Flexmeister

Assessing system performance of an integrated balancing and redispatch market design on the Dutch electricity grid

Master Thesis

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by

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Cover: Dutch Ancillary Services by TenneT TSO B.V. — (source: tennet.eu/nl-en/grids-and-markets/dutch-ancillary-services)

Preface

Dear reader,

This thesis marks the completion of my master's degree in Complex Systems Engineering and Management at the Faculty of Technology, Policy and Management at Delft University of Technology. I am grateful for the experiences and opportunities over the past few years. During my studies I developed a strong interest in the energy industry and I am thankful to conclude my degree with a project on the complex dynamics of market design, system simulation and electricity markets.

I would like to thank my graduation committee for helping me realise this thesis. First of all, many thanks to Pieter Bots for your enthusiasm, time and invaluable feedback whenever I needed it. Also, I am thankful for your improvements to the optimisation tool that made this project possible. Second, I would like to thank Sander Renes for helping me to better understand economic perspectives and for always providing me with thoughtful advice. In addition, you provided me with insights on how economic institutions influence socio-technical systems. Third, I want to thank Martijn Ophuis at TenneT for your guidance, knowledge and advice which contributed greatly to this study. I have learned a lot from you and the industry expertise you shared. I am grateful to the team at TenneT for giving me my first real insight into the electricity sector and for teaching me about aspects I did not even know existed. Finally, I want to express my gratitude to my friends and family for their support.

A.T.J. (Anne) Schuurmans
Delft, September 2025

Abstract

The increasing demand for electricity and fluctuating renewable generation intensify congestion risks on the Dutch transmission grid, challenging the reliability ensured by TenneT, the national Transmission System Operator (TSO). Currently, redispatch and balancing are operated in separate markets, limiting efficient use of flexibility and increasing system costs. This study develops and evaluates Flexmeister, an integrated balancing and redispatch market design, where suppliers provide a uniform flexibility product that TenneT can allocate in real time. The simulations in this study were based on the actual Dutch high-voltage grid topology, physical power flow constraints, realistic generator locations, parametrised bidding behaviour and representative time-series data. To evaluate the performance of Flexmeister, four market designs were simulated: the *Current* (separated) design, *Gross*, *Net*, and *All-in-one* (one-step optimisation). Three market designs were structured around three sequential market rounds: DA, redispatch and imbalance, whereas *All-in-one* executed redispatch and imbalance at the same time-step. The benchmark results demonstrated that integrated designs consistently outperformed the current design across all key performance indicators: extra capacity, total costs, activated volumes and clearing prices up and down. Simulations consistently reported the performance in the following order: *All-in-one* > *Net* > *Gross* > *Current*. Unlike the *Current* design, the integrated designs required no additional out-of-market capacity, thereby improving reliability without costly infrastructure investments. The findings provide the first quantitative evidence that market integration can strengthen grid reliability and lower societal costs. Moreover, the developed simulation model bridges economic market design and technical system modelling, offering policymakers and grid operators a practical tool to support the energy transition.

Executive Summary

The core responsibility of TenneT as the Dutch Transmission System Operator (TSO) is to ensure a safe and reliable electricity grid, 24 hours and 365 days a year in the Netherlands. However, rising demand and fluctuating renewable production create congestion that threatens system reliability. This challenge is amplified by the current separation between the redispatch and balancing markets. Redispatch is the local shifting of feed-in and off-take from the grid to prevent overload and manage congestion. Balancing ensures that electricity generation is continuously matched with demand in real time to maintain the grid frequency at 50 Hertz. As a result, TenneT must rely on costly additional generation capacity, raising both economic inefficiency and integrity risks for the system. Although outages are rare, they come with extremely high costs.

This study developed and tested Flexmeister: a combined balancing and redispatch market in which suppliers provide uniform flexibility capacity. This allows TenneT to decide in real time whether capacity is used for balancing or redispatch, thereby improving reliability and reducing costs, activated volumes and clearing prices. The research question for this study is: How does an integrated balancing and congestion market perform in the Netherlands compared to the current two separated markets? Research to date was limited to qualitative studies and a proof-of-concept for a highly simplified network.

This study advanced the state-of-the-art on several points:

1. *Topology of the Dutch electricity grid*: This study used the actual topology of the Dutch electricity grid, enabling a realistic representation of generators, stations, load and imbalances.
2. *Asset placing*: Generator assets were explicitly placed in their real geographical locations, allowing Flexmeister's performance to be tested under realistic conditions of location-specific generation and transmission line constraints.
3. *Physical characteristics of the grid*: The model incorporated the physical characteristics of the grid by applying Kirchhoff's Voltage Law, ensuring that power flows are simulated in line with real-world physics rather than simplified copperplate assumptions through Linny-R.
4. *Bidding behaviour*: This was parametrised instead of fixed, making the model flexible enough to capture realistic market dynamics.
5. *Time series data*: The analysis was based on carefully selected days with both high and low levels of congestion and imbalance, providing insight into how Flexmeister performs under contrasting system conditions. This approach ensured that the model was tested not only under typical circumstances, but also under stress situations that are critical for system reliability.

Methodologically, the study started with the design of a flex market followed by simulations of this new design. First, the uniform flex product integrated automatic Frequency Restoration Reserve (aFRR), manual Frequency Restoration Reserve (mFRR) and redispatch. Second, this new design was translated into four models: *Current*, *Gross*, *Net* and *All-in-one*. All four market designs were structured around three sequential market rounds. The first round, identical for all models, represented the day-ahead (DA) market, where expected production and consumption are scheduled without considering grid constraints. The subsequent rounds differ per design. In the *Current* model, redispatch and imbalance were separated, reflecting today's market structure with no interaction between the two markets. By contrast, the integrated designs *Gross*, *Net* and *All-in-one* introduced a uniform flexibility product that could be activated for both redispatch and imbalance. The distinction between *Gross* and *Net* lies in how opposing activations across rounds were settled: under *Gross* both up and down regulation were remunerated separately. Under *Net*, only the netted effect was considered. The *All-in-one* design integrated redispatch and imbalance into a single round, simultaneously resolving congestion and balancing needs.

Design	Current	Gross	Net	All-in-one
Optimisation	2-step	1-step	2-step	2-step
Product	aFRR, mFRR, redispatch	Uniform flex	Uniform flex	Uniform flex
Explanation	Represents the current situation	New market design, gross optimisation and remuneration	New market design, net optimisation and remuneration	Optimal performance for integrated balancing and congestion market

Figure 1: Visualisation of the four market designs

Together, the four models in Figure 1 created a benchmark for measuring performance. The lower bound (0) was represented by model *Current*, reflecting today's markets. The upper bound (1) reflected the theoretical optimum which was obtained in design *All-in-one*. This benchmark was established for interpreting the KPIs: extra capacity, total costs, total volumes and clearing prices up and down. To account for reliability in the *Current* model, additional capacity was introduced to simulate the Buiten Systemen Om (BSO) process. BSO refers to extra capacity that TenneT obliges market participants to provide to guarantee grid stability. Including this capacity ensured that solving the model remained feasible under all circumstances. In practice, it represented the situation where TenneT requires generators to offer capacity beyond their market bids.

Based on this study, the results in Figure 2 reported that the new integrated market designs significantly outperform the current separated markets in costs. Simulations consistently reported the performance in the following order: *All-in-one* > *Net* > *Gross* > *Current*. Therefore, the results supported the hypothesis that an integrated balancing and congestion market, Flexmeister, outperformed the current separated markets. Concerning the activation of extra capacity, this occurred only in *Current* during the redispatch round. Increasing the redispatch share from 20/80 to 40/60 reduced both the activation frequency and total activated volume. Moreover, activations and volumes were consistently higher in redispatch up than down, with the only marginal pricing (MP) mechanism requiring less extra capacity than the only pay-as-bid (PAB) and PAB & MP mechanisms. No extra capacity was needed under Flexmeister: *Gross*, *Net* and *All-in-one*, which increased reliability without investments in infrastructure. Besides, volumes, costs and clearing prices decreased under the new designs. This resulted in lower system costs and therefore, lower expenses for consumers and society.

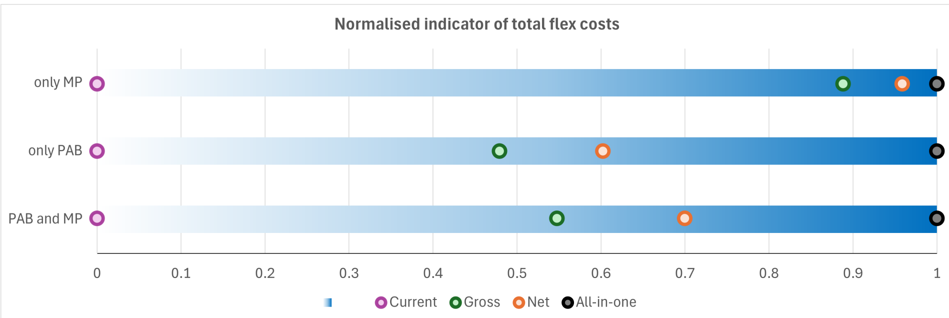

Figure 2: Benchmark normalised total flex costs

This study was subject to several limitations. First, no historical redispatch bid data were available. However, bid parameters were based on empirically grounded assumptions, limiting the impact. Second, the simulations were based on selected days rather than full-year data and assumptions were required on bidding behaviour and network modelling. Nevertheless, the study provided a model that can be adjusted easily by incorporating new data, for either historical bid data or full-year simulation. Third, only the energy market for balancing was taken into account and the capacity market was considered out of scope. However, due to the normalised scores in combination with the benchmark, this limitation applied to all models and was not expected to significantly influence relative performance.

This study indicated that by making better use of flexibility through an integrated market, grid operators can improve reliability without billions in physical infrastructure investments. This would accelerate the connection of new sustainable sources and reduce social costs. Moreover, this study underscored how economic institutions influence technical systems and therefore, influence the reliability of the system. For example, actors such as the Autoriteit Consument en Markt, TenneT, the European Union and national governments influence the reliability of the electricity system through the institutions they shape, including market design, pricing mechanisms, regulatory frameworks and legal constraints. In addition, the study delivered a reusable model for the Dutch electricity grid, including different market rounds. Taking into account the perspective from another actor, this study found that revenue from ancillary services for suppliers might slightly decrease. However, from a societal point of view, the integrated market contributed to a more reliable and safer grid. This allows for connections for new customers and increases the whole market, also for those same suppliers of balancing and redispatch capacity. This study bridged the gap between economic market designs and technical system models of electricity grids. Overall, this study provided the first quantitative evidence that integrated market design can deliver a more reliable and cost-efficient electricity grid. Concluding that market design and not just physical grid investments, can contribute to the energy transition whilst operating a reliable grid. Besides, it offered policymakers and grid operators a practical tool to accelerate the energy transition without major infrastructure investments. By enabling faster and cheaper integration of renewables, Flexmeister supported both security of supply and the achievement of climate goals.

The contribution of this study was a well-structured plug and play model, including features that have not been included in a study on quantitative performance of an integrated balancing and redispatch market before. In addition, it can be used easily and allows for including other data. This study provided the first realistic quantitative model that bridges the gap between theoretical market designs and technical system models. These elements make the model applicable for grid operators and policymakers, as it shows how an integrated market design can increase reliability and reduce social costs without large scale infrastructure investments.

Contents

Nomenclature

Abbreviations

Abbreviation	Definition
aFRR	automatic Frequency Restoration Reserves
BSO	Buiten Systemen Om
BSP	Balancing Service Provider
CLC	Capacity Limiting Contract
CM	Congestion Management
CSP	Congestion Service Provider
DA	Day-Ahead
DSO	Distribution System Operator
E-HV	(Extra) High Voltage
FCR	Frequency Containment Reserves
GoO	Guarantee of Origin
ID	Intra-Day
ISP	Imbalance Settlement Period
LB	Lower Bound
mFRR	manual Frequency Restoration Reserves
MW	Megawatt
MWh	Megawatt-hour
OPF	Optimal Power Flow
SDE++	Sustainable Energy Production and Climate Transition Incentive Scheme (Stimulering Duurzame Energieproductie en Klimaattransitie)
TSO	Transmission System Operator (TenneT)
UB	Upper Bound

1 Introduction

This study addressed the Dutch Transmission System Operator (TSO), TenneT's core responsibility: to ensure a safe and reliable electricity grid, 24 hours and 365 days a year in the Netherlands. Increasing electricity demand combined with variable renewable production are creating congestion, undermining the reliability of the Dutch electricity system. The challenge is amplified by the separation of the redispatch and balancing markets, which hinders TenneT in using flexibility resources efficiently. Balancing ensures that electricity generation and demand are continuously matched in real time to maintain the grid frequency at 50 Hertz by activating balancing products. Balancing products include automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserves (mFRR), which help correct imbalances between supply and demand. In addition, redispatch adjusts generation to relieve local grid constraints on network elements such as transmission lines. As a result of the separated markets, TenneT is often forced to activate costly extra transmission capacity. This not only creates inefficiencies but also undermines overall system integrity.

Strengthening the high-voltage (HV) grid is a priority, given its increasing vulnerability to congestion (Netbeheer Nederland, 2024). Accordingly, grid investments are projected to reach €195 billion by 2040, including €107 billion for the onshore network (Algemeen Dagblad, 2025). Meanwhile, electricity demand and renewable generation from sources such as solar and wind are rising sharply (Ministerie van Algemene Zaken, 2025). However, the Dutch grid faces structural bottlenecks, such as congestion and limited capacity, which hinder this growth. As a result, around 20,000 parties remain on a waiting list for new or upgraded connections, an indicator of limited capacity (Algemeen Dagblad, 2025).

In response to these challenges, the Dutch government, the national regulator (Authority for Consumers and Markets, ACM), grid operators and market participants are collaborating on measures to accelerate the expansion of grid connection capacity (Ministerie van Algemene Zaken, 2025). For example, time-bound transport rights (TDTRs) grant HV grid parties guaranteed access for a set number of hours per year, covering at least 85% of the time (TenneT, 2025e). During the remaining hours, restrictions may apply, particularly at times of peak demand. TDTRs unlock connection capacity, but do not decide how the scarce flexibility resources are activated and coordinated, which influences overall system efficiency (Gorenstein Dedecca et al., 2025). At the European level, demand for flexibility is expected to rise even further, particularly as fossil-based generation capacity declines (Gorenstein Dedecca et al., 2025). Market design therefore remains pivotal, coordinating balancing and redispatch in one market may yield lower system costs and improved reliability.

The growing demand for flexibility raises the question whether better coordination between markets could reduce risks and inefficiencies. Currently, redispatch and balancing are separated into distinct markets, forcing TenneT to treat flexibility as two different products. This prevents optimal deployment and has already led to costly incidents, where balancing capacity could not legally be used for redispatch. The following real-life example illustrates the consequences of this separation.

1.1. Real-life example

Treating flexibility as two separate products can have severe consequences, which was evident in a manual Frequency Restoration Reserve (mFRR) incident, where contracted capacity could not be used for redispatch services. mFRR is a balancing reserve product, also referred to as emergency power, that is activated in critical situations. In one instance, contracted mFRR capacity was technically available but left unused, because legal restrictions did not allow it to be activated for redispatch. At the same time, there were insufficient redispatch bids in the affected area. This illustrates how market separation can block the use of flexibility, even when it is already contracted and paid for.

On 27 November 2020, this situation escalated. TenneT had the physical resources available to solve the grid issue early, but legal constraints prevented their use for redispatch. Contracted mFRR capacity, although already paid for through the capacity auction and available for activation, could not legally be used for redispatch. As a result, TenneT had to instruct a supplier to ramp down without a clear price, pushing the grid into an ALERT state. An Alert state means that TenneT can no longer rely on regular market mechanisms and must resort to costly and less predictable emergency measures, leaving the system closer to its operational limits and thereby increasing the risk of outages.

Only after three months of negotiations was the case settled at €321,000. If the mFRR capacity had been available for redispatch, the issue could have been resolved within two weeks at an estimated €155,000. The cost difference of €166,000 and time difference of 2.5 months highlight the inefficiency of the current market separation and point to the value of an integrated flexibility market such as *Flexmeister*.

1.2. New market design

In the Netherlands, TenneT is responsible for the balancing and congestion markets. Although organised separately with different products, both markets ultimately serve the same purpose: providing flexibility. Providers of flexibility must offer their capacity on either the balancing or congestion market.

One promising idea is to integrate the currently separated balancing and redispatch markets, so that available resources can be deployed where they are most valuable. This study therefore develops and analyses a new integrated market design, called ‘Flexmeister’. In this concept, flexibility providers offer a single, uniform flexibility product that TenneT can allocate to balancing or redispatch as system needs dictate. This approach aims to address inefficiencies in the current separated design.

The separation creates inefficiencies and system performance suffers when flexibility is fragmented across markets. For instance, insufficient redispatch bids are available, while surplus capacity exists in the balancing market. By integrating both markets, the design improves coordination and access to flexibility capacity. Operators face fewer challenges in locating and activating the required volumes. Additionally, market participants no longer have to choose between offering their capacity on the balancing or congestion market. Instead, an integrated market enables them to submit bids through a single system. This streamlines activation for TenneT, reduces administrative tasks and improves market accessibility.

The integrated design is expected to improve social welfare by reducing overall system costs. One large, liquid market typically outperforms two fragmented markets, especially as available flexibility increases. As a result, activation prices are expected to stabilise or even decline. A single bid ladder is expected to reduce the likelihood of the ALERT and EMERGENCY system states, by improving access to available bids. Moreover, surplus balancing capacity can be reallocated for redispatch when needed.

A study from Stok, 2024 explored the idea of an integrated market design for balancing and congestion. Suppliers submit flexibility bids, after which TenneT decides how the offered capacity will be used. Building on the concept from Stok, 2024, this study will further explore the design choices for such an integrated market and how to quantify and measure performance of the integrated design.

1.3. Research gap, questions and approach

A literature review was conducted to examine current perspectives on balancing and congestion markets, as well as the potential for their integration. The reviewed studies highlight that an integrated market for balancing and redispatch can improve capacity utilisation and system efficiency (Koltsaklis & Knápek, 2024; Poplavskaya, Joos, et al., 2020). In addition, coordinated bidding strategies and local auction mechanisms have also shown potential to enhance market performance and reduce costs (Boomsma et al., 2021; Ziras et al., 2025). Other contributions point to the benefits of improved imbalance pricing and harmonised European balancing markets, including voluntary and second chance bids (Chaves-Ávila et al., 2014; Poplavskaya et al., 2021). Taken together, these findings suggest that integrating balancing and congestion markets enables a more dynamic and efficient use of flexibility, thereby supporting grid optimisation (Poplavskaya & De Vries, 2018; Poplavskaya, Lago, & De Vries, 2020).

Previous research proposed designs for balancing and congestion markets (Poplavskaya, Joos, et al., 2020). Only recently has a proof-of-concept for an integrated balancing and redispatch market been presented (Stok, 2024).

This study contributes to the state-of-the-art knowledge by quantifying, for the first time, how integrated market designs perform against separated markets in terms of system costs and efficiency in a HV grid. In doing so, it contributes to understanding the potential of market integration to enhance social welfare. The research question for this study is:

How does an integrated balancing and congestion market perform in the Netherlands compared to the current two separated markets?

To answer this research question, the following sub-questions will be answered:

1. What is the proposed design of the integrated balancing and congestion market, based on literature and insights from expert consultation?
2. How does the new proposed design perform compared to the current separated markets based on the KPIs: extra capacity, total costs, total volumes and clearing prices up and down?
3. What is the impact of reserving transmission line capacity for balancing services on the performance of the proposed market design?

The approach of this study combines conceptual design with quantitative modelling. First, a literature review, policy documents and an input session with experts from TenneT were used to identify the limitations of the current separated balancing and redispatch markets. Next, a new integrated market design, *Flexmeister*, was developed and implemented in a location-specific model of the Dutch transmission grid, incorporating physical laws and bidding behaviour. To create a benchmark for performance, four market designs were simulated: *Current*, *Gross*, *Net*, and *All-in-one*. These represent different ways of structuring the integration of balancing and redispatch. Here, *Current* simulates today's separated market, representing the lower bound (0) on the benchmark. The theoretical optimal performance and therefore upper bound (1) is simulated in *All-in-one* where technical constraints and timelines are not taken into account, so redispatch and imbalance are resolved simultaneously. In designs *Gross*, *Net* and *All-in-one*, the redispatch and imbalance rounds are operated with the uniform flex product. The difference between *Gross* and *Net* is the remuneration for activation in opposite directions over the two rounds. The results were then analysed in terms of reliability through activation of extra capacity. Besides, the total costs, activated volumes and clearing prices were analysed based on the benchmark. Allowing for a systematic comparison of the integrated market with today's design and the theoretical optimum.

1.4. Academic relevance and contribution

By combining conceptual design with quantitative modelling, this study not only provides practical insights for system operation, but also adds to the academic debate on how market design influences both technical reliability and economic efficiency. This study advanced the state-of-the-art on several points:

1. *Topology of the Dutch electricity grid*: This study used the actual topology of the Dutch electricity grid, enabling a realistic representation of generators, load and imbalances.
2. *Asset placing*: Generator assets were explicitly placed in their real geographical locations, allowing Flexmeister's performance to be tested under realistic conditions of location-specific genera-

tion and transmission line constraints.

3. *Physical characteristics of the grid*: The simulation model incorporated the physical characteristics of the grid by applying Kirchhoff's Voltage Law through Linny-R, ensuring that power flows were simulated in line with real-world physics rather than simplified copperplate assumptions.
4. *Bidding behaviour*: This was parametrised instead of fixed, making the simulation model flexible enough to capture realistic market dynamics.
5. *Time series data*: The analysis was based on carefully selected days with both high and low levels of congestion and imbalance, providing insight into how Flexmeister performs under contrasting system conditions. This approach ensured that the simulation model was tested not only under typical circumstances, but also under stress situations that are critical for system reliability.

A key contribution of this study was a well-structured plug and play simulation model, including features that have not been included in a study on quantitative performance of an integrated balancing and redispatch market before. This study provided the first realistic quantitative model that bridges the gap between theoretical market designs and technical system models. These elements make the simulation model applicable for grid operators and policymakers, as it shows how an integrated market design can increase reliability and reduce social costs without large scale infrastructure investments. Moreover, it can be used easily and allows for including other data.

1.5. Main findings

The simulation results confirm that *Flexmeister*, an integrated balancing and congestion market, outperforms the current system on all indicators in the following order: *All-in-one* > *Net* > *Gross* > *Current*. Unlike the current market, *Flexmeister* designs do not require costly additional capacity outside the market. Integration strengthens system reliability, the core task of TenneT, while simultaneously lowering costs, activated volumes and clearing prices. *Flexmeister* improves reliability without additional infrastructure investments and enables faster integration of renewable energy plants. This study also highlights the institutional role of regulators and policymakers in shaping system performance. Moreover, this study provides a reusable model that bridges technical grid modelling with market design. Together, these findings deliver the first quantitative evidence that market integration can support both reliability and the energy transition.

1.6. Outline

This study started by analysing new market designs for an integrated balancing and redispatch market and then proposed a uniform flex product in Chapter 2. Next, four models: *Current*, *Gross*, *Net* and *All-in-one* were introduced to measure the performance of this new market design. In Chapter 3, these simulation models were then validated on system behaviour over the three market rounds: DA, redispatch and imbalance. Once the models were validated, the results were discussed in Chapter 4 based on the five KPIs: extra capacity, total costs, total volume, clearing price up and clearing price down, followed by a sensitivity analysis. Lastly, these results were discussed, limitations were addressed and a conclusion was given in Chapter 5.

2 Method

This chapter was structured in two main parts. First, a new design for an integrated balancing and congestion market was developed. Starting by analysing academic literature to identify problems arising from separated balancing and congestion markets and how to resolve those problems. Then, technical and policy documents were analysed to select which ancillary services should be included in the integrated market design. Lastly, an expert consultation was conducted to develop and test the proposed market design.

Second, this design was translated into a set of four simulation models that operationalise the market under different conditions. These four models form the basis of the experimental design, in which scenarios were created by varying the pricing mechanisms. Bidding behaviour was incorporated through predefined bid structures, after which the models were evaluated using a Mixed-Integer Linear Programming (MILP) simulation model of the Dutch HV electricity grid. The models simulated the Optimal Power Flow (OPF) under the different market structures and were benchmarked against the current separated markets using key performance indicators (KPIs): extra capacity, total system cost, total volume and clearing prices up and down.

2.1. Proposed new market design

Currently, the balancing and congestion markets in the Netherlands are separated, run through different processes and require different products. To move towards one market, design choices must be taken to define this new market structure. Therefore, literature and technical and policy documentation were studied and combined with an interactive session with experts from TenneT. The new market design was defined in terms of features such as included products, pre-qualification, minimum bid, market type, bid attributes, divisibility of bids, optimisation timing and settlement approach. In practice, electricity market products were also specified along these dimensions, making them a suitable framework for structuring the design of an integrated flexibility market. In addition, this new market design built on the principle of an integrated market, where the TSO determines whether the uniform flexibility capacity is used for balancing or congestion services, see Figure 2.1.

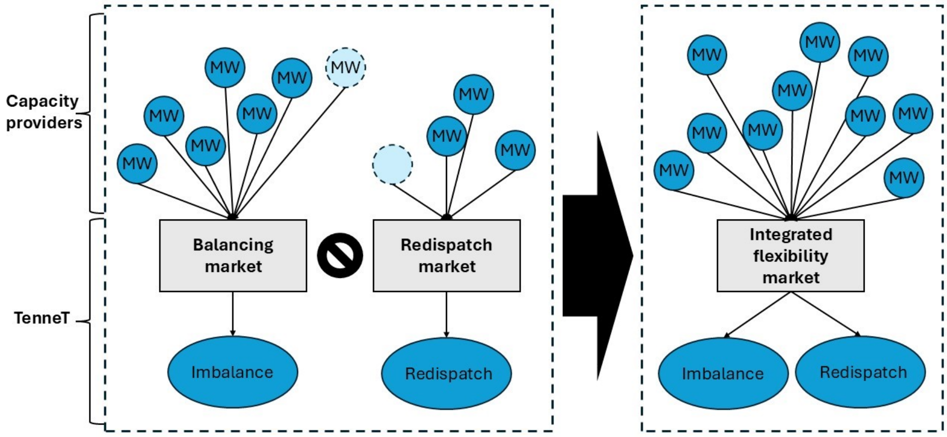

Figure 2.1: Visualisation of an integrated flexibility market

2.1.1. Literature

This section begins the design analysis by reviewing academic literature, to identify problems and solutions for balancing and redispatch markets. This analysis started with a study that looked into three interaction models for balancing and redispatch services (Poplavskaya, Joos, et al., 2020):

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

In this context, market-based denotes competitive procurement and settlement through a market: merit order clearing. Cost-based denotes TSO directed activation remunerated at regulated costs, generally without price competition in a contract format.

In Model MB/MB the balancing and redispatch markets were cleared consecutively, meaning that balancing was scheduled first and redispatch was procured afterwards, based on separate merit orders. In contrast, Model CMB, applied a single common market clearing where balancing and redispatch resources competed in one merit order with shared requirements. The study from Poplavskaya, Joos, et al., 2020 focused on ranking the models on qualitative scores: low, moderate or high, for allocative efficiency, resource availability, susceptibility to gaming, ease of implementation and transparent cost allocation.

Two models from Poplavskaya, Joos, et al., 2020 were particularly relevant to the integrated market envisioned in this study: MB/MB and CMB. MB/MB aligns with market-based procurement in both services and CMB represents a joint market with a single merit order. These insights were kept in mind to use as conceptual baselines for the proposed new market design and experiment design.

In addition, previous research (Stok, 2024) introduced a new market design for integrated balancing and congestion services. The design used a single product named "flex capacity", cleared in an energy auction, including aFRR, mFRR and redispatch. The bid attributes for the flex capacity were: location, price and capacity. Timing considered both co-optimisation and a sequential variant, where redispatch is executed prior to balancing. The settlement was tested for pay-as-bid as well as marginal pricing and bids were divisible. Stok, 2024 simulated a proof-of-concept model comprising six nodes, based on hypothetical and increasing levels for load and imbalance. The results of that study showed significant potential efficiency gains. Therefore, it was decided to analyse similar integrated market designs for balancing and redispatch on a network simulating the entire Dutch high-voltage grid. The research by Stok, 2024 served as one of the main drivers for this current study.

Whereas Poplavskaya, Joos, et al., 2020 focused on qualitative scores and Stok, 2024 demonstrated a proof-of-concept, this study quantitatively assessed efficiency on a location-specific Dutch HV grid using normalised performance scores. Thereby, enabling direct comparison across designs.

2.1.2. Technical and policy documents

Whereas the previous section focused on problems and solutions arising from separated balancing and congestion markets, this section evaluated ancillary services for balancing and congestion management (CM) to be included in the proposed new integrated market design. An “ancillary service” is defined as a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services (“Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU”, 2019). Mainly focusing on the characteristics of the different products such as time blocks, settlement approach and activation time. Based on this analysis and judgement, a selection of products was made for inclusion in the proposed new market design. See Appendix A for a more detailed analysis.

Balancing

Three balancing products were analysed: FCR, aFRR and mFRR. FCR differs from the other two, as it does not allow for energy bids and operates cross-border within continental Europe, requiring automatic frequency response devices. aFRR and mFRR both allow for capacity and (future) energy bids, and remuneration is linked to both. Capacity blocks differ: FCR uses 4-hour blocks, whereas aFRR and mFRR use 15-minute blocks. Capacity bids use pay-as-bid, while energy bids use marginal pricing. Currently, mFRR lacks energy bids but includes a fixed reward based on aFRR marginal prices. Future implementation of mFRR energy bids is expected due to EU regulation. Bid attributes for FCR, aFRR and mFRR are price and volume.

Congestion

Congestion refers to limited transmission capacity in the grid and is resolved through CM. Two mechanisms address this: capacity limitation contracts (CLCs) and redispatch. CLCs are bilateral contracts where large users reduce contracted capacity (GTV) day-ahead, without market mechanisms. Redispatch, offered through GOPACS (Grid Operators Platform for AnCillary Services) or RESIN (Regional Energy System Information Network), uses market-based energy bids (up and down) including location, price, and volume, settled under pay-as-bid. Redispatch can be activated from D-1 to one hour before real-time. Bid attributes for redispatch are price, volume and location. Figure 2.2 shows the activation timelines of balancing and congestion products.

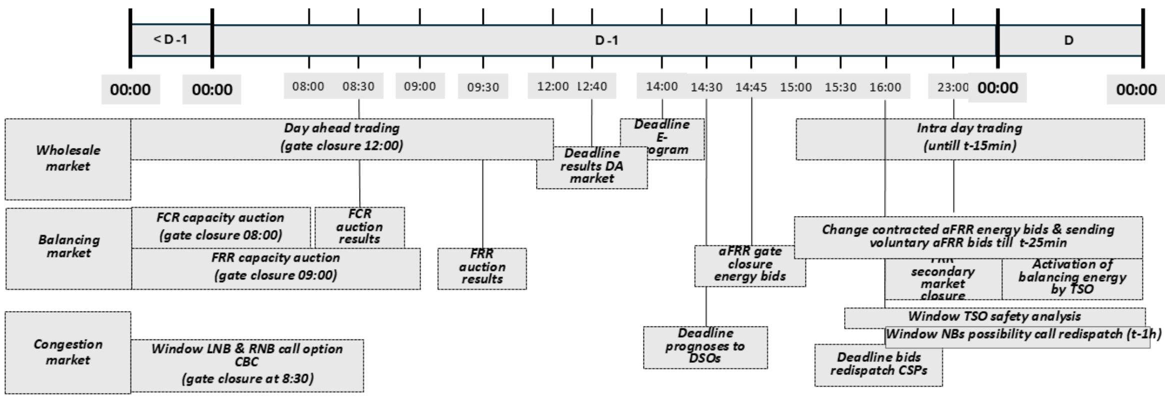

Figure 2.2: Timelines wholesale, balancing and congestion management

Selection for market design

By combining insights from the literature study, it was concluded that market-based procurement in both redispatch and balancing services should be analysed. Besides, a joint market with a single merit order was expected to resolve some of the problems arising from separated markets. Based on the technical and policy documents, it was concluded that the following products were included in the new market design: aFRR, mFRR and redispatch. FCR was excluded due to technical requirements such as activation speed and the absence of energy bids. CLCs were excluded due to their non-market bilateral nature.

In addition, pre-qualification was required to ensure reliability of the grid. In this new design, the minimum bid size is 1 MW for upward or downward activation. Bigger bids can be divided to only use part of the volume. The attributes for bids merge the ones for balancing and redispatch, resulting in location, price and volume. The optimisation timing consists of two steps, as balancing and redispatch were not executed in the same time step.

2.1.3. Expert consultation

An input session was held with experts from TenneT to complement the literature study and the analysis of technical and policy documents with insights from industry professionals. In this session, the experts were asked to cluster ancillary services into subcategories and to select one representative product from the new subcategories, the uniform flexibility product. Then, the groups were asked to further define the product along the selected dimensions, thereby contributing to the specification of the new flexibility product. Building on the expertise of professionals within the field ensured that the proposed design was grounded not only in theory but also in practical system knowledge.

Products

During the input session, experts were divided into two teams: Group A and Group B. Each team received an extensive list of products for ancillary services and was asked to cluster these products into smaller subgroups. No fixed number of subgroups was prescribed; the only instruction was to group the list of products based on which products they could envision to be combined in a uniform product. The complete product list, along with definitions, can be found in Appendix A. From these subgroups derived by Group A and Group B, three products were included in both subgroups. Therefore, these three products were included in the uniform flexibility product: aFRR, mFRR and redispatch. These were the same products that were also included in the previous section after a literature study and document analysis. In addition, Group B also incorporated two contract based products:

- Capacity Limiting Contract (CLC), a bilateral agreement to reduce congestion in a specific area
- Foreseeable Unavailability and Unforeseeable Unavailability, (Voorziene Niet Beschikbaarheid and Onvoorziene Niet Beschikbaarheid, VNB/ONB), contracts to ensure system reliability during planned or unplanned unavailability of transmission infrastructure

However, it was concluded not to incorporate these two products: CLC and VNB/ONB, due to their contractual nature instead of market-based procurement.

From the new subgroups obtained by Group A and Group B, two subgroups were selected for further specification: product 3A and product 2B Table 2.1. These subgroups aligned most with the uniform flexibility product for an integrated balancing and redispatch design, based on the analysis of documentation and literature.

Table 2.1: Overview of selected products identified by expert teams

Group A	**Group B**
Product 3A (energy)	Product 2B (transport)
aFRR (energy)	Redispatch
mFRR (energy)	aFRR
Redispatch	mFRR
	CLC*
	VNB/ONB*

*Products were not included in the new uniform flexibility product

Dimensions

The experts were then asked to further define the dimensions of a uniform flex product for product 3A and 2B. Dimensions to be specified were the products included, bids, type of procurement, bid attributes, optimisation timing, settlement approach and divisibility of the bids, see Table 2.2. See Appendix A for the full list of dimensions and a more detailed description.

Table 2.2: Comparison of design dimensions between Group A and Group B

Dimension	Group A	Group B
Products	aFRR, mFRR, redispatch	aFRR, mFRR, CBC, redispatch, VNB/ONB
Type of procurement	Market	Market and contracts
Bids	Energy	Capacity and energy
Bid attributes	Location, price, volume	Location, price, volume
Optimisation timing	2-step	2-step
Settlement approach	First PAB to gain liquidity, MP in a later stage	PAB for capacity, MP for energy
Divisibility	Yes	Yes

Both groups had similar views on the products to be included in a uniform flex product. Moreover, the specification of the dimensions was also aligned. The difference was that group B focused on a broader product, by also including CLCs as well as VNB/ONB and including the capacity markets for aFRR and mFRR products. Group A created a more focused product, specified to an energy auction for aFRR, mFRR and redispatch, which were also included in the design of group B. The uniform flexibility product should be procurement through a market and solely focus on energy and not on capacity. In addition, the bid attributes are location, price and volume and the optimisation timing should be a 2-step approach in which redispatch and balancing are executed consecutively. The product should be tested for MP, PAB and a combination of both and bids should be divisible. Overall, the industry experts from both groups created a similar flexibility product including: aFRR, mFRR and redispatch, comparable to literature.

2.1.4. New market design

Based on the literature study and documentation analysis, combined with the expert consultation, an integrated flexibility market design was derived. Table 2.3 outlines the design.

Table 2.3: New market design based on analysis

Feature	Documentation	Literature	Expert consultation	Result
Products	aFRR, mFRR, redispatch	aFRR, mFRR, redispatch	aFRR, mFRR, redispatch	aFRR, mFRR, redispatch
Prequalification	Yes	–	Yes	Yes
Minimum bid	1 MW	–	1 MW	1 MW
Market type	Energy auction	Energy auction	Energy auction	Energy auction
Bid attributes	Location, price, volume	Location, price, capacity	Location, price, volume	Location, price, volume
Divisibility of bids	Yes	Yes	Yes	Yes
Optimisation timing	2-step	2-step	2-step	1-step
Settlement	PAB, MP	PAB, LMP, MP	First PAB to gain liquidity, MP in a later stage	PAB, MP

The uniform flexibility product includes: aFRR, mFRR, and redispatch. Thereby, the focus shifts from balancing and congestion to balancing and redispatch. CLCs and VNB/ONB were not included in the new market design, as they were based on bilateral agreements contrary to the market-based procurement of the included products.

Suppliers must pre-qualify to participate in the market for the uniform flex product. Pre-qualification gives TenneT the certainty that a supplier can physically and measurably supply a bid when accepted, and that the measured energy effect can be correctly settled. The minimum 1 MW bid size remains for both balancing and redispatch. The threshold ensures that activated bids are reliably measurable and systematically effective. Bids <1 MW mainly result in higher transaction costs and complexity. Bids are energy-only; capacity bids were excluded from the uniform flex product both to align with the objective of the uniform flex product, which focuses on energy bids and to simplify the analysis in this study.

Strategic behaviour may arise from interconnections between capacity and energy markets. For instance, capacity market acceptance may influence energy bid pricing and vice versa, which justifies treating them separately in analysis. In the aFRR energy market, marginal pricing incentivised bidding at marginal costs, supported by capacity market obligations and sufficient liquidity. Accepted capacity bidders must participate in the energy market, promoting marginal-cost bidding. Free bids are also allowed, as they increase competition.

TenneT maintains a capacity auction to fulfil its legal obligation to ensure the availability of balancing capacity. Ex-ante capacity procurement ensures system security. Some bid shading was expected under pay-as-bid. However, to keep the scope tractable, this study assumed limited strategic interaction between the capacity and energy markets. Therefore, the capacity market was excluded from the simulation, as its impact was expected to be minimal for the scope of this study.

Bid attributes include price, volume and location, requiring additional data compared to the current balancing bids. The locational element enables the balancing bids to be used for redispatch purposes, instead of relying on the 'copper plate principle'. Similarly, to current FRR and redispatch products, bids will be divisible, meaning that only part of the offered volume may be activated. The duration of the bids is in Imbalance Settlement Periods (ISPs) and can vary from one ISP to multiple consecutive ISPs. An ISP is the time unit for which balance responsible parties' imbalance is calculated. Currently, the duration for aFRR and mFRR is already one ISP. For redispatch the current duration is four ISPs, but will also change to one ISP in the future. In addition, this does not mean that parties will be activated for a full ISP, but can also be activated for 1 minute only within an ISP. The price for activation within an ISP is determined by the minute in which the highest price is reached. However, in reality TenneT measures imbalance every four seconds, adding even more granularity, but this is not published on the transparency page.

Regarding the time frame, balancing activation occurs in real time. Bids may be modified up until 30 minutes before the start of the ISP, after which they remain fixed. Congestion actions can also be scheduled until 30 before the ISP as well, but may start earlier once redispatch are requested, from D-1 onwards. This timing allows the TSO, when activating a bid for congestion that is in fact contracted balancing capacity, to request additional bids. The optimisation of the uniform flex product considers both cost-efficiency and system effectiveness. Minimising system cost is key, but location-specific impact is also critical. Activating a low-cost bid that does not relieve a constraint may be ineffective. The optimisation must balance cost and physical impact. The new market design will be evaluated under both Pay-as-Bid (PAB) and Marginal Pricing (MP) mechanisms.

The result from this analysis as shown in Table 2.3 has been used for the simulation model for the further course of this study.

2.1.5. Four market designs

To assess the performance of this new market design, four market models were evaluated: *Current, Gross, Net* and *All-in-one*. A benchmark was established to quantify the relative improvements in performance of the new market designs, see Figure 2.3. In other words, the current market design was used to create the lower bound (LB) of the benchmark for performance. The upper bound (UB) reflected the optimal performance of an integrated congestion and balancing market. The one-step optimisation market design *All-in-one*, was the theoretically optimal solution for an integrated congestion and balancing market. This design co-optimised energy bids, which was more efficient in market clearing (Dvorkin et al., 2018). Co-optimisation has been shown to reduce total costs and increase system reliability (Hassan et al., 2018). Simultaneously resolving congestion and balancing needs was considered the theoretical optimum as it eliminated sequential inefficiencies and allocated resources in one co-optimised step, assuming no technical constraints. By contrast, separate market mechanisms which are actually coupled, could lead to inefficiencies due to misaligned incentives and result in sub-optimal dispatch. Such as energy and transmission constraints in the DA, balancing and redispatch markets.

The concept of this new market design was based on an integrated flexibility product, available for both balancing and redispatch services. Suppliers provide bids for upward and or downward activation, with bids comprising a volume, location and price. As there were two rounds in which the flex product could be used: balancing and redispatch, suppliers could provide upward and downward bids for both rounds. The main difference between the models lies in how bid activation was handled:

- **Current**; suppliers need to choose in which market they want to offer their capacity for flexibility services, either in the redispatch or balancing market
- **Gross**; suppliers can provide bids for upward and downward volume for the uniform flex product. They are remunerated for each activation, regardless of the direction over two activation rounds. For example, if a supplier is activated for upward generation in redispatch and downward in imbalance, both bids are paid
- **Net**; again suppliers can provide bids for upward and downward volume for the uniform flex product. However, they are corrected for inverse activation. That is, if a supplier is activated upward in redispatch and downward in imbalance, only the net effect is remunerated
- **All-in-one**; in this theoretically optimal market, both balancing and redispatch rounds are integrated into a single time step. Suppliers can only provide one upward and one downward bid for the uniform flex product

In addition, flow chart diagrams can be found in Appendix A for a visual representation of the models.

Due to the characteristics of these designs, the new models: *Gross, Net* and *All-in-one* were expected to outperform the *Current* model. As suppliers were remunerated for inverse activation in the *Gross* model, the *Net* model corrected for this and was expected to be more cost effective than the *Gross* model. Lastly, the *All-in-one* model was expected to outperform all designs in terms of total costs, being the theoretically optimal solution.

Design	Current	Gross	Net	All-in-one
Optimisation	2-step	1-step	2-step	2-step
Product	aFRR, mFRR, redispatch	Uniform flex	Uniform flex	Uniform flex
Explanation	Represents the current situation	New market design, gross optimisation and remuneration	New market design, net optimisation and remuneration	Optimal performance for integrated balancing and congestion market

Figure 2.3: Expected performance four market designs

2.1.6. Remuneration for balancing and congestion

In terms of remuneration, Pay-as-Bid (PAB) and Marginal Pricing (MP) were selected to reflect the predominant settlement mechanisms in European electricity markets and to induce distinct bidding incentives (Haghighat et al., 2012; Poplavskaya, Joos, et al., 2020).

Under PAB, each accepted offer is settled at its own bid, so bids are settled against different prices. This places the informational burden on bidders: they must anticipate the clearing price and residual demand. Under uncertainty, the bidders typically add a markup over marginal cost, also known as bid shading, which can raise average payments and weaken cost reflectivity. Because a bidder's own bid sets the price they receive, any upward markup translates directly into higher revenue conditional on acceptance. Therefore, PAB creates a direct incentive to shade above marginal cost when the market price is uncertain.

Under MP, all accepted bids receive a uniform clearing price set by the marginal accepted offer, so the bids are settled against the same price. In competitive settings, this rewards cost revealing bids, when bidders add too much of a mark-up in MP, they risk not being selected at all. Hence, MP improves price discovery and dispatch efficiency and usually results in lower average prices (Haghighat et al., 2012; Poplavskaya, Joos, et al., 2020). Because a bidder's own offer does not determine the settlement price, only the probability of clearing. Therefore, marking up above cost reduces acceptance chances without increasing the price received, pushing bids toward marginal cost.

In practice, redispatch is remunerated under PAB, reflecting its locational and constraint-driven nature, whereas MP is applied to balancing energy. This contrast is useful for the analysis: implementing both mechanisms within the same modelling framework, including identical data, scenarios and constraints, enables an assessment of their effects on system performance within an integrated market (Haghighat et al., 2012; Poplavskaya, Joos, et al., 2020).

2.2. Simulation model

Based on the new market design for an integrated balancing and redispatch market, simulations quantified the performance of this new design. This was tested through four models, applying different decision rules to the same electricity grid. Although complete datasets for submitted redispatch bids and balancing bids including locations were limited. The model was parametrised with empirically grounded estimates. The estimates were based on conservative assumptions, triangulation with publicly available data and expert validation. More details on parameters and estimated values were provided in the appendices referred to in the corresponding sections.

The simulation models were based on three rounds: DA, redispatch and imbalance. In the DA round, Linear programming (LP), is typically used for economic dispatch (Brown et al., 2018). For example, this can be executed in Python/PyPSA as well (Brown et al., 2018), a software tool for electrical power systems for simulation and optimisation over multiple periods. However, after clearing the DA market an Optimal Power Flow (OPF) analysis was performed. An OPF is a mathematical optimisation that computes generator outputs and network flows to meet demand while minimising a chosen objective: cost, subject to power balance and network physics. This was necessary as the DA round was cleared by economic dispatch, which can cause congestion and this can be restored via redispatch.

The initial cost optimised dispatch often needs to be adjusted through redispatch. Moreover, adjustments are needed for balancing due to forecasting inaccuracies. Redispatch mainly resolves congestion issues, whereas balancing secures system stability in real-time. Especially in the second round, Kirchhoff's Current Law (KCL) and Kirchhoff's Voltage Law (KVL) should be applied to ensure that power flows within the grid comply with physical principles. Furthermore, network constraints, including transmission line capacities and power losses, were explicitly taken into account, requiring a Mixed Integer Linear Programming (MILP) tool. In addition, the solver treated those time steps as independent scenarios as time dependent processes were not in scope of this study, such as batteries and ramp up and ramp down conditions of power plants.

2.2.1. Tool selection - Linny-R

Linny-R was used as an optimisation tool, due to its graphical language for specification of MILP models (Bots, 2025), specifically for the electricity grid. It models production systems using processes, products, clusters and links, for a more detailed explanation of the language, please refer to (Bots, 2025). Besides, prior experience with Linny-R contributed to a more efficient familiarisation with the tool and accelerated the model-building process.

Moreover, Linny-R enables economic dispatch and visualises product flows within a physical network, making it well-suited for electricity market modelling. It supports optimisation over multiple time periods while maintaining a clear connection between economic decisions and physical grid constraints. This makes it possible to analyse time-coupled processes such as balancing and redispatch, which are affected by grid limitations. In addition, Linny-R supports scenario adjustments across simulation rounds, enabling stepwise simulation of multiple market stages within a consistent framework.

2.2.2. Overview

The simulation models were built on the topology of the Dutch electricity grid. Figure 2.4, adapted from TenneT, shows the HV (220 and 380 kV) electricity grid. For the scope of this study, a simplified backbone representation of the HV grid was constructed, comprising 32 nodes and 40 transmission lines, as shown in Figure 2.5.

In this study, the Dutch grid was represented in a simplified form, leaving out details such as lower-voltage infrastructure. For the scope of this study, this level of abstraction was sufficient, due to institutional scope, impact of performance and modelling tractability. First, the institutional scope, balancing and redispatch are TSO level functions executed and settled on the HV grid, whereas mid and low-voltage constraints are DSO responsibilities and fall outside these markets. Second, system costs and congestion are dominated by HV transmission elements and circuits and strongly influence the market performance. Third, including the mid and low-voltage grids would vastly expand network size and data needs and would substantially increase model complexity and compromise tractability. Therefore, the backbone model provided a workable representation of the HV grid including key characteristics needed to evaluate system wide effects of the new designs. This abstraction excludes lower-voltage infrastructure, but the network closely mirrors the actual HV network in the TenneT map. In addition, the station in Tilburg was included in the HV grid as the current station is being connected to the HV grid (TenneT, 2024c).

This representation, hereafter referred to as the backbone model, served as the foundation for the four different market designs and corresponding models analysed in this study. For a more detailed description of stations and links included see Appendix B.

Figure 2.4: TenneT grid map onshore Netherlands, adapted from (TenneT, 2024b)

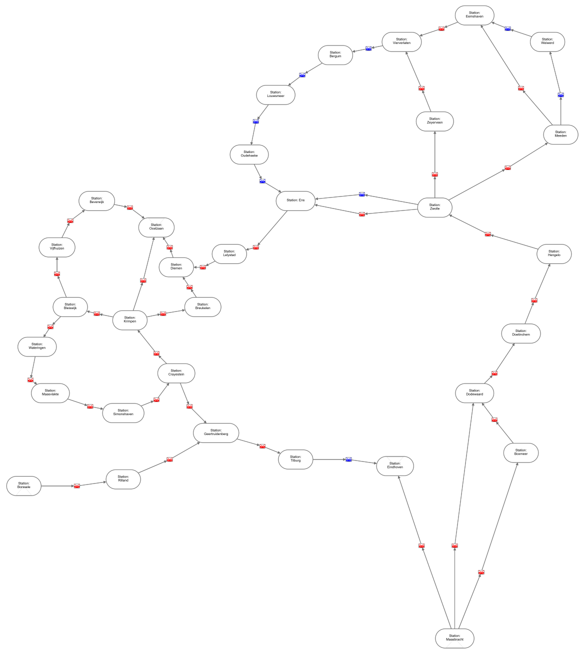

Figure 2.5: Visualisation of grid in backbone model

2.2.3. Backbone model

The four designs were all based on the same underlying network topology and model structure shown in Figure 2.5, ensuring that comparisons between them were consistent. In addition to the topology, the models shared the same parameters, including:

- Installed Capacity (generators); the maximum generation potential of each power plant or technology type connected to the grid. Defines the upper bound of the supply that can be activated in the model.
- Transmission Line Capacity; the maximum amount of electricity that can be transported across each line in the network without causing congestion.

This study was, to the best of current knowledge, the first to simulate the Dutch HV grid topology at this level of detail for evaluating integrated balancing and redispatch market designs. By grounding the models in the backbone structure of the actual Dutch grid, the results were more representative than those based on simplified proof-of-concept networks. Building on this foundation, the next step was to select representative days on which the simulations were run, to capture different system conditions while keeping the model tractable.

Time series data

To evaluate the performance of the proposed market designs under a variety of conditions, four representative days were selected. Since the designs integrate balancing and congestion management, both were considered in the selection process. Imbalance data were retrieved from TenneT's transparency platform (TenneT, 2025b), focusing on frequency restoration reserve (aFRR) activation, while redispatch volumes were obtained from the GOPACS platform (GOPACS, 2025). The selection aimed to capture both extreme and more typical system conditions, ensuring that the market designs could be tested under both stress situations and average circumstances.

The analysis resulted in four days representing distinct system states. For imbalance, the day with the highest average imbalance (8 November 2024), the lowest average imbalance (29 April 2024) and the median imbalance level (4 January 2024) were selected. For congestion, the period with the highest redispatch volumes (18 November 2024) was identified, with average redispatch activation of approximately 230 MWh per hour. Two of the imbalance days (29 April and 4 January) had no redispatch activity, thereby also serving as low congestion days. This specific selection supported a scenario-based evaluation of the new market designs under both typical and extreme conditions. Please refer to Appendix B for a more detailed description on the day selection.

In contrast to a full-year approach, which would yield more balanced averages by smoothing out extreme events, this study deliberately focused on four selected days: including one with extreme imbalance and one with extreme congestion. This targeted selection allowed the robustness of the designs to be assessed under both typical and stress conditions, which was particularly valuable for understanding system performance during critical events. Consequently, absolute averages may be upward biased relative to annual values. Even so, the normalised metrics remain valid for comparing the new designs with the *Current* benchmark and the theoretical *All-in-one* optimum. This holds provided that all designs were evaluated on the same days with identical scenarios, inputs and constraints, that bidding behaviour was held constant, which was the case in this study. Any selection bias acted as a common, approximately multiplicative factor across designs. Under these conditions, normalising to the baseline removed the shared level effect and preserved the relative differences in performance.

The four selected days result in 96 time steps for the simulation with different circumstances. However, the solver treated those time steps as independent scenarios as time dependent processes were out of scope for this study, such as batteries and ramp up and ramp down conditions of power plants. Some input parameters were given a time series to include different circumstances including:

- Total Imbalance, reflecting the net system imbalance to be resolved in each time step, obtained from (ENTSO-E, 2025a)
- Total Load, representing the overall electricity demand across the grid, obtained from (ENTSO-E, 2025c)

- Factor Solar, a variable accounting for the variability in solar generation as a share of installed capacity, obtained from (Pfenninger & Staffell, 2016)
- Factor Wind, a variable accounting for the variability in wind generation as a share of installed capacity, obtained from (Pfenninger & Staffell, 2016)

The main difference between the models lies in the clusters that were added per node, reflecting the design-specific market configurations or decision rules. These clusters determine which market rounds were active: redispatch, balancing or combined, and influence how flexibility was procured and activated. As such, each model simulated the same system context, but applied different operational layers through its cluster.

Generators
Three types of generators were distinguished: conventional, solar and wind. These types were selected because they span the operational spectrum relevant for the HV grid, dispatchable conventional and weather dependent renewables. These generator types differ in operational behaviour, technology-specific parameters such as bid volumes and prices, marginal costs and generation profiles were specified at the type level. Within each technology, generators located at different stations were treated as homogeneous and differ only in their installed capacity. In addition, unit specific features such as ramping limits, start-up costs, minimum up/down times and efficiency differences were not modelled to maintain tractability, scope and due to data limitations. Other technologies such as biomass and nuclear were operationally similar to conventional plants for the scope of this study, because they provide controllable and non-weather related output and ramp rates were not taken into account.

These three technologies: conventional, solar and wind, were selected as they represent the key generation categories in modern power systems, with different levels of controllability and weather dependence. The availability of the sun and the wind directly determined the available capacity of the solar and wind units at any given time. Conventional units were typically more expensive, but offered dispatchable power and could operate regardless of weather conditions, making them essential for ensuring system reliability. Each generation type: conventional, solar and wind, was represented by two units per station, each responsible for half of the installed capacity of that type at the station. These two units shared the same installed capacity, but were assigned different marginal costs. Herein, the first generator of a type on a specific location was always less expensive than the second and therefore, should be activated first. This differentiation allowed the model to capture heterogeneity within a single generation type, reflecting that in reality units of the same technology often operate at different cost levels.

Asset placing
In this study, there were six generators per station, two of each technology: conventional, solar and wind. The capacity allocated to these generators was based on real data of power plants in the Netherlands. The conventional plants were obtained from the list of (Wikipedia, 2025), verified with an expert from TenneT. In addition, the solar and wind plants were based on (Rijksdienst voor Ondernemend Nederland, 2025), with only operational plants of at least 1 MW capacity being included in the dataset. Plants were allocated to stations, based on geographic location. The longitude and latitude were obtained for each plant, after which the distance to every station was calculated individually. Each plant was then linked to the station with the shortest distance. After assigning plants to stations, installed capacity was aggregated by station and by technology, to obtain the total volume per type at each station. The total capacity per station per type was then divided by two to obtain the capacity of a generator within a specific station.

This study applied explicit asset placing by assigning generators to their geographical locations within the network. This ensured that location-specific generation patterns and transmission constraints were reflected in the simulations. As a result, the evaluation of market design performance accounted for spatial system conditions rather than relying on aggregated capacity distributed equally.

Total capacity
After assigning the plants to stations, the total installed capacity for fossil, solar and wind was determined. The total capacity included in the backbone model for fossil was 19 GW, solar is 24 GW and

Wind 12 GW, resulting in a total installed capacity of 55 GW. Showing similar results based on analysis outlined in Appendix C, verified with (ENTSO-E, 2025b). With an average load of 12.6 GW (Centraal Bureau voor de Statistiek, 2024) and peak load of 29 GW in 2024 in the Netherlands (TenneT, 2024a), this should be sufficient to meet demand at all times. Resulting in almost twice as much power installed as peak demand and more than four times as much power as average consumption. However, solar and wind are intermittent and may not always be available. In addition, the system is dimensioned to cover peak load rather than average load, following the N-1 security principle applied by TenneT (ENTSO-E, 2013). This ensured that the grid can handle demand even in case of outages of critical infrastructure, while at the same time providing sufficient flexibility to accommodate variability from renewable generation and unexpected demand fluctuations. In practice, this means that a structural surplus of capacity must be available beyond average demand to safeguard system reliability.

Extra capacity
Since the models explicitly balance the system under physical network constraints using Kirchhoff's laws, an additional artefact was required to guarantee feasibility of the OPF problem across all time steps. This was introduced as a fourth type of generation: 'Extra', which did not represent an actual technology but served to provide additional capacity whenever the installed capacity from conventional, solar and wind generators was insufficient. This ensured that the model always had a feasible solution. These additional units were assigned prices that were significantly higher than those of regular redispatch, imbalance or flexibility bids. As a result, they were only activated when strictly necessary, representing the function of Buiten Systemen Om (BSO) capacity in real operations. BSO refers to out-of-market resources that the TSO can activate in circumstances when market-based resources are insufficient to maintain system balance or resolve congestion. These are typically last-resort measures, such as emergency contracts or non-market redispatch agreements and therefore associated with very high costs. The inclusion of extra capacity therefore does not disturb the normal cost-optimal dispatch, but provides a valuable insight into how often TenneT would have to rely on BSO under different market designs. The extra capacity could be considered as bids from suppliers that did not offer their capacity in the markets.

In the models, this capacity is included in all three optimisation rounds to ensure that a feasible solution can always be found, regardless of whether conventional, solar and wind units are sufficient. So in all three optimisation rounds it was ensured that a simulation was executed, regardless of whether a generator of type 'extra' was activated in previous rounds. Importantly, this BSO capacity was made available independently in every round, meaning that its availability was not constrained by activations in previous rounds. This isolated the economics of each clearing stage, otherwise day-ahead choices would constrain availability in later rounds. This approach guaranteed system feasibility under extreme conditions, but at the same time highlights that whenever this generation type was dispatched, it reflected an exceptional situation rather than normal market operation.

2.2.4. 3 rounds

For all but one market design, several sequential market clearing rounds were needed to resolve electricity and flexibility needs. Three sequential market clearing rounds were included: Day-Ahead, Redispatch and Imbalance. Herein, these rounds represent the optimisation steps in Linny-R, the stages in which the system was re-optimised under updated constraints, such as transport limits or imbalance. Importantly, these optimisation steps should not be confused with bids submitted by the market participants, which are discussed separately later in this chapter. The bids differ per pricing mechanism, whereas the optimisation steps differ per simulation model.

Day-Ahead round

The first round for all four designs was based on the Day-Ahead (DA) market. During this round, the demand side was introduced and economic dispatch for supply and demand was executed. In this first round, transport limitations and security analysis were not taken into account. The results of this round were the E-programs, schedules indicating how much each party was expected to produce or consume and at what price. In addition, the DA round was solved under the copper-plate assumption: no transmission capacity constraints were imposed and bids were cleared purely by merit order. The system was thus represented as a copperplate without transport limits.

In practice, the DA auction closes at 12:00 on D-1 and the Intra-day (ID) market opens at 15:00 on D-1 and trades until shortly before delivery. In this study, a rolling single-interval market clearing was implemented, that mimics DA economic dispatch, but it was executed at the time of delivery for each interval. Economically, this design sits between DA and ID. Participants can be viewed as updating volumes up to delivery, as in ID. Each interval was cleared as an independent welfare-maximising auction, as in DA. For readability each clearing was referred to as the “DA round”, but given the timing it could equally be interpreted as an ID round. Modelling both explicit DA and ID rounds was out of scope: the objective was to obtain wholesale energy schedules, so called E-programs, from economic dispatch. The E-programs were needed to feed the subsequent rounds: a security assessment resulting in endogenous congestion and a round in which exogenous imbalance was added. For every time step, independently, the solver cleared the market, applied the security analysis and evaluated imbalance.

Redispatch round

The second round was based on congestion, for market designs: *Current, Gross, Net* and *All-in-one*. In the first round, the DA market was cleared based on economic dispatch which can cause congestion and this can be restored via redispatch. To simulate this principle, in this second round, a security analysis and transport limitations were included by enforcing Kirchhoff’s Current and Voltage Laws (KCL and KVL), ensuring that power flows respect physical constraints. Unlike the DA round, transmission capacities were finite and binding in the redispatch round. Congestion is defined as a violation of these transmission limits, so when scheduled flows exceeded line capacities. When the DA schedules were tested against the network in this round, any such violations were identified and the model triggered redispatch to restore feasibility. The transmission capacities were set equal to the operational limits applied by TenneT under the N-1 security criterion (ENTSO-E, 2013). As a result, transmission bottlenecks arose as an outcome of the model’s dispatch decisions interacting with physical network limits, rather than being imposed exogenously. In other words, congestion emerged endogenously in the redispatch round from the interaction between selected bids in the DA round and network constraints in the redispatch round.

This approach grounded the simulations in the actual physics of the grid and to the best of our knowledge, represented one of the first applications of such a method to an integrated redispatch and imbalance market for the Netherlands.

Market design *All-in-one* was based on the principle of resolving congestion and balancing needs within the same time step. Therefore, the *All-in-one* design used only two rounds in total: the first to clear the DA market and the second to resolve congestion and balancing needs simultaneously.

Imbalance round

The third round, which was present in *Current*, *Gross* and *Net*, aimed at restoring balance in the grid. After the DA market clearing, the system was balanced on a DA forecast. However, since imbalances are continuously monitored and producers and consumers may deviate from their E-programmes, real-time imbalances could still occur. In this round, exogenous imbalance volumes were introduced into the model. In the real world, imbalance can for example originate from deviations from the DA schedules due to forecast errors, outages or behavioural deviations. These deviations must be resolved in the third round, the imbalance round. Thus, the third round both adds the imbalances to the system and clears them through balancing actions.

In reality, imbalance is measured nationally, again according to the copper-plate principle. However, in the model imbalance was represented and measured locally, with the national total preserved by ensuring that the sum across stations equalled the national level. Imbalance was distributed equally across all nodes, this rule was fixed across all designs. A strict copper-plate treatment in this round would risk undoing redispatch actions and would re-create congestion. To approximate real-world operation without inducing such modelling artefacts, the transmission constraints were relaxed in the imbalance round compared to the redispatch round. This was justified because N-1 security had already been ensured in the preceding redispatch round.

In *All-in-one* congestion and imbalance were resolved in a single step. Therefore, the settings had to be aligned with either the redispatch round, the imbalance round or a combination thereof. A hybrid configuration was chosen: KCL and KVL were enforced as in the redispatch round, while line capacity limits followed the relaxed levels that were used in the imbalance round in the other designs. This preserved physical consistency and ensured comparability across designs without penalising *All-in-one* with stricter constraints than those applied in the other designs.

2.2.5. Four market models

The four market models were built on the technical network, the backbone model, but differed in their decision rules for the redispatch and imbalance rounds.

Current

Model *Current* consisted of three rounds: DA, redispatch and imbalance, see Table 2.5. Its main distinction from the new designs was the separation of markets, where part of the available upward capacity was reserved for redispatch and the remainder for imbalance. For example, if a generator had a capacity of 10 MW and was accepted for 8 MW in the DA round. This resulted in 2 MW for upward generation and 8 MW for downward generation. However, due to the separated market structure in the *Current* design, only 30% of the volume for both upward and downward generation was available for redispatch services and the remaining 70% for imbalance.

Gross

The *Gross* design was based on three rounds, similar to the *Current* design. However, unlike in *Current*, where redispatch and balancing were procured through separate markets, the *Gross* design applied a single uniform flex product across both rounds. The uniform flex product was used for both redispatch in round two and balancing in round three. Suppliers were able to provide two different bids over the two rounds. Resulting in two bids for upward activation and two bids for downward activation. When a supplier was activated in opposite direction over round two and three, they were remunerated for both activations.

A consequence of using a single uniform flexibility product across both rounds in *Gross* and *Net* was that actions taken in the redispatch round may partially be reversed in the imbalance round. This occurred because transmission line constraints were enforced less strictly in the imbalance round. In reality, balancing activations are not constrained by location and therefore, it would be unrealistic to apply the same strict grid restrictions as in the redispatch round. At the same time, it would also be unrealistic to remove all grid restrictions, since this would undo redispatch actions entirely and lead to congestion in practice. For this reason, transmission capacity was relaxed by allowing higher limits in the imbalance round, giving the solver slightly more freedom. As a result, during a negative imbalance both upward and downward activations could occur simultaneously in *Gross* and *Net*. As fossil generation activated in the redispatch round may then be curtailed again, while solar generation that was previously curtailed in the redispatch round due to congestion was activated. In the *Gross* design, suppliers were remunerated for both actions.

Net

The *Net* model was similar to the *Gross* model, except for the remuneration in opposite directions. When a supplier was activated for upward generation in round two and then activated for downward generation in round three, they were remunerated for the difference between those activations against the price of the biggest volume see Table 2.4. In the simulations, remuneration was directly connected to the system costs. In other words, the cash out for TenneT and was therefore, the objective that the solver minimised.

Table 2.4: System cost formulas for settlement methods in Gross and Net

Design	Pricing	Remuneration formula	Explanation
Gross	MP	$V_i^{\uparrow} \cdot P_m^{\uparrow} + V_i^{\downarrow} \cdot P_m^{\downarrow}$	One marginal price per direction
Gross	PAB	$V_i^{\uparrow} \cdot P_i^{\uparrow} + V_i^{\downarrow} \cdot P_i^{\downarrow}$	Each bid is paid its own price
Net	MP	$\begin{cases} (V_i^{\uparrow} - V_i^{\downarrow}) \cdot P_m^{\uparrow}, & \text{if } V_i^{\uparrow} > V_i^{\downarrow} \\ (V_i^{\downarrow} - V_i^{\uparrow}) \cdot P_m^{\downarrow}, & \text{if } V_i^{\downarrow} > V_i^{\uparrow} \\ 0, & \text{if equal} \end{cases}$	Net volume priced at marginal price
Net	PAB	$\begin{cases} (V_i^{\uparrow} - V_i^{\downarrow}) \cdot P_i^{\uparrow}, & \text{if } V_i^{\uparrow} > V_i^{\downarrow} \\ (V_i^{\downarrow} - V_i^{\uparrow}) \cdot P_i^{\downarrow}, & \text{if } V_i^{\downarrow} > V_i^{\uparrow} \\ 0, & \text{if equal} \end{cases}$	Net volume priced at own bid

Where: $V_i^{\uparrow}, V_i^{\downarrow}$ = Volume up and down for supplier i (MW); $P_m^{\uparrow}, P_m^{\downarrow}$ = Marginal market price for up-/down-regulation (€/MWh); $P_i^{\uparrow}, P_i^{\downarrow}$ = Bidder's offered price for up-/downward bids.

In model *Gross* with MP, the total activated upward and downward volumes were settled separately at their respective marginal market prices. This ensured that every unit of activated capacity was valued at the same price within a direction, reflecting uniform pricing. Under *Gross* with PAB, all activated bids were remunerated at their individual bid prices, leading to a more heterogeneous cost structure that better reflected individual supplier bids but could increase total system costs.

By contrast, the *Net* model only accounted for the netted difference between upward and downward activation, which avoided paying twice when activations cancel each other out. With MP, this net volume was settled against the relevant marginal price, while with PAB it was settled at the bid price of the dominant direction. As a result, the *Net* designs reduced redundant payments and could lower overall system costs, but they also diminished incentives for suppliers to bid flexibly in both directions.

All-in-one

The *All-in-one* model represented the theoretical optimum for resolving congestion and imbalance simultaneously, whilst all uniform flex capacity was available for both services. Hence, imbalance and congestion were resolved within the same time-step, resulting in a single merit order and a single marginal clearing price that applied to all activated capacity. This meant that all accepted bids, whether for resolving congestion or balancing, were remunerated at this common price. Thereby eliminating inconsistencies between separate redispatch and imbalance prices.

In reality, such simultaneous optimisation is technically unfeasible, as congestion management and balancing actions are executed on different timescales and rely on distinct operational procedures. Nevertheless, including this modelling setup provided a valuable benchmark, as it represented the theoretical efficiency gains that could be achieved if all flexibility resources were perfectly pooled into a single market. The results from *All-in-one* should therefore be interpreted as an upper bound against which the more realistic designs *Gross* and *Net* can be evaluated, rather than as a directly implementable market design. Table 2.5 provided an overview of the types of optimisation steps for each round in each model.

Table 2.5: Overview of optimisation steps per round and remuneration principles per market design

Design	Round 1	Round 2	Round 3	Remuneration principle
Current	DA	Redispatch	Imbalance	Full activation paid
Gross	DA	Flex	Flex2	Full activation paid (both directions remunerated)
Net	DA	Flex	Flex2	Netted activation paid (upward minus downward)
All-in-one	DA	Flex	–	Full activation paid

2.2.6. Complexity simplifications

In addition, other assumptions were made to create the four models to assess the performance of the new market design:

- Only four days were included to analyse system behaviour and the performance of the new designs. The selected days reflect a variety of conditions, see Appendix B, while keeping the computational time within reasonable limits.
- A time resolution of one-hour blocks was used for the optimisation of the grid, to balance computational tractability with sufficient detail to capture variations in load and renewable generation.
- The grid only includes the Netherlands; interconnections with Belgium, Germany, the United Kingdom, Denmark and Norway are out of scope for this study. The expected impact of this simplification was limited, since interconnections can both reduce Dutch congestion and imbalance by providing support from abroad and increase them when the Netherlands provides support to neighbouring countries. The net effect was therefore assumed to be small. In addition, interconnections could be represented by adding additional generation capacity at stations connected to cross-border lines.
- Installed offshore capacity was included in the model, but represented as if connected directly to an onshore station. This simplification was appropriate, since the offshore connections are radial DC export cables without offshore loops, so the offshore lines were not included in the meshed AC network and KVL would not be applied.

2.3. Bids

As explained in section *Three rounds*, the optimisation steps define when and how the system is re-optimised in the different simulation models. In this section, the focus shifts from those steps to the bids, which differ between the pricing mechanisms MP and PAB.

For the experiment design in Table 2.9, bids were used corresponding to the pricing mechanisms. In the imbalance pricing, the price for downward regulation and upward regulation were different (TenneT, 2022). The simulation models were formulated and operated from TenneT's buy-side perspective. Under this sign convention, upward bids for redispatch and balancing services as well as uniform flex product bids had positive prices. TenneT had to pay this price to the suppliers for upward activation. Whenever a negative price occurred, this implied that the supplier was willing to pay to be activated downward, to reduce generation (TenneT, 2022). Upward activation denoted increasing generation and downward denoted decreasing generation for suppliers. See Appendix C for a more detailed explanation on bid generation under different pricing mechanisms.

In this study, the bidding structure was fully parametrised, meaning that all market rounds, designs and pricing mechanisms were specified through adjustable parameters. This approach provided a transparent and flexible framework while keeping the underlying structure consistent. Moreover, it ensured that the model can be readily adapted as empirical insights or new datasets on bidding behaviour become available. In such cases, parameter values can be updated without modifying the fundamental structure of the model, making it robust models and a scalable tool for future research.

Marginal pricing

In the Marginal Pricing (MP) scenarios, bids were based on the marginal costs Formula 2.1 and adjusted using fixed bid adjustment coefficients in Table 2.6. These coefficients represent markup or markdown percentages relative to marginal cost and differ per market round and direction. In the DA round, no adjustment was applied, meaning no additional margins were applied. In contrast, in the redispatch and imbalance rounds, upward bids were increased by a fixed percentage. For upward regulation, generators placed bids above their marginal costs: 10% higher for redispatch and 5% higher for imbalance. This MP rule applied to all generator types: conventional, solar and wind and both directions. The only exception were downward bids from solar and wind, which incorporate GoO revenues as a minimum to the MP formula based bid, see Section Solar and Wind.

Although in a perfectly competitive market MP would imply bids equal to true marginal costs, in practice generators tend to include a small premium to reflect cost uncertainty, opportunity costs and strategic behaviour. Therefore, in the MP scenarios a limited degree of bid shading was introduced, smaller than in the only PAB scenarios, to ensure the simulations reflect more realistic market behaviour. The extent of this bid shading was controlled through parameter a, which could be adjusted to represent higher or lower levels of strategic bidding behaviour depending on future datasets.

$$B_{\text{MP}}(MC) = [MC * a] \tag{2.1}$$

Where:

- MC = the marginal cost of a generator
- a = the bid adjustment coefficient, dependent on direction and round
- For downward bids from solar and wind, the effective bid equalled the maximum of the MP formula based value and the GoO based value in Table 2.7

Conventional units

For downward regulation, conventional generators were willing to pay to reduce output. This was reflected in bid adjustment coefficients below 1: -0.90 for redispatch and -0.95 for imbalance. Although these downward bids resulted in negative prices, this was economically rational. Generators accepted in the DA market already receive the corresponding revenues. If they can reduce their output for a price below their marginal costs, they increase their profit margin by avoiding higher-cost production.

Table 2.6: Bid adjustment coefficients

	Up	**Down**
Redispatch	1.10	-0.90
Imbalance	1.05	-0.95

Where: Values from this table were values for a in Formula 2.1

Solar and Wind

In contrast to conventional units, renewable units were not willing to pay for downward regulation. As renewable generators were dependent on the revenues from the Sustainable Energy Production and Climate Transition Incentive Scheme (Stimulering Duurzame Energieproductie en Klimaattransitie, SDE++) and Guarantees of Origin (GoOs). The generators wanted to be paid for downward activation due to missed revenues from those mechanisms. Herein, SDE++ is a Dutch subsidy scheme that provides financial support to renewable energy projects by compensating the gap between market revenues and production costs. In addition, GoOs are tradable certificates that prove the renewable origin of generated electricity and represent an additional revenue stream for producers through their sale to consumers or suppliers who aim to meet sustainability targets.

Therefore, for downward activation for renewables, the MP rule still applied, but the GoO value introduced a minimum: the downward bid equals $\max\{B_{\text{MP}}, GoO\}$, as shown in Table 2.7. In 2024, the average price of a GoO in Europe was between 5 and 6 €/MWh (Kyrylo, 2023). Margins were added for the redispatch and balancing round. Redispatch was more expensive than balancing due to reflect the higher risk premium originating from the locational component. In addition, wind was more expensive than solar to reflect the higher expected opportunity costs and curtailment risk. For this model, SDE++ was not included in the bids for downward regulation due to the wide variety of SDE++ programmes and their associated complexity. Additionally, parties tend to bid higher in the redispatch round compared to imbalance, as the two-stage auction setup allows them to test higher prices early on. If their bid was not accepted, they still had a second opportunity in the imbalance round.

Table 2.7: Bids downward activations for renewables

	Redispatch	**Imbalance**
Solar	9	6
Wind	10	7

Where: Values from this table were values for GoO in Formula 2.1

2.3.1. Pay-as-bid formula

In a market with a Pay-As-Bid (PAB) pricing mechanism, suppliers received the price they bid rather than a uniform clearing price as in MP. Rational suppliers would therefore tend to bid above their marginal costs in order to capture a surplus, while still ensuring that their bid remains competitive enough to be accepted. The PAB formula used in this study aimed to approximate such bidding behaviour, by adding a margin on top of the marginal costs that reflects both strategic mark-ups and competitive pressure.

For the runs with PAB, the following formula was used:

$$B_{\mathsf{PAB}}(MC) = \left[MC + (MC^{\alpha} + \beta \cdot MC + \gamma) \cdot \left(1 - \frac{MC}{MC_{\mathsf{max}}}\right) \cdot \frac{1}{\sqrt{b}}\right] \tag{2.2}$$

Where:

- MC = Marginal cost of the bid
- α = Non-linearity parameter
- β = Linear sensitivity coefficient
- γ = Constant bias term
- MC_{max} = Maximum marginal cost in the bidding set
- b = Number of bidders on that station
- $B(MC)$ = Adjusted bid price

In Formula 2.2, the first term: MC, represented the cost-reflective baseline, the marginal costs: the additional expense to produce or consume one more unit of energy. The second term in brackets added a premium above these marginal costs. Herein, the expression $(MC^{\alpha} + \beta \cdot MC + \gamma)$ allowed for non-linear, linear and constant components of this premium (Royston & Altman, 1994). The premium was parametrised as $f(MC) = MC^{\alpha} + \beta MC + \gamma$. An additive combination of a non-linear power term (MC^{α}), a linear component (βMC) and a constant (γ), consistent with the literature on fractional-polynomial regression and power-transform methods (Royston & Altman, 1994).

This premium was then multiplied by $(1 - MC/MC_{\mathsf{max}})$, which ensured that the premium became smaller as the marginal cost approaches the maximum value in the set. In effect, the highest-cost bidder could not add any mark-up, whereas low-cost bidders could add relatively larger mark-ups, reflecting their stronger competitive position. Finally, the factor $1/\sqrt{b}$ ensured that a larger number of competing bidders reduces the margin, simulating increased competition and smaller price mark-ups.

For renewable generators, Guarantees of Origin (GoOs) strongly affected their willingness to bid for downward activation. Therefore, if the outcome of Equation 2.2 fell below the GoO based bid levels in Table 2.7, those values GoO were used instead.

Since no historical bid data was publicly available, the parameter values used for the PAB formulation were based on plausible but hypothetical assumptions. The values noted in Table 2.8 were chosen to generate realistic bid shading behaviour for the simulations, rather than to replicate exact historical bidding patterns. As such, they served to illustrate the functioning of the model under PAB, while allowing future research to calibrate the parameters once empirical data becomes available.

Table 2.8: Parameter values used for PAB bids in round 2 and 3

Parameter	R = 2	R = 3
MC_{max}	73.0	73.0
α	0.5	0.5
β	0.2	0.2
γ	10	5

The choice of parameter values for α and β was guided by their effect on the curvature of the bid function $B(MC)$ relative to the 45-degree line representing marginal costs. A value of $\alpha = 0.5$ introduced moderate convexity, ensuring that low-cost units apply proportionally stronger mark ups, while high cost units remained close to their marginal costs. This reflected the empirical observation that infra marginal units typically have more strategic room to shade their bids without risking exclusion from the merit order.

The value of $\beta = 0.2$ was chosen to complement this effect by providing a mild linear adjustment across all cost levels, preventing the function from becoming excessively concave while still differentiating bidding behaviour across generators. Together, these parameters generated a bid curve that was consistent with economic theory: low cost units exercise greater mark ups under PAB, while high-cost units behave almost competitively, reflecting the reduced incentive for bid shading near the margin.

Figure 2.6 and Figure 2.7 visualised the behaviour from Equation 2.2. In the upward direction, bids lies above the marginal cost line and the premium was largest for low MC, decreasing as MC got closer to MCmax due to the factor $(1 - MC/MC_{\max})$. The two formulas mainly induced a vertical level shift consistent with the different γ, while preserving the merit order, low-MC units remain cheapest after shading. In the downward direction, bids were non positive and became more negative for higher MC, reflecting that high cost units save more by curtailing and accept lower prices for down regulation.

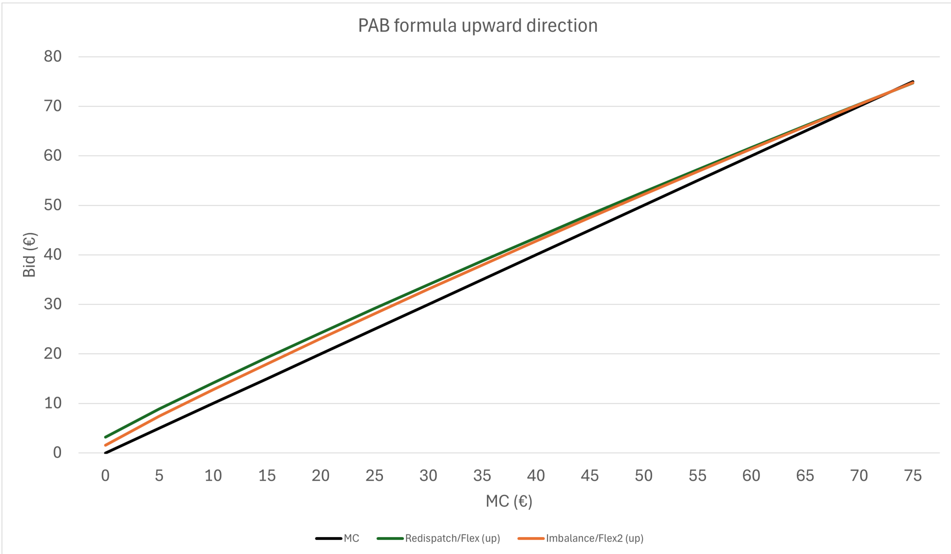

Figure 2.6: Pay-as-bid formula upward activation

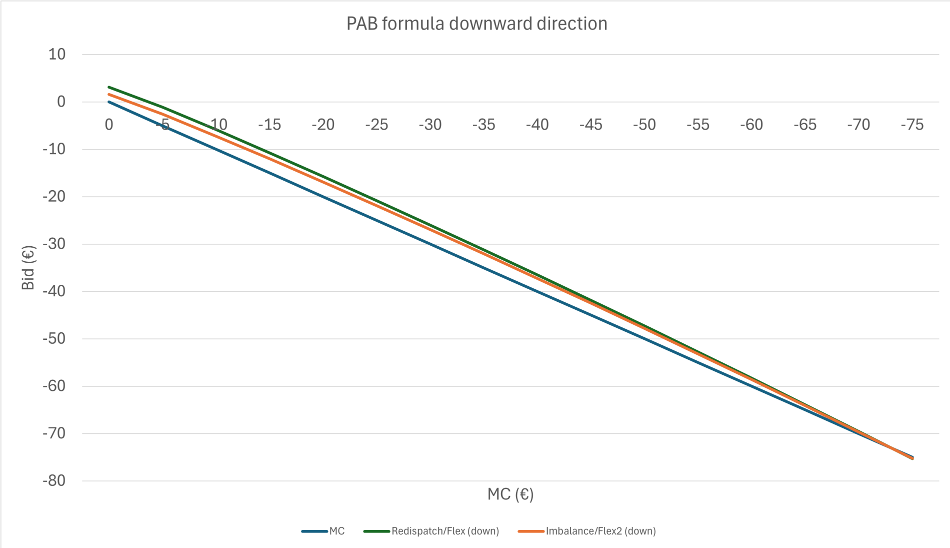

Figure 2.7: Pay-as-bid formula downward activation

Incorporating a parametrised formula of this kind made the model highly adaptable and future-proof. As more empirical data or specific studies on bidding behaviour in the Dutch redispatch and balancing markets becomes available, the parameters α, β, and γ can easily be adjusted to reflect new insights. This flexibility ensured that the model remains relevant and accurate over time without requiring a complete redesign.

2.3.2. Extra capacity

A uniform marginal cost of 200 €/MWh was assigned to the artificial “extra capacity” resource across all products and activation directions (day-ahead, redispatch up/down, imbalance up/down). The level was set significantly higher than regular bids in the simulations so that extra capacity functioned purely as an out-of-market product, reflecting the higher cost of last resort measures. The extra capacity restored feasibility when market supply was insufficient, but was never preferred to market bids. Using a single price across rounds avoided creating artificial arbitrage and preserved the activation and merit order of the real markets. The value of 200 €/MWh was therefore a penalty parameter, high enough to deter activation except under scarcity, but not so extreme as to introduce numerical scaling issues for the solver.

2.4. Experiment design

This study analysed the effects of pricing mechanisms in different market designs on system costs, capacity and price for downward and upward activation. Now that the four designs have been defined: *Current, Gross, Net* and *All-in-one*, more variations were included by incorporating different pricing mechanisms. Resulting in 11 design scenarios, combining each market design with two pricing mechanisms: Pay-as-Bid (PAB) and Marginal Pricing (MP) Table 2.9.

PAB and MP were selected for this study to represent the two predominant pricing mechanisms in European electricity markets and create different incentives for market participants (Haghighat et al., 2012; Poplavskaya, Joos, et al., 2020). PAB reflects the current redispatch system and is associated with encouraging strategic bidding behaviour, whereas MP improves price efficiency and tends to result in lower average prices (Haghighat et al., 2012; Poplavskaya, Joos, et al., 2020). Thereby allowing a comparison of their effects on market performance in terms of total costs, total volumes and clearing prices.

However, this study also explored the impact of only PAB or MP within the current setup, allowing for consistent comparisons across all design types under the same pricing mechanism. The *All-in-one* design was not tested for mixed pricing (PAB and MP), since it involved a single optimisation step, making such a combination incompatible. Uniform pricing refers to scenarios where the same pricing mechanism (either PAB or MP) was applied to both redispatch and balancing, while mixed pricing used PAB for redispatch and MP for balancing. In total, 11 design scenarios were analysed: each of the four market designs was tested under both uniform and mixed pricing mechanisms, except the *All-in-one* design, which was only tested under uniform pricing due to its single-step optimisation structure.

Table 2.9: Experimental design

Current	**Gross**	**Net**	**All-in-one**
only MP	only MP	only MP	MP
only PAB	only PAB	only PAB	PAB
PAB for redispatch MP for balancing	PAB for redispatch MP for balancing	PAB for redispatch MP for balancing	–

Key Performance Indicators (KPIs)

To evaluate the performance of the proposed market designs, five Key Performance Indicators (KPIs) were used: extra capacity, total system costs, total volume and clearing price for downward and upward activation:

- **Extra capacity**, indicator for how often the feasibility backstop (BSO) is used
- **Total system costs**, combines the economic value of all activated bids
- **Total volume**, refers to the total volume activated across the system. Reflecting how much of the available resources is required to meet balancing and redispatch needs
- **Clearing price down**, represents the clearing price for downward activation. Average over the two flex rounds in which flexibility bids are accepted, an indicator of the cost-efficiency and effectiveness
- **Clearing price up**, similar to clearing price down, but for upward bids

These KPIs allow for a comparison between the four different market designs and pricing mechanisms. All KPIs are evaluated over four days with hourly resolution. For each KPI, average values, maximum values and standard deviations were reported.

For extra capacity, results reported the activation count, the number of time steps in which extra capacity was used and the activated volume. For this extra capacity, lower values indicated higher efficiency. Hence, when no extra capacity was used, the system was more efficient then when lots of extra capacity was used. For the other four KPIs, lower values also reflected more favourable market outcomes, while higher values indicated higher costs or inefficiencies:

- Extra capacity, lower count and volumes reflect a more efficient market design
- Total system costs, lower costs reflect a more efficient market design
- Total volume, higher volumes signal greater deployment of flexibility, which can indicate inefficiency when not accompanied by lower costs or reduced extra capacity use
- Clearing price down, lower prices mean the TSO pays less for downward activation, while negative prices indicate that suppliers are willing to pay to reduce output
- Clearing price up, lower prices imply cheaper upward activation for the TSO, whereas higher prices reflect more expensive balancing. This indicator should be interpreted in relation to total capacity used and overall system costs

This study used the clearing price instead of the average price. In electricity markets, the clearing price reflected the short term marginal costs of operations (Abada et al., 2025). The price to accept the last bid of supply to meet demand, best reflecting the value of electricity at that time and location. In marginal pricing, the clearing price was applied to all accepted bids. By contrast, under pay-as-bid (PAB), each supplier received the price it offered, but the clearing price still corresponded to the last accepted bid needed to meet demand.

Line limitations

To address the third sub-question of this study, the parameter line reservation was systematically varied. Line reservation referred to the fraction of transmission line capacity that was withheld from the redispatch round to ensure sufficient capacity remained available for the balancing round. In the baseline, the default reservation of 50% was applied, similar to a study from Trukšinas et al., 2024. The additional scenarios tested 10% and 20% reservation. Varying this parameter made it possible to isolate the effect of internal capacity reservations on congestion management and the overall efficiency of the different market designs. Such reservations were relevant in practice: under the N-1 security principle applied by TenneT, operators typically use round half of the nominal network capacity in normal operation to ensure the system remains secure in the event of a line outage (ENTSO-E, 2013).

3 Validation

To validate the models, various aspects were assessed, including the DA merit order simulation and system behaviour under redispatch and balancing. In this section, graphs illustrate the behaviour of the *Current*, *Gross* and *All-in-one* models. The *Net* model was not validated separately, as it was identical to *Gross* in terms of power flows and bidding behaviour. The only difference was the remuneration rule, applied ex post after optimisation was completed. Since this adjustment did not affect the underlying system behaviour or dispatch logic, a separate validation for the *Net* model was not required.

In the following figures, the time steps were displayed on the x-axis, with the volume in MWh or price in €/MWh on the y-axis. The sum of the generation was grouped per type: S1, S2, W1, W2, F1 and F2. Here, $X \in \{\mathrm{F}, \mathrm{S}, \mathrm{W}\}$; X_1 is cheaper than X_2 and therefore should be activated first. Moreover, extra capacity was shown through a red line and the relevant metric was given by the black line.

In this chapter, several hypotheses were tested to validate system behaviour of the models for the three rounds across all time steps:

1. DA: supply was equal to demand
2. DA: volumes were equal under all designs
3. DA: cheapest generators were activated first
4. DA: clearing prices followed the merit order
5. Redispatch: volume up was equal to volume down
6. Redispatch: in *All-in-one*, the difference between volume up and down followed the direction of imbalance
7. Redispatch: volume of redispatch was identical under *Current* and *Gross*
8. Redispatch: cheapest generators were activated first
9. Redispatch: clearing prices followed the merit order
10. Imbalance: the difference between volume up and volume down was equal to the total imbalance
11. Imbalance: total imbalance level was equal under all designs
12. Imbalance: cheapest generators were activated first
13. Imbalance: clearing prices followed merit order

3.1. DA round

In the DA round, demand and supply were cleared by the merit order principle, meaning the cheapest bids were accepted first, followed by increasingly expensive ones until demand was fully met.

Supply equals demand

The behaviour to be tested was that in the DA round, supply must equal demand in every time step across all models. The variables used were the total system load, shown by the black line, compared to the sum of the variables of all activated generation processes, stacked per technology type. The validation criterion was that, for every time step, the stacked generation must exactly equal the load curve. As shown in Figure 3.1, Figure 3.2 and Figure 3.3, the total activated generation consistently matched the system load, confirming that supply equalled demand in all simulations. In *Gross* and *All-in-one*, production was consistently slightly higher than the load due to a minor error in the load factor, which sums to 1.022 instead of 1.0 due to a rounding error. This deviation represented only a very small fraction of the total system volume and therefore had a negligible impact on the overall results. If this deviation had effect at all, this slight upward bias in effective load would have increased the redispatch requirement in *Gross* and *All-in-one* relative to *Current*. Therefore, even if any effect were material, which it was not given the negligible magnitude, it only made *Current* comparatively easier and render the reported performance of *Gross* and *All-in-one* conservative. Overall, ensuring that supply equalled demand in the DA round was essential, as this confirmed that the model replicated the fundamental requirement of market clearing in electricity systems.

Equal volume across models

A second hypothesis was that the activated DA volume was equal across all market designs. The variables used were the total activated generation volumes per model in the DA round. The validation criterion was that, since all designs share the same DA market structure and optimisation settings, the activated volumes should be identical. The results confirmed this: Figures 3.1, 3.2 and Figure 3.3 showed that the activated DA volumes were equal under *Current*, *Gross* and *All-in-one*. This consistency verified that differences observed in later rounds were not caused by variations in the initial DA outcomes, but purely by the design of the subsequent redispatch and imbalance rounds. It was important that DA volumes were consistent across designs, since differences at this stage would bias subsequent redispatch and imbalance outcomes and undermine comparability.

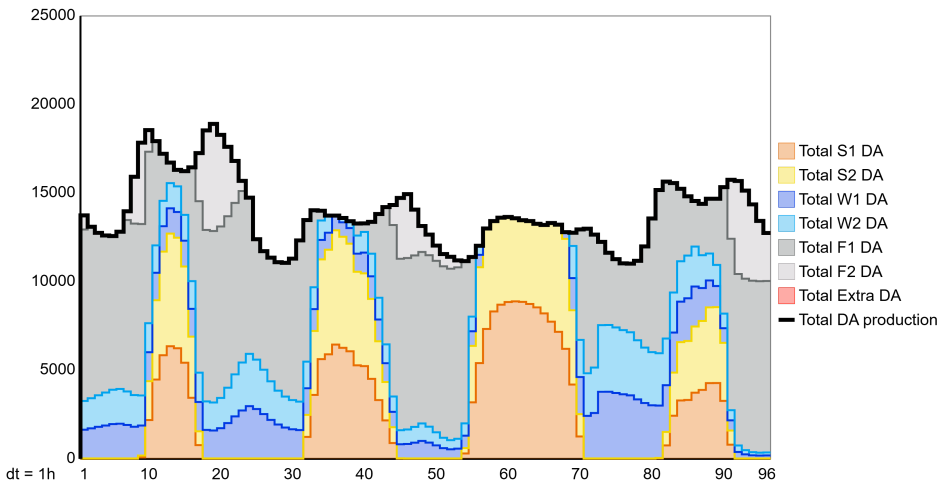

Figure 3.1: Current: DA round, supply equals demand

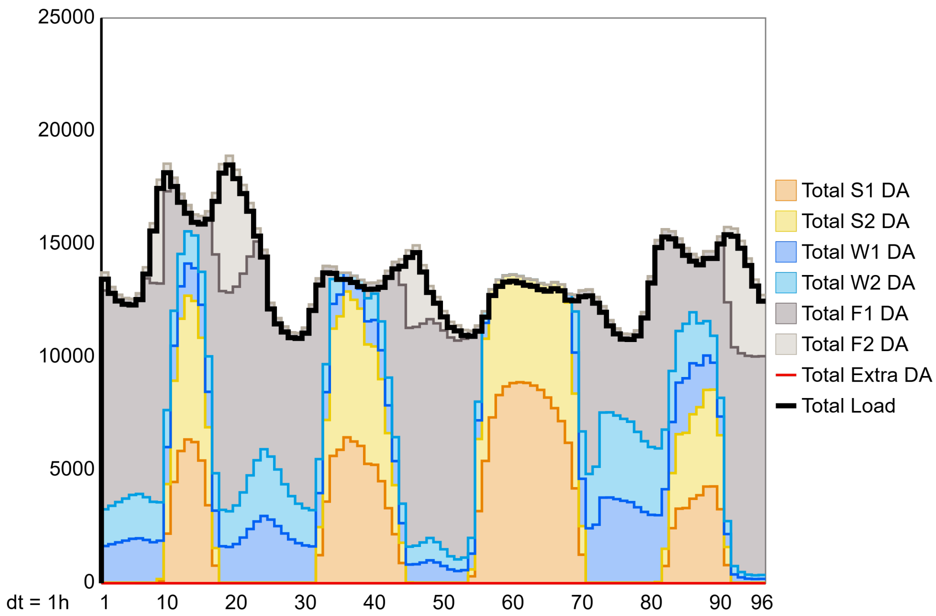

Figure 3.2: Gross: DA round, supply equals demand

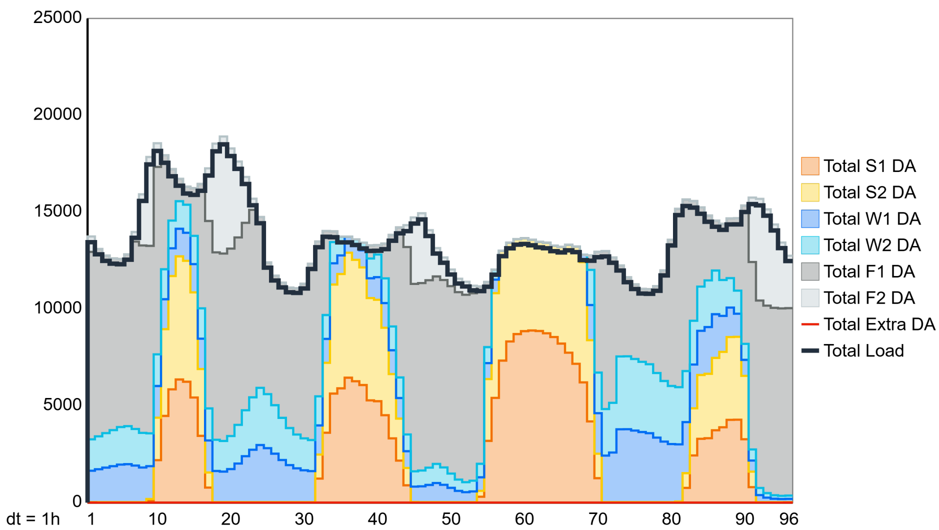

Figure 3.3: All-in-one: DA round, supply equals demand

Cheapest generators activated first

The third hypothesis tested whether the model correctly activated generation volumes according to the merit order. The behaviour to be tested was that, in every time step of the DA round, generation bids were accepted in order from lowest to highest marginal costs until demand was met. The variables used were the activated generation volumes per technology type, represented as stacked areas in Figure 3.1, Figure 3.2 and Figure 3.3. The validation criterion was that the order of activation should always followed the ranking of increasing costs. The results confirmed this behaviour: solar power, the cheapest source, was always activated first whenever available, followed by wind as the second cheapest source. When demand was not fully covered by solar and wind, fossil generation was used. The additional ”extra” capacity, set at a very high marginal cost of €200/MWh to represent BSO measures was never activated, showing that sufficient generation capacity was always available in the DA rounds. Verifying that the cheapest generators were activated first, ensured that the model correctly implements the merit order principle, which was a key indicator of system behaviour according to market principles.

Merit order clearing prices

The fourth hypothesis examined whether the clearing prices in the DA round correctly reflected the marginal cost of the last activated unit. The behaviour tested was that the clearing price followed the merit order, such that the price was set by the marginal unit required to meet demand. The variables used were the DA clearing prices, shown by the black line and the bid prices of individual generation units, shown by coloured lines for S1, S2, W1, W2, F1 and F2 in Figure 3.4, Figure 3.5 and Figure 3.6. The validation criterion was that the clearing price must correspond exactly to the marginal cost of the final activated unit. The results confirm this pattern: the clearing price consistently aligned with the cost of the marginal unit, in line with the activation order shown in Figure 3.1, Figure 3.2 and Figure 3.3. This demonstrated that the model correctly applies the merit order logic both in dispatching volumes and in determining prices. The alignment of clearing prices with the merit order was relevant as it confirmed that the price formation in the model reflected the marginal cost of the last unit activated which was consistent with actual market practice.

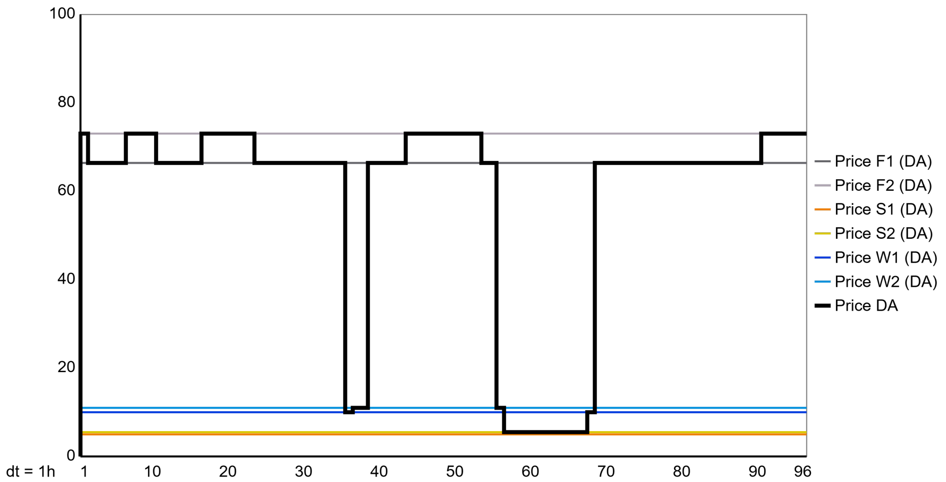

Figure 3.4: Current: Prices in DA round

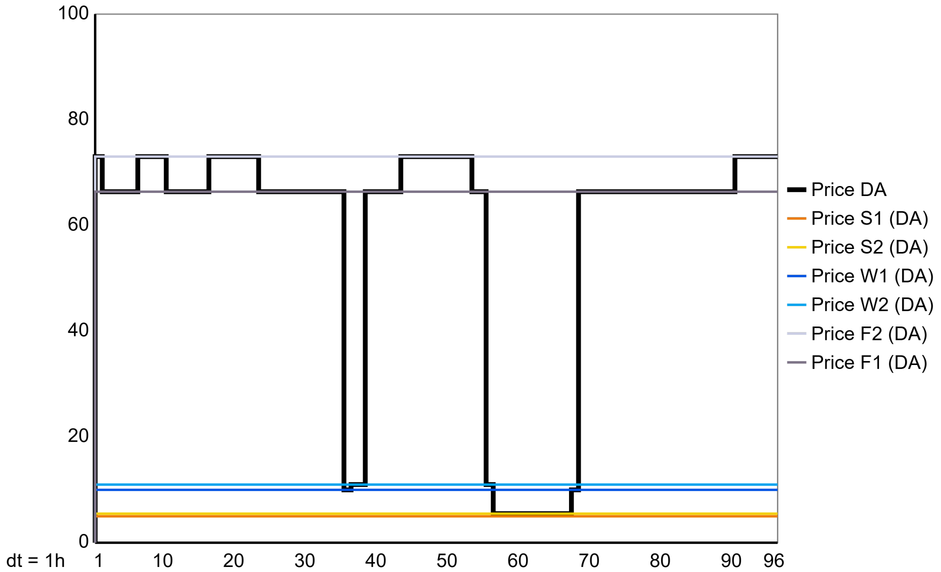

Figure 3.5: Gross: Prices in DA round

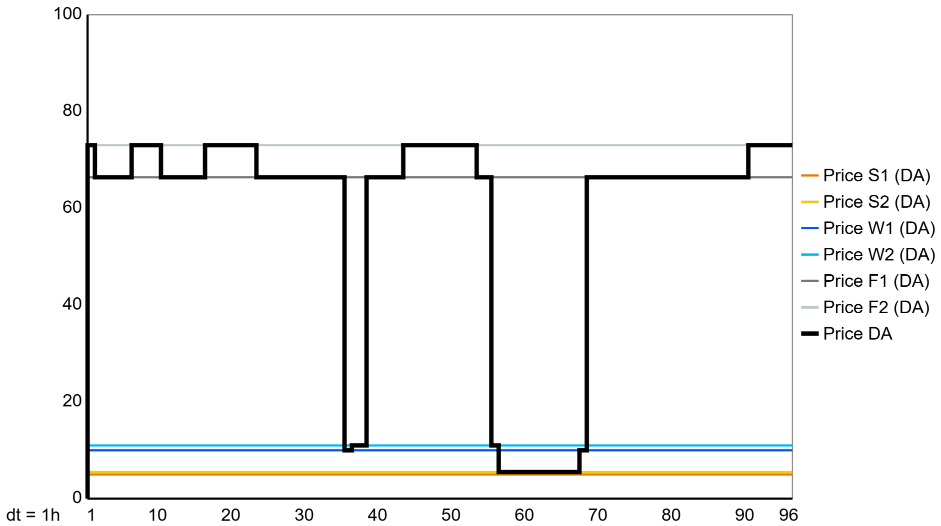

Figure 3.6: All-in-one: Prices in DA round

All hypotheses for the DA round were confirmed. The first hypothesis: supply equals demand, was supported as the activated generation volumes consistently matched the system load in all time steps. The second hypothesis: all models produced equal DA volumes, also holds with only a negligible deviation in the *Gross* and *All-in-one* models, due to a minor load factor error. However, this only made the results for the new designs more conservative. The third hypothesis: cheapest generators were activated first, was confirmed by the dispatch order consistently following the merit order from solar, to wind, to fossil. Finally, the fourth hypothesis: clearing prices followed the merit order, was also confirmed as the clearing price always corresponded to the marginal unit required to meet demand. None of the hypotheses were rejected.

3.2. System behaviour for redispatch and balancing

In addition, the behaviour of the models in the redispatch, balancing and flex rounds for redispatch and balancing services needed to be validated. After the DA round was cleared based on economic dispatch, congestion could occur and was resolved through redispatch.

3.2.1. Redispatch

In these rounds, the validation focused on whether the activated volumes and clearing prices followed the expected system behaviour: redispatch volumes should be symmetric across upward and downward activation, redispatch outcomes under *Current* and *Gross* should be identical and activations in both redispatch and imbalance rounds followed the merit order. As *All-in-one* employed a one-step optimisation rather than sequential rounds, it was expected to show different behaviour than *Current* and *Gross*.

Volume up equals volume down

The first behaviour to be tested in the redispatch round was whether upward and downward redispatch activations were symmetric. By definition, redispatch requires that upward activation is matched by an equal downward activation elsewhere in the system. The variables used to test the hypothesis were the total upward redispatch volumes, represented by the black lines in Figures 3.7 and 3.8 and the total downward volumes, represented by the green stacked areas. The validation criterion was that these two curves match in every time step. The results confirmed this hypothesis: in both *Current* and *Gross*, the upward and downward volumes were consistently equal across all scenarios. In this study, upward and downward redispatch volumes were equal which confirmed that congestion was resolved in a system consistent manner. In addition, it ensured that the performance of the different market designs could be assessed on a fair and comparable basis.

However, the simulations also revealed that in *Current*, the assumption that only 30% of the total market volume was available for redispatch, with the remainder reserved for imbalance, sometimes resulted in insufficient redispatch capacity to resolve congestion. In such cases, the model used the additional "extra" capacity. As mentioned before in Chapter 2 in the extra capacity section: all models included extra capacity, in all three optimisation rounds to ensure that a feasible solution could always be found, regardless of whether they were activated in previous rounds. Hence, even if an extra generator was not activated in, for example, Bergum during the DA round, it could still be activated upward in Bergum during the redispatch round. In reality, this would correspond to BSO products, out of market measures that the TSO can activate at very high costs when regular market bids are insufficient. The activation of this artificial capacity in *Current* therefore underscored an important limitation of separated markets: under stress conditions, the restricted redispatch pool may force reliance on BSO resources. On the contrary, the integrated designs more effectively used the available flexibility, reducing the need for BSO measures.

All-in-one: difference between volume up and down followed imbalance direction

For *All-in-one*, the hypothesis that upward and downward redispatch were equal did not apply. In this design, congestion and balancing were co-optimised in a single step. As a result, the model could procure a net upward (or net downward) volume at a given time step that simultaneously relieves line constraints and resolved the system imbalance. Equal activation of volume up and down within a time step was therefore not required and not expected. Hence, the validation for *All-in-one* tested a different condition: for every time step, the signed difference between upward and downward redispatch equalled the model's net imbalance for that time step. Figure 3.9 showed the resulting activation volumes: upward and downward activations were frequently asymmetric, as expected. This confirmed that the observed asymmetry was a consequence of the one-step formulation rather than a modelling error.

In addition, for All-in-one, upward and downward activation did not need to be equal within a time step. Instead, the difference between them should match the system's net imbalance for that time step. The variables used were the upward and downward redispatch volumes per time step and the system's imbalance. These were shown in Figure 3.10, where the imbalance was shown by the black line and the upward and downward activations were shown by stacked areas. For every time step, the two series moved in the same direction and were close in magnitude.

A small residual gap remained in some time steps. This was because in the flex round of *All-in-one* KCL was enforced but imbalance was also added in this round. The transmission limits were looser than in the flex round in the other new designs, but similar to the transmission limits in the flex2 round of the other new designs. This hybrid set-up was chosen to keep *All-in-one* comparable with the two-step designs. Their second step, flex2, the imbalance round, also operated with the more relaxed limits as strict redispatch limits would artificially penalise the one-step optimisation, whereas copper-plate limits would undo congestion management. The less strict limits therefore permitted additional cheaper activation, which would be infeasible under the stricter redispatch constraints, but feasible under the imbalance constraints in the other models. These extra activations increased upward or downward redispatch flows to relieve line constraints, but did not translate one-on-one into the net imbalance, which only reflects the system wide balance. The resulting gap was thus an expected consequence of the co-optimised but relaxed constraint set. In addition, the merit order was respected and all network constraints were satisfied, so the residual did not indicate a modelling error.

The hypothesis was accepted. The small remaining difference was explained by the intentionally looser line capacity limits in the second optimisation round of *All-in-one*. This allowed additional cheaper up and down regulation, which would be unavailable by stricter line limitations in the other designs. The observed asymmetry between upward and downward volumes and the small residual were therefore, a consequence of the one-step optimisation with a combination of settings from the redispatch and imbalance settings of the other models and not a modelling error.

Equal redispatch volumes under Current and Gross

A second hypothesis tested whether the total redispatch volumes in *Current* and *Gross* were identical. Since both models shared the same DA market outcome and the same network characteristics, the redispatch requirements should be equal. The variables used were the aggregated redispatch volumes per time step in Figures 3.7 and 3.8. The validation criterion was that the redispatch volumes align across the two models. The results largely confirmed this expectation. However, in the *Current* design, additional "extra" capacity was activated due to the absence of sufficient redispatch bids. Model *Gross* resolved redispatch completely with regular bids, without activating extra capacity. In addition, because *All-in-one* co-optimisation in a single step, the total redispatch volume need not equal that of *Current* or *Gross*. Overall, identical redispatch volumes under *Current* and *Gross*, ensured that differences observed in outcomes such as costs or volumes arose solely from the market design and or remuneration structure and not from inconsistencies in the physical redispatch requirements.

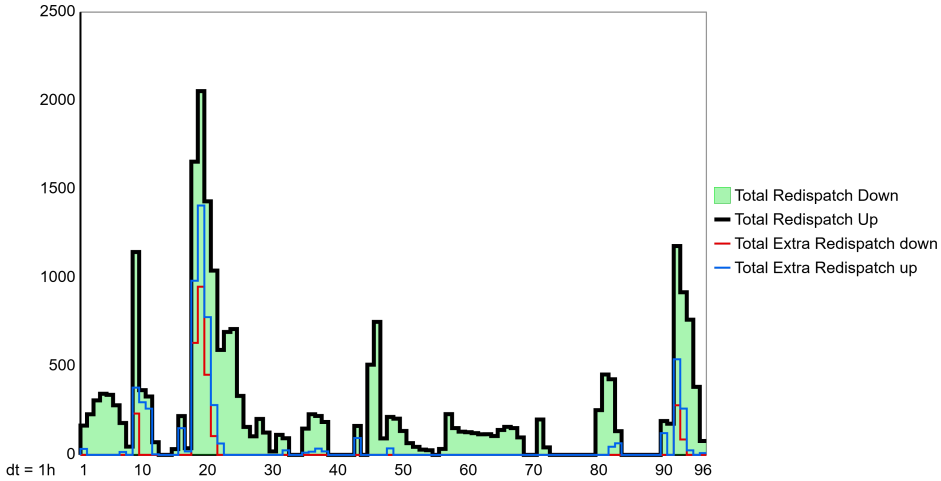

Figure 3.7: Current: Total redispatch in Redispatch round

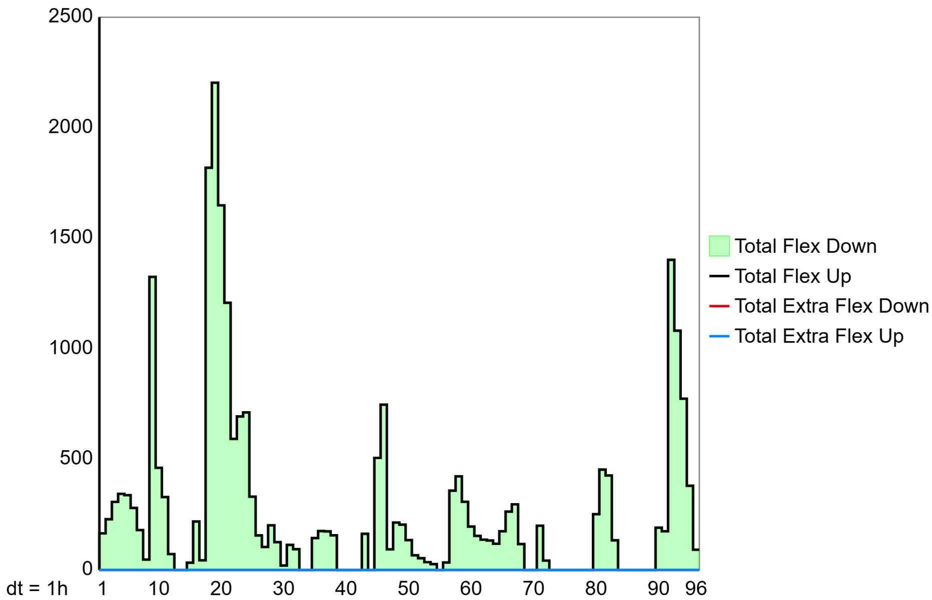

Figure 3.8: Gross: Total redispatch in Flex round

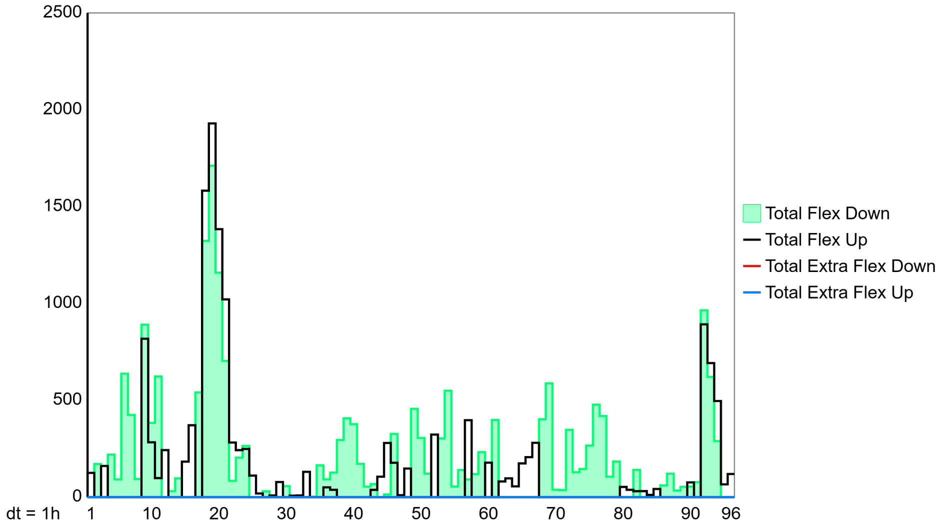

Figure 3.9: All-in-one: Total redispatch in Flex round

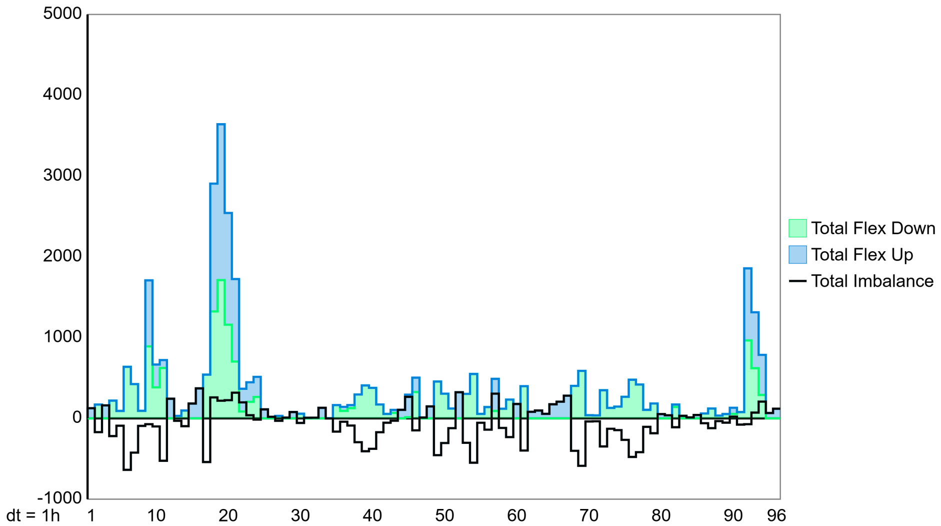

Figure 3.10: All-in-one: Total imbalance in Flex round

Activation order Redispatch/Flex round

The behaviour to be tested was whether redispatch upward activation followed the expected merit order and whether the availability of flexibility differed across the *Current* and *Gross* designs. The variables used were the total upward redispatch volume, shown by the black line and the disaggregated activation per generation type, shown as stacked areas in Figure 3.11, Figure 3.12 and Figure 3.13. The validation criterion was that activation should begin with the cheapest resources: solar when available, followed by wind and finally fossil generators until the required upward redispatch volume was met. The results confirmed this order: solar was activated first, wind followed when additional upward activation was needed and most of the redispatch was provided by fossil units. A further result was that in the *Current* design, extra capacity had to be activated to meet redispatch needs, as shown in Figure 3.11. In contrast, the *Gross* design achieved similar total levels of upward activation without relying on extra capacity, by activating more on F1 and F2 fossil generators, see Figure 3.12. Besides, the *All-in-one* design was also optimised without relying on extra capacity. This demonstrated that the additional flexibility available in *Gross* and *All-in-one* from an integrated market reduces the reliance on expensive extra capacity compared to the *Current* design.

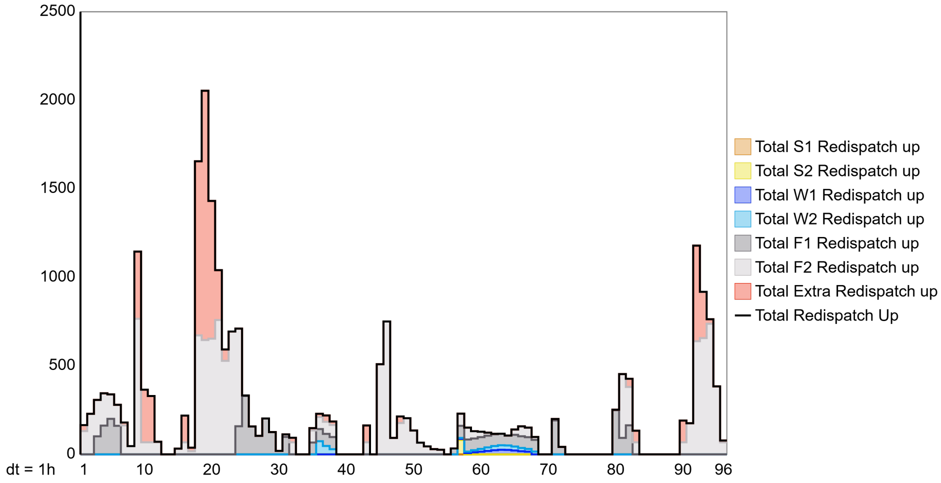

Figure 3.11: Current: Order of upward activation in Redispatch round

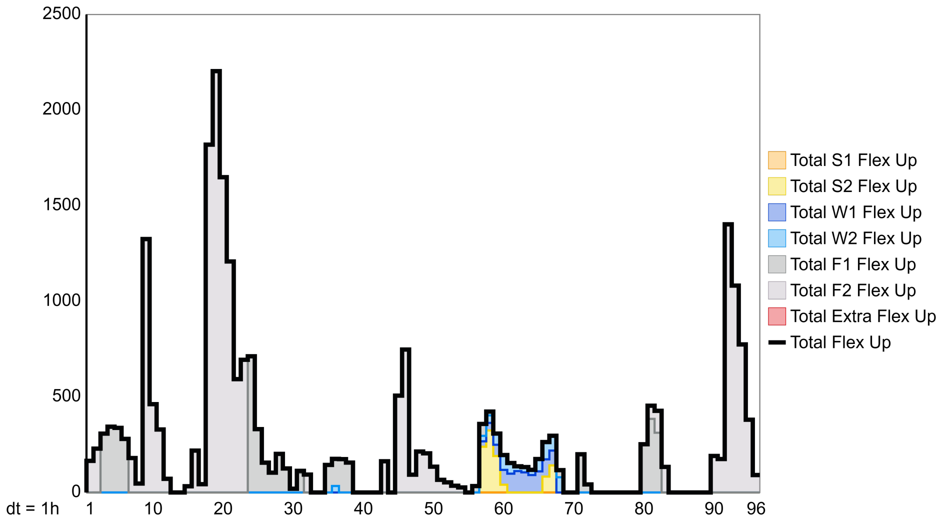

Figure 3.12: Gross: Order of upward activation in Flex round

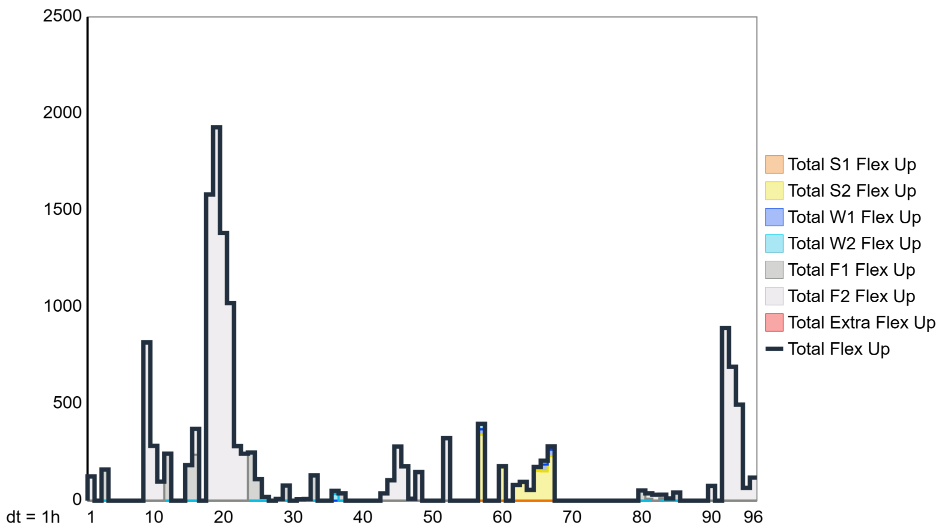

Figure 3.13: All-in-one: Order of upward activation in Flex round

The same behaviour applied to activation in downward direction shown in Figure 3.14, Figure 3.15 and Figure 3.16. The variables used were the total downward redispatch volume shown by the black line and the activation per generation type, shown as stacked areas in Figure 3.14, Figure 3.15 and Figure 3.16. The validation criterion was that the cheapest units should be deactivated first, followed by the more expensive generators until the required downward redispatch volume is realised. The results confirmed this expected activation order: in both designs, the cheapest assets were curtailed first, with fossil generators providing most of the downward redispatch as they were willing to pay the most to reduce production. In *Current*, however, additional extra capacity had to be activated to ensure sufficient downward redispatch, see Figure 3.14. In contrast, the *Gross* and *All-in-one* designs relied less on such extreme measures and instead made more use of fossil flexibility, as well as some wind and solar curtailment. This resulted in time steps where wind set the clearing price for downward redispatch in the merit order as no fossil capacity was activated during the DA round. Confirming cheapest first activation in redispatch was important, as it validated that redispatch actions were cost minimising within the network constraints and indicated that the system behaviour was simulated correctly.

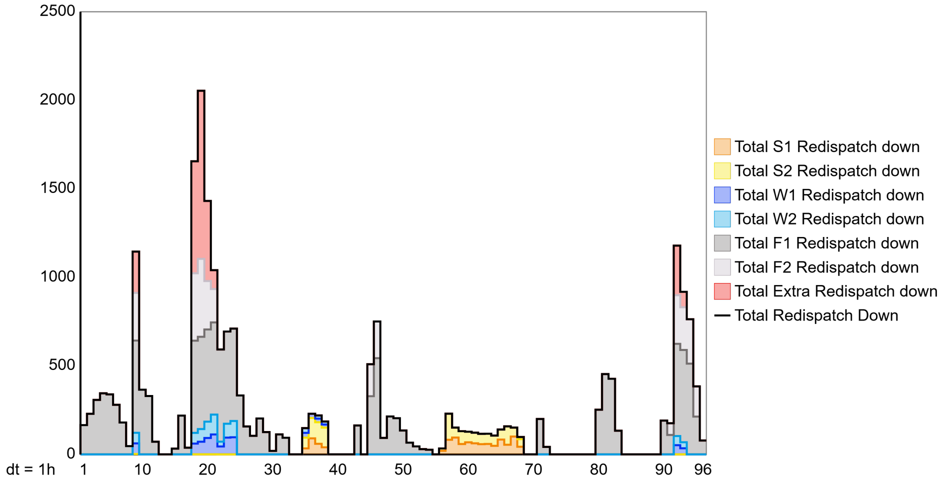

Figure 3.14: Current: Order of downward activation in Redispatch round

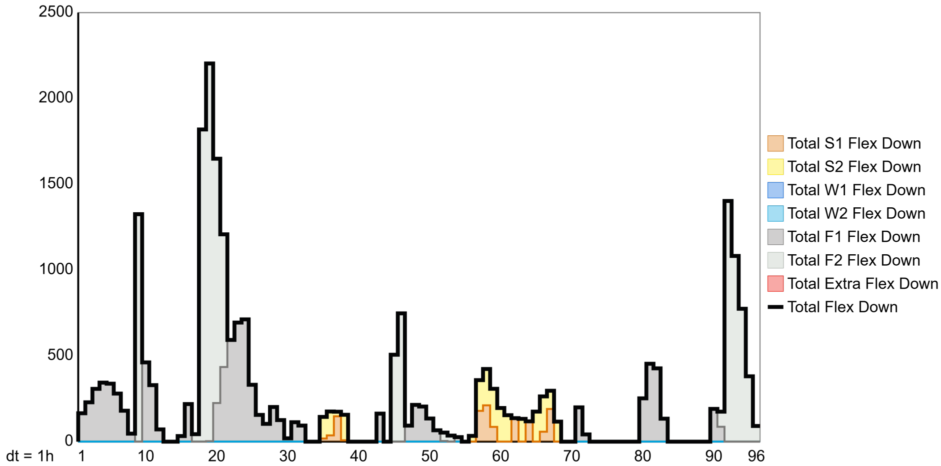

Figure 3.15: Gross: Order of downward activation in Flex round

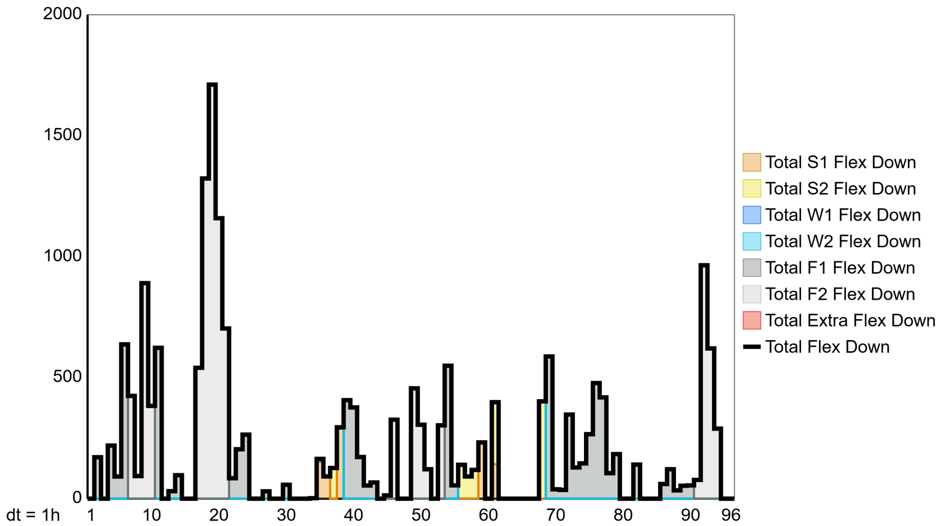

Figure 3.16: All-in-one: Order of downward activation in Flex round

Merit order clearing prices

The hypothesis to be tested was whether redispatch clearing prices followed the merit order of available bids and how these outcomes differ between the *Current* and *Gross* designs due to observations between the type of generation activated in the redispatch round. The variables used were the redispatch clearing prices for upward and downward activation shown in Figure 3.17, Figure 3.18 and Figure 3.19. The validation criterion was that prices should increase stepwise as increasingly expensive bids were activated, reflecting the step-wise nature of redispatch bids rather than smoothly adjusted hourly prices. The results confirmed this hypothesis: both figures show the step-wise structure of the merit order. However, in *Current*, prices frequently reached the upper bound of 200 €/MWh, originating from the activation of extra redispatch capacity. This underscored the effect of limited liquidity in the separated redispatch market. On the contrary, in *Gross* and *All-in-one*, redispatch prices remained lower and more stable because a larger pool of flexibility bids was available, reducing reliance on artificially expensive capacity. It was relevant to validate that redispatch clearing prices followed the merit order, as this confirmed that the models simulated market-based redispatch and reflected the merit order principles.

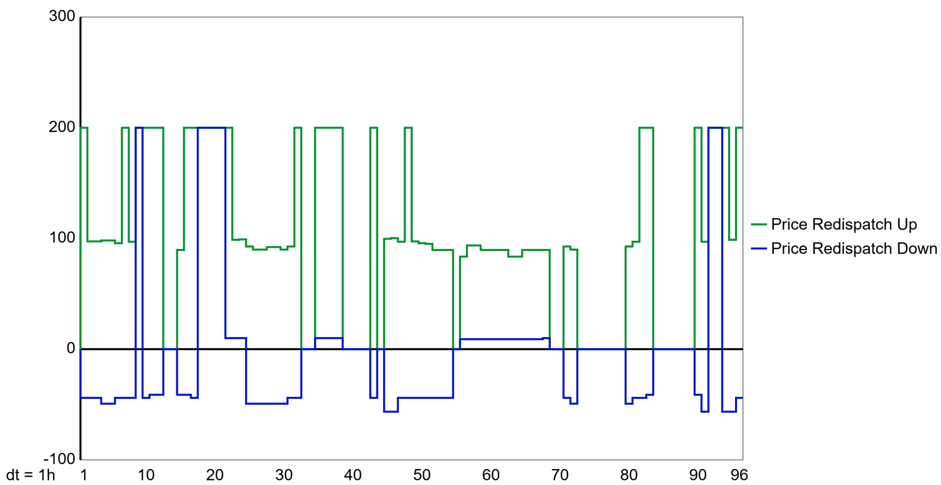

Figure 3.17: Current: Upward and downward prices in Redispatch round

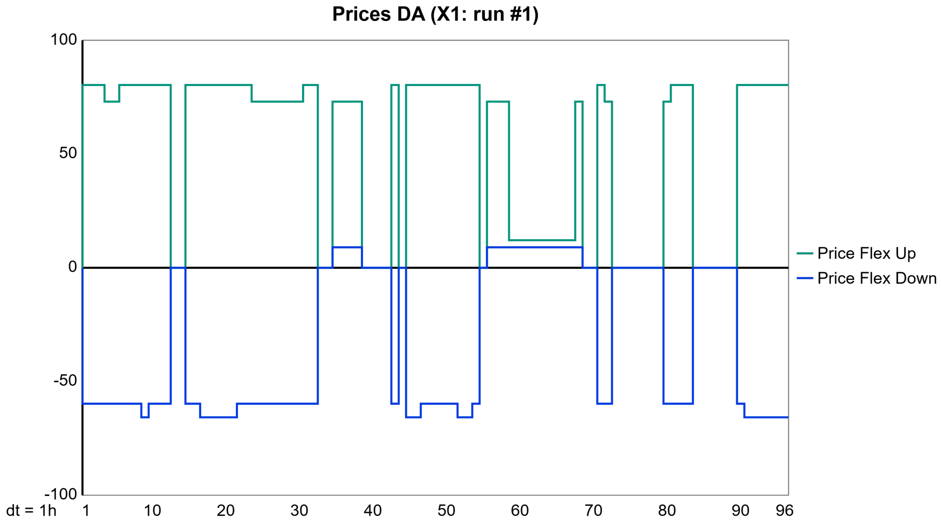

Figure 3.18: Gross: Upward and downward prices in Flex round

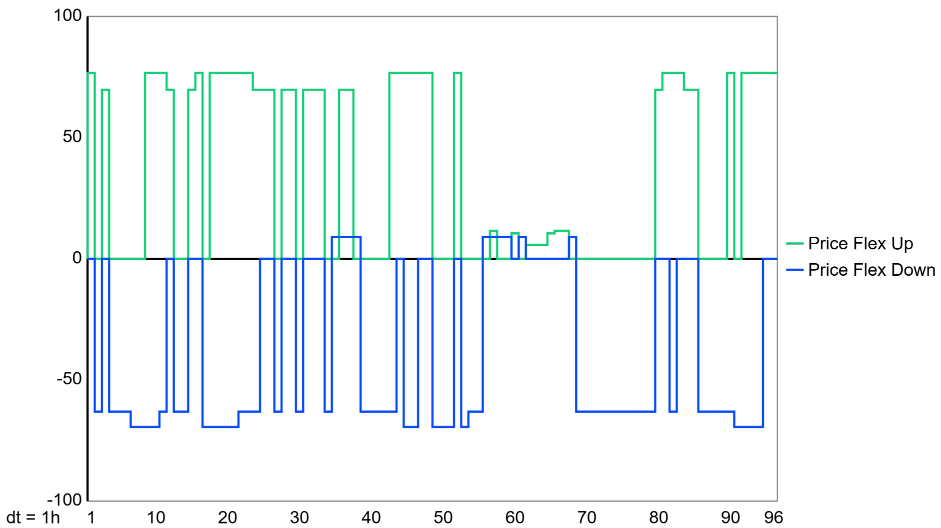

Figure 3.19: All-in-one: Upward and downward prices in Flex round

In conclusion, the redispatch validation confirmed that all hypotheses hold. For *Current* and *Gross*, upward and downward redispatch volumes were always equal within each time step, consistent with the requirement of symmetrical activation. Moreover, the total redispatch volumes under *Current* and *Gross* were equal, as expected given that both models were based on identical DA outcomes and physical network constraints. Model *All-in-one* reported asymmetry between upward and downward volumes, the small gap was a consequence of the one-step optimisation with a combination of settings from the redispatch and imbalance rounds of the other models and not a modelling error. The merit order logic was also respected, with the cheapest resources activated first in both upward and downward directions. The main difference between *Current* and *Gross* lies in the availability of flexibility: in *Current*, the restricted liquidity in the redispatch market resulted in the activation of expensive extra capacity, whereas in *Gross* as well as in *All-in-one*, the integrated flex market enabled the same redispatch volumes to be resolved with regular generation units at lower prices.

3.2.2. Imbalance

Lastly, system behaviour for the imbalance rounds was analysed. For the imbalance round specifically: the total imbalance introduced into the system should be resolved by the difference between upward and downward activations and the overall imbalance level should be consistent across all designs. In addition, the activation order and merit order clearing prices were tested again.

Difference upward and downward activation equal to total imbalance

The behaviour to be tested was that in the imbalance round, the difference between upward and downward activation must equal the total system imbalance. The variables used were the total imbalance shown by the black lines in Figure 3.20 and Figure 3.21, compared to the stacked blue areas representing upward activation and the green areas representing downward activation. The validation criterion was that, for every time step, the imbalance curve should equal the difference between upward and downward activation, regardless of the absolute volumes activated for upward and downward generation. The results confirmed this hypothesis. Although at certain time steps, t=35-36 and t=57, the absolute levels of upward and downward activation exceed the imbalance, but their difference consistently matches the imbalance. This behaviour arose from the more relaxed transmission line capacity constraints applied in the imbalance round, where 20% extra capacity was allowed to reflect the fact that balancing in practice was not limited by locational transmission constraints. If line capacities were set to infinity, redispatch actions from the previous rounds would be largely reversed, recreating congestion. The modelling choice therefore ensured realistic balancing behaviour while maintaining feasible system operation.

Equal imbalance levels under all designs

The hypothesis tested here was that the total imbalance level should be the same under all models. The variable used for this validation was the total imbalance, shown by the black lines in Figure 3.20, Figure 3.21 and Figure 3.10. The validation criterion was that these black lines should show identical patterns and values across the different models. The results confirmed this expectation, demonstrating that imbalance levels are equal under all designs. This finding was relevant, as it ensured that any observed differences in costs, volumes or prices between the models can be attributed to the market design itself, rather than to differences in the imbalance input.

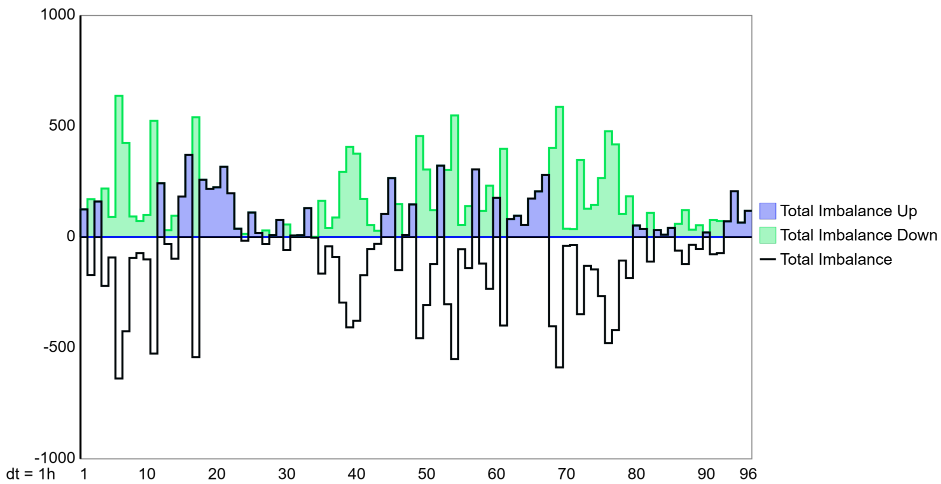

Figure 3.20: Current: Total imbalance in Imbalance round

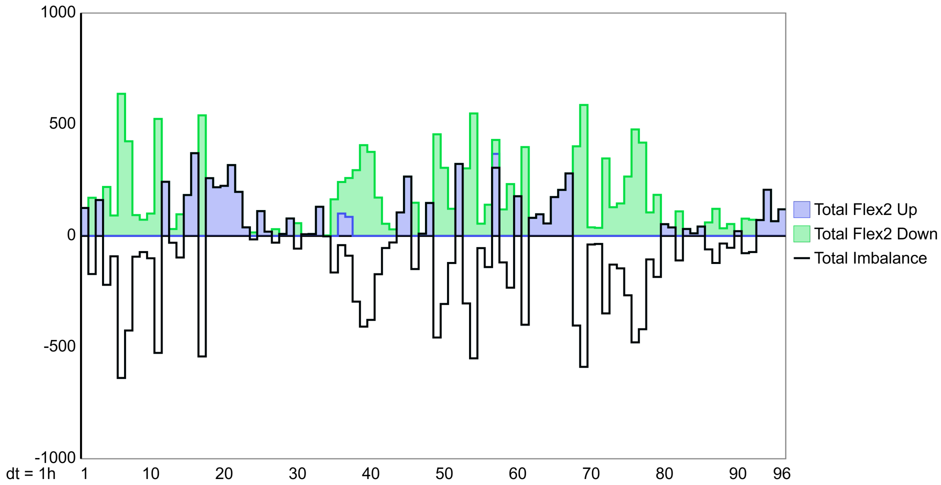

Figure 3.21: Gross: Total imbalance in Flex2 round

Activation order Imbalance/Flex2 rounds

The hypothesis was whether the model activated generation units in the correct merit order during the imbalance round, meaning that cheaper units were activated before more expensive ones whenever sufficient capacity was available. The variables used to test this were the volumes of activated generation per technology type, as shown in Figures 3.22 and 3.23. The validation criterion was that for upward imbalance, activation should proceed from the cheapest technologies: solar and wind, to conventional generators. Only in cases of insufficient capacity, the capacity from artificial generation type extra should have been used. The results confirmed this behaviour: in both *Current* and *Gross*, upward activation was realised primarily by F1 and F2 generators, with smaller contributions from S1 and S2 whenever solar capacity was available. Importantly, no extra imbalance capacity was required in either design, indicating that sufficient market-based flexibility was available to restore balance, also in *Current*. This graph was not available for *All-in-one* as there was no Flex2 round, only a Flex round.

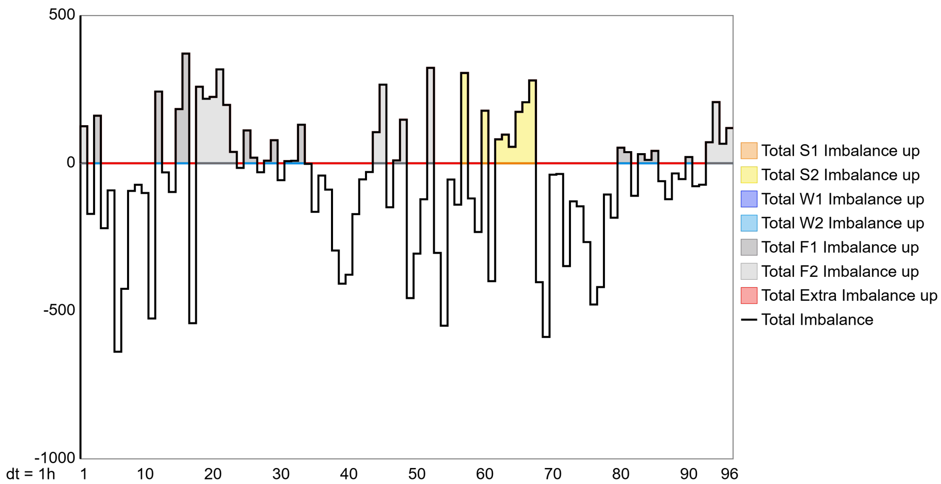

Figure 3.22: Current: Order of upward activation in Imbalance round

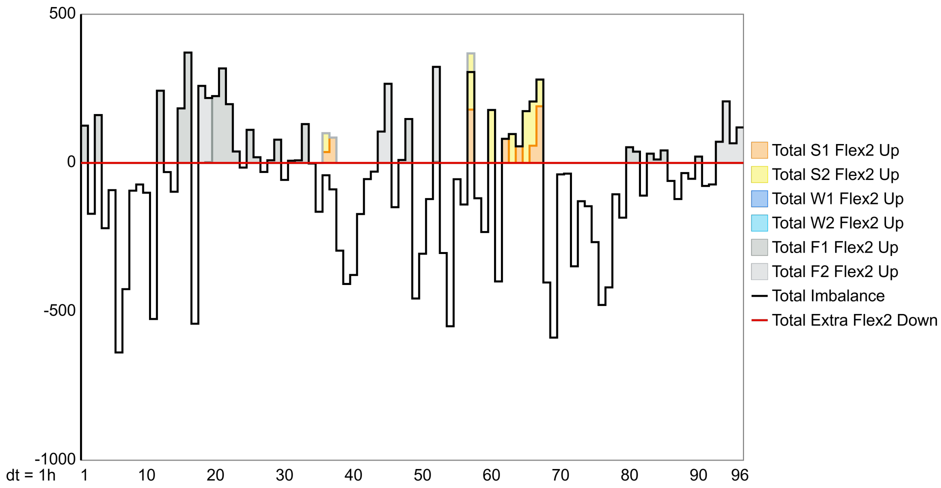

Figure 3.23: Gross: Order of upward activation in Imbalance round

Similarly, it was tested whether the model also follows the merit order when activating downward generation in the imbalance round. The relevant variables were the total imbalance, shown by the black lines in Figures 3.24 and 3.25, compared with the stacked areas indicating the activated downward volumes by generator type. The validation criterion was that cheaper units should be deactivated first, followed by more expensive ones. The results confirmed this behaviour: in both *Current* and *Gross*, most of the downward activation was realised by F1 and F2 generators, with occasional contributions from solar units (S1 and S2) when only solar power had been activated in the DA round. Validating that the cheapest generators were activated first in imbalance rounds confirmed that the model minimised costs for balancing actions, consistent with market principles.

Importantly, no extra capacity was required in the imbalance round in any design. In *Current*, this followed from the assumption that 70% of capacity was reserved for balancing, which proved sufficient to meet imbalance requirements. In contrast, redispatch was constrained to 30% and therefore required extra capacity in earlier rounds. In *Gross*, all capacity was pooled across redispatch and imbalance, which ensured sufficient availability in the imbalance round. This validated that the assumed split in *Current* and the unified pool in *Gross* both provided enough downward activation to resolve imbalances under the simulated system conditions. For *All-in-one*, this graph was unavailable because the design includes only one flex round, there was no Flex2 round.

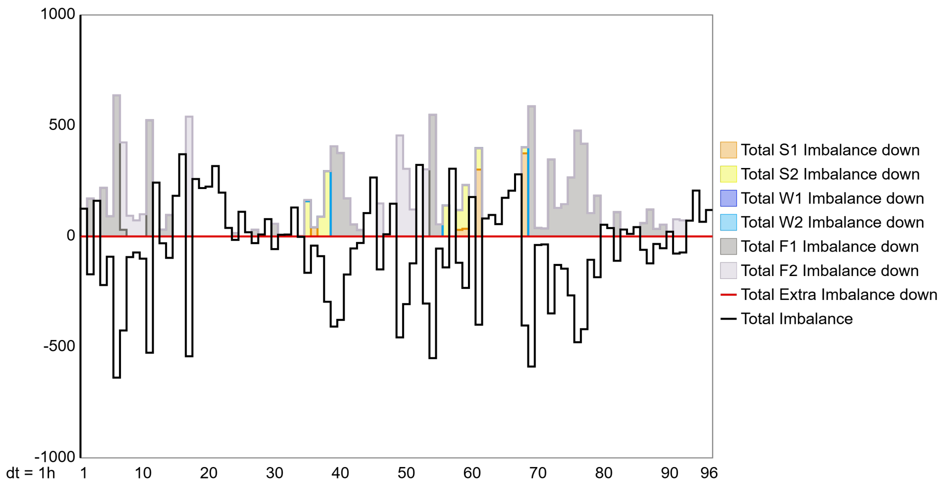

Figure 3.24: Current: Order of downward activation in Imbalance round

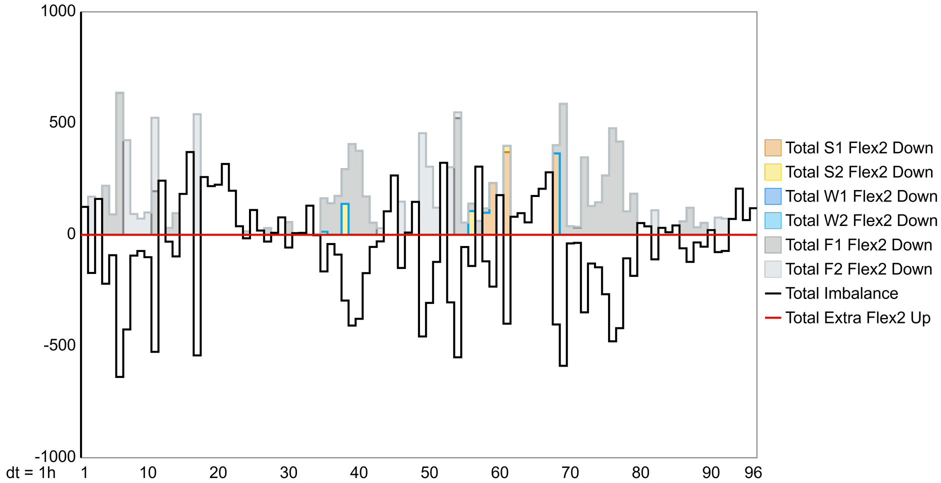

Figure 3.25: Gross: Order of downward activation in Flex2 round

Merit order clearing prices

The behaviour to be tested was whether clearing prices in the imbalance round followed the merit order. The relevant variables were the upward and downward imbalance prices shown in Figures 3.26 and 3.27, compared against the sequence of activated volumes per generator type in Figures 3.20 and 3.25. The validation criterion was that prices should rise when more expensive units are activated and conversely, fall or even become negative when units with a willingness to pay for curtailment were deactivated. The results confirmed this behaviour. Upward activation was consistently priced above zero, reflecting the cost of activating additional generation during scarcity. Downward activation frequently reached negative prices, particularly when renewable units such as solar and wind were unavailable, though occasional positive prices occurred when wind was dispatched downward against a cost. This mirrored real-world dynamics where upward flexibility is scarce and costly, while downward flexibility can hold negative value in times of oversupply. Compared to redispatch prices, imbalance prices were less extreme, as no extra capacity was activated in either *Current* or *Gross*. This confirmed that the models produced realistic price patterns that follow the merit order and reflect expected market behaviour. Again, this graph was not available for *All-in-one*, as there was only a Flex round.

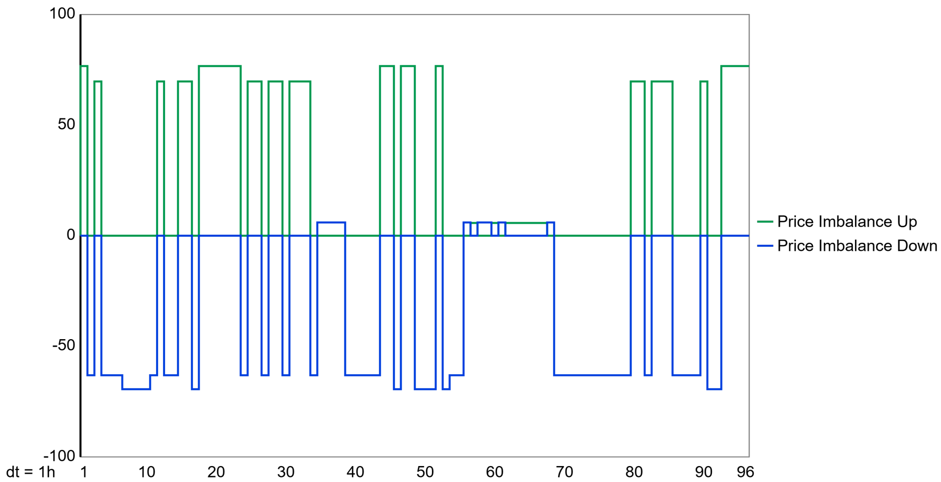

Figure 3.26: Current: Upward and downward prices in Imbalance round

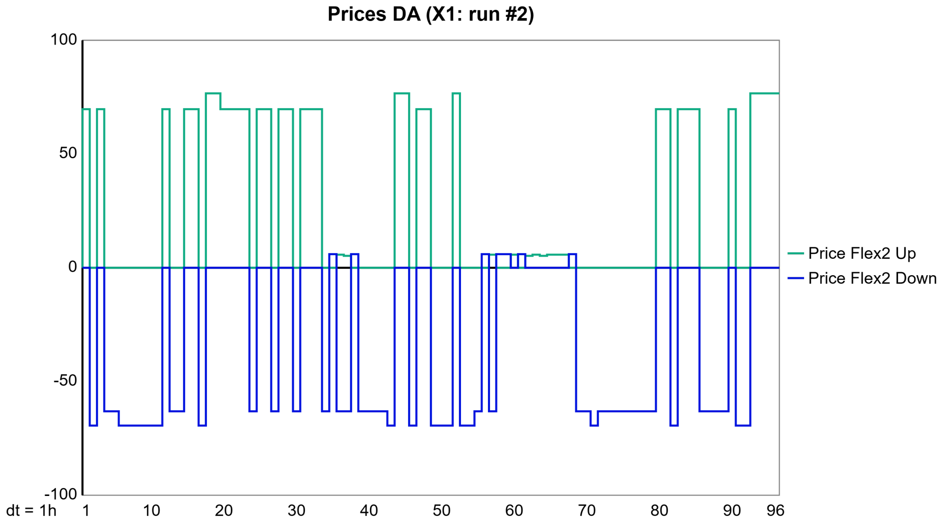

Figure 3.27: Gross: Upward and downward prices in Flex2 round

All hypotheses for the imbalance round were confirmed by the simulation results. The difference between upward and downward activation consistently equalled the total imbalance, verifying that system imbalances were resolved correctly. The total imbalance levels were identical across all designs as expected, since the imbalance profile was added to the models. The activation order followed the merit order in all time steps, with cheaper units being dispatched first. In addition, clearing prices reflected this order by rising with scarcity and falling or turning negative during oversupply. Importantly, no extra capacity was needed in any of the designs during the imbalance round, indicating that the available volumes in the market were sufficient to resolve imbalances under the tested conditions.

4 Results

This chapter presents the results of the four model configurations simulated to evaluate the integrated balancing and redispatch market design: *Current*, *Gross*, *Net*, and *All-in-one*. The first indicator for performance is the use of extra capacity. In the model, extra capacity was added to guarantee feasibility of the simulations, representing out-of-market reserves that TenneT could require generators to provide. In addition, the models were analysed based on four additional KPIs: total costs, total volumes, clearing price down and clearing price up. The results given in this chapter reflect the 'total flex' results, the average of the redispatch and imbalance rounds. Please refer to Appendix D for the absolute numbers for the total flex results and the results for the separate redispatch and the imbalance rounds.

To report the results of this study, normalisation was used for the KPIs. Normalisation scales the values of a performance indicator to a dimensionless interval between 0 and 1, using relative scaling between a lower and an upper reference value. Hence, normalisation was appropriate because all designs were evaluated on the same days with identical scenarios, inputs and constraints. So scaling to common reference points removes unit and level effects, while preserving the ordering and relative differences between designs.

In this study, the *Current* design was set to 0, where a split in total available capacity of 30% for redispatch and 70% for imbalance was used. In addition, the *All-in-one* design, representing the theoretical optimum, was set to 1. Designs *Gross* and *Net* were then placed proportionally within this range, where higher scores indicate better performance relative to the optimum. For example, a normalised score of 0.23 means that the design achieves 23% of the possible improvement between the current situation (0) and the theoretical optimum (1). Finally, for the *PAB & MP* design, no *all-in-one* scenario could be simulated. For all the KPIs in this study lower values indicated better performance, the upper reference was set to the smallest absolute *All-in-one* value observed in the *only MP* and *only PAB* simulations. This maximised the improvement range (*Current*-*All-in-one*) and thus produced smaller normalised scores for the design, a conservative estimate of the improvement.

The box plots display the distribution of a KPI, for example total flexibility costs across the different market design scenarios: only MP, only PAB and PAB & MP. For each scenario, four designs were reported: *Current*, *Gross*, *Net* and *All-in-one*, represented by separate box-and-whisker plots. Each box indicates the interquartile range (IQR), the middle 50% of observations between the first (Q1) and third (Q3) quartile, with the line inside denoting the median. The whiskers extend to data points within 1.5 times the interquartile range, while observations beyond this range were shown as outliers. This representation made it possible to compare not only the median performance across designs, but also the variability and the presence of extreme values. A lower median and a more compact middle range indicated a design with consistently lower total flexibility costs, whereas wider spreads or frequent outliers point to greater uncertainty or volatility in performance.

4.1. Performance of new designs

This section outlines the results for the five KPIs: extra capacity, total costs, total volumes, clearing price down, clearing price up, over the three pricing mechanisms: only MP, only PAB and PAB & MP for the four models: *Current, Gross, Net, All-in-one*.

4.1.1. Extra capacity

All models included an artificial generation capacity: extra capacity, enabling the solver to always find a solution and representing the BSO product of TenneT. The extra capacity simulated TenneT's procedure where they request suppliers to provide a bid out-of-the-market. The activation of extra capacity was reported through i) activation count, the number of time steps that extra capacity was used and ii) the activated volume in MWh that was activated. As mentioned before in Chapter 3, the artificial extra capacity was only used in *Current*, more specifically, only in the redispatch round, no activations occurred in the imbalance round. In *Gross*, *Net* and *All-in-one*, no activations were observed in the redispatch and imbalance rounds. Therefore, the count and volume of activated extra capacity were reported only for design *Current* in the redispatch round. In *Current*, the activation count and volume under redispatch and imbalance sharing ratios of 20/80, 30/70 (default) and 40/60 were reported.

Table 4.1 reported the results for the *Current* model, the number of time steps in which extra capacity was activated during the redispatch round. Activations were consistently more frequent in redispatch up than in redispatch down across all share ratios: 20/80, 30/70 and 40/60. For redispatch up, the only MP design reported the fewest activations at each ratio, while only PAB and PAB & MP reported higher counts, in redispatch down the three designs were equal. In both directions, the activation count decreased as the redispatch share increased from 20/80 to 40/60, indicating that greater redispatch availability reduces the likelihood that TenneT must activate out-of-market extra capacity.

Table 4.2 reported the cumulative extra capacity activated during the redispatch round for *Current*. Volumes were systematically higher in upward direction than in downward direction, across all share ratios. In redispatch down, volumes were identical across the three designs, however, in redispatch up, only MP consistently reported lower volumes than only PAB and PAB & MP, which were equal. In both directions, the activated volume declined as the redispatch share increased from 20/80 to 40/60, reaching zero in downward direction redispatch at 40/60. These results indicate that increasing the volume available for redispatch services, reduced not only the frequency but also the magnitude of reliance on out-of-market extra capacity.

Table 4.1: Current: Count extra capacity activated during Redispatch round

(a) Redispatch Down

	20/80	30/70	40/60
only MP	7	3	0
only PAB	7	3	0
PAB & MP	7	3	0

(b) Redispatch Up

	20/80	30/70	40/60
only MP	20	10	6
only PAB	27	17	10
PAB & MP	27	17	10

No extra capacity activations occurred in *Gross*, *Net* and *All-in-one* in both directions and all rounds. Therefore, the count was always 0 for the three new designs in upward and downward direction in the redispatch and imbalance rounds.

Table 4.2: Current: Volume extra capacity activated during Redispatch round [MWh]

(a) Redispatch Down

	20/80	30/70	40/60
only MP	2741	593	0
only PAB	2741	593	0
PAB & MP	2741	593	0

(b) Redispatch Up

	20/80	30/70	40/60
only MP	5498	3176	1668
only PAB	5991	3666	2103
PAB & MP	5991	3666	2103

No extra capacity activations occurred in *Gross*, *Net* and *All-in-one* in both directions and all rounds. Therefore, the volume was always 0 for the three new designs in upward and downward direction in the redispatch and imbalance rounds.

4.1.2. Total costs

The reported total flex costs represent the costs incurred in the redispatch round and the imbalance round. It can be observed that all three new designs: *Gross*, *Net* and *All-in-one*, lead to costs reductions compared to the *Current* design see Figure 4.1 and Table 4.3. As expected, total costs under the *Net* design were even lower than under *Gross*. The *All-in-one* design outperformed both *Gross* and *Net*, as it represented the theoretical optimum.

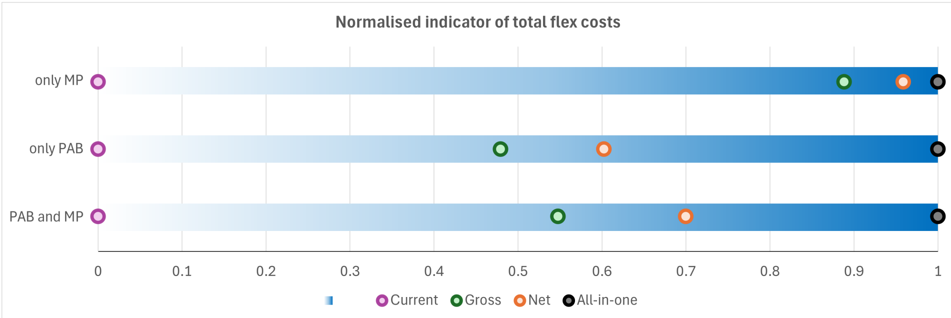

Figure 4.1: Benchmark normalised total flex costs

Table 4.3: Normalised scores for total flex costs

	Current	Gross	Net	All-in-one
only MP	0.00	0.89	0.96	1.00
only PAB	0.00	0.48	0.60	1.00
PAB and MP	0.00	0.55	0.70	–

The distribution of total flex costs across the different market designs was reported in Figure 4.2. First, all scenarios exhibited a wide spread in outcomes, with some extreme outliers indicating that in specific circumstances very high flexibility costs could occur. Second, the median of the costs was clearly higher in the *only PAB* and *PAB & MP* designs, compared to the *only MP* design, suggesting that these market designs were generally more costly in terms of flexibility provision. Third, the *only MP* scenario showed a relatively narrow interquartile range and a lower median, indicating more stable and predictable outcomes. By contrast, the PAB designs displayed a higher degree of variation, reflecting less robust performance and a greater exposure to cost increases.

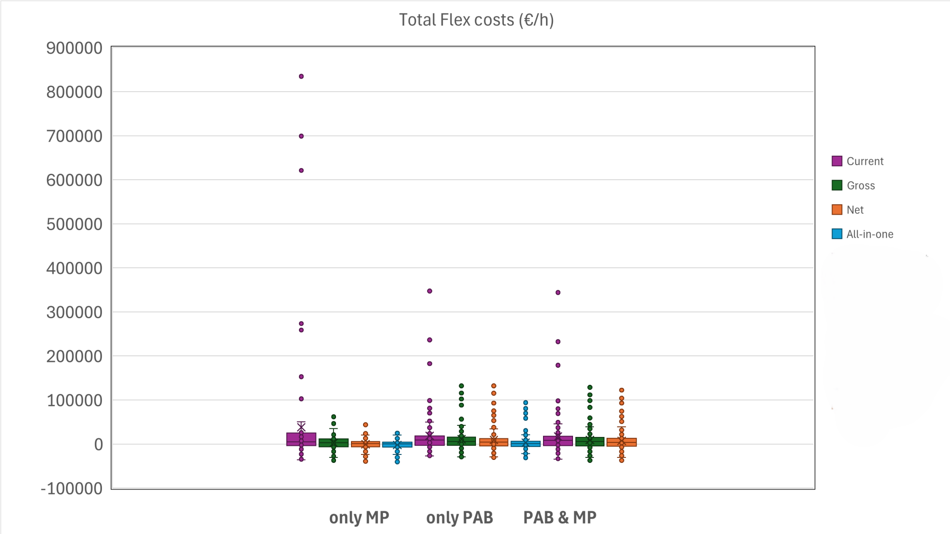

Figure 4.2: Total flex costs

There was a strong difference between the decrease in total costs under only MP compared to only PAB and PAB and MP. When conventional units bid negative prices for downward regulation, MP transmits the more negative marginal price to all accepted units, amplifying the cost reduction. Under PAB, each unit was settled at its own, often less negative bid, so infra-marginal units did not benefit from the more negative marginal bid. As a result, aggregate cost reductions were typically larger under MP than under PAB

4.1.3. Total volume

The total volume needed for both redispatch and balancing services in MWh was reported for the four designs by pricing mechanism. In the PAB and MP figures, no *All-in-one* design was included because it was cleared in one time step. In this chapter, only the total flex volumes were reported, expressed as anchored relative performance scores of the redispatch and imbalance rounds. This metric provided a single system level metric that was comparable across designs, including the one step *All-in-one* design. Strictly speaking, for total volume, this was an anchored relative performance score rather than a bounded normalisation as reported for the other KPIs. Here, scores were anchored at 0 for *Current* and 1 for *All-in-one* and some scores for *Gross* fell below 0. Hence, in this section the scores were based on relative performance and not explicit normalised scores. The relative scores offered the same interpretation as before with the normalised scores, as the performance of *Gross* and *Net* were compared to the anchored *Current* and *All-in-one* scores. The detailed results per round, including separate box plot figures for total redispatch volumes and total imbalance, were provided in Appendix D.

It was observed that the flex volume needed decreased in a descending order from *Current* to *Gross* to *Net* to *All-in-one*, see Figure 4.3 and Table 4.4. Across pricing mechanisms, the ranking was consistent: *All-in-one* reported the lowest total flex volume, followed by *Net*, while *Gross* was close to or slightly below the *Current* baseline. The lower volumes under *All-in-one* were consistent with the one-step co-optimisation where balancing and congestion were settled simultaneously.

In addition, for *Gross* the scores were negative in two scenarios: only PAB and PAB & MP), reflecting a slightly larger total flex volume than in *Current*. This higher volume did not indicate poorer performance: in *Gross* the solver procured additional low-priced physical bids to satisfy constraints, whereas in *Current* the same constraints had to be met by activating high-priced extra capacity because too few redispatch bids were available. Accordingly, the volume KPI should be read together with costs and extra capacity used. In the results, the additional volume in *Gross* was contracted at lower prices and avoided extra capacity, resulting in lower total costs as shown in the previous section.

The box plot figures provided more detail in the total volumes per time step, with only MP reporting the biggest decrease, see Figure 4.4. In addition to the average and middle 50% decreasing, the range of the middle 50% decreased. However, in some of the time steps in design *Gross* compared to *Current*, the flex volume needed increased in the new design under only MP, only PAB as well as PAB & MP. This originated from the extra capacity added in the *Current* design. Where redundant capacity was always available against a relatively high price, to make all time steps feasible. In design *Gross* sometimes more capacity was activated in order to come to a feasible and cheaper solution. For example, by activating capacity in the neighbouring station against a lower price.

Within the middle 50%, the upper quartile decreased in the *Net* design compared to *Gross* and *Current*. This originated from activation in opposite direction, where suppliers were only remunerated for the net activated volume rather than the absolute volume. In addition, the maximum of the middle 50% decreased even further in the *All-in-one* design. As redispatch and imbalance were resolved in the same time step, less volume was needed. Imbalance activation could resolve some of the redispatch actions and the volume for redispatch services strongly decreased in descending order over the designs, see Appendix D for the box plots of the redispatch and imbalance volumes.

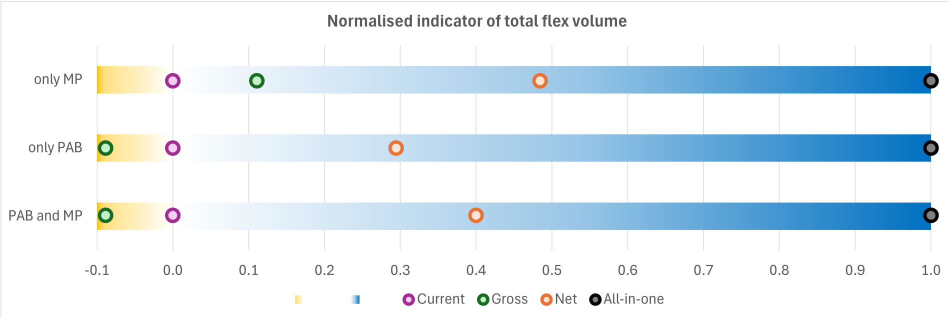

Figure 4.3: Benchmark relative scores total flex volumes

Table 4.4: Relative scores for total volume

	Current	Gross	Net	All-in-one
only MP	0.00	0.11	0.48	1.00
only PAB	0.00	-0.09	0.29	1.00
PAB and MP	0.00	-0.09	0.40	-

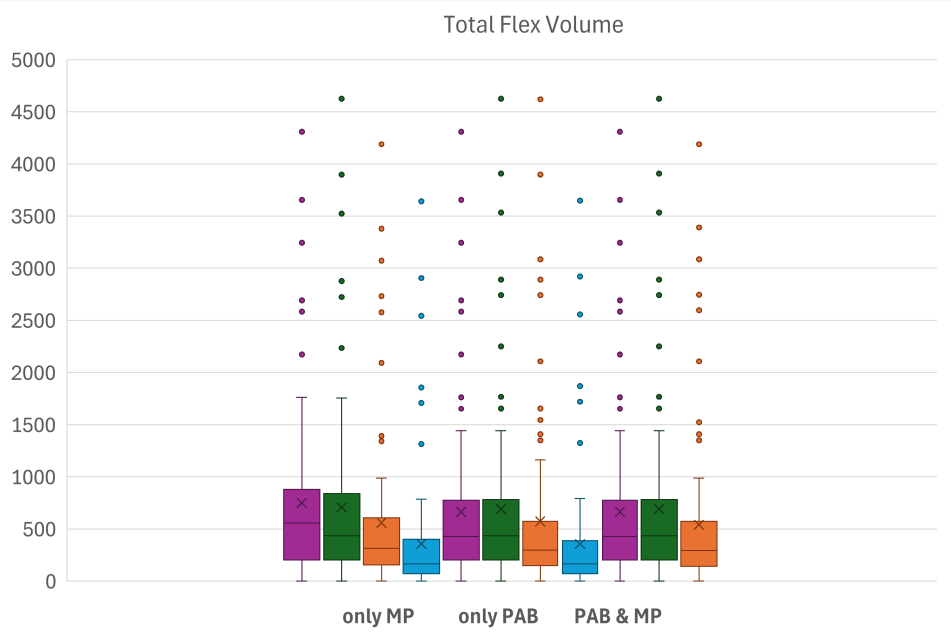

Figure 4.4: Total flex volumes

4.1.4. Clearing price

The clearing price was given for both downward and upward activation in €/MWh, for the four different designs per pricing mechanism. Where the clearing price in a specific direction was the average of the clearing prices in that direction during the second and third round.

In Figure 4.5 and Table 4.5 a higher score indicated a larger reduction in the clearing price relative to *Current*. For downward activation this meant a numerically smaller price, which could either be less positive or more negative. *Current* represented the highest clearing price and *All-in-one* the lowest. *Gross* was between those design and *Net* was equal to *Gross* under only PAB and PAB & MP, but under only MP the clearing price in *Net* was even lower than *All-in-one*. This could be explained by the remuneration rule in Net combined with netting of activations in opposite direction. Under only MP, the clearing price was the marginal accepted bid at the priced quantity. In *Net*, the priced quantity for downward activation was the net down volume, which was typically smaller than the gross down volume priced in *All-in-one*. With a merit order where prices become less negative as quantity increases, a smaller priced quantity left the marginal bid more negative, which resulted in a lower clearing price. Hence, *Net* could report a lower clearing price down than *All-in-one* under only MP. This was a price mechanism effect of netting volumes in opposite direction. Therefore, the results from the clearing prices should be interpreted jointly with the volume and total cost KPIs rather than the observation that Net procured cheaper flexibility.

In Figure 4.6 and Table 4.6 a higher score indicated a larger reduction in the clearing price relative to *Current*. For upward activation this meant a numerically smaller price, which was less positive, there were no negative prices for upward activation. Under only MP, *Gross* achieved a stronger reduction than *Net*. Indicating that *Gross* realised a stronger reduction in prices than *Net*. This originated from the netted out volumes due to the remuneration of volumes activated in opposite direction in *Net* compared to *Gross*. This follows from the remuneration rule in *Net*: opposing upward and downward activations were netted, so the cleared quantity in each direction was smaller. With marginal pricing, the clearing price equalled the marginal accepted bid. Hence, a smaller cleared quantity stopped earlier on the merit order and resulted in a relatively expensive, less negative marginal bid. *Gross* cleared the full gross volume in both directions and was therefore further on the merit order. This resulted in cheaper upward activation bids, which lowered the marginal price more than in *Net*. Under only PAB and PAB & MP, *Gross* and *Net* reported the same prices.

The clearing price down showed that the average decreased in the new designs compared to the

Current design, see Figure 4.7. Moreover, the data reported that the *All-in-one* design had a similar maximum than *Current*, but the minimum strongly decreased. Linking this to the merit order, it denoted that prices earlier on the merit order were selected, since less volume was needed as was shown in the section before about total volume. During some time steps the price remained the same, however, in most of the time steps the price strongly decreased. For the *Gross* design the average price was similar to the *Net* design. Although the middle 50% was lower under *Gross* compared to *Net*. Indicating that on average the clearing price down was similar, but with a wider and more negative spread under *Gross*. In the new designs the outliers were also less extreme.

It can be concluded that for the clearing price down, the average price decreased under the new designs. Combining the results, it can be concluded that the new designs comprise lower clearing down prices that were at least comparable to and in some cases lower than those of the *current* design.

The clearing price up also reported a decrease in the average value over the new designs under all pricing mechanisms. Figure 4.8 shows that the maximum for the middle 50% slightly decreased, whilst the minimum for the middle 50% strongly decreased over the new designs.

Lastly, it could be observed that under only PAB and PAB & MP, the changes over the designs were similar. Combined with the results from the total volumes used, it can be concluded that clearing prices for both upward and downward activation decrease in the new designs *Gross*, *Net* and *All-in-one* compared to *Current*.

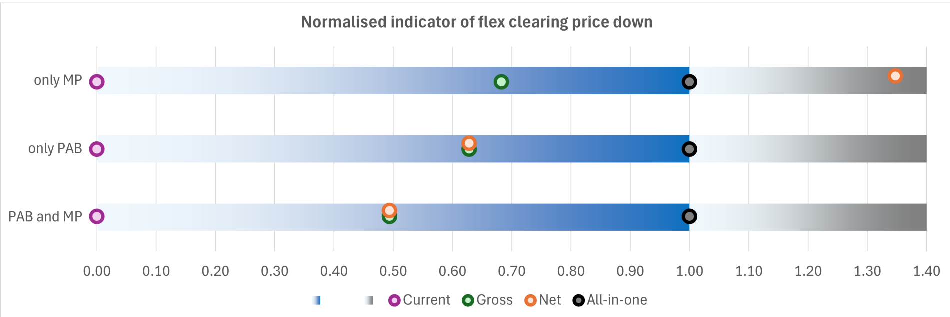

Figure 4.5: Benchmark normalised flex clearing price down

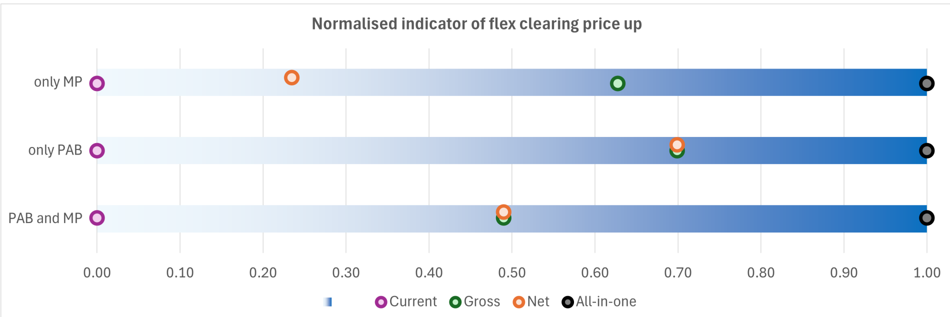

Figure 4.6: Benchmark normalised flex clearing price up

Table 4.5: Normalised scores of flex clearing price down

	Current	Gross	Net	All-in-one
only MP	0.00	0.63	0.23	1.00
only PAB	0.00	0.70	0.70	1.00
PAB and MP	0.00	0.49	0.49	-

Table 4.6: Normalised scores of flex clearing price up

	Current	Gross	Net	All-in-one
only MP	0.00	0.68	1.35	1.00
only PAB	0.00	0.63	0.63	1.00
PAB and MP	0.00	0.49	0.49	-

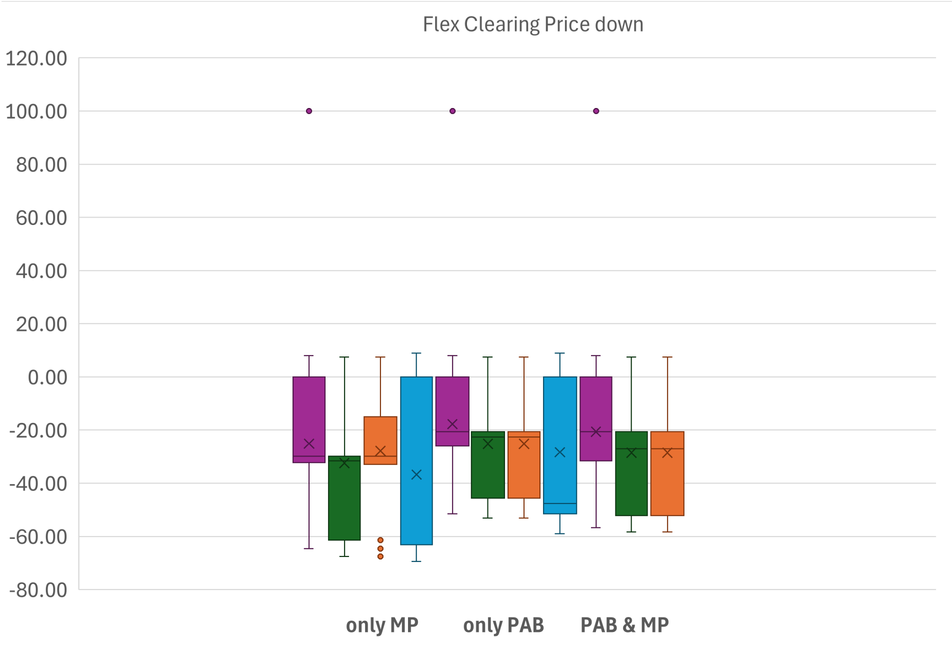

Figure 4.7: Flex clearing price down

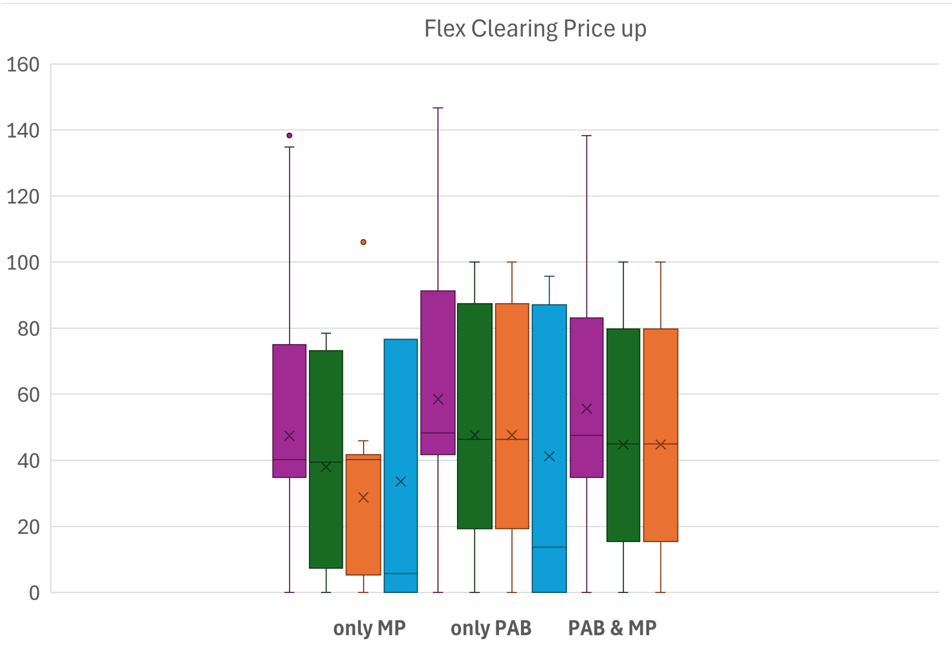

Figure 4.8: Flex clearing price up

4.2. Effect of line reservation

To analyse the impact of reserving transmission line capacity for balancing services on the performance of the proposed market design, the model incorporated a parameter: Line Reservation. This parameter was implemented as a multiplicative factor applied to the nominal line capacity, taking values in [0,1]. A value close to 0 corresponded to highly restricted capacity available for balancing, whereas a value of 1 implied that the full line capacity could be utilised. In practice, however, the transmission grid was operated according to the N-1 security principle (ENTSO-E, 2013), which in the simple case of two identical parallel circuits, motivated operating around half of the post-contingency limit. Hence, the default value of the line reservation factor was set to 0.5, similar to (Trukšinas et al., 2024). Because line reservation was a design/policy lever that defined the market's feasible set rather than an exogenous uncertainty, the effects were reported and evaluated at 10% and 20% lower settings as policy variants. Figures reported performance of the designs grouped per pricing mechanism for the different values of line limitations. Design *All-in-one* was not varied, as it resolved balancing and redispatch in a single round.

This study did not extend the analysis to scenarios with higher transmission line capacity. The rationale was that the N-1 security principle applied by TSOs such as TenneT already implies that the physical grid has been dimensioned with redundancy, but that operationally only part of the nominal capacity was made available. Increasing the available transmission capacity beyond this standard would therefore not reflect realistic operational practice and would overlap with the effects of market design with those of grid reinforcement. In addition, expansion of transmission capacity was outside the scope of this study. Since expansion of capacity would represent a long-term infrastructure investment. Instead, the operational availability was varied via the line reservation factor, which tested the design settings without changing the physical grid.

As line limitations became stricter, available transfer capacity decreased and system scarcity increased. This shifted the solution away from re-routing towards additional procurement of flexibility. Consistent with this mechanism, the total flex volume increased in Figure 4.10 and the total flex costs increased in Figure 4.9. Prices moved in the expected directions, as the clearing price up increased in Figure 4.12, while the clearing price down slightly decreased in Figure 4.11. The price changes reflected movements on the merit order as larger volumes were cleared: more upward volume resulted in more expensive marginal upward activation bids.

The cost effect was the strongest under *Current* in Figure 4.9, because additional capacity need was met by extra capacity at a high penalty price. Stricter line limits triggered the use of extra capacity more often and at larger volumes. By contrast, *Gross*, *Net* and *All-in-one* mitigated the cost escalation by utilising an integrated market for a uniform flex product.

As mentioned before, these indicators should be interpreted together. For example, a design may contract more volume under stricter line limits, but at lower clearing prices and with no extra capacity, resulting in lower total costs than *Current*. Thus, volume and price movements were consistent with the observed cost differences across designs. Stricter line limitations therefore, underscore the potential of an integrated market.

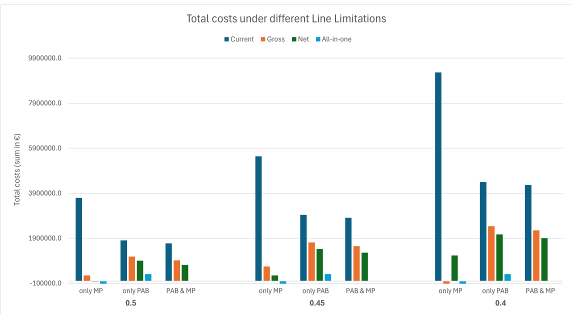

Figure 4.9: Line limitations: Total Flex Costs

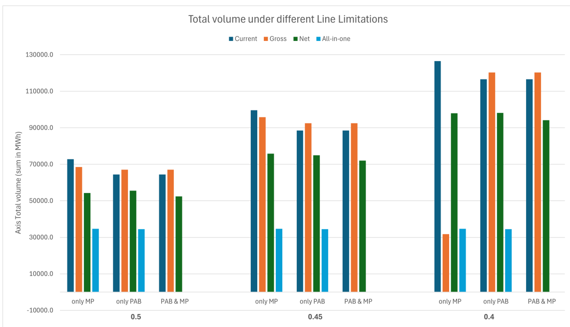

Figure 4.10: Line limitations: Total Flex Volume

Figure 4.11: Line limitations: Clearing price down

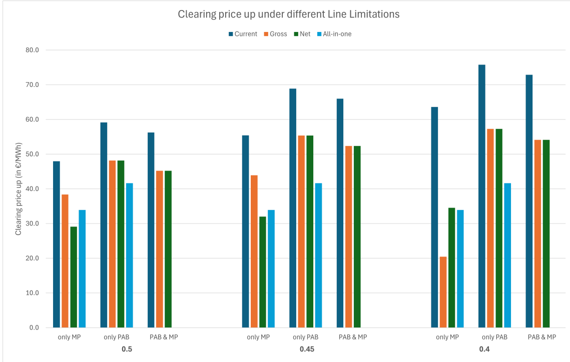

Figure 4.12: Line limitations: Clearing price up

4.3. Sensitivity analysis

A sensitivity analysis was conducted to test how model outcomes respond to external or exogenous parameters. Where the sub-question parameter varied the internal market design in terms of line limitations, these sensitivity parameters test for external influences on the model. By contrast, the line reservation factor was not treated as a sensitivity, because it was an internal policy lever that defined the market's feasible set and was a design choice rather than an exogenous uncertainty. Therefore, the sensitivity analysis was reserved for external drivers, with the market design held fixed. These parameters were not central to the market design itself, but they could significantly influence the results and were therefore analysed.

The following parameters were included in the sensitivity analysis:

- *Redispatch/imbalance share*, an exogenous operation setting in today's system, that splits available flexibility across two markets. Varying the share tested robustness to the baseline allocation of available capacity. In addition, it revealed how scarcity in the redispatch market translated into costs, volumes and extra capacity usage.
- *Load level*, external demand conditions shift power flows and congestion patterns independently of the market design. This stressed the network limits and changed the activation mix.
- *Imbalance level*, forecasting errors were also exogenous drivers of balancing energy needs. Higher imbalance levels increase balancing volume and price volatility.
- *Renewable capacity*, exogenous generation capacity composition changes the load shape and variability as well as locational injections. Hence, increasing renewable generation raises curtailment needs, reshapes congestion and tests liquidity of upward and downward bids, that affects KPIs even with the same market rules.

4.3.1. Current: share redispatch & imbalance

To simulate the current situation, model *Current* was used. A key modelling choice was the split of available capacity between the redispatch and imbalance rounds. The split in available volume for both rounds significantly affects results. In this subsection, the results were reported in terms of relative performance, with the 20/80 split as the baseline. Hence, 20% of the available capacity was allocated to redispatch and 80% was allocated to balancing services. The percentages for 30/70 and 40/60 reported the percentage division with respect to the 20/80 baseline. Respectively, 30% and 40% of the available capacity was allocated to redispatch services and 70% and 60% to imbalance services. Herein, negative numbers indicated a decrease and positive numbers an increase in the KPI.

When the share of available flexibility volume for redispatch increased (from 20% to 40%), the total system costs decreased significantly Table 4.7. This effect was visible in all scenarios, regardless of the pricing mechanism used.

A logical explanation was that a larger available redispatch volume led to a more optimal utilisation of cheaper flexibility. In the model, both relatively expensive and cheaper units were available at each station. With a low available volume such as 20/80, it was possible that only the more expensive units could be activated to meet grid demand which were equally expensive for all stations (€200/MWh). As the permitted redispatch volume increased, such as 30/70 or 40/60, there was more room to solve the problem with cheaper units, even if they were less efficient in terms of location or performance.

While this resulted in a slight increase in total activated volume Table 4.8, this volume increase was marginal compared to the significant cost savings. In short, the system gained more flexibility and therefore relied less frequently on expensive units. The result was a more optimised cost picture, even when that required slightly more activations in terms of volume. As mentioned before, for the default settings, the capacity shares in *Current* were set to 30% for redispatch and 70% for balancing services.

Table 4.7: Total Costs: Relative change for different redispatch/imbalance capacity shares

Total Costs	20/80	30/70	40/60
only MP	–	-24.94%	-63.79%
only PAB	–	-30.06%	-43.02%
PAB & MP	–	-29.94%	-43.15%

Table 4.8: Total volume: Relative change for different redispatch/imbalance capacity shares

Total Volume	20/80	30/70	40/60
only MP	–	2.61%	3.34%
only PAB	–	1.40%	2.70%
PAB & MP	–	1.40%	2.70%

4.3.2. Load level

The simulation was also tested for varying load levels, with an increase of 10% and 20% of the total load. To test the different designs on robustness under higher load levels, as expected in the future (Sijm, 2024). Since a uniform increase in load intensifies the pressure on the existing grid, this naturally leads to more congestion and consequently a higher need for redispatch. Testing higher load scenarios therefore, provided a concise robustness check of the market designs under more strained system conditions.

The figures reported the total system costs Figure 4.13 and total activated flexibility volumes Figure 4.14 over 96 hours for the market designs and pricing mechanisms, under increasing load levels (100%, 110%, 120%).

As the load level increased from 100% to 120%, both the total system costs and activated flexibility volumes increased. However, the increase in costs was stronger under design *Current*, especially under only MP. Although total system costs increased under all designs, *Net* and *All-in-one* resulted in a smaller cost increase compared to *Current*. Suggesting that these designs allocated costs in a more balanced way under more extreme conditions, as the total activated flexibility volume was comparable across the designs. This illustrated that the new uniform flex product offered a more robust and cost-effective result under higher load levels than the current market with separated balancing and redispatch markets.

Figure 4.13: Total flex costs under different Load levels

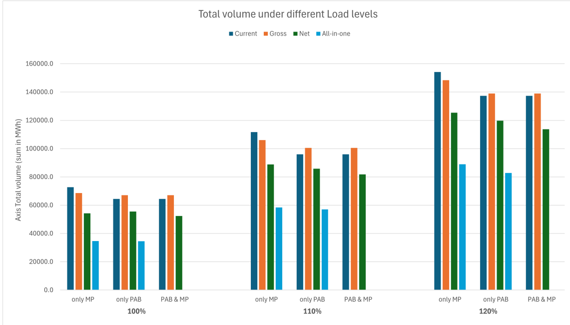

Figure 4.14: Total flex volume under different Load levels

Figure 4.15 and 4.16 reported that flexibility clearing prices strongly reacted to increasing load levels. Particularly under *Current*, both upward and downward prices became more extreme, indicating reduced cost control when extra capacity was activated at high prices. In contrast, *Net* and *All-in-one* resulted in more stable clearing prices, suggesting that they better managed price volatility under system stress due to a higher available volume originating from the uniform flex product.

Figure 4.15: Clearing price down under different Load levels

Figure 4.16: Clearing price up under different Load levels

4.3.3. Imbalance level

Testing for more extreme imbalance levels, 110% and 120%, helped assessing whether the designs remained robust under larger imbalance. In addition, this provided insights into system conditions, as they could cause significant cost spikes or unintended effects in cost allocation.

The total flex costs increased strongly with increasing imbalance levels, see Figure 4.17 and 4.18. Similar to the varying load levels, *Current* was strongly affected by the increasing imbalance levels. While all designs activate similar volumes of flexibility, the cost differences indicate that the different designs manage flexibility more efficiently under stress conditions.

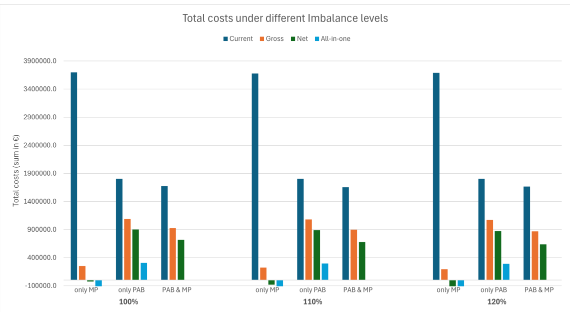

Figure 4.17: Total flex costs under different Imbalance levels

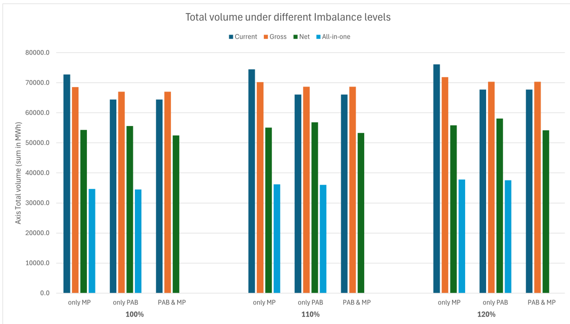

Figure 4.18: Total flex volume under different Imbalance levels

Besides the total costs and total volume, the clearing price down and up were analysed, see Figure 4.19 and 4.20. When more imbalance was added to the system, the prices became more extreme. Again, *Current* denoted the strongest reaction to the increased imbalance level. Whilst *Net* and *All-in-one* reported a smaller increase in prices, indicating a more robust system under extreme conditions.

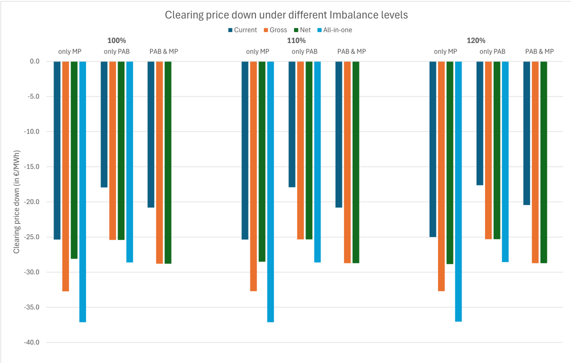

Figure 4.19: Clearing price down under different Imbalance levels

Figure 4.20: Clearing price up under different Imbalance levels

4.3.4. Renewables: Solar & Wind

Lastly, the models were tested under varying levels for renewables: solar and wind. Where capacity was increased to 110% and 120% to test the impact of more renewable capacity in the system on the performance of the designs. This also provided insights in suitability of the designs for the future grid, where increased levels of solar and wind capacity are expected.

The total costs and total volumes under 110% and 120% of renewable capacities are shown in Figures 4.21 and Figure 4.22. Although the costs under only MP in the current design with 100% capacity seems high, it was similar to the levels under the default conditions. Whilst in these figures, the costs under other configurations were lower, indicating that more renewables lead to even stronger decreases in total costs. However, the difference between 110% and 120% seemed small under total costs. For total volumes, there were small increases under both 110% and 120% under the different designs. This originated from more efficient bids in which prices were also taken into account. Hence, more volume was activated against lower prices.

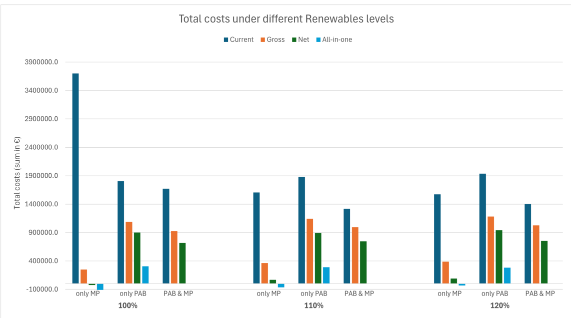

Figure 4.21: Total flex costs under different Renewables levels

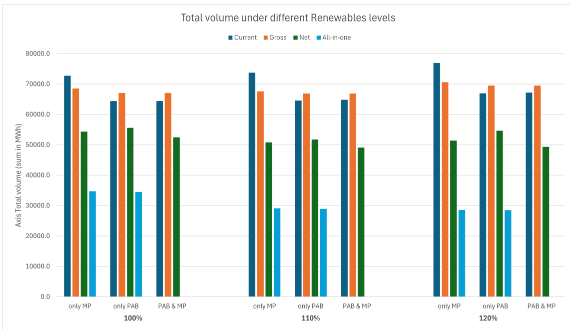

Figure 4.22: Total flex volume under different Renewables levels

The clearing price down and up were shown in Figure 4.23 and Figure 4.24. With more renewable capacity, prices became less extreme. The price drops for downward activation became less strong under higher renewable capacities. In addition, increased levels of solar and wind lead to a structural surplus in the system and increase congestion, making downward activation more frequently with less extreme prices. The impact on the clearing price up was less strong, as conventional generators still needed to be activated for upward regulation under similar prices. Therefore, the impact of more renewables affected both the clearing price up and down. Under these simulations the price down reported stronger changes than the clearing price up. However, in reality conventional generators may adjust for the fewer operating hours in the different markets. This resulted in higher prices for upward activation under systems with more renewable capacity.

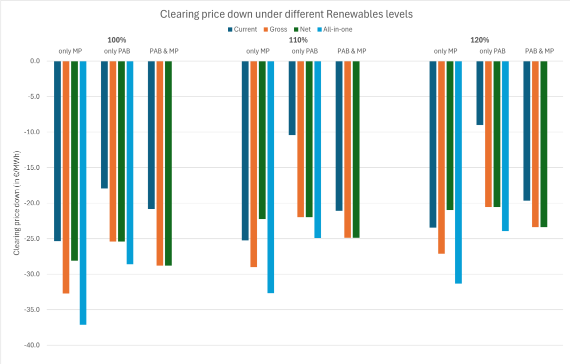

Figure 4.23: Clearing price down under different Renewables levels

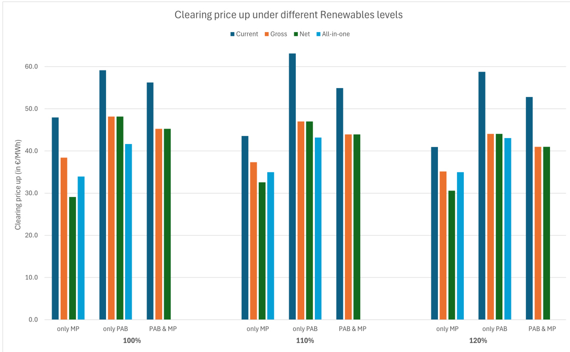

Figure 4.24: Clearing price up under different Renewables levels

Overall, the sensitivity analysis confirmed the main results: the integrated designs, especially *Net* and *All-in-one*, consistently reduced total costs and stabilised prices compared to *Current*. The largest effects on costs came from the redispatch/imbalance share. Where a higher redispatch share lowered costs by unlocking cheaper physical bids and avoiding extra capacity activations. In addition, the imbalance level amplified balancing volumes and price spikes with *Current* denoting the strongest increase. Increasing load levels also raised costs and volumes, but the integrated designs dampened this effect. Changes in renewable capacity mainly reshaped clearing prices, with stronger effects on downward prices and modest impacts on total costs and small increases in volume. Interpreting volume jointly with costs and extra capacity remains essential. *Gross* showed slightly higher volumes while still delivering lower costs by procuring cheaper bids. Factors not analysed, such as grid reinforcement, cross-border exchanges and storage could affect absolute levels, but were not expected to overturn the comparative ranking observed in this study.

5 Discussion & Conclusion

This chapter presents the discussion and conclusions of this study. The research question was: *How does an integrated balancing and congestion market perform in the Netherlands compared to the current two separated markets?* Four models: *Current*, *Gross*, *Net* and *All-in-one* and three pricing mechanisms: only MP, only PAB and PAB & MP were evaluated, resulting in eleven scenarios. The results were evaluated against five KPIs: extra capacity, total costs, total volume, clearing price down and clearing price up. Building on these results, this chapter discusses the implications of the findings, the robustness of the designs and their potential relevance for future market design.

5.1. Discussion

The simulation used the Dutch (E-)HV grid and four representative days to capture both typical and stress condition without excessive computational burden. Performance was evaluated using normalised and where noted, relative scores, with the *Current* and *All-in-one* designs as benchmarks and focused on relative scores rather than absolute values.

5.1.1. Performance assessment of the new designs

The scores were interpreted against the benchmark, where *Current* provided the lower bound and *All-in-one* the theoretical optimal and therefore upper bound. Subsequently, *Gross* and *Net* could be interpreted compared to the *Current* and *All-in-one* designs.

Extra capacity

Across all designs, artificial extra capacity was activated only in the *Current* design and only in the redispatch round. Both the frequency and the total activated volume declined as the redispatch share increased from 20/80 to 40/60, with systematically higher use in redispatch up than in redispatch down. In addition, within redispatch up, only MP required less extra capacity than only PAB and PAB& MP. In contrast, *Gross*, *Net* and *All-in-one* required no extra capacity in either round.

The observation that extra capacity was triggered only in *Current* reflected scarcity in that design rather than an artefact of the 200 €/MWh bid price. Operationally, an activation of extra capacity in *Current* indicated a shortage of redispatch bids at the required locations and times. The model only activated extra capacity when network constraints were not met with submitted bids in the redispatch market. The price for extra capacity was substantially higher than all market bids, so the additional capacity only served as a backstop and did not disrupt the merit order. A sensitivity analyses around €150–250/MWh would not change the ranking and therefore, not influence the activation of extra capacity. Moreover, the absence of additional capacity in *Gross*, *Net* and *All-in-one* resulted from the usage of a uniform flex product. This underscored that integration of balancing and congestion actions reduces the need for out-of-market interventions by the TSO, such as BSO products. These findings were based on the assumed share ratios. Nevertheless, the pattern was robust and supported the conclusion that moving from *Current* to *Gross* or *Net* could largely eliminate the reliance on extra capacity.

Total costs

Across pricing mechanisms, the integrated designs reduced total costs relative to *Current*, being the largest under only MP, then PAB & MP and smallest under only PAB. This indicated that integrating redispatch and balancing leveraged cross market synergies, where balancing relieved congestion and vice versa. Most savings can already be captured by switching from *Current* to *Net* or *Gross*, with *Net* coming closest to the performance of *All-in-one*.

The magnitude of the cost reductions presented in this study was subject to both upward and downward biases. On one hand, the decrease in total costs could have been overestimated, as the model assumed that market participants did not adapt prices strategically to outcomes from previous rounds. In practice, parties would adjust their offers based on anticipated market results, which would reduce the efficiency gains. On the other hand, the decrease in costs could have been underestimated as the analysis was based on only four selected days skewed towards extremes, where a full-year simulation would dilute these events. However, the sensitivity analysis showed that *Current* was the least robust system and changes have a stronger impact on performance. Besides, for both the strategic behaviour and the time series data, changes in these phenomena would affect all designs. Therefore, the normalised scores still provided a robust indication of the relative performance and the order of magnitude of improvements across designs.

Total volume

Most integrated designs used less volume than *Current*. *All-in-one* reported the strongest decrease in volume, but a significant decrease was also realised by *Gross* and *Net*.

The new designs were based on the assumption that all of the available volume for upward and downward generation by players in the DA market were included. In reality ,it would be highly unlikely that all players submit complete bids in terms of volume for upward and downward activation. In the *Current* design, this was approximated by allocating 30% of the total volume to redispatch services and the remainder to balancing. This assumption influences the comparison: if the real-world allocation were closer to 20/80, the efficiency gains of the new designs would likely be larger, since a relatively smaller redispatch share would make the integration of the two markets more beneficial. Conversely, under a 40/60 split, the redispatch market already had relatively more volume available, which reduced the incremental benefits of integration. Nonetheless, across reasonable allocations the simulations consistently show that a combined redispatch and balancing market outperforms two separated markets. The assumption that providers do not bid their full capacity applies to *Current* as well as to the uniform flex markets. Even with identical shares, the volume to which the share is applied would also decrease in the separate markets, which may even increase the relative advantage of integration.

Clearing price up and down

The new designs reported the strongest reduction in the clearing prices for activation up and down. Similar to the other KPIs, *All-in-one* reported the strongest decrease, followed by *Net* and then *Gross*.

These prices and bids were strongly influenced by the assumptions used to determine them. In reality, these prices would be strongly affected by the strategic behaviour of bidding parties. Due to the design of the simulation model and the formulation of PAB and MP settlements, such strategic behaviour could be incorporated relatively easily in future extensions of the analysis. In addition, market imperfections arising from the locational component, limited storage capacity, constrained demand-side flexibility and technical limits further amplify these effects. It must be mentioned that in reality, these prices would show stronger fluctuations and higher average levels. This is because actual market outcomes are shaped not only by cost reflective bids, as assumed in the model, but also by strategic bidding behaviour, where participants anticipate scarcity and adjust their bids accordingly.

Moreover, physical and operational constraints such as start-up costs, ramping limitations and minimum generation levels restrict the availability of low cost flexibility, which would lead to the acceptance of higher priced bids. Finally, market imperfections such as locational constraints, limited demand side flexibility and finite storage capacity would increase volatility and clearing prices. Taken together, these factors imply that the model likely underestimated both the variability and the average level of redispatch and imbalance prices. Still, these results indicate that under the new designs, bids earlier on the merit order were more likely to be accepted as the marginal bid due to the decreased volume needed. Based on this study, it could be assumed that the clearing price for upward and downward activation were expected to decrease under the new designs. This study reported the strongest decrease under *All-in-one*, with some of the decrease already being realised under *Gross* and *Net*.

Overall, for all KPIs, *All-in-one* reported the most optimal performance, followed by *Net* and then *Gross*. Nevertheless, a substantial share of the gains over *Current* was already captured by both *Net* and *Gross*.

5.1.2. Degrees of freedom in market design and simulation

The analysis further revealed levers within a uniform flex market that could be adjusted and affect the performance of the designs. These levers reflect the broader system and market factors, such as market participation, bidding structure, generation mix and storage availability, that influence the functioning and performance of a uniform flex market and could not all be adjusted by a TSO.

First, the number of bidders, more participants increase competition, lowering costs and prices. The total volume required is largely unaffected, except in the PAB only scenarios reported in the results.

Second, the number of bids per participant affects the shape of the merit order. Smaller bids create a smoother merit order, reducing price jumps and leading to more efficient dispatch outcomes.

Third, more time steps included in the simulation provide more detailed insights in terms of total costs, total volume and the clearing price up and down under different conditions. Including more time steps in the simulation is expected to influence the results, since the current analysis was based on only four days in which extreme redispatch and imbalance events were disproportionately represented compared to their actual frequency over a full-year. Expanding the temporal scope would therefore provide a more balanced assessment of performance across both typical and exceptional system conditions and yield more reliable insights for the further implementation of a uniform flex market.

Fourth, the installed capacity and especially the type of generation highly influences the results. More renewable plants are likely to result in higher costs for downward activation, under the assumption that conventional plants are willing to pay for downward activation. For the clearing price up, this was expected to increase as well since conventional plants will be activated less frequently in the DA market, due to the increase of renewables with lower prices. Resulting in higher prices for conventional plants in the uniform flex market, or separated balancing and redispatch markets, to still make the conventional plants profitable.

Lastly, the adoption of more renewable and therefore, intermittent energy sources would create a strong incentive for parties focusing on storage to participate in the uniform flex market. Due to the limited controllability of intermittent energy sources, combined with the restricted flexibility on consumer demand, the demand for flexible supply or storage is expected to increase. Therefore, integrating storage into a uniform flex market is expected to reduce total system costs by mitigating price extremes and avoiding expensive 'extra' capacity. However, when there are limited storage providers participating in the market, an opportunity for strategic behaviour occurs, dependent on their market power. The total volume needed will likely be similar, as this is mostly dependent on the type of market and the pricing mechanism rather than the type of generation providing the capacity. In terms of pricing, storage would decrease upward prices during scarcity and limit the occurrence of negative downward prices.

5.1.3. Interpreting results compared to previous research

Research from Stok, 2024 reported substantial cost reduction. This study identified a decrease of a similar magnitude in costs and even larger reductions in activated volume. The difference did not occur from the fact that in this study imbalance causes redispatch. However, some of the imbalance could be resolved by adjusting volume used for redispatch services and by applying locational balancing. The changes in terms of costs and volumes somewhat differ, but the same behaviour could be observed over the designs. This indicated that an integrated flex market outperforms the current separated redispatch and balancing markets. The same behaviour in performance comparing the new designs with each other also shows that *All-in-one* out performs *Net*, which in turn outperforms *Gross*. It was expected that results would be less favourable applied to the Dutch (E-)HV grid compared to a proof-of-concept model, but results were still positive. When comparing results from this study with the proof-of-concept from Stok, 2024, both studies underscored the potential of an integrated flex market and emphasised the incentive for further analysis.

Of the three interaction models in (Poplavskaya, Joos, et al., 2020), the models most aligned with the integrated flex market in this study were model MB/MB and CMB. These models were assessed qualitatively in terms of amongst others allocative efficiency and availability. Poplavskaya, Joos, et al., 2020 reported high resource availability, which was also observed in this study. In addition, prior work (Poplavskaya, Joos, et al., 2020) noted that a common resource pool may require contracting more balancing capacity because some of that capacity would be used for redispatch. This study focused on an integrated pool and that it outperformed two separated pools, including the *Current* design when the allocation between redispatch and balancing was varied in the sensitivity analysis. By combining insights from both qualitative and quantitative research, the results indicated clear potential for a market-based, integrated balancing and redispatch design.

This study provided a first indication of quantitative performance of an integrated uniform flex market compared to a similar simulation of the current markets and therefore, its potential. Although the first results are promising, further research is needed due several limitations that affect the measured performance. Moreover, this study could serve as a starting point for more extensive and detailed research into the performance of integrated balancing and redispatch market. For TenneT, the findings provide an incentive to further explore the potential of a uniform integrated flex market. Particularly, by developing internal simulations and models based on actual data.

5.1.4. Limitations

Although at first the results show promising insights, it is important to discuss the limitations of this study. In addition, it should be mentioned how these limitations influence the conclusions to be drawn from these results.

Poor data

First, this study relied on assumptions that materially influence the absolute results, particularly total costs and upward and downward clearing prices. Due to the limited data that was available, assumptions were made for the bids in the uniform flex market over the two rounds as well as in the balancing and redispatch round in design *Current*. Some data was available for balancing bids, but most of this was unfeasible due to the absence of the locational component in these bids, which play a significant role in the simulations in this study. The absence of data was partially resolved by focusing on relative changes rather than absolute figures through the performance benchmark and normalised scores. However, a study with real data as input could provide better insights in the performance of a uniform flex market. In addition, a sensitivity analysis showed how input variables influenced the direction of the KPIs.

Bidding behaviour and strategic interaction

Second, due to the complexity of the markets, simplified bidding behaviour was difficult to incorporate in the model through bids. However, a study focused from the perspective of a bidder or supplying party could provide more insights into their strategy adjustments in a new combined market. Moreover, not all parties participating in the DA market are expected to submit bids in both the balancing and redispatch markets or in a uniform flex market. The assumption that all parties submit bids under all market designs therefore introduces some inaccuracies in the absolute results. That said, because this assumption is applied consistently across all models and we benchmark on relative changes, the impact on comparative results is limited. In addition, suppliers were likely to adjust their bids based on market outcomes or the bidding behaviour of competitors. The market participants were assumed to be price takers and submitted fixed bids. In reality, adaptive strategies are assumed in all markets. Exclusively under pricing mechanism only PAB, the margin added to the MC is based on the number of bidders within a station. Suppliers could withhold capacity, which influences the market in terms of prices, total costs, total volume and thus market efficiency. For the scope of this study, strategic behaviour was not taken into account due to complexity. The focus was on comparing the four market designs with prices that were based on assumptions and could be interpreted easily.

Model simplifications and technical limitations

Third, this simulation was based on a highly simplified model. All capacity was declared feasible for both redispatch and balancing services. In reality, some of the capacity will not meet technical requirements, for example ramp up and or ramp down speed. Besides, it only distinguished three types of generators. In addition, there was no distinction between conventional plants, resulting in no difference between gas, coal and nuclear plants. Another assumption was that all generators were connected to the (E-)HV grid, whilst in reality this was not true and especially lots of solar power was connected to the medium and low-voltage grids. This implies that the model may overestimate the flexibility available to the TSO and underestimate congestion at the distribution level. As a result, the findings represent transmission-level outcomes for TSO operated balancing and redispatch markets, while DSO-level congestion management and local flexibility on medium- and low-voltage grids were not modelled. Moreover, this model focused on the (E-)HV grid only, not taking into account distribution grids operated by DSOs (50 kV/20 kV/13 kV/10 kV/6 kV) as well as low-voltage grids (380/400V). Besides, this simulation divided the capacity allocated to a station over six plants, whilst in reality the volume, especially of solar and wind was distributed amongst many more plants resulting in more bids.

In the imbalance round, the solver selected bids based on price and location, whereas the real imbalance market is cleared nationally on price only. In this study and simulation models, imbalance volumes were assigned to stations, making the problem partly locational. This can tilt the solution toward geographically proximate bids and away from cheaper bids elsewhere. Potentially increasing modelled balancing costs and changing which units are activated. At the same time, it reduces the risk that the imbalance round undoes earlier redispatch and recreates congestion. To limit this effect, transmission limits were relaxed in the imbalance round and because the assumption was applied consistently across designs, the relative comparison between designs remains valid.

In addition, this model and simulation considered the Netherlands as an island. In reality, the grid was highly interconnected with other countries such as Germany, Belgium, the United Kingdom and the Nordics. This assumption may slightly overstate the domestic need for imbalance and redispatch, since part of these issues could already be alleviated through cross-border exchanges. At the same time, neighbouring systems also rely on Dutch flexibility to resolve their own imbalances and congestion. The net effect of including interconnections was therefore expected to be limited.

Energy-market only

Lastly, this study focused exclusively on energy markets, as described in Chapter 2, while capacity markets were excluded from the scope. In reality, capacity auctions also formed an integral part of the overall market mechanism. Although only limited strategic interaction was expected from their inclusion, accounting for capacity markets could provide a more comprehensive representation of the system and allow for a more complete simulation. This assumption may reduce the realism of the absolute results, as capacity revenues could influence bidding strategies and participation incentives in energy and balancing markets. Nevertheless, since all model configurations were subject to the same assumption, the relative comparison between designs remains valid and the overall impact on the conclusions was expected to be limited.

5.1.5. Future research

From the limitations of this study, opportunities for future studies arise.

Full-year simulation with real data

The first suggestion was to perform a study based on the same four designs and models, but simulating a year rather than four days. This study would benefit from real data and provide more detailed insights by incorporating more time steps and scenarios over a full year. Based on this suggestion, the hypothesis would be that the average percentage differences between the designs would change only slightly, while the absolute values would change substantially when simulating a full year and even more when real data is used.

Regulatory framework analysis

Another suggestion would be a study on the regulatory framework concerning the Dutch balancing and redispatch markets. Such an analysis would identify any legal and regulatory barriers to the implementation of a uniform flex market. This study should outline the adjustments required to align the new market design with Dutch and EU energy policy objectives. For this suggestion, the hypothesis would be that the current regulatory framework contains legal and procedural barriers that would hinder the implementation of a uniform flex market. Some of the required adjustments would align with existing Dutch and EU energy policy objectives and some would not. The extent to which the required adjustments align with objectives such as market integration and security of supply, underscore the need for further research into the regulatory implications of a uniform flexibility market.

Future energy system adaptation

Lastly, future research could focus on testing the proposed market design under future energy system scenarios. These could include varying levels of nuclear generation, increased shares of variable renewable energy sources and large-scale battery deployment. Analysing the performance of the designs under these conditions would provide insights into the resilience and adaptability of the market design in a changing energy environment. For example: including more nuclear capacity into the uniform flex market design is expected to lower overall system balancing and redispatch costs. This would reduce total system costs and upward activation prices when renewable output is limited, though it may increase prices for downward activation. Batteries could reduce both upward and downward prices, lowering price volatility and total system costs by shifting supply and demand across time. However, the strategic bidding behaviour of such assets is complex and would require more expertise to model accurately.

5.2. Academic relevance and contribution

This study contributed to the academic debate on how market design shapes both technical reliability and economic efficiency by combining conceptual design with quantitative electricity system modelling. It provided a transparent, reusable model that represents market institutions alongside network physics, enabling causal mechanisms to be tested rather than inferred from stylised models.

First, the model used the actual topology of the Dutch transmission system, enabling a realistic mapping between generators, loads and imbalances. Second, generation assets were placed at their real geographic nodes, so that outcomes arise from location specific constraints and not from artefacts of aggregation. Third, the physical behaviour of the grid was captured through enforcement of Kirchhoff's laws and binding line capacities, replacing copperplate simplifications with network-consistent flows by simulating in Linny-R. Fourth, bidding behaviour was parametrised rather than fixed, which permits data adoption without rebuilding the model. Fifth, the empirical design covered carefully selected days with both high and low congestion and imbalance, so the results were tested for typical conditions and stress situations that were critical for reliability.

The study made two overarching contributions. Methodologically, it integrated market design and network modelling in a single framework, allowing performance differences to be traced to design features such as: netting and co-optimisation, rather than to modelling artefacts. In addition, it provided quantitative evidence that integrated designs can lower costs and volumes while maintaining feasibility without out-of-market capacity, highlighting market institutions as levers for reliability alongside physical investment.

Lastly, the model is generalisable. Although calibrated to the Dutch grid, the approach and code can be applied to other European systems with similar institutions. This study therefore, offered a basis for further research on market performance, including strategic bidding, alternative settlement rules and larger datasets.

5.3. Conclusion

This study was initiated due to separated markets for balancing and redispatch services. Limited availability of redispatch bids provided a strong incentive for market participants to increase their bids. With increasing congestion, these prices were expected to increase even further. Therefore, a new market design was created, based on a uniform flex product. The flex product is offered by market participants and can be activated by TenneT for redispatch or balancing services. This new design was assessed quantitatively through a (mixed integer) linear programming model. Herein, four different models were distinguished: *Current, Gross, Net* and *All-in-one*.

Simulation results consistently reported the performance in the following order: *All-in-one* > *Net* > *Gross* > *Current*. In the new designs *Gross*, *Net* and *All-in-one*, extra capacity was never activated. In *Current*, extra capacity was often activated, simulating the BSO services, resulting in system reliability warning, which is time consuming and increases costs.

All five KPIs improve under integration: extra capacity, total costs, total volume and clearing price up and down. Improvements were robust across share ratios from 20/80 to 40/60 in *Current* and pricing mechanisms. The results in *Gross*, *Net* and *All-in-one* were achieved without any reliance on extra capacity. A decrease in price meant lower upward clearing prices and more negative downward clearing prices, consistent with fewer counter activations and better use of low cost flexibility. While *All-in-one* achieved the largest improvements, a substantial share was already captured by *Net* and *Gross*, indicating that partial integration already realised most of the benefits.

The results supported the hypothesis that an integrated balancing and congestion market, Flexmeister, outperformed the current separated markets. In addition, a significant part of the benefits from *All-in-one* could already captured by switching from *Current* to *Net* or *Gross*, with *Net* coming closest to the performance of *All-in-one*.

By being the first study analysing the quantitative performance of these new uniform flex market, it provided a strong incentive for further research. To be more conservative: the results suggest that the new designs were no worse than the current one, increase reliability and often offer lower total costs.

In addition, stricter line restrictions resulted in higher total costs and an increased activated volume, especially for redispatch services. Still, these results indicated that under the new designs, bids earlier on the merit order were more likely to be accepted as the marginal bid due to the decreased volume needed.

The sensitivity analysis showed that the availability of available redispatch volume strongly affects the total costs under design *Current*. This suggests that a small volume in the redispatch market could lead to problems in resolving congestion. An increase in the total load showed a lower increase in system performance. In addition increased imbalance levels strongly influence the total flex costs, being the most extreme under only MP. However, the total system costs still decreased under the new designs *Gross*, *Net* and *All-in-one*. Thus, these designs allocate costs in a more balanced way under extreme conditions. Overall, these findings were indicative and would improve when based on empirical data.

The results showed that better use of flexibility through an integrated market can safeguard reliability without large scale grid investments. Implementing an integrated flex market has the potential to accelerate the connection of new renewable sources and reduce social costs. In addition, the study also suggested that economic institutions shape technical system outcomes and therefore, system reliability. Actors such as the ACM, TenneT, the European Union and national governments influence reliability through market design, pricing mechanisms, regulatory frameworks and legal constraints. When an integrated balancing and redispatch market would be implemented, the consequences on a multi-actor level should be analysed. For flex services providers, revenues from ancillary services may decrease slightly. From a societal perspective, the integrated market improves reliability and safety, enables new customer connections and expands overall market activity, including for suppliers of balancing and redispatch capacity. Therefore, the adoption of an integrated flex market is expected to contribute to social welfare.

Overall, the new market designs underscored that using an integrated flex product, made the TSO less reliant on out of market capacity and can lower total costs, total volume and clearing prices. Herein, the models were increasingly more efficient, with *Net* outperforming *Gross* and *All-in-one* outperforming *Net*. Regarding the pricing mechanism only MP showed the strongest decrease in total costs and prices, but was also the most vulnerable for price volatility. The analysis bridged economic market design and technical grid modelling and provided first quantitative evidence that integrated market design delivers a more reliable and cost-efficient system. Market design, not just physical expansion, can support the energy transition while maintaining reliability of the grid. Flexmeister enabled faster and cheaper integration of renewables, supporting security of supply and climate goals.

5.4. Recommendations

As mentioned before, results from this study provided a promising potential for an integrated balancing and redispatch market. However, further research is required to gain a better understanding of the performance of a uniform flex market. Regulatory aspects should be analysed to identify the potential legal or regulatory barriers to implement a uniform flex market.

First, new simulations should be based on a full year using real bidding data, including locational information, to capture more scenarios and increase robustness. Simultaneously a regulatory framework could be assessed. Legal and procedural barriers to implement a uniform flex market should be identified, along with the adjustments needed to align it with Dutch and EU policy objectives. When both steps are completed, the market design should be tested under different future energy system scenarios, such as higher shares of renewables, increased nuclear capacity and battery deployment. Research revolving around strategic behaviour could also be relevant for academics, to better understand the impact of dominant players on total costs, total volume and prices. When these researches still show significant potential for an integrated flex market, backed by data, a regulatory framework and it was tested for various future energy systems. Lastly, a transition path towards a uniform flex product should be created.

5.5. Reflection

This study has deepened my understanding of the complexity that arises at the intersection between the technical electricity grid and the dynamics of economic markets. It has also provided me insights in creating and translating abstract market design concepts and how to capture those in simulation models and decision rules to be used for a quantitative performance assessment. Another lesson learned for future research is how economic markets have impact on the performance of a technical system. This study taught me to combine insights in terms of technical feasibility, the economics of electricity markets, simulation models and building on those results to provide recommendations.

The market design directly influenced the volume of flexibility required for technical security services of the electricity grid. These services, such as balancing and congestion management, ensure system reliability and thereby influence the social welfare within a country. In other words, design choices for markets had a direct impact on the technical safety of an electricity grid. This study addressed a problem in a socio-technical system, the Dutch electricity markets for balancing and redispatch. By integrating knowledge from different disciplines, a new market design was developed and subsequently evaluated through a quantitative performance assessment. Finally, recommendations were derived from the results, making this study well aligned with the objectives of the MSc programme in Complex Systems Engineering and Management.

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A

Detailed analysis for new market design

Part of this study is creating a new market design, based on three pillars: Previous research, documentation and expert consultation. This appendix outlines the analysis conducted to create this new design which is later used in the simulation to create recommendations. This appendix outlines the detailed analysis of balancing and redispatch markets, performed to gain a better understanding of their functioning and the flexibility products that are offered. After analysing both markets, similarities and differences were identified to contribute to the new design for a two-step optimisation of an integrated market.

There are three main types of markets: wholesale markets, balancing markets and congestion markets, as shown in Figure A.1.

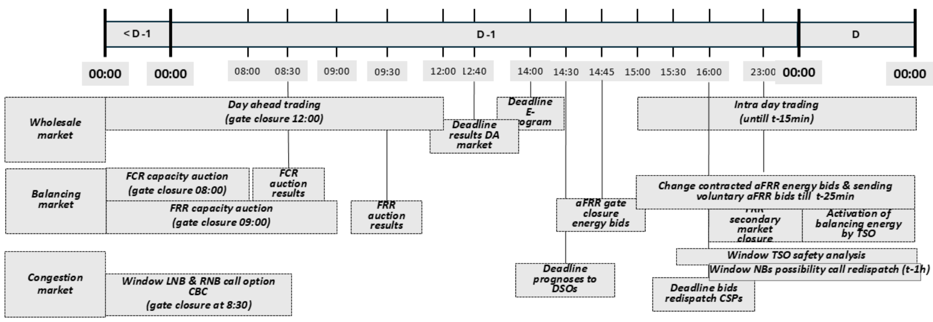

Figure A.1: Timelines wholesale, balancing and congestion management

Wholesale electricity markets

In the Netherlands, there are three main wholesale markets for electricity trade, distinguished by their trading time frames: the forwards and futures market, the day-ahead (DA) market and the intra-day (ID) market (TenneT, 2025a). These markets are used by actors such as producers, suppliers, Balance Responsible Parties (BRPs) and large consumers. Each market differs in structure, trading platform and time granularity.

The forward and futures market facilitates electricity trade up to years in advance. However, the further in the future, the less liquid the market. This market provides financial security by allowing participants to hedge against future price volatility through pre-agreed contracts (De Boer, 2024). Futures are standardized products traded on trading platforms, while forwards are typically bilateral contracts or over-the-counter (OTC) agreements.

The DA market is often referred to as "the wholesale market" or "the electricity market". In this market, producers and consumers submit bids for each hour of the day through a blind auction. These bids are aggregated into a merit order and the resulting market-clearing price reflects the marginal cost of electricity per hour. The DA market operates on the EPEX Spot and NordPool Spot platforms (TenneT, 2025a).

The ID market opens shortly after closure of the DA market and allows BRPs to adjust their portfolios. Trading on the DA market is executed in blocks of an hour, where ID is traded in 15 minutes blocks. This market does not operate through an auction mechanism, but via bilateral transactions. The ID market uses the EPEX Spot, Etpa and NordPool Spot trading platforms, collectively referred to as the "spot market" (De Boer, 2024).

For the scope of this study, the forwards and futures market is excluded. Trade of actual production and consumption occurs on the DA market rather than this market. The forwards and futures market allows for ex-ante price determination, but no final production or consumption or flexibility services on a system level. Although electricity is traded through these markets, their main purpose is the hedging of prices and limiting financial risk for big producers and consumers in the future. In addition, the ID market focuses on portfolio balance, wherein BRPs adjust production and consumption within their own portfolio rather than on system level. Actual production and consumption are determined through the DA market, the ID market focuses on financial transactions between BRPs.

The DA market is taken into account for this study as production and consumption levels and the day-ahead price are established here. The production and consumption volumes influence the electricity supply and demand on a system level and therefore affect the imbalance and congestion markets.

A.1. Background on proposed market design analysis

TenneT, the Transmission System Operator (TSO) in the Netherlands, is responsible for maintaining the main frequency of 50 Hz at all times within its control area. When an imbalance occurs, TenneT sends a signal to the Balancing Service Providers (BSPs), who then activate balancing energy to restore the system balance. Various balancing products are available to fix the imbalance in the system: Frequency Containment Reserves (FCR), automatic Frequency Restoration Reserves (aFRR) and manual Frequency Restoration Reserves (mFRR).

A.1.1. Documentation

Documentation has been analysed for imbalance, FCR, aFRR, mFRR, resulting in the similarities and differences between these products.

Balancing

In the context of electricity markets, there are three types of imbalances: European grid, control area and market party imbalance. The control area balance reflects the total of all balancing group deviations within a control area. These deviations typically come from differences between predicted and actual generation or consumption. The control area balance is calculated using the control energy that has not been applied. Since balancing group deviations are not immediately available online. The published data are based on operational measurement and adjusted for corrections when necessary (TenneT, n.d.). Market party or portfolio imbalance is defined as an energy volume calculated for a BRP that represents the difference between the volume allocated to that BRP and the final position of that BRP (TenneT, 2022). This includes imbalance adjustments applied to that BRP, within a given ISP (TenneT, 2022).

To prevent imbalance as much as possible, every supplier or customer with a connection to the grid must be connected to a Balancing Responsible Party (BRP) as they bear balance responsibility. Previously, BRPs were known as "Programmaverantwoordelijke partij (PV)". A BRP is financially responsible for the imbalances that occur in its portfolio of connections. BRPs have the option to correct their imbalance before the Imbalance Settlement Period (ISP) expires (15 minutes), without financial consequences (TenneT, 2024a). Furthermore, there is a difference between BRPs and BSPs. A BRP is responsible for balancing production, consumption and trade in electricity to maintain the balance of the system. Whereas a BSP provides balancing services which can be activated to restore the system balance, as ordered by TenneT. When a BRP causes an imbalance due to less energy supply to the network or more energy consumption than agreed in the program, the BRP pays TenneT the imbalance price on the shortage. On the contrary, BRPs that supply more or consume less than planned receive the imbalance price. The imbalance price is calculated based on bids for used up-regulation and down-regulation power on the market for regulation and reserve power (Godfried et al., 2004).

In addition, a BRP can balance its portfolio by trading with other parties. Those transactions are then reported to TenneT and the sum of transactions of a BRP is called an E-program (TenneT, 2025b) or commercial trade schedule (TenneT, 2025b). This E-program contains the position, the internal commercial trade program and the external commercial trade program. There are BRPs with and without grid connections. This E-program must be submitted at 14:00 each day by the BRPs (TenneT, 2018). When a difference occurs between the last approved version of an E-program and the actual position of the BRP, the BRP creates an imbalance (TenneT, 2022). TenneT then uses imbalance netting to avoid simultaneous activation of FRR in opposite directions.

The BRPs and BSPs have different roles and therefore, different processes. On D-1, the day before implementation, each BRP submits an E-program for the day of implementation (TenneT, 2022). TenneT then checks whether these trade transactions add up to zero for supply and demand to be in balance at every hour of the day of execution. Simultaneously, the BSPs receive bids for aFRR and mFRR up to gate closure on day D. Then on D, the day of implementation, energy is fed into and withdrawn from the electricity grid. BRPs should behave according to their submitted E-programs. But if a power imbalance occurs, TenneT will take measures to restore the imbalance within an ISP. BRPs can adjust their E-program for up to four ISPs before delivery; for domestic trade, this is possible until D+1 at 10:00 am. BSPs manage balancing during D and can adjust their bids for up to two ISPs before delivery. On D+1, after the day of execution, the financial settlement process starts at 10:00 am. In this phase, the transfer prices are determined and published and the imbalance per BRP is subsequently determined and invoiced.

TenneT uses the Load Frequency Control (LFC) system for national power balancing (TenneT, 2025b). The LFC is used to respond to imbalance in the Netherlands and restore it within 15 minutes. In addition, the LFC determines the Area Control Error (ACE) for TenneT, so the Netherlands. The ACE is the difference between cross-border electricity exchange based on E-programmes compared to the measured exchange on interconnectors (TenneT, 2025b). Based on this difference, FCR is activated to correct for the Dutch frequency deviation.

Furthermore, European TSOs in the area of Continental Europe (CE) participate in the International Grid Control Cooperation (IGCC). The IGCC addresses the market imbalance for the TSOs in a coordinated way. For example, the IGCC converts market imbalances from different countries with opposite directions into mutual support. This reduces market imbalances of the countries, which results in lower imbalance prices and preserves FRR for future balance disruptions (TenneT, 2025b).

Frequency Containment Reserves (FCR)

When an imbalance occurs in the system, the first balancing product to be activated is FCR, formerly known as “primary reserve”. Whenever the frequency differs from the standard of 50 Hertz, FCR is activated automatically within seconds by the BSPs to stabilize the frequency. FCR works cross-border and for the entire synchronous network of continental Europe. The BSPs produce more electricity (upward regulation) when the frequency is below the standard and they produce less (downward regulation) when the frequency is above the 50 Hertz standard. In parallel, the TSO of the area where the imbalance occurs automatically requests the BSPs to activate the automatic Frequency Restoration Reserves (aFFR). Sometimes, the activation of aFFR can be avoided by netting through the International Grid Control Cooperation (IGCC). With IGCC, TSOs avoid activation of aFFR in opposite directions in neighbouring areas. The extent to which the IGCC can be used depends on the available cross-border capacity. The total FCR capacity is regulated on a European level and is set for a capacity of 3000 MW. The distribution of the FCR obligation among the TSOs is calculated by taking the net production and consumption of their control area and dividing it by the net production and consumption of the entire zone over the course of the last year. This results in the frequency constant, set to 4.1026% for the Netherlands in 2025, resulting in 123 MW FCR capacity. This implies that TenneT needs to contract FCR capacity of 123 MW in both upward and downward direction. This capacity needs to respond within 2 seconds after a frequency deviation and needs to be fully activated within 30 seconds when necessary.

automatic Frequency Restoration Reserve (aFRR)

The reserve capacity FRR is the sum of aFRR and mFRR. This reserve capacity is based on historical imbalance values and a reference outage, which refers to the largest imbalance that can occur in the Netherlands. This imbalance can be due to an instantaneous change in power from a single electricity generation unit, a single consumption facility, an interconnector or disconnection of an AC line. The division of FRR in aFRR and mFRR is based on the Continental Europe Handbook, Policy 1, which includes the minimum amount of aFRR to be contracted. The actual contracted volumes may differ, because of economic optimisation. For 2025 Q1-2, the aFRR (minimum) volume was 454 MW upward and 496 MW downward (TenneT, 2025b).

aFFR, formerly known as “regelvermogen” is purchased through “bied-verplichting”, bid obligation. This means that BSPs are contracted to submit aFRR energy bids to TenneT. Non-contracted BSPs can also submit “free bids”, which compete on the same merit order list as contracted bids. This system ensures that there is always sufficient aFRR available, while the price for these bids remains determined by the market (TenneT, 2025b). aFRR is activated once imbalance in the control area is detected. This capacity is activated automatically and has an expected response time of 30 seconds (Tijdink & TenneT, 2023). Not coincidentally, this is the same time period that FCR needs to run at full capacity. Simultaneously, aFRR is activated, allowing FCR to deactivate and freeing up capacity for the following deviations. The system is designed in such a way that whenever a deviation from the 50 Hz frequency occurs, FCR is activated to absorb initial frequency fluctuations. Then, aFRR is activated to “free up” the capacity of FCR, allowing it to be used again to absorb imbalance.

The aFRR product has both capacity and energy bids Capacity bids are auctioned daily, pricing works through a pay-as-bid mechanism and asymmetric bids are possible, meaning that a supplier can offer different capacities for upward and downward activation. In addition, the bids should be in multiples of 5 MW and have a minimum of 5 MW (Tijdink & TenneT, 2023). aFRR is activated when initial balancing services like FCR and the IGCC are insufficient. As mentioned before, TenneT contracts suppliers to offer bids for a specified period of time (TenneT, 2025b). For aFRR capacity, an auction takes place daily where suppliers offer capacity against a price, where TenneT has the possibility to reserve this capacity. The BSPs can submit bids until 9:00 and at 9:30 the results of the auction are published. As discussed before, there are BSPs which are obligated to bid in the energy auction but non-contracted BSPs can also offer energy bids (free bids), which are both placed on the same merit order. This assures that prices are determined by the market, as the contracted aFRR energy bids do not have priority over the free bids (TenneT, 2025b). The aFRR energy bids need a minimum ramp up rate of 20%, full activation time of 15 minutes and need a minimum size of 1 MW. The activation of aFRR occurs through automatic deviation by TenneT through delta setpoints. The bids can have a minimum size of 1 MW, maximum size of 999 MW and expected response within 30 seconds (TenneT, 2025b). In addition, power measurement of the portfolio should be sent in real time with a resolution of 4 seconds.

There are both capacity and energy auctions to ensure the availability of aFRR capacity for imbalance services. Suppliers are offered remuneration for aFRR capacity and energy separately. The capacity costs are based on the reservation costs of the capacity that needs to be available for aFRR. Those costs are based on the potential revenues for the supplier when capacity is used for the wholesale markets. Next, the supplier can offer energy bids for the capacity that has already been reserved. Those costs are determined by the activation of the asset and costs needed to produce the required electricity, which should be based on the marginal costs of the asset.

manual Frequency Restoration Reserves (mFRR)

mFRR, manual Frequency Restoration Reserve was formerly known as “noodvermogen”. Manual refers to the property of mFRR that it needs to be activated manually by a person in a control room. This balancing product is used when the expected duration of imbalance is long or when large imbalance occurs. Similar to the relation between FCR and aFRR, mFRR is used to free up aFRR volume for new imbalances. For mFRR, there are no obligated bids, but capacity contracts. When a BSP is contracted in the capacity auction, this capacity needs to be available at all times for balancing services when called for. Those capacity contracts are obtained through public tenders on capacity (TenneT, 2024a).

The pricing of those contracts uses a pay-as-bid mechanism and the minimum contracted volume is 20 MW for a BSP (TenneT, 2024a). For 2025 Q1-2, the mFRR (minimum) volume was 850 MW upward and 566MW downward (TenneT, 2025b). The timeline for mFRR activation is similar to that of aFRR. BSPs can submit bids until 9:00 and at 9:30 the results of the auction are published. On the day of activation, TenneT requests manual activation of the assets with a predefined settlement price for ISPs.

Similarities and differences between products

As discussed previously, FCR, aFRR and mFRR share some characteristics, but also differ in some of the characteristics of the products. Table A.1 outlines the type of product, market type, remuneration, blocks, minimum capacity, pricing mechanism energy and pricing mechanism capacity. This figure shows that the products, FCR, aFRR and mFRR differ in market type, as only aFRR and mFRR allow for energy bids, whereas all three cover capacity bids. Second, the remuneration is linked to the market type, showing that for aFRR and mFRR, both capacity and energy bids can provide remuneration. Next, the length of the block for which the capacity and or energy is offered differs, for FCR the block comprises 4 hours compared to the 15 minutes for aFRR and mFRR. The minimum capacity is the same for all of the products. The pricing mechanism for the two products are the same for energy bids, marginal pricing. For the capacity bids, all three products have a pay-as-bid mechanism.

Table A.1: Overview of balancing products and market characteristics

Product	**FCR (primary reserve)**	**aFRR (secondary reserve)**	**mFRR (tertiary reserve)**
Market type	Capacity bids (€/MW)	Capacity bids (€/MW) and energy bids (€/MWh)	Capacity bids (€/MW)
Remuneration for	Contracted capacity	Contracted capacity and activated energy	Contracted capacity
Minimum availability	4 hours	24 hours (will become 4 hours)	24 hours (will become 4 hours)
Minimum capacity	1 MW upward and downward	1 MW upward or downward	1 MW upward and downward

The three balancing services products also have different timelines, see Figure A.1. The FCR capacity auction allows bids until 8:00, followed by an award period of 30 minutes. Whereas aFRR and mFRR allow capacity bids until 9:00 on the day ahead, which are also followed by an award period of 30 minutes Then, for aFRR energy bids, those can be submitted from 9:30 until 14:45 the day ahead. On the day of activation, FCR capacity is offered for blocks of 4 hours compared to 15 minute blocks for aFRR and mFRR capacity. Then, the bids for aFRR are activated by using the bid ladder. For mFRR, there is manual activation of the capacity which is offered at the predefined price.

Bid price ladder

An upward bid is a bid for upward adjustment of the BSP to the TSO (TenneT, 2022). On the contrary, a downward bid is a bid for a downward adjustment of the BSP to the TSO (TenneT, 2022). For every ISP, for both upward and downward bids, this includes the energy price requested by the BSP (€/MWh) and the size of the capacity (MW). In addition, upward regulation is the increase in the input or reduction of extraction of electrical energy on/from the electricity grid. This is requested by the TSO to maintain balance in the system. Downward regulation is the reduction of the input or increase in extraction from the grid at the request of TenneT.

The imbalance price system has a specified sign convention, based on power changes from the perspective of the electricity network. Upward bids ensure electricity is fed into the grid and therefore, have a positive sign. Downward bids draw electricity from the grid and have a negative sign. A BRP surplus means that the BRP inserts more or withdraws less electricity from the grid than indicated in its last approved E-program and therefore, has a positive sign. Vice versa, for a BRP shortage this means that the BRP inserts less or withdraws more electricity from the grid than indicated in its most recently approved E-program and has a negative sign.

Positive prices for upward regulation result in a financial flow to the BSP (TenneT pays), and negative prices result in a financial flow to TenneT (BSP pays). The other way around, for downward regulation positive prices result in a financial flow towards TenneT (BSP pays), and negative prices result in a financial flow to the BSP (TenneT pays).

In the case of upward regulation, the price is determined by the highest activated bid. So the parties causing shortages have to pay a high price to make up for the shortage. For downward regulation, the price is determined by the lowest accepted bid. Resulting in low compensation for parties that supply more than planned, see Figure A.2.

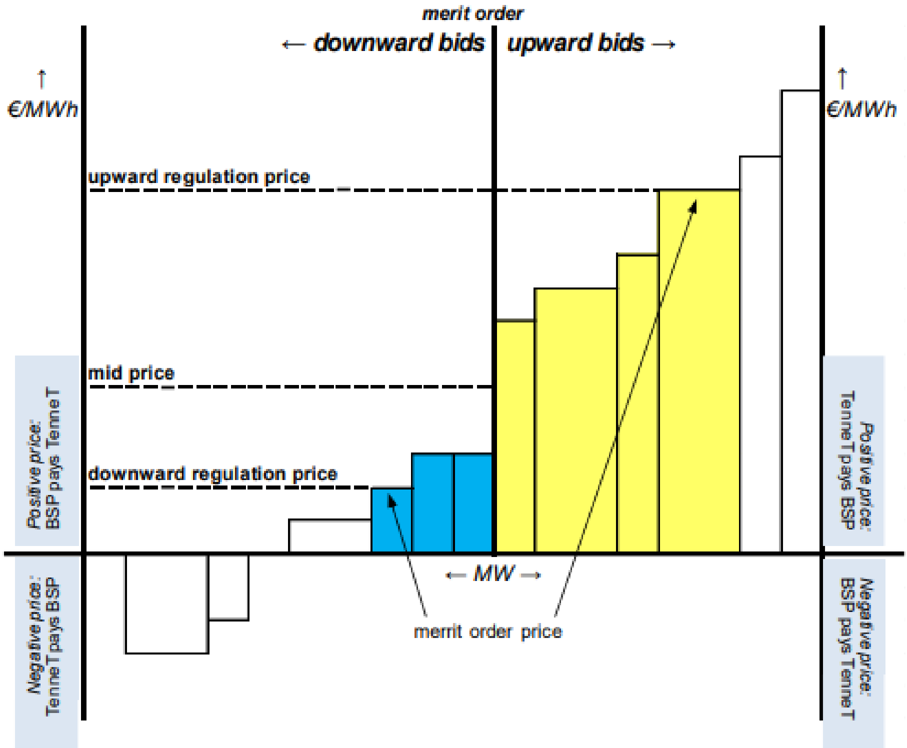

Figure A.2: Marginal pricing based on merit order for upward and downward regulation (TenneT, 2022)

The Mid price is the average of the lowest price for upward regulation and the highest price for downward regulation on the merit order for an ISP. This mid-price is used in two cases. The first one is when TenneT did not activate balancing services. For example when BRPs deviate from their approved E-programs, but this does not result in imbalance through imbalance netting with other TSOs and in the case of a disruption or black-out. The second is when the price for downward regulation is higher than the mid-price or the upward regulation price is lower than the mid-price. This scenario is also called reverse pricing (TenneT, 2022).

The regulation state is a parameter used for the determination of the imbalance price for an ISP. There are four regulation states: 0, +1, -1 and 2. Regulation state 0 occurs when TenneT does not use downward or upward regulation. Regulation state +1 refers to the situation where TenneT only uses upward regulation within an ISP. Regulation state -1 is applied when TenneT only uses downward regulation within an ISP. When both upward and downward regulation are used within an ISP, the development of the series of balance deltas within the ISP determines the control state. If the series of balance deltas within the ISP continuously increases or is constant, control state +1 applies. When the series of balance deltas within the ISP continuously decreases or is constant this is control state -1. When the series of balance deltas within the ISP both increases and decreases, control state 2 applies.

Congestion

Net congestion occurs when the capacity of the transmission grid is overloaded. Therefore, congestion results in insufficient capacity to transport all the electricity to the right locations. This can be caused by a high demand or by a high supply of electricity in specific geographic areas. When a transmission line within the grid becomes overloaded with electrical power, congestion occurs, which can result in overheating of a wire. In other words, congestion implies a shortage of transport capacity in the electricity network. Congestion management is applied to mitigate the effects of net congestion. Congestion management uses price mechanisms and market forces to manage the supply and demand for electricity locally. The two mainly used mechanisms are Capacity Limit Contracts (CLCs), where flexible capacity is activated day-ahead and redispatch, where flexible capacity is activated intra-day (Autoriteit Consument en Markt, 2022). Companies with a contracted capacity of ≥60 MW are obligated to participate in congestion management when there is insufficient flexible capacity available. Companies with a contracted capacity of ≥1 MW can offer their capacity voluntarily, or be obligated by TenneT. Depending on the stage of congestion within that specific geographical area. Those companies can participate voluntarily, determine their capacity and price, and are obligated to participate or receive regulated prices due to the failure of the market. Those services are offered by Congestion Service Providers (CSPs). Unlike balancing services, congestion management bids are location-specific, to alleviate congestion at specific locations in the grid.

A Capacity Limit Contract (CLC) implies that a connected party uses its contracted transmission capacity (GTV) to a limited capacity for a certain period (De Boer, 2025). The party, therefore, temporarily does not use part of the GTV, for a fee agreed in advance with the network operator. Those CLCs are not activated through market mechanisms but are based on bilateral contracts with large-scale consumers or generators (Autoriteit Consument en Markt, 2022).

Redispatch

The other mechanism for congestion management is redispatch, shifting input and consumption from the grid. Redispatch is a combination of simultaneous upward and downward adjustment of production and or load. This is used to influence transmission in favour of grid security (TenneT, 2023). To determine when this is required, the N-1 criterion is used for a grid security analysis. The N-1 criterion states that the grid continues on the same level of operation, despite the failure of a random element. However, TenneT applies the N-2 criterion in its grid. This leaves the possibility of maintenance on the grid with the N-1 criterion still intact (TenneT, 2019). This N-2 criterion contributes to the high reliability of the Dutch high-voltage electricity grid (Autoriteit Consument en Markt, 2022). Thus, redispatch shifts the capacity from one location, with a bottleneck, to another location where sufficient capacity is still available. Currently, Tennet uses both the GOPACS and RESIN platform to select redispatch bids (TenneT, 2023).

GOPACS is the platform for grid operators for congestion management and it is planned that in the future, this will be the central platform for congestion services (TenneT, 2023). Here, the grid operators can request flexible power up to fifteen minutes before delivery from CSPs (De Boer, 2024). For example, when there is feed-in congestion due to a high amount of wind power being fed into the system, the grid operator can send a message via GOPACS to CSPs. The CSPs can either curtail their production or consume more power. But if a CSP decides to supply less power, another CSP outside the congestion area should operate in the opposite direction, so add more power to the grid to maintain the balance of the grid. The grid operator then has to pay the second BSP the difference between the price the first CSP is willing to pay to curtail wind energy and the price the second CSP is willing to receive to increase production. When the grid operator requests a bid during an ISP, the following 3 ISPs are used as preparation time. Bids should contain at least 4 consecutive ISPs (4 x 15 minutes), but for GOPACS bids can be offered to every ISP (TenneT, 2019).

As mentioned before, redispatch bids can be offered through both GOPACS and Resin. Redispatch bids can be either upwards or downwards, meaning the supplier offers up and down regulation of energy. For those bids, the location, price and volume are needed. The auction is then based on energy activation. Those redispatch bids can be offered from D-1 until 1 hour before real-time. Lastly, the pricing mechanism for those redispatch bids is pay-as-bid.

Pre-qualification

TenneT requires technical standards to generators, to ensure the reliability and stability of the grid (TenneT, 2025c). During compliance of the verification process, TenneT check whether the generators meet the requirements necessary for the services they applied for. After approval, the parties are allowed to offer their services for the Dutch grid.

A.1.2. Literature

Literature has been studied to analyse the previously proposed designs.

Market designs from literature

To begin with (Poplavskaya, Joos, et al., 2020) provided an analysis of existing approaches to balancing and congestion management and how this affects incentives for service providers. (Poplavskaya, Joos, et al., 2020) looked into three interaction models for balancing and redispatch services: I) market-based balancing, cost-based redispatch (MB/CB), II) market-based balancing, market-based redispatch (MB/MB), II) common market-based balancing and redispatch (CMB). In Model II, the two markets cleared consecutively whereas Model III has a single merit order and requirements.This study focused on ranking the models on qualitative scores for allocative efficiency, resource availability, susceptibility to gaming, ease of implementation and transparent cost allocation. However, it did not look into the quantitative results of those market designs. Model II and Model III show similarities with the design originating from the literature and documentation review. Model II focuses on market-based procurement for both balancing and redispatch services, similar to what has been concluded above. Model III uses a single merit order similar to the integrated market design mentioned before. The main difference between this study and the new market designs that will be studied is in the specific configuration of this market design. This study will therefore examine different set-ups of the new proposed market design. Where redispatch and balancing are resolved with the same uniform flex product in consecutive steps, similar to Model II, and in 1-step, similar to Model III.

In addition, previous research (Stok, 2024) introduced a new market design for integrated balancing and congestion services. Within this study, the new market design was defined by a single product named “flex capacity”. This flex capacity was defined by an energy auction, including the aFRR, mFRR and redispatch products. The variables for a bid of this flex capacity include location, price and capacity. In addition, the timing was dependent on co optimisation as well as separate optimisation where redispatch is performed prior to balancing. The settlement was tested for Pay-as-bid as well as Marginal pricing and the bids were divisible. This research was one of the drivers for this study and focused on a proof-of-concept model for the proposed new market designs. However, this proof-of-concept was performed on a six node model, with hypothetical numbers for bids, transport capacity and DA and flex bids. The results of this research were promising, therefore it was decided to analyse similar integrated market designs for balancing and redispatch on a network simulating the Dutch high-voltage grid.

Dimension specifications from literature

As mentioned before, the congestion and balancing markets have been analysed, with a focus on differences and similarities between the markets as well as the products delivered for those markets, see Appendix A. In addition, previous research has looked into the characteristics of this new flexibility product. (Poplavskaya, Joos, et al., 2020) used dimensions to provide an overview of the differences between balancing and redispatch services. However, they did not define the specifications for the dimensions in their different market designs in detail. The following dimensions were included: purpose, procedure, location, decision to award, action direction, time frame, duration, approach to procurement, capacity reservation and standardized pre-qualification. In addition, they address dimensions to further identify the differences between redispatch services in countries. The ones included were: approach to system management, method of redispatch procurement, required information for providers, participation in electricity markets, capacity remuneration, minimum bid, bidding, remuneration of redispatch, procured jointly with balancing. However, detailed specifications of these dimensions were not provided for the individual market models. The dimensions can guide in defining the new market design proposed in this study. 12 (Stok, 2024) took a different approach and used the following dimensions to specify a new market design: type of auctions, type of products, variables in bid, timing, settlement approach and dividable bids. Based on this framework, a new market design was created, see Table A.2

Table A.2: Dimension specifications for Integrated market design (Stok, 2024)

Dimension	**Integrated market design**
Type of procurement	Energy auction
Type of products	aFRR (automatic Frequency Restoration Reserve), mFRR (manual Frequency Restoration Reserve) and redispatch products
Variables in bid	Each bid must specify a location (node/station), a price component (in €/MW or €/MWh) and the available capacity (MW) for activation
Timing	Two implementation options: • Co-optimisation of redispatch and balancing in a simultaneous time step • Separate optimisation, with redispatch resolved before balancing activation
Settlement approach	Two pricing mechanisms are proposed: • Pay-as-bid (PAB), where each bidder receives their own submitted price if accepted • Marginal pricing (MP), where all accepted bidders receive the clearing price of the most expensive accepted bid
Dividable bids	Bids can be partially accepted, meaning only part of the offered capacity can be activated if optimal for the system. This ensures more flexibility and granularity in market outcomes

A.1.3. Expert consultation

An input session was held with experts from TenneT to support the design of a uniform flexibility product for an integrated balancing and congestion market. Including a product categorisation exercise, identified design dimensions and final proposals from the two groups.

Program

To incorporate the expertise of TenneT employees, an input session was organised to reflect on the design for an integrated balancing and congestion market. During this session, expert insights were gathered without participants being informed of the outcomes of prior research. This was done to ensure unbiased input and avoid steering the group towards pre-defined solutions. The input session consisted of 6 parts:

1. i) an introduction of the project
2. ii) an overview of existing products to be integrated into uniform products
3. iii) a discussion on the proposed uniform products
4. iv) an introduction to the dimensions of the new flex product
5. v) a discussion on the proposed dimensions, and
6. vi) a concluding discussion of the overall input session outcomes.

Product list

A list of ancillary services products Table A.3 was compiled to provide a clear scope for which products to combine into new uniform products. This list served as the starting point for the expert discussions and ensured that all participants shared a common understanding of the current product landscape. The included products represent a broad range of services currently used for balancing, congestion management, and system reliability (**tennet-2025c**) and (TenneT, 2025d). Although some of these products are not directly related to balancing or congestion (e.g., GoO, energy procurement), they were included to assess their potential role in a broader uniform product scope.

Table A.3: List of ancillary services for expert session

Product	Description
FCR	Frequency Containment Reserve, activated automatically in response to frequency deviations. Full activation within 30 seconds, max duration 15 minutes.
aFRR	Automatic Frequency Restoration Reserve, activated by TenneT to correct longer-lasting frequency deviations. Must activate within 5 minutes.
mFRR	Manual Frequency Restoration Reserve, or emergency power, manually activated during major disturbances.
CLC	Capacity Limiting Contract, bilateral agreement to reduce congestion in a specific area.
Redispatch	Temporary adjustment of consumption or generation to reduce congestion, based on bids.
VNB and ONB	(Voorziene Niet Beschikbaarheid, Onvoorziene Niet Beschikbaarheid) Planned Unavailability of Transmission Infrastructure and Unplannend Unavailability of Transmission Infrastructure. Contracts to ensure system reliability during outages and maintenance.
Inertia	Service protecting against very short-term frequency fluctuations, partly through auctions.
Gridlosses	Electricity lost during transmission that TenneT must compensate for (via tenders).
Blackstart	Enables re-energizing the high-voltage grid after a total blackout.
Reactive power	Unused electricity flowing through the grid, procured through tenders.
GoO	TenneT buys Guarantees of Origin to support renewable energy for its own operations.
Energy procurement	Electricity for TenneT's buildings and substations, under a fixed-price contract.

New uniform products

To support the discussion on product integration, the presented services from Table A.3 were grouped into new products based on their role in the electrical grid. The participants were divided into two groups, group A and group B. Group A came up with 4 different products, group B came up with 3 products, see Table C.3.2. Group A focused on technical product characteristics, distinguishing energy-based from capacity-based products. Group B categorised products according to their functional role in the system: system services, transport-related services, and facilitation services.

Table A.4: Overview of products in Group A and Group B, categorised by function

Group A	Group B
Product 1A (capacity)	**Product 1B (system)**
Inertia	Inertia
FCR	Blindvermogen
Product 2A (capacity)	**Product 2B (transport)**
aFRR (capacity)	Redispatch
mFRR (capacity)	aFRR
BPC	mFRR
CLC	CLC
VNB/ONB	VNB/ONB
Blackstart	
Product 3A (energy)	**Product 3B (facilitary)**
aFRR (energy)	Kabelverliezen
mFRR (energy)	Energy procurement
Redispatch	Gridlosses
Product 4A (energy)	
Kabelverliezen	
Gridlosses	
Energy procurement	

Product 1A includes services that are activated automatically or pre-contracted to provide immediate system support based on available capacity. These products play a central role in frequency stability and inertial response. Product 2A includes contracted reserves and support services for maintaining operational security during grid disturbances. These services are typically activated on instruction and often require prequalification and availability payments. Product 3A consists of voluntary or market-based activation products that are procured based on energy delivery rather than capacity reservation. Their flexibility allows them to complement contracted reserves and support dynamic grid balancing. Product 4A contains cost-recovery and facilitation services related to the operational energy needs of the grid. These include grid losses and internal energy procurement, which are essential for the functioning of substations and grid infrastructure. Product 1B includes services that provide direct technical support to the stability of the electricity system. They are often deployed in real-time and respond to frequency and voltage deviations on very short timescales. Product 2B comprises products used to resolve congestion and transport-related limitations in the high-voltage grid. They support the secure operation of the grid and enable the efficient use of transmission capacity. Product 3B combines facilitation products to ensure the operational continuity of the grid and administrative functions such as loss settlement and internal energy supply. While not directly related to balancing or congestion, they support the infrastructure necessary for those processes.

Based on the product categorisation, product 3A and 2B were selected for further development, as these groups appear most suitable for integration into a combined balancing and congestion market. Product 3A consists of energy-based flexibility services, such as voluntary aFRR, mFRR and redispatch which are dynamic and can be activated based on system needs rather than fixed availability. These products offer the operational flexibility needed to respond to real-time balancing requirements. Product 2B, on the other hand, comprises transport-related system services, including redispatch, aFRR, mFRR and CLCs which are directly linked to the physical limitations of the grid. The overlap in functionality between these two groups, particularly in terms of activation potential and operational flexibility make them suitable for serving an integrated balancing and redispatch market.

Dimensions for designing flex product

Building on the products that were selected, market design dimensions were identified to guide the discussion on how these products could be integrated. These dimensions, see Table A.5, reflect the choices shaping how flexibility can be procured, activated and settled in the integrated balancing and congestion market. By exploring these dimensions, the experts evaluated potential design configurations and their implications for system operation and market functioning.

Table A.5: Design dimensions for flexibility product procurement mechanisms

Dimension	Description	Options
Products	Types of flexibility products included	aFRR, mFRR, redispatch
Bids	How bids are submitted	Market-based, contract-based or hybrid
Type of procurement	Basis of product procurement	Energy or capacity or both
Bid attributes	Variables included in bid	Location, price, volume
Optimisation timing	Structure of market clearing	1-step or 2-step optimisation
Settlement approach	How accepted bids are remunerated	Pay-as-bid or Marginal Pricing
Dividability	Whether partial bids are accepted	Yes or no

Results from design dimensions by experts

Table A.6: Comparison of market design features between Group A and Group B

Dimension	Group A	Group B
Products	aFRR, mFRR, redispatch	aFRR, mFRR, CLC, redispatch, VNB/ONB
Type of procurement	Market	Market and contracts
Bids	Energy	Capacity and energy
Bid attributes	Location, price, volume	Location, price, volume
Optimisation timing	2-step	2-step
Settlement approach	First PAB to gain liquidity, MP in a later stage	PAB for capacity, MP for energy
Divisibility	Yes	Yes

New dimensions uniform flex product

To explore how this new uniform flex product could be structured, the experts were asked to define the dimensions of their new flex products. Group A and B were asked to continue with product 3A and 2B, the results are presented in table C.3.4.

A.2. Flow Chart Diagrams

A Flow Chart Diagram (FCD) is a visual representation of a process, using symbols and arrows to show the sequence of steps and the relationships between process components. Each shape has a specific meaning, such as diamonds for decision points, rectangles for process steps and ovals for start or end points. Arrows indicate the direction of the process flow and show how information, decisions or actions follow one another. These diagrams can be used to better understand the designs introduced in Chapter 2.

The *Current* market design uses separate markets for redispatch and balancing, divided over three rounds see Figure A.3. First, the DA market is cleared, after which the available volume for upward and downward activation are determined, based on this DA round. Then, capacity constraints on transmission lines are added resulting in a flow analysis after planned transport in the DA round. In design *Current* the capacity allocated to redispatch services is set to 30% and the remaining 70% is available for imbalance services. The red line between the redispatch and imbalance bids visualises the separate markets. Based on the redispatch bids combined with the flow prognosis, redispatch is executed resulting in redispatch costs. In the third round, imbalance is added and resolved by the imbalance bids after the DA round has been accepted and redispatch actions have been awarded.

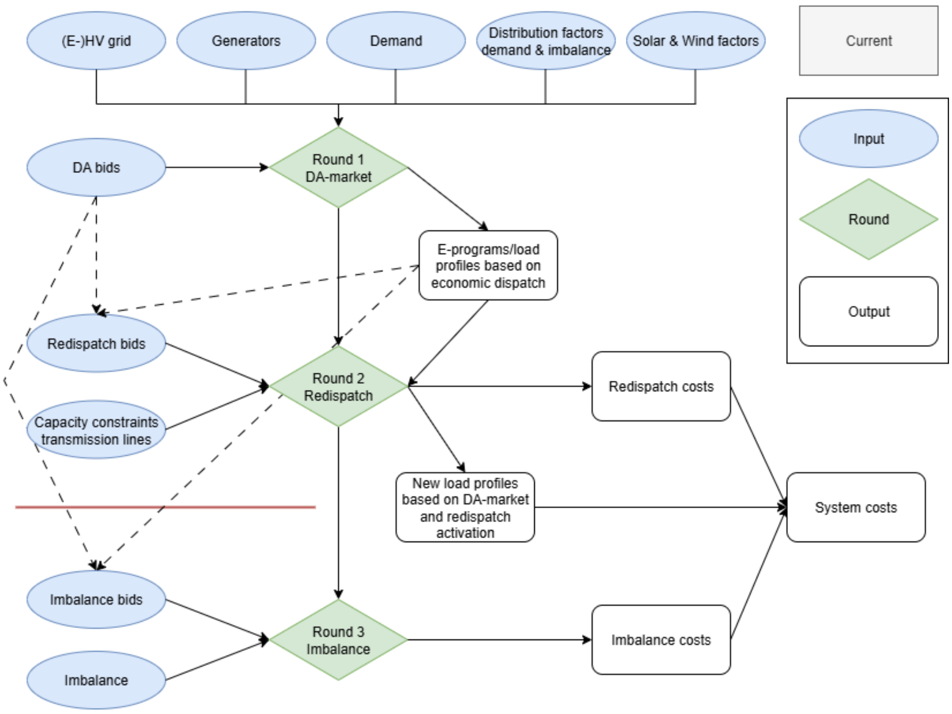

Figure A.3: Flow chart diagram for design Current

The *Gross* and *Net* market designs retain separate rounds for redispatch and balancing but use a uniform flex product for both services, see Figure A.4. After the DA market is cleared, the same pool of uniform flex bids is available for activation in both Round 2 (redispatch) and Round 3 (balancing) but have different prices in the two rounds. Capacity constraints are applied before redispatch, after which new load profiles are calculated and used for the imbalance round. The main difference between *Gross* and *Net* lies in remuneration. In *Gross* all activations are remunerated, while in *Net* only the netted difference between upward and downward activation is paid. So activation in opposite directions are subtracted and remunerated against the price of the net activation.

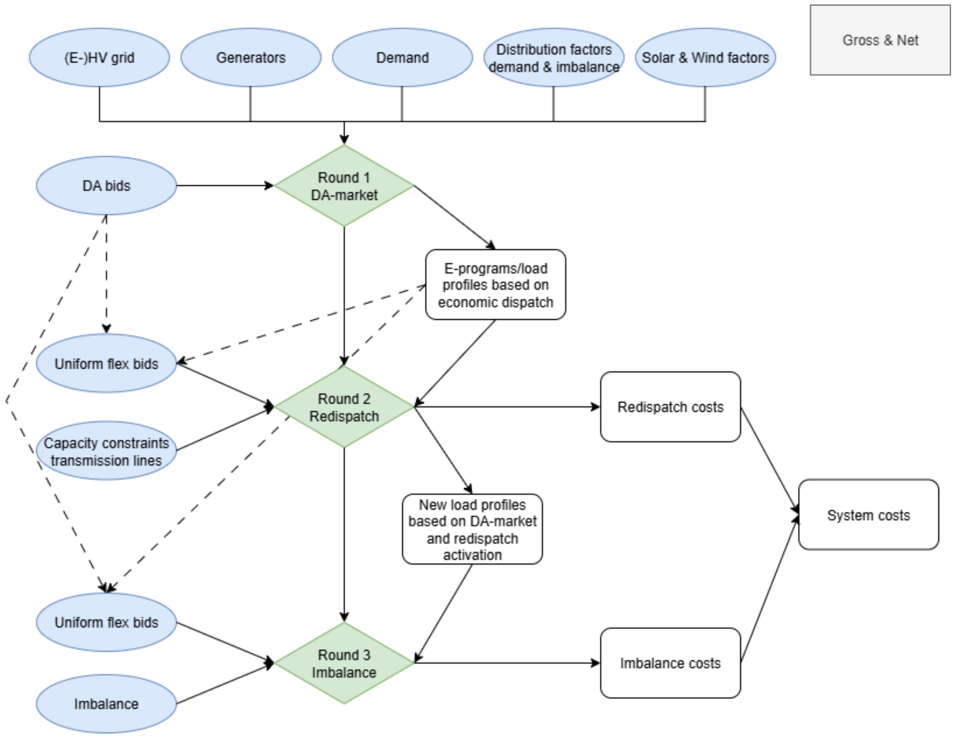

Figure A.4: Flow chart diagram for design Gross and Net

The *All-in-one* market design integrates redispatch and balancing into a single round, as shown in Figure A.5. After the DA market is cleared in Round 1, uniform flex bids are used directly in Round 2 to simultaneously resolve congestion and imbalance. Capacity constraints on transmission lines are applied before the activation of flexibility, ensuring that all activated capacity meets both technical and economic requirements. By combining both services in one step, the design aims to increase efficiency in capacity allocation and reduce total system costs, which are calculated as the sum of redispatch and imbalance costs.

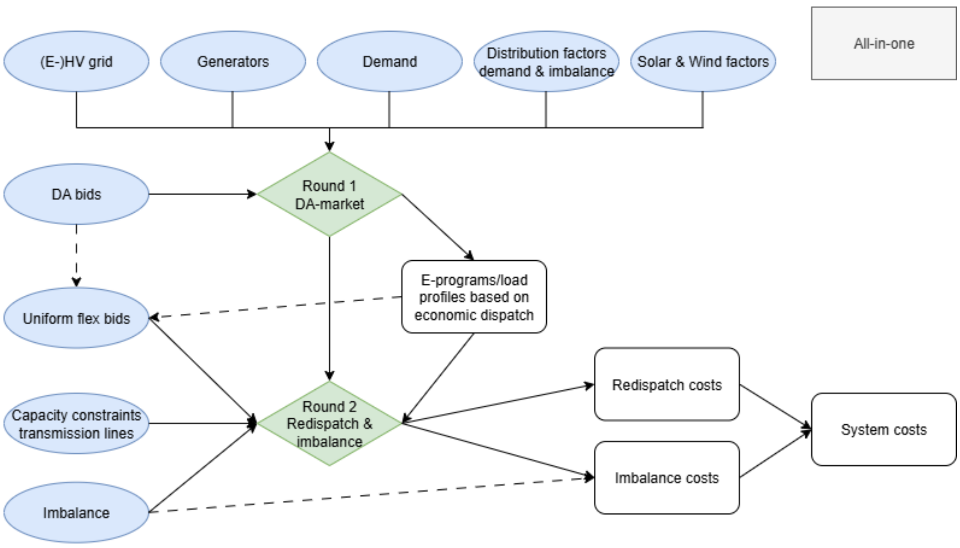

Figure A.5: Flow chart diagram for design All-in-one

B

Model guide

This appendix provides a detailed guide for understanding the models, starting with an explanation of the backbone model, which is used as the base for the four designs. Followed by an explanation of the products and processes and datasets including selectors for all four designs: *Current, Gross, Net, All-in-one.*. For a more detailed description on Linny-R notation, please refer to (Bots, 2025).

B.1. Backbone model

First, a backbone model, serving as the base for the other designs was constructed, see Figure 2.5. In this model, the stations are represented through products, without a specified Lower Bound (LB), Upper Bound (UB) and Price. The transmission lines between stations are simulated through processes and links. The names of these processes are defined by the station from which they start, followed by '-' and then the name of the station towards which the process is headed. In addition, these processes are marked as grid elements, either part of the 220 kV or 380 kV grid and have a specified length of line or cable. The LB is set to minus the UB, with the UB being specified by the capacity of that specific line multiplied by a dataset [Line_limitations], with three selectors 1-Bid [infinity], 2-Redisp [0.5] and 3-Imbal [0.6]. Overall, the backbone model comprises 32 stations and 40 transmission lines.

B.1.1. Stations included:

- Bergum
- Beverwijk
- Bleiswijk
- Borssele
- Boxmeer
- Breukelen
- Crayestein
- Diemen
- Dodewaard
- Doetinchem
- Eemshaven
- Eindhoven
- Ens
- Geertruidenberg
- Hengelo
- Krimpen
- Lelystad
- Louwsmeer
- Maasbracht
- Maasvlakte
- Meeden
- Oostzaan
- Oudehaske
- Rilland
- Simonshaven
- Tilburg
- Vierverlaten
- Vijfhuizen
- Wateringen
- Weiwerd
- Zeyerveen
- Zwolle

B.1.2. Transmission lines included:

- Beverwijk-Oostzaan
- Vijfhuizen-Beverwijk
- Bleiswijk-Vijfhuizen
- Borssele-Rilland
- Boxmeer-Dodewaard
- Breukelen-Diemen

- Crayestein-Krimpen
- Lelystad-Diemen
- Dodewaard-Doetinchem
- Doetinchem-Hengelo
- Meeden-Eemshaven
- Zwolle-Ens380
- Geertruidenberg-Tilburg
- Krimpen-Bleiswijk
- Krimpen-Breukelen
- Crayestein-Geertruidenberg
- Krimpen-Oostzaan
- Ens-Lelystad
- Maasbracht-Boxmeer
- Maasbracht-Dodewaard
- Maasbracht-Eindhoven
- Maasvlakte-Simonshaven
- Diemen-Oostzaan
- Rilland-Geertruidenberg
- Simonshaven-Crayestein
- Bleiswijk-Wateringen
- Wateringen-Maasvlakte
- Hengelo-Zwolle
- Zwolle-Meeden
- Zwolle-Ens220
- Bergum-Louwsmeer
- Louwsmeer-Oudehaske
- Weiwerd-Meeden
- Oudehaske-Ens
- Weiwerd-Eemshaven
- Eemshaven-Vierverlaten
- Vierverlaten-Zeyerveen
- Vierverlaten-Bergum
- Tilburg-Eindhoven
- Zwolle-Zeyerveen

B.2. From backbone to specific model

As was mentioned in chapter 2, the four models are based on the same backbone model. Comprising 32 stations and 40 transmission lines. To those stations, different clusters will be added depending on the designs. Within those clusters, different decision rules are used and rounds have different names. However, the principle of the rounds remains similar over the designs. Whilst different input and output sheets were used for designs *Gross* and *Net*, the same Linny-r model was used. Resulting in three different Linny-R models.

Rounds Three rounds are executed consecutively: DA, redispatch and imbalance. With the latter two having different names under the new designs: Flex and Flex2. These rounds are realised through products and processes, defined by selectors. Providing each process to have different settings over the different rounds named: 1-Bid, 2-Redisp, 3-Imbal.

B.2.1. Products and processes within a station

For all the designs, the models consists of clusters, containing products and processes. Each generator, for example F1, operates through a set of products and processes with a direction (if applicable) for an attribute such as LB, UB and Price.

Example for Station: X, generator F1
For example, for Station X, with six generators (F1, F2, W1, W2, S1, S2), the complete set of products and processes for generator F1 is shown below for the Current see TableB.1.

For design Current products and processes included are shown in TableB.1, the three rounds are the DA, Redispatch and Imbalance round. The DA round processes are always upward due to the nature of the process and therefore, no direction is added in the name. See Table B.2 for the similar products and processes in the *Gross* design and Table for the products and processes included per cluster in the *All-in-one* design.

Table B.1: Design: Current, products and processes within station X, example F1

Type	Round	Direction	Attribute	Dataset
Process	DA	n/a	LB	[Station X: F1: DA: LB]
Process	DA	n/a	UB	[Station X: F1: DA: UB]
Product	DA	n/a	Price	[Station X: F1: DA: MC]
Process	Redispatch	Up	LB	[Station X: F1: Redispatch: Up: LB]
Process	Redispatch	Up	UB	[Station X: F1: Redispatch: Up: UB]
Product	Redispatch	Up	Price	[Station X: F1: Redispatch: Up: MC]
Process	Redispatch	Down	LB	[Station X: F1: Redispatch: Down: LB]
Process	Redispatch	Down	UB	[Station X: F1: Redispatch: Down: UB]
Product	Redispatch	Down	Price	[Station X: F1: Redispatch: Down: MC]
Process	Imbalance	Up	LB	[Station X: F1: Imbalance: Up: LB]
Process	Imbalance	Up	UB	[Station X: F1: Imbalance: Up: UB]
Product	Imbalance	Up	Price	[Station X: F1: Imbalance: Up: MC]
Process	Imbalance	Down	LB	[Station X: F1: Imbalance: Down: LB]
Process	Imbalance	Down	UB	[Station X: F1: Imbalance: Down: UB]
Product	Imbalance	Down	Price	[Station X: F1: Imbalance: Down: MC]

Table B.2: Design: Gross, products and processes within station X, example F1

Type	Round	Direction	Attribute	Dataset
Process	DA	n/a	LB	[Station X: F1: DA: LB]
Process	DA	n/a	UB	[Station X: F1: DA: UB]
Product	DA	n/a	Price	[Station X: F1: DA: MC]
Process	Flex	Up	LB	[Station X: F1: Flex: Up: LB]
Process	Flex	Up	UB	[Station X: F1: Flex: Up: UB]
Product	Flex	Up	Price	[Station X: F1: Flex: Up: MC]
Process	Flex	Down	LB	[Station X: F1: Flex: Down: LB]
Process	Flex	Down	UB	[Station X: F1: Flex: Down: UB]
Product	Flex	Down	Price	[Station X: F1: Flex: Down: MC]
Process	Flex2	Up	LB	[Station X: F1: Flex2: Up: LB]
Process	Flex2	Up	UB	[Station X: F1: Flex2: Up: UB]
Product	Flex2	Up	Price	[Station X: F1: Flex2: Up: MC]
Process	Flex2	Down	LB	[Station X: F1: Flex2: Down: LB]
Process	Flex2	Down	UB	[Station X: F1: Flex2: Down: UB]
Product	Flex2	Down	Price	[Station X: F1: Flex2: Down: MC]

Table B.3: Design: All-in-one, products and processes within station X, example F1

Type	Round	Direction	Attribute	Dataset
Process	DA	n/a	LB	[Station X: F1: DA: LB]
Process	DA	n/a	UB	[Station X: F1: DA: UB]
Product	DA	n/a	Price	[Station X: F1: DA: MC]
Process	Flex	Up	LB	[Station X: F1: Flex: Up: LB]
Process	Flex	Up	UB	[Station X: F1: Flex: Up: UB]
Product	Flex	Up	Price	[Station X: F1: Flex: Up: MC]
Process	Flex	Down	LB	[Station X: F1: Flex: Down: LB]
Process	Flex	Down	UB	[Station X: F1: Flex: Down: UB]
Product	Flex	Down	Price	[Station X: F1: Flex: Down: MC]

Selectors

Within the models, processes are dependent on settings over the different rounds, the selectors named: 1-Bid, 2-Redisp, 3-Imbal. The settings for these selectors for every process are shown in Table B.4, Table B.5 and Table B.6 for *Current*, *Gross* and *All-in-one* respectively. Where selector name, refers to the value of the variable within the round similar to the name of the selector. So describe the DA process in words, the LB in the DA round is 0 where the LB is equal to the capacity of the specified generator, indicated by ::. The level determined in this first round, 1-Bid, is then set as LB and UB for round 2-Redisp and round 3-Imbal. So the level of this process is not allowed to change any more.

Then the redispatch down process, which has a LB and UB of 0 in round 1-Bid, as this process is not activated yet. In round 2-Redisp, the LB of the process is 0 and the UB of the process is equal to the accepted DA bid in round 1-Bid, multiplied by Share Redispatch. This Share Redispatch determines how much of the accepted volume available for downward generation, dependent on the DA round, is available for redispatch services. Which is varied in the sensitivity analysis from 20% to 30% and 40%. Similarly, Share Imbalance determines how much of the accepted volume in the DA round is available for balancing services. For upward activation in the redispatch round, available volume is the difference between the total capacity of that generator minus the production accepted in the DA round. Once this level has been determined in round 2-Redisp, it is fixed for the third round by setting the LB and UB to the level from round 2-Redisp.

Lastly, the imbalance round in model *Current* is structured in a similar way as redispatch. For downward activation, the LB of available volume in the third round is 0 and the UB is the product of Share Imbalance and the accepted volume from the DA round. Imbalance processes in model *Current* have an LB and UB of 0 in round 2-Redisp, as those bids can only be used in the third round to resolve imbalance. For upward activation, again the LB and UB in round 2-Redisp are 0 as the processes can not be used during this round. In round 3-Imbal, the LB is 0 and the UB is the difference between the capacity of the generator and the accepted DA bid, multiplied by the percentage available for balancing services.

The difference between F1 and F2 generators compared to S1, S2, W1 and W2 generators is that the latter ones are also affected by a weather factor: Factor Solar or Factor Wind. Those factors are location specific and are multiplied with the capacity of a generator, to determine how much of installed capacity is available during that time step. So selectors are similar, the only difference is that every: [:: Vermogen] is replaced with [:: Vermogen] * [Factor Solar] for S1 and S2 and [:: Vermogen] * [Factor Wind] for W1 and W2.

Table B.4: Design: Current, selectors for processes within station X, example F1

<table>
<tr><th>Round</th><th>Direction</th><th>Name</th><th>1-Bid</th><th>2-Redisp</th><th>3-Imbal</th></tr>
<tr><td>DA</td><td></td><td>LB</td><td>0</td><td>[1-Bid:|L]</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td></td><td>UB</td><td>[:: Vermogen]</td><td>[1-Bid:|L]</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td></td><td>MC</td><td>From dataset</td><td>n/a</td><td>n/a</td></tr>
<tr><td>DA</td><td></td><td>Capacity</td><td>From dataset</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Redispatch</td><td>Down</td><td>LB</td><td>0</td><td>0</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Redispatch</td><td>Down</td><td>UB</td><td>0</td><td>[1-Bid:::DA|L] * [Share Redispatch]</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Redispatch</td><td>Down</td><td>MC</td><td>n/a</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>Redispatch</td><td>Up</td><td>LB</td><td>0</td><td>0</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Redispatch</td><td>Up</td><td>UB</td><td>0</td><td>([::: Vermogen] - [1-Bid::: DA|L]) * [Share Redispatch]</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Redispatch</td><td>Up</td><td>MC</td><td>n/a</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>Imbalance</td><td>Down</td><td>LB</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Imbalance</td><td>Down</td><td>UB</td><td>0</td><td>0</td><td>[1-Bid::: DA|L] * [Share Imbalance]</td></tr>
<tr><td>Imbalance</td><td>Down</td><td>MC</td><td>n/a</td><td>n/a</td><td>From dataset</td></tr>
<tr><td>Imbalance</td><td>Up</td><td>LB</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Imbalance</td><td>Up</td><td>UB</td><td>0</td><td>0</td><td>([::: Vermogen] - [1-Bid::: DA|L]) * [Share Imbalanc</td></tr>
<tr><td>Imbalance</td><td>Up</td><td>MC</td><td>n/a</td><td>n/a</td><td>From dataset</td></tr>
</table>

The DA processes are similar for *Current*, *Gross* and *All-in-one*. The difference between the designs is the separate compared to integrated markets. This also results in different processes, products and selectors, also known as decision rules or settings for the new designs.

During round 2-Redisp, Redispatch processes are replaced by Flex processes. Besides, all volume from round 1-Bid is available in these processes. Again, the LB and UB for both Flex Up and Flex Down are 0 in round 1-Bid and can not be used. For Flex Down during round 2-Redisp, the LB is 0 and the UB is equal to the level for which the generator is accepted in the DA round. For Flex Up the LB is 0 and the UB is the difference between the capacity and the accepted level in round 1-Bid for that generator. These settings are the same for design *All-in-one*, the only difference being that there is no round 3-Imbal in *All-in-one* so no levels are specified for this round, see Table B.6.

Round 3-Imbal in model *Gross* is different compared to the imbalance round in model *Current*. For Flex2 Down, the available volume for downward activation is dependent on the activation of that generator in round 1-Bid and round 2-Redisp. The LB for available volume for downward activation is 0 and the UB is the activated level in 1-Bid plus the level of upward activation in 2-Redisp minus the level of downward activation in 2-Redisp. For upward activation, the LB is 0 and the UB is the capacity minus the accepted level in 1-Bid minus upward activation in 2-Redisp plus downward activation in 2-Redisp.

Table B.5: Design: Gross, selectors for processes within station X, example F1

<table>
<tr><th>Round</th><th>Direction</th><th>Name</th><th>1-Bid</th><th>2-Redisp</th><th>3-Imbal</th></tr>
<tr><td>DA</td><td>n/a</td><td>LB</td><td>0</td><td>[1-Bid:|L]</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td>n/a</td><td>UB</td><td>[:: Vermogen]</td><td>[1-Bid:|L]</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td>n/a</td><td>MC</td><td>From dataset</td><td>n/a</td><td>n/a</td></tr>
<tr><td>DA</td><td>n/a</td><td>Capacity</td><td>From dataset</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Flex</td><td>Down</td><td>LB</td><td>0</td><td>0</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Flex</td><td>Down</td><td>UB</td><td>0</td><td>[1-Bid:::DA|L]</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Flex</td><td>Down</td><td>MC</td><td>n/a</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>Flex</td><td>Up</td><td>LB</td><td>0</td><td>0</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Flex</td><td>Up</td><td>UB</td><td>0</td><td>[::: Vermogen] - [1-Bid:::DA|L]</td><td>[2-Redisp:|L]</td></tr>
<tr><td>Flex</td><td>Up</td><td>MC</td><td>n/a</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>Flex2</td><td>Down</td><td>LB</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Flex2</td><td>Down</td><td>UB</td><td>0</td><td>0</td><td>[1-Bid:::DA|L] + [2-Redisp::: Flex: Up|L] - [2-Redisp::: Flex: Down|L]</td></tr>
<tr><td>Flex2</td><td>Down</td><td>MC</td><td>n/a</td><td>n/a</td><td>From dataset</td></tr>
<tr><td>Flex2</td><td>Up</td><td>LB</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>Flex2</td><td>Up</td><td>UB</td><td>0</td><td>0</td><td>[::: Vermogen] - [1-Bid:::DA|L] - [2-Redisp::: Flex: Up|L] + [2-Redisp::: Flex: Do</td></tr>
<tr><td>Flex2</td><td>Up</td><td>MC</td><td>n/a</td><td>n/a</td><td>From dataset</td></tr>
</table>

Table B.6: Design: All-in-one, selectors for processes within station X, example F1

<table>
<tr><th>Round</th><th>Direction</th><th>Name</th><th>1-Bid</th><th>2-Redisp</th></tr>
<tr><td>DA</td><td>n/a</td><td>LB</td><td>0</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td>n/a</td><td>UB</td><td>[:: Vermogen]</td><td>[1-Bid:|L]</td></tr>
<tr><td>DA</td><td>n/a</td><td>MC</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>DA</td><td>n/a</td><td>Capacity</td><td>From dataset</td><td>n/a</td></tr>
<tr><td>Flex</td><td>Down</td><td>LB</td><td>0</td><td>0</td></tr>
<tr><td>Flex</td><td>Down</td><td>UB</td><td>0</td><td>[1-Bid:::DA|L]</td></tr>
<tr><td>Flex</td><td>Down</td><td>MC</td><td>n/a</td><td>From dataset</td></tr>
<tr><td>Flex</td><td>Up</td><td>LB</td><td>0</td><td>0</td></tr>
<tr><td>Flex</td><td>Up</td><td>UB</td><td>0</td><td>[::: Vermogen] - [1-Bid:::DA|L]</td></tr>
<tr><td>Flex</td><td>Up</td><td>MC</td><td>n/a</td><td>From dataset</td></tr>
</table>

Illustrative examples for differences in Current and Gross volumes of the rounds

Figure B.1 illustrates the allocation and use of available capacity across three rounds in the *Current* design. Where the total capacity from the day-ahead (DA) market for downward activation is split into 30% for redispatch services and 70% for imbalance services. As well as the available volume for upward generation, being defined by the capacity minus the DA bid and also being multiplied with the shares.

In Round 1, a bid in the DA market is accepted, setting the volume for the available downward capacity. The total DA bid volume is then divided based on the fixed allocation shares for redispatch and imbalance of 30% and 70%. In round 2, the system requires 150 MWh of upward redispatch. However, only 60 MWh is available for redispatch services due to the 30% allocation share. This shortage forces the activation of 90 MWh of extra redispatch capacity which is more expensive, shown in red in the figure. In round 3, the imbalance market requires 50 MWh of downward activation. While this reduces the net system requirement, the extra redispatch capacity from round 2 remains partly in use. This occurs despite sufficient upward capacity still being available in the imbalance services allocation.

This example underscores the inefficiencies, also shown in the validation of the models as well as the sensitivity analysis, of separated markets. Where capacity restrictions between redispatch and imbalance can cause the unnecessary activation of expensive extra redispatch capacity even when sufficient capacity is available in the balancing market.

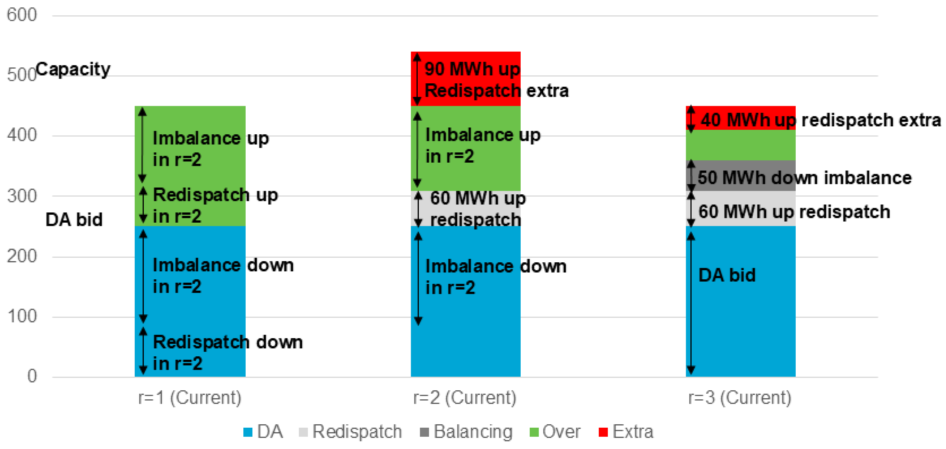

Figure B.1: Current: Illustrative example for available volume for upward and downward activation

Comparing this to the example shown in Figure B.2, illustrating the allocation and use of capacity in the *Gross* market design. Where redispatch and imbalance services are replaced by uniform flex capacity.

Similarly as in *Current*, in round 1, a bid in the DA market is accepted. Again, determining the total upward and downward capacity that can be used for both redispatch and imbalance. Unlike in the *Current* design, there is no split between the two services, the concept of a combined flex market. So the level of the DA bid is the volume available for Flex Down. The difference between the capacity and the DA bid is the volume available for upward activation. In round 2, the system requires 150 MWh of upward redispatch. Since the upward flexibility is obtained from one flex capacity market, the entire 150 MWh is available without the need for extra costly capacity. In round 3, the imbalance market requires 50 MWh of downward activation. This can be obtained from the flex capacity market for downward activation. Because redispatch and imbalance are integrated in a uniform flex market, no extra redispatch volume is required. Resulting in a more efficient utilisation of resources compared to the *Current* design.

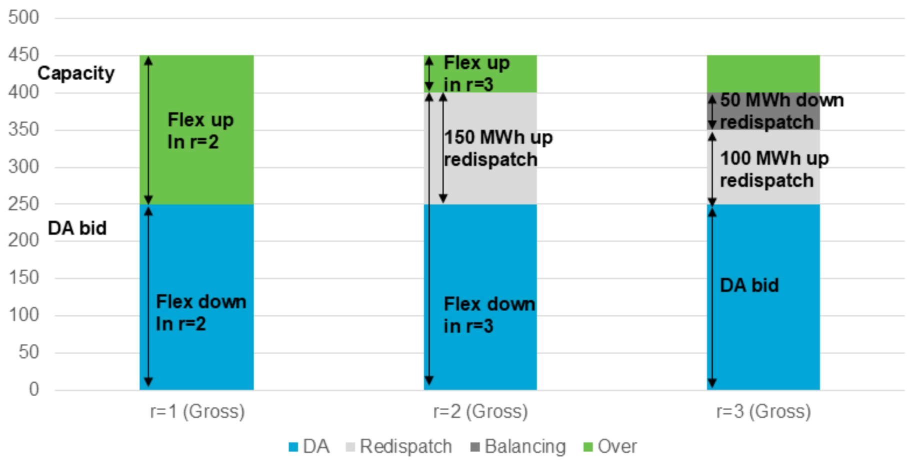

Figure B.2: Gross: Illustrative example for available volume for upward and downward activation

The same example in Figure B.2 can be used to illustrate the difference in remuneration mechanisms between the *Gross* and *Net* designs. Both designs are based on the same activations: in round 2, 150 MWh of upward redispatch is activated, while in round 3, 50 MWh of downward redispatch and 100 MWh of upward balancing are activated. The difference lies in how the activated volumes are remunerated.

In *Gross*, both upward and downward activations are remunerated separately at their respective prices.

For the upward action in round 2:

$$150\ [\text{MWh}] \times 200\ [e/\text{MWh}] = €30{,}000$$

For the downward action in round 3, a negative price of -180 €/MWh applies:

$$50\ [\text{MWh}] \times (-180)\ [e/\text{MWh}] = -€9{,}000$$

The total remuneration in the *Gross* design therefore becomes:

$$30{,}000 - 9{,}000 = €27{,}000$$

In *Net*, only the net volume is remunerated. The downward volume from round 3 is subtracted from the upward volume in round 2:

$$(150 - 50)\ [\text{MWh}] \times 200\ [e/\text{MWh}] = 100 \times 200 = €20{,}000$$

This example shows that *Gross* generally results in higher total remuneration, as upward and downward actions are fully and separately remunerated. In contrast to the *Net* design where only the net volume is remunerated against the price of the corresponding activation direction.

B.3. Selection of four days

To gain a better understanding of the operation of the different market designs, their performances should be studied under varying circumstances. As the new market designs focus on an integrated balancing and congestion market, both elements are considered jointly. Therefore, four days have been chosen based on combinations of high and low imbalance and congestion conditions. Balancing data has been retrieved from the transparency page for the volume of frequency restoration reserve activation (TenneT, 2025b). In addition, congestion data has been retrieved from GOPACS transparency platform, specifically redispatch volumes (GOPACS, 2025).

Imbalance To select representative days for the simulation, aFRR balance data from 2024, retrieved from TenneT's transparency platform, was analysed (TenneT, 2025b). The analysis focused on identifying days with high and low absolute imbalance values. In addition, an average day was identified as the day whose average imbalance was closest to the median of all daily averages. Daily averages were calculated by aggregating the 96 ISP values per day, which were subsequently compared across all days. The day with the highest absolute average imbalance was identified as 08-11-2024, with an average of -172,866.1 kWh. Conversely, the day with the lowest absolute average imbalance was 29-04-2024 corresponding to -426.8 kWh. Lastly, the day with an average imbalance value was identified as 04-01-2024, with an average value of 4380.2 kWh, being the closest value to the median value of 4349.2 kWh.

Redispatch In parallel, redispatch volume activation data was analysed using volumes published on the GOPACS transparency platform (GOPACS, 2025). Unlike imbalance data, redispatch volumes are reported in broader time blocks. In addition, upward and downward volumes for redispatch are always equal due to symmetrical activation. The period with the highest total redispatch volume was identified as 18 November 2024, between 12:00 and 19:00, with an upward and downward activation of 1639.3 MWh. This corresponds to an average redispatch volume of approximately 230 MWh per hour.

For the day with low congestion, various days are relevant, as redispatch capacity is not activated as frequently as imbalance capacity over the course of an entire year. Since 29-04-2024 was chosen for the day with low imbalance, this day was also tested for congestion. On this day, no redispatch volume was activated as well as for the average imbalance day 04-01-2024. This selection supports a scenario-based evaluation of the integrated market design under contrasting system conditions see Table B.7.

Table B.7: Overview time series data based on imbalance and redispatch

Reason	Day	Imbalance	Redispatch
Max imbalance	8-11-2024	-172,886.1	1.6
Min imbalance	29-4-2024	-426.8	–
Max redispatch	18-11-2024	6,054.3	1,639.3
Median imbalance	4-1-2024	4,380.2	–

C

Bids and model input

C.1. Bids

This appendix outlines the bids under different pricing mechanisms used in the scenarios. The three pricing mechanisms are: only MP, only PAB and PAB and MP. Under only MP, prices are based directly on marginal costs adjusted by coefficients for both the redispatch and imbalance rounds. In only PAB, prices are determined by a parametrised function of marginal cost, again both for the redispatch and imbalance round. In only PAB and MP, PAB is used for redispatch in round 2, whilst MP is applied for imbalance pricing in round 3.

C.1.1. Marginal pricing

Based on MC and bid adjustment coefficients, varying depending on the round and direction of activation. Under only MP, pricing is similar for all designs.

Marginal pricing formulas

$$\text{Redispatch}_{\text{Up}} = MC \cdot \text{Coefficient}_{\text{Redispatch, Up}} \tag{C.1}$$

$$\text{Redispatch}_{\text{Down}} = MC \cdot \text{Coefficient}_{\text{Redispatch, Down}} \tag{C.2}$$

$$\text{Imbalance}_{\text{Up}} = MC \cdot \text{Coefficient}_{\text{Imbalance, Up}} \tag{C.3}$$

$$\text{Imbalance}_{\text{Down}} = MC \cdot \text{Coefficient}_{\text{Imbalance, Down}} \tag{C.4}$$

Exception for solar and wind during downward activation

Different formulas are used for downward activation of solar and wind, variable Renewable Energy Sources (vRES). As vRES typically have low marginal costs, but are dependent on opportunity costs related to the loss of Guarantees of Origin (GoOs). Therefore, their bid is adjusted to the maximum between the marginal cost plus the profit margin (C.2 or C.4) and the fixed GoO value from Table C.2. To reflect their opportunity costs within the different scenarios, for curtailment of vRES.

$$\text{Redispatch}^{\text{vRES}}_{\text{Down}} = \max\left(MC \cdot \text{Coefficient}_{\text{Redispatch, Down}}, GoO\right) \tag{C.5}$$

$$\text{Imbalance}^{\text{vRES}}_{\text{Down}} = \max\left(MC \cdot \text{Coefficient}_{\text{Imbalance, Down}}, GoO\right) \tag{C.6}$$

The adjustment coefficients in Table C.1 are used to reflect operational preferences or incentives. For example, upward activations are typically more expensive due to startup costs or opportunity costs, which is why a multiplier above 1 is used. Conversely, downward activations often reflect lost revenue or curtailment penalties, which are captured using a negative coefficient.

In addition, a small variation in bidding behaviour within a specific technology was incorporated as each station includes two generators of a type: X1 and X2. While both share the same coefficients from Table C.1, generator X2 is systematically 10% more expensive in marginal cost compared to X1. Resulting in higher bids in the redispatch and imbalance rounds as well. This includes some heterogeneity between units of the same generation type and prevents completely symetric bidding between the two generators of a type within a station.

Table C.1: Bid adjustment coefficients

	Up	**Down**
Redispatch	1.10	-0.90
Imbalance	1.05	-0.95

Table C.2: Bids downward activations for renewables

	Redispatch	**Imbalance**
Solar	9	6
Wind	10	7

For example, assume a generator with marginal cost $MC = 50$ €/MWh. The bid for redispatch upward activation under only MP is calculated as:

$$\text{Bid}_{\text{Redispatch, Up}} = 50 \cdot 1.10 = 55 \text{ €/MWh}$$

Now assume a generator that is a solar plant, providing a bid for redispatch downward activation during the imbalance round, with a corresponding GoO value of 6 €/MWh:

$$\text{Bid}^{\text{solar}}_{\text{Imbalance, Down}} = \max(50 \cdot -0.95,\, 6) = \max(-47.5,\, 6) = 6 \text{ €/MWh}$$

C.1.2. Pay-as-bid

Under only PAB, the bids for both the redispatch and imbalance rounds are based on the MC and a PAB bid formula including parameters C.7. The parameters vary depending on the round and are used to define the margin added to the MC to create the price for a bid. For downward pricing, this margin is subtracted from the MC. Under only PAB, pricing is similar for all designs.

Formula C.7 is based on three behavioural parameters: non-linearity (α), sensitivity (β) and a fixed bias term (γ). These parameters reflect different bidding strategies. In addition, the term $\left(1 - \frac{MC}{MC_{\text{max}}}\right)$ introduces a correction factor, which reduces the profit margin for bidders with high MC and increases the margin for bidders with low MC. This simulates competitiveness on generators with lower MC. Finally, the number of bidders b, see Table C.6, affects the influence of the adjustment. Where increased competition results in more conservative bidding behaviour.

For the scenarios with PAB, the following formula was used:

$$B_{\text{PAB}}(MC) = \left[MC + (MC^{\alpha} + \beta \cdot MC + \gamma) \cdot \left(1 - \frac{MC}{MC_{\text{max}}}\right) \cdot \frac{1}{\sqrt{b}}\right] \tag{C.7}$$

Where:

- MC = Marginal cost of the bid
- α = Non-linearity parameter
- β = Linear sensitivity coefficient
- γ = Constant bias term
- MC_{max} = Maximum marginal cost in the bidding set

- b = Number of bidders on that station
- $B(MC)$ = Adjusted bid price

Exception for downward bids of vRES in Flex and Flex2

Similarly as in only MP, under only PAB an exception was made for solar and wind units (vRES) during downward activation in the redispatch and imbalance rounds. Also in the new designs *Gross*, *Net* and *All-in-one*, in rounds Flex and Flex2, the bid price is based on the maximum of B(MC) and the corresponding GoO value.

$$\text{Flex}^{\text{vRES}}_{\text{Down}} = \max\left(B(MC),\ GoO\right) \tag{C.8}$$

$$\text{Flex2}^{\text{vRES}}_{\text{Down}} = \max\left(B(MC),\ GoO\right) \tag{C.9}$$

Parameter γ varied per round to reflect changing bidding environments. In round 2 (redispatch), a higher bias is used to simulate more strategic bidding due to longer lead times. In round 3 (imbalance), this bias is lower, representing the more urgent and reactive nature of the imbalance market.

Table C.3: Parameter values used for PAB bids in round 2 and 3

Parameter	R = 2	R = 3
MC_{max}	73.0	73.0
α	0.5	0.5
β	0.2	0.2
γ	10	5

C.1.3. Pay-as-bid and Marginal pricing

In these scenarios, both pricing mechanisms are combined over two activation rounds. In round 2 redispatch, prices are determined by the PAB method as shown in Equation C.7, using the parameter values listed in Table C.3. In round 3 imbalance, MP is applied by using the coefficients defined in Table C.1.

This combination of pricing mechanisms provides insights into the potential differences of market participants when under different pricing mechanisms. Redispatch reflects more strategic bidding behaviour due to PAB, while imbalance activation relies on merit-order selection under MP. Simulating the behaviour closest to the real markets, where PAB is used for redispatch services and MP for energy based balancing services.

For downward activation of vRES (solar and wind), the same exceptions apply as in the other designs:

$$\text{Flex}^{\text{vRES}}_{\text{Down}} = \max\left(B(MC),\ GoO\right) \tag{C.10}$$

$$\text{Flex2}^{\text{vRES}}_{\text{Down}} = \max\left(B(MC),\ GoO\right) \tag{C.11}$$

C.2. Backbone model

This section focuses on data gathering used in the backbone model, including the input parameters such as total load, imbalance and solar and wind availability factors. In addition, the installed capacity per generation type, the number of players per station as well as line capacity values and formulas are given. The setup and construction of the backbone model were explained in Appendix B.

C.2.1. Input parameters

Input parameters with time series, such as total load, total imbalance and solar and wind factors are based on the four days: 04-01-2024, 29-04-2024, 08-11-2024 and 18-11-2024.

For the total load hourly values were obtained from (ENTSO-E, 2025c) and added to the simulation as demand. In the sensitivity analyses, the values were multiplied by 1.1 and 1.2 to increase the consumption to 110% and 120%. Similarly, for the total imbalance, values were obtained with hourly resolution from (ENTSO-E, 2025a). This parameter was also varied under the sensitivity analysis by multiplying with 1.1 and 1.2. Lastly, for solar and wind availability factors were included and obtained from (Pfenninger & Staffell, 2016). In contrast to the total load and total imbalance that was applied to the whole system, the availability factor for solar and wind was location specific. Hence, for every station different factors were obtained and added to the simulation. Values were based on coordinates of station, resulting in a data sheet with solar and wind factors per station (Pfenninger & Staffell, 2016). The most recent data was from 2019 and therefore this data was used instead of 2024. As mentioned before, for the total load hourly values were obtained from (ENTSO-E, 2025c) and aggregated to match the hourly resolution. Although weather data from 2019 was applied instead of 2024, this assumption is not expected to influence the results in a significant way, as solar and wind patterns fluctuate over the years. The selected days may not exactly match the actual imbalance and congestion situations of 2024. However, they still include a range of renewable generation patterns, which is important for analysing energy supply (Bett & Thornton, 2015). This variation is sufficient to represent the conditions needed for the scenarios analysed.

C.2.2. Generators and installed capacity in the Netherlands

Plants were allocated to stations based on their geographic location. Longitude and latitude were obtained for each plant, after which the distance to every station was calculated individually. Each plant was then linked to the station with the shortest distance. Fossil fuel plants (F1 and F2) were based on the list from (Wikipedia, 2025) and verified with an expert from TenneT. Solar and wind plants were obtained from (Rijksdienst voor Ondernemend Nederland, 2025), with only operational plants of at least 1 MW capacity being included in the dataset. After assigning the plants to stations, the total installed capacity for fossil, solar and wind was determined. These totals were then compared with aggregate capacity values from (ENTSO-E, 2025b). The volumes were proportionally scaled, so that the total capacities in the model matched the official total capacities from ENTSO-E datasets. Although values in the model for capacities, as shown in Table C.4 do not match actual installed capacity. This is an approximation based on datasets that were available. To determine the capacity per generator in each station. The values from Table C.4 were divided by two.

Table C.4: Overview of Fossil, Solar, Wind and total values per station

Location	Fossil	Solar	Wind	Sum
Bergum	664	68.51	36.94	769.45
Beverwijk	869	674.56	692.63	2236.20
Bleiswijk	81	904.92	514.37	1500.29
Borssele	1724	323.44	1205.71	3253.14
Boxmeer	25	1759.62	0	1784.62
Breukelen	576	424.93	179.53	1180.46
Crayestein	32	255.39	57.66	345.05
Diemen	701	327.89	328.08	1356.97
Dodewaard	24	1976.82	168.86	2169.68
Doetinchem	0	1517.81	127.41	1645.22
Eemshaven	4630	155.53	766.36	5551.89
Eindhoven	50	1477.84	15.30	1543.13
Ens	–	701.65	676.35	1377.99
Geertruidenberg	1520	744.82	393.54	2658.36
Hengelo	132	673.26	0	805.26
Krimpen	270	482.31	78.62	830.93
Lelystad	880	808.29	1863.97	3552.26
Louwsmeer	20	216.06	113.26	349.32
Maasbracht	1545	1408.24	213.98	3167.22
Maasvlakte	2835	80.67	240.59	3156.26
Meeden	–	730.96	613.76	1344.72
Oostzaan	435	453.87	99.26	988.13
Oudehaske	–	312.30	551.08	863.38
Rilland	–	829.46	523.70	1353.16
Simonshaven	1667	598.14	778.06	3043.20
Tilburg	–	1167.65	489.17	1656.82
Vierverlaten	–	604.69	0	604.69
Vijfhuizen	–	657.77	68.90	726.67
Wateringen	97	702.09	228.97	1028.06
Weiwerd	579	24.92	339.55	943.47
Zeyerveen	–	1709.75	31.81	1741.56
Zwolle	1	1225.83	302.60	1529.44
Total	19357	24000	11700	55057

Marginal costs

Marginal costs are defined as the change of total cost when producing one more unit of energy, so one more MWh (Li et al., 2021). There is a difference between the marginal costs in the short-term and in the long-term. As in the short-term, the energy system including the infrastructure is fixed, so an additional unit of energy is based on operational costs. This is also used as the hourly energy price in real-time. Whereas in the long-term, the long term operation costs, investments and reinforcement costs are also included (Braga & Saraiva, 2005) and (Li et al., 2021). For the scope and purposes of this study, the marginal costs were focused on the short-term to best reflect the real-time price of energy. Implying that investments and a long-term vision were excluded from the prices and therefore, marginal costs.

These marginal costs were used as input for the bids in the three rounds. In the DA round, bids are solely based on the marginal costs. As in a market with perfect competition, players are incentivised to bid at their marginal costs. If they bid above their marginal costs, suppliers are likely not to be selected, causing them to lose revenue. Therefore, for fossil generators, the marginal costs are based on the fuel rate multiplied by the price. For solar and wind, availability factors are multiplied by the installed capacity and prices are assumed based on expert input as well as costs for solar and wind (Fürstenwerth et al., 2015), see Table C.5.

The assumed marginal costs shown in Table C.5, are not the actual operational costs. In reality, these values will vary between individual plants due to differences in efficiency and technology. Especially for the fossil plants, which are assumed to be similar whilst in reality they show a wide variety in performance and conditions. However, the fuel rate for conventional generators is based on Formula C.12, based on the LHV (Itard, 2024) with costs from (Investing.com, n.d.). Since 1 MWh $= 3.6$ GJ $= 3600$ MJ, the fuel rate is:

$$\text{Fuel rate } = \frac{\text{required fuel energy}}{\text{gas LHV}} = \frac{3600/\eta}{\text{LHV}_{\text{gas}}} \tag{C.12}$$

where η is electric efficiency and LHV_{gas} is the Lower Heating Value of natural gas in MJ/m^3

Assuming an efficiency of $\eta = 58\%$ and a LHV of 35 MJ/m^3, the fuel rate FR in m^3/MWh is calculated as:

$$\text{Fuel rate} = \frac{3600/0.58}{35} \approx \frac{6206.9}{35} \approx 177 \text{ m}^3/\text{MWh}. \tag{C.13}$$

For solar and wind, location-specific conditions also impact the performance such as wind resource quality or solar irradiation. However, these estimates serve as reasonable approximations for modelling purposes in the scope of this study. In addition, they reflect that wind power tends to have slightly higher marginal costs than solar. Whilst remaining within the correct order of magnitude found in literature and documentation.

Table C.5: Fuel rates, prices, and costs per technology

Technology	Fuel rate (m^3/MWh)	Price (€/m^3)	Cost (€/MWh)
Natural gas	176.885	0.37543	66.41
Solar	n/a	5	5
Wind	n/a	10	10

Number of players per station

Although capacities per generation type were first aggregated and then divided between two generators within a station. The datasets (Wikipedia, 2025) and (Rijksdienst voor Ondernemend Nederland, 2025) were also used to estimate the number of suppliers present at each station. These values are not exact as they are based on assumptions and publicly available data, but they provide a reasonable approximation of the distribution and range of market participants across stations. This number of suppliers was also applied in the PAB formula, allowing the profit margin to depend on the number of players at a node and the potential strategic market power. This does not represent the actual market, although approach serves as an indicator for adding competition and market concentration within the system.

Table C.6: Number of players per location

Location	#Players
Bergum	4
Beverwijk	19
Bleiswijk	7
Borssele	26
Boxmeer	10
Breukelen	14
Crayestein	6
Diemen	10
Dodewaard	17
Doetinchem	15
Eemshaven	21
Eindhoven	13
Ens	11
Geertruidenberg	20
Hengelo	12
Krimpen	10
Lelystad	35
Louwsmeer	7
Maasbracht	22
Maasvlakte	13
Meeden	18
Oostzaan	9
Oudehaske	6
Rilland	16
Simonshaven	31
Tilburg	17
Vierverlaten	4
Vijfhuizen	7
Wateringen	8
Weiwerd	10
Zeyerveen	10
Zwolle	14
Grand Total	**442**

C.2.3. Line capacity

In this study, the capacity of a transmission line was determined by its thermal limit. The maximum current a conductor can carry is limited by how much heat it can safely handle, which depends on the material, thickness and environmental conditions such as temperature, wind, and sunlight. This level of detail was not included in the scope of this study. Under standard conditions, the maximum apparent power transfer capability of a three-phase line can be calculated as shown in Formula C.14. The calculated S_{max} values are indicative and not the exact values, as actual capacities vary with changing weather conditions. However, for the scope and objective of this study, they provide a sufficient estimate to be used in the simulations. The values obtained are shown in Table C.7.

$$S_{\text{max}} = \sqrt{3} \cdot U \cdot I_{\text{max}} \tag{C.14}$$

where:

- S_{max} = maximum apparent power capacity of the line [MVA]
- U = nominal line-to-line voltage [kV], 380 or 220 in this simulation
- I_{max} = maximum allowable current under thermal limits [kA], obtained from TenneT

Table C.7: Transmission line capacities

Line	Capacity (MW)
Beverwijk–Oostzaan	4343.9834
Vijfhuizen–Beverwijk	3949.0758
Bleiswijk–Vijfhuizen	3949.0758
Borssele–Rilland	5265.4345
Boxmeer–Dodewaard	1892.2655
Breukelen–Diemen	2040.3559
Crayestein–Krimpen	5265.4345
Lelystad–Diemen	5265.4345
Dodewaard–Doetinchem	4080.7117
Doetinchem–Hengelo	4080.7117
Meeden–Eemshaven	5265.4345
Zwolle–Ens380	5265.4345
Geertruidenberg–Tilburg	5265.4345
Krimpen–Bleiswijk	5265.4345
Krimpen–Breukelen	1645.4483
Crayestein–Geertruidenberg	5265.4345
Krimpen–Oostzaan	1645.4483
Ens–Lelystad	5265.4345
Maasbracht–Boxmeer	1892.2655
Maasbracht–Dodewaard	1645.4483
Maasbracht–Eindhoven	5265.4345
Maasvlakte–Simonshaven	5265.4345
Diemen–Oostzaan	1974.5379
Rilland–Geertruidenberg	4080.7117
Simonshaven–Crayestein	5265.4345
Bleiswijk–Wateringen	3251.4058
Wateringen–Maasvlakte	5265.4345
Hengelo–Zwolle	4080.7117
Zwolle–Meeden	5265.4345
Zwolle–Ens220	1905.2559
Bergum–Louwsmeer	1905.2559
Louwsmeer–Oudehaske	2095.7815
Weiwerd–Meeden	1905.2559
Oudehaske–Ens	2000.5187
Weiwerd–Eemshaven	952.6279
Eemshaven–Vierverlaten	10530.8690
Vierverlaten–Zeyerveen	2095.7815
Vierverlaten–Bergum	952.6279
Tilburg–Eindhoven	5265.4345
Zwolle–Zeyerveen	2095.7815

D

Results

D.1. Research question

In addition to the tables and graphs shown in Chapter 4 where total flex costs are displayed. This appendix provides tables and graphs for the separate redispatch and imbalance rounds. Here, the KPIs: total costs, total volume, clearing price up and down are reported separately for a more detailed understanding of the models and performance.

D.1.1. Normalisation of performance indicators

The normalised scores used in this study are obtained through relative scaling of the performance indicator values to an interval between 0 and 1. This transformation removes the original units (e.g., €/MWh) and yields a dimensionless indicator that enables direct comparison across designs. The normalization is defined as follows:

$$\text{Score} = \frac{X - \text{Current}}{\text{All-in-one} - \text{Current}}, \tag{D.1}$$

where:

- X denotes the value of the performance indicator for a given design (e.g., Gross or Net),
- *Current* represents the performance of the existing market design, which is set equal to 0,
- *All-in-one* denotes the performance of the theoretical optimum, which is set equal to 1.

A score of 0 indicates performance equal to the *current* market design, while a score of 1 corresponds to the theoretical optimum. Intermediate scores represent the relative position of a design between these two extremes. For example, a normalized score of 0.23 means that the design achieves 23% of the potential improvement over the current market, leaving 77% unrealised. This approach ensures that all results are expressed on a common, dimensionless scale, thereby improving interpretability and comparability.

D.1.2. Total costs for redispatch and imbalance rounds

Figure D.1 and Figure D.3 visualise the normalised indicator scores for total costs in the redispatch and imbalance rounds. Moreover, in Table D.1 and Table D.2 the normalised scores for total costs are shown. It can be observed that during the redispatch round, only MP show the biggest decrease in costs, see Table D.1. In addition, these results indicate that all-in-one is the most efficient. Except for only MP under *Net*, were the biggest decrease is realised due to the netted volume being significantly smaller under *Net* in the redispatch round. This originates from the higher prices in the redispatch round compared to the imbalance round under *Net*. In the imbalance round, Table D.2 shows in an increase in imbalance costs under almost all scenarios. Except for only PAB under *All-in-one*, where a decrease in imbalance costs is realised. What can be concluded from these tables is that the flex designs shift costs from the redispatch round to the imbalance round and result in synergies in terms of total costs over the two flex rounds.

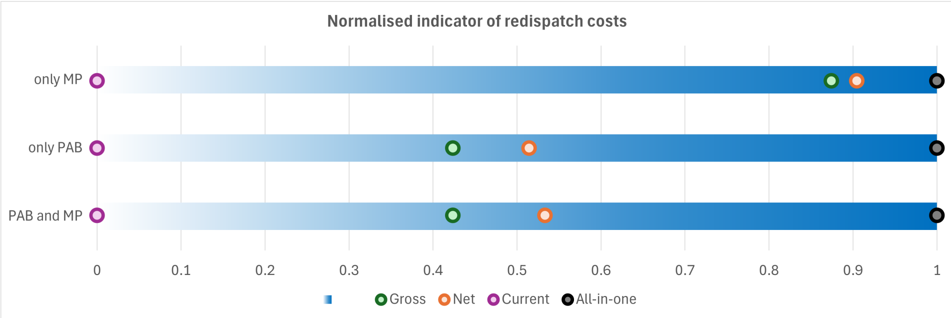

Figure D.1: Benchmark normalised total redispatch costs

Table D.1: Normalised indicator of total redispatch costs

	Current	Gross	Net	All-in-one
only MP	0.00	0.87	0.90	1.00
only PAB	0.00	0.42	0.51	1.00
PAB and MP	0.00	0.42	0.53	–

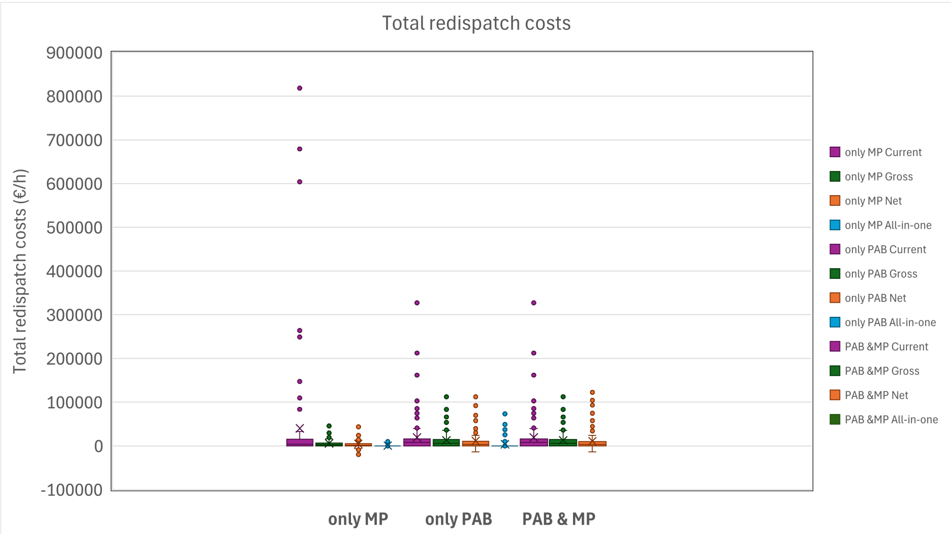

Figure D.2: Total redispatch costs

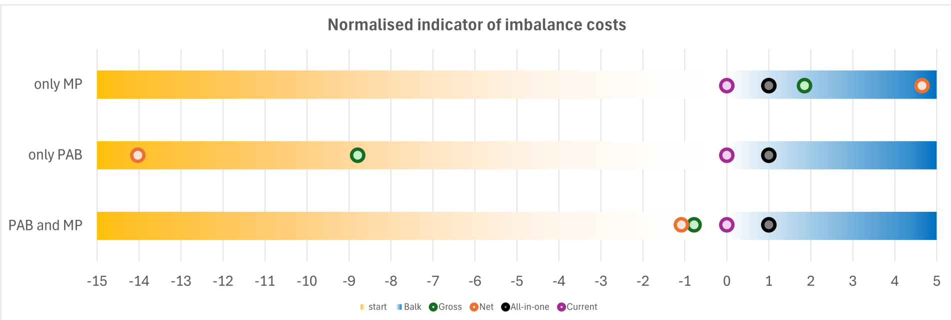

Figure D.3: Benchmark normalised total imbalance costs

Table D.2: Normalised indicator of total imbalance costs

	Current	Gross	Net	All-in-one
only MP	0.00	1.85	4.65	1.00
only PAB	0.00	-8.80	-14.03	1.00
PAB and MP	0.00	-0.78	-1.08	–

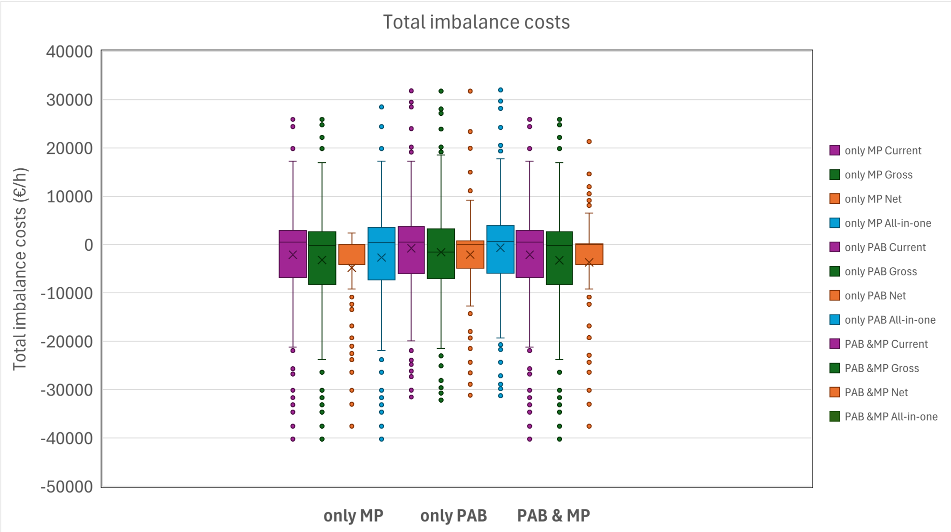

Figure D.4: Total imbalance costs

Absolute numbers

In addition to the normalised indicators, the absolute values of total costs are also reported, see Table D.3, Table D.4 and Table D.5. These values are based on the model's assumptions and should not be interpreted as exact real-world figures, but they provide a empirically grounded indication of the order of magnitude. Presenting both normalised and absolute results offers a more complete picture of the simulations and supports the interpretation of the comparative analysis.

Table D.3: Absolute total flex costs (€/h)

	Current	Gross	Net	All-in-one
only MP	38526.9	2596.1	-245.6	-1921.0
only PAB	18809.8	11326.3	9403.8	3189.5
PAB and MP	17437.9	9635.3	7467.0	–

Table D.4: Absolute total redispatch costs (€/h)

	Current	Gross	Net	All-in-one
only MP	3902686.2	557258.3	441535.5	75812.5
only PAB	1878142.4	1239259.7	1102042.1	369548.7
PAB and MP	1878142.4	1239259.7	1073612.5	–

Table D.5: Absolute total imbalance costs (€/h)

	Current	Gross	Net	All-in-one
only MP	-204105.5	-308037.4	-465110.8	-260228.3
only PAB	-72400.9	-151934.8	-199281.9	-63357.9
PAB and MP	-204105.4	-314271.6	-356777.9	–

Switching from *Current* to *Gross* or *Net* already captures a share of the potential cost savings, especially under only MP. *All-in-one* consistently outperforms the other designs, as expected due to the theoretically optimum.

D.1.3. Total volumes for redispatch and imbalance rounds

The total volume needed for redispatch and imbalance is shown per design for the different pricing mechanisms. Under pricing mechanism PAB and MP, no results for *All-in-one* were obtained due to the one step optimisation of this design.

The normalised redispatch scores in Table D.6 fall within the expected range. *Net* captured a significant of the reduction toward *All-in-one*. *Gross* remained close to the baseline and was slightly negative in only PAB and PAB & MP, a bit more volume than *Current*, which is consistent with gross settlement as opposite direction activations were not netted and additional low cost physical bids were accepted.

For the normalised imbalance scores in Table D.7, the denominator was unstable because the difference between *Current* and *All-in-one* was very small. This followed from the different determination of imbalance in *All-in-one*, with a one-step co-optimisation in which part of the net imbalance is resolved through redispatch. In addition, there was a small absolute imbalance difference resulting in a small denominator. Small denominators then generate very large scores that no longer represent a meaningful proportion.

In *Current*, imbalance could only be addressed in the imbalance round. In *All-in-one*, the imbalance volume was computed ex post from the residual mismatch after the one-step co-optimised. Because the one-step formulation made it ambiguous to attribute each unit of flexibility to a specific service, the imbalance volume was determined ex post and allocated the remaining volume to redispatch. This approach, together with the small denominator, explained the extreme normalised values for imbalance volumes.

Table D.6: Normalised indicators for redispatch volume

	Current	Gross	Net	All-in-one
only MP	0.00	0.12	0.31	1.00
only PAB	0.00	-0.07	0.13	1.00
PAB and MP	0.00	-0.07	0.18	-

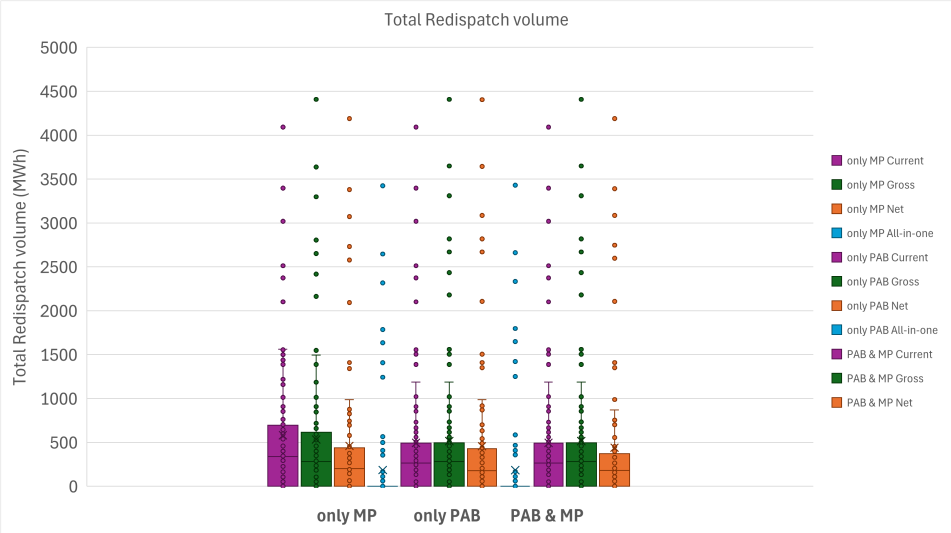

Figure D.5: Total Redispatch volume

Table D.7: Normalised indicators for imbalance volume

	Current	Gross	Net	All-in-one
only MP	0.00	-1049050.08	13990816.96	1.00
only PAB	0.00	-739907.27	5226736.17	1.00
PAB and MP	0.00	950886.17	-8822964.20	-

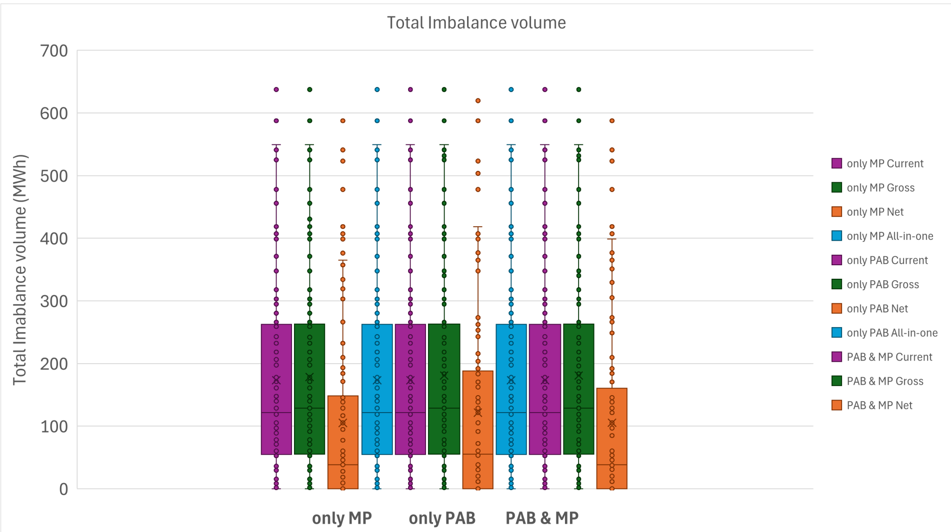

Figure D.6: Total Imbalance volume

In the redispatch round analysing only MP in (Figure D.5), *All-in-one* had the lowest average volume with a limited spread. *Net* was next with similarly low volumes. *Current* and *Gross* were comparable. In the imbalance round (Figure D.6), *Net* reported the lowest volumes with the tightest middle range, while *All-in-one* was higher and more volatile, consistent with one-step co-optimisation shifting volume from redispatch to imbalance. *Gross* was close to *Current* and slightly lower on average in redispatch. For only PAB, in redispatch, *All-in-one* again showed the lowest average and spread, followed by *Net*. *Gross* was similar to *Current* but with more extreme outliers, reflecting cost-driven acceptance of additional physical bids under gross settlement. In the imbalance round, *Net* had the smallest volumes and spread. *All-in-one* was below *Current* and *Gross* and *Gross* showed a few more outliers. Together, the figures indicated that *All-in-one* shifted volume from redispatch to imbalance, while *Net* reduces volumes through its remuneration and netting. Lastly, for PAB & MP, in redispatch, *Net* yielded the lowest average and spread, whereas *Gross* was slightly higher than *Current* and exhibited more outliers. In the imbalance round, *Net* again had the lowest volumes. *Gross* and *Current* were similar, with Gross showing somewhat more variation.

Absolute numbers

Table D.8: Absolute average flex volumes (MWh/h)

	Current	Gross	Net	All-in-one
only MP	758.1	714.1	565.9	361.4
only PAB	670.8	698.4	579.1	359.5
PAB and MP	670.8	698.4	546.3	-

Table D.9: Absolute redispatch volumes (MWh/h)

	Current	Gross	Net	All-in-one
only MP	55946.1	51228.7	44114.8	17862.0
only PAB	47561.3	49505.5	43777.5	17678.2
PAB and MP	47561.3	49505.5	42204.4	-

Table D.10: Absolute imbalance volumes (MWh/h)

	Current	Gross	Net	All-in-one
only MP	16832.0	17328.2	10214.3	16832.0
only PAB	16832.0	17542.3	11814.3	16832.0
PAB and MP	16832.0	17542.3	10241.2	-

Over all the pricing mechanisms, *All-in-one* shows the best performance in the redispatch round and *Net* in the imbalance round. *Current* and *Gross* show similar values, with sometimes a small increase in volume for *Gross* due to selecting more price efficient bids at the cost of activated volume.

D.1.4. Clearing price down and up for redispatch and imbalance rounds

Current was set to 0 (highest price) and *All-in-one* to 1 (lowest price). A higher score means a larger price reduction relative to *Current*. For down regulation this reads as a more negative price, negative scores mean prices higher than in *Current*.

For redispatch the normalised scores were given in Table D.11 and Table D.13. Both *Gross* and *Net* reduced prices relative to *Current*. For price down, the reductions were similar across the two designs. For price up, *Net* generally achieved a larger reduction.

For the normalised scores in the imbalance round, *All-in-one* again reported the lowest prices. *Gross* showed moderate reductions. *Net* aligned with *Gross* under only PAB and PAB & MP, but under only MP scores turned negative. This followed from netting and the reallocation of volumes between rounds: the priced quantity in the imbalance round could shift relative to *Current*, moving the marginal accepted bid along the merit order.

Table D.11: Normalised scores of redispatch clearing price down

	Current	Gross	Net	All-in-one
only MP	0.00	0.71	0.65	1.00
only PAB	0.00	0.63	0.63	1.00
PAB and MP	0.00	0.41	0.41	-

Table D.12: Normalised scores of imbalance clearing price down

	Current	Gross	Net	All-in-one
only MP	0.00	0.47	-0.53	1.00
only PAB	0.00	0.89	0.89	1.00
PAB and MP	0.00	0.72	0.72	1.00

Table D.13: Normalised scores of redispatch clearing price up

	Current	Gross	Net	All-in-one
only MP	0.00	0.51	0.78	1.00
only PAB	0.00	0.48	0.48	1.00
PAB and MP	0.00	0.48	0.48	-

Table D.14: Normalised scores of imbalance clearing price up

	Current	Gross	Net	All-in-one
only MP	0.00	-0.05	-1.11	1.00
only PAB	0.00	-0.04	-0.04	1.00
PAB and MP	0.00	-0.03	-0.03	1.00

Absolute numbers

The absolute numbers were presented below in addition to the normalised scores. For redispatch clearing price down in Table D.17, *All-in-one* was most negative, with *Gross* and *Net* close by, under only PAB and PAB & MP, *Gross* and *Net* were equal. For redispatch price up in Table D.18, *All-in-one* was the lowest in all reported simulations. *Net* was lower than *Gross* under only MP, while *Gross* and *Net* were equal under only PAB and PAB & MP. These patterns were consistent with moving further along the merit order as volumes changed.

In the imbalance round, clearing price down in Table D.19, *All-in-one* again reached the most negative levels, with *Net* often close under only MP. For the imbalance price up in Table D.20, the pattern was mixed: under only MP and only PAB, *All-in-one* was priced higher than in *Current*, while *Net* was lowest under only MP. This reflected that, after one-step co-optimisation, the remaining upward requirement was concentrated at more expensive locations, so the marginal accepted bid could lie above the *Current* benchmark even though total volumes are lower. This also originated from the one-step co-optimisation and allocating the flex volume used to imbalance and redispatch volumes, with prices in round Flex being more expensive than in round Flex2.

Table D.15: Absolute flex clearing price down (€/MWh)

	Current	Gross	Net	All-in-one
only MP	-25.3	-32.7	-28.1	-37.1
only PAB	-17.9	-25.4	-25.4	-28.6
PAB and MP	-20.8	-28.8	-28.8	-

Table D.16: Absolute flex clearing price up (€/MWh)

	Current	Gross	Net	All-in-one
only MP	48.0	38.4	29.1	34.0
only PAB	59.1	48.2	48.2	41.7
PAB and MP	56.2	45.2	45.2	-

Table D.17: Absolute redispatch clearing price down (€/MWh)

	Current	Gross	Net	All-in-one
only MP	-21.8	-32.7	-31.7	-37.1
only PAB	-12.7	-22.8	-22.8	-28.6
PAB and MP	-12.7	-22.8	-22.8	-

Table D.18: Absolute redispatch clearing price up (€/MWh)

	Current	Gross	Net	All-in-one
only MP	70.3	51.6	41.8	34.0
only PAB	86.9	65.3	65.3	41.7
PAB and MP	86.9	65.3	65.3	-

Table D.19: Absolute imbalance clearing price down (€/MWh)

	Current	Gross	Net	All-in-one
only MP	-28.9	-32.7	-24.5	-37.1
only PAB	-23.1	-28.0	-28.0	-28.6
PAB and MP	-28.9	-34.8	-34.8	-

Table D.20: Absolute imbalance clearing price up (€/MWh)

	Current	Gross	Net	All-in-one
only MP	25.6	25.2	16.4	34.0
only PAB	31.4	31.0	31.0	41.7
PAB and MP	25.6	25.2	25.2	-

D.2. Line limitations

In the following section, the figures show the performance of the four designs under the three different pricing mechanisms for the different line limitation values. With lower values for line limitations, decreasing the capacity of the lines.

D.2.1. Costs

Figure D.7 shows that line limitations result in a strong increase of redispatch costs, especially under only MP. Under only PAB and PAB & MP also show an increase in costs, but more moderate. *Net* outperforms *Gross* and *Current* under all pricing mechanisms, indicating a more efficient distribution of redispatch volumes under limited transport capacity. The result of *Gross* under only MP with line limitations 0.4 shows unexpected behaviour and might originate from an error. The costs for the imbalance round are displayed in Figure D.8. Imbalance costs remain negative, again this is not revenue, but their range varies. *Net* reports the most negative costs, especially under only MP and only PAB, originating from the remuneration of netted volumes. Under stricter line limitations, the differences between designs increase. PAB and MP shows more stable and less extreme values. This suggests that designs with more efficient allocation are less sensitive to congestion effects on the balancing market.

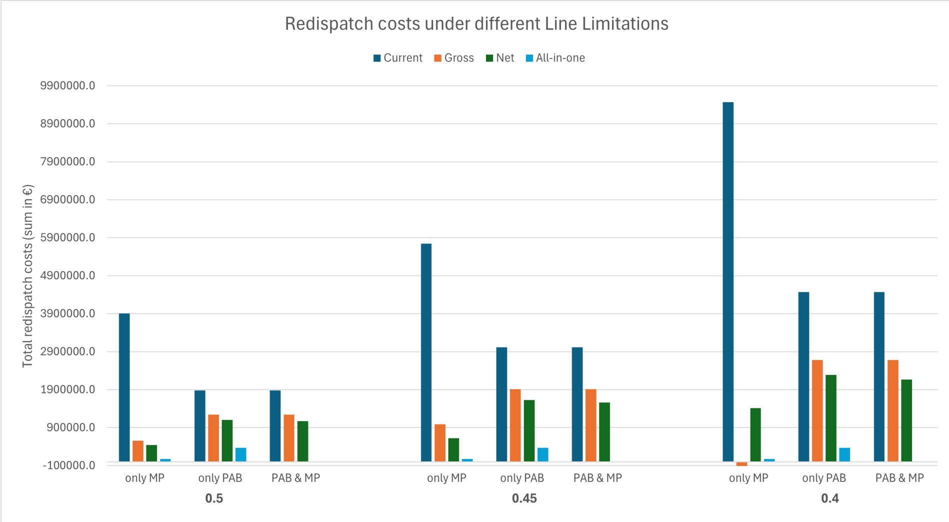

Figure D.7: Line limitations: Total Redispatch Costs

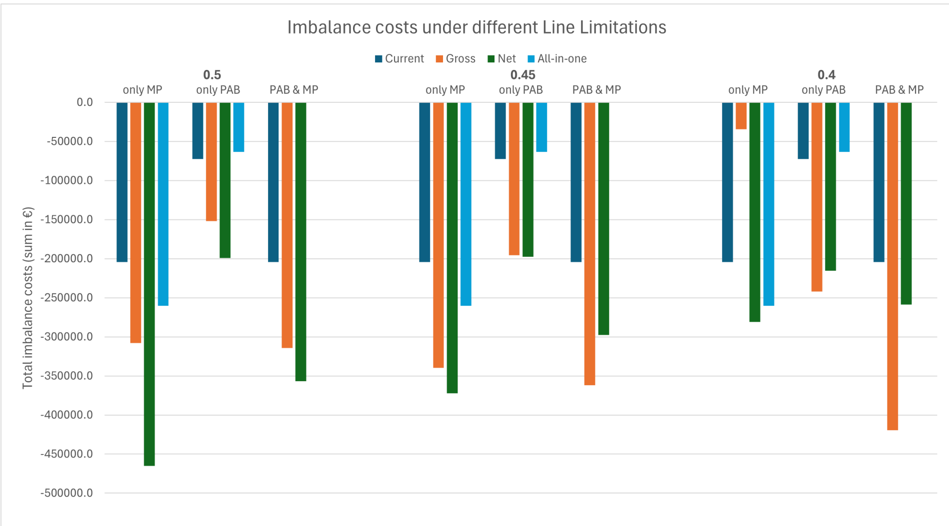

Figure D.8: Line limitations: Total Imbalance Costs

D.2.2. Volumes

Figure 4.10 shows that in the redispatch round, volumes increase as line limits become stricter, since more congestion is created. The difference between market designs is small between 0.5 and 0.45, but increases strongly under 0.4, where only MP reports the highest volumes. Again the redispatch volume under only MP and 0.4 shows low values, likely originating from an error mentioned before. Analysing the imbalance round, Figure D.10 shows that under 0.5 and 0.45 volumes remain stable, but increases under the strictest limitation of 0.4. *Net* reports the lowest imbalance volumes, with *All-in-one* showing higher imbalance volumes but lower redispatch volumes than *Net*.

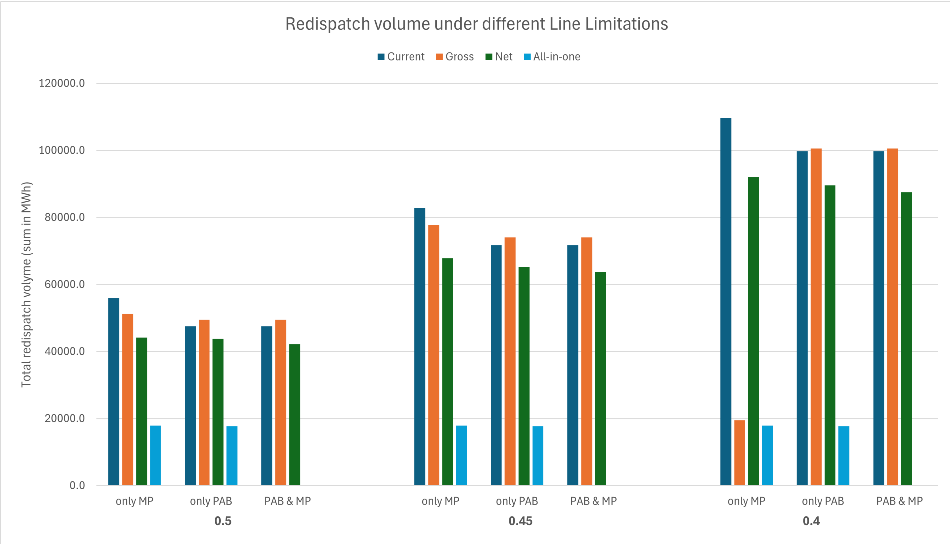

Figure D.9: Line limitations: Total Redispatch Volume

Figure D.10: Line limitations: Total Imbalance Volume