A New Market Design For Balancing and Redispatch

Evaluation of New Market Design Options for Integrating Balancing and Redispatch in the Dutch Electricity Market

Master Thesis

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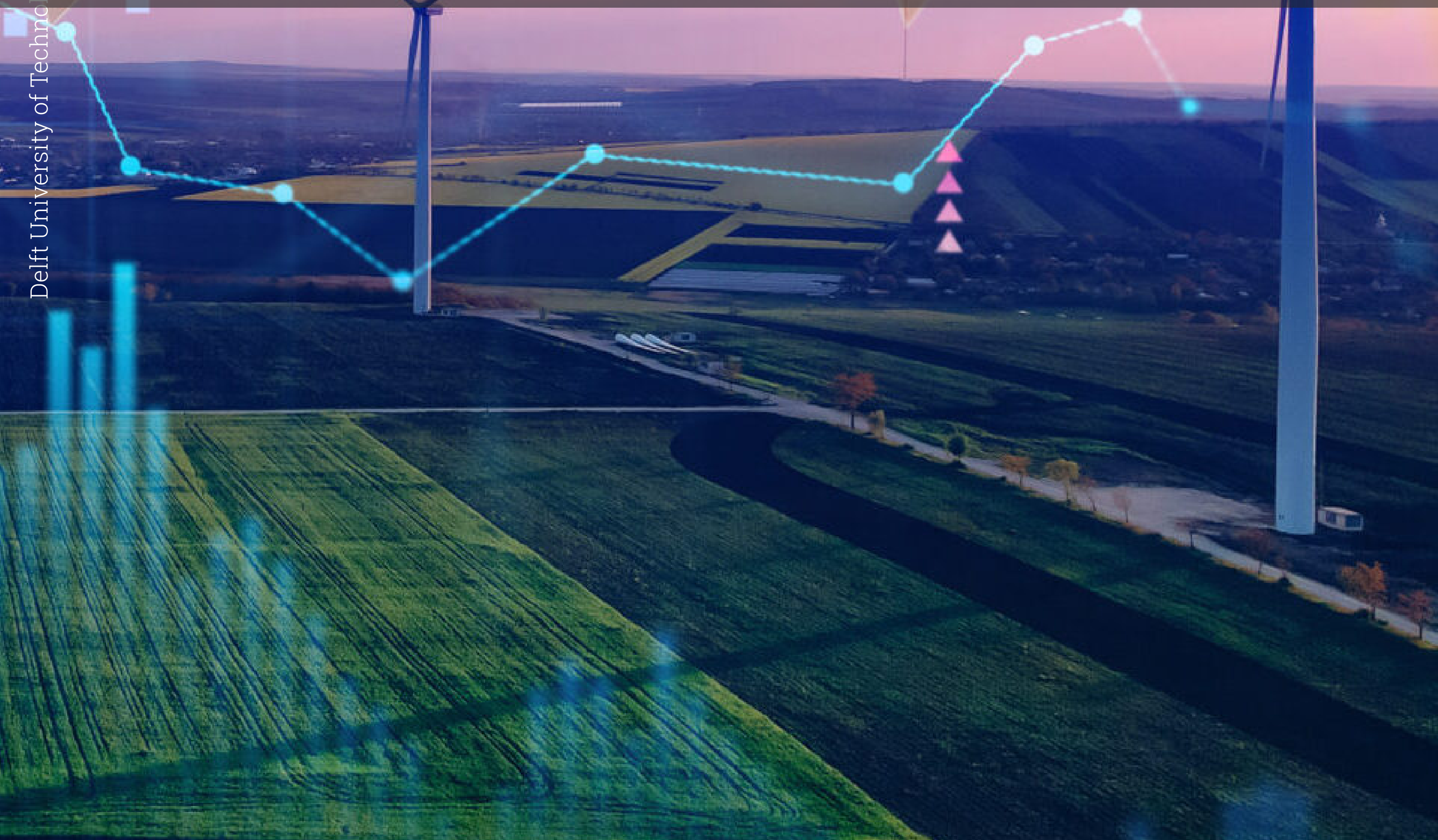

TU Delft

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by

Laura Stok

to obtain the degree of Master of Science

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Cover image (Zeeuwind, 2024)

TU Delft

Preface

This thesis marks the end of my time as a student at Delft University of Technology. Looking back, I feel grateful for the experiences and learning opportunities over the past few years. It was during this time that I developed a strong interest in the energy sector, especially as renewable electricity takes on a bigger role in the market. One of the key challenges now is increasing flexibility in the electricity system. I'm thankful to have had the chance, in the final phase of my studies, to immerse myself in the complex dynamics of electricity markets and explore these critical issues.

This project has been both challenging and rewarding, with its technical aspects and its potential to contribute to real-world solutions. I'm glad to have worked on this topic and to have been part of something that could have a positive impact.

I was also fortunate to conduct my thesis at TenneT, a major player in the energy sector with a central role in the energy transition. Working with TenneT was a great experience and provided me with valuable insights from industry experts.

I'd like to thank those who supported me during this project. First, a big thank you to Pieter Bots for giving me the opportunity to work on this project and for your guidance along the way. Your enthusiasm for the subject and your willingness to take the time to review the simulation model have been incredibly helpful. I also appreciate your effort in expanding the optimization tool to suit the needs of this project. I'd also like to thank Sander Renes for helping me understand the economic perspective and for always being available when I needed advice. Lastly, I'm grateful to Martijn Ophuis at TenneT for your support and expertise, which were essential for my research. Your knowledge has been essential to the success of this research, and I have learned a great deal from you.

Laura Stok
Delft, September 2024

Executive Summary

The increasing integration of non-dispatchable renewable energy sources and the rising electrification of society pose significant challenges to the stability and efficiency of electricity grids. Managing these challenges requires enhanced flexibility in the power system. In the Dutch high voltage grid, this flexibility is provided through balancing and congestion management services, both managed by the Transmission System Operator (TSO), TenneT. Currently, these services operate as two separate markets, where market participants bid their flexible capacity to either inject or withdraw energy from the system. However, the current market design has several issues, including competition for the same capacity, inaccurate price signals, and increased congestion due to balancing without accounting for transport constraints. Enhancing these markets could enable more flexibility to facilitate the needs of the future power system. Although there are numerous studies on new market designs for redispatch and balancing, there is a lack of quantitative evaluations, highlighting the need for modeling approaches in this area. This thesis addresses this gap by providing a quantitative evaluation of new market designs aimed at integrating balancing and redispatch services in the Dutch electricity market. The study assesses the performance improvements of various market design options compared to the current design, focusing on three key performance indicators (KPIs): total costs for resolving congestion and imbalance, required flexible capacity, and average market prices.

Three new market design options were developed:

1. Market design option 1: Simultaneous co-optimization with net capacity use
2. Market design option 2: Separate 2-step optimization with net capacity use
3. Market design option 3: Separate 2-step optimization with gross capacity use

Each design integrates redispatch and balancing capacity into a single 'flex product' and considers transport constraints. Market design 1 is considered an optimal solution, demonstrating the potential benefits of full co-optimization without the limitations of current technical and operational constraints. In contrast, design options 2 and 3 perform separate optimization. These designs account for these operational limitations, making it challenging to perform redispatch and balancing simultaneously. In market design 2, net capacity usage is implemented, while in market design 3, gross capacity usage is applied. Net capacity usage refers to adjusting the activated redispatch capacity in the opposite direction (e.g., ramping up followed by ramping down) during the balancing step to resolve imbalances. This adjustment leads to a reduction in the overall net capacity used. In contrast, gross capacity usage means that capacity cannot be adjusted, requiring new capacity to be activated for balancing. A simulation model for each design option was developed using the Linny-R optimization program. All market designs were evaluated under different pricing approaches, including Marginal Pricing (MP), Locational Marginal Pricing (LMP), and Pay-As-Bid (PAB). Resulting in a total of eleven market design variations. A simulation model was developed for each design variation, along with the current market design.

The simulations were conducted using a small electricity network with six nodes, selecting the variables to ensure a feasible solution, as a real electricity system is expected always resolve congestion and imbalances. This small network allowed for close monitoring of energy flows and detailed analysis of system behavior. The simulations generated values for each KPI, which were converted into percentage improvements. Table 1 presents these performance improvements for each KPI across different market designs compared to the current market design.

Reduction in:	1: Co-optimization, net capacity			2: Separate optimization, net capacity				3: Separate optimization, gross capacity			
	MP	**PAB**	**LMP**	**MP**	**PAB**	**LMP**	**PAB + MP**	**MP**	**PAB**	**LMP**	**PAB + MP**
Required flexible capacity	21%	21%	21%	17%	14%	17%	12%	0%	0%	0%	0%
Average market price	38%	-4%	42%	8%	-7%	23%	-19%	20%	-6%	32%	-5%
Total costs	55%	39%	57%	13%	32%	22%	0%	16%	21%	31%	7%

Table 1: Relative improvements [%] in market design performance compared to the current market design for each KPI

The results suggest that co-optimising redispatch and balancing can reduce capacity needs by 21% compared to the current market design. However, 81% of this improvement can be achieved by only introducing a flex product that integrates redispatch and balancing along with net capacity usage, indicating that co-optimization is not essential for capacity improvements. Furthermore, all new market designs show either a reduction or no increase in total costs, indicating that capacity savings are enough to offset some of the higher market prices.

The simulation model showed that the market design using co-optimization led to a 21% reduction in the required flex capacity compared to the current market design. However, 81% of this improvement can be realized by only introducing a flex product that integrates redispatch and balancing, along with implementing the net capacity approach. This suggests that co-optimization is not essential to achieve capacity improvements; integrating redispatch and balancing products together with net capacity calculation can lead to significant gains. It also highlights the significant impact of the current separation between redispatch and balancing capacities, which prevents them from being used interchangeably, thereby increasing the required capacity to address imbalances and congestion. The design using separate optimization steps takes operational constraints into account, making it a more practical solution.

While the simulations show promising results for introducing a flex product with two-step optimization, these findings should be put in perspective. The use of a simplified small electricity system and the specific selected values for variables limits the generalizability of the results. A sensitivity analysis showed that factors such as load, imbalance levels, and available flexible capacity influence results on required capacity reduction. But it still represented an improvement and the small difference in required capacity between co-optimization and separate optimization with net capacity remained consistent. However, the variables had a greater impact on the average price and total costs, leading to higher costs than the current market design in some cases. Another consideration when interpreting the results is that the small electricity network used in the simulation increases the likelihood of capacity being used for both redispatch and balancing, which leads to lower net capacity. As a result, the outcomes might not be as favorable if the simulation were conducted on a larger network.

In conclusion, this study suggests that co-optimization is not essential for capacity improvements; integrating redispatch and balancing with net capacity calculations can significantly reduce capacity needs. Since implementing co-optimization in a single timestep poses operational and technical challenges, the promising results of two-step optimization demonstrate that this approach can be a practical and valuable option for the TSO to consider. However, further research into alternative settlement methods is needed, as using the highest market clearing price results in relatively high costs, though still lower than those of the current model. Additionally, the study demonstrated that a simplified small electricity network can effectively show the benefits of new market designs over the current one. Despite the chosen variables affecting outcomes, the performance ranking of market designs remained consistent, and the small difference in required capacity between co-optimization and separate optimization with net capacity was not significantly impacted by these variables. Instead, geographical factors and network scale have a greater influence.

Future research should explore the operational feasibility of integrating redispatch and balancing into a single flex product, including handling different product characteristics and developing a unified interface and consistent pre-qualification process. Additionally, testing the design options with market participants would provide valuable insights into their bid behavior and anticipated risks. And expanding the simulation to cover the entire national grid would offer a more comprehensive assessment of these market designs and their real-world applicability.

Contents

1
Introduction

1.1. Balancing and redispatch services

Flexibility of the power system is seen as the key to coping with some of the challenges in the future power system, both to handle the changing power system and enable the energy transition (European Union Agency for the Cooperation of Energy Regulators, 2023). Due to the increased integration of non-dispatchable forms of generation and the higher rate of increase in peak load demand compared to total energy, flexibility resources are becoming an attractive solution (Sæle et al., 2020). Another reason for more flexibility is the growing appearance of congestion as a result of the growing number of producers and consumers of electricity due to the electrification ambitions. With flexible electricity, more space become available on the grid (TenneT, 2024b).

In the context of the Dutch high voltage grid, flexibility is provided through balancing and congestion management services, both overseen by the Transmission System Operator (TSO) TenneT. Both services are currently organized as two separate markets, where market participants bid their flexible capacity to either inject or withdraw energy from the system. Although the redispatch market and balancing market share the goal of ensuring a stable and reliable energy supply, the separate markets can conflict with each other (Poplavskaya et al., 2020):

1. First of all, both markets compete for the same capacity. Market participants need to choose to offer their capacity on the balancing market or the redispatch market. Besides the opportunity costs it creates for market participants, it leads to an uneven division of capacity between the two markets. Especially, since balancing is a more attractive option for providers (Poplavskaya et al., 2020). This led to scenarios where there is no capacity available for redispatch, resulting in high costs, while there was flexible capacity on the imbalance market (ACM, 2022).
2. Additionally, the two separate auctions on separate platforms make it complex for market participants to participate in both auction. It is complex - particularly for smaller parties - to be involved in both auctions and to have a clear overview what the economic benefits are. Here, the TSO misses out on possible flexibility resources for either balancing or congestion management.
3. Furthermore, transport constraints are currently not considered during balancing operations. This means that congestion can be caused by activating balancing energy. With the anticipated rise in congestion, this approach is suboptimal and leads to higher costs for congestion management.
4. Another drawback is that, during congestion, imbalance prices may provide misleading signals. Because transport constraints are not considered in the balancing market, incorrect price signals can be sent in congested regions. These prices should be structured to provide accurate incentives to market participants (Chaves-Ávila et al., 2014; Roques, 2008).
5. And vice versa, imbalance is not considered during redispatch operations. Most redispatch activations are 'balance-neutral'. If this balance-neutral requirement is not considered, a redispatch activation could help solving an imbalance, potentially reducing the amount of capacity needed to solve both congestion and imbalance issues.

1.2. A new market design integrating balancing and redispatch

Given the conflicts of the balancing market and the redispatch market, it could be argued that integrating these services into a single market will enhance its effectiveness. Currently, market participants can choose themselves to offer capacity for balancing or redispatch purposes. In a new integrated market design, market participants will offer 'Flex Capacity' in a unified market, allowing TenneT to allocate this capacity to address both congestion and imbalance issues. Figure 1.1 visualises this new integrated market design.

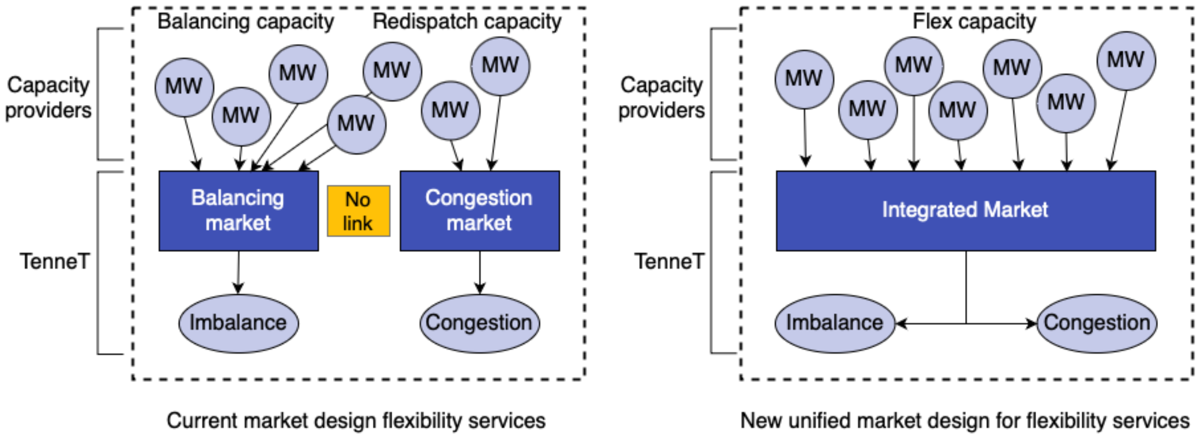

Figure 1.1: Current and new market design

1.3. Introducing co-optimization in the market design

Multiple studies discuss the advantages of co-optimising balancing and congestion management services, noting that it will enhance flexibility (McCulloch et al., 2023; Rieß et al., 2017) and increase overall economic benefits (Rieß et al., 2017; Poplavskaya et al., 2020). In a market design with co-optimization, congestion and imbalances are addressed simultaneously rather than separately. The advantage of this co-optimization is that the same capacity can be used to manage congestion through redispatch while also resolving imbalances. This can lead to a reduction in capacity needs. Given these benefits, one might wonder why this hasn't been implemented yet. The primary challenge is the complexity of integrating the two markets for co-optimization, given their different time schedules and different characteristics. In general, congestion issues are known in advance. In contrast, balancing must be dealt with in real-time. This limits the extent to which balancing and redispatch can be co-optimised in advance of real time (Norwegian Water Resources and Energy Directorate, 2019). It is essential to explore the potential benefits of co-optimization compared to keeping optimization steps separate. While co-optimization may lead to efficiency gains, integrating the markets while maintaining separate optimization steps could be easier to implement with fewer adjustments. This highlights the importance of understanding the performance improvements of market integration without co-optimization in a single timestep compared to the current market. Additionally, examining different pricing approaches and their effects on market outcomes helps to understand how to maximizing the benefits of integrating balancing and redispatch markets.

1.4. Research gap

Within the existing literature, a distinction exists between conceptual studies (McCulloch et al., 2023; Poplavskaya et al., 2020; Rieß et al., 2017; Chaves-Ávila et al., 2014) and those offering quantitative modeling results (Håberg et al., 2019; Poplavskaya, 2021). However, Poplavskaya (2021) examined designs by evaluating their impact on service providers' incentives and average market price. And Håberg et al. (2019) created a model for a market design where congestion was considered during balancing. These quantitative evaluations do not focus on capacity savings or co-optimization. The scarcity of quantitative evaluations highlights the need for modeling approaches in this research area. Both Rieß et al. (2017) and Poplavskaya (2021) emphasize the importance of such quantitative evaluations for understanding efficiency, cost distribution, and incentives in combined designs for balancing and redispatch services. As mentioned by Poplavskaya (2021), the area of ancillary service markets is generally still far from fully explored in the literature. This study aims to fill this gap by providing a quantitative evaluation.

1.5. Research question and sub-questions

The objective of this study is to perform a quantitative evaluation of new market designs integration redispatch and balancing services. Different market designs are developed, focusing on whether to use co-optimization or not, and whether to calculate total net capacity or gross capacity. While introducing a flex product and considered transport constraints.

Therefore, this study aims to answer the following research question:

How much performance improvement can be achieved with a new market design that integrates redispatch and balancing, with and without co-optimization, across various pricing scenarios?

The following three sub-questions are formulated to answer the main research question:

1. What are the possible options for market integration, and which ones should be included in the new design?
2. What are the possible options for the pricing mechanism, and which ones should be included in the new design?
3. How do the different design options impact the performance indicators: total system costs, required flexible capacity, and average market price?
4. Which choice variables, such as different values of load, imbalance, flex capacity, could influence these outcomes, and how do they affect the results of the various design options?

The research questions will be answered by first developing several market design options integrating redispatch and balancing. They have to include both with and without co-optimization, across different pricing scenarios to evaluate the differences in performance. These three market design options, along with the current design, were simulated to obtain quantitative results. The simulations were carried out using a small electricity network with 6 nodes, with variables chosen to ensure a feasible solution, as a real electricity system is expected to always have a feasible solution. Additionally, a sensitivity analysis is performed to assess the impact of the chosen variables in the simulation model on the results.

1.6. Main findings

Our main findings indicate that implementing co-optimization results in a 21% reduction in required flex capacity compared to the current market design. However, on average, 71% of this improvement can be achieved by only introducing a flex product that integrates redispatch and balancing, along with using the net capacity approach. This suggests that co-optimization is not essential for capacity improvements; integrating redispatch and balancing with net capacity calculations can yield substantial gains. Pay-as-Bid is identified as the most cost-effective option for this market design. If Marginal Pricing is used, further research is needed to explore alternative settlement methods for the net capacity approach, as it requires a single price for settlement while there are two market clearing prices from the redispatch and balancing markets. Using the highest market clearing price from both auctions results in relatively high total costs, although these costs remain lower than those in the current market design. The sensitivity analysis showed that despite the chosen variables affecting outcomes, the performance ranking of market designs remained consistent, and the small difference in required capacity between co-optimization and separate optimization with net capacity was not significantly impacted by these variables. Instead, geographical factors and network scale have a greater influence.

1.7. Outline

Chapter 2 examines the current market design, highlighting the key differences between redispatch and balancing, and introduces three new market design options with different pricing approaches. Chapter 3 explains the simulation model used to evaluate these designs, covering the parameters and the simulation process. Chapter 4 focuses on validating the model, ensuring the system behaves as expected. In Chapter 5, the simulation results are presented, with an emphasis on key metrics such as required capacity, market prices, and total costs. Additionally, Chapter 5 includes a sensitivity analysis to assess the impact of the chosen parameters on the outcomes. Finally, Chapter 6 discusses the findings and overall insights and concludes by evaluating the benefits of the proposed market designs and proposing areas for future research.

2

New market design integrating balancing and redispatch

2.1. Main differences between the redispatch and balancing market

In the current market design, redispatch and grid balancing involves two different processes. Design choices must be made when integrating both services for co-optimization. To distinguish the design options, an analysis of both market is done. This analysis, based on literature and documentation of TenneT can be found in Appendix A. This breakdown of both services contributes to identifying differences which is necessary for defining design choices. The differences Table 2.1 outlines the main differences between these markets, emphasizing why integration is challenging and how certain design choices are required for an integrated design. The six main aspects which are different in the balancing and redispatch market, making integrating difficult are discussed below.

Differences	Balancing	Redispatch
Type of products	Up and down regulation of FCR, aFRR, mFRR	Up and down regulation energy
Type of auction	Capacity [€/MW] & Energy [€/MWh]	Energy [€/MWh]
Timing	Real-time	D-1 till 1h before real-time
Variables in bid	Price, capacity	Effectiveness (location), price, capacity
Settlement approach	Marginal pricing	Pay-as-bid
Dividable bids	Yes	Not all bids

Table 2.1: Overview of the differences between the current balancing and redispatch market

The first difference is the type of product used in the balancing or redispatch market. Although both products are flexible capacity, they have different names with unique characteristics. The balancing process uses three products with different characteristics, whereas performing redispatch involves one product. This difference makes market integration more challenging due to the varying characteristics of these products. For a detailed comparison of the technical aspects of each product, refer to Appendix A. The balancing market includes Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), and manual Frequency Restoration Reserve (mFRR). FCR is particularly unique, as it requires the provider to install a device that measures and controls the frequency, meaning it operates without an energy auction. Additionally, FCR addresses imbalances across the entire synchronous area, while the other products focus on imbalances or congestion within national boundaries. Another challenge is that each product currently has its own pre-qualification process. The second difference mentioned in the table is the types of auctions. The balancing market uses both capacity and energy auctions, while redispatch only involves an energy auction. In the capacity reservation auction, participants bid to reserve the capacity they are willing to provide if called upon. This auction takes place in advance and ensures that sufficient resources are available to maintain grid stability. The auction focuses on securing the commitment of resources to be available for future use, but it doesn't involve the actual production or delivery of electricity. The energy activation auction, on the other hand, involves participants bidding to provide actual energy when an imbalance occurs. The timing of both auction differs with the capacity auction occuring ahead of time to reserve capacity, while the energy auction responds to real-time conditions.

The fourth difference are the variables considered in the bids. In the balancing bids, location is not taken into account, meaning transport constraints are not considered during market optimization. In contrast, the redispatch auction incorporates location in the bids through an effectiveness variable in the bid. This factor accounts for the power loss associated with activated flexible capacity, meaning that more capacity is procured than is actually used to resolve congestion. As a result, redispatch capacity located closer to the congested area is more effective, as it experiences less power loss. This effectiveness factor is ranging from 0 to 1. It is determined by the ratio between the capacity reduction at the congestion line (MW) and the required capacity (MW) provided by a market participant (TenneT, 2021). When redispatch capacity is sourced from a further location, greater power loss occurs, which in turn reduces the effectiveness factor of the redispatch capacity in that location. Besides this, transport constraints such as capacities of transmission lines and the power flow constraint are considered in this market.

The last difference is whether the bids can be activated partially or not. In the balancing auction, the capacity offered in a bid can be activated partially, allowing for more flexibility in responding to grid imbalances. Conversely, in the redispatch auction, certain bids may require full activation resulting in higher costs. After the bids are placed the settlement takes place. The balancing market uses a Marginal Pricing (MP) approach for the settlement, where the market clearing price is set by the last activated bid in the merit order, meaning the most expensive accepted bid. All activated bids receive this market clearing price. On the other hand, the redispatch market operates on a Pay-As-Bid (PAB) basis, where participants are pay according to the exact price they bid. This difference in settlement approaches significantly influences how market participants formulate their bids, which can, in turn, impact the overall merit order and the final costs associated with balancing and redispatch operations.

2.2. Design choices for an integrated market

The differences between the redispatch and balancing markets underscore the key challenges in integrating both services. Design choices related to these aspects must be made, as illustrated in Table 2.2. Certain aspects will be incorporated into the market integration, while others will be excluded. The design considerations for an integrated market are focused on optimising the framework for TenneT. The aim is to create an effective market that prioritizes the needs of the grid operator, rather than the preferences of market participants.

Type of auctions

This study aims to design an integrated energy market, with a primary focus on addressing imbalances and congestion through the effective activation of balancing and redispatch capacity. As the emphasis is not on ensuring sufficient capacity availability, the capacity auction falls outside the scope of this study.

Type of products

It was decided to exclude the FCR product, which is one of the balancing products, from the integration of balancing and redispatch products. This is due to its significant differences from the other products, making it unsuitable for co-optimization. Firstly, FCR requires providers to use a frequency measurement device, distinguishing it from other products. As a result, FCR is not activated through an energy auction but is automatically controlled by the device. Since the integrated design focuses solely on the energy auction, FCR is excluded from consideration. Additionally, FCR maintains frequency stability across Europe, while redispatch and FRR are focused on the national system. mFRR, aFRR and

Integrated market design:		
	Included for market integration	**Excluded for market integration**
Type of auctions	Energy auction	Capacity auction
Type of products	aFRR, mFRR, redispatch product	FCR
Variables in bid	Location, price, capacity	-
Timing	2 options: • co-optimization at simultaneous timestep • seperate optimistion with performing redispatch before balancing	-
Settlement approach	2 options: • Pay-as-bid (PAB) • Marginal pricing (MP) • Locational Marginal Pricing (LMP)	-
Dividable bids	Dividable bids	Non-dividable bids

Table 2.2: Market design choices

redispatch capacity are included and combined into a single product named ”flex capacity”. Despite their differences, these products share a common purpose: providing ”flexible capacity”. Therefore, the new market design integrates both redispatch capacity and FRR capacity into a unified ”flex product” reflecting their shared role in maintaining grid stability.

Variables in bid

To address one of the current design’s limitations, being the lack of consideration for transport constraints when activating balancing bids, location will now be considered into balancing operations. This change aligns with the approach already used in redispatch, where location is taken into account. The integrated market design will incorporate the effectiveness factor, currently used as a variable in redispatch bids. This factor accounts for the power loss associated with activated flexible capacity, meaning that more capacity is procured than is actually used to resolve congestion. Power loss, influenced by the location of the resource relative to the congestion point, will be factored into bid selection for both redispatch and balancing. In addition to the effectiveness variable, transport constraints will also be considered in the market optimization. This approach ensures that, beyond cost and capacity, bid selection is influenced by factors such as distance, transmission line capacity, and power flow limitations.

Timing

For the timing of the redispatch and balancing auctions, two different options will be considered. The first option will co-optimize redispatch and balancing simultaneously, which is expected to yield optimal results. However, due to existing operational and technical constraints, simultaneous co-optimization may be challenging. Therefore, a second option has been developed, which conducts co-optimization in two stages across two separate auctions. In this second option, congestion is addressed first, followed by the resolution of imbalances.

Settlement approach

Both PAB and MP will be considered as pricing scenarios to assess their impact on the outcomes. Additionally, Locational Marginal Pricing (LMP), a pricing mechanism not currently used in the redispatch and balancing markets, will be evaluated. This study focuses on PAB, MP, and LMP as they are the most commonly used in European electricity markets. Another reason to include LMP is the previously mentioned drawback of the current redispatch and balancing market design to fail to provide accurate long-term price signals. Since LMP is known to address this issue, its effect on the total costs for resolving imbalances and congestion under each new market design option is evaluated.

Dividable bids

This design assumes that all bids are divisible, meaning they can be partially activated. While non-divisible bids could be allowed in the auction, incorporating them would add significant operational complexity. Since this study focuses on the broader market design and not on these specific operational challenges, the developed market designs do not involve non-divisible bids. Therefore, non-divisible bids are excluded from this study.

2.3. Conceptualisation of the designs

Three design options are proposed for a new market design integrating redispatch and balancing. Each new design option introduces the ”flex product”, which integrates the redispatch and balancing products, allowing capacity to be used for both purposes. Additionally, all designs ensure that transport constraints are considered when addressing both congestion and imbalance. This requires to add a locational aspect to the imbalances, rather than treating it as a system-wide issue. The new design options can be categorized by two key aspects: 1) co-optimization in one simultaneous step or separate optimization in two steps , and (2) net or gross flex capacity. These aspects are plotted on the Design Options Matrix in Figure 2.1

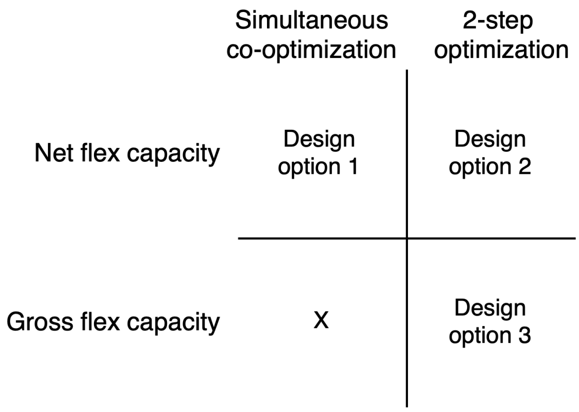

Figure 2.1: Design options matrix for integrating balancing and redispatch

The foundation of design option 1 is to identify the most optimal solution, without being constrained by current technical and operational limitations. This approach addresses congestion and imbalance simultaneously, aiming to demonstrate the potential benefits of full co-optimization. Design option 2 and 3 do consider the operational constraints, which make co-optimization in a single timestep challenging. As a result, this design implements optimization in two separate steps, aligning more closely with the existing market structure, where redispatch operations are performed first, followed by balancing.

Design option 2 allows activated redispatch capacity to also address imbalances. For example, an asset upregulated by 100 MW to resolve congestion could be down regulated by 60 MW to address an imbalance, resulting in a net energy use of 40 MW. In this design, the flex capacity provider is compensated based on net energy use. Since only one price can be used for the settlement of the net capacity and two market clearing prices are formed. The settlement will be done using the maximum price of both. The maximum price approach is used to evaluate the total costs under the ”worst-case” settlement approach in terms of cost-effectiveness from the perspective of the TSO. Design option 3 does not allow activated redispatch capacity to also address imbalances. For example, an asset upregulated by 100 MW to resolve congestion could be downregulated by 60 MW to address an imbalance, resulting in a gross energy use of 160 MW. This design option introduces only the flex product and incorporates transport constraints to evaluate the impact of this single change.

These three design options will be compared to the current market design, defined as market design 0. In the current market design for redispatch and balancing there are separate auctions for redispatch and balancing, where market participants submit their bids independently. Capacity for redispatch purposes can not be used for balancing purposes. First, the redispatch auction is conducted, followed by the balancing auction. The redispatch market optimization does not take system imbalances into account and any capacity activation has to be balance-neutral. Similarly, the balancing auction does not consider congestion or any other transport constraints.

This results in the following 4 design option:

1. Design option 0: Current market design
2. Market design option 1: Simultaneous co-optimization with net capacity use
3. Market design option 2: Separate 2-step optimization with net capacity use
4. Market design option 3: Separate 2-step optimization with gross capacity use

2.4. Pricing approaches for the new market design options

For all design options, three pricing approaches are considered. In the current market design, MP for balancing is considered and PAB for redispatch is considered. Given that one of the drawbacks of the current market design is the lack of accurate price signals, the LMP approach is also included.

- **Marginal Pricing (MP):** Marginal pricing sets the price of electricity based on the cost of the last unit of energy dispatched. This ensures that all participants are payed the market-clearing price.
- **Locational Marginal Pricing (LMP):** Locational marginal pricing is similar to MP but the settlement is divided in seperate regions. Each region develops its own market clearing price. This study considers two regions, A and B (see Figure 2.2. Each region has a separate settlement price defined by the highest activated bid in that respective region. This method provides price signals that reflect the value of energy at specific locations, promoting efficient dispatch and congestion management. LMP helps to optimize the use of the transmission network by providing localized price signals.
- **Pay-As-Bid (PAB):** Under the pay-as-bid scheme, participants are payed based on their bid prices rather than a uniform market-clearing price.

The various pricing approaches use different settlement methods, which in turn influence bidding behavior. In the PAB pricing approach, a margin is added to the bid's marginal costs. This margin depends on several factors, including competition, market conditions, risk, and strategic bidding behavior. These factors are accounted for in the bid behavior in the market. However, potential variations in bid behavior under the LMP approach are not considered, as it is assumed that participants will bid their marginal price. An analysis of these different pricing mechanisms and bid behaviors can be found in Appendix B.

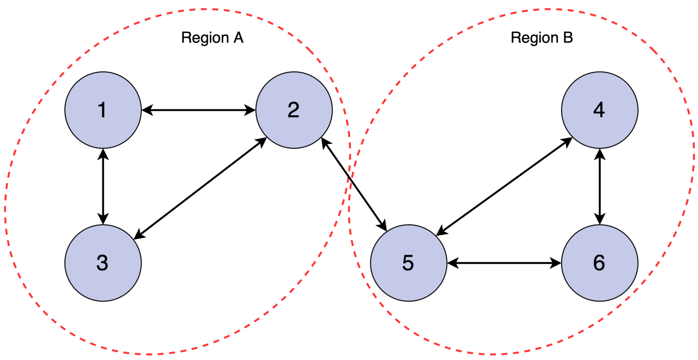

Figure 2.2: Regions for the LMP approach within the electricity network of the simulation model

The application of pricing approaches varies across the different market design options. In design option 1, co-optimization occurs in a single step, allowing for the use of a single pricing approach.

However, design options 2 and 3 involve two distinct stages for activating redispatch and balancing capacity. This requires the consideration of two separate pricing approaches.

2.5. Experimental design

Various experiments will be conducted, each applying different pricing approaches to the market designs. Considering the range of pricing approaches, a total of 11 market design options will be simulated and compared. Table 2.3 provides an overview of all the options. In the current market design, PAB is used for redispatch and MP for balancing. For the co-optimization in market design 1, only one pricing approach is selected per experiment, with MP, PAB, and LMP all being considered. In market design 2, scenarios are explored where the same pricing approach is applied to both redispatch and balancing, meaning that either MP, PAB, or LMP is used for both services. However, one scenario includes PAB for redispatch and MP for balancing, similar to the current market design. In this scenario, one flex capacity is provided with two separate bid prices. The scenario where MP is applied to redispatch and PAB to balancing is not included, as this combination is highly unlikely since both services would need to change their pricing approach.

Current market design	**1: Simultaneous co-optimization**	**2: Separate optimization, net capacity**	**3: Separate optimization, gross capacity**
PAB for redispatch MP for balancing	MP	MP for both	MP for both
	PAB	PAB for both	PAB for both
	LMP	LMP for both	LMP for both
		PAB for redispatch MP for balancing	PAB for redispatch MP for balancing

Table 2.3: Experiments for each market design option with different pricing approaches

The aim of the experiments is to assess the potential benefits of each market design compared to the current one, focusing on three key performance indicators (KPIs). The first KPI is the required capacity, which represents the amount of flexible capacity needed to resolve congestion and imbalances. A reduction in required capacity is considered favorable in the TSO's perspective, as it frees up more flexible capacity for other uses and relieves the grid by reducing power flows through the system. While this could lead to cost savings for the TSO, the extent of savings largely depends on the pricing approach used. The second KPI is the average market price paid for flexible capacity, which is calculated by dividing the total costs by the required capacity. This KPI helps evaluate the effect of different pricing approaches on the market price. The final KPI is the total cost, which includes the costs of buying flexible capacity. The inclusion of the average market price as a KPI helps assess the impact of the pricing approach, since the total cost is also influenced by the amount of required capacity.

3

Simulation model

Several simulation models are developed for the current market design (Design Option 0) en for the new market designs (Design Option 1, 2 and 3). The optimization program Linny-R is used for simulation and to generate quantitative simulation results. These results will be used to perform a quantitative evaluation of the new design options with various pricing scenarios.

3.1. Model design, parameters, and simplifications

The data and network shown in Figure 3.1 is used to simulate the operation of a small-scale electricity system. The simulations were carried out using a small network with 6 nodes, with variables chosen to ensure a feasible solution, as a real electricity system is expected to always have a feasible solution. An example of an unfeasible solution would be if power generation is unable to reach the loads due to power flow constraints and limited transmission capacities. In this case, the physical network constraints are too restrictive, making it impossible to meet all power demand with the generation traded in the Day-Ahead (DA) market, even with the use of balancing and redispatch capacity.

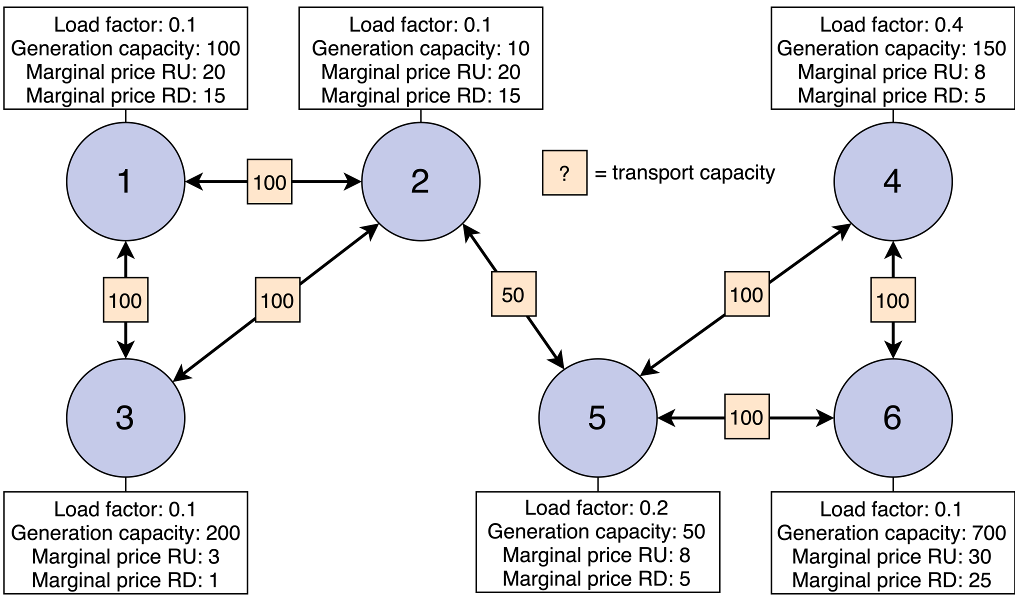

Figure 3.1: Simplified small-scale electricity network used in the simulation model

Using this small network made it possible to closely monitor energy flows and perform calculations to better understand system behavior. It mimics the behavior of a real electricity system allowing for the evaluation of the output for each each design. Each circle represents a node, corresponding to a high-voltage substation. Each high-voltage substation is connected to both generation and load, as well as to capacity bids intended for resolving congestion and imbalance. The nodes are connected to each other by links representing the grid transmission lines. The model consists of two regions, each with three nodes, and a single connection between the regions. In total, the model includes seven transmission lines.

To ensure the simulation model remains feasible, key parameters such as load, imbalance, and transmission capacity are carefully selected. While imbalance and transmission capacity are kept constant, the load gradually increases until it reaches the maximum level that still results in a feasible outcome. This approach guarantees that congestion and imbalances can always be resolved, supply and demand remain balanced, and all constraints are met. A reduced transmission capacity between the two areas is set to necessitate redispatch, for when the power flow constraint is already met. And marginal prices range from 1 to 30, with Node 6 providing the highest capacity at the highest price. But the marginal prices for Ramping Up (RU) and for Ramping Down (RD) are different. Capacity providers charge more for RU than for RD, reflecting the generally lower costs associated with the down regulation of an asset (TenneT, 2024a). Some nodes share similar marginal prices to demonstrate the contrasting impacts of MP and PAB bids and illustrate how certain bids can increase more significantly under different pricing approaches.

The electricity flows bi-directionally through the transmission lines. However, it depends on the market design options whether transport constraints like the power flow constraints or capacity constraint is considered. In the model considering transport constraints, each link operates at 380 kV with specific capacity and distance of 40 km. This distance is based on the average distance (= 39 km) of all 380 and 220 kV high-voltage lines in the Dutch grid. Power losses are simulated to be proportional to the load. Additionally, the model conducts a power flow analysis to ensure compliance with this requirement.

Several simplifications of the real-world system have been made during development of the simulation model:

1. The Dutch electricity system is simplified to a simple representation existing of 6 nodes.
2. The capacities nor marginal prices are not based on real bid data
3. Redispatch bids are not done within a specific region but within the whole system
4. The high-voltage grid in the simulation only includes the 380 kV grid lines, not 220, 150, 110 kV.
5. The N-1 criterion for determining redispatch is not used because the network have only one link between 2 and 5.

3.2. Simulation of congestion and imbalance

To evaluate the market design options, it is necessary to simulate both congestion and imbalances, which requires simulating the Day-Ahead (DA) market as well. The DA market simulation generates the input data that creates congestion and imbalances. The process for both the DA market and the redispatch and balancing markets is outlined below, using a simplified high-level process approach for the simulation. A detailed analysis of the full process in a real-world electricity system is provided in Appendix A.

3.2.1. Day-ahead market

Congestion occurs because transport constraints are not considered during the DA market. In the DA market, electricity is traded one day in advance. Each electricity consumer is represented by a Balance Responsible Parties (BRP). The BRP submits an energy program (e-program) consisting of the expected electricity demand for the next day. On the supply side, energy providers submit bids to sell electricity. Each bid specifies a capacity and a price. The bids are arranged in a merit order, from low to high costs. In the DA market, generation is economically dispatched based on the lowest marginal costs, without considering network constraints. This means that demand is met using the cheapest available supply bids.

The DA market assumes that power can flow freely between nodes up to the transport capacity, aiming to minimize total costs. However, this dispatch does not yet account for technical constraints like transport capacity limits or Kirchhoff's laws. Once the DA market clears, the power flows between the nodes are determined. Here, Kirchhoff's circuit laws, particularly Kirchhoff's Current Law (KCL), Kirchhoff's Voltage Law (KVL) are applied to ensure that the power flows through the grid are in accordance with physical laws. Additionally, the network's limitations, such as transmission line capacity and power losses, are considered. Sometimes this leads to cases where the physical limitation make it impossible for the generation to fully reach demand. Here, redispatch is necessary.

Balancing is necessary due to the unpredictability of electricity demand and supply. The DA market operates as a forward market, where electricity generators and consumers (or their representatives) trade energy for the following day. Market participants submit bids based on their forecasted generation and demand, typically 24 hours in advance. Since these bids are based on predictions rather than real-time data, a deviation between the scheduled (Day-Ahead) and actual (real-time) generation or demand can occur. These imbalances can arise from forecasting errors, generator outages, variability in renewable energy output, or fluctuations in demand. If more electricity is produced than consumed, a surplus occurs, or if less electricity is generated than consumed, a deficit occurs. In the simulation model, an error factor is used which is multiplied by the load to create an imbalance between the load and the generation.

3.2.2. Redispatch and balancing market

The initial economic dispatch in the DA market, optimized for cost, often necessitates redispatch and balancing due to network constraints and forecasting errors. Redispatch primarily addresses congestion, while balancing maintains system stability in real-time.

When congestion or other network issues are identified, TSOs initiate redispatch to prevent the overloading of transmission lines and ensure grid stability. Redispatch involves adjusting the generation schedule by reducing output in congested areas (downward redispatch) and increasing output in areas where more electricity is needed or where the grid can handle additional power (upward redispatch). These redispatch adjustments are made based on bids submitted by generators, which include price, capacity, and location information.

Imbalances, on the other hand, are managed through the balancing market. The electricity grid must maintain a balance between supply and demand. Large imbalances can destabilize the grid, leading to frequency deviations and, in extreme cases, blackouts. When imbalances are detected, TSOs use real-time balancing markets to buy balancing capacity, which is then used to either increase or decrease generation to restore balance between supply and demand.

11 different experiments are conducted across the three market design options, each using different pricing approaches. All experiments use the same generation profile input from the DA market simulation, ensuring a consistent comparison of the market designs under the same congestion and imbalance conditions.

3.3. Day-ahead market simulation

The DA market simulation model generates a generation profile for each node based on the economic dispatch without considering physical network constraints. This generation profile is used as input in the simulations for the redispatch and balancing market designs to introduce power flows in the system.

Variable	Baseline Value	Explanation
Total system Load	{20; 40; 60; 80; 100; 200; 400; 800; 1000}	An increasing load profile is used

Table 3.1: Load levels for the simulations

Each node has a load and a generation capacity. The load used in the simulation is detailed in Table 3.1, with nine different load levels considered. The load is gradually increased until it reaches the maximum level where a feasible solution exists after applying redispatch and balancing. The load in each node is determined by the distribution factor of the node multiplied by the total system load. The distribution load factor for each node is given in Figure 3.1. This Figure also displays the offered generation capacity and a corresponding bid price for each node. Since the DA market uses the MP approach, each bid reflects the marginal price. In the simulation, generation is economically dispatched based on the lowest marginal costs, without considering network constraints. The model will generate a generation profile for each load level.

Although transport constraints are not considered in the DA market simulation, power losses are accounted for to represent the actual losses that occur within the grid. In the real DA market, these losses are typically managed through long-term capacity contracts, which are not included into this model. Since the model must satisfy the required loads, it directly accounts for power losses to maintain accuracy in the simulation. Therefore, it is expected that generation will be slightly higher to meet the load.

3.4. Design option 0: Current market design

The simulation output of the current market design for redispatch and balancing is used as reference values. The simulation model of the current market design consists of two separate auctions with seperate capacity for redispatch and balancing. First, congestion is resolved using redispatch capacity bids. Second, imbalance is addressed using balancing capacity bids.

For the redispatch and balancing processes, the same electricity network from Figure 3.1 is used. Each node has a fixed generation profile and load profile based on the DA simulation. The combination of load, generation, and transport constraints leads to congestion, which is resolved through redispatch. During redispatch, capacity for ramping up and down is available at each node (see Figure 3.2), with redispatch capacity matching the generation capacity at each node. The dispatch process takes transport constraints into account, and a power flow analysis is performed to ensure compliance with KVL. Power losses are automatically factored into the dispatch, in this way the effectiveness variable in each redispatch bid is considered. This variable reflects the location of the asset and the extent of power loss, which is calculated based on the distance between the asset and the congested area.

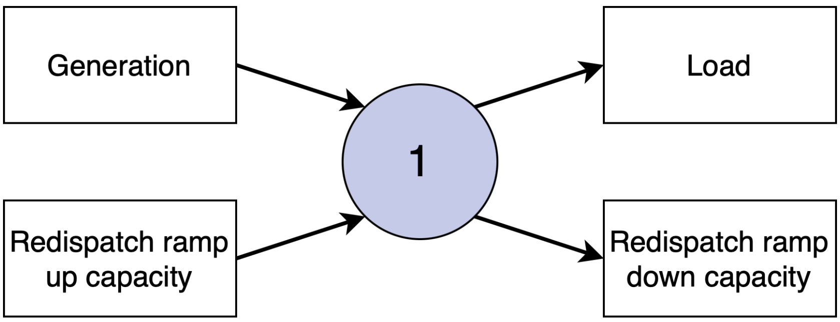

Figure 3.2: Node in redispatch model in Design Option 0

When capacity is activated to solve congestion, the PAB approach is used in the auction. This settlement method influences bidding behavior, as explained in B.

The following formula is used for the redispatch capacity bids:

$$P = MC + \rho \tag{3.1}$$

With ρ representing the margin added on top of the marginal costs:

$$\rho = \frac{\beta \cdot B_{\text{max}}}{A \cdot MC} \tag{3.2}$$

With β representing the combined effect of the level of strategic behaviors and the influence of competition:

$$\beta = \frac{\gamma}{\alpha} \tag{3.3}$$

Here:

- P represents the bid price.
- MC represents the marginal costs of a market participant.
- ρ represents the margin over the marginal cost.
- B_{max} represents the highest bid.
- β represents the combined effect of strategic behaviors (γ) and market competition (α), impacting the margin.
- A represents the amount of assets in a node, indicating the level of competition.

This margin over the marginal costs is added in the formula to account for the bid behavior of market participants under the PAB pricing approach. α accounts for how much competition impacts the margin. γ accounts for different strategic behaviors, cost structures beyond marginal costs, market conditions, and levels of risks and uncertainty impacting the margin. The values of the marginal costs (MC) and the competition (A), represented by the number of assets, are defined for each node in Table 3.2.

In the PAB approach, each activated flex provider receives the price they bid. The total system costs for redispatch are the costs for the capacity activated, calculated as follows:

$$\text{System Costs PAB} = \sum_i (\text{Capacity Activated}_i \times \text{Bid Price}_i) \tag{3.4}$$

Node	Competition ramp up [# assets]	Competition ramp down [# assets]
1	1	2
2	2	3
3	3	4
4	4	5
5	5	6
6	6	7

Table 3.2: Amount of other market participants per node

During the second step, imbalance is resolved. The imbalance is created by a deviated load using an error factor. The error factor is multiplier with the load. The error factor used in the simulations is 1.3, creating more load than generation which results in an electricity deficit. Each node is provided with balancing capacity, including both price and capacity. Transport constraints are neglected during the dispatch of the balancing market. So the bids with the lowest price are selected first, meaning an economic dispatch is performed. The MP approach is used in the balancing auction. Which means that each market participant will bid its marginal costs. The market clearing price is determined by the most expensive activated bid. The system costs for balancing are the total costs for the capacity activated, calculated using the market clearing price:

$$\text{System Costs MP} = \sum(\text{Capacity Activated} \times \text{Market Clearing Price}) \tag{3.5}$$

And to calculate the total system costs the costs of the balancing and redispatch capacity is summed:

$$\text{Total system costs} = \sum_i(\text{Redispatch system costs}_i + \text{Balancing system costs}_i) \tag{3.6}$$

And to calculate the required capacity the activated capacity (both redispatch and balancing) is summed to account for the total required flexible capacity:

$$\text{Total Required Flexible Capacity} = \sum_i(\text{Redispatch Capacity}_i + \text{Balancing Capacity}_i) \tag{3.7}$$

The average market price (€/MWh) is determined by dividing the total system costs by the total required capacity:

$$\text{Average Market Price} = \frac{\text{Total System Costs}}{\text{Total Required Capacity}} \tag{3.8}$$

3.5. Design option 1: Simultaneous co-optimization with net capacity

In this design option, the TSO optimizes the dispatch of flex capacity simultaneously for congestion and imbalances. Flex capacity is provided, addressing both imbalance and congestion in a single step. Each node has a generation and load input from the DA simulation. Transport constraints are considered in the co-optimization, meaning each transmission line has a capacity and the KVL is considered. Imbalance is created by the load multiplied by an the error factor of 1.3.

The simulation of this market design option is executed under the settlement approaches of MP, LMP and PAB. The calculation of the KPIs follows the same method as in the current market model. For the MP approach, equation 3.5 is used to determine the total costs, while equation 3.4 is applied for the PAB approach. The required capacity is calculated as the sum of all activated capacity bids, and the average price is derived by dividing the total costs by the required capacity. For the LMP approach, a similar equation to the MP approach is used, but the settlement is divided into two regions, A and B, each with its own market clearing price, determined by the highest activated bid in that region. Figure 2.2 visualises these regions.

3.6. Design option 2: Separate optimization with net capacity

In this design option, the TSO optimizes the flex capacity separately, first for redispatch to solve congestion and secondly for balancing to solve imbalances. Flex capacity providers submit bids that include their capacity, location and price.

During redispatch, flex capacity is used to address congestion. The simulation utilizes the same generation, load, and transport constraints as in the other simulation models. Various cost settlement scenarios are considered, with redispatch being conducted using one of three approaches: MP, LMP, PAB.

During the balancing auction, imbalances are resolved using the remaining flex capacity. The remaining flex capacity is calculated as follows:

$$\text{Flex capacity}_{\text{remaining}} = \text{Flex capacity} + \text{Redispatch flex capacity}_{\text{up}} - \text{Redispatch flex capacity}_{\text{down}} \quad (3.9)$$

A new situation arises where formerly activated ramp-up or ramp-down redispatch capacity can be adjusted to correct imbalances. After capacity is adjusted, less capacity is used in the end. This remaining capacity is called the net capacity use. The capacity provided during redispatch is subtracted from the capacity provided during balancing if they occur in opposite directions (e.g., ramping up followed by ramping down).

$$\begin{aligned}\text{Net Required Capacity Used} = {} & |\text{Ramp-Up Redispatch Capacity} - \text{Ramp-Down Balancing Capacity}| \\ & + |\text{Ramp-Down Redispatch Capacity} - \text{Ramp-Up Balancing Capacity}|\end{aligned} \quad (3.10)$$

The total system cost is calculated as follows. The price is determined by the maximum receiving price of both auctions:

$$\text{Total System Costs} = \text{Net Required Capacity Used} \times \text{Price} \quad (3.11)$$

3.7. Design option 3: Separate optimization with gross capacity

This design option is similar to design option 2, only capacity used for redispatch is not allowed to be adjusted for balancing purposes. Therefore, this is called the gross capacity used instead of the net capacity. Here, only the Flex product is introduced, and transport constraints are considered during redispatch and balancing. First, during redispatch, the flex capacity is used to solve congestion. Secondly, the remaining flex capacity is used to solve imbalances. The remaining flex capacity is calculated using equation 3.9.

If settlement is based on gross capacity, all provided capacity is summed together:

$$\begin{aligned}\text{Total Capacity Used} = {} & (\text{Ramp-Up Redispatch Capacity} + \text{Ramp-Down Redispatch Capacity}) \\ & + (\text{Ramp-Up Balancing Capacity} + \text{Ramp-Down Balancing Capacity})\end{aligned} \quad (3.12)$$

The total system cost is then calculated as follows; the price paid depends on the cost settlement scenario and is either the bid price (PAB) or the Market clearing price (MP):

$$\text{Total System Costs} = (\text{Total Redispatch Capacity Used} \times \text{Price}) + (\text{Total Balancing Capacity Used} \times \text{Price}) \quad (3.13)$$

4 Validation

4.1. Validation of the day ahead market simulation

The DA model should dispatch units based on merit order, without considering capacity constraints, but accounting for power losses. Additionally, demand should match supply.

4.1.1. Validation of the supply in the merit order

The simulation model is first run without power losses to verify the system behavior. Figure 4.1 displays a graph with the output of the simulation model, showing the generation profile for each node and a black line representing the load. The graph demonstrates that supply and demand are equal because the total capacity provided by the generation units matches the load line. The legend also shows the marginal price for the generation in each node, indicating that the correct merit order is followed.

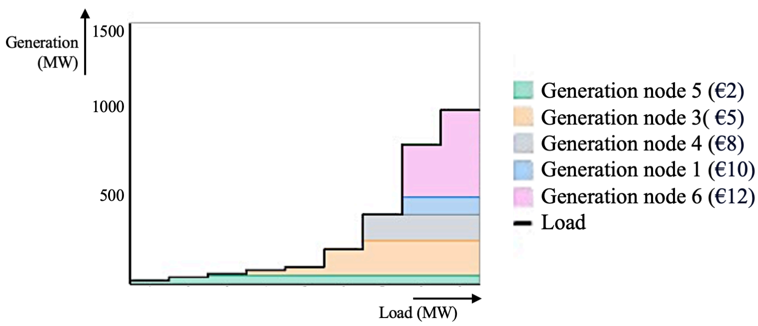

Figure 4.1: Output Day Ahead market - generation profile following the merit order

The Day-ahead electricity market clearing price is simulated, determined by the most expensive activated unit (see Figure 4.2). As the load rises, the price increases as units with higher marginal costs are dispatched, indicating that cheaper units are activated first.

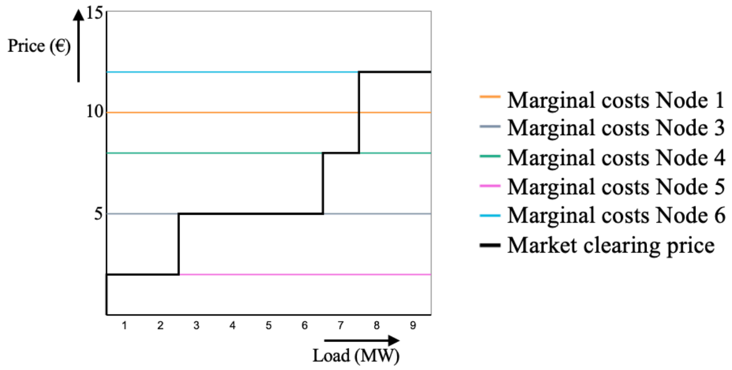

Figure 4.2: Output Day Ahead market - Market clearing price and marginal costs per node

4.1.2. Validation of the power loss

The power loss is validated by increasing the distance of the transmission lines. Figure 4.3 shows the generation and load for a market with power losses, where generation slightly exceeds demand as expected. To verify if the required capacity increases with distance, the transmission line distance is extended to 500 km. As anticipated, Figure 4.4 shows a further increase in generation. For reference, the total generation for the system without power losses and a total load of 20 MW is 20 MW. With power losses, generation is 21.77 MW for 100 km and 31.57 MW for 500 km.

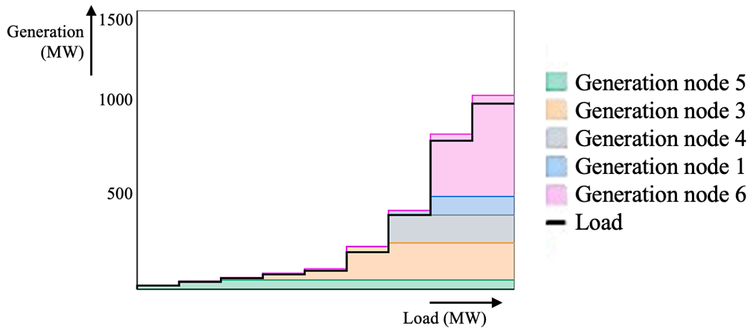

Figure 4.3: Output Day Ahead market - Generation and load with power loss (transmission line distance = 100 km)

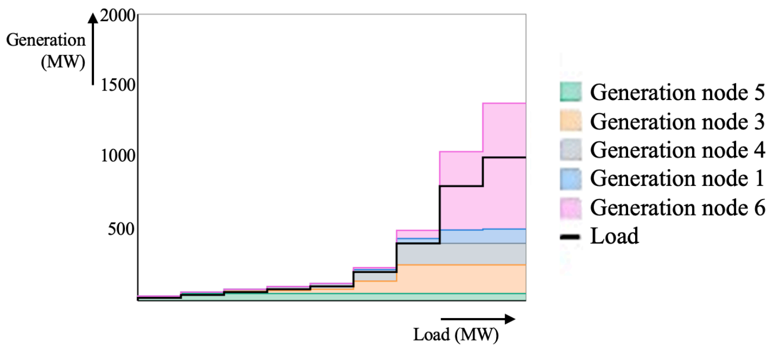

Figure 4.4: Output Day Ahead market - Generation and load with power loss (transmission line distance = 500 km)

The DA model doesn't consider the capacities of the grid connections. However, to demonstrate potential congestion in the system, the power flow through a transmission line is compared to its maximum capacity. Figure 4.5 shows the percentage of the capacity being available. If the value becomes negative, it indicates potential congestion. This figure shows that because the DA market does not consider transport constraints and an economic dispatch is done, congestion may occur. When the load increases, congestion might be alleviated as new generation units are activated, changing the distribution of power flows and potentially using different transport routes.

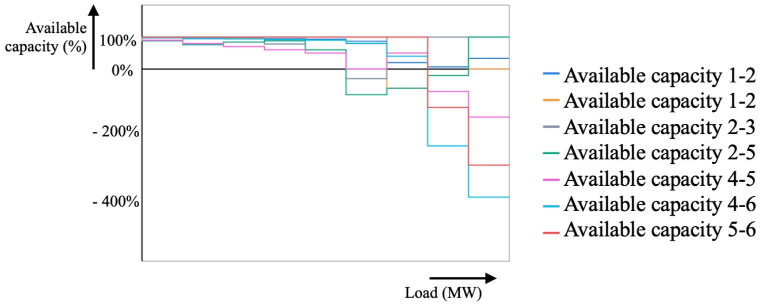

Figure 4.5: Output Day Ahead market - Percentage of available capacity per each grid transport link

4.2. Validation of system behavior for redispatch and balancing

4.2.1. Redispatch validation

To validate the current market design, congestion is introduced to observe if it gets resolved. Initially, only the power flow constraint is considered in the network to understand its influence. Power losses are not considered, and the transmission lines do not yet have a maximum capacity. Figure 4.6 shows that the activated redispatch capacity for ramp-up and ramp-down is exactly the same. This meets the balance-neutral requirement of redispatch. Initially, the activated redispatch increases, but at a higher load, it decreases again. This can be explained by new generation units being activated, resulting in a different power flow. Therefore, a higher load doesn't necessarily mean more redispatch. Especially in a smaller system, it depends on which generation units are activated.

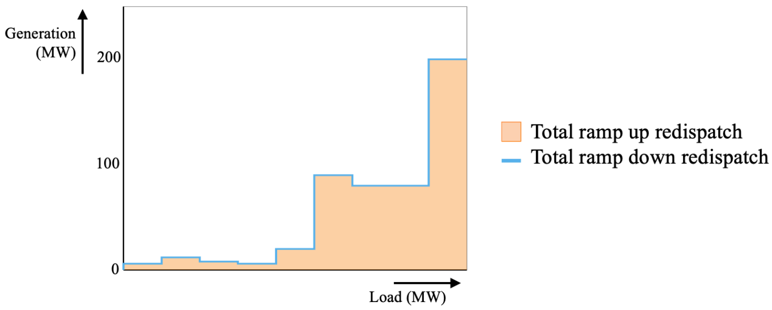

Figure 4.6: Redispatch ramp up and down capacity activated

To assess the impact of capacity constraints on the system, a 50 MW capacity constraint is applied to each transmission line separately. The results are shown in Appendix D. The table shows that limiting some transmission lines to 50 MW has no impact, while lines 2-3, 5-6, and 4-6 exhibit an increase in the required redispatch capacity.

4.2.2. Power loss validation

The power loss is considered since it adds the effectiveness variable in the redispatch bid. To validate the influence of power losses, the same experiment is conducted with power losses included. The results are shown in Appendix D. As expected, the ramp-up capacity increases slightly since power is lost during transport, while the ramp-down capacity decreases slightly because power losses already extract power from the system, reducing the need for ramp-down capacity. In this experiment, imposing a capacity constraint on different transmission lines affects the redispatch capacity activated in more cases than in the previous experiment without power losses. This can be explained by the fact that power losses vary depending on the route taken.

Another method to validate the influence of power loss is to observe whether the model selects different routes when the distance of a transmission line increases. By increasing the distance, we expect the model to choose an alternative route. When performing this validation experiment, the model behaves as expected. The results are shown in Appendix D.

4.2.3. Validation of activation of balancing and redispatch capacity

To validate whether the model solves imbalance, an imbalance is created. The model should solve this nonetheless the location. And the model does solve the imbalance in the merit order, which shows that its correct and not considering transport constraints (see Figure D.2 in Appendix D). Looking at the dispatch of redispatch capacity, the location influences the dispatch and the activation does not follow the merit order like balancing market. If the location of the congestion is changes, the dispatch will change for redispatch but if we change the location of the imbalance the dispatch will not change. Therefore, the balancing and redispatch model behaves as expected.

4.3. Validation of co-optimization

As expected, the activated flex capacity for ramping up and ramping down is not equal if congestion and imbalances are solved simultaneously. This is shown in Figure 4.8. Part of the capacity is used to address imbalances, while another part is used to resolve congestion. Additionally, the capacity is not activated strictly according to the merit order due to the transport constraints considered in the system. This can be seen in Figure 4.8. In this figure the cheapest unit is on the bottom and the most expensive one on top. Notable is that the most expensive unit is activated in step 2 and 3. and the cheapest unit is activated after step 5.

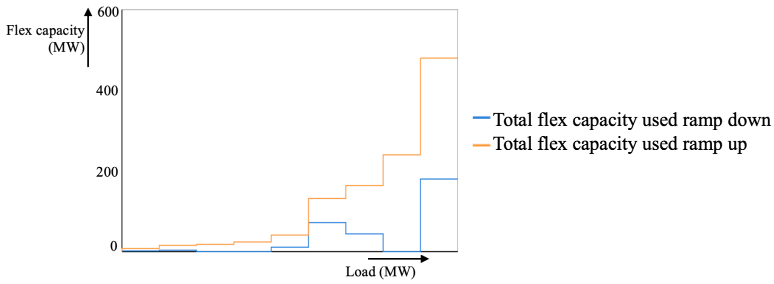

Figure 4.7: Market design 1: Capacity activation flex product

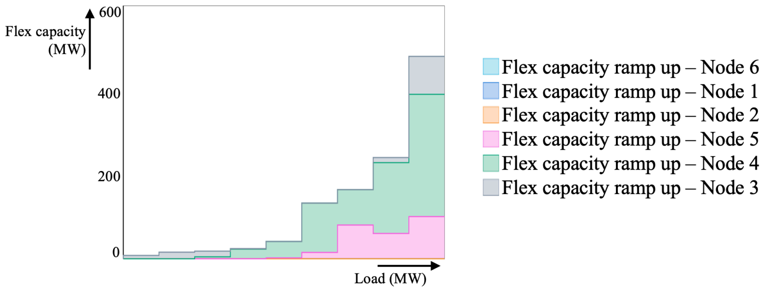

Figure 4.8: Market design 1: dispatch order

4.4. Validation of Kirchhoff's circuit law

When transport constraints are taken into account, Kirchhoff's circuit law must be satisfied. According to this law, the sum of all voltages around any closed loop in a circuit must be zero. To verify if the model adheres to these constraints, simulations are conducted both with and without considering these power flow constraints, typically during the redispatch process. The power flow through the transmission lines is then summed up. To perform this summation, a specific direction is assigned to the loop: energy flowing in the clockwise direction is considered a voltage gain, while energy flowing counterclockwise is considered a voltage drop. The electrical network used in the analysis (refer to Figure 3.1), which consists of 6 nodes and forms 2 closed loops, is evaluated. The sums are calculated for both loops, as demonstrated in the following equation:

$$\text{Kirchhoff's circuit law} = \sum(\text{Voltage Drops}) - \sum(\text{Voltage Gains}) = 0$$

In Table 4.1, the total power flow in the closed loops of regions A and B is shown. The results confirm that the model adheres to the power flow constraint. When the power flow constraint is applied in the model, the sum is consistently zero. However, without this constraint, the sum is not always zero.

	with power flow constraints		**without power flow constraints**	
Load:	**Sum of capacity in closed Loop region A**	**Sum of capacity in closed Loop region B**	**Sum of capacity in closed Loop region A**	**Sum of capacity in closed Loop region B**
40 MW	0	36	0	0
400 MW	-50	60	0	0
1000 MW	150	-50	0	0

Table 4.1: Comparison of power flow in closed loop regions A and B with and without power flow constraints under different load conditions.

5 Results

Each simulation of the various market design options produces results for three KPIs: the required capacity, the average market price and the total costs to solve congestion and imbalances. The simulations consider different load levels, with the results averaged and compared to the average of the current market design. The results indicating these values for each KPI across the various design options are detailed in Appendix C. To evaluate the benefits of the developed market design options, the results of each design option is compared to the results of the current market design. This results in Table 5.1. This table shows the relative improvement in KPI performance for each market design compared to the current market design. The performance improvement is expressed as a percentage, where a higher percentage indicates better performance. From the TSO's perspective, a reduction in required capacity, average flex price, and total costs is considered desirable. Therefore, any reduction is presented as a positive percentage improvement. A negative percentage indicates that the market design performed worse on this KPI. Design option 1 is developed to identify the most optimal solution, unrestricted by current technical and operational limitations. As a result, the performance improvement of design option 1 demonstrates the maximum potential gains for an integrated market using co-optimization. The performance improvements of design options 2 and 3 are compared with this improvement of the "most optimal" design to see how closely they match these potential gains. This comparison focuses on the effects of introducing a flex product and considering transport constraints, with or without implementing co-optimization.

	1: Co-optimization, net capacity			2: Separate optimization, net capacity				3: Separate optimization, gross capacity			
Reduction in:	MP	PAB	LMP	MP *	PAB	LMP *	PAB + MP *	MP	PAB	LMP	PAB + MP
Required capacity	21%	21%	21%	17%	14%	17%	12%	0%	0%	0%	0%
Average market price	38%	-4%	42%	8%	-7%	23%	-19%	20%	-6%	32%	-5%
Total costs	55%	39%	57%	13%	32%	22%	0%	16%	21%	31%	7%

Table 5.1: Relative improvements [%] in market design performance compared to the current market design for each KPI

Regarding the comparison with the reference model, it is important to note that in the current market design, solving imbalance doesn't consider transport constraints and can lead to congestion. This congestion, in turn, necessitates additional capacity, resulting in higher costs for addressing both imbalances and congestion. However, this extra capacity and the associated costs are not accounted for in the comparison. This means that, in reality, the required capacity and total costs of the reference model could be higher.

5.1. Required capacity

The first row shows the improvement of the given market design on required capacity to solve congestion and imbalance. The congestion and imbalance problem is similar for each market design. As expected, design option 1 achieved the most optimal results and needs the least capacity to solve con-

*: these pricing models, use maximum price settlement. Since the net capacity used, the maximum market clearing price of the redispatch and balancing market is used

gestion and imbalance. Co-optimization considers congestion and imbalance at the similar timestep, making smart use of flex capacity. In this way the model uses the capacity to solve both problems at the same time. This reduction in required capacity results in an improvement of 21% compared to the current market design. However, interestingly, the improvement in required capacity of design option 2 doesn't deviate much from design 1. This indicates that even without co-optimization, simply integrating the products results in significant improvements in the required flex capacity.

For this particular situation, the simulation model shows a larger improvement in design option 2 for MP and LMP than in a market design where PAB is used. This can be explained by the different bid behaviors for MP and PAB, resulting in a slightly different merit order. Since the already activated redispatch capacity can be alternated in the second phase to solve imbalances, the total net capacity used can be lowered. For the net capacity use, it matters which assets in the separate steps. If similar assets are used during redispatch and balancing in opposite direction (first ramping up and then ramping down or other way around), less net capacity is required to solve redispatch and imbalance problems. This means that the asset deployed in both steps, influences the total required capacity. Since this market design optimizes in two steps rather than through co-optimization, the activation of similar assets in each step is not intentionally coordinated. As a result, a different merit order may incidentally lead to the use of different assets, leading to a lower performance improvement. However, the required capacity is never greater than in the current market design. The improvement always falls between 0% and the gains achieved by the co-optimization approach. In the MP and LMP scenarios, the simulation shows that more similar assets are activated in both steps, which explains the higher gains in required capacity. The results also indicate that market design 2, which is using PAB for redispatch and MP for balancing, leads to a lower improvement. This is likely because PAB and MP create different merit orders, reducing the likelihood of the same assets being used in both steps.

Market design 3 results in the same amount of required capacity as the current market design. The two-step optimization with gross capacity means that redispatch capacity cannot be adjusted for balancing, leading to no improvement in the capacity used. However, since transport constraints are not accounted for during balancing in the current market design, additional redispatch capacity might be needed after balancing. This extra capacity, however, is not included in the required capacity results for the current market design. Considering this, market design 3 could potentially perform better than the current market on the required capacity.

5.2. Average market price

The second row of Table 5.1 shows the improvement in the average price paid for flexible capacity compared to the current market design. Most designs show an improvement, indicating a reduction in market price compared to the current market design. In market design 1, both the MP and LMP pricing approaches show a price reduction, which can be explained by the fact that less capacity is used. In these pricing approaches, the price is set by the most expensive asset needed to meet demand, so using less capacity likely results in a lower market clearing price. Another contributing factor is the absence of PAB for redispatch like in the current market, as PAB tends to lead to different bidding behavior. Consequently, market design 1 with PAB results in a higher average market price compared to the current market due to these differences in bidding behavior.

Market design 3 has a relatively small improvement in the average price. This can be explained by the settlement method used. Since the net capacity is used, the settlement can only use one price for settlement, unlike market design 3. But if MP, LMP or a combination of PAB for redispatch and MP for balancing is applied, two different market prices appear. In these designs, the maximum price approach is used to solve this. But despite using the maximum price settlement method for the MP, LMP and PAB+MP pricing mechanisms, the MP and LMP scenario still show an improvement over the current design. Similar to design option 1, design option 2 shows an increase in price for the scenarios incorporating PAB. And especially the PAB+MP results in a price which is 19% higher. Due to the maximum price settlement which picks the maximum price of the PAB redispatch market and MP balancing market.

Notably, market design 3 shows significant improvement despite not using co-optimization and not being capable of adjusting redispatch capacity. This improvement is attributed to the introduction of

MP. In the scenario where PAB and MP is used, just like the current design, the price is a bit higher. This can be explained by the fact that transport constraints are considered, resulting in more expensive assets being used. In this way, no congestion is created with balancing the grid. But since the extra costs of the congestion created by balancing in the current design are not included, it could be that the improvement is higher than indicated.

And among all options, the LMP approach consistently achieves the lowest prices, as one area's low price reduces the overall average market price. However it has to be taken in mind that if the locations of the assets and their bid prices differed, the outcome could be different.

5.3. Total costs

The final row illustrates the reductions in total costs associated with resolving congestion and imbalance, relative to the current market design. All new design options demonstrate cost improvements. And even though market design 2 has a higher average market price for some cases, none result in an increase in total cost. This suggests that the capacity savings in design 2 are sufficient to offset its relatively high market price. However, design option 2, using the same pricing approach as the current market design, shows no cost improvements. This indicates that the gains in required capacity are not enough to offset the low average market price under these combination of pricing approaches.

The reason market design 3 using PAB+MP pricing shows an improvement in total costs, despite having no improvement in required capacity and a higher average price, is due to the method used to calculate total costs. The comparison between market designs 0 and 3 is made by summing the total costs for all load levels in each design, rather than comparing them on a per-load basis. As a result, market design 3 may show a reduction in overall costs due to more favorable results in some load conditions, even though its performance in terms of required capacity or average price may not be consistently better. This method highlights the cumulative effect of total costs across all load scenarios, rather than focusing on improvements at individual load levels. At most load levels, the total costs were higher, but at higher loads, the costs were lower. This can be attributed to the integrated product, which ensures that more capacity is available, leading to a different market clearing price. Since participants bid one capacity that can be used for both purposes, there is a greater overall availability of capacity. In the balancing step, where MP is used, this increased capacity can result in a lower market clearing price, ultimately leading to lower total costs.

5.4. Comparison of maximum price approach and average price approach

Given the strong potential shown for separate optimization using net capacity, an additional simulation was conducted for this market design option. While the gains in required capacity were significant, the improvements in average price and total costs were relatively lower, which was attributed to the maximum price approach applied. To explore the potential cost reductions with an alternative method, the average price method was tested. This approach provides greater insight into the impact of the maximum price settlement. The results, presented in Appendix C, indicate that the average price method leads to a greater relative improvement in total costs, as shown in Table 5.2. These findings suggest that multiple settlement approaches can be applied to net capacity, and even with the PAB+MP pricing method, this market design shows substantial potential.

Reduction in:	**Market design 2: separate optimization, net capacity**		
	MP (with average price)	**LMP (with average price)**	**PAB + MP (with average price)**
Total costs	42%	47%	22%

Table 5.2: Relative improvements [%] in performance on total costs compared to the current market design for each KPI

5.5. Sensitivity analysis

Specific parameter values are selected for the model simulations to ensure feasibility, taking into account constraints such as power flow, capacity limits, and operational requirements. Acknowledging that these values may influence the results, simulations of the design options are conducted with varying values for load, imbalance, and provided flexible capacity. This sensitivity analysis aims to evaluate how these parameters impact the KPIs for each design option. The results of the sensitivity analysis are detailed in Appendix E. The sensitivity analysis simulations still account for different load levels, with the results averaged and compared to the average of the current market design.

5.5.1. Impact on the required capacity

First, the impact of the parameters on the required capacity was analysed. The sensitivity analysis shows that the impact of the load level and the imbalance level on the required capacity was fairly consistent across different market designs. As expected, higher loads and larger positive or negative imbalances led to an increase in required capacity for all market designs. The provided flex capacity parameter had minimal effect on the required capacity outcome, although the net capacity did change slightly as more cheaper assets were activated when more capacity was available. This influence is bigger in the PAB pricing approach since the bid prices are closer to each other. Due to the similar impact on required capacity across market designs, the relative performance improvement of market design 2 (separate optimization, net capacity) compared to market design 1 (co-optimization) remained close. Even though the results show that higher loads lead to reduced performance improvements the differences in improvements are similar. This indicates that, despite fluctuations in required capacity, the potential gains of co-optimization can largely be achieved through separate optimization combined with net capacity usage.

5.5.2. Impact on the average market price

Secondly, the impact of the parameters on the average market price was analysed. The impact on the impact of the load on the average market price shows a gradual increase. However, the relationship between the load and average market price is slightly volatile. In most cases the price is lower at lower loads and higher if it increases however fluctuation can occur due to the since the KVL, powerloss and capacity constraints make it a complex relationship. For some loads, these constraints can result in a sudden activation of an expensive asset, setting the marginal clearing price. And the maximum pricing approach for some of the cases in market design 2 (separate optimization, net capacity) makes this impact more significant.

The impact of the imbalance levels on the average market price seems quite small. And unexpectedly, the average price tends to be higher with smaller imbalances in some cases. This is because the simulation runs across different load levels, and the average price is calculated an average. The lower imbalance has a relatively lower impact on the costs than on the capacity used. For this reason, higher imbalances result in a lower average price because the costs are divided by the total capacity used. This is also due to the fact that imbalance has a smaller impact than redispatch due to the small electricity network used in the simulation, requiring more redispatch.

The influence of the amount of provided flexible capacity on the average price is minimal due to the transport constraints considered in the new market designs. An increase in available capacity does not lead to the use of cheaper capacity because of these physical network limitations. Interestingly, there is an increase in the average price as more capacity becomes available. This can be attributed to the fact that the redispatch and balancing steps are still optimized separately. When the available capacity changes, certain assets are activated during redispatch, considering transport constraints, which sometimes leaves less capacity for the balancing step. As a result, prices rise due to the MP approach used during balancing. This highlights a drawback of separate optimization. And how different parameters or network design has more impact on the separate optimization designs.

5.5.3. Impact on the total costs

The impact of the parameters on total costs is analyzed next. The effect of load on total costs is nearly exponential, driven by the combination of higher costs and increased capacity usage. When examining the relative improvement of the market designs on the total costs compared to the current market design, market design 2 exhibits occasional dips in improvement along the various loads. However, overall, the cost improvements remain positive. Notably, the relative improvement of the PAB option tends to increase with higher load levels.

The relationship between imbalance and total costs behaves as expected, with larger imbalances leading to higher costs. However, the relative improvement in co-optimization is greater for larger imbalances, as more cost savings are achieved in such scenarios. For separate optimization (market design 2), the results are less consistent, with significant variation between pricing approaches, demonstrating the impact of pricing methods on total costs under varying imbalance levels.

A similar trend is observed with the level of provided capacity. Interestingly, an increase in available capacity causes market designs 2 and 3, which utilize separate optimization, to perform significantly worse when using PAB or PAB+MP pricing. This is because, in the current market design, an increase in capacity results in a more substantial reduction in costs due to the economic dispatch. In contrast, in market design 2, the capacity reduction does not offset the relatively high market price when more flexible capacity is available, especially under PAB or PAB+MP pricing. This highlights the limitations of separate optimization in effectively utilizing additional capacity.

6 Discussion & Conclusion

The simulation results show that the developed model functions as a proof-of-concept. It demonstrates how simulating different proposed market design options can reveal improvements over the current market design. Although the simulation model uses a small electricity network with just 6 nodes, it is still possible to draw some useful conclusions and gain insights from the results. Three distinct market design options were developed, each featuring a different process. The key differences involved whether to use co-optimization or not, and whether to include net capacity use or gross capacity use. Net capacity usage refers to adjusting the activated redispatch capacity in the opposite direction (e.g., ramping up followed by ramping down) during the balancing step to resolve imbalances. This adjustment leads to a reduction in the overall net capacity used. In contrast, gross capacity usage means that capacity cannot be adjusted, requiring new capacity to be activated for balancing. Furthermore, all design options introduced a flex product and accounted for transport constraints. Each market design was evaluated using three pricing mechanisms: MP, PAB, and LMP. Resulting in a total of eleven market design variations. A simulation model was developed for each design variation, along with the current market design. Quantitative results were obtained for three KPIs: the required capacity to address congestion and imbalance, the average market price for flexible capacity, and the total costs.

6.1. Discussion of simulation model results

The simulations were carried out using a small electricity network with 6 nodes, with variables chosen to ensure a feasible solution, as a real electricity system is expected to always have a feasible solution. Using this small network made it possible to closely monitor energy flows and perform calculations to better understand system behavior.

6.1.1. Evaluation of the performance improvement of each market design option

The results suggest that a new market design which co-optimizes the redispatch and balancing steps leads to a 21% reduction in the required flex capacity compared to the current market design. This design option demonstrates the potential benefits of co-optimization, even though there are several operational constraints involved in its implementation. However, 83% of this improvement can be realized by only introducing a flex product that integrates redispatch and balancing, along with implementing net capacity usage. This suggests that co-optimization is not essential to achieve capacity improvements; integrating redispatch and balancing products together with net capacity usage can lead to significant gains. It also highlights the significant impact of the current separation between redispatch and balancing capacities, which prevents them from being used interchangeably, thereby increasing the required capacity to address imbalances and congestion. Due to the current operational challenges of implementing simultaneous co-optimization, greater emphasis should be placed on integrating the products that enable net capacity usage. Furthermore, all new market designs show either a reduction or no increase in total costs, indicating that capacity savings are enough to offset some of the higher market prices. The average market price variated for each market design since it was highly dependent on the pricing approach used.

The evaluation of the results for market design 3, which applied gross capacity usage, revealed that although no improvements were observed in capacity reduction, this design still resulted in lower total costs. This is particularly interesting because, unlike the current market design, transport constraints are considered during balancing. However, by combining the redispatch and balancing bids, more capacity becomes available in both markets, potentially increasing the availability of lower-cost capacity.

6.1.2. Evaluation of the pricing approaches

In addition to comparing the three market design options, different pricing approaches (MP, PAB, and LMP) are applied on each design option. As expected, these pricing methods affect average prices and costs, but no single mechanism consistently performs best across all market designs. PAB typically results in higher average prices, but this depends highly on the simulated bidding behavior. Therefore, the results do not fairly indicate which pricing mechanism leads to the lowest costs for each market design. However, other insights can be gained from the impact of different pricing mechanisms. First of all, it shows that the settlement method is a critical consideration if applying net capacity usage. Since net capacity is used during settlement, only one price can apply. But in the market designs using MP as the pricing method, redispatch and balancing have different market clearing prices. To solve this, the maximum price approach was used to evaluate potential cost improvements of this market design, despite it being the least favorable pricing method from a cost improvement perspective. The results indicate that when this method is applied, and the same settlement method as the current market design (PAB and MP) is used for a fair comparison, the costs remain similar to those of the current market design. This is a positive outcome, as there are capacity savings without an increase in costs, even with the maximum pricing approach. This suggests that the capacity savings are sufficient to offset the relatively high market prices. To understand the impact of the maximum price settlement approach, an additional simulation was conducted using the average market clearing price, resulting in a 19% greater relative cost improvement. This demonstrates that there are multiple ways to handle the settlement of net capacity but that it is an extra consideration.

Second of all, the simulation results show that using separate optimization with PAB for redispatch and MP for balancing is a poor combination. The differing merit orders in these pricing approaches, due to different bidding behaviors, negatively impact performance. In market design 2, when net capacity is used, more net capacity is consumed because there is a higher chance that different assets will be dispatched in the separate steps. This issue also affects market design 3, which uses gross capacity. Since MP is applied in the balancing step, if cheaper capacity is already used during redispatch, it leads to a higher market clearing price for balancing. While PAB is shown to work bests at relatively higher capacities. This results in higher total costs than using similar pricing approaches for market design 3. This demonstrates that this combination of pricing approaches is unsuitable for separate optimization. It also illustrates how two-step optimization does not consider balancing during activation of assets to solve congestion, unlike co-optimization, which integrates both processes simultaneously.

The simulation shows that each pricing mechanism influences the required capacity due to the varying merit orders. This has to be considered in the choice making. Finally, for all market designs, the LMP approach results in the lowest total costs, primarily because a cheaper region drives down the price. However, if the asset distribution were different, the cost reduction could be significantly smaller.

6.2. Considerations for the new market designs

When implementing the net capacity approach, the total capacity reduction may raise concerns about the potential profits for individual market participants. A key risk is that if a participant ramps up 100 MW for redispatch and ramps down 100 MW for balancing, they are effectively paid for a net of 0 MW. While there is a higher likelihood of capacity being activated, the overall capacity usage is lower, which could negatively impact participants' earnings. One potential solution is to modify how net capacity is calculated. For instance, if 100 MW is ramped up during redispatch and 60 MW is ramped down during balancing, the settlement could be calculated as (100-60) + 60 = 100 MW, rather than the current 160 MW. In the previous example, it would be (100-100) + 100 = 100 MW, instead of the 200 MW in the current market model. Another risk of the new market designs for market participants is that while some may see increased profits, those operating in areas with more congestion might experience decreased profits. This is because the proposed new market designs take transport constraints into account. Participants providing flexible capacity in congested areas may be disadvantaged by this, whereas currently, they are unaffected when offering capacity solely for balancing. However, an benefit of considering transport constraints is the creation of better long-term price signals. This can encourage market participants to establish flexible capacity in less congested areas, which could help alleviate congestion problems in the long run.

The results also suggest that the choice of market design depends on the TSO's primary objective, whether it is focused on reducing costs or minimizing capacity requirements. Reducing capacity requirements helps alleviate congestion, allowing providers, particularly those in congested areas, to continue offering capacity, which benefits all grid users in the long term. Cost reduction can also benefit the TSO. While profit maximization is not typically the TSO's goal, lowering costs can free up funds for other initiatives. Cost savings in balancing have a limited impact, as these costs are passed on to those responsible for imbalances. However, redispatch costs are directly handled by the TSO. At the same time, the TSO must ensure that market participants remain incentivized, as their participation is crucial for providing flexible capacity. Therefore, the average market price should not drop too low, as it could reduce the availability of flexible capacity.

6.3. Limitations

The results provide some interesting insights, but they must be put in perception. First of all, a simplified network with only a few nodes and transmission lines is used, which could influence the results. Because the network is smaller, the likelihood of capacity being used for both redispatch and balancing, resulting in a lower net capacity, is higher. Therefore, it is expected that the results might be less favorable if the simulation were conducted with a larger network.

Secondly, the simulation model does not represent a real network or actual bidding behaviors. And the parameters are chosen to have a feasible outcome for this physical network, not based on historical data. So the outcomes may vary with other values for the parameters and depend on the network's geographical structure. To address these limitations, a sensitivity analysis was conducted. This analysis showed the impact of the load, level of imbalance and provided flexible capacity.Varying the values of these parameters impacted the extent of the capacity reduction. A higher load resulted in a lower relative performance improvement of all the market designs compared to the current market design. However, although the capacity reduction was smaller, the difference of the relative performance improvement of market design 2 (separate optimization with net capacity) remained close to market design 1 (co-optimization). This indicates that significant improvements can still be achieved with separate optimization using net capacity for different parameter values. The results also showed that the PAB pricing option tended to improve with higher load levels. This shows that PAB could still be considered as an option even though the main results lower cost improvements than MP or LMP.

Another limitation is the absence of data on activated bids in the redispatch and balancing markets. While some data is available for balancing market bids, the specific locations of these bids are not provided, as location is currently not considered. Additionally, there is no data available on activated redispatch bids. This lack of data complicates the simulation of market participants' bidding behavior and makes it difficult to understand the geographical distribution of the bids. In the beginning phase of this study, a simulation model is developed of the whole Dutch national grid. However as a result to the missing data, the simulations were conducted on a fictional electricity network rather than the actual Dutch electricity grid.Without accurate location data for balancing assets, which is important for the new market designs considering transport constraints, the results would not realistically reflect real-world conditions. For this exploratory research, a small-scale electricity network was used, allowing for detailed calculations and the ability to track power flows, helping to better understand system behavior. For upscaling the model, this study emphasizes the importance of the geographic distribution of the network and bids, as these factors are critical for dispatch decisions when transport constraints are considered. The specific dispatch significantly affects net capacity usage. This highlights that locational data is crucial for scaling the model to produce accurate quantitative results for these market designs in the real electricity system. To accurately simulate bid behavior, data on both redispatch and balancing bids would be required. This would allow for the calculation of a ratio that demonstrates the relationship between PAB and MP bids for flexible capacity.

6.4. Reflection

Reflecting on the academic relevance of this thesis, the literature reveals a notable gap in the discussion of redispatch and balancing markets, with even less quantitative research available on this topic. In contrast, markets like the Day-Ahead (DA) market have been extensively studied. Although this research was exploratory and utilized a simplified small-scale electricity network, it provides a proof-of-concept that highlights the potential benefits of product integration without the need for co-optimization. While co-optimization has been suggested in the literature as a method to improve redispatch and balancing market design, this study demonstrates that integrating these products alone can deliver significant improvements. Further research into product integration is necessary, given its potential, but it is also essential to first study operational constraints to assess the feasibility and implementation of such integration.

In terms of societal relevance, congestion is a critical issue that is hindering the energy transition by preventing wind farms and batteries from connecting to the grid. This results in higher costs and delays in reducing emissions through the energy transition. While much attention has been given to creating flexibility through batteries and flexible demand, the role of price signals in markets like redispatch and balancing requires more focus. Enhancing ancillary services such as redispatch and balancing could provide much-needed flexibility to the grid, which is essential before large-scale grid expansion is realized. This study offers an exploratory analysis of the performance improvements from integrating redispatch and balancing, demonstrating the potential to increase grid flexibility.

Reflecting on the process of this study, several important aspects emerged. Initially, a simulation model of the full Dutch electricity grid was developed, which took a significant amount of time. Due to the lack of data on balancing and redispatch bids, it was decided to run the simulation on a smaller-scale electricity grid. Moreover, in a larger network, it became challenging to track power flows and understand cost distribution. In hindsight, it would have been more effective to start with a small network simulation. If interesting results arise, the network could then be expanded. Unfortunately, time was lost following the wrong order. The optimization program Linny-R was used for the simulation. The strength of this tool lies in its user-friendly interface, allowing not only calculations but also visualization of power flows within the physical network. However, implementing separate optimization with an integrated flex product was difficult within this tool. Although it was possible, it required transferring the output from the first optimization into a new model for the second step. Other options, like using several time steps, were available but made it harder to analyze the results of separate optimization steps.

6.5. Conclusion

The insights will be used to answer the main research question:

How much performance improvement can be achieved with a new market design that integrates redispatch and balancing, with and without co-optimization, across various pricing scenarios?

This study explored the potential benefits of new market designs for balancing and redispatch, with a focus on the introduction of a flex product, co-optimization, and the consideration of transport constraints. Three distinct market design options were developed, each featuring a different process. The key differences involved whether to use co-optimization or not, and whether to include net capacity use or gross capacity use. Net capacity usage refers to adjusting the activated redispatch capacity in the opposite direction (e.g., ramping up followed by ramping down) during the balancing step to resolve imbalances. This adjustment leads to a reduction in the overall net capacity used. Furthermore, all design options introduced a flex product and accounted for transport constraints. Each market design was evaluated using three pricing mechanisms: MP, PAB, and LMP. Resulting in a total of eleven market design variations, indicating possible options for market integration.

The simulation model showed that the market design using co-optimization led to a 21% reduction in the required flex capacity compared to the current market design. However, 81% of this improvement can be realized by only introducing a flex product that integrates redispatch and balancing, along with implementing the net capacity approach. This suggests that co-optimization is not essential to achieve capacity improvements; integrating redispatch and balancing products together with net capacity calculation can lead to significant gains. It also highlights the significant impact of the current separation between redispatch and balancing capacities, which prevents them from being used interchangeably, thereby increasing the required capacity to address imbalances and congestion. The design using separate optimization steps takes operational constraints into account, making it a more practical solution. Furthermore, all new market designs show either a reduction or no increase in total costs, indicating that capacity savings are enough to offset some of the higher market prices. The average market price variated for each market design since it was highly dependent on the pricing approach used.

In addition to comparing the three market design options, different pricing approaches (MP, PAB, and LMP) were applied. As expected, these pricing mechanisms impacted average prices and costs, but no single method consistently performed best across all designs. PAB generally led to higher average prices, but this varied depending on bidding behavior, making it difficult to determine the most cost-effective mechanism. The results also highlighted that settlement methods are crucial when using net capacity, as only one price can apply. In market designs using MP, redispatch and balancing had different market clearing prices, so the maximum price approach was applied for cost comparison. While this method wasn't the most favorable for cost reduction, it showed that capacity savings could offset the higher market prices. The simulations also revealed that using separate optimization with PAB for redispatch and MP for balancing is a poor combination. The differing merit orders caused by different bidding behaviors increased net capacity usage and led to higher total costs. This issue persisted in market design 3, where MP in balancing resulted in higher clearing prices when cheaper capacity had already been used in redispatch resulting in higher total costs. Therefore, this combination of pricing mechanisms is not suitable for separate optimization. Additionally, the simulations showed that LMP consistently resulted in the lowest total costs, though this was largely due to a cheaper region driving down prices, and different asset distribution could lead to less cost reduction.

This study demonstrated a proof-of-concept by using a simulation model of a simplified small electricity network to show relative improvements of new market designs compared to the current design. It shows that such a simplified model can still provide valuable insights into system behavior and indicate the potential benefits of different market designs. The sensitivity analysis revealed that although different variables can affect the outcomes, the overall ranking of market design performance remained consistent. Moreover, chosen variables for the model did not impact the small difference on required capacity for the market design co-optimization compared to the market design separate optimization with net capacity on capacity reduction was minimal. However geographical factors, such as the locations of assets and transmission lines, have a more significant effect on the outcomes since the dispatch of capacity in the separate optimization steps influences the net capacity usage.

Although this research was exploratory and used a simplified small-scale electricity network, it provides a proof-of-concept that showcases the potential benefits of product integration without relying on co-optimization. This highlights the potential to increase grid flexibility, which is crucial for supporting the energy transition. While much focus has been placed on creating flexibility through batteries and flexible demand, greater attention should be given to the role of price signals in markets like redispatch and balancing.

While this study has provided insights into the benefits of the introduction of a flex product, several areas need further investigation. One critical aspect is the operational feasibility of integrating different products into a single flex product. Future research should explore how to address the varying characteristics of these products and how to streamline their integration through a unified interface for market participants. This includes developing a consistent pre-qualification process that ensures all participants can engage with the flex product effectively. Additionally, it would be beneficial to test one of the design options with market participants to examine their reactions. Understanding potential drawbacks from their perspective, as well as observing how they might adjust their behavior in response to the new design, could provide practical insights for further refinement. Finally, expanding the simulation model to cover the entire national grid would offer a more comprehensive evaluation of the proposed market designs. This would allow for a better assessment of the potential impacts on a larger scale, providing a clearer picture of the real-world applicability of these innovations.

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A

Analysis of redispatch and balancing market

One reason flexibility products are not interoperable is that they have different technical specifications and product requirements (McCulloch et al., 2023). Therefore, before developing a market design integrating balancing and redispatch, it is important to get a thorough understanding of their functioning and products. This chapter includes an analysis of both markets, based on literature and documentation of TenneT. This breakdown of both services contributes to identifying conflicts and differences which is necessary for defining design choices.

A.1. Grid balancing

To balance the grid, three types of balancing products can be activated: Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), and manual Frequency Restoration Reserve (mFRR). Each product has its own characteristics (as illustrated on the right in A.1) and is activated through separate markets with different timeframes (as shown in the left figure A.1. When a frequency deviation occurs, the TSO activates balancing products based on the duration and magnitude of the imbalance.

Figure A.1: Balancing products and its characteristics (Modified figure from TenneT (2019))

A.1.1. Occurrence of imbalance

An imbalance occurs when a Balancing Responsible Party (BRP) deviates from its Energy Program (E-program). Each party connected to the electricity grid has to be assigned to a BRP. A BRP has a portfolio with consumers and producers. Their task is to balance the demand and supply of the connected parties.

During the day-ahead period, the BRP collects information from all parties within their portfolio about the expected supply and demand. Next, the BRP prepares an E-program for each Imbalance Settlement Period (ISP) for the following day. The E-program outlines the supply and consumption schedule in 15-minute intervals for the entire 24-hour period of the next day (ACM, 2024). All BRPs submit this

E-program each day at 14:00. If the BRP expects a shortage or surplus, they can trade on the wholesale electricity market, which can be on the long-term market, day-ahead market or intraday market. Then, during the day, the actual supply or demand could deviate from the E-program submitted by the BRPs, which is causing an imbalance in the system (TenneT, n.d.-c). A portion of the imbalances from the BRPs will cancel each other out. Therefore, the overall imbalance of the Dutch grid is the sum of all deviations from all BRPs. Imbalances are location dependent but the sum of all imbalances is considered as a system imbalance.

If the BRP contributed to a system imbalance, the BRP will have to pay TenneT. If the BRP's imbalance supported the system (i.e. it was in the opposite direction of the system imbalance), the BRP will receive the imbalance price from TenneT. During the ISP, BRPs have the opportunity to correct their own imbalance. TenneT publishes real-time imbalance prices (TenneT, 2019) . With this information, BRPs can decide whether it is financially beneficial to increase or decrease their imbalance. BRPs are then essentially participating in the imbalance market, a practice known as passive balancing. BRPs must estimate what the imbalance market will do, which introduces a risk of making incorrect predictions (Ziegler, 2022). If this estimation is incorrect, BRPs will have to pay significant fees.

The process for activating balancing products is shown in figure A.3. The following sections discuss this process per product.

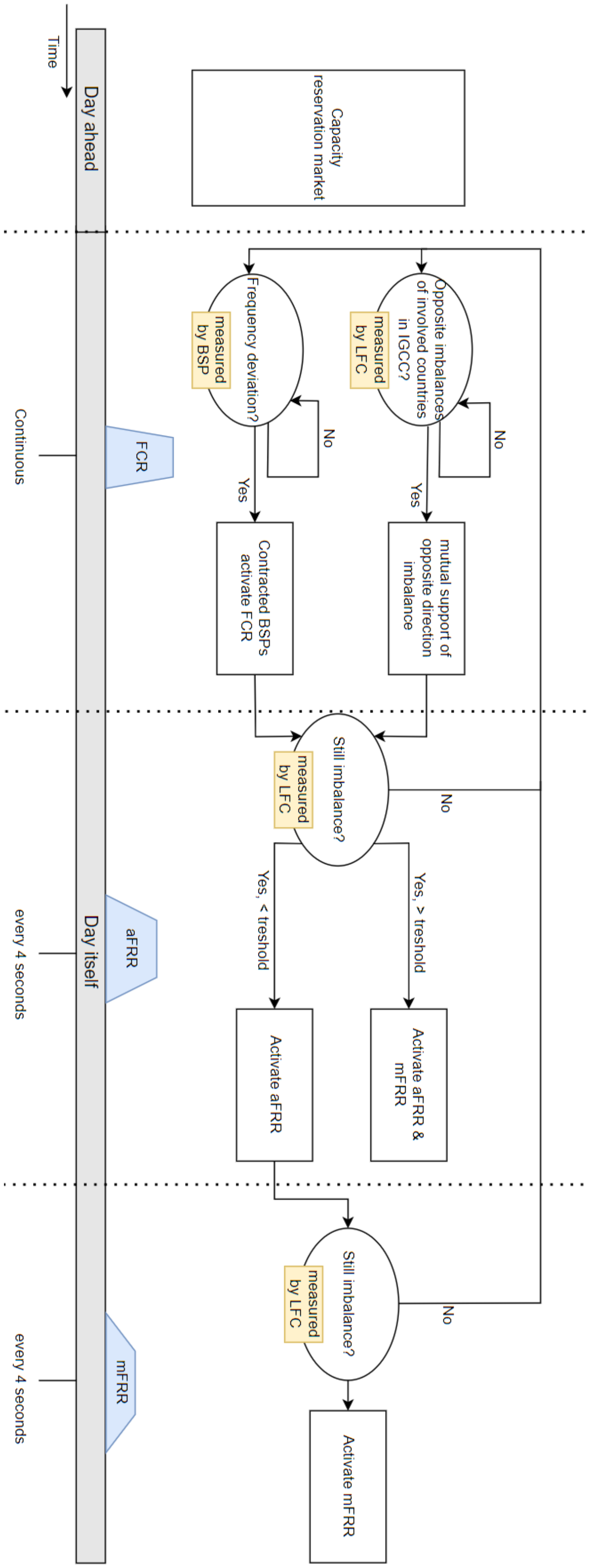

Figure A.2: Balancing system process

A.1.2. International Grid Control Cooperation (IGCC)

During the entire day, two parallel processes make sure to stabilise the system frequency within limits before it is necessary to activate FRR. One of these processes involves the collaboration between TSOs. TSOs of different countries participate in the International Grid Control Cooperation (IGCC). This collaboration ensures that if different countries have market imbalances in opposite directions, they can support each other. In this way, market imbalances of the involved countries are decreased, resulting in lower imbalance prices (TenneT, 2022).

A.1.3. Frequency Containment Reserve (FCR)

The other process involves contracted BSPs providing FCR. FCR is designed for short-term imbalances because of its very fast response times, often within seconds, to maintain grid frequency. In shorter than 2 seconds, installations respond to frequency deviations European Commission, 2016) by increasing or decreasing their production or consumption. Activation typically lasts seconds or minutes under normal conditions. However, in alert situations, activation may extend up to 15 minutes (TenneT, 2024c). Providers of FCR provide capacity quickly and automatically. The frequency is self-measured by the connected plants, so there is no need for a control signal from the grid operator.

Droop control is a method used to regulate the output of the reserve power in response to frequency changes. The "droop" is a value and decides the deliveries of FCR, which is based on the magnitude of the capacity (TenneT, 2024c).

TenneT organises daily auctions in blocks of 4 hours with other TSO's named "the common auction" (TenneT, n.d.-a). BSPs place a bid and TenneT selects FCR volumes based on a merit order. TenneT contracts a specific amount of FCR, to comply with its international balancing obligation set forth in EU regulations. There is no separate activation price for actual energy providing. The timeline of this auction is shown in figure A.3.

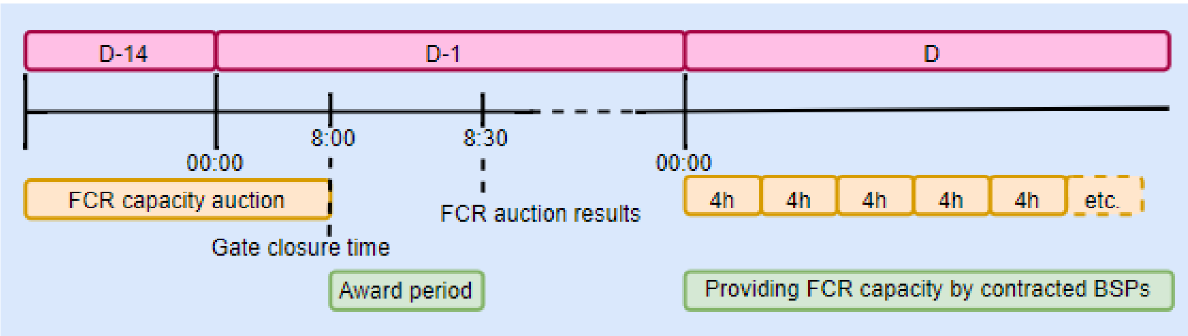

Figure A.3: Timeline FCR

ENTSO-E establishes the minimum FCR capacity, representing a percentage of the total FCR capacity necessary for the synchronous zone, set at 3000 MW in both positive and negative directions. In 2024, this percentage stands at 3.7%, implying that the Netherlands must maintain 111 MW available for both directions at all times (ENTSO-E, 2013). One of the requirements of contracting FCR is that 30% of the mandatory FCR capacity has to be allocated to providers with a connection in the Netherlands. On average TenneT contracts around 60MW FCR in the Netherlands (TenneT, n.d.-a).

A.1.4. automatically Frequency Restoration Reserve (aFRR)

For larger disturbances, FRR is activated. FRR can be activated automaticly (aFRR) or manualy (mFRR). This is determined by TenneTs system for grid balancing which is called "Load Frequency Control" (LFC). The purpose of LFC is restoring imbalance within the frequency recovery time of 15 minutes defined by ENTSO-E (TenneT, 2022). To provide system balancing at all times, the LFC monitors continuously the energy exchange with the electricity network in the synchronous area of Continental Europe (CE) (TenneT, 2022). The LFC continuously calculates the Area Control Error (ACE) of the

Netherlands. The ACE is based on unintended international electricity exchange. To measure this, the difference between the total cross-border exchange as set in the E-program's and the total measured exchange on the inter-connectors is calculated. This difference is corrected for the predicted frequency support of FCR. And based on those calculations the LFC will activate aFRR *automatically*, when necessary. If an imbalance is too large to solve it with only volumes of aFFR, additional volume of mFRR will be *manualy* activated. TenneT only activates balancing products when actual imbalance occurs (real-time), not for predicted imbalances.

Similar to FCR, ENTSO-E also has set a minimum requirement for aFRR capacity and total FRR capacity (ENTSO-E, 2013). For the first half of 2024, the minimum required aFRR capacity is 350 MW up and 350 MW down (TenneT, n.d.-a). Each half year TenneT calculates the amount of balancing reserves needed. To guarantee this minimum, TenneT organizes daily capacity auctions through the Action Platform for Ancillary Services (APFAS) (TenneT, 2023b). In APFAS, FRR auctions are organized where capacity bids of aFRR and mFRR are selected at the same time. The algorithm considers the minimum amount of aFRR and then optimizes the allocation of the remaining necessary total FRR capacity by awarding it to the cheapest option.

aFRR is activated first if an imbalance cannot be solved by the initial balancing solutions like FCR and the IGCC. mFRR can be activated directly together with aFRR if the imbalance is above a certain treshold. In order to ensure that there are sufficient bids of aFRR available, TenneT establishes contracts in which suppliers commit to submitting bids for a certain period. A daily auction takes place where the aFRR provider places a bid for capacity reservation. BSPs can place bids untill 9:00 and at 9:30 the auction results are published. Contracted BSPs are obligated to bid in the energy auction. Besides these contracted BSPs, not-contracted BSPs can also place bids. These bids are called 'free bids'. The bids from contracted BSPs and not-contracted BSPs compete in the same merit order-list. Contracted aFRR energy bids do not have priority over free energy bids (TenneT, 2022). This guarantees sufficient availability of balancing energy bids at all times, with their prices remaining determined by the market. Contracted BSPs need to submit their energy bids before 14:45 and non-contracted BSPs don't have a deadline. Both parties can to change their bids up to 30 minutes before the designated time.

Activation of energy happens real-time and is done automatically through delta-setpoints calculated by the Load Frequency Control (LFC) system (TenneT, 2022). After a BSP is activated to provide energy, TenneT sends a new setpoint every 4 seconds to the BSPs. These setpoints have a minimum step op 1 MW (TenneT, 2022). This approach allows the grid operator to adjust reserve capacity real-time in an accurate way.

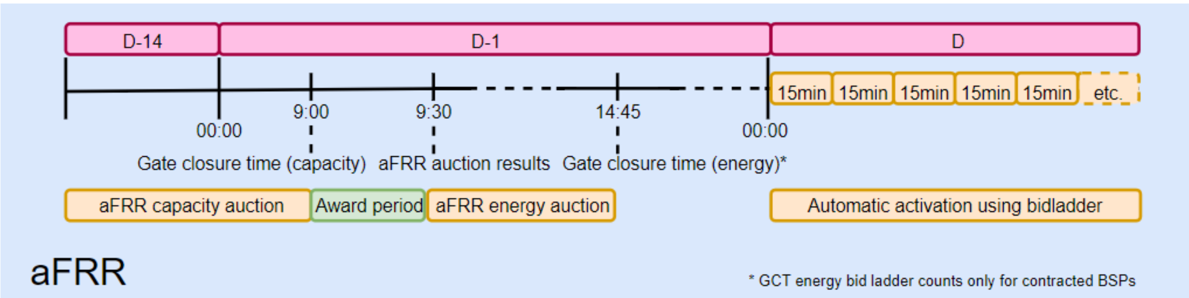

Figure A.4: Timeline aFRR

A.1.5. manually Frequency Restoration Reserve (mFRR)

In addition to aFRR, TenneT has the option to activate mFRR capacity to maintain balance in case of incidents and substantial long-lasting power deviations. The goal of mFRR is to make aFRR volumes available again for new potential imbalances. The timeline of aFRR and mFRR is similar, but mFRR does not include a energy auction (see figure A.5). If a BSP is contracted in the capacity auction, they need to have this capacity available at all times. TenneT activates the procured amount manually without making use of a merit order list. The settlement price is predefined for regulating up or down (TenneT, 2023b.

The minimum capacity is set to a capacity of 954 MW up and 726 MW down for the first half of 2024 (ENTSO-E, 2013). This value is recalculated each half year.

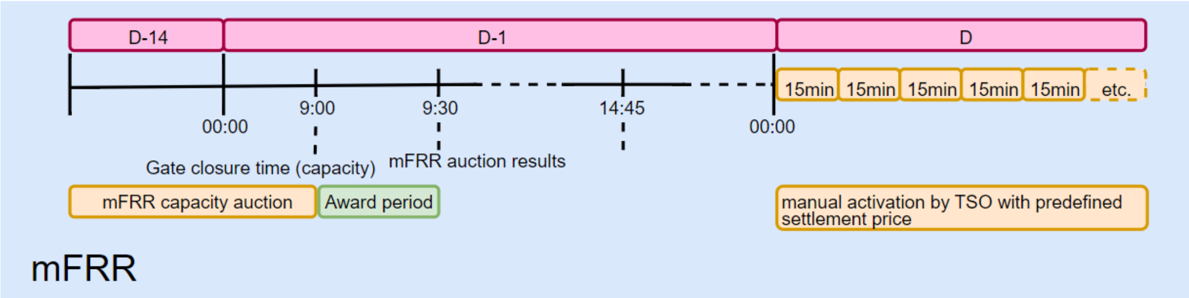

Figure A.5: Timeline mFRR

A.1.6. Balancing product characteristics

Table A.1: Overview of characteristics of balancing products FCR, aFRR and mFRR

	FCR	aFRR	mFRR
Divisible bids	-	Yes	Yes (Mandatory divisible above 100 MW; optional below 100 MW)
Pricing Mechanism energy auction	-	Marginal pricing	Marginal pricing
Pricing Mechanism capacity auction	Pay-as-bid	Pay-as-bid	Pay-as-bid
Min. Bid Size	1 MW	1 MW	1 MW
Max. Bid Size	25 MW	999 MW	999 MW
Blocks/Auction	4-hr blocks	15 min	15 min
Activation	Freq. control	Automatic LFC, 4s	Manual LFC, 4s
Full Cap. opregelen	<= 30 s	5 min	15 min
Full Cap. afregelen	<= 30 s	5 min	10 min
Compensation	Cap. (EUR/MW)	Cap. (EUR/MW) + Activation (EUR/MWh)	Cap. (EUR/MW) + Activation (EUR/MWh)
Imbalance measurement based on	Synchronous area	Dutch grid	Dutch grid
Freq. Bidding	Daily	Daily	Daily

A.2. Redispatch

Avoiding congestion is essential for a secure electricity market. TenneT mitigates the risk of expected congestion, by reducing power flows over certain network elements. To determine when this is necessary, a grid security analysis is deployed under the N-1 criterion. The N-1 criterion means that the grid must be able to continue full operation after the failure of two random elements. This criterion has the goal to ensure high grid reliability Rijksoverheid, 2016. Congestion occurs when a line segment of the transmission grid becomes overloaded with electric power. This can lead to overheating of a wire. Congestion occurs when the demand for electricity transport exceeds the maximum electricity grid capacity. Congestion is essentially a shortage of transport capacity. To determine how much power a segment of the grid can handle, a load flow analysis is deployed. TenneT's system, called *Power Factory*, makes use of the AC Newton-Raphson technique (balanced and unbalanced) to perform a load flow analysis (PowerFactory, n.d.). After TenneT determines when and where congestion will occur, there are two options to avoid expected congestion:

Capacity Limitation Contracts (CLC)
A CLC implies that a contracted party will limit its transported capacity if deemed necessary from TenneT. A CLC offers more certainty for both parties. A party does not need to be a CSP to enter in a CLC, only if they offer a capacity larger than 60 MW. Since this isn't activated via a market mechanism, it will be excluded in this study.

Redispatch
The second option involves redispatch, also known as ROD (Reserve Power Other Purpose) which involves relocating generation and consumption within the grid geographically. This reduces the power flow on a grid segment within a specific location and thereby resolves transport problems. TenneT posts the current congestion in a platform. CSPs with a connection in the specified location can respond by placing a buy-order. A buy-order is always combined with a sell-order outside the congested area, to keep the grid balanced. TenneT will pay for the potential difference in costs of the buy and sell order. This is called "the spread". An order from a CSP has to include the costs, the capacity and the location.

A.3. Redispatch bids

Redispatch bids are placed on two different platforms. TenneT uses their own platform EQUALITY (formerly named RESIN) and a platform originated from a collaboration between TenneT and regional grid operators named GOPACS. Currently, buy and sell orders have to be done on the same platform. TenneT's future vision is to combine the bids from both platforms (TenneT, 2023a).

Table A.2: Comparison between GOPACS and EQUALITY

Feature	GOPACS	EQUALITY
Divisible buy/sell-offers	Divisible	Un-divisible
Bid frequency	per 1 ISP	per 4 ISPs (1 hour)
Prioritised	Yes	No, after GOPACS bids
Balance-neutral	Yes	No
Order book	Open	Closed

When TenneT expects congestion in a certain area, bids on GOPACS will be used first to solve it. GOPACS offers divisible bids which means that buy and sell orders can be a portion of the capacity bid. Buy and sell orders are minimum 0.1 MW and CSPs can choose if they want to offer divisible capacity (all or some) or all or none (GOPACS, 2021). Bids are done per ISP, which is 15 minutes. GOPACS also makes sure that the actions required to solve congestion, do not create an imbalance. If the congestion cannot be solved with offers on GOPACS, bids on EQUALITY will be used. The EQUALITY platform does not offer divisible bids, so CSPs only provide buy and sell orders as *all or none*. Flexibility is not provided through capacity but through time. Bids are for 4 ISPs. Ramping up or down happens outside the timespan of 3 ISPs, which isn't considered when balancing. This means that EQUALITY can create imbalance, in contrast to GOPACS.

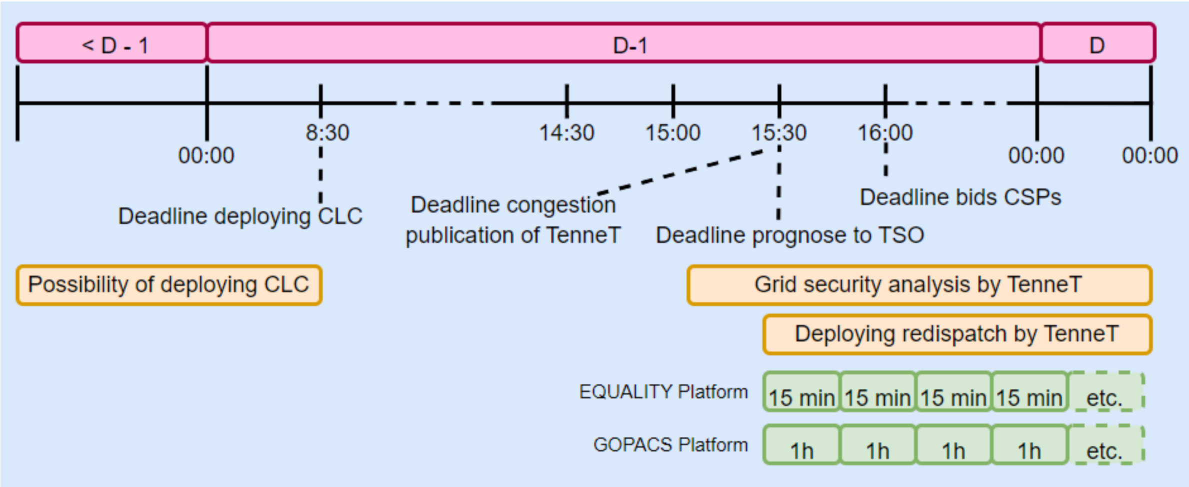

Figure A.6: Timeline Redispatch process

To bid offers for redispatch, connected parties need a transmission capacity of more than 60 MW. Currently, around 40 CSPs place bids on GOPACS and around 7 CSPs place bids on RESIN.

A.4. Differences between the two services

After analysing the operation of grid balancing and redispatch, the main differences have been identified. The identified differences indicate crucial design choices when integrating both market segments. The differences between the two services are distinguished in table A.3.

Table A.3: Comparison of Balancing and Redispatch Markets

Aspect	Balancing	Redispatch
Type of products	up and down regulation of FCR, aFRR, mFRR	up and down regulation energy
Variables of bid	Price, capacity	Effectivity (location), price, capacity
Type of auctions	Capacity reservation & energy activation	Energy activation
Timing	real-time	D-1 till 1h before real-time
The activation	Ramp up or ramp down	Ramp up and Ramp down
Pricing mechanism	Marginal pricing	Pay-as-bid

B

Analysis pricing mechanisms

An analysis is conducted to define the various pricing options for the market design and to examine the differing behaviors of market participants under each pricing scenario.

B.1. Marginal pricing v.s. pay-as-bid

Both balancing and redispatch capacity is offered through an auction with a sealed-bid mechanism (Haghighat et al., 2012). Market participants bid with their capacity and price. The redispatch auction also considers the location by multiplying the effectiveness factor by the price. This together forms the market supply curve, which shows the bid price as a function of the cumulative bid quantity (see figure B.1). It is a single-sided buyer auction with the TSO as the only buyer (Rieß et al., 2017). The market clearing price is at the price where supply is equal to the demand. The submitted bids which are equal to or lower than the market clearing price are accepted and pay according to either the:

- Marginal pricing approach
- pay-as-bid approach

Currently, the auction for balancing capacity makes use of the marginal pricing approach and the auction for redispatch uses the pay-as-bid approach. When integrating balancing and redispatch services into a one market, one of these pricing approaches can be considered.

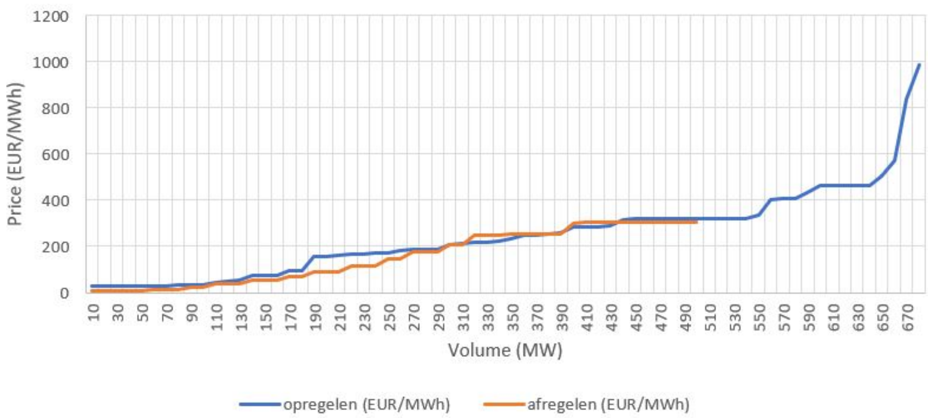

Figure B.1: Market supply curve of the Dutch auction for aFRR balancing energy on 1-01-2023 00:00-00:15 (TenneT, n.d.-b)

Both settlement approaches are multi-unit auction formats. A multiunit auction is an auction in which several homogeneous items are sold. The units can be sold each at the same price (a marginal price auction) or at different prices (a pay as bid auction). This study focuses on pay-as-bid, marginal pricing and locational marginal pricing as these are the most widely used in European electricity markets.

In a pay-as-bid auction, suppliers with accepted bids are pay the price they offered. Consequently, the TSO pays different settlement prices to various suppliers. In a marginal pricing auction, all market participants with activated bids receive the same price, regardless of their individual bids (see Figure B.2). The offers are activated according to the merit order. The offer with the highest price among those accepted determines the market price pay to all providers (see Figure B.2). Therefore, supplier with lower marginal costs receive a larger surplus.

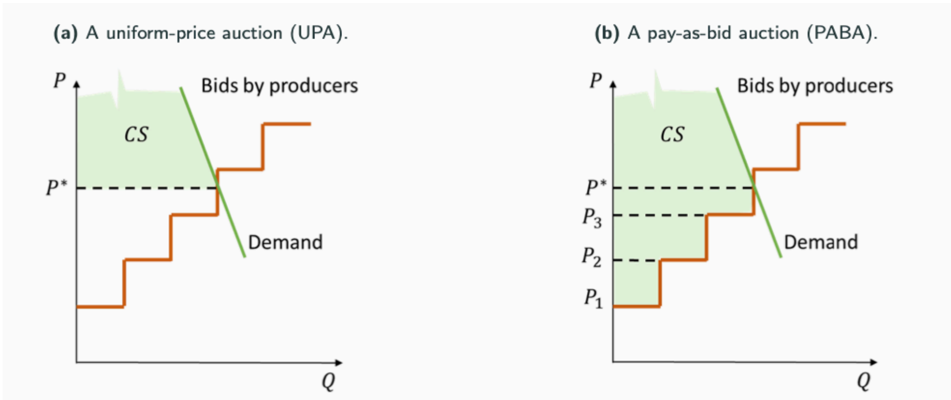

Figure B.2: Demand and supply curve of Uniform-price auction and pay-as-bid auction

B.2. Pros and Cons of pay-as-bid, marginal pricing or locational marginal pricing

When comparing pay-as-bid auctions marginal pricing and locational marginal pricing auctions, each has distinct advantages and disadvantages.

B.2.1. Economically efficient selection of bids

Marginal pricing is more transparent since providers bid their marginal costs and consider their opportunity cost as a minimum. In this way, the cheapest assets are activated. Under the pay-as-bid approach, offers do not only depend on marginal costs and opportunity costs but also on the potential to successfully forecast the market equilibrium. Since forecasting this equilibrium is an extra effort and relatively more expensive for small players, forecasting errors can occur. This can lead to an different order in the merit order, leading to a non-optimal selection of assets. This is shown in figure B.3. Therefor, marginal pricing has a higher chance of an economically efficient selection of bids.

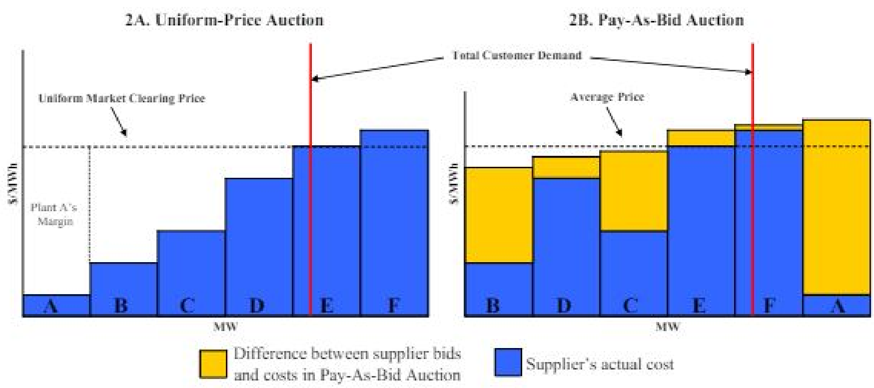

Figure B.3: Different dispatch of assets under pay-as-bid and marginal pricing approach (Tierney et al., 2008)

B.2.2. Long-term incentives

Marginal pricing often results in a more economically efficient order of bids, revealing a more accurate price signal. In contrast, pay-as-bid auctions can distort the asset mix in the merit order, leading to misleading price signals for long-term investments. This reduces the share of cheaper technologies and increases reliance on more expensive technologies (Tierney et al., 2008).

Currently, the settlement price of balancing and redispatch is determined on a system-wide basis. However, an alternative approach is to settle the price by region. The primary advantage of this method is that it provides market participants with more accurate long-term price signals.

B.2.3. Financial outcomes for participants

Both mechanisms have their advantages and disadvantages. Pay-as-bid is simpler because bidders are pay what they ask for, resulting in more predictable revenues for sellers, which is beneficial for providers with large portfolios who may not know which units will deliver the requested capacity. However, pay-as-bid also poses challenges, as bidders must predict the equilibrium market price to ensure their offer is selected and generates a sufficient profit margin (Ofgem, 2012). This requirement makes market entry more difficult.

B.2.4. Market power

Marginal pricing simplifies the monitoring of bids to ensure they match the corresponding assets. Strategic bidding can be distinguished easier. However, this advantage might not apply to balancing markets, where bids lack specific locations and suppliers own multiple assets which it can activate. Another reason for marginal pricing to reduce the risk of market power abuse is that the entry barriers are relatively lower. This results in more possibility for competition and therefor reduced risk of market power.

B.3. Market participants behavior under marginal pricing or pay-as-bid

According to economic theory, the results of marginal pricing and pay-as-bid are similar in a market with perfect competition (Vickrey, 1961). To receive the same price in pay-as-bid as in marginal pricing, the bidding approach has to be different. This means that market participants will likely behave differently under both approaches. The pay-as-bid approach can result in higher bids since bidders have a reason to bid higher than their true marginal costs. In order to make profit they have to include a margin to cover long-run costs and generate profit. Something which isn't necessary using marginal pricing because suppliers gain profits even if they bid their marginal costs (Haghighat et al., 2012; Elia Group, 2020).

Under the assumption of perfect competition, the results of both pricing approaches are the same. The assumption of perfect competition depends on four requirements. 1) many independently owned market parties with no market power; 2) no entry or exit barriers ; 3) perfect information ; 4) homogeneity of the product (Elia Group, 2020). If these assumptions hold, bidders can perfectly predict the demand and supply curves. when pay-as-bid is applied, they can set the price of their bids at the level of the equilibrium price. with marginal pricing, they set their price at marginal costs, because they are remunerated at the price of the last accepted bid. Figure B.4 shows this difference of bidding and how, in a perfectly competitive market, the dispatch and remuneration is the same under pay-as-bid and marginal pricing.

However, these assumptions of perfect competition do not hold in the studied context of balancing markets (Elia Group, 2020). Which means the choice for marginal pricing or pay-as-bid does matter and influences the market output.

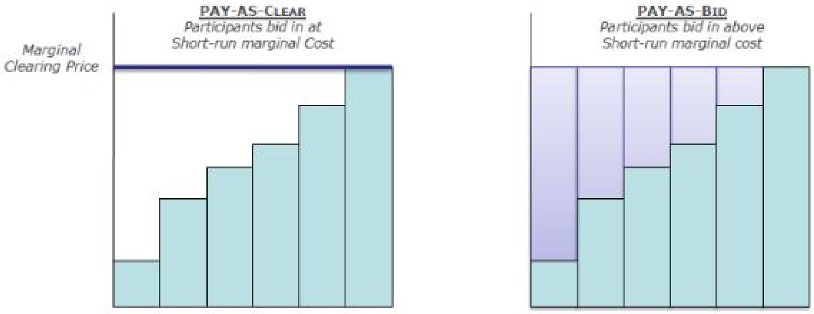

Figure B.4: Different bid behavior under pay-as-bid and marginal pricing approach (Ofgem, 2012)

B.4. Bid function Pay-as-bid

In the redispatch market, the pay-as-bid approach is used in auction. This means that each market player providing capacity for redispatch bids using the following formula:

$$P = MC + \rho \tag{B.1}$$

Here:

- P represents the bid price
- MC represents the marginal costs of a market participant
- ρ represents the margin over the marginal cost

Gibbons (1992) discusses how firms (or suppliers) strategically set prices or bids to maximize their own profit. margin is a strategic decision that reflects a balance between competitive pressures, cost considerations, and profit objectives. In a pay-as-bid market for redispatch, the margin (ρ) that a market participant sets can be influenced by the level of competition (represented by the number of different assets (A) in a region). Additionally, the margin is defined by how high the marginal costs of the market participant are. If these are relatively low, the margin will be relatively more (see figure ..[refer to figure explaining bids in pay as bid]).

This margin can be expressed mathematically as:

$$\rho = \frac{\gamma \cdot B_{\text{max}}/MC}{\alpha \cdot A} \tag{B.2}$$

Here:

- B_{max} represents the highest bid
- MC represents the marginal costs of a market participant
- γ represents the coefficient which determines how much other factors such as strategic behaviors, cost structures beyond marginal costs, market conditions, and levels of risks and uncertainty impacts the margin
- α represents the coefficients which determines how much competition impacts the margin
- A represents the amount of assets in a node, showing the competition

Here, the margin above marginal costs is determined by the highest bid and the player's own marginal costs. The coefficient γ quantifies the additional margin players add to their costs, based on the highest bid in the auction. This coefficient varies across scenarios to account for different strategic behaviors, cost structures beyond marginal costs, market conditions, and levels of risk and uncertainty (Gibbons, 1992). This margin, depicted above the division line in the formula, is then divided by the number of bids in the region, reflecting regional competition. A monopolistic player tends to bid higher than when faced with multiple competitive assets. Increased competition leads to lower bids to enhance activation chances. The coefficient α determines how competition impacts this margin.

C KPI results

Each simulation produces results for the KPIs such as system costs, required flexible capacity, and average market price. Given that each model is run across multiple timesteps with varying loads, the average values of these outputs are used for comparison.

Figure C.1 presents the required capacity for each market design to solve the same congestion and imbalance problem.

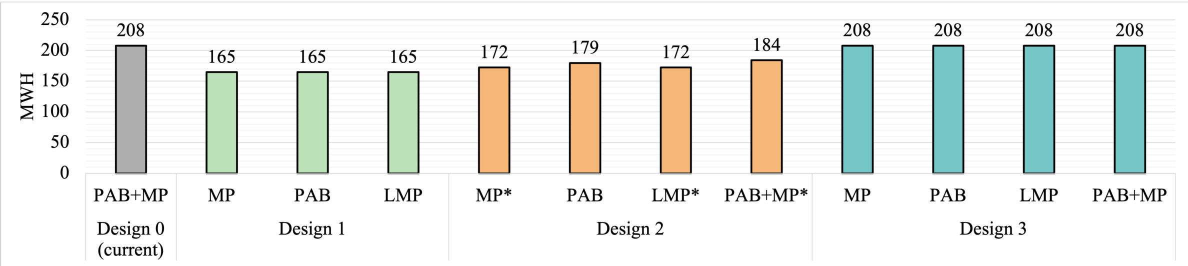

Figure C.1: Required capacity to solve congestion and imbalance [MWh]

Figure $C.2$ displays the average market price paid for flexible capacity across different market designs.

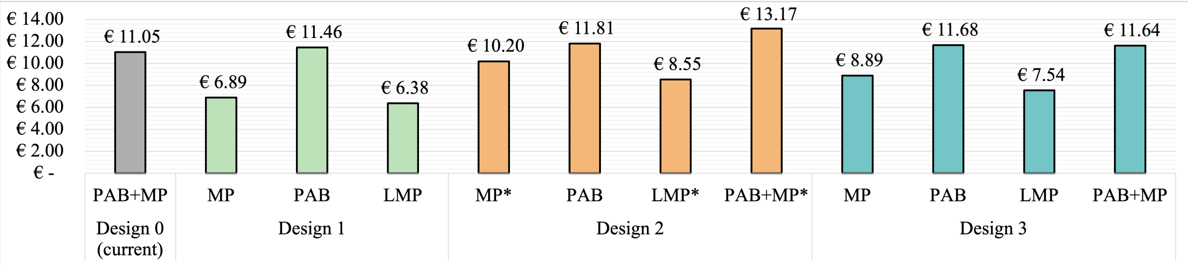

Figure C.2: Average market price for flex capacity [€/MWh]

Figure C.3 illustrates the total costs associated with resolving congestion and imbalance across all design options.

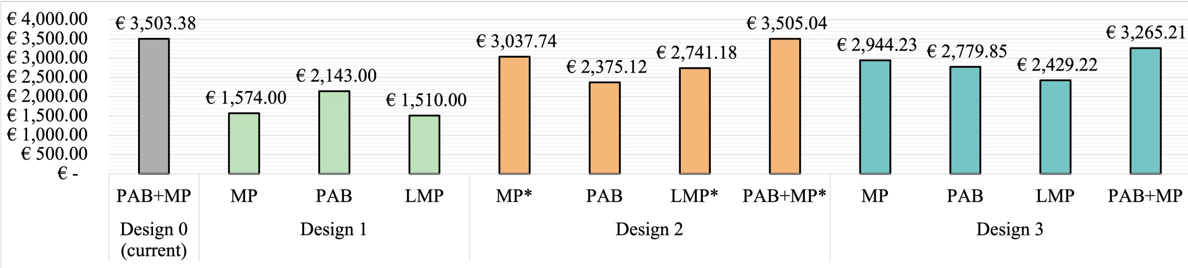

Figure C.3: Total redispatch & balancing costs [€]

Regarding the comparison with the reference model, it is important to note that in the current market design, solving imbalance doesn't consider transport constraints and can lead to congestion. This congestion, in turn, necessitates additional capacity, resulting in higher costs for addressing both imbalances and congestion. However, this extra capacity and the associated costs are not accounted for in the comparison. This means that, in reality, the required capacity and total costs of the reference model could be higher.

C.1. Comparison of maximum price approach and average price approach

To assess the potential gains in total costs using an alternative to the maximum price approach, the average price method is applied. This provides deeper insight into the impact of the maximum price settlement approach. Figure C.4 demonstrates that this method results in a greater relative cost improvement.

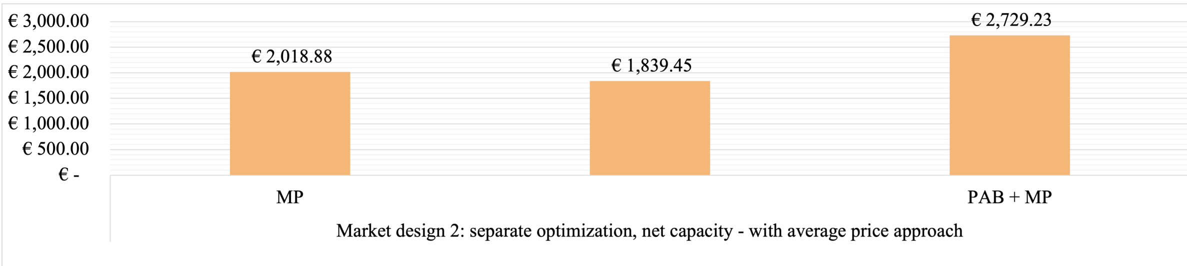

Figure C.4: Total redispatch & balancing costs [€]

D

Model validation

D.1. Redispatch validation

Table D.1 illustrates the results of changing the capacity of each transmission line to 50 MW. The mean activated redispatch capacity is calculated over 9 timesteps with an increasing load from 20 MW to 1000 MW. As expected, the activated ramp-up and ramp-down capacities are equal. The table shows that limiting some transmission lines to 50 MW has no impact, while lines 2-3, 5-6, and 4-6 exhibit an increase in the required redispatch capacity.

Table D.1: Mean Ramp Up and Down with Capacity Constraints

Capacity constraint of 50 MW on transmission line:	Mean Ramp up (MWh)	Mean Ramp down (MWh)
None, only power flow constraint (Figure 4.6)	31.33	31.33
1-2	31.33	31.33
1-3	31.33	31.33
2-3	34.11	34.11
2-5	31.33	31.33
4-5	31.33	31.33
5-6	85.78	85.78
4-6	69.11	69.11

Table D.2 illustrates the same experiment as above, only now the power loss is considered.

Table D.2: Mean Ramp Up and Down with Capacity Constraints

Capacity constraint of 50 MW on transmission line	Mean Ramp up (MWh)	Mean Ramp down (MWh)
None, only power flow and power loss constraints	35.76	32.02
1-2	35.42	32.40
1-3	35.31	32.85
2-3	37.45	35.90
2-5	35.76	32.02
4-5	38.18	32.50
5-6	90.68	88.19
4-6	72.48	72.29

D.2. Power loss validation in redispatch model

Figure D.1 demonstrates that the model behaves as expected.

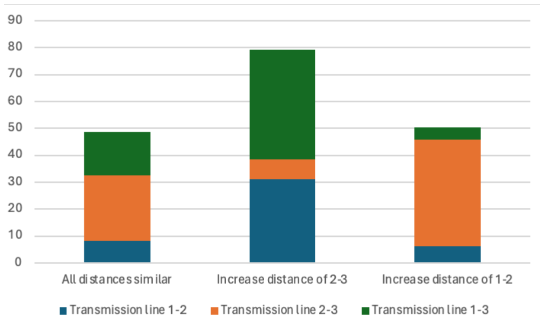

Figure D.1: Validation of distance

D.3. Validation of activation of balancing and redispatch capacity

To validate whether the model solves imbalance, an imbalance is created. The model should solve this nonetheless the location. And the model does solve the imbalance in the merit order, which shows that its correct and not considering transport constraints (see Figure D.2.

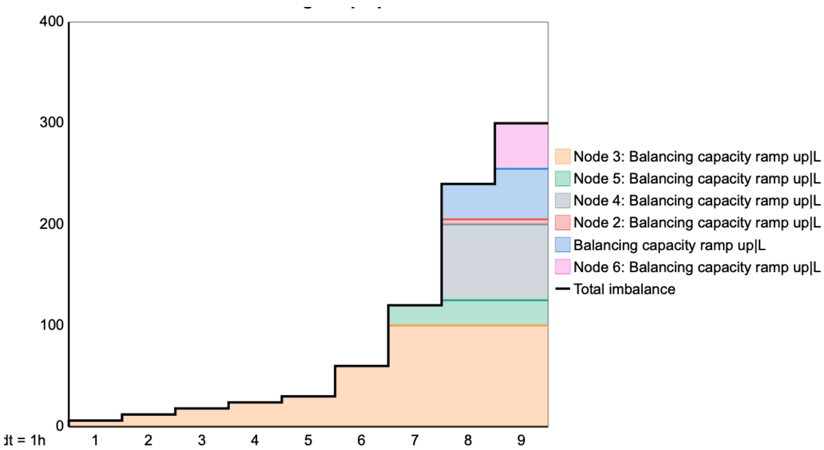

Figure D.2: Imbalance merit order

While looking at the dispatch of redispatch capacity, you can see that location influences the dispatch and the activation does not follow the merit order like balancing market.

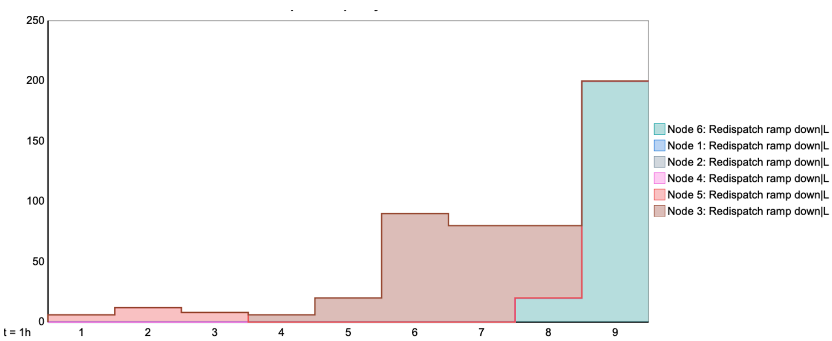

Figure D.3: Capacity activation redispatch

If we change the location of the congestion the dispatch will change while if we change the location of the imbalance the dispatch will not change. Figure D.4 shows that the dispatch changes, even though prices are the same. When changing the imbalance problem, the dispatch of balancing stays exactly the same.

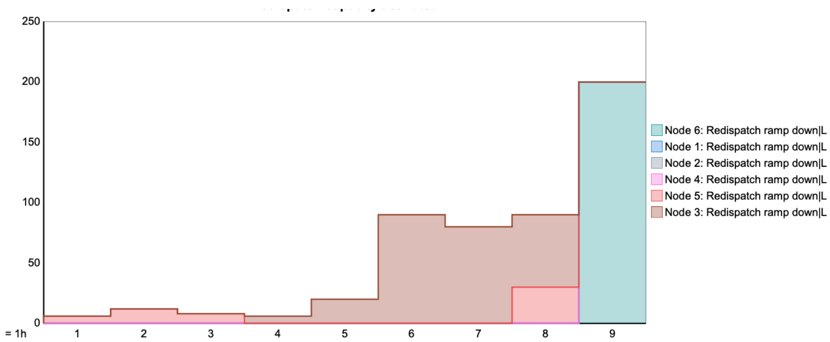

Figure D.4: Capacity activation redispatch with different congestion problem

E

Sensitivity analysis

A sensitivity analysis is conducted to assess the impact of the chosen parameters on the results. In the simulation, certain variables are selected to ensure a feasible outcome, based on the assumption that the electricity market must always remain feasible. Meaning there is sufficient available capacity and transport constraints are adequate to resolve imbalances and congestion at a given load and imbalance level. However, since a real network topology is not used, and the selected variables may influence the outcomes, a sensitivity analysis is performed on three key variables. These include load levels, provided flexible capacity, and the level of imbalance. The graphs illustrate the linearity of the parameter changes, while also displaying the relative improvement to highlight the impact of the parameters on the overall performance.

E.1. Impact of different load levels

The simulation is conducted across nine different load levels (20, 40, 70, 80, 100, 200, 400, 800, 1000). Here, the individual results on the KPI's for each load level are presented. It must be noted that at a higher load, the imbalance also increases because it is a factor of the load.

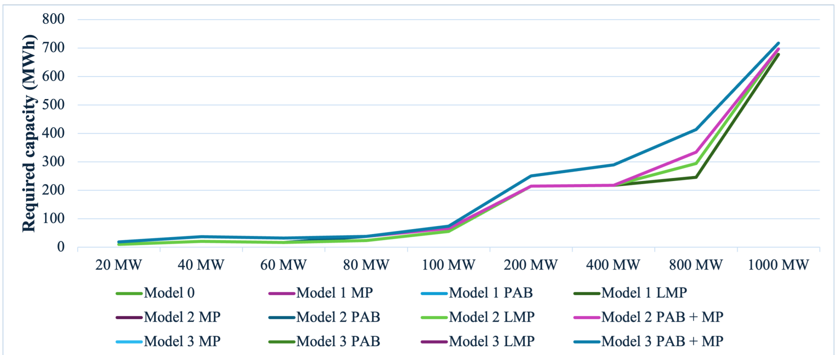

Figure E.1: Sensitivity analysis results on required capacity for varying load levels

In Figure E.1 it can be seen that as the load increases, the required capacity follows a non-linear upward trend. Initially, there is only a small increase in required capacity at lower loads (20-80 MW), but as the load surpasses 100 MW, there is a significant jump in required capacity, which continues to accelerate at higher load levels (200 MW and beyond). This suggests that at lower loads, the system can handle imbalances and congestion more efficiently, while at higher loads, more capacity is needed to meet demand, due physical network constraints.

Load	1: Co-optimization, net capacity			2: No co-optimization, net capacity				3: No co-optimization, gross capacity			
	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
20 MW	45%	45%	45%	45%	45%	45%	0%	0%	0%	0%	0%
40 MW	45%	45%	45%	45%	45%	45%	0%	0%	0%	0%	0%
60 MW	49%	49%	49%	49%	49%	49%	0%	0%	0%	0%	0%
80 MW	38%	38%	38%	38%	0%	38%	0%	0%	0%	0%	0%
100 MW	24%	24%	24%	10%	10%	24%	10%	0%	0%	0%	0%
200 MW	14%	14%	14%	14%	14%	14%	14%	0%	0%	0%	0%
400 MW	25%	25%	25%	25%	25%	25%	25%	0%	0%	0%	0%
800 MW	41%	41%	41%	29%	19%	29%	19%	0%	0%	0%	0%
1000 MW	6%	6%	6%	3%	3%	3%	3%	0%	0%	0%	0%

Table E.1: Relative performance improvement (%) of a new market design on the required capacity compared to the current market design

The results in Table E.1 show that for the relative improvement in required capacity, the higher loads lead to reduced performance improvements. The relationship between load and required capacity is non-linear, suggesting more complex interactions. This can be attributed to the fact that transport constraints are considered in both redispatch and balancing in the new market design, whereas in the current market design, these constraints are not taken into account during balancing. As a result, increasing load has a smaller impact on required capacity in the current design.

The fluctuations in the improvement of required capacity are primarily driven by the influence of KVL. At higher load levels, new generation assets are activated, which significantly affects power flow. Consequently, the need for flexible capacity can increase or decrease suddenly to satisfy KVL requirements across the two loops. Additionally, the results show that for market design 2, which uses PAB + MP, there are no improvements at lower load levels. This is because different assets are deployed in the redispatch and balancing steps due to variations in the merit order. As a result, more net capacity is used at lower loads, whereas at higher loads, similar assets are more frequently utilized, leading to greater efficiency.

Additionally, the merit orders of the current market design and the new market design are a bit different since all capacity is combined. Therefore the step to a more expensive asset can happen at another load increase, resulting in a not linear decrease in relative improvement.

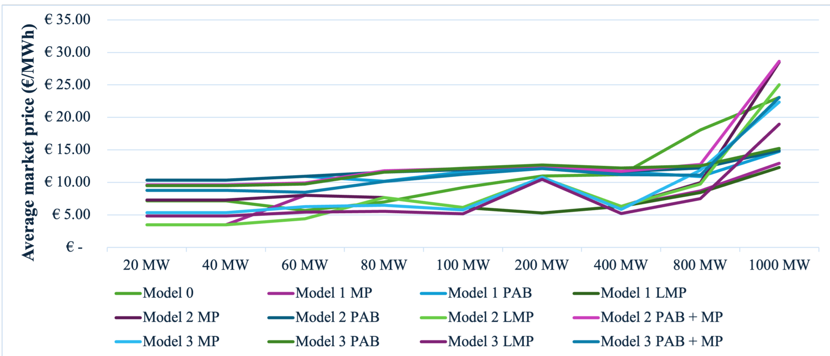

Figure E.2: Sensitivity analysis results on the average market price for varying load levels

Figure E.2 shows a gradual increase in market price as load levels rise. However, the relationship is slightly volatile, with some fluctuations at mid-level loads. This can be explained by the fact that, due to varying power losses in two transmission lines combined with the KVL constraint, an expensive asset needs to be activated during redispatch for as little as 0.00045 MW. Since the maximum price approach is applied, this small activation sets the marginal clearing price for both steps, even though only a minimal amount of capacity is drawn from that asset. This shows that the impact is not linear, since the KVL, powerloss and capcity constraints make it a complex connection. And the maximum

*: denotes that these pricing models, use a maximum price settlement. Since the net capacity used, the maximum market clearing price between the redispatch and balancing market is used

pricing approach for some of the cases in market design 2 (separate optimization, net capacity) makes this impact more significant.

	1: Co-optimization, net capacity			2: No co-optimization, net capacity				3: No co-optimization, gross capacity			
Load	**MP**	**PAB**	**LMP**	**MP***	**PAB**	**LMP***	**PAB + MP***	**MP**	**PAB**	**LMP**	**PAB + MP**
20 MW	51%	-45%	51%	-2%	-45%	51%	-34%	25%	-33%	32%	-23%
40 MW	51%	-45%	51%	-2%	-45%	51%	-34%	25%	-33%	32%	-23%
60 MW	-41%	-92%	23%	-41%	-92%	23%	-74%	-10%	-71%	5%	-49%
80 MW	-10%	-46%	-10%	-10%	-65%	-10%	-68%	7%	-65%	21%	-45%
100 MW	33%	-26%	33%	33%	-30%	33%	-32%	38%	-32%	44%	-22%
200 MW	52%	-14%	52%	2%	-14%	2%	-14%	1%	-16%	5%	-11%
400 MW	44%	-4%	44%	44%	-4%	44%	-5%	48%	-9%	53%	0%
800 MW	52%	40%	53%	45%	33%	46%	29%	34%	31%	58%	39%
1000 MW	44%	36%	47%	-24%	36%	-8%	-24%	3%	34%	18%	0%

Table E.2: Relative performance improvement (%) of a new market design on the average price compared to the current market design

Table E.2 indicates the relative improvements on the average price for each load. It shows that PAB pricing struggles at lower loads but can perform better at higher load levels. It is also shown that the different load levels have less influence on the average market price in the LMP scnearios. LMP pricing consistently offers the most substantial improvements across different models and load levels.

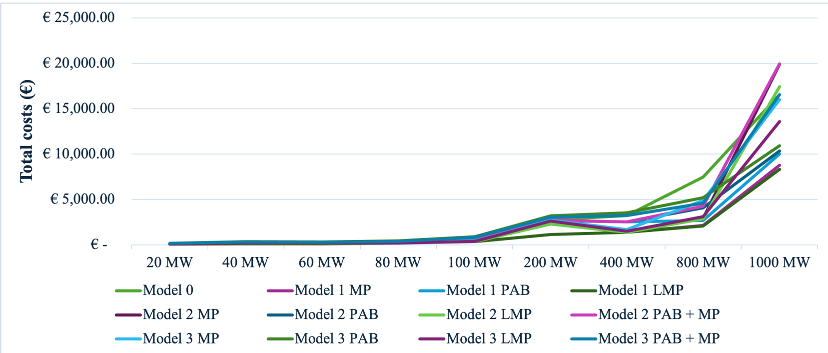

Figure E.3: Sensitivity analysis results on the total costs for varying load levels

The graph in Figure E.3 shows a steady increase of costs with rising load levels, following a nearly exponential pattern. This relationship suggests that the cost of managing the system rises sharply as higher loads demand more flexible capacity and redispatch, leading to greater operational expenses. This can be explained by the relatively small electricity network with only two loops, which offers limited alternative routes when the load becomes too high.

	1: Co-optimization, net capacity			2: No co-optimization, net capacity				3: No co-optimization, gross capacity			
Load	**MP**	**PAB**	**LMP**	**MP***	**PAB**	**LMP***	**PAB + MP***	**MP**	**PAB**	**LMP**	**PAB + MP**
20 MW	73%	21%	73%	44%	21%	73%	-34%	25%	-33%	32%	-23%
40 MW	73%	21%	73%	44%	21%	73%	-34%	25%	-33%	32%	-23%
60 MW	28%	2%	61%	28%	2%	61%	-74%	-10%	-71%	5%	-49%
80 MW	31%	9%	31%	-66%	9%	31%	-68%	7%	-66%	21%	-45%
100 MW	50%	5%	50%	50%	-17%	50%	-18%	38%	-32%	44%	-22%
200 MW	59%	2%	59%	16%	2%	16%	2%	2%	-16%	5%	-11%
400 MW	58%	22%	58%	58%	22%	58%	21%	48%	-9%	53%	0%
800 MW	71%	64%	72%	61%	46%	62%	43%	34%	31%	58%	39%
1000 MW	47%	40%	50%	-20%	37%	-5%	-21%	3%	34%	18%	0%

Table E.3: Relative performance improvement (%) of the new market designs on the total costs compared to the current market design

Table E.3 shows the results per load of the improvement on the total costs. As the load increases, the performance of certain pricing approaches, particularly MP and LMP, continues to show positive results. In contrast, PAB + MP pricing tends to perform poorly at lower load levels across all market designs but stabilizes and even shows some improvement at higher loads, particularly in market design 3 with gross capacity use, where it reaches 39% improvement at 1000 MW. This can by the fact that more capacity is available. resulting in a lower market clearing price for certain loads resulting in lower costs.

E.2. Impact of a varying magnitude of imbalance

For the main results, a big imbalance is chosen compared to imbalances in the Dutch electricity grid. The imbalance is a factor of the load and the imbalance can be positive or negative indicating a capacity deficit or a capacity surplus. To evaluate the impact of the magnitude and the direction of the imbalance, different factors are used in the sensitivity test. The value of the imbalance factor decreases from 1.3 to 1.05 indicating a dificit since the load is too high, to 0.95 and 0.7, indicating a surplus because the load is lower than the generation.

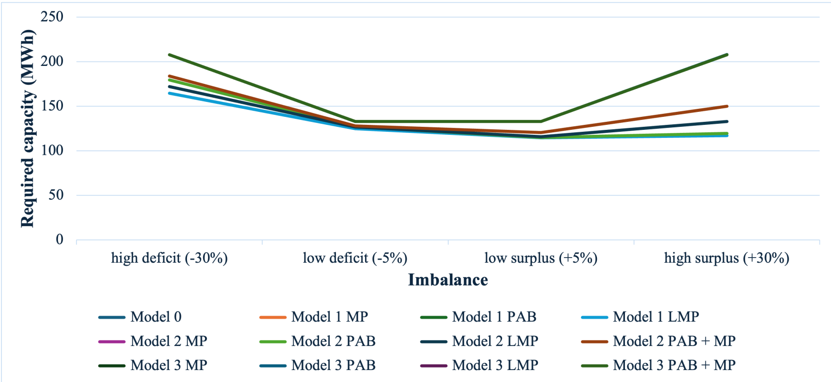

Figure E.4: Sensitivity analysis results on the required capacity for varying imbalance levels

The relationship between imbalance and the required capacity is non-linear across all models and pricing approaches. It follows a U-shaped curve, meaning moderate imbalances (small deficits or surpluses) result in better performance, while extreme imbalances lead to higher capacity requirements and costs. As expected, this U-shaped curve indicates that the system requires more capacity to handle extreme imbalances (both high deficits and high surpluses) than it does for moderate imbalances.

	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
Imbalance	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
High deficit	21%	21%	21%	17%	14%	17%	12%	0%	0%	0%	0%
Low deficit	6%	6%	6%	5%	4%	5%	4%	0%	0%	0%	0%
Low Surplus	14%	14%	14%	13%	14%	13%	9%	0%	0%	0%	0%
High surplus	44%	44%	44%	36%	43%	36%	28%	0%	0%	0%	0%

Table E.4: Relative performance improvement (%) of the new market designs on the required capacity compared to the current market design

Table E.4 illustrates the effect of the imbalance factor on the required capacity for each market design option. As expected, lower imbalances result in a reduction in required capacity. Consequently, the relative improvement compared to the current market design is smaller. This occurs because a similar amount of capacity is still used for redispatch, but less is needed for balancing. The lower relative improvement suggests that greater gains are achieved when the imbalance is higher. In market design 3, the imbalance has no effect on capacity, as the amount used remains similar to the current market design. Additionally, the differences in performance improvements between market designs 1 and 2 remain relatively small across varying imbalances.

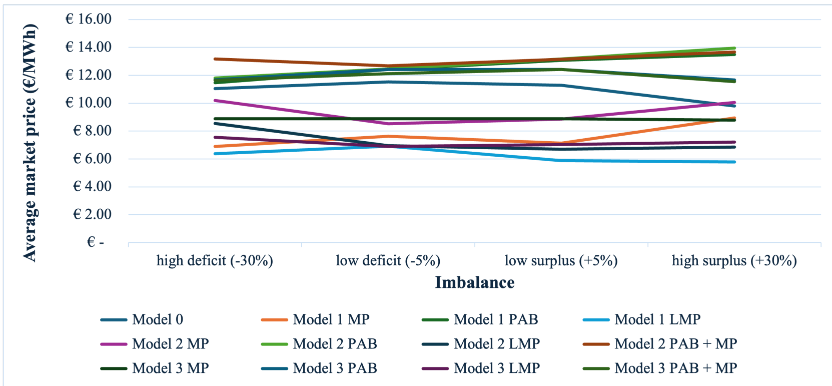

Figure E.5: Sensitivity analysis results on the average market price for varying imbalance levels

Figure E.5 illustrates the relationship between different imbalance levels and the average market price. While the trend appears relatively stable, it still displays some non-linearity. Unexpectedly, the average price tends to be higher with smaller imbalances in some cases. This is because the simulation runs across different load levels, and the average price is calculated based on these. For large imbalances, the costs at lower loads are spread over a higher capacity. However, with smaller imbalances (in the load range of 20-400 MW), the same costs are distributed across a lower capacity. This leads to smaller imbalances resulting in a higher average market price, as fewer assets are needed to handle the imbalance, and the total capacity used is lower, increasing the cost per unit of capacity. The price reduction at higher load levels is not sufficient to offset this effect.

	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
Imbalance	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
High deficit	38%	-4%	42%	8%	-7%	23%	-19%	20%	-6%	32%	-5%
Low deficit	34%	-8%	40%	26%	-8%	40%	-10%	23%	-8%	40%	-5%
Low Surplus	37%	-16%	48%	22%	-17%	41%	-16%	21%	-10%	38%	-10%
High Surplus	9%	-38%	41%	-2%	-42%	30%	-40%	10%	-19%	26%	-18%

Table E.5: Relative performance improvement (%) of the new market designs on the average market price compared to the current market design

Table E.5 shows the impact of the imbalance factor on the average price of the flex capacity. PAB pricing performs poorly in for all imbalance levels, particularly in scenarios with significant surpluses. However, the level of imbalance does not significantly impact performance as expected. One reason for this is that, due to the relatively small electricity network used in the simulation, the redispatch capacity is larger than the capacity used for balancing the imbalance.

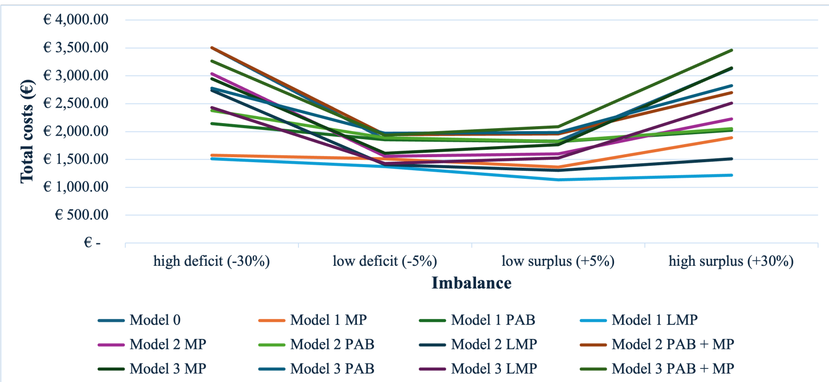

Figure E.6: Sensitivity analysis results on the total costs for varying load imbalance

The total costs graph E.6 exhibits clear non-linearity, forming a U-shaped curve. This suggests that extreme imbalances lead to higher costs, while moderate imbalances result in the most cost-efficient operation, as you would expect. The variables have similar impact on the costs of all the market designs.

Imbalance	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
High deficit	55%	39%	57%	13%	32%	22%	0%	16%	21%	31%	7%
Low deficit	19%	0%	26%	16%	-2%	24%	-5%	13%	13%	23%	-4%
Low Surplus	25%	1%	38%	12%	0%	29%	-7%	3%	-8%	16%	-14%
High Surplus	40%	35%	61%	29%	34%	52%	14%	0%	10%	20%	-11%

Table E.6: Relative performance improvement (%) of the new market designs on the total costs compared to the current market design

Figure E.6 shows the changes in the relative performance improvements for different imbalance levels. For the PAB pricing scenarios the total cost improvement decreases much if the imbalance is low. And similar to the sensitivity analysis of the different values of load, PAB pricing scenario performs better under high values of imbalance.

E.3. Impact of a varying flexible capacity

The provided capacity is set at a level that is sufficient to meet the high load. Experiments were conducted to examine the impact of increasing the provided capacity. No simulations were run with less capacity, as this would not result in a feasible solution for all market designs.

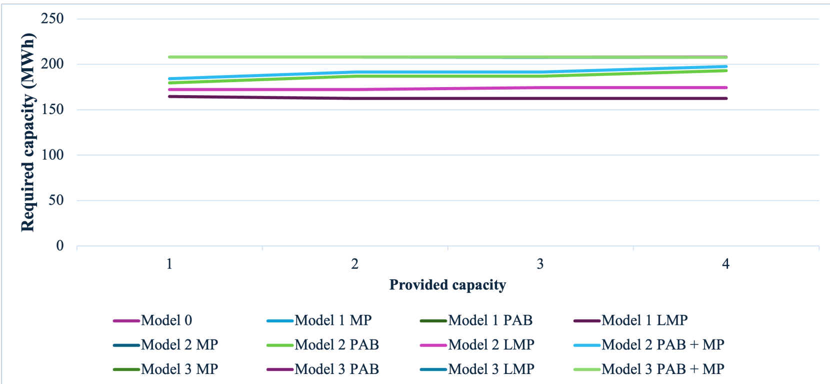

Figure E.7: Sensitivity analysis results on the required capacity for varying capacity levels

The relationship between provided capacity and required capacity is illustrated in Figure E.7. The provided capacity has minimal impact on the required capacity, and several lines are not visible because, for multiple market designs, the required capacity remains nearly identical.

Flex Capacity	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
x1	21%	21%	21%	17%	14%	17%	12%	0%	0%	0%	0%
x2	22%	22%	22%	17%	10%	17%	8%	0%	0%	0%	0%
x3	22%	22%	22%	16%	10%	16%	8%	0%	0%	0%	0%
x4	22%	22%	22%	16%	7%	16%	5%	0%	0%	0%	0%

Table E.7: Relative performance improvement (%) of the new market designs on the required capacity compared to the current market design

Table E.7 shows the impact of the capacity on the required capacity. As expected this does not change the results as much. The biggest changes are found for market design 2. Here the increase in available capacity changes the activated assets resulting in a different net capacity use. This influence is bigger in the PAB pricing approach since the bid prices are closer to each other.

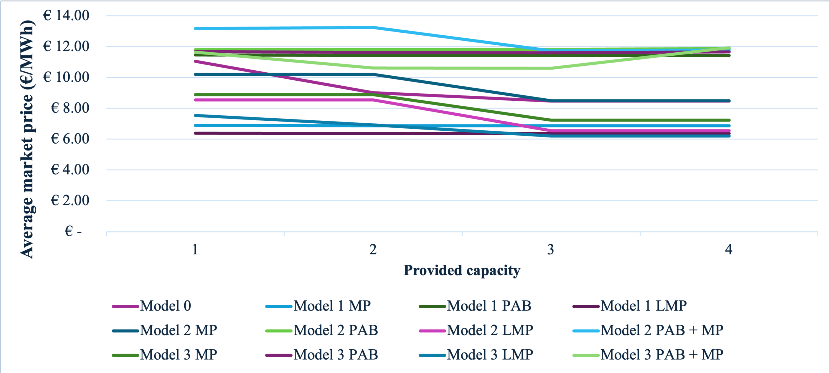

Figure E.8: Sensitivity analysis results on the average market price for varying capacity levels

The influence of provided capacity on the average market price follows a slightly non-linear trend in Figure E.8. While some variation exists, the average market price generally decreases as the provided capacity increases. This is as expected. However, in market design 3 with PAB+MP, the results show a more unpredictable pattern. The price increase if a capacity of a factor 4 is provided. This can be explained by the fact that the two optimization steps of redispatch and balancing are still performed separately. When the capacity changes, certain assets are activated during redispatch, taking transport constraints into account. This sometimes leaves less available capacity from those assets for balancing, leading to higher prices due to the MP approach used in the balancing step.

Flex	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
Capacity	MP	PAB	LMP	MP*	PAB	LMP*	PAB + MP*	MP	PAB	LMP	PAB + MP
x1	38%	-4%	42%	8%	-7%	23%	-19%	20%	-6%	32%	-5%
x2	24%	-27%	29%	-13%	-31%	5%	-47%	2%	-29%	23%	-18%
x3	19%	-35%	25%	0%	-40%	23%	-39%	15%	-37%	27%	-25%
x4	19%	-35%	25%	0%	-40%	23%	-39%	15%	-38%	27%	-41%

Table E.8: Relative performance improvement (%) of the new market designs on the average market price compared to the current market design

Table E.8 shows the influence of flex capacity on the relative improvement in average market price compared to the current market design. The table indicates that as more capacity becomes available, the relative improvement decreases. This occurs because the price in the current market design decreases more significantly than in the new market designs. As a result, the performance improvement relative to the current market design declines, even though the price itself decreases (as illustrated in Figure E.8). In the current market design, transport constraints are not considered during balancing, so increasing the available capacity has a greater impact than when transport constraints are taken into account.

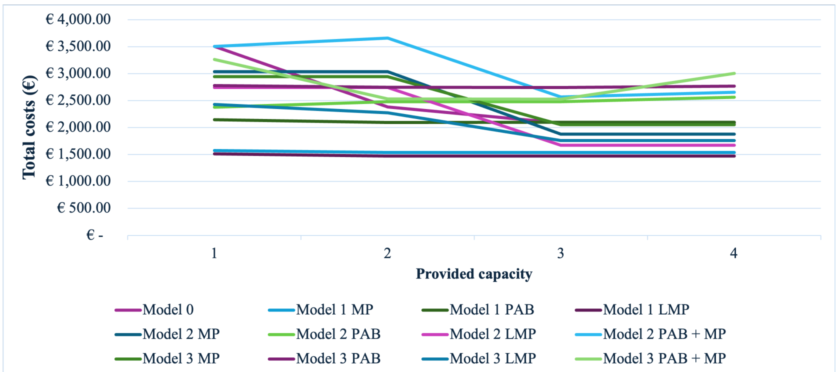

Figure E.9: Sensitivity analysis results on the total costs for varying capacity levels

The relationship between provided capacity and total costs is non-linear, as shown in Figure E.9. This non-linearity arises from the consideration of transport constraints. In market designs 2 and 3, the increase in total costs with a larger volume of capacity is due to the separate optimization process. If more capacity is used from a certain asset during redispatch, it can lead to a higher market clearing price during the balancing step, contributing to the overall increase in costs.

Capacity	1: Co-optimization, net capacity			2: Separate optimization, net capacity				2: Separate optimization, net capacity			
	MP	**PAB**	**LMP**	**MP***	**PAB**	**LMP***	**PAB + MP***	**MP**	**PAB**	**LMP**	**PAB + MP**
x1	55%	39%	57%	13%	32%	22%	0%	16%	21%	31%	7%
x2	36%	12%	38%	-27%	-4%	-15%	-53%	-24%	-15%	5%	-6%
x3	26%	-1%	29%	10%	-19%	20%	-23%	1%	-32%	16%	-21%
x4	26%	-1%	29%	10%	-23%	20%	-27%	1%	-33%	16%	-44%

Table E.9: Relative performance improvement (%) of the new market designs on the total costs compared to the current market design

Table E.9 presents the relative improvements of the market designs for different levels of provided flexible capacity. The table reveals that as capacity increases, the PAB+MP scenario for market designs 2 and 3 performs worse than in the main results. This is because, in the current market design, an increase in capacity has a relatively larger impact in reducing costs. In contrast, the new designs, which account for transport constraints, do not always benefit from additional capacity leading to a cheaper solution. As a result, the relative improvement decreases. This trend is also observed in the other market designs, but they still show significant improvements overall.