agents first compete both on volume and price in the BC market and then on balancing energy price in the subsequent BE market. Specifically, the market environment has been extended in the following ways:

1) It includes a detailed model of the BC market for upward and downward regulation with 24 hourly auctions per day each.

2) Asymmetric bidding is allowed: BSPs may submit different volumes and prices in the positive and negative BC markets for any given hour.
3) Positive and negative market are cleared in parallel, so agents cannot obtain updated information in one market to make a decision about the other, so they have to decide whether and how much to bid in both markets beforehand.
4) It accommodates the possibility to submit voluntary bids in the balancing energy market.
5) The day-ahead market is modelled implicitly by allowing agents to calculate their opportunity costs based on the expected DA market price for each hour of the next day using a naïve price forecast (see Section 6.3.2 for more detail).

Based on the BC market results, the set of participants in the BE market is always different. After the BC market is cleared, the agents are notified which generators and volumes have been awarded. This information is then passed on to the BE market, as is shown in Figure 6.2. The awarded bidders commit their capacity in the BC market whereas the non-awarded bidders may choose to participate in the BE market after the clearing of the DA market as 'second-chance' bidders. Finally, additional short-term flexibility in the BE can be provided by voluntary bidders that did not participate in the BC market. Then, a common merit order is built in the BE market clearing. The details of the model architecture and the extensions are graphically illustrated in Appendix E.

Participants in the balancing market are heterogeneous, some of them are price-takers whereas others bid strategically. The optimal bids of the latter are determined using reinforcement learning. Specifically, the agents in the extended Elba-ABM have been enhanced as follows:

1. complex BSP bidding: agents can decide both on their bid volume and bid price taking the expected DA market price into account,
2. two new agent groups, voluntary bidders and "second-chance' bidders, introduced,
3. strategic bidders in the balancing market modelled with the help of reinforcement learning by representing them as two algorithms for one agent (one in the BC and the other in the BE market) that collaborate in order to maximize annual profits.

Model assumptions about the market and the agents are specified in Appendix F. Sections 6.3.1 and 6.3.2 provide further details about the implementation of the extended Elba model on the market and agent levels, respectively.

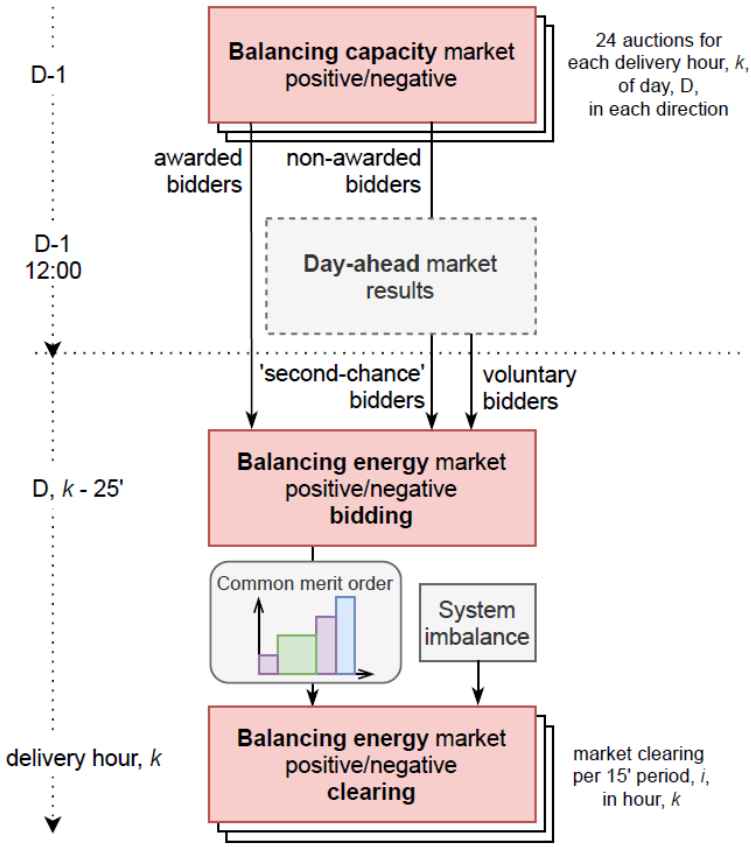

Figure 6.2. Temporal flow between the balancing capacity and balancing energy markets and their links with the day-ahead market as well as three bidder types in the balancing energy market, regular bidders, 'second-chance' bidders and voluntary bidders.

6.3.1. Model extension: Balancing capacity market

The extended Elba-ABM model includes a detailed design of the balancing *capacity* market with the following characteristics:

- 48 daily auctions based on a predefined reserve requirement. The demand for BC is determined by the TSO and therefore fixed and inelastic.
- pay-as-bid settlement of awarded bids
- bidding *prior to* the gate closure time (GCT) of the DA market: the GCT of the BC market is D-1 at 8am. Daily bidding in the BC market with hourly products implies that market actors can submit up to 24 hourly bids in each direction for the next day.
- the minimum bid requirement is 1MW.

A special procedure is introduced for situations in which the TSO could not procure a sufficient amount of balancing capacity to fulfil its reserve requirement: the TSO announces a second auction round in which all prequalified generators are obliged to provide their available capacity and the awarded power plants are remunerated on a cost-based basis.

The balancing *energy* market model (same as in the original Elba-ABM) follows the requirements of the GL EB[43]:

- BE bids are submitted in a standalone market close to real time,
- hourly BE auctions close 25 minutes before delivery,
- product duration is one hour,
- awarded bids receive the uniform marginal price,
- voluntary bids are allowed.

6.3.2. Model extension: Agent design and bidder types

The agents' decisions in the BC and BE markets are linked to the expected prices in other short-term markets and to their variable costs [131]. Their bids are composed of three decision variables: the BC bid price per generator and hour, $p_{g,k}^{+BC}$, BC bid volume $q_{g,k}^{+BC}$ and BE bid price $p_{g,k}^{+BE}$ in the positive market (upward regulation) and similar decision variables in the negative market $(-BC, -BE)$. BSPs submit BC and BE prices in separate marketplaces in different timeframes. The demand for BC, D_k^{BC}, is set by the TSO[44]. In the positive BC market, the generator bid is $b_{g,k}^{+BC} = \{p_{g,k}^{+BC}, q_{g,k}^{+BC}\}$, $k \in d$ and in the BE market: $b_{g,k}^{+BE} = \{p_{g,k}^{BE}, q_{g,k}^{+BE}\}$; in the latter, the bid volume is equal to the committed BC bid volume, $q_{g,k}^{+BC,awarded}$.

Agents bid differently in the positive and negative BC markets, as only the former involves actually producing energy. BC prices in the positive market are related to agents' opportunity costs per generator, i.e. the revenue forgone by not participating in other markets. Note that hydro power plants have low variable costs (1-2€/MWh, as assumed in [21, p. 153], which implies that they have high opportunity costs, as compared to gas turbines with high variable costs that mostly serve as peakers and have a much lower load factor. In the BE market, price-taker agents have no influence over the market outcome and bid at their short-term variable cost in the positive BE market $p_{g,k}^{+BE} = c_g^{var}\ \forall k$ while in the negative BE market, they bid up to their avoided variable costs as, i.e. willing to pay to the TSO. This is motivated by

[43] The GL EB further mandates that each standard balancing product in the future is procured in a single TSO-TSO balancing platform [37]. However, for the sake of simplicity, this model assumes a single bidding zone.

[44] The demand for balancing capacity depends on the TSO's estimations and the bidding zone's generation and demand volumes. The demand for automatic frequency restoration reserve (aFRR) varies depending on the country size and the TSO's estimation of the biggest plant outage, etc. and can range between several hundreds to several thousands of MW. The demand of 200MW is assumed in the simulation scenarios in Section 6.4 based on the demand of the Austrian TSO, APG, for aFRR.

the fact that even if they reduce output, they still receive the revenues from the day-ahead market [143].

Market actors may have different portfolios and strategies and decide on the bid volumes and prices individually per generator considering their variable costs and/or their prior experience. In the model, the choice can be made between two agent types:

1) *price-taking bidders* that bid their true opportunity costs in the BC market and, if awarded, bid their true short-term marginal costs in the BE market as would be expected under the assumption of perfect competition;
2) *strategic bidders* that attempt to maximize their profits based on market information and previous experience using a collaborative machine-learning algorithm. Since the balancing market is a two-stage process, reinforcement learning (RL) has been implemented as two collaborating agents in two different timeframes, daily (BC market) and hourly (BE market).

Link to the day-ahead market

Participation in the day-ahead market is implicitly considered in the model. An agent can sell its capacity either in the BC or the DA market or split it between the two. It is assumed that all agents are price-takers in the DA market, i.e. any volume is offered at their variable costs. To determine their opportunity costs, the agents in the BD market consider the expected DA market price that is calculated using a naïve forecast. It is based on the DA market prices of the day before prior to, during and after the delivery hour, *k*: $\{\lambda^{DA}_{d-1,k-2\ldots k+2}\}$[45], where $\lambda^{DA}_{d,k}$ is the market price on day d and hour k. We calculate the forecast error and the standard deviation of the forecast. Assuming a normal distribution of the forecast error, we use the confidence interval of 95% to obtain the lower bound, which determines the expected marginal price. It is assumed that each actor has the same price expectation for a given hour.

The trading options of market participants and, ergo, their strategies in the BC market depend on another factor, whether or not they are expected to be infra or extra-marginal in the DA market, that is, whether their variable costs are expected to be below or above the DA marginal price [107]. For instance, if an actor is expecting to be infra-marginal in the day-ahead market, he may decide not to bid in the BC market[46].

[45] The previous day is considered based on the following rule: if weekday of the delivery hour is Tuesday-Friday, DA market prices are considered from the day before; if weekday of the delivery hour is Monday - DA market prices from Friday of the previous week, if weekday of the delivery hour is Saturday or Sunday – DA market prices from Saturday or Sunday of the previous week.

[46] Note that this distinction has no bearing for the bids in the BE market as it takes place after the GCT of the DA market.

Voluntary and second-chance bidders

Actors that did not participate in the BC market, i.e. voluntary bidders, as well as 'second-chance' bidders, compete both on volume and on price in the BE market. Note that all voluntary bidders are assumed to be price-takers.

'Second-chance' bidders are those bidders that were not awarded in the BC market and, after the GCT of the DA market, evaluate if they take a second chance and participate by submitting voluntary bids to the BE market (see also Figure 6.2). As the DA market is not modelled explicitly, it is assumed that if a generator's variable costs are below the actual DA marginal price, the generator's full volume was awarded in DA market. If that is the case, the agent bids the maximum available capacity in the negative BE market. Conversely, if extra-marginal in the DA market, the agent bids the maximum available capacity in the positive BE market.

Bid submission

In the BC market, the agents' action domain includes the following constraints for the BC bid volume in the positive and negative markets (based on [111, p. 81]:

$$q_{g,k}^{DA} + q_{g,k}^{+BC} \leq q_g^{max}$$
$$q_g^{min} + q_{g,k}^{-BC} \leq q_{g,k}^{DA}$$

where $q_{g,k}^{DA}$ is the *expected* volume in the DA market in a given hour. Consequently, the bids submitted in the positive and negative market must validate the condition:

$$q_{g,k}^{+BC} + q_{g,k}^{-BC} = q_g^{max} - q_g^{min}$$

For the positive market, *opportunity costs* in a given hour, k, are calculated as follows (based on [111, p. 81]):

$$c_{g,k}^{opp,+BC}\left(q_{g,k}^{+BC}\right) = max\left(\lambda_k^{DA} - c_g^{var}, \quad \frac{\left(c_g^{var} - \lambda_k^{DA}\right) * q_{g,k}^{min}}{q_{g,k}^{+BC}}\right)$$

where λ_k^{DA} corresponds to the *expected* price in the DA market and $c_{g,k}^{opp,+BC}$ corresponds to the opportunity cost of generator *g* in hour *k* in the positive BC market.

For a power plant that is likely to be infra-marginal in the DA market ($\lambda_k^{DA} > c_g^{var}$), the opportunity costs, $c_{g,k}^{opp,-BC}$, are the difference between the expected DA price and the plant's variable costs. An extra-marginal power plant, in turn, faces fixed operational costs equal to the minimum volume required for the plant to deliver the committed volume for upward regulation. Conversely, in the negative market, opportunity costs of each generator are given by:

$$c_{g,k}^{opp,-BC}\left(q_{g,k}^{-BC}\right) = \max\left(0, \quad \left(c_g^{var} - \lambda_k^{DA}\right) * \frac{q_g^{min} + q_{g,k}^{-BC}}{q_{g,k}^{-BC}}\right)$$

An infra-marginal power plant has no opportunity costs in the negative market as it receives the DA price and does not face any costs for reducing its output. An extra-marginal power plant ($\lambda_k^{DA} < c_g^{var}$), should run at least $q_g^{min} + q_{g,k}^{-BC}$ in the DA market in order to provide downward regulation. If the expected DA price is lower than a generator's variable costs, it must still be able to reduce its output, i.e. it runs at $q_g^{min} + q_{g,k}^{-BC}$.

Positive and negative BC auctions are cleared simultaneously and the bid volumes depend on the expected DA market price.

For *price-taking bidders,* we assume a risk-neutral strategy, which translates into:

$$b_{g,k}^{+BC} = \begin{cases} \{c_{g,k}^{opp,+BC}, q_g^{avail}\}, \text{if } \lambda_k^{DA} < c_g^{var} \\ \{0,0\}, \qquad \text{else} \end{cases}$$

$$b_{g,k}^{-BC} = \begin{cases} \{0,0\}, \quad \text{if } \lambda_k^{DA} < c_g^{var} \\ \{0, q_{g,k}^{avail}\}, \qquad \text{else} \end{cases}$$

If a generator is extra-marginal, the price-taking agent will not bid in the negative BC market but will bid the maximum available capacity in the positive BC market at the generator's opportunity costs. Conversely, if the generator is infra-marginal, such an agent will place the maximum available volume in the negative BC market at a price of zero as it does not face any opportunity costs. At the same time, it will not bid any capacity in the positive BC market.

If the actor was not awarded in either the positive or negative BC auction, the maximum available capacity is bid in the DA market[47]. If he was awarded in the positive market, the DA market receives the difference between the committed positive volume and the maximum capacity of a generator. If awarded in the negative BC market, the maximum available volume is bid into the DA market[48]: $q_{g,k}^{DA} = q_g^{max} - q_{g,k}^{+BC,\ awarded}$.

For strategic bidders, two collaborating RL agents represent one market actor using a profit-maximizing strategy.

The BC market agent places two bids in the BC market per generator for each hour of the following day considering the available information in both markets. The RL agent in the BC market has two decision variables, the bid price and the bid volume, which have a significant effect on the action space. The level of discretization of the action space depends on the number of generators in the agents' portfolio. In order to limit the state-action space and the computational time and yet obtain meaningful results, the discretization of price actions is set to 7 and of volume actions to 4 per

[47] Since the DA market closes *after* the BC market, then, if the bidder was not awarded in the BC market, he can either still bid in the DA market or, if voluntary bids are allowed, place a voluntary bid in the BE market instead ('second-chance' bidder).

[48] The volume submitted to the DA market is used only for reference purposes to identify the bidders' preferences.

generator for a portfolio of three generators. This means that the combined discretized price-volume action space of an agent with three generators equals to 21,952 action pairs in each market time step. As a result, the agent can place either a markup or a markdown (also known as 'bid shading' [160]) up to its opportunity cost (i.e. bid up to maximum twice its opportunity costs). With regard to the bid volume, the bidder may bid 0%, 30%, 70% or 100% of the available capacity of a generator in its portfolio in the BC market.

For the training, the agent's model in the BC market is updated with the following information, separately for the positive and the negative markets:

1) demand for balancing capacity
2) the agent's past bid prices and volumes,
3) past seven DA market and weighted average BC and BE market prices,[49]
4) profit from the DA market,
5) the hour and weekday of the bid.

It is assumed that if the BC volume bid is less than the total available capacity, the rest is bid in the DA market.

The BE market agent places bids in the BE market using the algorithm formulated in [143]. Similar to the BC market, we use Q-fitted algorithm[50] to maximize the agent's cumulative reward over the entire portfolio and the episode (one year), based on the memory of previous market results and agent's own performance. Besides, as part of the dataset in the BE market, the agent now receives the volumes of capacities awarded in the BC market per hour and generator in its portfolio.

Together, BC and BE agents maximize the total reward for the strategic bidder. Different timeframes of the BC and BE markets create modelling challenges: the BC agent cannot otherwise quantify the expected reward and place an appropriate BC bid; it must assume that the BE agent is behaving optimally. Collaboration of the reinforcement learning algorithms is achieved in three ways:

1) through sequential training in the two markets,
2) sharing market information passed to the two agent's datasets,
3) sharing profits.

The profit of a BSP depends on whether the capacity bid was awarded and whether or not the committed capacity bid received an activation call. If the bid capacity was not included in the merit order for balancing energy (extramarginal BC bid), the BSP faces the opportunity costs for withholding capacity and the profit only includes the payment obtained from the amount, $q_{g,k}^{BC}$, of the bid volume multiplied by the bid

[49] As bidders are remunerated pay-as-bid in the BC market, the TSO does not usually provide the information about the marginal price but rather publishes the hourly weighted average price.
[50] Interested readers are invited to refer to [97], [143] for more details on the implementation of the learning algorithm.

price: $\pi^{BC} = \sum_{g=1}^{G} q_{g,k}^{BC} * (p_{g,k}^{BC} - c_g^{opp})\ \forall\ k$. Conversely, if activated, the overall profit is a sum of the two markets:

$$\pi^{BM} = \begin{cases} \pi^{BC} + \pi^{BE}, & \text{if } b^{BC} \text{ is awarded} \\ 0, & \text{else.} \end{cases}, \text{ where } \pi^{BE} = \sum_{g=1}^{G} q_{g,k}^{BE} * (p_{g,k}^{BE} - c_g^{var})\ \forall\ k$$

6.4. Scenarios and results

6.4.1. Description of the simulation scenarios

To study the effects of voluntary bids on bidding behavior, we analyze several scenarios in which the number of bidders is limited for two reasons. The first reason is methodological: increasing the number of participants would risk 'crowding out' the strategic bidder from the BC market, making the training less effective and, ergo, the results less conclusive. Second, an oligopolistic setting represents the 'worst-case' scenario, in which a change in market design can be expected to have the most benefit. Therefore, the scenarios contain three agents, each with a portfolio of three to five generation units. Each agent submits separate bids per generator submits to the positive and one to the negative balancing markets. The details of the agents' portfolios can be found in Appendix G.

The following three scenarios are defined:
1) *'all_TC'*: Baseline scenario with only price-taker actors (who bid their 'true-cost').
2) *'TC_&_SB'*: Scenario with true-cost bidders and one strategic bidder.
3) *'all_SB':* Scenario with three strategic bidders. In this scenario, a single true-cost-bidding agent is added that bids a high capacity price (300€/MW) as a proxy for scarcity situations in which the learning agents withhold balancing capacity.

Three variations of Scenarios 2 and 3 are analyzed. They include:

a) *'no voluntary bids'*: voluntary bidding in the BE market is not allowed,
b) *'+vol'*: the introduction of a single voluntary bidder with both cheap and expensive generation units who bids different – randomly chosen – flexibility volumes between 50% and 100% of the available capacity into the BE market.
c) *'+vol & second_chance':* in addition to a voluntary bidder, non-awarded BSPs may participate in the BE market as second-chance bidders (see also Figure 6.2).

With the help of these seven scenarios, we trace the effects on the bidding strategies and on overall market efficiency based on market prices, total market costs as well as agents' profits.

6.4.2. Summary and discussion of the results

When analyzing the results, it is important to bear in mind the balancing market

complexity. A bidder has an option to participate in the positive or in the negative BC market or split its available capacity between the two. The BE market is also split in two separate auctions. Agents' bidding strategies in the positive and negative BC and BE markets differ.

In the following, we highlight the main takeaways from the simulation scenarios, whereas all the results are summarized in Appendix H.

The price duration curves for scenarios *'all_TC'* and *'TC_&SB'* (a) to c)) are shown for the BC market in Figure 6.3 and for the BE market in Figure 6.4. This comparison demonstrates the extent to which the presence of a single strategic bidder in the balancing market can affect the market outcome, even considering market design improvements such as the introduction of a standalone BE market and the use of marginal pricing (as was discussed in [143]).

In *'TC_&_SB'* scenarios, the strategic bidder can affect market results, which translates into higher market costs (for the TSO) as compared to the *'all_TC'* scenario. While the total BC costs increased from M€ 12 to M€ 19, the BE market costs are over three times higher (M€ 5,9 vs. M€ 18,8). Heim and Götz [161] already found that the market outcome can be significantly affected by the actions of a single dominant supplier, leading, for example, to a dramatic decrease in market liquidity. A similar effect can be observed in Figure 6.4 (orange line): the presence of a strategic bidder, roughly covering a fourth to a third of the total supply, leads to prices above 100 €/MWh ca. 10% of the time and to price spikes of almost 500 €/MWh. (In comparison, less than 2% of the time was all or nearly all supply needed to offset an imbalance.)

The agents' decisions in the BC markets are linked to their strategies in the BE market by the estimated likelihood of being called in the BE market and expected profits in both markets [131], [160]. As a result, a strategic bidder may forego profits in the BC market to increase his participation in the lucrative BE market. Figure 6.5 shows that in a scenario with *no voluntary bids* the strategic agent frequently bids close to its true costs. Notably, it also bids below its costs 16% of the time in order to secure its participation in the BE market. The incentive to participate in the latter is high: the profits of the strategic bidder in the positive BE market were 5,3 times higher than those in the positive BC market (M€ 0,5 vs. M€ 2,65, see Figure 6.5, left).

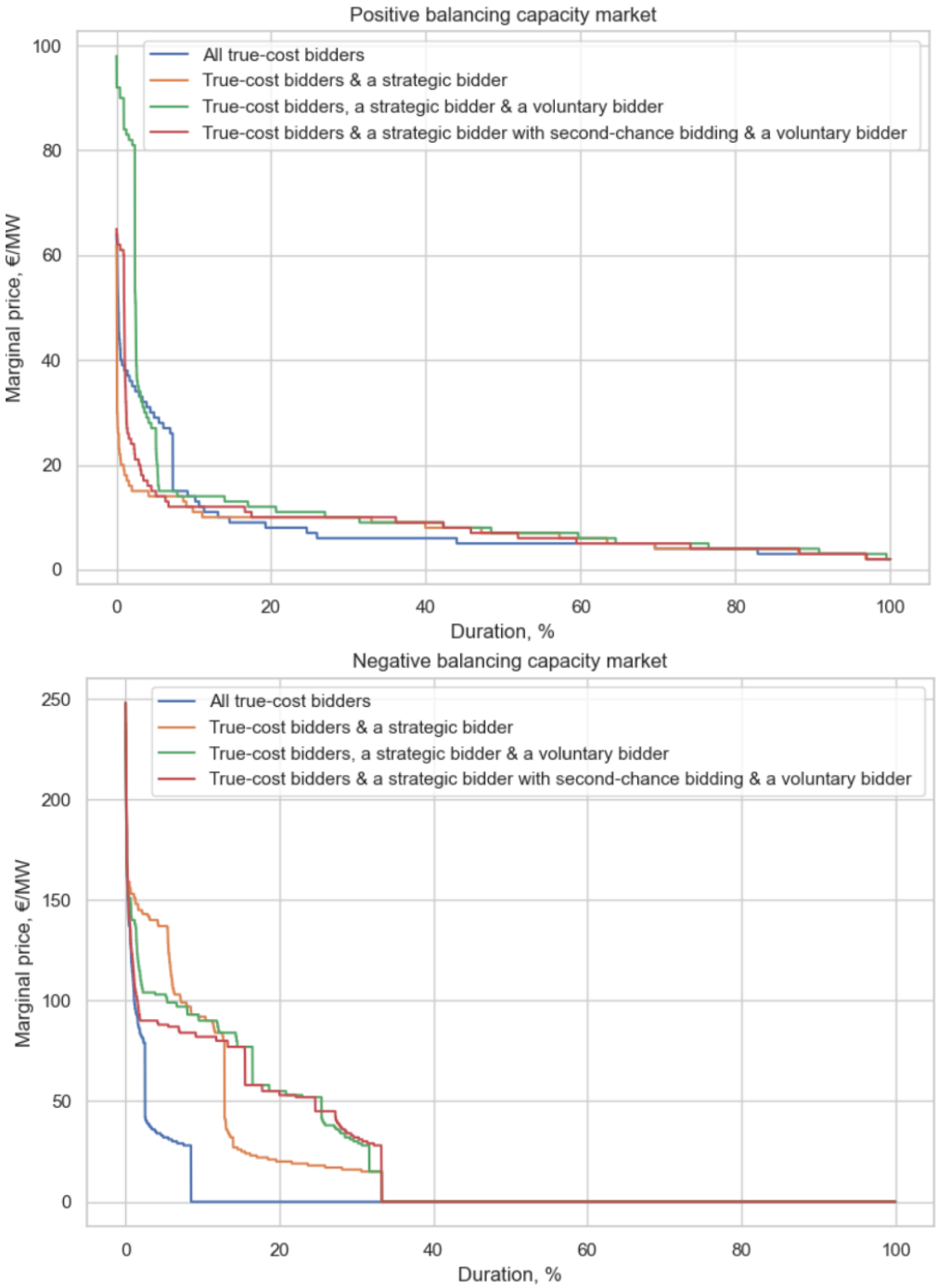

Figure 6.3. Price duration curves in positive (top) and negative (bottom) balancing ***capacity*** *markets, scenarios with all true-cost bidders and different bidder types.*

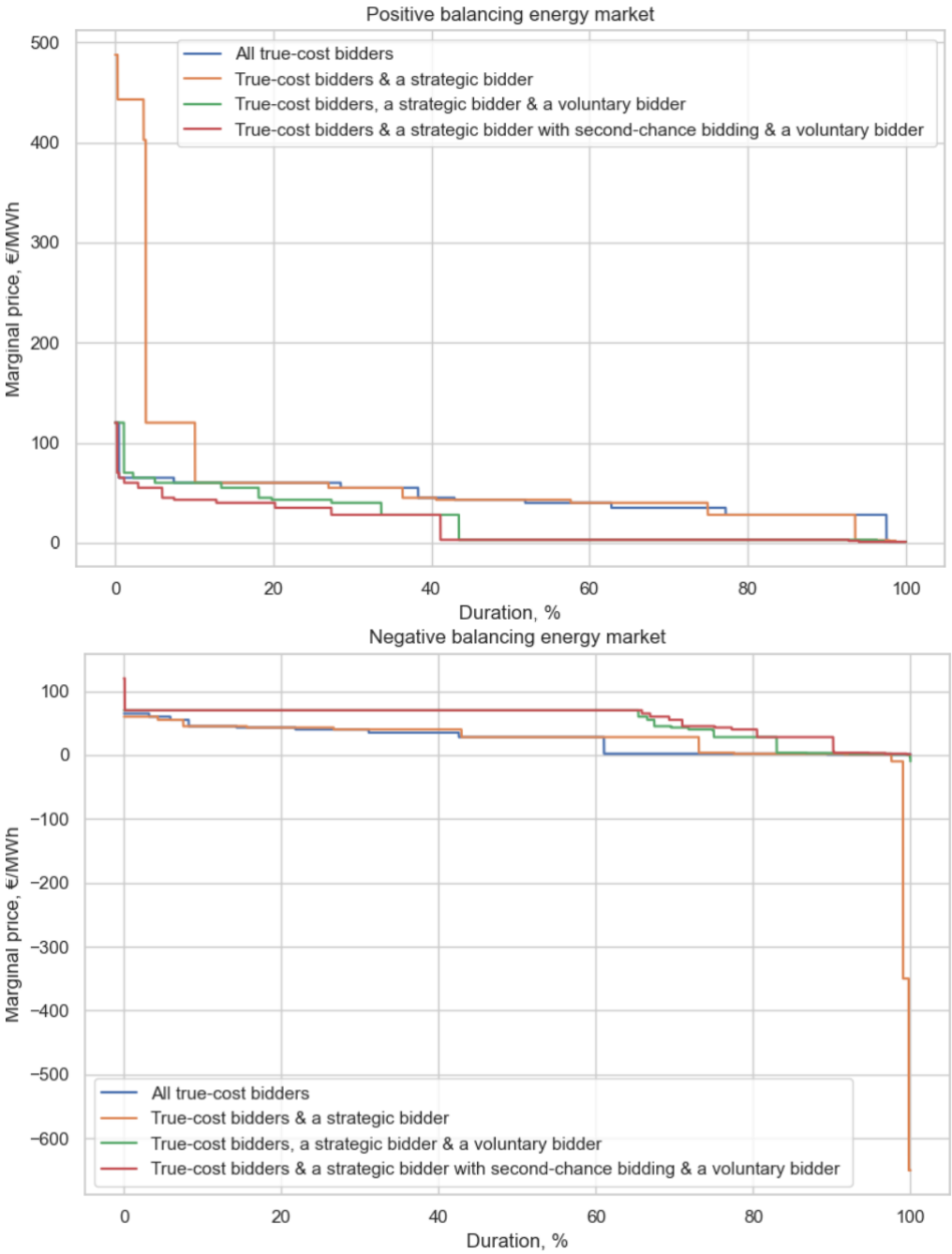

*Figure 6.4. Price duration curves in positive (top) and negative (bottom) balancing **energy** markets, scenarios with all true-cost bidders and different bidder types*

This trend is reversed in the scenarios *'TC_&_SB+vol'* and *'TC_&_SB+vol&second_chance'.* The introduction of a voluntary bidder adds considerable price pressure on the incumbents in the BE market and reduces market power. It should be noted that we did not assume that the voluntary bidder's portfolio consists of only cheap generation (see Appendix G for agent portfolios). Voluntary bidders prompted more competitive behavior: the deviated from their true costs in the BE market only 20% and 11% of the time, respectively, as compared to 46% in the *no-voluntary-bids* scenario (Figure 6.5). This led to a reduction of weighted average positive BE market prices of 72% in scenario *TC_&_SB* (see Appendix H). Simulations of the BE market for downward regulation produce similarly positive results (see also Figure 6.6, right).

Second-chance bidders do not obtain revenues from the BC market (by definition), yet their presence in the BE market helps reduce the weighted average price and the total BE market costs further (Figure 6.6, right). This can be explained by the intensified competition stemming from those bids that were initially filtered out by the BC market where the volume is limited volume to its high BC reservation costs.

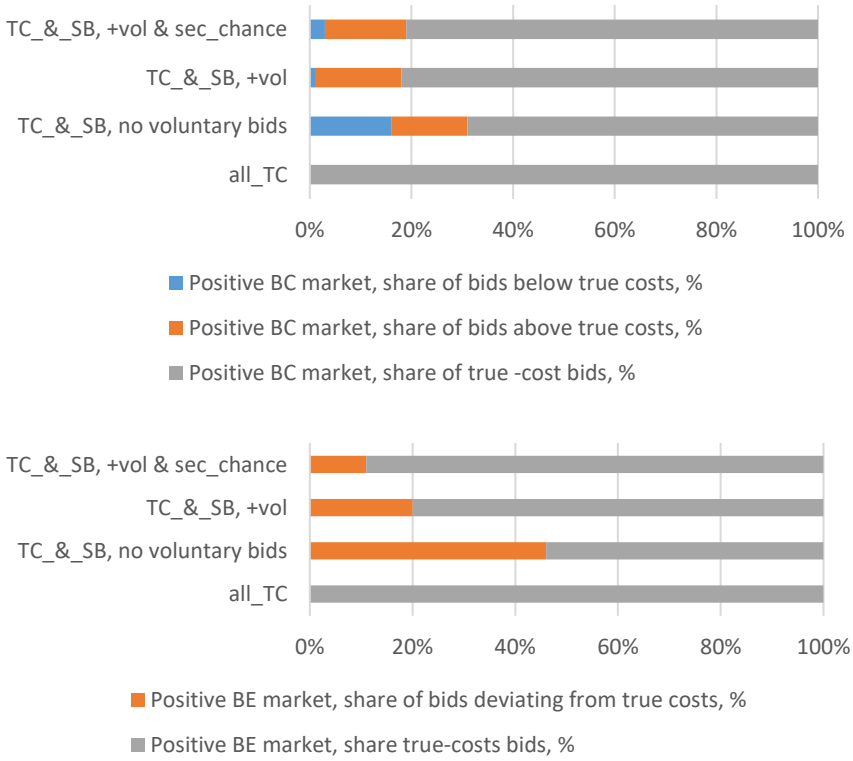

Figure 6.5. The share of times the strategic agent bid its true costs or deviated from them over the year in the positive BC market (top) and in the BE market (bottom). The results for the negative market can be found in Appendix H.

Although the introduction of voluntary bids improves prices in the BE market, the same cannot be said about the BC market. As is illustrated in Figure 6.3, the strategic agent almost never underbids its BC cost but bids higher more often when its participation in the BE market is no longer contingent on the outcome of the BC market (when second-chance bidding is allowed). As a result, the strategic agent (agent #2) increases its profits in the positive BC market and even more so in the negative BC market (see Figure 6.6, left). Given dwindling BE profits, the RL agent maximizes profits elsewhere thanks to the collaborative learning algorithm. The negative market where it can earn profits from committing capacity to reduce output while also generating revenues in the DA market also proves to be more lucrative.

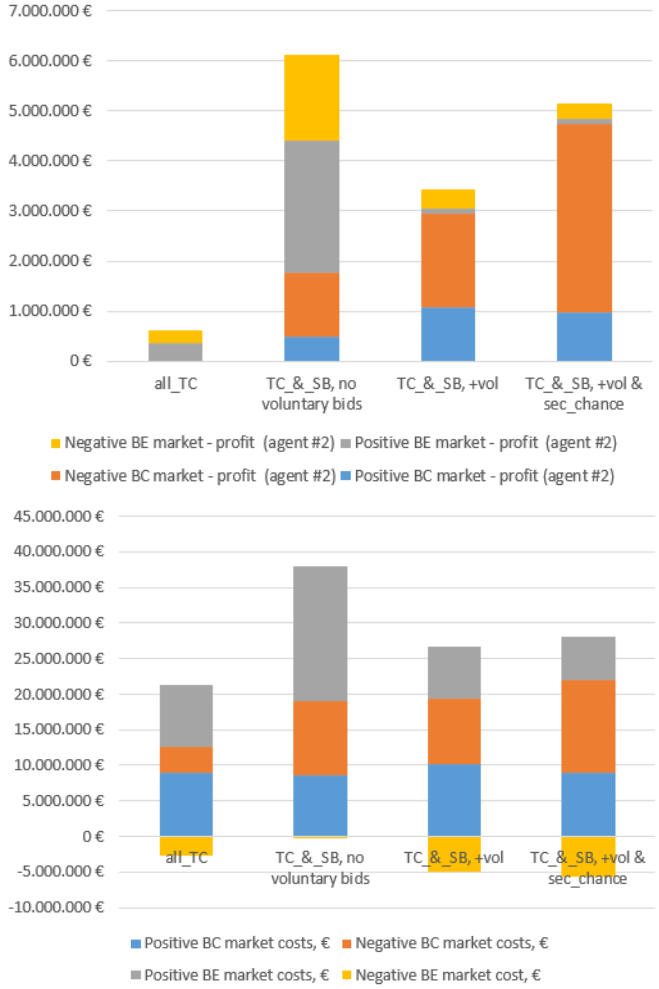

Figure 6.6. Cumulative yearly profits of the strategic agent (agent #2) (top) and the total yearly BC and BE market costs (bottom) in the scenarios 'all_TC' and 'TC_&_SB'.

On the market side, the efficiency gains obtained in the BE market still outweigh the increased costs in the BC market. It should be kept in mind that negative amounts in the negative BE market indicate payments to the TSO.

If we assume that the balancing market is an oligopoly and all agents bid strategically (scenarios *'all_SB'*), a different picture emerges. All scenario variants produce extremely high yearly BC market costs in the model (between M€ 233 and M€ 54). These results, however, should be interpreted with caution. First of all, unlike true-cost bidders submitting all available capacity to the BC market, strategic bidders can choose how much to submit in the positive and/or negative BC market in order to generate more profit. As BC demand is inelastic, in order to ensure that sufficient capacity is procured at all times, an expensive backup bidder with a constant bid of 300 €/MW was introduced. In the simulations, it is used to signal scarcity in the market. However, as this bidder sets the price much of the time, this modeling choice influences the average prices in the model significantly. Strategic bidders optimize their profits over a total of four marketplaces, i.e. positive and negative auctions in the BC and BE markets. As a result, a large share of the BC market costs produced in these scenarios can be traced back to the back-up generator.

Considering pay-as-bid pricing in the BC market and the model assumption that strategic bidders can bid up to twice their current opportunity costs, they cannot fully profit from the high prices generated by the backup bidder. Yet, they jointly push the price upwards and earn profits that by far exceed those in the *'TC_&_SB'* scenarios (see Appendix H). Learning effects in frequently repeated auctions[145], demonstrated in our results, allow strategic bidders to increase their profits substantially by learning from previous auction results.

Since in the BE market, the price pressure is still created by the voluntary bids, strategic bidders are compelled to moderate their bids and bid their true costs 46% (*'all_SB+vol'*) and 64% *('all_SB+vol&second_chance')* of all times, as compared to only 2% in the scenario with *no voluntary bids*. Similarly, a significant reduction is observed in the weighted average BE market prices (Appendix E). However, high concentration in the BC market raises the total costs to such an extent that they eclipse the gains from the BE market. In addition, similar to the *'TC_&_SB'* scenarios, in the presence of voluntary bidders, strategic bidders tend to shift most of their balancing capacity to the negative market. Remember that reinforcement learning algorithm i.a. considers the profits from the DA market (see Section 6.3.2.3) and, in this way, inframarginal generators maximize profits in the negative market while at the same time getting paid in the DA market.

6.4.3. Impact of introducing voluntary bids

The need for additional short-term flexibility is becoming more urgent as the volatility of residual demand and scarcity events are going to increase in the future. Voluntary bids benefit the balancing energy market, as set out in Section 6.4.2, as well as

flexibility owners. Although participation in the BE market as a voluntary bidder means that they forego revenues from the capacity market, it provides additional flexibility for those BSPs that find it difficult to estimate their availability farther ahead of real time.

Such voluntary bidders are likely to have an impact on both the overall market and other bidders. Voluntary bidders with very low costs are likely to emerge, consider, for instance, aggregators of EV fleets. Yet, such bidders will also need to pass technical prequalification, so it would be unrealistic to assume that their entry into the balancing market would be massive or cheap across the board. For this reason, the impact of a single voluntary bidder with differently priced assets was studied. Considering that the balancing capacity market provides most of the input to the balancing energy market, the introduction of voluntary bids does not eliminate but rather weakens the link between the two market stages. Reduced predictability and downward price pressure incentivize agents to bid closer to their true costs.

Second-chance bidding further improves competition in the BE market. Since the bids in the BC market are based on generators' opportunity costs as opposed to variable costs in the BE market, a bidder that was 'too expensive' in one market is not necessarily so in the subsequent market. An important implication is that the conditions for high market concentration are created by the BC market itself: only a few bidders are awarded since the volume of reserved capacity is both inelastic and limited. In particular, in smaller countries like Austria and the Netherlands, only a few hundred MW per product are procured [132], [162]. However, higher volumes of procured balancing capacity would be undesirable in view of BC reservation costs that are mostly recovered directly through grid tariffs paid by consumers [163].

Yet, short-term flexibility comes at a cost. Under the market design proposed in the GL EB, the cost shifts to the balancing capacity market. As our research shows, the extent of this shift largely depends on the degree of market concentration. Removing the BC market altogether as proposed in previous research (e.g. [142], [164] could be a means to prevent existing distortions. Currently, removing the balancing capacity procurement appears feasible in the short run as it would entail a risk of a shortage of balancing energy.

Improving the conditions for new actors and technologies to participate, i.a. in the TSOs' prequalification procedures, is essential for improving competition in the balancing *capacity* markets. The results presented in this paper indicate that the work of improving balancing market design is far from over and the adjustment, harmonization and integration of the European balancing *capacity* markets are crucial next steps for ensuring cost-efficient balancing service procurement. They would not only increase the available pool of balancing capacity but also might allow a degree of demand elasticity, which would discourage strategic bidding.

6.5. Conclusion and policy implications

The design of an efficient balancing markets has gained importance both due to the ongoing market harmonization efforts and to the increasing shares of volatile renewables in European power systems. In the European Balancing Guideline adopted in 2019, the new target design for the European balancing energy markets was proposed and envisaged to improve market access for all types of flexibility providers and increase competition. We provide new insights into the implications of the balancing market design changes with a particular focus on 1) the links between the bidding strategies in the balancing capacity and energy markets and 2) on the introduction of voluntary bids.

By expanding the agent-based model of the balancing market, Elba-ABM, we demonstrate complex bidding strategies of balancing service providers that take the information from the positive and negative auctions in the balancing capacity and energy markets into account. The novel collaborative reinforcement learning algorithm developed in this paper represented interdependent bidder strategies in the two markets. For instance, we show that a strategic bidder learns to optimally distribute limited available capacity between the positive and the negative markets and to underbid its costs in the balancing capacity market in order to secure a place in the lucrative balancing energy market.

The efficiency of balancing energy markets can greatly profit from short-term flexibility: it does not only expand the TSO's options for handling system imbalances but also substantially reduces the market's exposure to strategic bidding. We show that the authorization of voluntary bids in the balancing energy market tends to reduce the cost of balancing energy procurement and compels strategic bidders to bid close to their true costs. Notably, this holds true even in the scenarios with highly concentrated markets with all strategic bidders. Furthermore, if bidders that were not awarded in the balancing capacity market can take a second chance by submitting a balancing energy bid, this leads to additional efficiency gains. The reason is that it allows to overcome the initial concentration caused by the balancing capacity market having a limited and inelastic reserve demand.

We warn, however, that, the authorization of voluntary bids is not a 'silver bullet' for reducing potential for strategic bidding in the balancing energy market, especially if the number of new flexibility providers remains limited. Strategy-wise, the balancing energy market remains linked to the balancing capacity market, a prerequisite for participation in the second, energy activation, stage. We show that the changes in balancing energy market design can shift possible strategic bidding to the balancing capacity market. In the face of falling profits in the balancing energy market, learning agents tend to pursue a more aggressive profit-maximizing strategy in the balancing capacity market. This may lead to much larger costs there and reduces the efficiency gains obtained in the balancing energy market through voluntary bids. We further

show that this is particularly an issue in concentrated markets where decreasing profits from the balancing market risk to drive positive balancing capacity away from the market. Therefore, securing competition in the balancing capacity market, e.g. by allowing prequalification of new technologies and by integrating European balancing capacity markets, is of paramount importance to efficient balancing markets.

Future research should focus on modelling and studying the implications of balancing market integration as well as on further applications of reinforcement learning in electricity markets.

7

Effect of market interdependencies between balancing and redispatch on the bidding behavior[51]

The authors provide a critical analysis of existing approaches to balancing and congestion management (specifically redispatch) and their effects on the incentives for service providers. This issue is particularly important in the view of the harmonization of ancillary service procurement in Europe, introduction of cross-border balancing markets and cooperation on congestion management. There is no universally established procurement mechanism for either of the two services. Based on case studies of Germany, France and the Netherlands and the introduction of an EU balancing energy platforms, we derive three stylized interaction models and discuss their comparative conflicts, risks and performance. We argue that market-based redispatch procurement can both increase allocative efficiency and resource availability as long as structural congestion is addressed first. Timeframe of procurement and remuneration mechanisms are other crucial factors affecting market efficiency. Combining redispatch with wholesale markets might yield a further improvement while minimizing conflicts between redispatch and balancing.

[51] This chapter has been published as Poplavskaya K., *et al.*, Redispatch and balancing: Same but different. Links, conflicts and solutions. Proceedings of the 17th International Conference on the European Energy Market, 2020.

7.1. Introduction

Balancing and congestion management, two key functions of the transmission system operator (TSO), both require short-term flexibility. The TSO must ensure, on the one hand, a continuous balance of supply and demand and, on the other hand, that energy can be securely transmitted from generation to load. For the former, balancing resources are activated to contain or restore system frequency. For the latter, if the market result cannot be accommodated by the available transmission capacity, generation units or loads can be redispatched, i.e. their dispatch is adjusted downwards upstream and upwards downstream of the congestion point[52]. In this paper we address the question if and how these services and the way they are procured by need to be coordinated.

Both balancing and redispatching involve adjusting the schedule and real-time operation of generators and some loads; so far, only TSOs procure these services[53]. The two services can conflict with each other. For instance, a balancing service cannot be provided by a generator that is redispatched to relieve congestion. Conversely, activation of balancing resources may aggravate congestion, causing higher system costs or reducing the effect of redispatching. Both services need to cope with short-term uncertainty, yet some aspects are more predictable, such as structural congestion and imbalances caused by "discrete trading periods"[165]. The degree of alignment between the two processes depends on a number of factors, such as the technical and regulatory requirements and the reliability of forecasts. Procurement mechanisms, their timeframes and the geographic scope of the two services result in different incentives, opportunities and strategies for the participants.

While market-based balancing service provision is the most common approach in the EU, the approach to redispatch ranges from mandatory cost-based to market-based provision, in some cases integrated with the balancing market [10], [165]. Compared to balancing, the procurement of redispatch has received only limited scientific attention, presumably because of a lack of transparency in the procurement process or limited volumes in some countries. Thus, the main objective of this paper is to analyze approaches to balancing and redispatch as well as relations between them and identify solutions for maximizing their joint economic efficiency. We show that separate procurement of balancing and congestion management resources works best, but that the efficiency depends on the procurement timeframes, the degree of congestion and the remuneration of redispatch.

[52] We focus on control areas in which intra-zonal congestion is handled through redispatching, as is common in Europe. Intra-zonal congestion can also be solved through changes of network topology or, in Scandinavia and Italy, by splitting a control area into several zones in case of congestion.
[53] Congestion management is expected to be conducted on the distribution network level in the future as the number of DER in the power networks increases, however, this aspect is out of the scope of this paper.

7.2. Background: relations and differences between balancing and redispatching

The main differences between balancing and redispatch are summarized in Table 7.1. While balancing resources are not geographically bound, the location of a redispatch unit is key to its effectiveness with regard to the congestion point. The activated volume cannot be directly translated into the amount of congestion it can relieve. Consequently, when selecting resources for congestion management, the TSO has to consider not only the cost or the bid of the provider but also its effectiveness. In a meshed European network, there are multiple options, but the ones farther from the congestion point likely have a lower effectiveness, which greatly constrains the options available to the TSO.

Table 7.1. Overview of the main differences between balancing and redispatch.

	Balancing	**Redispatch**
- Purpose	Frequency control	Congestion management
- Procedure	Mainly curative	Preventive and curative
- Location	Irrelevant within control area	Key criterion
- Decision to award	Price-based (merit-order)	Based on cost/price & effectiveness
- Action direction	One-way (imbalance-dependent)	Symmetric
- Timeframe	(Mostly) real time	From day-ahead to real time
- Duration	From a few minutes to an hour	From an hour to several hours
- Approach to procurement	Market-based/ Mandatory cost-based	Heterogeneous
- Capacity reservation	Yes	No[54]
-Standardized prequalification	Yes	No

While balancing is mostly carried out in real time, redispatch is a continuous process starting with the TSOs' individual and joint planning processes and procured in several steps, from day-ahead to real time [167]. It does not require prior reservation, unlike balancing, which typically relies on the reserved capacity.

In balancing, a distinction should be made between proactive and reactive approaches to system management. A proactive TSO depends less on the scheduling of market actors and intervenes earlier utilizing slower but cheaper resources.

[54] Some TSOs do have complimentary mechanisms to contract additional capacity that can be activated for redispatch and is remunerated for capacity reservation. This is normally applicable to avoid early decommissioning of power plants, e.g. [166].

Conversely, a reactive TSO approach uses a more decentralized approach in which BRPs are expected to minimize imbalances. In case of congestion, however, participants in zonal markets have no incentive to solve congestion within a bidding zone, unless they are activated for redispatch, which is why redispatching is to a large extent preventive in nature, i.e. it is the goal of the TSO to avoid market intervention as much as possible instead of resolving congestion [168]. Besides, the TSO's preference for using redispatch instead of other measures such as grid expansion depends on their own regulatory incentives [168].

Product requirements for redispatching have thus far not been standardized in most European countries. In general terms, however, redispatch measures can be subdivided into preventive (transmission constraints are considered *ex ante*) and curative (so-called *ex post* redispatch) [169]. The former takes place prior to the day-ahead (DA) market coupling whereas the latter close to real time. Due to a high interconnection level among the European countries, power flows in one country have significant effects on the grid situation in the neighboring countries, e.g. causing a congestion elsewhere or limiting cross-border capacities at a different border due to loop flows. For this reason, preventive measures, among others, involve TSO coordination to reduce congestion. Curative redispatch is used to solve system security issues arising from infeasible market outcomes.

The differences in procurement mechanisms, remuneration and timeframes create opportunity costs for market actors. Currently, balancing is a more attractive option for providers because the service is procured competitively and the selected providers are likely to make a net profit, as compared to redispatch service that is often settled at cost. Consequently, redispatching creates local opportunities different from the zonal incentives in the balancing and/or DA markets. The location-bound nature of redispatch implies that the pool of possible providers is more limited leading to a greater likelihood of market power. Inc-dec gaming[55] is a commonly cited concern, in particular in areas with frequent and predictable congestion [170], [171], [172].

7.3. Methodology

Based on the fundamental relations and differences between balancing and redispatch services described in Sections 7.1 and 7.2, we illustrate different procurement approaches of the TSOs in Germany, France and the Netherlands (Section 7.4). Guided by the country studies and the current EU regulation, we derive three possible interaction models between the two services. We then analyze each model with respect to potential conflicts and effects on the participants' incentives

[55] Inc-dec gaming refers to a situation caused by differences between the zonal electricity market price and the local value of a redispatch action. If the value is expected to be higher than the zonal price, a market actor will have an incentive to reduce their offer on the day-ahead market in order to increase it for redispatch and secure higher profits (cf. e.g.[170]).

(Section 7.5). Finally, the efficiency of the three models is assessed with the help of evaluation criteria, such as allocative efficiency and susceptibility to gaming, and recommendations for improving efficiency and coordination of the two services are derived (Section 7.6).

As the procurement method of balancing energy is expected to be harmonized in the following few years through European balancing platforms [37], [173], [174], the focus is on discussing the different approaches to redispatch and their interrelations with the balancing market in the context of current regulatory developments.

7.4. Regulatory perspective

The relations and differences between redispatch and balancing stem not only from the technical requirements but also from the applicable regulation. EU regulation should be considered in view of the recent internal market harmonization rules, including the harmonization of ancillary service procurement. In this section, it is compared to the current approach to redispatch in Germany, France and the Netherlands in order to derive the core properties of each.

7.4.1. EU perspective and future developments

According to the European Balancing Guideline (GL EB), balancing energy shall be procured through a TSO-TSO platform that uses a common merit order with a single cross-border marginal price [37], [173]. The use of the European platform is obligatory for all TSOs using standard balancing products[56]. The gate closure time for the standard balancing energy product is set at 25 minutes before real time. Finally, voluntary bids, i.e. bids that were not contracted in the balancing capacity market, will be allowed to provide balancing energy [87].

Cross-border congestion management and cooperation regarding redispatch in addressed in the CACM Regulation (Capacity Allocation and Congestion Management) [8]. Specifically redispatching shall be conducted according to the following principles, as stipulated in the EU Electricity Market Regulation (Art.13 [175]):

1. Redispatch should be procured in a market-based way.
2. The redispatch market is explicitly open to all types of generation, loads and storage (Art. 13 (1)).
3. Redispatch service providers must be financially compensated.

[56] Automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and replacement reserve (RR). Frequency containment reserve is out of the scope of this regulation and of this study as only balancing capacity is usually procured for this product.

4. *"Balancing bids used for redispatching shall not set the balancing energy price"* (Art. 13(2)).
5. Derogations from principle 1 are allowed if the bidding zone contains structural congestion and is thus likely to be prone to strategic behavior; or if there is a low and uncompetitive volume of generation, demand response or storage; or if the TSO exhausted "all available market-based resources" (Art. 13(3)).
6. The approach to redispatch should give *"efficient economic signals to the market participants and TSOs involved"* (Art 16(1)).

Concerning the use of balancing bids to handle system constraints, including for redispatching, *cross-border* congestion shall be priced into market prices by reflecting the current state of cross-border capacities at the time of the balancing auction. In contrast, the GL EB does not allow balancing bids activated to solve an *internal* congestion to set the balancing energy price. Besides, the bids submitted to the European balancing platforms will not contain internal network locational information [37].

7.4.2. Germany

Balancing services are jointly procured by the *Netzverbund* of the four German TSOs using common auctions. The German TSOs use a reactive approach to system management: market actors are expected to minimize their own imbalances whereas the TSOs handle the remaining deviations using balancing reserves.

Redispatch services are procured independently from balancing services. All generation or storage facilities that are obliged by a TSO to adjust their active power for redispatch are remunerated based on reported costs. The TSOs may send redispatch instructions after receiving generation and load schedules at 14:30 day-ahead and later make adjustments continuously as they obtain more information [165].

Currently, redispatch is only provided by large conventional power plants. The Act on the Acceleration of the Expansion of the Energy Transmission Grid [176] adopted in 2019 foresees all conventional and renewable generators above 100 kW to be integrated in the redispatch process starting October 2021. However, the market-based approach for congestion management was decided against due the concerns about the risk of market power and manipulation [170].

7.4.3. France

Both balancing, mFRR and RR (see footnote 5), and redispatch are procured through auctions within a so-called 'balancing mechanism'. The French TSO, RTE, has a proactive system management approach and carries out balancing activations prior to the actual imbalance up to one hour before real time, which enables the TSO to

use slower reserves. Due to the start-up times of some generation technologies, RTE may instruct some power plants to start ahead of market gate closure if it expects network constraints. Instructions for redispatch are issued prior to balancing instructions. Joint procurement of mFRR and redispatch implies that mFRR bids used for redispatch get remunerated for capacity reservation besides energy activation regardless of the activation purpose.

7.4.4. The Netherlands

The Dutch TSO, TenneT, uses a reactive system management strategy. Its main peculiarity is that market participants are allowed and encouraged to use so-called 'passive balancing' (cf. [177]), intentional schedule deviations to minimize not own but system imbalances in response to real-time imbalance signals. TenneT then solves residual imbalances. Another feature of this approach is that availability of balancing resources is increased through allowing voluntary aFRR energy bids.

Redispatch service is auctioned as a specific product, 'reserve other purposes'[168]. A unit might be provided for both redispatch and balancing but, if committed for either, it must be removed from the other merit order. A daily continuous auction for "reserve other purposes" takes place between 15:00 D-1 and 45 minutes before real time. Awarded bids receive energy prices pay-as-bid. The TSO monitors the congestion situation continuously and may prevent intraday trades if they create or aggravate congestion [165]. TenneT can call for additional bids in a specific location if insufficient volume to relieve congestion was provided.

The three countries' approaches to redispatch are juxtaposed in Table 7.2. Germany has a more regulated approach in which generators are compensated for their costs, while France and the Netherlands have a market-based approach to both procurement and remuneration for delivered services. In France, balancing and congestion management reserves are procured together, in the other countries separately.

7.5. Interaction models and possible conflicts

Table 7.2 summarizes the design options and shows the fundamental differences in the three countries' procurement mechanisms, a combined procurement of balancing and redispatch in France, a cost-based approach to redispatch and a balancing market in Germany and two separate markets for the two services in the Netherlands. Combining this with the planned procurement of balancing energy through EU platforms, three stylized interaction models can be derived:

i) market-based balancing, cost-based redispatch (MB/CB),
ii) market-based balancing, market-based redispatch (MB/MB),
iii) common market-based balancing and redispatch (CMB).

Table 7.2. National differences concerning redispatch service.

	France	**Germany**	**the Netherlands**
Approach to system management	Proactive	Rather reactive	Reactive
Method of redispatch procurement	Market-based (together with mFRR/RR balancing mechanism)	Regulated, cost-based	Market-based ('reserve other purposes' product)
Required information for providers	Same rules as in the balancing mechanism apply	Location; costs	Location; price-volume bids
Participation in electricity markets	yes	yes	yes
Capacity remuneration	yes (mFRR)/no (RR)	no	no
Minimum bid	1MW	n/a	1 MW
Bidding	Mandatory (for units >12MW) and voluntary (for smaller units)	Mandatory for generators >10 MW	Voluntary (additional TSO call possible)
Remuneration of redispatch	Pay-as-bid	Cost-based	Pay-as-bid
Procured jointly with balancing	yes	no	no

The three stylized models are compared in Table 7.3. Note that Model II implies the two markets cleared consecutively whereas Model III has a single merit order and requirements. Considering the distinction made between preventive and curative redispatch, it is predominantly the latter that can conflict with balancing as both must be activated close to real time. In turn, units with lower ramping rates can be activated for redispatch as part of preventive redispatch without competing with the balancing resources.

The models are evaluated in Table 7.4 with respect to their allocative efficiency, availability of resources, susceptibility to gaming, ease of implementation and cost allocation.

Table 7.3. Potential conflicts and provider incentives associated with different procurement approaches.

Model	Potential conflicts and risks	Effects on incentives
I MB/CB	- Balancing action is not possible due to redispatch - Activation of balancing bids can cause congestion - Risk of diluting wholesale market price signals if redispatch volume is high	- Market actors lack incentives to provide redispatch, so they need to be obligated. Otherwise, market actors may prefer to provide flexibility for balancing or wholesale markets. - Cost-based redispatch creates opportunity costs, not only with regard to the DA market but also the balancing market, which providers factor in.
II MB/MB	- Activation of balancing bids can cause congestion - Risk of diluting wholesale market price signals if redispatch volume is high - High relevance of procurement timeframes: risk of conflicting bidding strategies	- Different incentives: balancing energy is remunerated with the marginal price on the EU platform whereas redispatch is remunerated PaB. - If expected profits from redispatch are high, the cost of capacity reservation that is not explicitly remunerated may be factored into activation bids [171] - Highest incentive and potential for inc-dec gaming
III CMB	- Risk of redispatch actions 'contaminating' the imbalance price. - Risk of diluting wholesale market price signals if redispatch volume is high	- Requires locational information for balancing bids, drastically limiting portfolio bidding for balancing and thus affecting competition. - Redispatch providers will likely take into account balancing energy price developments and expectation of being awarded even if those activated for redispatch are compensated with a PaB price.

Table 7.4. Summary of the performance of balancing and redispatch services in the three models.

Approach	Allocative efficiency	Availabi-lity	Susceptibility to gaming	Ease of implementa-tion	Transparent cost allocation
I MB/CB	low	low for redispatch	moderate	high	high
II MB/MB	high	high	high	moderate	high
III CMB	low	high	low	low	low

Allocative efficiency refers to how much the value of flexibility used for different purposes is maximized (balancing and redispatch) [169]. In Model II, market actors can plan how much to bid in each of the two markets. As different types of providers can participate, allocative efficiency is likely to be high. In Model III, allocative efficiency might be low as, due to the procurement close to real time, this approach is not amenable to preventive redispatch and the pool of the available resources is likely to be limited. Besides, if the same pool of resources is used for both, the use of units for redispatch will limit the choice of resources for balancing and may cause a need for a larger volume of balancing capacity reservation, leading to higher costs.

Resource availability is higher in the market-based approaches as compared to Model I as the actors have an economic incentive to participate. The main issue with Model I is that cost-based redispatch only considers generation and not load or storage, for which the costs cannot be determined in the same way (i.e. based on their variable costs) [178], lowering resource availability. As potential providers have no incentives to participate in cost-based redispatch, they must be compelled instead. Besides, additional mechanisms are likely to be needed to avoid early decommissioning of plants relying on market prices alone [171], causing additional costs, which have to be factored in when evaluating efficiency and costs of procurement. Models II and III may reduce or make it superfluous to procure additional grid reserves.

Concerning *susceptibility to gaming,* Model II has the highest potential for inc-dec gaming, making regulatory oversight hardly avoidable. Market actors can leverage their network positions and affect electricity market results; yet, the risk exists mostly if congestion is structural, i.e. frequent and predictable. The ultimate risk is that market distortions induced by redispatch erode the DA marginal price as the reference price and cause welfare losses. Yet, cost-based redispatch is not immune to strategic bidding either. A limited number of predefined providers coupled with the information asymmetry existing between the providers and the TSO may mean that the reported costs are likely to deviate from reality if no caps on costs or benchmarking practices exist [171]. Cost-based redispatch can be justified by low competition, according to the Clean Energy Package (CEP), but this is a circular argument: if cost-based redispatch is applied, competition levels are likely to be low, which justifies the cost-based approach.

The gaming potential in Model III is likely the lowest if the bidders do not know in advance if their bids are going to be used for balancing or redispatching. In Model III, if a certain balancing bid is expected to provoke or aggravate congestion, it can be taken out of the merit order, i.e. the bid is skipped, or the bids for the two purposes are co-optimized [169]. The latter is difficult to achieve if, besides its cost, the effectiveness of the unit is to be considered for redispatch.

Europe-wide implementation of Models I and II clearly entails lower transition costs than a common market, although Model II may require more effort as specific

product requirements need to be defined. It is questionable whether Model III can be easily reconciled with the planned balancing platforms. Besides, based on EU regulation, activations of balancing bids for any purpose should follow the merit order, which is not necessarily possible for redispatch bids due to effectiveness considerations [169]. Conversely, if a balancing bid cannot be activated due to congestion, its actual cost was not accounted for in the price, which is in fact higher.

The allocation of costs between redispatch and balancing can be accomplished much easier in Models I and II rather than in Model III where there is a risk of redispatch costs 'contaminating' the imbalance price. As balancing and redispatch costs tend to be recovered in different ways, allocating their costs in a transparent cost-reflective manner is more difficult in a common market.

7.6. Solutions

The CEP requires redispatch methods to provide *"efficient economic signals to the market participants and TSOs involved"* [175]. This requirement is incompatible with Model I, which also has low allocative efficiency and resource availability and is not immune to gaming. If the volume is high and congestion is structural, then the likelihood of eroding the short-term market price is high. Therefore, when assessing the potential for strategic bidding, the presence of structural congestion is a crucial factor, regardless of the approach [178]. If structural congestion is tackled prior to day-ahead market clearing, the remaining congestion can no longer be predicted by market actors, therefore reducing the room for gaming [178].

The integration of balancing and redispatch into a single market (Model III) is likely to reduce strategic bidding behavior and the conflicts between the two services. Co-optimization using a common platform can solve the conflicts between redispatch and balancing but also creates a number of challenges linked to EU-level balancing energy procurement. This approach does not actually lead to an optimal allocation: if redispatch is integrated into the balancing platform, which closes close to real time, a significant share of redispatch resources would not be utilized. This increases the likelihood that e.g. renewables are curtailed before slower thermal plants due to the operational restrictions of the latter [178]. The choice of timeframe of redispatch needs to "ensure the right balance between availability and liquidity" [177, p. 23].

Table 7.4 shows that Model II, separate markets for balancing and redispatch, produces the fewest tradeoffs. Both TSOs and DSOs suggest using the market approach in the so-called orange phase, i.e. when congestion is expected [169]. Different rules should be followed in the red or emergency phase when the TSO cannot secure sufficient flexibility resources. They further call for standard congestion management product requirements on the national level [177, p. 11]. Indeed, similar to the best practice from the balancing markets, standardization of product requirements, such as activation parameters, availability and baseline

methodology for validation of service delivery, is crucial for stimulating competition. By facilitating transparency and comparability, standardization makes it easier to estimate the business case of service provision and investment needs.

The often-cited concerns against market-based redispatch are justified in many cases. Local markets are by definition more concentrated, which can make it easier to exercise market power, so it is unlikely that the risk of strategic bidding can be fully eliminated. Yet, these concerns are often based on a number of assumptions that are not universally applicable but rather country or even case-specific. The fact that market-based redispatch is already used in several countries without posing serious issues implies that the main source of concern is not the market approach *per se*. For instance, it is possible that the expected issues in Germany are linked to economic considerations as much as they are to the reality of the German grid, characterized by particularly pronounced structural congestion on the North-South axis. That said, market-based approach is viable only under the condition that structural congestion has been solved either before market clearing or through grid reinforcement.

Besides the timeframe of procurement and the presence of structural congestion, the choice of remuneration of redispatch units is an important factor defining the actors' incentives. By capping the maximum redispatch price at the DA price, for instance, market distortion can be minimized [171]. As redispatch is used in different timeframes, an alternative solution could be to integrate it with the day-ahead market (an approach enabling such integration was developed in [179] and [180]) or with the intraday market (e.g. Dutch pilot project, IDCONS [181]). This would address allocative efficiency, as preventive redispatch can be accommodated and therefore the pool of providers increased. It can also lower the gaming risk as market actors still bid in the wholesale markets and are incentivized to bid competitively. In this way it can ensured that only a small amount of curative redispatch is needed, limiting the conflict between redispatch and balancing.

7.7. Conclusions

This paper addresses the relations and potential conflicts between balancing and redispatch and their effect of the incentives of services providers. We compared three approaches to their procurement, i) market-based balancing, cost-based redispatch, ii) separate redispatch and balancing markets, and iii) a combined market for the two services.

Procurement of the two services in separate markets was shown to have the fewest tradeoffs, as compared to the other two approaches. We show that the efficiency of the chosen approach depends on 1) the timeframes of procurement of the two services, 2) the presence of structural congestion, and 3) the remuneration of redispatch. The timeframes for procurement should be carefully considered:

redispatch must be prioritized as fewer resources are inherently available at a specific location as compared to balancing. Redispatching prior to balancing may allow the TSO to access slower plants preventing competition for scarce short-term flexibility close to real time.

In the presence of structural congestion, the problem is not a market-based approach but rather the frequent and predicable nature of congestion itself, a situation that cannot be removed by market design. In this situation, grid reinforcement should be prioritized if the long-run cost to society is lower than the cumulative cost of the congestion. Integrating redispatching with day-ahead or intraday markets may help reduce gaming risks while preventing a conflict with the balancing market. Regardless of the approach, standardized product requirements for redispatch are essential to enable competition.

Further research should include a quantitative assessment of the three models to give additional insights into efficiency, distribution of costs and incentives.

8

Integration of redispatch into the day-ahead market to increase cross-border capacity[57]

The zonal electricity market design in the Central Western European electricity market relies on redispatching generation units after market closure to manage congestion within bidding zones, while congestion between the zones is handled using flow-based market coupling. The combination of internal congestion in the meshed European network with a growing share of renewables increases the frequency and magnitude of congestion events and limits cross-border trade. The growing costs of redispatching and the divergence between grid physics and zonal markets lead to welfare losses. This paper is the first to propose an approach to improve the combined efficiency of flow-based market coupling and redispatching. We develop a novel methodology for congestion management in a zonal market with flow-based market coupling in order to increase cross-border exchanges by integrating preventive redispatch into the day-ahead market. For this, set of integrated-redispatch units is selected based on their high potential to reduce congestion and free up grid capacity for cross-border exchange. We use multi-step optimization models to demonstrate the benefits of the zonal market with integrated redispatch by comparing it to the nodal market model and a zonal market model with flow-based market coupling. The case study demonstrates the potential of the proposed method to significantly increase cross-border capacity and reduce the need for costly ex post redispatch. The approach is shown to be a feasible option for improving European market integration and thereby to achieve overall welfare gains.

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8.1. Introduction and background

Zonal electricity market results can produce flows that exceed available capacity on some transmission lines, creating congestion. With the fast-growing share of variable renewable energy sources (vRES) and other distributed energy resources in the European power networks, the occurrence and magnitude of congestion are increasing [182].

In the European Union (EU), the European institutions and transmission system operators (TSOs) are becoming concerned with the growing frequency of congestion events and the resulting increase in costs of remedial actions that the TSOs need to take [60]. For instance, in Germany, the cost of remedial actions exceeded one billion euro in 2018[58] [183]. Redispatch is one of the remedial actions that allows TSOs to regulate a power plant downward upstream of congestion and another plant upward downstream of congestion against remuneration after the market clearing. The costs of congestion management in Europe are largely passed on to consumers in the form of higher grid tariffs negatively affecting overall economic welfare. Therefore, it is important to address ways in which the volume of costly *ex post* redispatch can be reduced.

Internal congestion in the highly meshed European networks further causes unscheduled power flows among neighboring zones. This exacerbates congestion and limits capacity for cross-border trade, decreasing the economic efficiency of generator dispatch. In order to increase the volume of transmission capacity that is available for cross-border trade, flow-based market coupling (FBMC) was introduced in 2015 in the six countries[59] of Central Western Europe as an alternative to the net transfer capacity (NTC) method that was used until then and is still applied in the rest of the EU [184] (cf. Sections 8.1.1 and 8.2.2 below). Yet, grid representation in zonal market coupling is inherently imprecise as only a limited number of grid constrains is taken into account. Besides, if dispatch is altered extensively outside the market *ex post*, large differences between the market results and actual physical flows also risk to dilute the day-ahead market price signals and further reduce economic welfare [180]. Researchers (e.g. [185]) warn that the current aggregated view of the meshed European network is bound to produce more operational problems. According to the Belgian regulator, CREG, *"system security is at risk due to a lack of anticipation of remedial actions in the grid models, which lead to erroneous load flow calculations at different stages"* and a high probability of uncoordinated flows, i.e. those not accounted for in the coordinated grid models [186, p. 29].

In this paper, we investigate the integration of preventive redispatch into the day-

[58] Such remedial actions, according to ACER, include redispatch, countertrading and other measures for congestion management such as grid reserve [183].
[59] Austria, Belgium, France, Germany, Luxemburg, and the Netherlands.

ahead market to optimize cross-border trade, making an explicit tradeoff between redispatch costs and welfare gains. In doing so, we intend to provide a practicable solution for maximizing the utilization of cross-border capacities and demonstrate its potential to improve cost efficiency and increase economic welfare.

The rest of the paper is structured as follows: Section 8.1.1 explains the links between FBMC and internal congestion along with the associated issues whereas Section 8.1.2 provides motivation for the new approach to tackling them and its expected contribution. The proposed methodology is formulated in Section 8.2. The results of the implementation of the new approach and its comparison with the existing nodal and zonal market designs are illustrated using a two-zone case study in Section 8.3 and discussed in Section 8.4. Section 8.5 concludes.

8.1.1. The relationship between flow-based market coupling and congestion within a zone

In contrast to the centralized approach of security-constrained economic dispatch that is applied in countries such as the U.S. and Australia, the dispatch in the countries of the EU is largely de-coupled from grid constraints within zones. Most European countries represent a single bidding zone (with the exceptions of Italy and the Nordic region). Researchers in [186] compared nodal and zonal market designs and showed that market design had a direct and tangible influence on the grid situation. Zonal market design, they found, created such challenges as unscheduled cross-border flows and efficiency losses [186]. Although it did allow to increase market liquidity, congestion in zonal markets was "unavoidable" by design [185]. One of the consequences is a suboptimal use of cross-border transfer capacity.

In Central Western Europe, FBMC was introduced as an integral part of the EU Electricity Target Model in order to optimize and increase the amount of transfer capacity for integrated markets [184]. As FBMC was implemented less than five years ago, the available body of research is still limited. For instance, researchers in [187] provided the first overview of the main FMBC parameters soon after its official implementation. Authors in [188] discussed the implications of FBMC implementation, focusing on the increased transparency of congestion data from the point of view of traders. An overview of the differences between the commonly applied NTC (net transfer capacity) approach and FBMC is provided in [189].

In both approaches a feasible flow domain is determined. This is a combination of feasible import/export positions for each bidding zone, considering exchanges among all the involved zones and the grid security limits. In NTC, zonal borders are used in the cross-border capacity calculation process. In FBMC, the feasible domain is determined by calculating the impact of the flows in each zone on each critical element. These elements include critical branches between the zones, some branches inside the zones as well as critical generator outages [190]. Based on

monitoring and experience, TSOs consider elements as critical if their states are likely to be affected by cross-border exchanges. The impact on the critical elements is determined with power transfer distribution factors (PTDFs) that are derived from a linearized DC load flow calculation. The resulting feasible flow domain that is delimited by the physical constraints for all critical branches and outages is usually larger than the feasible flow domain that results from the NTC approach, leading to more available cross-border network capacity without jeopardizing system security [189]. Given the benefits of FBMC, flow-based capacity calculation is to be introduced in all "highly interdependent" bidding zones in the EU, following the Guideline on Capacity Allocation and Congestion Management (CACM) [79]. This requirement is applicable unless the TSOs can demonstrate that for certain zones the application of the flow-based approach would not yet be more efficient compared to the coordinated NTC approach (Art. 20.7 [79]).

Although the FBMC approach was shown to create efficiency gains, it still has a number of issues that so far remain unresolved and may affect its efficiency. Firstly, the process of calculating available cross-border capacity is based on estimated market results. TSOs calculate the capacity that is available for cross-border exchange two days ahead of delivery, based on forecasts of conventional and renewable energy generation, load and outages (the D2CF: day-minus-two congestion forecast). Information about the expected flows for the so-called Base Case (cf. Section 8.2.2) is obtained by merging the D-2 congestion forecasts of all TSOs, after which their hourly results are transferred to the power exchange a day ahead of delivery. The reference flows from the Base Case prior to the allocation of day-ahead capacity are then used to calculate the remaining available margin (RAM), i.e. the capacity available for cross-border trade (cf. Section 8.2.2) creating the link between the grid and the market. Yet, information about the actual (as opposed to projected) generation and demand is available to the TSOs only after market clearing, which in turn requires information about the cross-border capacity available for trade. This situation is often referred to as a "chicken and egg problem" (e.g. [191]). The imprecision of this process means that cross-border capacity is not used efficiently.

Secondly, the way in which the flow-based parameters are calculated is inherently imprecise. The effect of a power flow between two zones on a network element is represented with the help of zonal PTDFs. Zonal PTDFs are calculated as averages of nodal PTDFs that are weighted with generation shift keys (GSKs) per node (cf. Section 8.2.2). GSKs describe the extent to which the output of individual generators is adjusted due to line flow changes resulting from a change of a zone's net export position (NEX), i.e. the difference between its imports and exports. There is so far no harmonized way for their determination: the methods vary among Central Western European countries, e.g. pro-rata for all flexible units or based on generators' costs [187], and rely heavily on heuristics [192]. Several researchers investigated and compared GSK methodologies. The results presented in [193] showed how the choice of the GSK methodology could affect the size and shape of

the flow-based domain. The authors in [192] studied the impact of the GSK method on the efficiency of FBMC and found that the impact is high as long as no internal congestion is present. Otherwise, the influence of the choice of GSK method becomes marginal [192]. Therefore, the third crucial factor affecting the efficiency of FBMC is internal congestion [178]. Research shows that the expected efficiency of FBMC as compared to the nodal outcome falls to almost half in the presence of internal congestion [192]. Other researchers stressed that in order to ensure the integration of renewables, it was important to consider internal congestion in network and market models [186].

There are a number of ways addressed in literature in which the efficiency of congestion management can be improved. They include addressing the deficiencies of the zonal markets, TSO cooperation mechanisms, and market-related measures. One of the proposed solutions to tackle frequent structural congestion is to redefine the bidding zones [194] in order to align their borders with the locations of expected bottlenecks or to increase bidding zone granularity. However, redefining of the bidding zones remains a highly contentious issue in Europe [180]. How small is small enough – if the nodal approach is not an option – is a difficult (and political) question. Besides, bidding zone redefinition solves congestion issues only temporarily: once new generation or load is connected elsewhere, congestion is likely to occur again and a new re-definition would be necessary [79]. Coordinated cross-border redispatch (or countertrading) is another way to increase the efficiency of remedial actions but requires more coordination and cooperation among the TSOs. A common TSO methodology is under development in accordance with Article 35 of the CACM [79]. Some Member States use intraday markets to improve congestion management, as more reliable forecast information is available. For instance, the Spanish TSO uses a dedicated market (*mercado de solución de restricciones técnicas*) in the intraday phase and the Dutch TSO uses intraday market bids to solve some of the congestion (GOPACS project [195]). These approaches – although useful in addressing congestion *ex post* day-ahead market – treat the symptom rather than the cause of congestion, inherently imprecise grid representation in zonal markets. In addition, the potential of such improvements is limited by the low degree of harmonization of intraday markets [196] and heterogenous approaches to redispatch .

Current redispatch practices are also suboptimal because only limited resources – primarily large power plants – are utilized. Besides, the purpose of redispatching is currently not to minimize costs but only to relieve constraint violations [194], which is the most straightforward but typically not the most cost-efficient approach. A way to increase the resource availability for congestion management that was addressed in several research and pilot projects is to utilize a larger number of small generators and demand-side flexibility [51]. For instance, researchers in [197] pointed out the risk that future resources to deal with congestion might be insufficient in Germany. They proposed the use of electric vehicle charging for congestion management. Flexibility market concepts have been developed in the projects ENKO in Northern

Germany [198] and USEF [199]. In a recent study that has its roots in the approach proposed in this paper, the Belgian TSO, Elia, proposed to include additional flexibility options such as phase shifting transformers and high voltage direct current lines as well as flexible generation, into the market coupling to offer more degrees of freedom in tackling congestion and increasing cross-border trade [180].

8.1.2. Motivation and contribution

Ensuring effective EU electricity market integration by increasing cross-border exchanges and tackling congestion more efficiently is at the top of the EU's energy policy agenda [182]. Cross-border transfer capacity is limited by a number of factors such as line constraints and long-term trade commitments. Furthermore, it is affected by the network use *within* a zone since in an interconnected system internal flows have a direct impact on cross-zonal flows. Progressive integration of renewables and distributed resources is likely to increase the number of congestion events [200]. Frequent internal congestion leads to an inefficient use of the interconnectors and a lower economic welfare.

Given these challenges, in this paper a novel approach is proposed which integrates preventive redispatch in the day-ahead market (hereafter *integrated redispatch (IRD)*). It combines the characteristics of nodal network representation only for IRD units in the zonal markets, which use a flow-based approach to market coupling. The expected added value of integrating the effect of redispatch units on the network *ex ante* is an improved use of cross-border capacity and market outcome, that is, a better price convergence between the zones. Arguably, accounting for the impact of redispatch units on critical network elements during day-ahead market clearing can reduce residual congestion, leading to cost savings and to approaching a system optimum.

The proposed method replicates the operating principles of FBMC. It is meant to improve the efficiency of FBMC in two ways:

1) by allowing to account for redispatch during the day-ahead market stage and thus (largely) avoid costly *ex-post* redispatch;
2) by allowing redispatched generators to free up capacity on congested lines and thus increase cross-border the transmission capacity and therefore to dispatch more cost-efficient generators.

Finally, this paper presents the first comprehensive discussion of the relation between FBMC and congestion management as well as a first solution to improve their joint efficiency. This is particularly important given the planned implementation of the FBMC approach in the EU beyond Central Western Europe.

8.2. Methodology

In this section, the proposed methodology for enhancing FBMC and addressing grid congestion is formulated (Section 8.2.3). In order to demonstrate how it compares to the existing approaches, we first formulate the nodal market (Section 8.2.1) and the zonal market with FBMC in Central Western Europe (Section 8.2.2.):

1) Nodal market

This setup (hereafter the *nodal model*) models optimal dispatch of generators according to locational marginal pricing. It is based on the marginal value of power in each node, given demand and network constraints. The output is based on an exact representation of the grid, with all nodes and constraints for all network branches taken into account in the process of market clearing [201]. From a purely economic perspective, the nodal market is considered to be the most efficient, as is shown in e.g. [202]. Nodal prices do not just include the cost of production of energy but also its delivery to the point of consumption right from the start, leading to efficiency gains compared with the zonal model (e.g. [203], [204]). This setup is therefore used as the benchmark for the study.

2) Zonal model with FBMC and *ex post* redispatch

This setup emulates the current practice in Central Western Europe (hereafter the *business-as-usual model*). The nodes are assigned to bidding zones and only the flows on some lines are considered for the flow calculation, which may therefore lead to an infeasible dispatch, e.g. due to internal congestion. *Ex-post* redispatch is conducted in case of congestion.

3) Proposed approach: Zonal model with FBMC and integrated redispatch (IRD)

This setup (hereafter the *model with integrated redispatch*) represents a middle ground between the benchmark and the current practice. A number of generation units are selected based on their relevance for redispatch. Their impact on the flows on the critical branches, i.e. nodal PTDFs, is calculated in addition to the "classic" zonal PTDF in the flow-based domain.

The *nodal model* is solved in one step, while the zonal *business-as-usual model* and the zonal *model with integrated redispatch* are solved in several optimization steps, as illustrated in Figure 8.1.

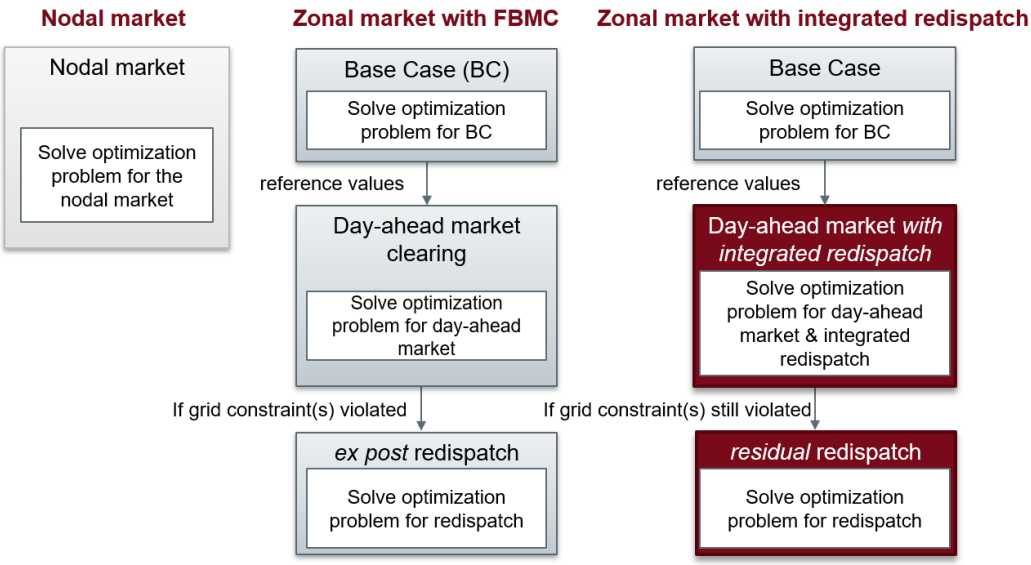

Figure 8.1. Model flow charts for the three analyzed setups, nodal, zonal with flow-based market coupling as currently applied in Central Western Europe and the proposed approach integrating day-ahead market clearing and redispatch. FBMC – flow-based market coupling.

Both the *business-as-usual model* and the *model with integrated redispatch* rely on the same Base Case to obtain zonal PTDFs, expected generation values and flows on the critical branches. Next optimization step represents single day-ahead market coupling in the *business-as-usual model.* In the *model with integrated redispatch*, day-ahead dispatch and possible redispatch action are co-optimized. Due to the inherent approximation character of zonal PTDFs, some residual redispatch might still be needed also in the *model with integrated redispatch*. The final step in the *business-as-usual model* and in the *model with integrated redispatch* uses the same algorithm and is contingent on the state of the grid and whether the dispatch resulting from the day-ahead market clearing is feasible, i.e. no physical grid constraints are violated.

In the zonal setup with integrated redispatch, a only subset of generators can be used for integrated redispatch whereas if any residual redispatch is still necessary, all generators can be activated *ex post*. The model used in this study is solved for one time step, intertemporal constraints are not considered. Further model assumptions are listed in Appendix I.

In the model, a distinction is be made between dispatchable generators, whose output can change depending on the market outcome, and non-dispatchable generators, such as variable renewables. While for the former the capacity constraint

is $d_g \leq D_g^{max} \forall\ g \in G^{disp}$, for the latter it is $d_g = D_g^{max} \forall\ g \in G^{non-disp}$, where d_g is the dispatch of generator g.[60] Besides, non-dispatchable generators cannot be redispatched *ex post* unless curtailment is allowed. Finally, in the zonal models, such generators are excluded from the calculation of GSKs due to their fixed output (see also Section 8.2.2.2).

The modelled setups and each of the steps involved are explained in more detail in the following sub-sections.

8.2.1. Nodal model

The model represents optimal dispatch of generators and is subject to nodal energy balances, flow and generation limits and non-negativity constraints. It considers the state of the entire network explicitly in order to identify the least-cost dispatch by using nodal power balance and nodal PTDFs for each power line. The objective function is formulated as the minimum-cost dispatch, $\boldsymbol{d}_g$, of all generators:

$$\min \sum_{g=1}^{G} \boldsymbol{d}_g * c_g \tag{1}$$

s.t.

$$-(F_b - FRM_b^{\text{nod}}) \leq \boldsymbol{f}_b \leq (F_b - FRM_b^{\text{nod}}) \ , \qquad \forall b \tag{2}$$

$$\boldsymbol{f}_b = \sum_{n=1}^{N} PTDF_{b,n}^{\text{nod}} * \boldsymbol{p}_n \tag{3}$$

$$\boldsymbol{p}_n = \sum_{g=1}^{G_n} \boldsymbol{d}_g - l_n \ , \qquad \forall n \in N \tag{4}$$

The optimization function is subject to the flow-limit constraint (eq. 2), in which $\boldsymbol{f}_b$ is the flow of branch b, F_b is the maximum flow on the branch and FRM is the flow reliability margin, which is usually set by the TSO for each branch. The flow on branch $\boldsymbol{f}_b$ (eq. 3) is the product of the total active power injection $\boldsymbol{p_n}$ at node n and the nodal PTDF on branch b for node n. Finally, the nodal injection constraint (eq. 4), in which l_n is the load on node n is observed. The notation used in the paper is summarized in Appendix J. In the nodal model, all generators and all branches are included in the calculations.

Nodal PTDFs are defined based on [205] as:

$$PTDF^{\text{nod}} = \boldsymbol{S}\boldsymbol{K}^{\boldsymbol{T}}\boldsymbol{\Lambda}^{*} \tag{5}$$

[60] Full notation list can be found in Appendix J.

where $\boldsymbol{\Lambda} = \boldsymbol{KSK}^T$ and $\boldsymbol{\Lambda}^*$ is the pseudo-inverse of $\boldsymbol{\Lambda}$, which avoids the need for a slack node (reference node).

Nodal PTDFs represent the extent to which a given branch is affected by a marginal change of injection. Even when the output of a single generator changes, power flows change on many lines, including those not directly linked to the generator's node. This can also lead to line capacity violations on a non-adjacent line. In other words, congestion can be produced on a branch, which is not directly linked to the actual source of congestion due to the distribution of the physical flows.

The prices on all nodes converge when there is no congestion anywhere in the network and losses are disregarded. Otherwise, congestion produces different nodal market prices (see Section 8.3). For the calculation of consumer surplus in the nodal model, we assume that consumers are exposed to the actual price of their node[61]. Generators are remunerated according to the nodal marginal price. Finally, congestion rent is calculated per branch as the price difference between the nodes at the ends of the branch and the volume transported.

For all setups, since the demand in this analysis is assumed to be inelastic, the value of lost load (VOLL) or the cost of avoiding load shedding is used to denote consumers' willingness to pay and assumed to be equal to 1000 Euro/MWh.

8.2.2. Zonal model with flow-based market coupling

This is a multi-stage linear optimization problem that is solved in three steps, Base Case, single day-ahead market coupling and *ex post* redispatch. As per the principles of FBMC, not only interconnectors but also some internal power lines are considered to be critical branches.

Base Case

In the first step, the Base Case is formulated, which entails a forecast of the flows, generation and zonal net export positions (NEX) that are to be used in the next step, the day-ahead market coupling.

In practice, hourly D-2 congestion forecasts are produced by each TSO as inputs for the FBMC calculation. TSOs use historical grid states as a starting point. The obtained information is then adjusted to account for estimated generation from renewables, plant outages, generator output and the changes in the net position forecast [206]. Then, the D-2 congestion forecasts from all participating TSOs are merged into a

[61] Another approach implemented, for instance, in some of the US electricity markets, would be to expose only generation to the nodal prices while consumers pay the average price in a given region (cf. [202])

single Base Case, which serves as the starting point of the FBMC and considers the expected volume of commercial exchanges between the zones [190].

The load flows are estimated based on a reference day in order to calculate the flow-based parameters for the pre-defined critical branches and critical outages. Based on zonal PTDFs and the volume of commercial exchanges, the available capacity on each line is first calculated to represent a situation where there are no commercial exchanges. During the market coupling, the same zonal PTDFs are used to calculate the impact of a market exchange on the limiting branches. If the market outcome is the same as the estimation of the TSOs, then the grid models will be identical. As a result, the delta between the expected reference dispatch and the actual dispatch will be zero and the reference flows will be equal to the Base Case flows.

In the capacity allocation process, the Base Case is the starting point for linearization. The formulation of a Base Case presents a modelling challenge as it includes TSOs' estimations based on the historical values for reference days (the flows obtained from the Base Case calculation are therefore referred to as reference flows). Using a fully nodal model for this step would be unrealistic because the solution would have the optimal interzonal power exchange. This would imply that the TSO would have perfect foresight of the load levels, generation and prices that would result from the market clearing. In order to demonstrate the differences between the *business-as-usual model* and in the *model with integrated redispatch*, imperfect foresight of the TSO needs to be simulated. To this end, the common Base Case is first calculated with the flows that result from the complete network representation, as derived from the nodal model (see Sub-section 8.3.2.1). Next, they are reduced in this optimization step, by adding an additional constraint (eq. 6). The total flow on all interconnectors cannot exceed the total reference flow limited by a coefficient representing the interconnector share[62]:

$$-\left|\sum_{b \in IC(z_1,z_2)} f_b^{\mathrm{ref}}\right| * s^{\mathrm{IC}} \leq \sum_{b \in IC(z_1,z_2)} \boldsymbol{f_b} \leq \left|\sum_{b \in IC(z_1,z_2)} f_b^{\mathrm{ref}}\right| * s^{\mathrm{IC}}, \forall z_1, z_2 \in Z \tag{6}$$

where $IC(z_1, z_2)$ are a set of interconnector branches between any two zones, s^{IC} is the share of interconnector capacity and f_b^{ref} is the flow on a branch from the full nodal model (cf. eq. 3).

The objective function is identical to the one used in the nodal setup (eq. 1) and is

[62] In the modelled scenarios, the interconnector share was set to 50%. The closer the share is to 100%, the closer is the TSO foresight to a perfect one and the lower is the ability of the zonal approach with integrated redispatch to increase the exchange cost-efficiently.

aimed at minimizing total system costs. The net export position (NEX) per zone is equal to the net power injection in the zone and is calculated as follows:

$$\boldsymbol{NEX_z} = \sum_{n=1}^{N_z} \left(\sum_{g=1}^{G_n} \boldsymbol{d}_g - l_n \right), \quad \forall z \in Z \tag{7}$$

The expected flows on the critical branches together with the expected generation values from the Base Case are passed on to the next simulation steps as reference values.

Day-ahead market coupling

In the day-ahead market, the cost of dispatch is minimized based on the feasible domain for cross-border exchanges and disregarding intra-zonal flow constraints. The optimization minimizes total system costs subject to the flow limits, the zonal energy balance and generator non-negativity constraints. The flows resulting from FBMC are equal to the reference flow f_b^{ref} from the Base Case adjusted with the sum of the product of zonal PTDFs on each branch $PTDF_{b,z}^{\mathrm{zon}}$ and the difference in the total zonal generation as compared to the Base Case $\Delta \boldsymbol{p}_z$:

$$\boldsymbol{f}_b^{\mathrm{FBMC}} = f_b^{\mathrm{ref}} + \sum_{z=1}^{Z} PTDF_{b,z}^{\mathrm{zon}} * \Delta \boldsymbol{p}_z, \qquad \forall b \in CB \tag{8}$$

Zonal PTDFs $PTDF^{zon}$ represent the change of flow on the lines in case of a change of NEX of one megawatt and use GSKs to allocate different shares of generation to various power plants:

$$PTDF_{b,z}^{\mathrm{zon}} = \sum_{n=1}^{N_z} PTDF_{b,n}^{\mathrm{nod}} * GSK_{n,z}, \qquad \forall b \in CB, \forall z \in Z \tag{9}$$

As a result, they represent the approximated version of the actual flows. Zonal PTDFs represent the influence of those zones on the congested critical branch: the higher the PTDF, the higher the impact.

For the purposes of the present analysis, GSKs are based on the installed capacity of power plants in the zone.

$$GSK_{n,z} = \frac{\sum_{g=1}^{G_n} D_g^{\max}}{d_z}, \qquad \forall n \in N_z \quad \forall z \in Z \tag{10}$$

$$d_z = \sum_{g=1}^{G_z} D_g^{\max}, \qquad \forall z \in Z \tag{11}$$

$$\sum_{n=1}^{N_z} GSK_{n,z} = 1, \qquad \forall z \in Z \tag{12}$$

where $D_g^{\max}$ is the maximum dispatch of generator g and d_z is the total dispatch of all generators in zone z. It follows that the GSKs and the zonal PTDFs are independent from the Base Case results. Note that in the calculation of the GSKs, *only dispatchable* generators capable of responding to market signals are considered. Any must-run generators are excluded due to their fixed output. All GSKs within a zone must sum up to one (eq. 12).

According to the principles of FBMC, the remaining available margin (RAM) for day-ahead trade accounts for the share of the total capacity reserved for other types of trade [187] and security margins[63], which are subtracted from the maximum thermal capacity for each critical branch. For this simulation, these values are disregarded and it is assumed that all the available transfer capacity is used for day-ahead trade.

The zonal prices are determined based on the merit order considering the amount of capacity available for cross-border exchange. In the zonal *business-as-usual model*, these prices are calculated as the dual of the zonal energy balance for each zone (eq. 4 for all nodes in a given zone). These correspond to the cost of the zonal marginal generator. If no inter-zonal congestion occurs, the prices will be the same across the zones. In an event of congestion on any of the critical branches, market splitting produces different prices in the zones.

Ex-post redispatch

Since only critical branches are included in FBMC and the GSKs are inaccurate, the actual grid constraints may still be violated by the market outcome. In the final step, the model checks whether the commercial transactions from the day-ahead market clearing are physically feasible and if not, infeasible flows are corrected by redispatching some units *ex post*.

The objective function for *ex post* redispatch is formulated as:

$$\min \sum_{g=1}^{G^{\mathrm{RD}}} \gamma\left(c_g * \Delta \boldsymbol{d}_g^{\mathrm{pos}} - c_g * \Delta \boldsymbol{d}_g^{\mathrm{neg}}\right) + \lambda * k_z^{\mathrm{FBMC}} * \left(\Delta \boldsymbol{d}_g^{\mathrm{pos}} + \Delta \boldsymbol{d}_g^{\mathrm{neg}}\right) \tag{13}$$

where is k_z^{FBMC} is the zonal market price and coefficients $\gamma$and λ denote cost-based and volume-based TSO penalties for redispatch, respectively. The values $\Delta \boldsymbol{d}_g^{\mathrm{pos}}$ and $\Delta \boldsymbol{d}_g^{\mathrm{neg}}$ represent the changes in the dispatch of generator g upward or downward, respectively. Their absolute values must be equal so as to preserve the energy balance in the zone. If $\gamma = 0$ and the value of λ is set to 1, the redispatch volume and therefore intervention into the market outcome is minimized. In contrast, if $\gamma =$

[63] These include the flow reliability margin (FRM) and the final adjustment value (FAV). For their more detailed description please refer to, e.g. [207].

1 and λ = 0, the optimizer would attempt to improve the market outcome minimizing total costs. The common approach in Europe today is to relieve congestion only, which is better represented by the former approach and is used in the simulation. All grid constraints are enforced.

In order to make sure that the results from the *business-as-usual model* are not skewed by additional factors as compared to the zonal setup with integrated redispatch, in the objective function in eq. 13, generator bids are assumed to be equal to their marginal costs, c_g. That is, generators do not additionally profit from activation for redispatch. In reality, the difference between the two is possible close to real time both due to the generators' technical constraints and due to lower competition levels where a generator could potentially exploit their locational advantage.

Concerning model output, the total welfare in the zonal business-as-usual setup is the sum of producer and consumer surplus and the congestion rent. It is reduced by the costs incurred from activating redispatch. Congestion rent is calculated as the price difference between two zones multiplied by the flow between these zones, from the low-price zone to the high-price one. Similar to the *nodal model*, consumers' willingness to pay is equal to the value of lost load whereas generator profits are calculated as the difference between their revenues and marginal costs.

8.2.3. Zonal model with integrated redispatch

The key idea of integrating redispatch with the day-ahead market is that a selected number of power plants are determined by the TSO as relevant for redispatch (see Section 8.4 for a further discussion). Integrated redispatch (IRD) units are included in the optimization model with their real impact on critical branches. That is, for such generators, nodal PTDFs are considered, which can help expand the feasible domain in FBMC. In other words, instead of redispatching these units after the market clearing, their impact is already taken into account during market clearing. As a result, more capacity is expected to be available to the market, less congestion will occur after the market clearing, and only residual redispatch may need to be dealt with *ex post.*

Importantly, IRD units participate in the day-ahead market on par with all the other generators but are the only ones whose dispatch can deviate from zonal market outcome in case of congestion. In contrast, the dispatch of the other generators impacts the lines only via zonal PTDFs.

Base case

The Base Case is formulated in the same way as for the zonal business-as-usual setup (see Section 8.2.2.1).

Day-ahead market coupling with integrated redispatch

In the second optimization step, however, the objective function is adjusted to account for the costs of upward and downward integrated redispatch:

$$\min \sum_{g=1}^{G} \boldsymbol{d}_{\boldsymbol{g}}^{\mathrm{IRD}}\, c_g \tag{14}$$

where c_g is the bid offered on the day-ahead market and the decision variable $\boldsymbol{d}_g^{\mathrm{IRD}}$ represents the actual generation *after* accounting for integrated-redispatch action (see also eq. 15). This objective function further implies that generator costs remain the same, regardless of whether these are used in the day-ahead market or for redispatch purposes. That is, generators make no profit from activation as part of integrated redispatch and are awarded pay-as-bid.

The decision variable for the generation offered by unit g on the day-ahead market is denoted by $\boldsymbol{d}_g^{DA}$. The difference between the actual generator dispatch and day-ahead market dispatch corresponds to the volume used as part of integrated redispatch:

$$\boldsymbol{d}_{\boldsymbol{g}}^{\mathrm{IRD}} - \boldsymbol{d}_g^{\mathrm{DA}} = \Delta \boldsymbol{d}_g^{\mathrm{IRD}}, \qquad \forall g \in G \tag{15}$$

Equations 14 and 15 show that two different decision variables are used for generator dispatch in this model: one representing the dispatching resulting from the day-ahead merit-order clearing, $\boldsymbol{d}_g^{\mathrm{DA}}$, and another for the actual generation, including integrated redispatch, $\boldsymbol{d}_{\boldsymbol{g}}^{\mathrm{IRD}}$. Then, IRD dispatch is understood as the volume of the deviation of the IRD plant from the day-ahead market result. Similar to the zonal business-as-usual setup, redispatch within a zone is energy-neutral. It follows that the total dispatch in the zone remains the same.

Generators that are deployed for integrated redispatch at nodes n^{IRD} are excluded from the calculation of GSKs (eq. 17) and, consequently, from zonal PTDFs $PTDF_{b,z}^{zon,IRD}$ (eq. 19). Their impact is instead described using nodal PTDFs (see eq. 5). GSKs are used for the remaining dispatchable generators, GSK^{IRD} (eq. 16 and 18).

$$GSK_{n,z}^{\mathrm{IRD}} = \frac{\sum_{g \in G}^{G_n} D_g^{\mathrm{MAX}}}{d_z}, \qquad \forall n \in N_z \wedge n \notin N^{\mathrm{IRD}}, \forall z \in Z \tag{16}$$

$$GSK_{n,z}^{\mathrm{IRD}} = 0, \qquad \forall n \in N^{\mathrm{IRD}}, \forall z \in Z \tag{17}$$

$$d_z = \sum_{n \notin N^{IRD}}^{N_z} \left(\sum_{g \in G}^{G_n} D_g^{\mathrm{MAX}}\right), \qquad \forall z \in Z \tag{18}$$

$$PTDF_{b,z}^{zon,IRD} = \sum_{n}^{N_z} PTDF_{b,n}^{nod} * GSK_{n,z}^{IRD} \,, \quad \forall b \in CB, \forall z \in Z \tag{19}$$

Neither are the IRD generators included in the calculation of the change of zonal generation as compared to the Base Case value, $\Delta \boldsymbol{p}_z^{\mathrm{ref,IRD}}$:

$$\Delta \boldsymbol{p}_z^{\mathrm{ref,IRD}} = \sum_{n \notin N^{IRD}}^{N_z} (\boldsymbol{p}_n - p_n^{\mathrm{ref}}) \,, \qquad \forall\, z \in Z \tag{20}$$

In the model, the flow on each branch in the second step is calculated by summing up the reference flow value from the Base Case, f_b^{ref}, with the delta dispatch of IRD generators at nodes n^{IRD} and their *nodal* PTDFs as well as with the sum of the delta dispatch of the other generators and their *zonal* PTDFs:

$$\boldsymbol{f}_b^{\mathrm{IRD}} = f_b^{\mathrm{ref}} + \sum_{n=1}^{N^{\mathrm{IRD}}} PTDF_{b,n} * (\boldsymbol{p}_n - p_n^{\mathrm{ref}}) + \sum_{z=1}^{Z} PTDF_{b,z}^{\mathrm{zon,IRD}} * \Delta \boldsymbol{p}_z^{\mathrm{ref,IRD}}, \quad \forall b \in B \tag{21}$$

IRD generators can be considered to be all generators in the set of dispatchable generators or only a subset of the latter. Since nodal PTDFs are used to obtain the effect of IRD generators on the grid, deeming all dispatchable generators capable of redispatch action will lead to the nodal result. This would, however, not be aligned with the main purpose of integrated redispatch: making use of those generators that have a significant effect on grid stability while keeping the main characteristics of a zonal market design.

While activation as part of integrated redispatch will have an effect on the zonal price, it is specifically avoided that these generators set the day-ahead market price if activated for redispatch. Doing otherwise would lead to a higher overall price corresponding to the bid of the up-regulated generator. As a result, the zonal price corresponds to the dual of the node injection constraint (see eq. 4) for the nodes in a given zone, *excluding* those nodes that have IRD generators connected to them. In other words, the prices at each node in a given zone will be the same, determining the zonal prices, with the exception of the IRD nodes.

Residual redispatch

If the use of integrated redispatch is unable to relieve all internal congestion in the day-ahead stage, residual redispatch measures can be taken in this step. It is formulated similarly to the *ex-post* redispatch step in the *business-as-usual model*, Section 8.2.2.3, and uses the same objective function (eq. 13). The redispatch

simulation is the same as the full nodal model but all generation values are fixed to the dispatch values of the day-ahead market step from Section 8.2.3.2. All generators are assumed to be dispatchable in this step and thus are redispatch-relevant. All grid limitations are enforced.

The key economic output indicators in this model are formulated in the same way as in the *business-as-usual model*. The only two differences consider zonal day-ahead prices and total system costs. Zonal prices correspond to the dual of the node injection constraint of any of the nodes located in a given zone.

The volume of integrated redispatch is calculated as a change of dispatch as compared to the "ideal" merit order result d_g^{MO}, i.e. the one where no grid limitations are considered (eq. 23 and 24). Only the units selected for IRD may have a different generation value because of the redispatch action. The ideal merit order dispatch is calculated in such a way that the same zonal generation is achieved (eq. 22).

$$\sum_{g \in G_z} d_g^{\mathrm{IRD}} = \sum_{g \in G_z} d_g^{\mathrm{MO}} \tag{22}$$

$$\Delta \boldsymbol{d}_g^{\mathrm{pos}} = \max\left(d_g^{\mathrm{IRD}} - d_g^{\mathrm{MO}}, 0\right) \tag{23}$$

$$\Delta \boldsymbol{d}_g^{\mathrm{neg}} = \max\left(d_g^{\mathrm{MO}} - d_g^{\mathrm{IRD}}, 0\right) \tag{24}$$

Then, total volume used for integrated redispatch in either direction is calculated as:

$$D_z^{\mathrm{IRD}} = \sum_{g \in G_z} \frac{\left(\Delta \boldsymbol{d}_g^{\mathrm{pos,MO}} + \Delta \boldsymbol{d}_g^{\mathrm{neg,MO}}\right)}{2} \qquad \forall z \in Z \tag{25}$$

The total costs of IRD units per zone are calculated as:

$$C^{\mathrm{IRD}} = \sum_{g \in G \in z} \left(c_g^{\mathrm{DA}} * \Delta \boldsymbol{d}_g^{\mathrm{pos,MO}} - c_g^{\mathrm{DA}} * \Delta \boldsymbol{d}_g^{\mathrm{neg,MO}}\right) \ \forall\, z \in Z \tag{26}$$

Total system costs, in turn do not just include the day-ahead market and the costs of IRD activation but also any possible costs of residual redispatch.

8.3. Simulation setup

In order to illustrate the improvement provided by the zonal model with integrated redispatch in a traceable manner, the proposed approach is illustrated with the help of a simple test network with two bidding zones, as shown in Figure 8.2, and compared with the *nodal* and *business-as-usual models*. Zone A (red nodes) has low-priced generation units, A and B, whereas Zone B (grey nodes) has a higher-priced unit D. Total generation capacity and load equal to 180MW and 20MW in Zone A and 120MW and 100MW in Zone B, respectively. In the zonal models, lines 0-5 and 2-3 are deemed interconnectors. They are included in the set of critical branches together with an internal branch between nodes 0 and 1 in Zone A. All branches have the same thermal capacity of 120MW whereas the branch 0-1 has a limited capacity of 30MW. For this analysis, line reactances are considered to be the same.

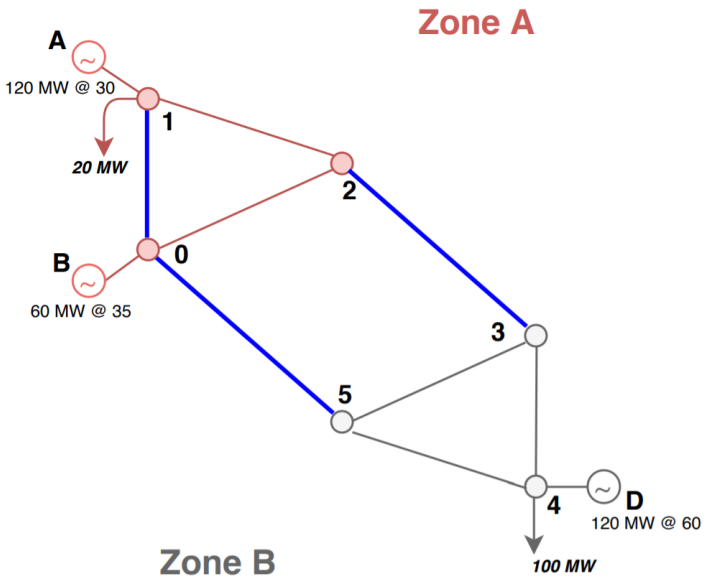

Figure 8.2. Overview of a 2-zone test network with 3 critical branches (in blue). The nodes and branches belonging to Zone A are marked in red, those belonging to Zone B are marked in gray. Next to the generators in the figure, the reader can find their maximum available capacities in MW and day-ahead market bids in €/MWh.

In all scenarios, generators are assumed to be dispatchable, i.e. able to change their output depending on the market outcome. In the zonal the *business-as-usual model*, all generators can be redispatched, i.e. change their output *ex post* to alleviate congestion.

The aim of this case study using a simple test network is to provide a better understanding of how intrazonal congestion affects cross-border exchange and the efficiency of FBMC as well as to demonstrate the potential benefits of the integrated-redispatch approach. The test network is intended for illustrative purposes rather that to represent grid and market reality in all their complexity. Market representation is limited to the day-ahead market clearing and does not consider other markets or intertemporal constraints.

8.3.1. Results and analysis

In all scenarios without congestion, the three models deliver identical results, as expected. A common merit order results in a single day-ahead price of 30€/MWh for both zones, the total system cost of 3.600€ and the total economic surplus of 116.400€. The value of lost load of 1.000€/MWh is used for the calculation of consumer surplus. In the zonal models, the total exchange between the two zones equal 100 MW (cf. Table 8.1).

In case of a limited transmission capacity on a critical branch, the results diverge.

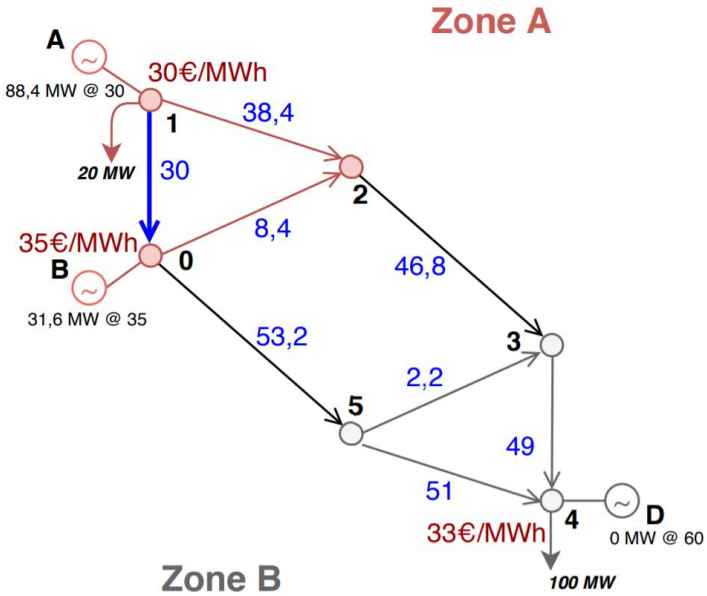

Figure 8.3. Six-node test network. Results from the nodal setup, generator dispatch, nodal prices (in red) and the flows on each branch (in blue).

Nodal setup

The Nodal setup, or the complete network consideration, the optimal dispatch is shown in Figure 8.3. Node 4 is able to import the entire volume needed to cover its demand of 100MW without activating the expensive generator D at a nodal price of 33€/MWh.

Since the individual line constraints are respected, there is no need for *ex-post* remedial actions and all commercial flows are feasible. Due to the congestion on line 0-1, however, nodal market prices diverge and range between 30 and 35€/MWh, depending on the node (in red in Figure 8.3). As a result, producer and consumer surplus decrease compared to the no-congestion case but the TSO obtains a congestion rent of 237€ (cf. Table 8.1).

Zonal business-as-usual setup

A common flow-based capacity calculation and exchange between the bidding zones is conducted. The cross-border transfer capacity is limited by the zonal PTDFs on the critical branches and the RAM. In this case study, security margins are assumed to be zero. The RAM is therefore equal to the maximum branch capacity. In this example, the capacity on the interconnectors (lines between nodes 0-5 and 2-3) is set to 120 MW each.

In order to emulate imperfect foresight of the TSO, as described in Section 8.2.2.1, the total flows between the two zones in the Base Case are assumed to be 50% of the total flow on all interconnectors between the two zones, as compared to the nodal outcome. The cross-border exchange is then equal to 50MW in total, based on D-2 estimate. Note that the Base Case is identical for both the *business-as-usual model* and the *model with integrated redispatch*.

The expected congestion leads to market splitting and produces two different zonal prices, 30€/MWh and of 60€/MWh in Zone A and Zone B, respectively, and a limited exchange of 67MW between the two zones (Figure 8.4. Day-ahead market coupling in the zonal business-as-usual setup: generator dispatch according to the outcome of the day-ahead market clearing and the zonal market prices in Zone A (in red) and Zone B (in grey). The numbers next to the generators in the figure show the day-ahead market dispatch of generators and their bids.). As a result, only the cheapest generator A could be activated in Zone A. To partially cover the demand in Zone B an expensive generator D needs to be activated.

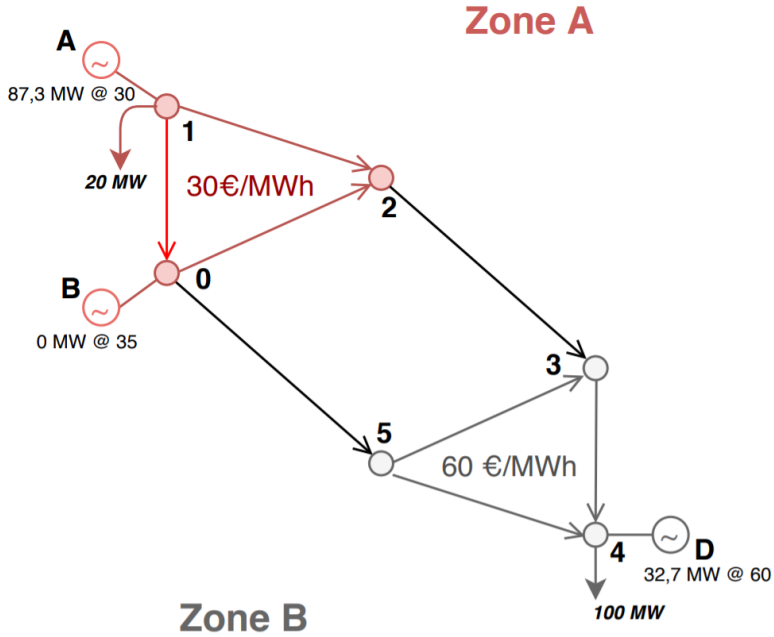

Figure 8.4. Day-ahead market coupling in the zonal business-as-usual setup: generator dispatch according to the outcome of the day-ahead market clearing and the zonal market prices in Zone A (in red) and Zone B (in grey). The numbers next to the generators in the figure show the day-ahead market dispatch of generators and their bids.

As a result of an imprecise flow calculation based on zonal PTDFs, the real flows that result from the day-ahead market clearing violate the limit on the internal critical branch between nodes 0 and 1 (shown in Figure 8.4 in red), which triggers

redispatch. Generator A was redispatched downwards whereas generator B in the same zone that was out of the merit order in the day-ahead market was redispatched upwards. The total volume of redispatch is 5,8MW in each direction (Figure 8.5). Generator B is remunerated pay-as-bid whereas generator A pays to the TSO the amount equal to its announced costs per MWh and the redispatched volume, i.e. the volume it no longer has to produce.

To simulate the current approach to redispatch, optimization based on volume minimization is used. Therefore, the value of the volume-based penalty coefficient, λ, in eq. 13 is set to 1.0 while the value of the cost-based penalty coefficient, γ, is set to zero[64].

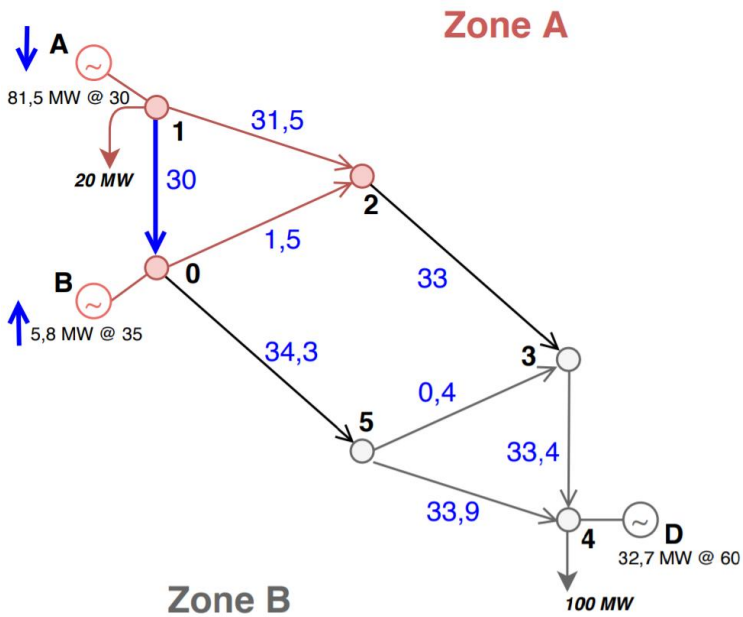

Figure 8.5. Activation of redispatch ex-post in Zone A in the zonal business-as-usual setup (redispatched generators A and B are marked with blue arrows).

Zonal setup with integrated redispatch

The same parameters and Base Case inputs are used in the zonal setup with integrated redispatch as in the zonal business-as-usual setup. Units A and B are predefined for IRD. Figure 8.6 shows the result of the second optimization step: the final dispatch volumes for each generator includes both volumes resulting both from the day-ahead market clearing and from integrated redispatch. The volume of the

[64] Both variants of the objective function lead to the same result since the chosen redispatch was the only feasible solution given flow limitations for such a simple network, yet can produce different results in a large network.

latter corresponds to 31, 6 MW in each direction, corresponding the difference of the plant's output from the day-ahead merit-order result.

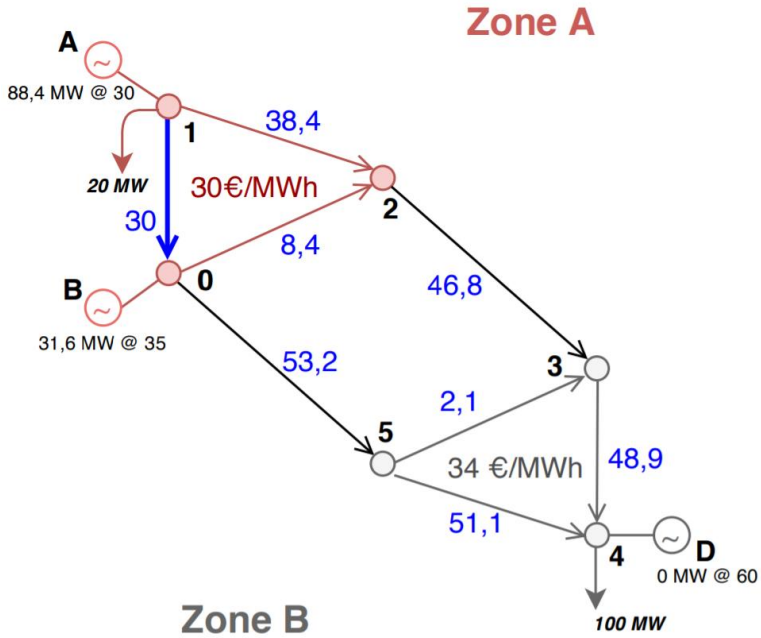

Figure 8.6. Results from the zonal setup with integrated redispatch. Activation of IRD generators in Zone A. The resulting zonal market prices in Zone A and Zone B are marked in red and grey, respectively.

Figure 8.6 shows that the joint optimization of the day-ahead market and integrated-redispatch action allows to greatly increase cross-border exchange to 100MW (Figure 8.6) and thus fully avoid the dispatch of the expensive generator D in Zone B. An increased cross-border exchange leads, among others, to the change of zonal prices. The price in the cheaper Zone A remained the same, 30€/MWh (generator A is marginal since generator B is activated upwards as part of IRD and does not set the day-ahead market price), whereas the price in Zone B went down from 60€/MWh in the zonal business-as-usual setup to 34€/MWh as activation of generator D is avoided.

The method for setting the day-ahead market price given the presence of integrated redispatch is crucial. In the *model with integrated redispatch*, IRD units do not impact zonal day-ahead prices, since a purely economic merit order is used to set the market clearing price (cf. Section 8.2.3.2). Instead, the IRD units are remunerated pay-as-bid, a common practice in Europe. To prevent IRD generators from affecting zonal day-ahead market prices, in the model the zonal price then corresponds to the dual of the nodal balance constraint of the nodes in each zone that do not have IRD generators connected to them (node 2 in Zone A in this case).

Thanks to the fact that the impact of IRD generators is represented with the help of nodal PTDFs, it was further possible to fully utilize the available capacity without causing congestion on critical branch 0-1 Hence, no residual redispatch was necessary in this case study.

Table 8.1 and Figure 8.7 summarize the results from each model illustrating how integrating redispatch action into the day-ahead market indeed may help improve the outcome as compared to the *business-as-usual model*.

Table 8.1. Overview of the results from all setups using a two-zone test network.

	No congestion	**Nodal setup (with congestion)**	**Zonal business-as-usual setup (with congestion)**	**Zonal setup with integrated redispatch (with congestion)**
Total system cost[1]	3.600	3.758	4.610	3.758
Redispatch cost, €	-	-	29	158
Congestion Rent, €	-	237	2.019	400
Producer Surplus, €	-	-	-	-
Consumer Surplus, €	116.400	116.005	113.400	116.000
Economic Surplus	116.400	116.242	115.390	116.242
Total cross-border exchange (MW)	100	100	67	100
Nodal prices, €/MWh	30	in the range 30-35	n/a	n/a
Day-ahead price Zone A, €/MWh	n/a	n/a	30	30
Day-ahead price Zone B, €/MWh	n/a	n/a	60	34

[1] *including the cost of redispatch*

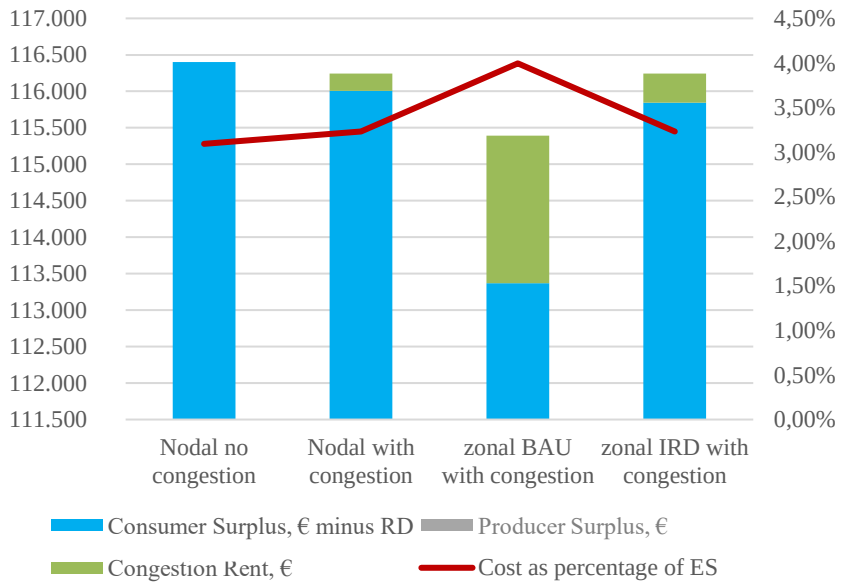

Figure 8.7. Economic surplus (ES) of the three setups and their comparison with a no-congestion case. Note that the cost of redispatch is subtracted from the consumer surplus.

The table shows that, in the simulation, the zonal setup with integrated redispatch achieves the nodal result with congestion (although this would not be generally the case due to a much higher complexity of the European grids). Consumer surplus and economic surplus are higher than in the zonal business-as-usual setup. Producer surplus is equal to zero in all setups, which however doesn't represent the general case. Instead, it is owed to the fact that only one generator is activated in each zone in the day-ahead market making it marginal. This, assuming marginal-cost bidding, generates a profit of zero by definition. Since inelastic demand was modelled with a high value of lost load (1.000€/MWh), the overall economic surplus is dominated by the consumer surplus.

In the case study:

- Activation of IRD units leads to a higher cross-zonal exchange: 100 MW (same as nodal market) as opposed to 67 MW in the zonal business-as-usual setup.
- The zonal setup with integrated redispatch increases the economic surplus compared with the zonal business-as-usual setup. In the case study, the IRD solution replicates the economically optimal solution. This can be explained by the small size of the test network and a limited number of generators and is therefore not generalizable for the European grid.

- The proposed approach indeed helps to increase price convergence between the two zones due to a higher flow between the zones and thus produces a more cost-efficient dispatch.
- The costs of integrated redispatch are covered by the congestion rent between the zones.
- Finally, in the zonal setup with integrated redispatch the congestion was solved in one step, i.e. no residual redispatch needed to be activated. In reality, depending on grid limitations and the location of congestion, a limited volume of residual redispatch might still be needed, yet this does not have an effect on higher cross-border flows produced in the zonal setup with integrated redispatch.

Therefore, in the zonal setup with integrated redispatch, market prices are more representative of the actual grid situation and efficiency gains can be achieved by reflexing the cost of congestion in the market, producing a more efficient dispatch and reducing the need for subsequent redispatch.

8.4. Discussion

The results presented in Section 8.3 demonstrate potential benefits of integrating preventive redispatch into the day-ahead market. The distinction between the IRD units and the rest of the generators lies in the fact that their effects on the critical branches are explicitly considered during the market coupling process. At the same time, the proposed approach ensures that IRD generators are not treated differently from other generators in the day-ahead market. They participate on par with the others and may only deviate from the market clearing outcome in case of expected congestion.

As a result, in the event of congestion, integrating redispatch in the day-ahead market helped to reduce total system costs and raise consumer surplus, as compared to the zonal business-as-usual setup. The use of integrated redispatch was shown to lead to an increase of cross-zonal exchange and therefore can facilitate zonal price convergence and generate market efficiency gains.

Two factors are likely to have a positive effect on the efficiency of the proposed approach. First, we assume that the costs of generators in the day-ahead market and in integrated redispatch are the same. In contrast, the costs of a generator used for *ex-post* redispatch are likely to be higher than their day-ahead market costs (cf. Sub-section 8.2.3.2). This can potentially lead to even higher costs of redispatch in the zonal business-as-usual setup and comparing the zonal setup with integrated redispatch more favorably. Second, the presented zonal models focus on intrazonal redispatch. The possibility of a coordinated cross-border redispatch (as expected to be implemented by the CACM Regulation [79]) is also likely to further increase the efficiency of the integrated-redispatch action, which can be investigated as a future

model enhancement.

The revenue streams of stakeholders depend on the design choices. If IRD units are remunerated pay-as-bid, then their profits will be zero if they bid at marginal cost, therefore, producer surplus would tend to be lower as compared to the *nodal model* with congestion. Welfare distribution among system stakeholders is also affected by whether IRD generators are remunerated through the market or through the TSO. It is assumed that all generators that were scheduled in the day-ahead market were remunerated there while the costs of integrated redispatch are part of TSOs' redispatch costs.

The choice of a compensation mechanism will affect generators' incentives [124]. Similar to conventional redispatch, the way to set up a pricing rule for integrated redispatch in a way that these generators cannot excessively profit from providing this service to the TSO becomes an important consideration. The redispatch payment should, on the one hand, be sufficient to cover the real costs but, on the other hand, should not result in additional profits for the generator in order to avoid possible market-distorting incentives. Technically, if activated for integrated redispatch often, in particular for downward redispatch, this may negatively affect these generators' financial positions, e.g. through efficiency losses from running at partial load. As a consequence, these generators may start to bid strategically to improve cost recovery, once they find out that they are used for integrated redispatch. This implies that the level of information of market participants about the state of the system plays an important role in defining their strategies.

A dedicated investigation of strategic bidding behavior and market power issues are out of the scope of this study. Yet, the proposed approach has clear benefits compared to the current practice as well as to the market-based redispatch, which raised concerns among researchers and regulators as potentially opening up opportunities for so-called inc-dec gaming[65]. The integration of integrated redispatch with the day-ahead market means that generators are not taken out of the market, i.e. are still subject to market mechanisms and competition. As IRD units may be used either in the day-ahead market or for redispatch, they are discouraged from bidding strategically, as otherwise they risk not being awarded. However, in a situation in which a generator is physically necessary to meet demand in a certain area, market design cannot remediate its market power.

The proposed approach has several limitations, which stem from the design choices and some model assumptions. Similar to other approaches, the TSOs would still face a tradeoff between the scope of available resources they use for congestion management and the degree of market interference The selection of IRD generators and the size of the pool affect the physical flows and, consequently, the economic

[65] The textbook example of inc-dec gaming, the Enron case in California, can be found in [208]. The analysis of inc-dec gaming potential in the German market is presented in [170].

efficiency of the outcome in the *model with integrated redispatch*. The design of the method cannot guarantee that the TSO secures sufficient redispatch potential or includes different kinds of providers. This would probably require the development of a dedicated harmonized methodology, for instance, one that involves a periodic re-evaluation of choice of IRD units. The value of integrated redispatch stems from a more precise grid representation based on IRD units rather than from improved forecasting of grid congestion. Finally, although the model has been formulated in a way to accommodate any number of nodes and branches, testing the developed methodology on the European network may reveal implementation challenges such as computational speed constraints, requiring a further development and fine-tuning.

The uncertainty associated with the output of variable renewable energy sources (vRES) may also affect the efficiency of the *model with integrated redispatch* since it relies on the calculation of cross-border capacity ahead of the market coupling algorithm. As a result, *ex post* changes in vRES output may potentially lead to higher volumes of residual redispatch.

The proposed approach does, however, have two benefits as compared to the current practice:

1) One of the major consequences of congestion in vRES-rich areas is that vRES often need to be curtailed and more expensive and CO_2-intensive generation needs to be regulated upwards. Since the proposed approach allows to increase available cross-border capacity, more cost-efficient vRES can be exported and the need for curtailment reduced.
2) As not only day-ahead but also intraday markets are now being integrated in the EU as part of XBID project[209], with the cross-border capacity for intraday trade being calculated within the intra-day timeframe, the proposed approach could be applied in the same way to the intraday market coupling when more precise grid information and vRES forecasts are available, further limiting the impact of uncertainty.

The effect of uncertainty can be addressed both at the macro level, for instance as pointed out in points 1 and 2 above, and at the micro level by providing market participants with tools to improve forecasting and scheduling of vRES. For instance, researchers in [210] proposed a probabilistic-possibilistic model for scheduling wind and thermal power plants that enables their participation in the electricity markets and addresses uncertainties such as high-impact low-probability events and calling probabilities in the reserve markets [210]. In [211], the authors developed a multi-objective bidding strategy framework for a portfolio with vRES that allows them to account for their intermittency and price uncertainties in different marketplaces. Both papers emphasize the value of integration of vRES and conventional generation in portfolios to better tackle uncertainty. Similarly, authors in [212] showed how vRES can successfully participate in electricity markets as part of a virtual power plant together with storage that allows to offset vRES variability more efficiently.

The effect of uncertainties, such as vRES forecasts, on the efficiency of different congestion management approaches, including integrated redispatch, would be an interesting topic for a future investigation.

Just like FBMC is an enhancement of the ATC approach, the proposed approach is intended as a further enhancement of FBMC. A combined use of integrated redispatch and non-costly remedial actions, such as transmission switching, the integration of distributed sources of flexibility (e.g. controlled EV charging [213] and storage [214]) for congestion management and improved TSO-DSO cooperation [215], are likely to yield further efficiency gains.

8.5. Conclusions

There is an increasing need to increase cross-border transmission capacity in order to be able to integrate more renewable energy into the European system, facilitate market integration and reduce redispatch costs. Hence, the efficiency of congestion management needs to be improved.

The authors propose a novel approach to congestion management in Europe by integrating preventive redispatch with the day-ahead market. It builds upon flow-based market coupling, which is currently used in Central Western Europe. Linear optimization models were used to compare the "integrated redispatch" mechanism formulated in this paper with two existing alternatives, 1) the nodal market, which is considered the optimal benchmark, and 2) the zonal market with flow-based market coupling. The results of the approach with integrated redispatch are closer to the nodal solution, increasing the total economic surplus, as compared to the zonal model with flow-based market coupling. The extent to which it approximates the nodal solution depends both on network complexity and on the number and specific choice of generators used for integrated redispatch.

The authors evaluated the physical and economic effects of the three approaches on the distribution of revenues and costs among different stakeholders as well as on the costs and the available cross-border transmission capacity. The results show that the zonal approach with integrated redispatch can:

- increase cross-border trade by freeing up more capacity for trade and making day-ahead dispatch more cost-efficient,
- increase price convergence thus contributing to European market integration,
- reduce the need for costly *ex post* redispatch,
- lower overall system costs delivering value to consumers while politically and practically more feasible in Europe than nodal pricing,
- potentially lower the risk of strategic bidding as compared to other market-based options.

Although the volume used for redispatch tends to be higher with integrated redispatch than in the current approach, it is more cost-efficient overall because of the welfare gains that result from increased cross-border trade. The integrated-redispatch approach may perform better if generator redispatch costs in business-as-usual are higher than their day-ahead market offers.

The main objectives of this study were to formulate a new methodological approach to redispatch in zonal markets with flow-based market coupling, illustrate its implementation using a simple network and in this way provide an impression of how the different approaches compare. It did not intend to provide an exact quantification of costs or welfare benefits. In the future, it is intended to quantify the results of the zonal integrated-redispatch approach by testing the developed model on a large network with a substantially higher number of generators and loads. Other crucial questions that could be addressed in future research include an investigation of modalities for the remuneration of redispatch-providing generators and the ways of minimizing potential strategic behavior of market participants. The future discussion should also address the effect of this approach on other short-term markets.

9

Discussion

9.1. Regulatory changes (and challenges)

A passing boat creates ripples on the water as it sails; we do not know what shores the waves will reach and how hard the waves will hit against them. In a similar way, the effects that regulatory changes may have on the market are often not fully predictable or foreseeable by their creators. It becomes more complex as the number of marketplaces increases, European market integration intensifies and network constraints make themselves more felt. Electricity markets are complex systems characterized by path dependencies, continuous interactions and feedback loops – making design adjustments akin to tinkering with an engine in operation where each cog is its own complex mechanism, an extremely challenging exercise with far-reaching, not fully known consequences. These are all reasons why it is not enough to give careful *a priori* thought to the possible measures for improving such complex dynamic systems to ensure that these measures "do what is expected". The danger is that some of these consequences reveal themselves only at a later point. Market models are highly valuable for addressing these challenges without interfering with the real system – contributing to informed decision-making[66].

Over time, the priorities of TSOs and regulators have evolved from a single question *"How can supply of consumer's electricity demand be satisfied?"* to a myriad of questions, such as "*How can cost-efficient supply be guaranteed?", "How can more variable renewables be integrated into markets?", "How can system flexibility be secured?", "How can abuse of market power be prevented?" and "How can the network be used most efficiently?*". These questions have been addressed through an array of European and national regulatory documents, in particular the EU Network Codes and the Clean Energy for all Europeans Package, paving the way for an intense and far-reaching transformation of the European electricity sector.

[66] These, however, have limitations of their own, see the dedicated Section 9.4.

The pace of regulatory change, which goes hand-in-hand with technological change, has been unprecedented. At the beginning of this PhD, the discussion about balancing market harmonization was just getting started, while at the time of its finalization, it is in full swing. Less than four years ago, the discussion about new distributed energy resources, aggregators and electric vehicles mainly preoccupied the minds of researchers. Currently, aggregators are about a third of the number of balancing service providers in Germany [216], Austrian consumers can buy electricity from their neighbors and the number of electric vehicle registrations in the EU reached 550,000 in 2019, as compared to a mere 700 in 2010 [217]. Having the opportunity to study the highly dynamic electricity markets as change is happening to them has been a great challenge as well as a privilege.

Less than ten years ago, in many EU countries, it was still hard to conceive how balancing could be procured in a market-based way, only for it to be considered standard in most EU countries today. Recently, the Overton window on balancing has evidently expanded; market-based redispatch seems to be following a similar path from rejection, through apprehension to cautious acceptance. The transition from mandatory cost-based balancing to full-fledged balancing markets is far from perfect or complete. Moreover, our analysis of early adopters of balancing markets warned of potential pitfalls and provided useful lessons for the countries with a slower pace of transition as well as for redispatch or other flexibility markets.

Similar to other electricity markets, market-based procurement of ancillary services requires addressing the extent of market regulation and the role of market transparency. Regarding the first issue, there is little consensus as to the acceptable level of regulation. In an immature market, a market with a suboptimal design or a in case of high market concentration, if all decisions are 'left to the market', these inefficiencies would only get exacerbated. Conversely, heavy-handed or reactionary regulation may create more damage than good by removing the confidence in the market and its stability. In addition, as is well-known from the experience with planned economies, the regulator is not all-seeing and often does not possess enough information in order to make system-optimal decisions. The author argues that the more immature a market is, the more important is its regulation. However, consistent market monitoring and reporting requirements are likely to be more effective than hard (and often arbitrary) rules. This, in line with the requirements of the dedicated EU regulation, REMIT[67], includes cross-border market monitoring ([218], Recital 4).

The role of market transparency is also growing. As REMIT puts it, the goal of transparency is to "*foster open and fair competition in wholesale energy markets for the benefit of final consumers of energy*" ([218], Recital 2). Successful market regulation relies on transparency; it is desired by market actors as much as by regulators and system operators. The more transparent the market, the less

[67] Regulation on Wholesale Energy Market Integrity and Transparency

potential there is to make use of 'insider information' ([218], Art. 3). It fosters competition by allowing less-experienced or smaller-scale actors to make informed trading decisions, contributing to the EU principle of the level playing field [175]. The chicken-and-egg problem is that sufficient transparency is required to increase competition, yet if degree of competitiveness is (still) low, a high level of transparency can increase market abuse. If we take the example of a redispatch market, publishing information about the exact location of congestion would likely be counterproductive, in particular if only few assets are available at a specific location. Under such sensitive circumstances, an increase of transparency relies on consistent market monitoring and regulatory oversight.

In order to account for potential effects of market regulation and design changes, the full market landscape should be considered. This research showed, for instance, the effects of voluntary bids in the balancing *energy* market on the performance of the balancing *capacity* market (see Chapter 6). Through opportunity costs, the strategies of actors in the balancing market are linked to those in short-term electricity markets, day-ahead and intraday. When redispatch or other flexibility markets are introduced, the complexity of the incentive structures will grow further and will likely lead to additional effects, such as increasing opportunity costs. Ongoing cross-border market integration complicates considering the full market landscape as both internal and external network constraints further affect market results.

The EU energy policy and the Member States have prioritized the integration of renewable energy sources and the electrification of energy consumption in response to the climate emergency. As much as variable renewables create operational challenges for network operation, their integration also provides new opportunities. The renewable energy transition prompted more intense cross-border cooperation and led to the emergence of new flexibility services, technologies and marketplaces. A previously held assumption that renewables themselves cannot contribute to system flexibility has been disproven by research [219], [220] and several TSOs e.g., the Danish and Austrian TSOs use wind generation for balancing.

Economic efficiency is hardly the single objective that has guided or should guide energy policy and market decisions; instead, it is complemented by system reliability and sustainability objectives. As Cramton put it in [221], an "*efficient welfare-maximizing outcome*" is a combination of short-run and long-run efficiency where not only the existing assets are used best but also efficient investment in new resources is facilitated. It is important to remember that markets are a means for achieving system and policy goals and not a goal in themselves. Other relevant considerations include fairness, transparency, public acceptance, empowering consumers and renewables integration. As a result, it may be justified to forego some efficiency gains in the short term for the sake of maximizing welfare in the future.

9.2. System balancing and the future of balancing market integration

Behind the term "balancing market" is, in fact, a whole series of different products [68], most of which are further subdivided in capacity and energy auctions for upward (positive) or downward (negative) regulation. This makes challenging not only their modelling but also the decision-making of BSPs, especially of the new entrants.

It has been shown that the market design rules as per the GL EB lead to tangible efficiency gains as compared to the *status quo*. The author demonstrated that the agents' tendency to bid strategically is significantly reduced under the new design, especially if voluntary bids from new flexibility providers are allowed. This design is shown to perform better as compared to business-as-usual even in a concentrated market. Beyond the market design, however, the degree of concentration does have a major impact on the market outcome in most studied scenarios irrespective of market design. Therefore, market design adjustments aimed at easing entry into the balancing market, such as allowing voluntary bids, were shown to have the highest positive effect. More specifically, we found that:

1) In a design with a standalone balancing energy market close to the time of delivery (no voluntary bids), the weighted average market prices are about 10% lower than in a combined market for balancing capacity and energy, in which bids for both markets had to be submitted simultaneously;
2) Although in an oligopoly, marginal pricing did not fully protect the market from price spikes, the weighted average prices were about 30% to 40% lower than under pay-as-bid pricing.
3) The introduction of a balancing energy market and marginal pricing, although leading to lower system costs, did not inoculate the market from strategic behavior: in fact, in an oligopoly in the presence of a single strategic bidder, total system costs in the balancing energy market almost tripled compared to the scenario with only price-taking actors;
4) In a new market design using a standalone balancing energy market *and* voluntary bids, total system costs in the balancing energy *and* balancing capacity markets went down by about 35%, as compared to the concentrated market with the original market design (combined balancing capacity and energy market with no voluntary bids).
5) The introduction of voluntary bidding in the balancing energy market with marginal pricing incentivizes all agents to bid more competitively: in this case, they bid above their true costs about 15% of all hours on average (mostly correlating with scarcity times) as compared to almost 50% of all hours when voluntary bids are not allowed.

[68] According to the European Balancing Guideline, 'standard balancing products' include FCR, aFRR, mFRR and (applied in some countries) RR.

6) If we assume that some actors still behave strategically, voluntary bids still cause a 50%-60% drop in balance energy market costs. This is partly offset by an increase in the cost of balancing capacity of 5%-17%, depending on scenario.
7) Overall, the relevance of a specific design decreases the more competitive a market is.

When interpreting these results, it is important to consider that they are based on typical rather than specific market actors. That said, the intention of the model is not to replicate the reality but to provide generalizable conclusions about the order of magnitude of the effects of market changes and competition levels.

In the final part of the balancing market analysis (Chapter 6), it was shown that strategic bidding can manifest itself in a number of ways, through price markups (or markdowns) but also through capacity withholding. The latter involves inducing artificial scarcity and raising the market price as a result. Such a behavior is certainly much more dangerous if marginal pricing is applied. Affecting the market result through capacity withholding is, understandably, also more realistic the more concentrated the market is. For this reason, the availability of voluntary bids is highly important for increasing the efficiency of the balancing energy market. It reduces the ability of market actors to collude, explicitly or implicitly, while incentivizing them to bid all available capacity and reveal their true costs more often.

Reservation of capacity is a double-edged sword: it helps to ensure that there is sufficient capacity when it is needed at a short notice but, at the same time, it intrinsically concentrates the subsequent balancing energy market. The latter occurs since over dimensioning reserve capacity would entail higher costs borne by consumers for units that would likely not even be activated. This makes the use of voluntary bids in the balancing energy market particularly important as it:

1) means that the reserve dimensioning no longer constrains the supply of balancing energy,
2) creates more competition,
3) makes the merit order position less predictable making it more difficult to exert market power,
4) potentially allows to reduce the volume of reserve capacity.

And yet, it would be unrealistic to expect the number of BSPs, in particular voluntary bidders, to suddenly grow fast. It is important to remember that such bidders are not exempt from the technical prequalification procedure, which in itself requires time, resources and technical expertise. In many countries, prequalification requirements are still tailored to traditional large-scale units. Therefore, in order to facilitate the actual entry of new BSPs, voluntary or not, prequalification requirements must be adjusted accordingly. Together with network tariffs (see also 10.5 Suggestion for future research), these are beyond the questions of market design yet are as essential to raise market efficiency. The two measures need to be

considered together to create an incentive to participate in the balancing market and intensify competition before marginal pricing is introduced in order to avoid its detrimental effects in concentrated markets.

If the market remains concentrated, authorizing voluntary bids would mean that the incumbent actors simply get a second chance to submit their energy bid if they were unsuccessful in the balancing capacity market. This essentially breaks the link between the balancing capacity and energy markets; a BSP is no longer incentivized to moderate its bids in the balancing capacity market whereas competition in the balancing energy market does not increase. Such a situation can produce the opposite of the intended effect i.e., higher prices in both markets. The recent German experience at the end of 2020 is the empirical evidence of this point when the standalone balancing energy market was introduced and led to price hikes of tens of thousands of euros per MWh [130].

It will take time to adjust the European balancing markets to the new design required by the GL EB. They follow a process determined by ENTSO-E methodologies approved by national NRAs or ACER, as per requirements of individual articles of GL EB. To appreciate this complexity, the reader is invited to take a look at the implementation timeline provided by ACER [174]. Thus, even if the target market design is assumed to be efficient, inefficiencies are inevitable along the implementation pathway. In reality, the timeline is defined not as much by the priority of a given design variable as it is by the methodology development and approval times. Balancing market experience shows that frequent design changes exacerbate market uncertainty leading to sometimes erratic behavior and extreme, unpredictable results. This fact makes it important to consider measures that can help smooth out the transition. So, clustering different measures should be beneficial to avoid such shocks. An approach to clustering market design changes based on their priority was proposed in Chapter 2 of this dissertation.

The harmonization of balancing energy markets and their integration in pan-European platforms is certainly a crucial step to increase competition and diversify the actor and technology landscape. However, it falls short of full-fledged integration. Several crucial aspects remain to be addressed. It is important to understand that the adopted rules on pricing, for example, are rather focused on the algorithm for the price calculation and not the pricing itself. However, despite a common merit order of BSPs from different European countries, the settlement remains largely TSO-TSO. BSPs in turn still will be settled nationally, which means that different prices can still be applied. Moreover, the integration is incomplete as long as the balancing capacity markets remain national, in particular as the bulk of balancing energy comes from resources previously committed there. It has been shown that there are tangible links between the bidding strategies in the two sequential markets and such a setup may cause unintended effects that should be studied in the future.

9.3. Redispatch in the context of market integration

In this work, the author analyzed the links between balancing and redispatch and between redispatch and market integration. The latter provides the interconnected countries with more flexibility in terms of addressing short-notice technical issues by allowing countries to import the missing production or export the surplus. At the same time, growing market integration exposes market vulnerabilities, as congestion in one country or on one border can lead to a reduction of transmission capacity on other borders or cause unscheduled flows. Moreover, frequent and large volumes of redispatch risk diluting short-term price signals as redispatch activation by definition intervenes with the dispatch determined by the market. As a result, large volumes of generation that have been awarded in the day-ahead market are later redispatched downward and thus not producing. For instance, according to the analysis of the Belgian regulator, CREG, about 5% of all downward redispatch activations in Germany in November 2018 exceeded 5000MW, a substantial chunk of the day-ahead merit order.

Improved TSO forecasting of congestion and TSO-TSO coordination of redispatching [222], coupled with preventive redispatch (for instance in a way proposed in Chapter 8) is likely to help factor in the cost of congestion in the market. Preventive redispatch does not contradict current CACM Regulation. Downward-redispatched units are still required to be remunerated by the Regulation regardless of the timeframe of procurement. The remuneration mechanism, as pointed out in Chapters 7 and 8, will make a crucial difference for the providers' incentives and should be studied in more detail in future research. Although this approach would increase the day-ahead market prices at the times of congestion, this does not imply efficiency losses. Rather, it implies redistribution of wealth: redispatch costs that are recovered through network tariffs are – at least partially – accounted for in the market itself.

Making redispatch procurement more efficient is crucial as redispatch volumes continue to rise and more countries are becoming affected. Still, it should go hand in hand with measures to minimize congestion in the first place. This should help tackle structural congestion, which, as was shown in Chapter 7, is likely the main source of strategic bidding when it comes to redispatch. Grid reinforcement is certainly a crucial measure we can hardly go without to integrate more renewable generation and smooth out increasing instances of negative residual load. Yet, as is known from traffic congestion, building more lanes on a congested freeway solves the problem only temporarily. This is not to diminish the role of grid reinforcement: while it will be even more important in the future in which pressure is mounting on system operation, it should be complemented by other measures. Traffic congestion

has been shown to abate with the expansion of local infrastructure, reducing or removing the need for people to hit the road in the first place. The intensifying decentralization and digitalization trends will and should fulfill a similar function: reducing the pressure on the transmission network as supply does not have to flow to the other side of the country to fulfill the demand. One of the consequences of the decentralization trend, however, is that congestion will also likely become not just the issue of the TSO but the DSO as well, increasing the need for cooperation between the two.

Redispatch is the next stepping stone in European market integration, as the ACER decisions on redispatch and countertrading as well as cost-sharing from these actions were adopted in December 2020 [222]. Remedial actions are increasingly harmonized, yet the approach to their procurement, whether cost-based or market-based, allowing smaller units or demand or not, is still debated. While some countries have been procuring redispatch in a market-based way for several years now (e.g., France and the Netherlands), others are struggling with how or even whether it can be implemented.

All in all, the experience and the analysis of the balancing market has shown that market design does not necessarily eliminate the risk of strategic bidding. In a concentrated market, no market design can really prevent its susceptibility to exploitation of market power. Concentration is unfortunately inherent to redispatch, being a local service, as the TSO usually has only a handful of options able to alleviate a given congestion point. This often prompts opponents of market-based procurement of ancillary services to argue for a cost-based approach. While it may sound reasonable at first sight, it does not really solve the underlying issues. First, even in cost-based approaches, information asymmetry between the TSO and flexibility providers cannot be fully avoided. Second, a cost-based approach lacks scarcity signals and therefore fails to incentivize expansion of redispatch resources. As the analysis of links between balancing and redispatch in Chapter 7 has shown, in cost-based procurement, the number of providers stagnates unavoidably leading to a higher concentration.

9.4. Market modelling and future use of the models developed in this dissertation

The author of this dissertation has demonstrated the merits of agent-based modelling to answer questions about market design and actor bidding strategies. It makes it possible to meaningfully compare the effects of individual design variables on actor behavior. This can be useful for both studying existing actor-market interactions under changing conditions and for modelling new marketplaces. Secondly, ABM provides flexibility in agent definition and interaction in a given environment, which, for instance, makes it amenable to integration with machine learning. Furthermore, different agent levels can be incorporated in an ABM e.g.,

market actor level and the level of agents representing individual flexibilities in an actor's portfolio. In this way, the units' constraints can be accounted for in the agents representing the flexibility resources and the bidding strategies at the market actor level.

In this dissertation, ABM was used for the first time to analyze the effects of balancing market design changes that are required by the GL EB. Reinforcement learning (RL) was used to mimic strategic behavior, one of the main concerns in the balancing market. In the next step, our ABM was extended with a collaborative RL algorithm – that is, two RL algorithms representing an individual agent in several marketplaces. It allowed us to trace the changes in agents' bidding strategies in the positive and negative balancing capacity and energy markets, advancing the knowledge of and helping assess the risk of strategic bidding behavior. For instance, this research showed that a RL agent's success depends on the choice and amount of available information. Specifically, the RL agent learns to maximize its profits by approximating its Q function based on the inputs about the system and the market constantly updated in its state. This has implications for market transparency and the time of publishing market results. It is noteworthy that a learning computer agent's ability to learn is impaired through a low volume of transactions or inadequate information, which in turn likely does not incentivize the agent to bid its true costs but rather bid with a higher degree of randomness. In the next development step, the model was made more realistic by adding bid volume to the agents' decision space in order to draw insights about the interrelations between positive and negative balancing markets.

This application of reinforcement learning also revealed some of its limitations. By definition, reinforcement learning is learning from the past. This means that if the new world is completely different, the model is no longer of use. As a result of its decision-making complexity, the RL algorithm is computationally intense and time-consuming. In order to keep computational time within reasonable boundaries, tradeoffs between the number of an agent's control variables (such as the number of flexible assets they have) and the size of its action space (i.e. combinations of its decision variables) on the one hand and the speed and precision on the other hand must be accounted for. This was done by discretizing the action space and reducing portfolio size.

There are several reasons for limiting the total number of agents embedded in a market environment. First, a larger number of true-cost bidding agents can simply "crowd out" the RL agents so the latter do not get adequate opportunities to train nor enough information about their performance to improve their policy. A tradeoff should therefore be found between the number of agents and portfolio granularity and keeping the number limited to allow all agents to be awarded frequently enough for them to learn successfully. Second, the number of RL agents needs to be limited in order to minimize their interference with each other during the training phase. Unlike other uses of RL (e.g., in operations research), where the perspective of a

single actor is modelled, the complexity grows exponentially in multi-agent models with RL. All agents train simultaneously which logically complicates learning. Then, they attempt to act optimally in an environment with a lot of moving parts, those of the market itself but also other profit-maximizing agents.

As a result of model and agent complexity, we ran into the limits of RL for this application. Expanding them would, for instance, require devising a smart approach to limiting the agents' action space or allowing agents to train sequentially instead of simultaneously. Machine learning is inherently non-deterministic, consequently, there could be multiple equilibria, making it difficult to say if the optimum is absolute or local. In a stochastic market environment, the model is unlikely to converge to a single equilibrium and the RL agents may not be equally successful. Yet, by keeping a limited number of RL agents (up to five in our simulations), the model has been shown to yield valuable insights and to perform well within a reasonable computational time.

Not everything can be explained by rational-choice theory and modelling approaches that represent fully rational actors. Importantly, the use of ABM and RL made it possible to avoid the constraining (and often unreasonable) assumptions of perfect competition and perfect information. It allowed the author to develop new ways of capturing strategic behavior in the balancing market whose concentration has been demonstrated on multiple occasions [27], [142], [223]. The modelling approach has been cross-validated in a recent project conducted for the Swedish TSO, Svenska kraftnät, in which Elba-ABM was used. During the analysis of the Swedish FCR-N[69] market, the model successfully replicated the market design and the historical market prices. The analysis showed a better market performance under a marginal pricing rule as compared to pay-as-bid pricing. It also revealed the market's susceptibility to gaming and indicated the shares of new flexibility sources required to improve the market outcome. [224]

Finally, the analysis of redispatch procurement performed in this dissertation using optimization methods lays the groundwork for future analysis that should help define the exact design variable choices for the future market-based redispatch required by the CEP (see the full list under 10.5 Suggestions for future work). Localized demand for redispatch seriously limits the available flexibility creating marker power that is difficult to avoid. In such conditions, studies of market power and strategic bidding under different market designs using ABM with machine learning will hopefully provide regulators and TSOs with valuable insights as to ways to – if not entirely avoid – minimize the use of market power before intervening into the actual market.

[69] Frequency containment reserve normal operation

10

Conclusions

10.1. Overview

Ancillary services, balancing and redispatch, are crucial for safeguarding system security and stability. European transmission system operators face increasing operational challenges due to the large-scale integration of variable renewables and decommissioning of conventional generation, which cause a growing demand for system flexibility. Positive changes such as harmonizing ancillary service procurement and democratizing market access have been achieved through far-reaching regulatory changes anchored in the Clean Energy for all Europeans Package of 2018-2019 and the EU Network Codes. The EU regulation, however, does not provide all the answers as to the design of ancillary service markets. Existing balancing markets have been prone to inefficiencies and market power. Whether redispatch will be market-based or what its design should be is still subject to debate. These considerations led to the main research question posed in this dissertation:

How can market design changes help transmission system operators procure balancing and redispatch services in a more economically efficient manner?

Improving the efficiency of balancing or redispatch service procurement requires, first, creating sufficient incentives for participation and, second, ensuring robustness against strategic bidding.

The first requirement can be fulfilled by easing market entry, in particular for new, often distributed, energy resources, which can be flexibly deployed for balancing or redispatch thanks to aggregation. For this, prequalification procedures should be reviewed to include a broader range of technologies on the supply and demand side. Aggregators emerging as crucial flexibility providers can be encouraged by adjusting their contractual obligations and providing flexible pooling options.

To fulfill the second requirement, several market design adjustments can be made. We find that the regulatory changes required by the EU with regard to balancing market design and integration are conducive to improving market efficiency. Given a high design complexity, however, some variables should be prioritized to avoid transition shocks. Once the ease-of-entry criterion is fulfilled, common procurement of balancing capacity and balancing energy with long contracting periods should be avoided. We show that procuring balancing energy in a separate auction close to real time increases market efficiency. Additional efficiency gains can be achieved by allowing voluntary bids, i.e. bids from parties who did not commit to the balancing capacity market. The pricing rule for balancing energy needs to be addressed after implementing the other changes. Marginal pricing was shown to lead to lower system costs and market prices as long as market concentration is addressed first. As this research has shown, these design variables combined are likely to reduce room for strategic behavior and incentivize balancing service providers to bid more competitively.

In contrast to balancing, the approach to redispatching for congestion management is far less harmonized and its design more open for discussion. The first requirement can be achieved by devising standardized technology-agnostic prequalification procedures for providers of redispatch. In addition, engaging more flexibility sources for redispatching requires rethinking the cost-based approach, which removes the incentive to participate. This research shows that allocative efficiency is maximized when balancing and redispatch services are procured via two separate markets, with the redispatch market clearing first. Strategic bidding is a concern for this market, too. The second requirement can – at least to an extent – be mitigated by addressing structural and predictable congestion before introducing market-based redispatch. In the broader EU electricity market context, we argue that integrating preventive redispatch into the day-ahead market coupling does not only allow to increase cross-border exchanges but can also help to reduce potential for strategic bidding.

The appropriate modeling approach depends on the level of market maturity, the level of complexity and the research questions. Agent-based modelling was combined with reinforcement learning techniques to study balancing markets with different degrees of competition. It was found to be a strong tool for analyzing strategic behavior in such a complex market environment. This dissertation is the first to develop and apply collaborative reinforcement learning algorithms to study interrelated bidding strategies in the balancing market. In the second part, optimization approaches were demonstrated to be useful to understand fledgling

markets, such as the one for redispatch, and to offer a good compromise between complexity and traceability of results.

10.2. Research outcomes

The main research question is highly complex and was therefore subdivided into several sub-questions. In the first part of this dissertation the conditions for participation and entry in the balancing market with a focus on new actors were addressed. The second part of the dissertation is concerned with the adjustments to the market design itself, in particular to determine how the balancing market can be made less vulnerable to strategic bidding. The insights from balancing market analysis were used to study the links between balancing and redispatch. In the last part, the analysis of redispatch was conducted from a broader perspective of interconnected electricity markets to get a better understanding of how redispatch – instead of hampering it – can promote market integration.

The answers to the following sub-questions will be discussed in the six subsequent sections.

1. *How can balancing market design be improved to stimulate the entry of new participants and technologies?*

2. *What are the main factors that influence the bidding strategies in the balancing capacity and energy markets?*

3. *What is the effect of changes to balancing energy market design on strategic bidding and market efficiency?*

4. *How are flexibility providers' interrelated bidding strategies in the balancing market affected by the introduction of voluntary bids?*

5. *How can the combined efficiency of balancing and redispatch procurement be improved considering links and potential conflicts between them?*

6. *How can redispatching be used to maximize cross-border exchanges in a flow-based market coupling regime?*

10.2.1. How can balancing market design be improved to stimulate the entry of new participants and technologies?

In order to stimulate the entry of new actors and sources of flexibility in the balancing market, in **Chapter 2**, we show that adjustments to formal access and prequalification requirements as well as to the auction configuration are necessary.

They need to account for the technical and decision-making capabilities of all actor types, including increasingly available smaller-scale distributed energy resources. This can be achieved, e.g., by allowing aggregation, shortening the capacity reservation period, reducing the minimum bid size to 1MW or less and introducing marginal pricing for balancing energy. In Chapter 2, a design framework was developed to analyze these measures and formulate policy options. The framework did not only answer the *'what?'* question but also the *'how?'* by proposing a roadmap for a stepwise adjustment of the market design. To this end, the design variables were prioritized, based on a hierarchy of their interdependencies. We show that formal access, aggregation requirements and splitting the balancing capacity and energy markets should be addressed first, since all other design variables depend on them. On the other hand, the pricing rule should be changed to marginal pricing last in order to avoid exacerbating incentives for strategic bidding.

The analysis of country case studies of balancing market design revealed large differences in the formal requirements for balancing service providers. This administrative aspect is often overlooked, yet it is crucial for the entry of new market actors and technologies and therefore for a more competitive market. In **Chapter 3,** we demonstrate how the access to the balancing market depends on balancing service providers' relations with balance responsible parties (BRPs) and – in the case of aggregators – with their customers' suppliers. Based on conceptual models of interactions between these actors, we show that incumbent market actors are in a superior position to participate and consolidate multiple activities, including aggregation. Requirements to obtain other actors' consent conflict with the EU non-discrimination principle. Furthermore, actors should be provided with a free choice of business model to maximize their contribution to system balancing. Finally, allowing an aggregator to flexibly pool resources beyond a single BRP can further help unlock aggregation potential.

10.2.2. What are the main factors that influence the bidding strategies in the balancing capacity and energy markets?

The bidding strategies of balancing service providers (BSPs) are affected by their costs for capacity reservation and energy activation, the availability of other marketplaces and market uncertainty. The analysis of the cost structures and optimal bidding strategies in sequential balancing and short-term electricity markets was performed using decision-theoretical bidding calculus. Balancing market design changes adopted in the European Balancing Guideline are expected to prompt BSPs to adjust their strategies. The theoretical analysis presented in **Chapter 4**, however, showed that even after the formal splitting of the balancing capacity and balancing energy markets, the bidding strategies in the two auctions remain linked. That is, the BSP will take the associated costs and expected profits from both market stages into account.

The analysis further revealed a larger influence of the introduction of voluntary bids on bidding strategy. First, voluntary bids coming from new market entrants, such as aggregators of small flexibilities added an extra level of uncertainty for regular bidders. Second, regular bidders themselves would be able to submit a voluntary bid if they were not 'in the money' in the balancing capacity market. However, this additional trading option creates extra opportunity costs, likely leading to higher prices in the balancing capacity market. This is particularly the case of the market design where balancing capacity market is cleared before the day-ahead market. Market efficiency can be improved by conducting balancing capacity auctions close to or even after the closure of the day-ahead market. Using theoretical bidding calculus, these effects, however, are difficult to quantify, considering the effects of multi-run and multi-stage auctions.

10.2.3. What is the effect of changes to balancing energy market design on strategic bidding and market efficiency?

Research performed in **Chapter 5** produced outcomes that were not immediately evident from the previous theoretical analysis: the introduction of a standalone balancing energy market close to real time improves market efficiency, leading to lower system costs and prices, in particular if combined with a marginal pricing rule. The latter was shown to perform better both when the balancing capacity and energy markets were combined and split. We show, however, that these adjustments alone do not shield the balancing energy market from non-competitive behavior – strategic bidders are still able to exploit market vulnerabilities in scarcity times. Additional measures are required to improve competition levels in the market. It is, however, expected that these improvements to the balancing energy market design will attract more participants.

To understand and quantify the effects of design changes better, an agent-based model, Elba-ABM, was developed in this dissertation. It represented current market conditions, in which balancing capacity and energy are bid for at the same time, and compared it with the target market, in which a standalone balancing energy auction. A benchmark for perfectly competitive markets according to neoclassical economic theory, i.e. actors bidding short-term marginal costs, was compared with strategic bidding. In a methodological innovation, the agent-based model was enhanced with reinforcement learning, which proved very fruitful in gaining insight in strategic behavior.

10.2.4. How are flexibility providers' interrelated bidding strategies in the balancing market affected by the introduction of voluntary bids?

Building on the model of Chapter 5, in **Chapter 6** we show that the participation of voluntary bidders in the standalone balancing energy market and with a marginal

pricing rule leads to lower systems costs and, importantly, ensures competitive bidding practices. Elba-ABM was extended to include a detailed model of the balancing capacity market with links to the (exogenous) day-ahead market. For the first time, the interdependencies between BSPs' bidding strategies in the balancing capacity and energy markets were represented with a collaborative reinforcement learning algorithm. This takes both the links between the positive and negative balancing capacity markets and the balancing capacity and energy markets into account. The simulation results confirmed a theoretical conclusion reached in Chapter 4: the introduction of voluntary bids is likely to shift some of the reservation costs from the balancing energy to the balancing capacity market, leading to higher balancing capacity prices. This can be explained by a price decrease in the balancing energy market and, ergo, declining profits, which remove the incentive for BSPs to underbid their capacity bids. This insight would not have been possible without explicitly accounting for the links between the bidding strategies of BSPs in the balancing capacity and energy markets in the model. However, despite the identified positive effects of the expected design changes, their success will still depend to a large extent on the level of competition. In oligopolistic markets, we showed that the cost increase of balancing capacity can, in the worst case, outstrip the benefits generated in the balancing energy market. This result creates an impetus for the harmonization and integration of balancing capacity markets.

10.2.5. How can the combined efficiency of balancing and redispatch procurement be improved considering links and potential conflicts between them?

Redispatch presents another commercialization opportunity for flexibility providers in addition to balancing. Alternatives create opportunity costs, as a result of which, the timing of the markets and the pricing rules shape the strategies of flexibility providers. This is the case if, in line with the Capacity Allocation and Congestion Management Regulation, redispatch is procured in a market-based way. In the research presented in **Chapter 7,** we show that organizing the two services into two separate markets is more likely to boost resource availability and improve allocative efficiency, as compared to cost-based redispatch or a combined market for balancing and redispatch. If two markets are used, flexibility providers can freely plan how much to bid in either market. If the redispatch market is cleared before the balancing energy market, the conflict between the two is minimized and a higher resource availability for location-specific redispatch can be ensured. Different rules, however, should be followed in the real-time emergency phase when the TSO cannot secure sufficient flexibility resources. A common concern about strategic bidding in a redispatch market applies mainly to locations with structural congestion. This should be handled first through other means, such as grid reinforcement.

10.2.6. How can redispatching be used to maximize cross-border exchanges in a flow-based market coupling regime?

A novel way to improve the efficiency of redispatch procurement is through integrating it into day-ahead market coupling. This is achieved by identifying flexible units with a high grid sensitivity and including them into the calculation of the flow-based domain, the feasible import/export 'envelope' between the countries of Central Western Europe using flow-based market coupling (FBMC). For this analysis, in **Chapter 8,** redispatch was placed into the broader context of European market integration. Frequent internal congestion in zonal markets may cause a reduction of the volume of cross-border capacity available for market exchanges leading to lower market integration. How the efficiency of redispatch can be improved by integrating redispatch with the day-ahead market clearing process was formulated as a multi-step optimization problem. The proposed approach was compared with the result of a nodal market and business-as-usual zonal markets using FBMC. We showed that the main benefit of the so-called 'integrated redispatch' is its potential to increase cross-border exchanges by freeing valuable capacity on the interconnectors for more cost-efficient generators. This can lead to overall economic efficiency gains by facilitating price convergence and thereby lower total system costs. Although this approach did not fully eliminate the need for *ex-post* redispatch, simulation results showed that the need for it could be significantly reduced.

Integrated redispatch can reduce the risk of strategic bidding since the generation units that are used for redispatch participate in the day-ahead market on par with other market participants, i.e., the possibility is removed to withhold capacity from the day-ahead market to later sell it at a high price in the redispatch market. Finally, the current network challenges expose the inefficiencies of 'network-blind' zonal markets. While implementing nodal markets that fully account for the grid reality would be politically and practically challenging in Europe, the proposed approach could be a feasible middle ground.

10.3. Policy recommendations

Achieving the efficiency objective in the context of growing system complexity and the most ambitious integration efforts in the history of European electricity markets is a formidable challenge. In a matter of less than a decade ENTSO-E and ACER managed to formulate a comprehensive set of Network Codes covering both technical and market requirements and guidelines. The implementation of the common European balancing energy platforms is underway and is planned to be completed within the next couple of years. The imbalance settlement and the balancing capacity markets are planned to be harmonized next. Meanwhile, cooperation on cross-border capacity calculation and redispatch cooperation mechanisms have been formalized in the CACM Regulation and the recent ACER decisions [8], [222].

Both the qualitative and model-based analyses in this dissertation demonstrated that the principles and requirements defined in the Clean Energy for all Europeans Package and other relevant policy and legislative documents do in fact lead to a greater market efficiency.

There is, however, still a lot of ground to be covered to reach the targets set out by the EU. This research at the intersection of policy, economics and technology has yielded a number of policy recommendations, as detailed in Sections 10.1 and 10.2 and summarized in the next paragraphs.

To generate long-lasting efficiency gains from adjusting market design, a broader market and policy landscape should be considered. The research in this dissertation has shown that the effects of adapting the approach to ancillary service procurement go beyond a single market as actors tend to participate in a number of marketplaces. For one, the balancing market alone involves auctions for capacity and energy for a number of standard balancing products. Providers of both balancing and redispatch services conduct trades in short-term markets constituting the bulk of their opportunity costs. The approach to redispatch may further affect the amount of volume bid in the day-ahead market. Although out of the scope of this dissertation, imbalance pricing is another factor affecting service providers' incentives. As a result, any of these changes can hardly be addressed in isolation.

As much as it is crucial to identify the features of the target market design, it is no less crucial to focus on the pathway towards it and understand how individual design variables can be prioritized. Using the example of the balancing markets, we showed that different design variables can enhance or neutralize each other's effects. For instance, formal access criteria have to be addressed in the first place, followed by the pooling requirements and the introduction of separate markets for the procurement of balancing capacity and energy. Only once several adaptations related to the auction configuration have been implemented can the pricing rule be changed to marginal to ensure optimal market performance. Finally, defining a clear transition pathway should help mitigate regulatory uncertainty, a crucial factor influencing bidders' strategies and investment decisions.

Concerning balancing market design, new entrants are needed to obtain competitive prices. Some market designs make entry easier than others. The market design choices, as per the Electricity Balancing Guideline, are likely to improve market performance, as model results in this dissertation have shown. Yet, each market design could be exploited at least to a larger or smaller extent in a more concentrated market. Therefore, particular attention should be given to market access conditions, such as reduction of minimum bid size, aggregated and asymmetric bidding along with market design adaptations, in view of many new types of flexibility providers that are emerging. Attracting voluntary bidders in the balancing energy market will be crucial to encourage competitive bidding and limit the number of scarcity events.

In order to facilitate the actual entry of new flexibility providers, voluntary or not, prequalification requirements must be adjusted accordingly. Together with network tariffs, these are beyond the questions of market design yet are as essential to raise market efficiency. Furthermore, securing competition in the balancing capacity market, e.g., by allowing participation of new technologies and by integrating European balancing capacity markets, is of paramount importance to efficient balancing markets.

Concerning redispatch, in order to provide "efficient economic signals to the market participants and TSOs involved"[175]*, market-based redispatch is most likely to attract flexibility resources without leading to excessive system costs as long as structural congestion is tackled first.* In the presence of structural congestion, the problem is not a market-based approach but rather the frequent and predictable nature of congestion itself, something that cannot be removed by market design. In this situation, grid reinforcement should be prioritized if the long-run cost to society is lower than the cumulative cost of the congestion. Integrating redispatching with day-ahead or intraday markets may help reduce gaming risks while preventing a conflict with the balancing market. In the context of market integration, we have proposed a promising method which would involve co-optimizing the day-ahead market and preventive redispatch. Not only does this reduce the need for costly *ex-post* redispatch but also may allow to use limited cross-border capacity in a more cost-efficient manner. In contrast, cost-based procurement by definition eliminates the incentive to provide flexibility thus reducing the number of providers leading to an oligopoly that was intended to be avoided in the first place – the vicious circle is perpetuated. Finally, cost-based procurement is contrary to the EU energy policy principle of revealing the true value of energy.

10.4. Other lessons learned

This Section summarizes general lessons the author learned from market design analysis and modelling electricity markets.

10.4.1. Lessons learned from market design analysis

The research has taught the author of this dissertation that *there are no perfect solutions, no silver bullets.* Rather, increasing market efficiency is all about minimizing tradeoffs, for instance, maximizing the integration of variables renewables, while keeping the lights on at a reasonable cost or tolerating a certain degree of market power at the beginning in order to secure a sufficient flexibility potential. This is particularly challenging to achieve in the context of numerous and sometimes contradictory policy goals and competing stakeholder interests.

Secondly, *the extent of possible change is ultimately constrained by local conditions and historical path dependencies.* For example, while nodal markets are widely

acknowledged to be the most economically efficient, the possibility of their introduction in the EU seems far-fetched, at least in the foreseeable future. And yet, legacy costs are tangible, so it is important to be able to look beyond straightforward solutions within the usual confines. The rapid energy sector evolution would certainly not have been possible without bold decisions and innovative research.

Thirdly, *market design changes are trial and error, there is no ultimate blueprint, so inefficiencies are unavoidable.* Not all changes are equally important or conducive to high gains in market efficiency. Given market design complexity, it is important to understand how exactly different changes (if they cannot be implemented all at once) can be prioritized to define a pathway based on efficiency considerations rather than ease of implementation or other less relevant factors. ABM can address these issues by creating an environment for experimentation in which trial and error can be conducted safely.

Fourthly, *not all strategic behavior constitutes market manipulation and abuse.* True-cost bidding can be discouraged by design, e.g., in pay-as-bid auctions. What also prevents true-cost bidding is in particular market uncertainty. It can be higher, for instance, due to long procurement times impairing forecasting capabilities of market actors, due to high price volatility or frequent regulatory changes. All these translate into higher risk premiums factored in the participants' bids or, in the worst case, drive flexibility from a market. It is crucial to understand the kind of incentives produced by different design variables (and other factors). The 'best' market design is the one where these incentives are best aligned with the goals of the system, market and energy policy.

Fifthly, *a close analysis of interrelated bidder strategies makes it evident that markets can hardly be considered or 'improved' in isolation; market actors do not act in them in isolation but tend to participate in several markets interconnected in time.* This is why in order to improve market performance it needs to be analyzed through the prism of the overall market landscape in order to avoid inconsistencies or, while attempting to fix an issue in one market, aggravating the situation in another one. It is hard to analytically assess these interactions, which makes market simulations particularly useful for this task.

10.4.2. Lessons learned from modelling electricity markets

Firstly, *in preparation for the modelling stages, be that ABM or optimization, conceptual frameworks such as the assessment framework presented in Chapter 2, actor interaction models in Chapter 3 or conceptualized market interaction models in Chapters 4 and 7 are highly useful tools.* They allow to identify crucial design variables, understanding market interdependencies and designing computer models. In addition, the assessment framework in Chapter 2 provided a structured decomposition of market design and analysis of three standard balancing products. It allowed the author to identify the design variables whose implementation should

be prioritized and greatly facilitated subsequent model-based analysis. Indeed, the assessment framework can be used in future research as a way to analyze future ancillary service markets, e.g., redispatch and flexibility markets.

Secondly, *the modelling stage itself is a careful balancing act between abstracting reality in order to keep computational time and complexity at bay and including enough detail to produce meaningful results and reveal important links.* Tasks that sound straightforward may end up requiring a significant modelling effort and vice versa whereas most often the conceptualization and design of different model elements is much more complex and time-consuming than the implementation itself. Another time-consuming process – regardless of the modelling approach – is the scenario definition and evaluation of results, which should be accounted for in research planning. Setting up meaningful scenarios, data analysis and its representation require a lot of skill and knowledge of both data science and the subject matter itself.

Thirdly, *machine learning provides exciting new opportunities to study strategic behavior in electricity markets.* In particular, the research presented in this dissertation is innovative as it embeds learning actors in the market environment. In contrast to other research that focuses on individual market participants or technologies, e.g., vRES or storage, that learn to generate profit in one or several markets, this research takes the market perspective and rather concentrates on improving the functioning of the market through preempting possible inefficiencies caused by price-distortive strategies. Although we use the previous knowledge from rational choice theory, neoclassical economic theory and game theory, we also show that they cannot fully anticipate the effects produced in multi-stage, multiple-round markets with heterogeneous actors. ABM with reinforcement learning representing actors learning from previous experience and available market information, we show, are more fit for purpose.

Finally, *no model can accurately predict possible exogenous factors, especially high-impact low-probability events, or fully replicate decision-making processes, let alone actors' internal heuristics or biases.* The assumptions that inevitably must be made in a model also have an important impact on the results and cannot be overlooked. This means that although good models are extremely useful at helping problem-owners make better informed decisions, they are an aid, not a substitute, for independent reasoning and their results should be taken with a (healthy) pinch of salt. Although the models developed during this dissertation are no exception, they fulfil the important tasks of advancing the understanding of the design of ancillary service markets and how their individual elements affect market outcome and efficiency. We trace the feedback loops between the macro and micro levels and vice versa. Methodologically, this dissertation advances the development of a whole array of modelling approaches, ABM, optimization and machine learning for electricity market analysis.

10.5. Suggestions for future research

The area of ancillary service markets is still far from fully explored. Moreover, more topics for future research emerge, as new regulatory changes are being introduced. The author proposes areas that will certainly benefit from further investigation.

Deepening and expanding balancing market analysis
The scope for future research has only broadened, precisely because of the depth attained in this dissertation: the next agenda point is the harmonization of the balancing capacity markets as well as of imbalance pricing. The analysis of the balancing market design itself is far from completed, considering its complexity, the effect of other design variables can be simulated and further investigated e.g., lead times or product duration. As mentioned earlier, there are in fact several balancing markets, one for each product, further subdivided into two directions. In this work, the author assumed a single balancing product, aFRR. In reality, many BSPs are prequalified for a number of balancing products. In the future, the research can be extended to study the interrelated bidding strategies of BSPs providing several products.

Imbalance pricing and balancing energy prices
Balancing markets are tightly interconnected with the imbalance settlement procedure. These are two faces of the same coin: total system imbalances provoked by out-of-balance BRPs are offset with BSP's resources through the balancing market and later financially settled with BRPs based on individual imbalances. The expected imbalance prices have been shown to affect both the BRPs' incentives to remain balanced but also their preferences between internal portfolio balancing versus service provision in the balancing market. While the imbalance price is in one way or another linked to the balancing energy price, it is in most cases not equal to the latter. Several researchers (e.g. [225], [226]) have argued that the imbalance price should reveal the *"true value of energy"* [175] and backpropagate to the other markets. As most research focused on either balancing or imbalance settlement and as harmonization of the latter is currently underway, this is an important moment to use new approaches to model the links between two.

Network tariffs and ancillary service provision
Over the years, the author learned from market actors that network tariffs are one of the major factors influencing their business case, especially when it comes to investing in and deploying new technologies. A lot of research has been dedicated to the study of network tariffs from a consumer perspective [227] or with regard to encouraging investment in renewables. If more flexibility is to be harvested for ancillary service provision from both supply and demand, both large-scale and small-scale, the importance of tariffs cannot be underestimated. System costs from balancing and redispatch are at least to an extent recovered through network tariffs. At the same time, some countries offer reduced tariffs to units providing system

services. These feedback loops between the incentive to provide ancillary services and network tariffs could provide another, often overlooked, dimension to the study of balancing and redispatch.

Modelling of future redispatch markets from the system perspective

From the point of view of modelling, the agent-based approach was considered inappropriate as the first step in making sense of the complex relations between the coupled markets and the network constraints. The latter become even more complex if flow-based market coupling is included. Therefore, multi-step optimization was conducted instead. This accomplished important preparatory work that did not just lead to useful insights but also provides the groundwork for future work in two ways. Firstly, the current approach to market coupling and redispatch as well as the proposed novel method have been tested on a small-scale network to ensure a better understanding of the results. Now that the main effects have been studied, the built model can be enhanced by a detailed network model in order to study additional effects and quantify the efficiency gains for a region. Second, modelling redispatch using agent-based modelling to study provider incentives and strategic bidding in future redispatch markets is certainly an interesting area of research. Due to its complexity, however, careful decisions need to be made as to which parts are better represented using ABM and which should be optimized instead e.g., using optimization of the electricity network and ABM to model markets and agent bidding.

TSO incentives are as important as market actor incentives

The TSO has several tools to address congestion, from long-term (grid reinforcement) to short-term measures (redispatch, non-costly remedial actions, countertrading) or even bidding zone redefinition. In the case of balancing, the TSO has only one recourse, activation of supply or demand. Based on its own incentives, the TSO may give preference to this or that type of measure. Since the TSO is a regulated entity, their cost recovery schemes and KPIs will affect ancillary service procurement. For instance, one of TSOs' typical KPIs is the number of blackouts or brownouts. If these are penalized, the TSO would ensure grid stability at all – even most exorbitant – costs before allowing a blackout. Balancing costs include the costs of balancing capacity and actually activated balancing energy, which have very different recovery schemes in the EU. If the cost of balancing is fully covered by the market actors, the TSO has no real incentive to reduce the costs of balancing. Similarly, if the full volume of redispatch is financed through grid tariffs, as is the case in most countries, the TSO would prefer redispatching over costly/CAPEX-intensive grid reinforcement. Future research could study the TSO side of ancillary service procurement and its links to innovation in incentive regulation.

Combining balancing and redispatch

In this dissertation, the first analysis of the relations between balancing and redispatch has been presented. As both of these services are gaining importance, modelling them in a single model is a promising area of future work. This should help to shed light on what kind of bidding strategies can be expected from flexibility

providers participating in both markets, to quantify the incentive to provide flexibility for either service or analyze the effect of potential strategic bidding.

Using a multi-modelling approach

Agent-based modelling has been shown to lend itself to combinations with machine learning. Similarly, interesting combinations of ABM and optimization can be explored. For instance, in Elba-ABM, the main focus was placed on market design and agent strategies. In the future, different technologies and their detailed constraints, such as ramp rates and start-up times, can be accounted for embedding per-unit or per-portfolio optimization into an ABM. This could be particularly useful in those markets where the technological landscape is rather homogeneous e.g., with predominant hydro power as the main provider of system flexibility (as in Austria, Sweden or Norway). Note, however, that new approaches will need to be developed to improve computational efficiency of the latter e.g., by creating a 'leaner' action space of the agents, in order to successfully combine such an ABM-optimization model with advanced decision-making using machine learning. Failing that, additional financial resources will be required to scale up the computational power available for the research.

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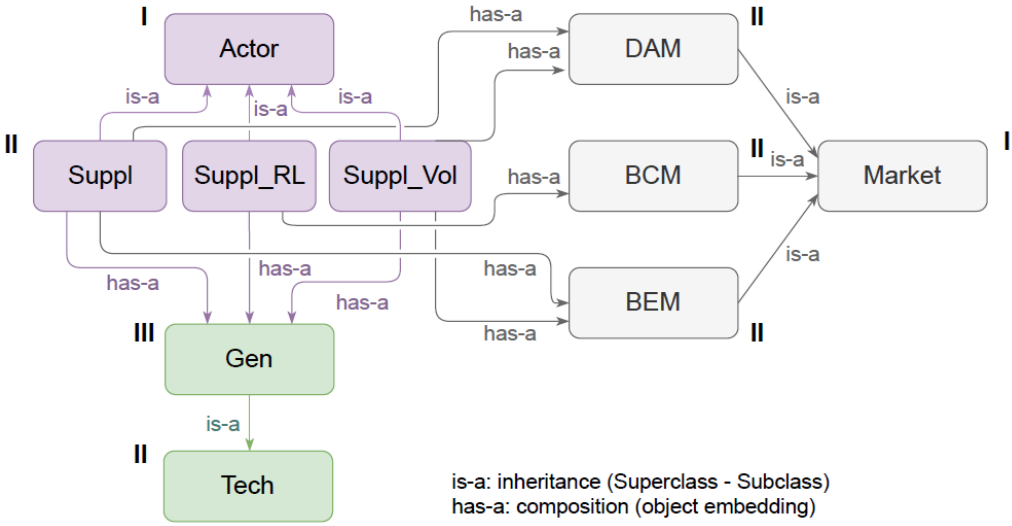
Appendix A - Structure of Elba-ABM



Elba-ABM is an agent-based model programmed in Python using the classical principles of object oriented programming. The model was organized around 3 class clusters:

1) *Markets:* Day-ahead (DAM), Balancing capacity (BCM) and balancing energy markets (BEM) inherit the main market attributes from generical class Market.
2) *Agents:* these represent market participants, balancing service providers (BSPs) and are embedded into the relevant market classes from the first cluster. Classes Suppl (true-cost bidding BSP), Suppl_RL (strategically bidding BSP) and Suppl_Vol (voluntary bidder in the balancing energy market) inherit the core agent attributes from the parent class Actor.
3) *Technologies:* Generation units are embedded into portfolios of agents in the second cluster. Class Tech is a generic class representing the main constraints of generation units, e.g. minimum load requirements. These technical attributes are inherited by class Gen that can stand for different technologies in an agent portfolio and be adjusted accordingly.

Appendix B - Algorithms used to represent reinforcement learning and rule-based strategies

Primer on reinforcement learning (RL)

In general terms, the RL algorithm is formulated in line with the main principles of Markov decision processes, as per [54]. In particular, at each time step k the agent is defined by a state s_k, takes an action a_k,and transitions from $s_k$to s_{k+1}following some probabilistic dynamics $p(s_k, a_k)$. In the transition, it receives a reward r_k following a distribution $q(s_k, a_k)$ that represents the profit of taking action a_k at state s_k. The goal of the agent is to first learn the optimal policy $a^* = \pi^*(s_k)$ during an exploration phase, i.e. training, and then use that policy during an exploitation phase, i.e. regular operation.

During the exploration phase, the policy is improved based on the agent's memory M that contains tuples of state, transitioned state, action taken, and reward collected during each transition:

$$M = \{s_k, a_k, s_{k+1}, r_k\}_{k=1}^{T_e}$$

During this exploration phase, the actions are chosen both at random and by using the current best available policy; by doing so, the agent explores new combinations (s_k, a_k) of state and action pairs and ensures that the ones that seem optimal so far are indeed the best. After the training is completed, the agent's optimal policy, $\pi^*(s_k)$ attempts to maximize the expected cumulative sum of rewards, R, over the entire episode, T_e:

$$R = \sum_{k=1}^{T_e} \gamma^{T_e - k} \; E_{q(s_k, a_k)} \; \{r_k\}$$

where γ is the discount factor and E is expected value.

Reinforcement learning for the balancing market

The RL algorithm used in this study is based on [228] and [229] and adapted to the balancing market model, Elba-ABM. Agents are embedded in the market environment, as is shown in the flow diagrams in Figure 5.3 and Figure 5.4.

The actions represent bid prices that can be submitted by the RL agent, for each

delivery period, k. Agent's step k, corresponds to the bidding period and is equal to one hour. Note that the system state, i.e. information the agent receives from the balancing market, is included in the agent state. As upward and downward regulation are procured in separate auctions, the agent's policies in these two markets are determined separately, i.e. we effectively consider a RL agent for the positive balancing market and another one for the negative balancing market.

For the sake of keeping a reasonable level of discretization and computation time, the maximum bid price is set to 10 times a generator's marginal costs (or 10 times less than a generator's costs in the negative market) whereas the action space is set to contain 50 actions per generator in the agent's portfolio: $A_g = \{a^1, \dots a^{50}\}\ g \in G$. For an agent with n generators, the action space has a size of:

$$C^R(50, n) = \frac{(50 + n - 1)!}{n!\,(50 - 1)!}$$

For instance, for a portfolio consisting of 3 generators, 19,600 possible combinations are considered.

At every step k and for each market clearing *i,* the agent receives some reward $r_{k,i}$ where bids are submitted on an hourly basis and the market is cleared every 15 minutes, $i = 1, 2, 3, 4$. In particular, if the imbalance is negative, the agent receives a reward $r_{k,i}$ equal to the market price, $\lambda_{k,i}^{+\mathrm{aFRR}}$ times the volume of awarded balancing energy $q_{k,i}^{+\mathrm{aFRR}}$. If the imbalance is positive, the agent receives a reward $r_{k,i} = \lambda_{k,i}^{-\mathrm{aFRR}} q_{k,i}^{-\mathrm{aFRR}}$.

Then, to define the reward at time step k, the agent of the positive market considers the average income during the periods where the positive market was cleared:

$$r_k^{+\mathrm{aFRR}} = \frac{1}{n^{+\mathrm{aFRR}}} \sum_{i \in \mathcal{N}_p} \lambda_{k,i}^{+\mathrm{aFRR}}\, q_{k,i}^{+\mathrm{aFRR}}$$

where $\mathcal{N}_p = \{i \mid i = 1, \dots, 4, I_{k,i} < 0\}$ and $I_{k,i}$ is the system imbalance for the market clearing i of time step k. This means that the reward in the positive market agent at times k is the average profit during the times when the system was short, so upward regulation was needed. The expression for the reward of the negative agents is the same. It is important to note that data in the memory *M* is only added if the specific (positive or negative) market is cleared. That is, if during transition from k to $k + 1$ only the -aFRR market is cleared, the equation above would indicate that the profit of the positive market was zero and vice verse for the +aFRR market.

In order to train the agents, we consider a balancing market simulation period of a year, during which the memory is updated. The RL agents are trained in the presence of other, non-RL agents, in the market, if they are part of the scenario. The agents are trained with the fitted Q-iteration [133], [135]. For the sake of simplicity and because the algorithm used is very standard, its mathematic details are not provided in this paper. However, the interested reader can consult [135] for further

information.

During the exploitation phase in the second year, the agent uses the collected information to bid optimally. Using the optimal policy, the RL agent takes an optimal action a_k^* for each state, defining the agent's bidding strategy:

$$a_k^* = \pi^*\left(\lambda_{k-1,4}^{+\text{aFRR}}, \dots \lambda_{k-1,1}^{+\text{aFRR}}, \lambda_{k-1,4}^{-\text{aFRR}}, \dots \lambda_{k-1,1}^{-\text{aFRR}}, \lambda_k^{\text{DA}}, q_{k-1,4}^{+\text{aFRR}}, \dots\ q_{k,i-1}^{+\text{aFRR}}, q_{k-1,4}^{-\text{aFRR}}, \dots\ q_{k-1,1}^{-\text{aFRR}}\ \right)$$

where λ_k^{DA} is the DA market price in the current hour.

Rule-based agent

The rule-based agent has a pre-defined strategy and is primarily used in the model for the calibration of the reinforcement learning agent.

The agent has a short-term memory of the previous success separately for each generator in his portfolio, expressed through binary variables, $d_{k,i}^{+\text{aFRR}} \in \{0,1\}$, $d_{k,i}^{-\text{aFRR}} \in \{0,1\}$, denoting whether the agent's generator was awarded in the positive or negative market per market clearing i in hour k. The strategy further differentiates between peak delivery hours, k^{peak}, and off-peak hours, k^{offpeak}: $K^{\text{peak}} = \{8, 9, \dots 16\} \not\ni\ k^{\text{offpeak}}$.

Then, based on the information saved in memory (see below), each generator uses and updates four coefficients, $\beta_{k-1}^{+\text{aFRR,peak}}$, $\beta_{k-1}^{+\text{aFRR,offpeak}}$, $\beta_{k-1}^{-\text{aFRR,peak}}$, $\beta_{k-1}^{-\text{aFRR,offpeak}}$, to build new bids. The bid for each market and each period is built by multiplying the coefficient by the marginal cost of the generators, c_g. The former is equal to 1.0 by default. Each of the four coefficients can vary between [0.5, 1.5] and they are updated following the following rule: if during the last eight positive market periods, i, the generator was awarded at least once per hour on average, i.e. the success ratio, $\omega^{+\text{aFRR,peak}} \geq 0.25$, the coefficients increase the bid markup by 5% or 10% in the off-peak or peak bidding period, respectively . To sum up, the bid price in the positive market is determined as follows:

$$b_{g,k}^{+\text{aFRR}} = \begin{cases} c_g * \beta_{k-1}^{+\text{aFRR,peak}} + 0{,}1, & if\ k \in K^{\text{peak}} \\ c_g * \beta_{k-1}^{+\text{aFRR,offpeak}} + 0{,}05, & if\ k \in K^{\text{offpeak}} \\ c_g * \dfrac{1 + \beta_{k-1}^{+\text{aFRR,peak}}}{2}, & if\ \omega^{+\text{aFRR,peak}} \leq 0.25 \end{cases}$$

Using the same 5% or 10% markups, the agent gradually reverts to true-cost bidding for those generator bids that were not awarded. Following a similar strategy in the –aFRR market, the coefficient is reduced by 5% or 10% if the condition is fulfilled.

For the rule-based agent in the *split BC-BE market*, the results of the previous two hours are memorized. For instance, for the peak periods in the positive market, the memory for each generator in the agent's portfolio contains:

$$M = \{\beta_{k-1}^{+\mathrm{aFRR,peak}},\ d_{i-8}^{+\mathrm{aFRR,peak}}, \dots\ d_{i-1}^{+\mathrm{aFRR,peak}}\}$$

where $\beta_{h-1}^{+\mathrm{aFRR,peak}}$ is the last coefficient used in the positive market in the peak period.

In the *joint BC-BE market,* the strategy is slightly adapted to account for the lower bidding frequency. The algorithm remains the same but, due to daily bidding, the results of the same hour but of the previous day are considered for the rule-based agent. The results of previous Friday are considered if the bidding takes place on a Monday. All hours of Saturday and Sunday are considered off-peak.

Appendix C - Agents and portfolios used in the simulation scenarios in Chapter 5

Total demand for aFRR capacity: ±200MW.

Scenario with an oligopoly

Agent ID	Generator ID	Variable costs, €/MWh	Installed capacity MW
1	a	10	170
	e	32	170
	i	55	170
	j	70	170
2	b	12	170
	f	35	170
	g	50	170
	k	72	170
3	c	15	170
	d	30	170
	h	52	170
	l	75	170

Scenario with a higher competition level

Agent ID	Generator ID	Variable costs, €/MWh	Installed capacity, MW
1	a	10	85
	h	31	85
	o	52	85
	v	73	85
2	b	11	85
	i	32	85
	p	53	85
	w	74	85
3	c	12	85
	j	33	85
	q	54	85
	x	75	85
4	d	13	85
	k	34	85
	r	55	85
	s	70	85
5	e	14	85
	l	35	85
	m	50	85
	t	71	85
6	f	15	85
	g	30	85
	n	51	85
	u	72	85

It is assumed that each generator can provide 10% of its capacity for balancing. The available balancing capacity of all generators slightly exceeds the set total BC

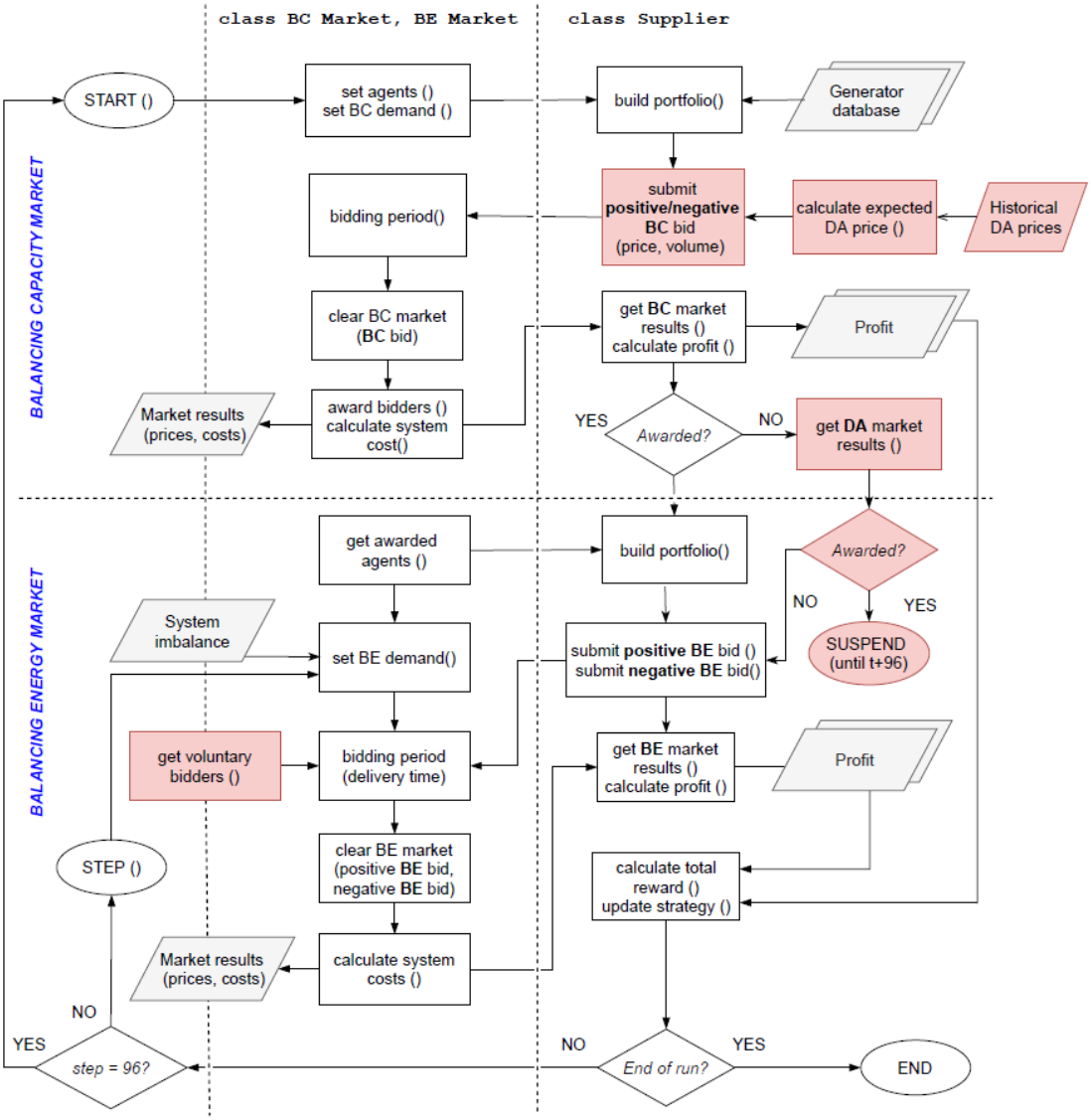
demand to ensure a specific number of participants in the subsequent BE market. Generator variable costs are approximated; the cost differences are kept low and each agent receives a generator in each cost category in order to eliminate portfolio effects on the market outcome.

Appendix D - Differences between the original Elba-ABM presented in Chapter 5 and the extended model presented in Chapter 6

Model characteristics	**Original Elba-ABM**	**Expanded Elba-ABM presented in this paper**
Modelling of the balancing capacity (BC) market	yes, rudimentary, all participants are assumed to have been awarded	yes, detailed, implementing all design variables,
Bidding frequency (BC market)	n/a	daily with hourly products
Asymmetric bids	no, only symmetrical	yes
Pricing rule	n/a (profits in the BC market are disregarded)	pay-as-bid
Bid components	n/a	bid volume and bid price, separately for positive and negative BC markets
Link to the day-ahead market?	no, focus on the BE market	yes (day-ahead market is exogenous)
Reinforcement learning used in the BC market	no	yes
Modelling of the balancing energy (BE) market	yes, detailed	yes, detailed
Bidding frequency (BE market)	Hourly with 15-minute market clearing	Hourly with 15-minute market clearing
Pricing rule	marginal or pay-as-bid	marginal (as per the GL EB)
Bid components	bid price	bid price
Voluntary bids	no	yes

allowed		
Reinforcement learning used in the BE market	yes	yes
Portfolio bidding	yes, each agent has a different set of generators	yes, each agent has a different set of generators

Appendix E - Detailed flow diagram of Elba-ABM model presented in Chapter 6



The model's balancing capacity market has been fundamentally elaborated to include multiple auction rounds in positive and negative directions. Besides, additional building blocks have been added to the model (marked in red) in order to establish a link between the BC market and the DA market and to allow 'second-chance' bidders and voluntary bidders.

Appendix F - Elba-ABM: Model assumptions

In the model, a number of assumptions were made about the market and the participants:

- There are several balancing products procured by the TSO, yet, in the model, it is assumed that participants can bid their available capacity only in the BC market for aFRR.
- To simplify, we assume that variable costs do not change over the simulation period and neither does plant availability (i.e. plant outages and maintenance are disregarded).
- Asymmetric bidding is assumed: BSPs can submit different volumes and prices to the positive and negative markets.
- All agents participating in the BC market are assumed to be prequalified.
- Technology-specific variable costs of the units in agents' portfolios are based on [180, S. 8].
- Four technologies are assumed to be able to provide aFRR, hydro, coal (as long as it is scheduled as a result of the DA market clearing), gas-fired power plants and combined-cycle gas turbines (CCGT). Unlike coal and gas turbines, hydro power plants do not have a minimum load requirement [20], [230, S. 192]. For coal-fired power plants, CCGT and gas turbines, minimum load requirement is assumed to be static, 40%, 30% and 10% of the total installed capacity, respectively, based on [204], [231], [232] (see Table A.1).
- Additional technical constraints of the simulated generations technologies such as ramp rates have been disregarded in the simulations.

Table A. 1. Assumed marginal costs and minimum load requirements of the technologies used in the simulations.

Technology	**Marginal cost, €/MWh**	**Minimum load**
Coal	28-60 €/MWh	40%
CCGT	40-55 €/MWh	30%
Gas	60-82 €/MWh	10%
Hydropower	1-2 €/MWh	-

Appendix G - Agents' portfolios used in the simulation scenarios in Chapter 6

Agent	Generator	Technology	Installed capacity, MW	Variable cost, €/MWh	Minimum load, %
Scenarios with true-cost bidders and a strategic bidder					
1 (true-cost bidder)	a	hydro	70	1	-
	f	coal	100	40	40
	g	CCGT	100	43	30
	j	gas	100	60	10
2 (strategic bidder)	b	hydro	70	1	-
	e	coal	100	35	40
	k	gas	100	65	10
	c	hydro	70	2	-
3 (true-cost bidder)	d	coal	100	28	40
	i	CCGT	100	55	
	h	CCGT	100	45	30
	l	oil	230	120	10
Scenarios with strategic bidders					
1 (strategic bidder)	a	hydro	60	1	-
	d	coal	120	30	40
	h	CCGT	120	55	30
2 (strategic bidder)	b	hydro	60	1	-
	f	coal	120	40	40
	g	CCGT	120	45	30
3 (strategic bidder)	c	hydro	60	2	-
	e	coal	120	35	40
	i	gas	120	60	10
4 (true-cost bidder)	j	oil	200	300	10
	k	oil	200	300	10

Voluntary bidder portfolio					
	Generator	Technology	Installed capacity, MW	Variable cost, €/MWh	Availability
5 (true-cost bidder)	y	wind	40	3	50-90%
	z	gas	60	60	50-90%

Appendix H - Summary of the simulation results in Chapter 6

all_TC - all true-cost bidders, TC_&_SB – true-cost and strategic bidders, all_SB – all strategic bidders

	all_TC	***TC_&_SB***			***all_SB***		
		no vol bids	*+vol*	*+vol & sec_chance*	*no vol bids*	*+vol*	*+vol & sec_chance*
Positive BC market costs, M€	8,9	8,6	10,1	8,9	23,4	251,5	438,6
Negative BC market costs, M€	3,7	10,4	9,2	13,2	210,1	91,5	102,9
Total BC market costs, M€	**12,6**	**19,0**	**19,3**	**22,1**	**233,5**	**343,0**	**541,5**
Positive BC market - profit (agent #2), M€	0,0	0,5	1,1	0,9	5,8	1,7	1,9
Negative BC market - profit (agent #2), M€	0,0	1,2	1,8	3,7	1,2	14,6	15,8
Total profit BC (agent # 2), M€	**0,0**	**1,7**	**2,9**	**4,6**	**7,0**	**16,3**	**17,7**
Positive BE market costs, M€	8,6	19,0	7,2	6,1	23,3	6,4	5,3
Negative BE market cost, M€	-2,6	-0,04	-5,0	-5,6	7,5	9,2	-4,7
Total BE market costs, M€	**6,0**	**18,9**	**2,2**	**0,5**	**30,8**	**15,6**	**0,6**
Positive BE market -	0,4	2,6	0,1	0,1	9,3	1,6	1,2

profit (agent #2), M€							
Negative BE market - profit (agent #2), M€	0,2	1,7	0,4	0,3	6,7	3,2	0,6
Total profit BE (agent #2), M€	**0,6**	**4,3**	**0,5**	**0,4**	**16,0**	**4,8**	**1,8**
Total balancing costs, M€	**18,6**	**37,9**	**21,5**	**22,6**	**264,3**	**358,6**	**542,1**
Positive BC market							
Weighted average price, €/MW	7,7	7,5	10,1	8,2	31,0	294,0	249,0
Share of bids ***below*** true costs, %	0%	16%	1%	3%	27%	9%	17%
Share of bids ***above*** true costs, %	0%	15%	17%	16%	40%	47%	42%
Negative BC market							
Weighted average price, €/MW	4,7	19,1	23,4	21,9	242,1	81,0	112,7
Share of bids ***below*** true costs, %	0%	11%	8%	3%	28%	11%	19%
Share of bids ***above*** true costs, %	0%	3%	14%	13%	37%	46%	43%
BE market							
Positive BE market, weighted average price, €/MWh	53,0	115,0	44,5	33,0	130,0	39,0	32,0
Negative BE market, weighted average price, €/MWh	16,0	0,3	29,0	36,0	-42,0	-4,0	27,0
Positive BE market, share of bids deviating	0%	46%	20%	11%	84%	54%	36%

from true costs, %							
Negative BE market, share of bids deviating from true costs, %	0%	35%	32%	12%	98%	78%	60%

Appendix I - Assumptions made in the optimization models presented in Chapter 8

The following model assumptions were made:

Regarding the grid:

- Lossless DC network.
- Outage scenarios are not considered.
- All zonal interconnectors and a few intra-zonal branches are included in the set of critical branches in FBMC;
- In case of congestion, other remedial actions (e.g. topological changes) or possible flexibility on the demand side are not considered.
- The redispatch action is energy-neutral within a zone, i.e. cross-border redispatch is not considered.

Regarding the market:

- For both zonal setups, zonal load is assumed not to change, as compared to the Base Case.
- It is assumed that all generation is traded on the day-ahead market, no long-term nominations or intraday market deviations from the day-ahead result are considered.
- For the sake of this analysis, generators are defined with fixed marginal costs.
- Demand is assumed to be inelastic.
- Perfect competition, no market power, i.e. generators bid their marginal costs.
- Intertemporal constraints are disregarded.

Appendix J - Notation used in Chapter 8

Scenario parameters

$\boldsymbol{b} \in \{\mathbf{1}, \dots, \boldsymbol{B}\}$	branches
$\boldsymbol{b} \in \boldsymbol{CB}$	critical branches
$\boldsymbol{b}^{\mathrm{IC}} \in \boldsymbol{B}^{\mathrm{IC}}$	Zonal interconnector branches
$\boldsymbol{c_g}$	Marginal costs of generator g [€/MWh]
$\boldsymbol{D_g^{\max}}$	Maximum dispatch of generator g [MW]
$\boldsymbol{F_b}$	maximum flow on branch b (=maximum thermal limit) [MW]
$\boldsymbol{FRM}$	flow reliability margin [MW] (assumed to be 0)
$\boldsymbol{g} \in \{\mathbf{1}, \dots, \boldsymbol{G}\}$	generators
$\boldsymbol{G_n}$	set of generators on node n
$\boldsymbol{G^{disp}}$	set of dispatchable generators
$\boldsymbol{G^{non-disp}}$	set of non-dispatchable generators
$\boldsymbol{k_{n,b}} \in \boldsymbol{K}$	*N x S* incidence matrix
$\boldsymbol{l_n}$	electrical load at node n [MW]
$\boldsymbol{n} \in \{\mathbf{1}, \dots, \boldsymbol{N}\}$	nodes
$\boldsymbol{N_z}$	set of nodes in zone z
$\boldsymbol{S}$	diagonal *S x S* matrix of branch susceptances
$\boldsymbol{s}^{\mathrm{IC}}$	Share of interconnector capacity
$\boldsymbol{z} \in \{\mathbf{1}, \dots, \boldsymbol{Z}\}$	zones
$\boldsymbol{\gamma}$	cost-based penalty coefficient for redispatch
$\boldsymbol{\lambda}$	volume-based penalty coefficient for redispatch

Model internal parameters

$\boldsymbol{d_g^{\mathrm{MO}}}$	dispatch of generator g that would have resulted from purely merit-order activation used in the Zonal IRD model [MWh]
$\boldsymbol{d_g^{\mathrm{ref}}}$	dispatch of generator g in the Base Case [MWh]
$\boldsymbol{f_b^{\mathrm{ref}}}$	reference flow on branch b in the Base Case [MW]
$\boldsymbol{GSK_{n,z}}$	generation shift key of node n in zone z
$\boldsymbol{GSK_{n,z}^{\mathrm{IRD}}}$	generation shift key of node n in zone z in zonal IRD model
$\boldsymbol{k_z^{\mathrm{FBMC}}}$	Zonal market price in zone z in the business-as-usual model
$\boldsymbol{p_z^{\mathrm{ref}}}$	reference power injection in zone z in the Base Case [MW]
$\boldsymbol{PTDF_{b,n}^{\mathrm{nod}}}$	nodal PTDF on branch b for node n
$\boldsymbol{PTDF_{b,z}^{\mathrm{zon}}}$	zonal PTDF on branch b in zone z
$\boldsymbol{RAM_b}$	remaining available margin on a critical branch [MW]

Decision variables

$\boldsymbol{C^{\mathrm{IRD}}}$	cost of units used for integrated redispatch in the Zonal IRD

	model [€]
$\boldsymbol{d_g}$	dispatch (i.e. electricity production) of generator g [MW] in the nodal and business-as-usual models
$\boldsymbol{d_g^{\mathrm{DA}}}$	generation offered by unit g on the day-ahead market [MW]
$\boldsymbol{d_g^{\mathrm{IRD}}}$	actual dispatch *after* accounting for IRD in the zonal IRD model
$\boldsymbol{d_z}$	total dispatch of all generators in zone z [MW]
$\Delta\boldsymbol{d_g^{\mathrm{ERD}}}$	generation after *ex-post* redispatch [MW] in the business-as-usual model
$\Delta\boldsymbol{d_g^{\mathrm{IRD}}}$	Change of dispatch due to the activation of IRD [MW] in the Zonal IRD model
$\Delta\boldsymbol{d_g^{\mathrm{neg}}}$	change of dispatch due to downward regulation due to redispatch [MW]
$\Delta\boldsymbol{d_g^{\mathrm{pos}}}$	change of dispatch due to upward regulation due to redispatch [MW]
$\Delta\boldsymbol{d_z}$	change of generation per zone as compared to the Base Case [MW]
$\boldsymbol{f_b}$	flow on branch b [MW]
$\boldsymbol{f_b^{\mathrm{FBMC}}}$	flow on branch b resulting from FBMC [MW]
$\boldsymbol{f_b^{\mathrm{IRD}}}$	flow on branch b resulting from IRD approach [MW]
$\boldsymbol{NEX_z}$	net export position of zone z [MW]
$\boldsymbol{p_n}$	total active power injection at node n (generation – demand at that node) [MW]
$\Delta\boldsymbol{p_z^{\mathrm{ref,IRD}}}$	change in zonal generation as compared to the Base Case value in the Zonal IRD model [MW]

List of Publications

(publications marked with an asterisk (*) form the basis for this dissertation)

Articles in scientific journals

1. * K. Poplavskaya, L. De Vries:
   "*Distributed energy resources and the organized balancing market: A symbiosis yet? Case of three European balancing markets*"; Energy Policy, **126** (2019), pp. 264 - 276.

2. S. Cejka, F. Zeilinger, P. Stern, M. Stefan, K. Poplavskaya, G. Taljan, J. Petek:
   "*Datenschutz in Blockchain-basierten Erneuerbaren-Energie-Gemeinschaften*"; Jusletter IT, **26** (2019).

3. * K. Poplavskaya, J. Lago, L. De Vries:
   "Effect of market design on strategic bidding behavior: Model-based analysis of European electricity balancing markets"; Applied Energy, **270** (2020), pp. 115-130.

4. * K. Poplavskaya, G. Totschnig, F. Leimgruber, G. Doorman, G. Etienne, L. De Vries:
   "Integration of day-ahead market and redispatch to increase cross-border exchanges: Model-based proof of concept"; Applied Energy, **278** (2020), 115669.

5. J. Lago, K. Poplavskaya, G. Suryanarayana, B. De Schutter:
   "A market framework for grid balancing support through imbalances trading"; Renewable and Sustainable Energy Reviews (2020), 110467

6. * K. Poplavskaya, J. Lago, S. Strömer, L. De Vries:
   "Making the most of short-term flexibility: Opportunities and challenges of voluntary bids in the balancing market for electricity" (under review); Energy Policy (2021).

Book chapters

1. K. Poplavskaya, L. de Vries:
   "Aggregators today and tomorrow: From intermediaries to orchestrators?", in: Sioshansi, F. (Ed.), Behind and Beyond the Meter. Digitalization, Aggregation, Optimization, Monetization, 1. Academic Press, Elsevier, Amsterdam, 2020.

Conference papers

1. K. Poplavskaya:
   "*Dreieck "Lieferant - Aggregator - Bilanzgruppenverantwortlicher" im*

österreichischen Strommarkt";
Conference proceeding of the 15th Symposium on Energy Innovation (Symposium Energieinnovation), **15** (2018), pp. 1 - 12.

2. K. Poplavskaya, L. De Vries:
"*To Pool or not To Pool? A Level Playing Field for Distributed Energy Resources in European Balancing Markets*"; IAEE Energy Forum, Groningen Special Issue (2018), pp. 17 - 18.

3. * K. Poplavskaya, L. de Vries:
"*A (not so) Independent Aggregator in the Balancing Market Theory, Policy and Reality Check*";
in: "*Proceedings 2018 15th International Conference on the European Energy Market (EEM)*", IEEE, New York, 2018, ISBN: 978-1-5386-1488-4, 6 p.

4. * K. Poplavskaya, F. Ocker, K. Ehrhart:
"*Impact of short-term market sequences on bidding behavior of market participants*"; 3rd European GRID SERVICE MARKETS Symposium, Lucerne, Switzerland; 03.07.2019 - 04.07.2019; in: "*Proceedings of 3rd European GRID SERVICE MARKETS Symposium*", (2019), Paper-Nr. 0402, 13 p.

5. E. Kraft, N. Lehmann, J. Huber, K. Poplavskaya: "*Klassifizierung und Bewertung von Aggregationsstrategien für heutige und zukünftige Geschäftsmodelle*", (2020) in: Zukünftige Stromnetze. Conexio, Pforzheim, Berlin, pp. 291–309.

6. * K. Poplavskaya, M. Joos, V. Krakowski, K. Knorr, L. de Vries:
" *Redispatch and balancing: Same but different. Links, conflicts and solutions*";
in: "*Proceedings 2020 17th International Conference on the European Energy Market (EEM)*", IEEE, New York, 2020, ISBN: 978-1-7281-6919-4/20, 6 p.

7. S. Cejka, A. Einfalt, K. Poplavskaya, M. Stefan, F. Zeilinger: *"Planning and operating future energy communities"*, (2020) in: CIRED 2020 Berlin Workshop. Berlin, Germany.

8. S. Cejka, K. Poplavskaya, M. Stefan, C. Monsberger: *"Blockchain technology and peer-to-peer trading in energy communities: A regulatory perspective"*, (2021) in: Frist IAEE Online Conference.

9. A. Fazeli, M. Stadie, M. Kerner, H. Nagaoka, J. Kapeller, J. Kathan, K. Poplavskaya, A. Burger, F. Jomrich: *„ A Techno-economic Investigation for the Application of Second-Life Electric Vehicle Batteries for Behind-The-Meter Services",* (2021) in: the 9th international conference on Smart Energy Grid Engineering.

Presentations and invited talks

1. K. Poplavskaya:
"*A Comparative Analysis of the Balancing Market Design Choices in Germany, Austria and the Netherlands*";
Presentation: PRIBAS Workshop on Multi-Market Modelling, Trondheim, Norway (invited); 02.09.2018.

2. K. Poplavskaya:
"*Impact of balancing market design on business case for storage*";
Presentation at the seminar "Business Models and Regulation for Storage", Brussels, Belgium (invited); 30.11.2018.
3. K. Poplavskaya, L. de Vries:
"*How to integrate distributed energy resources (DER) into European balancing markets?*";
Presentation at the 2nd Young Researcher Seminar 2018 on Market Design and Grid Regulation, Florence, Italy (invited); 03.07.2018 - 04.07.2018.

4. K. Poplavskaya, L. de Vries:
"*To Pool or not To Pool? A Level Playing Field for Distributed Energy Resources in European Balancing Markets*";
Presentation at 41st IAEE International Conference, Gronigen, NL; 11.06.2018 - 15.06.2018.

5. K. Poplavskaya, M. Stefan, S. Cejka:
"*Rechtliche Aspekte in Energy Communities. Regulatorische Bedingungen und Potenzial in Österreich*";
Invited talk at the meeting of the Technology Platform Smart Grids Austria, Graz; 20.11.2019.

6. K. Poplavskaya, M. Stefan, K. de Bruyn:
"*Energy Communities: Technische Lösungen versus rechtliche/regulatorische Rahmenbedingungen*";
Presentation at the 10th Symposium Communications for Energy Systems (ComForEn), Wien, Österreich; 14.10.2019 - 15.10.2019.

7. K. Poplavskaya, G. Totschnig, F. Leimgruber, L. de Vries, G. Doorman:
"*Optimizing Congestion Management by Integrating Redispatch into the Day-ahead Markets*";
Presentation at the 16th IAEE European Conference, Ljubljana, Slovenia; 25.08.2019 - 28.08.2019.

8. K. Poplavskaya:
"*Renewable Energy Communities: Implementation, Impact, Chances*";
Invited talk at the panel discussion at E-World, Essen, Germany; 13.02.2020.

9. K. Poplavskaya:
"Welcoming new entrants in electricity markets";
Invited talk at the panel discussion at FSR Insights by Florence School of Regulation, online; 24.02.2021

10. K. Poplavskaya, J. Lago, L. De Vries:
"The effect of voluntary bids on balancing market efficiency: Simulation-based analysis";
Presentation at First IAEE Online conference, online; 09.06.2021

Reports

1. K. Poplavskaya, W. Friedl, J. Kathan, K. De Bruyn, 2019. *Realization in the Existing Legal and Regulatory Framework.* Work Package 4.3 of Project LEAFS (Integration of loads and electric storage systems into advanced flexibility schemes for LV networks).

2. J. Kathan, K. Poplavskaya, W. Friedl, 2019. *Regulatory Gap Analysis.* Work Package 8 of Project LEAFS (Integration of loads and electric storage systems into advanced flexibility schemes for LV networks).

3. K. Poplavskaya, G. Totschnig, F. Leimgruber, Jan. 2019. *Optimizing congestion management for improved cross-border exchange with integrated redispatch*, Project report commissioned by ENTSO-E.

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5. D. Bauknecht, I. Gianinoni, J. Heeter, N. Kerkhof-Damen, O. Pascoe, U. Peyker, K. Poplavskaya, 2019. *Casebook on Innovative Regulatory Approaches with Focus on Experimental Sandboxes.* International Smart Grids Action Network (ISGAN).

6. K. Poplavskaya, N. Pardo, R. Bründlinger, T. Strasser, W. Friedl, 2019. *Smart Grids for Renewable Energy and Energy Efficiency*. Report commissed by the GIZ (Deutsche Gesellschaft für internationale Zusammenarbeit) and ERAV (Energy regulator of Viet Nam).

7. K. Poplavskaya, M. Stefan, 2019. *Regulatory analysis and proposal.* Work package 3 of project Blockchain Grid.

8. K. Poplavskaya, M. Joos, V. Krakowski, K. Knorr, 2020. *Regulatory analysis and market interaction*. Work package 3 of project REgions (Era-Net SG), dealing with the integration of renewable energy resources into ancillary service provision (balancing and redispatch).

9. B. Fina, H. Fechner, T. Esterl, P. Albinger, D. Reihs, K. Poplavskaya, 2020. *Handbuch Energiegemeinschaften. Empfehlungen zur rechtlichen und regulatorischen Umsetzung* (Handbook on Energy Communities. Report commissioned by the Austrian Klima- und Energiefonds).

10. B. Iglar, C. Monsberger, K. Poplavskaya, T. Esterl, 2020. *Report of market gaps and market opportunities*. Deliverable 7.1 of project CleanEnergy4Tourism.

11. K. Poplavskaya, F. Leimgruber, 2021. *Analysis of the Swedish FCR-N market design. Effects of transition to marginal pricing and free bidding.* Report commissioned by Svenska kraftnät.

Multiple client studies on new business models for distributed energy resources, congestion management, balancing, electricity market analysis in and beyond the EU.

Curriculum Vitæ

Ksenia Poplavskaya

Ksenia Poplavskaya is a research engineer at the Austrian largest research organization, AIT Austrian Institute Technology, Center for Energy, department of Integrated Energy Systems. Since 2017, she has in parallel been working on her PhD at Delft University of Technology, Faculty of Technology, Policy and Management. Since end of 2020, she is also part of ACER′s expert group on wholesale energy market trading. Ksenia′s main areas of expertise include short-term electricity and ancillary service markets, regulation of the electricity sector and business model innovation. For the last five years, in her research and project work she has been exploring design questions of interrelated electricity and ancillary service markets, bidding strategies and business models of market participants based on different modelling approaches (agent-based modelling with machine learning and optimization). Ksenia Poplavskaya has led and contributed to multiple national and international studies by providing analysis of electricity market rules and regulatory frameworks. She holds an MSc (Hons) in Environmental Technology and International Affairs from the Technical University of Vienna and the Diplomatic Academy of Vienna, Austria, and an MA (Hons) in English and German Language Studies from Lipetsk State University, Russia.