Assessment of Potential Social Welfare generated by Combining or Coordinating Portfolio-Based Markets for Scheduled Energy and Balancing Capacity

Report

commissioned by

Amprion GmbH on behalf of EPEX SPOT SE,
50Hertz Transmission GmbH, TenneT TSO GmbH
and TransnetBW GmbH

21th July 2025

IAEW | RWTH AACHEN UNIVERSITY

consentec

Assessment of Potential Social Welfare generated by Combining or Coordinating Portfolio-Based Markets for Scheduled Energy and Balancing Capacity

Report

commissioned by

Amprion GmbH on behalf of EPEX SPOT SE,
50Hertz Transmission GmbH, TenneT TSO GmbH
and TransnetBW GmbH

21th July 2025

Consentec GmbH

Grüner Weg 1
52070 Aachen
Deutschland
Tel. +49 (2 41) 93 83 6-0
E-Mail: info@consentec.de
https://www.consentec.de

In cooperation with:

Institut für Elektrische Anlagen und Netze, Digitalisierung und Energiewirtschaft (IAEW) der RWTH Aachen University
Lehrstuhl für Übertragungsnetze und Energiewirtschaft
Univ.-Prof. Dr.-Ing. A. Moser
Schinkelstraße 6, 52062 Aachen
Deutschland
https://www.iaew.rwth-aachen.de

Contents

Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
BC	Balancing capacity
BE	Balancing energy
CO	Co-optimization
CZC	Cross-zonal capacity
CZCA	Cross-zonal capacity allocation
DA	Day-ahead
DSR	Demand-side response
ERAA	European Resource Adequacy Assessment
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FBMC	Flow-based market coupling
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
GLEB	Guideline Electricity Balancing
ID	Intraday
MBO	Market-based optimization
mFRR	Manual Frequency Restoration Reserve
minRAM	Minimum Remaining Available Margin
MTU	Market Time Unit
NEMO	Nominated electricity market operator
RES	Renewable energy sources
RR	Replacement Reserve
SDAC	Single day-ahead coupling
SE	Scheduled energy
TSO	Transmission system operator

1 Introduction

For the stable operation of the power supply system, a continuously balanced power ratio between the energy supplied and consumed is essential. Since this balance is subject to fluctuations on both the generation and consumption sides, it must be continuously monitored and corrected as necessary. To achieve this, the transmission system operators (TSOs) responsible for reliable system operation provide the service of load-frequency control. This includes maintaining and deploying at least three types of reserves: frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), and manual frequency restoration reserve (mFRR).

Other than markets for scheduled energy (SE), where the establishment of cross-border co-operation and efficient coupling of domestic markets has been a major focus of EU energy policy and legislation for more than two decades, markets for balancing capacity and balancing energy have been dominantly organized on Member State level for a long time.

This only changed at the end of 2017 when the Regulation (EU) 2017/2195, commonly referred to as the Guideline on Electricity Balancing (GLEB), was published in the Official Journal of the European Union. This guideline aims to establish a functioning and liquid market for frequency control and control reserves. It sets direct requirements for the balancing and reserve energy systems that member states must implement.

Triggered in part by the guideline, there are currently many national and international developments in this area. First efforts were concentrated on cross-border markets for balancing energy (BE), such as the international platforms PICASSO and MARI for cross-border exchange and retrieval of balancing energy, and the introduction of the target market design. The implementation of cross-border balancing energy markets benefits from the fact that they do not have to "compete" with other electricity market segments for the use of scarce transmission capacity but can work with the capacity remaining/available after closure of SE markets/in real-time. This is different for balancing capacity (BC) markets which take place before or parallel to SE markets. Therefore, ongoing discussion frequently addresses the appropriate management of limited cross-zonal capacity (CZC).

The GLEB outlines several potential approaches to managing limited transmission capacity in the future, among them probabilistic and market-based method and co-optimization. Whereas the probabilistic method aims at determining available CZC for balancing capacity based on a statistic analysis of historic data, the market-based optimization (MBO) and co-optimization aim at allocating capacity to both market segments based on actual bids (or forecasts in the case of MBO). The difference is that the market-based method includes this allocation in BC markets where opportunity costs resulting from bidding in subsequent markets are considered based on (naturally uncertain) forecasts. Co-optimization, instead, means a full coupling and simultaneous clearing of BC and SE markets, thus minimizing these uncertainties.

One of the first applications of a cross-zonal market for balancing capacity is the balancing co-operation initiative ALPACA (“Allocation of Cross-zonal Capacity and Procurement of aFRR Co-operation Agreement”). Here, the TSOs of Germany, Austria, and the Czech Republic aim to achieve welfare gains by more efficiently procuring balancing reserves. Initially, the probabilistic method will be used to ensure the availability of cross-zonal capacity. This method is planned to be replaced by the market-based method at a later stage.

As long-term solutions, currently market-based optimization and co-optimization (CO) are considered the most suitable.[1] Recently, ACER (Agency for the Cooperation of Energy Regulators) published a study conducted by NTUA and UC Louvain quantifying welfare gains from the introduction of those methods. [2] The study concludes that CO is by far superior to MBM, resulting in welfare gains of EUR 678 million p.a. for the CORE region, with MBM capturing EUR 84 million p.a. only.

This study provides a quantitative assessment evaluating different approaches of CZCA the NTUA/UC Louvain study. A key distinction lies in the choice of case study: this study employs a 2030 scenario to reflect expected developments in the energy system while the NTUA/UC Louvain analysis is based on historical data. Another key factor investigated is the level of bid submission coordination between the SE and BC markets and the forecasting methodology. By modelling the cases of both complete and no coordination, the quantitative assessment identifies the bandwidth of potential cost savings for CO compared to the Status Quo, highlighting the sensitivity of results to assumptions about market coordination. In addition to the quantitative analyses, this study considers additional effects (including additional non-quantifiable impacts on social welfare) resulting from the approaches for allocating limited cross-zonal capacity. To fully evaluate the different CZCA approaches, those effects must also be included in the evaluation, as most of those aspects cannot be captured by the simulations or can only be captured partly. Accordingly, a qualitative assessment complements the quantitative findings so that the welfare gains from the simulations can be contextualized and effects on these welfare gains that cannot be reflected in the models are considered when discussing different approaches of CZCA.

Chapter 2 of this study quantitatively assesses the social welfare effects of cross-zonal capacity allocation (CZCA) for BC in general and co-optimization in particular by means of energy system modeling. It focuses on a realistic approximation of welfare gains which requires a reasonable modeling of the reference/status quo scenario as well as the different CZCA methods. Chapter 3 adds to these findings, by discussing qualitatively potential consequences of co-optimization which go beyond what can be assessed by means of energy system models. These include an extensive discussion on the practical questions that arise from the introduction of a new CZCA mechanism and the implementation effort to do so.

[1] In referring to the NTUA/UC Louvain study, this study focusses on the comparison between CO and MBO, while the probabilistic method (ProbM) is not the focus.

[2] NTUA/UC Louvain study on "Welfare Benefits of Co-Optimising Energy and Reserves". *https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_Cooptimisation_Benefits_Study_2024.pdf*

2 Quantitative Assessment

2.1 Context and Goal

Recently, ACER published a study conducted by NTUA and UC Louvain quantifying welfare gains from the introduction of co-optimization (*CO*) or market-based optimization (*MBO*). The study concludes that *CO* is by far superior to *MBO*. This result, however, may be largely driven by the chosen modelling approach and assumptions. The impact of these choices on the result is not further assessed in the study. Specifically, the following assumptions may play a critical role in shaping the results:

- **Lack of bid submission coordination between markets for SE and BC in *Status Quo* and *MBO***: The study employs a unit commitment model in which, for the *Status Quo* and *MBO* scenarios, SE and BC markets are assumed to clear sequentially. Specifically, the BC market outcome is fixed in an initial step and cannot be adjusted thereafter. In practice, particularly in European markets, market participants retain the ability to modify the schedules of individual portfolio assets, allowing for some degree of portfolio optimization between the two markets even after market clearing. As a result, this assumption likely leads to an underestimation of the efficiency of the *Status Quo* and *MBO*.
- **Simplified price forecasting method in *Status Quo* and *MBO*:** The study employs a basic price forecasting approach in which the expected price difference between a given day and the preceding day of the same type is used, with independent Gaussian errors added. This method is relatively simplistic, whereas real-world forecasting techniques may achieve greater accuracy. Consequently, this assumption likely contributes to an underestimation of the efficiency of the *Status Quo* and *MBO* as well.
- **Historical case study:** The study assesses welfare gains based on a case study of the CORE region, using data from the years 2020 to 2023. Due to the significant role of thermal power plants in this case study, their fixed costs and technical minima are identified as key drivers of efficiency gains in *CO*. However, in the future, the influence of thermal power plants—particularly in BC markets—is expected to decline, while emerging technologies such as battery storages, which are not considered in the NTUA/ UC Louvain study, will play a more prominent role. These assumptions may significantly shape the study's outcome, but since the introduction of *CO* and *MBO* is being evaluated for future implementation, their impact may diminish over time.

The objective of this study is to conduct a detailed assessment of the social welfare effects of different approaches to CZCA through quantitative modelling. In doing so, alternative modelling assumptions to those in the NTUA/ UC Louvain study are adopted to analyze the impact of these assumptions on the results.

2.2 Methodology

The alternative approaches for CZCA influence the SE and the BC market as the available CZC for the exchange of SE or BC is divided differently between the markets. With regards to the *Status Quo* this implies that the available CZC is exclusively utilized for the exchange of SE as no exchange of BC is possible. In both other cases, BC can be exchanged and thus the corresponding CZC needs to be allocated to assure its secure availability in case the exchanged BC is activated. This results in competition for the limited CZC between the SE and the BC markets. To address this issue, *CO* and *MBO* employ different methods for the allocation of CZC.

According to EB Regulation, the allocation of CZC should be based on the market value of the CZC. The market value of CZC represents the economic added value of the exchange of SE or BC. Figure 2.1 illustrates an optimal allocation of transmission capacity with the CZC market value for the exchange of SE and the CZC market value for the exchange of BC being equal (this case is called pareto optimum). To achieve the pareto optimum, however, both CZC market values need to be known for the allocation of CZC.

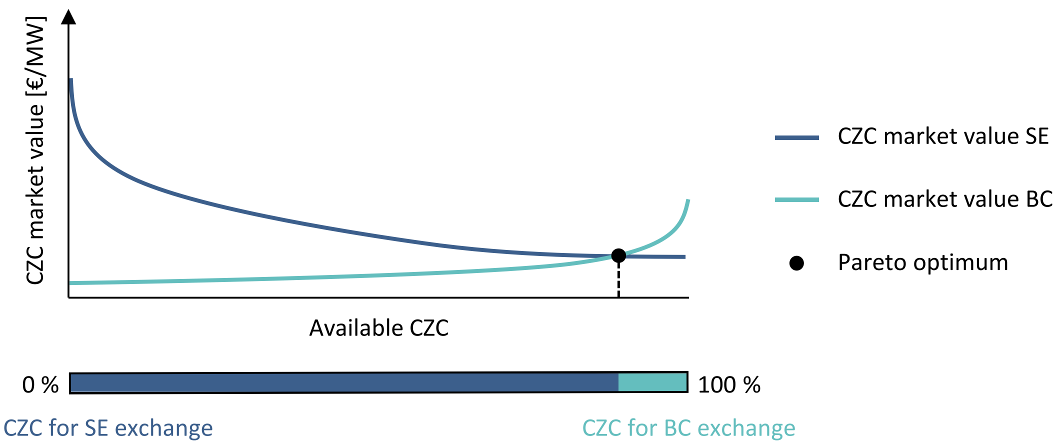

Figure 2.1 Comparison of CZC market values for CZCA

In most European countries, BC is procured prior to the market clearing of the day-ahead market. Consequently, the actual market value of CZC for SE is not known during the market clearing of BC and thus not available for the CZCA. In order to execute the CZCA anyway without changing the current market design, specifically the gate closure times, it is necessary to forecast the market value of the CZC for SE. This is done in the *MBO* approach.

The *CO* approach implies simultaneous market clearing in contrast to sequential market clearing. Through simultaneous market clearing, both market values are known at the point in time of CZCA and can be utilized. By comparing the actual market values for CZC, in theory the pareto optimum is reached with this method. In simulative investigations, where theoretical assumptions such as perfect foresight, perfect competition, and truthful bidding generally apply, this theoretical optimum can indeed be achieved. However, in practical settings, these assumptions often do not hold due to strategic bidding behavior, market imperfections, and technical constraints. Despite this, simulations cannot fully capture the complexity of real-world conditions, and thus *CO* is best represented under idealized assumptions within the simulation framework.

Even though gate closure times for the SE and BC market are not simultaneous in European markets, a certain coordination between both markets exists through the portfolio-based market design. Market participants can still change the schedules of their individual portfolio assets and therefore optimize their portfolio between both markets, even after market clearing.

To realistically compare *CO* to *MBO* and the *Status Quo*, this partial coordination in bid submission enabled by portfolio-based bidding would need to be modelled for *MBO* and *Status Quo*. However, due to the lack of publicly available information on portfolio structures in Europe, this is not feasible. Assuming limited coordination, as done in the NTUA/UC Louvain study, leads to underestimating the efficiency of *MBO* and *Status Quo*.

To address this, two extremes of bid submission coordination are modelled in this study: complete coordination, and no coordination. These extremes intend to bracket the range of possible real-world market outcomes.

In the *completely coordinated* approach, the two markets are simulated in such a way as if all units across a bidding zone were optimized jointly within one single portfolio (cf. left side of Figure 2.2). While the real markets clear sequentially, this approach reflects a situation of full coordination in which portfolio operators can align their bids across both markets and adjust dispatch accordingly. This represents a best-case scenario in terms of efficiency from bid submission coordination and provides an upper bound for the efficiency of *MBO* and *Status Quo*.

In the *non-coordinated* approach, the BC and SE markets are simulated sequentially, and no bid submission coordination is assumed. Each unit is treated as belonging to a separate portfolio (cf. right sight of Figure 2.2), assuming that bids directly reflect the final dispatch. This may provide a lower bound for the efficiency of *MBO* and *Status Quo*.

In reality, partial bid submission coordination exists: portfolios allow for coordination within groups of units, but not across the entire system (cf. middle of Figure 2.2). Accordingly, actual market behavior is expected to fall between the two extremes. Section 3.2.3 provides an expert-based assessment on the level of coordination in the current power system. By modeling the two extreme cases, this study provides a plausible range — or bandwidth—within which real-world outcomes likely lie, thereby offering insights into the efficiency implications of different levels of coordination.

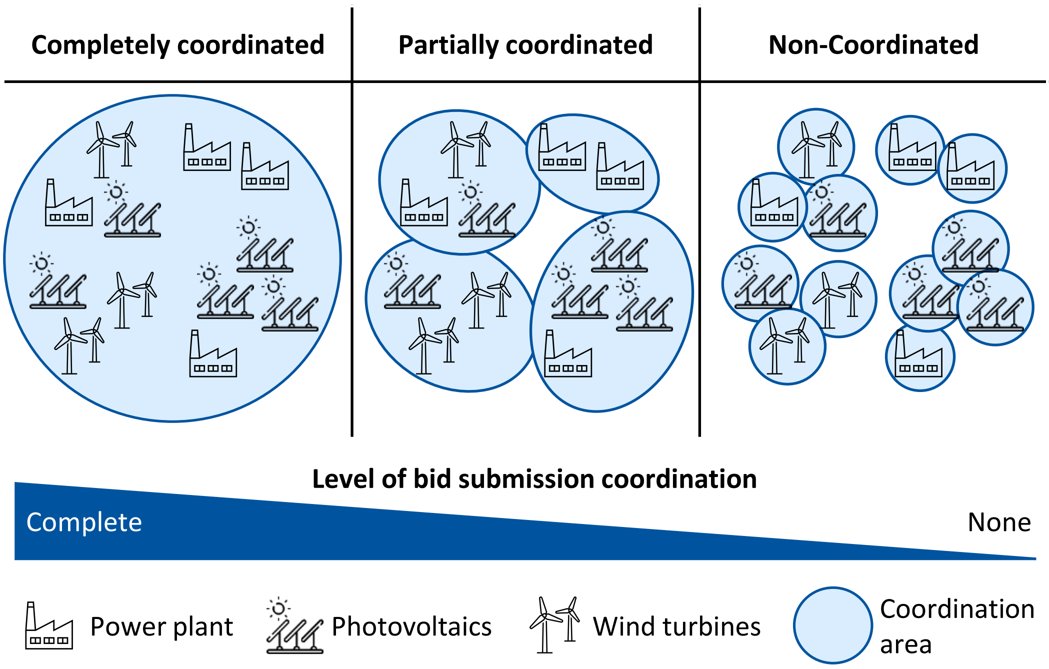

Figure 2.2 Different levels of bid submission coordination

As a result of the differentiation between the different CZCA approaches and between the *completely coordinated* and the *non-coordinated* approach, five different simulations are performed as part of this study. Figure 2.3 shows an overview of the simulations. As a first step, the three different CZCA approaches are compared to each other under the completely coordinated approach. Accordingly, the BC and SE markets are optimized in a joint simulation. In the second step, the *Status Quo* and the *MBO* are also assessed, assuming no coordination in the bid submission and thus a sequential optimization is performed (cf. Figure 2.3). The different steps of the methodology are described in section 2.2.1. The various simulations are outlined in sections 2.2.2 and 2.2.3.

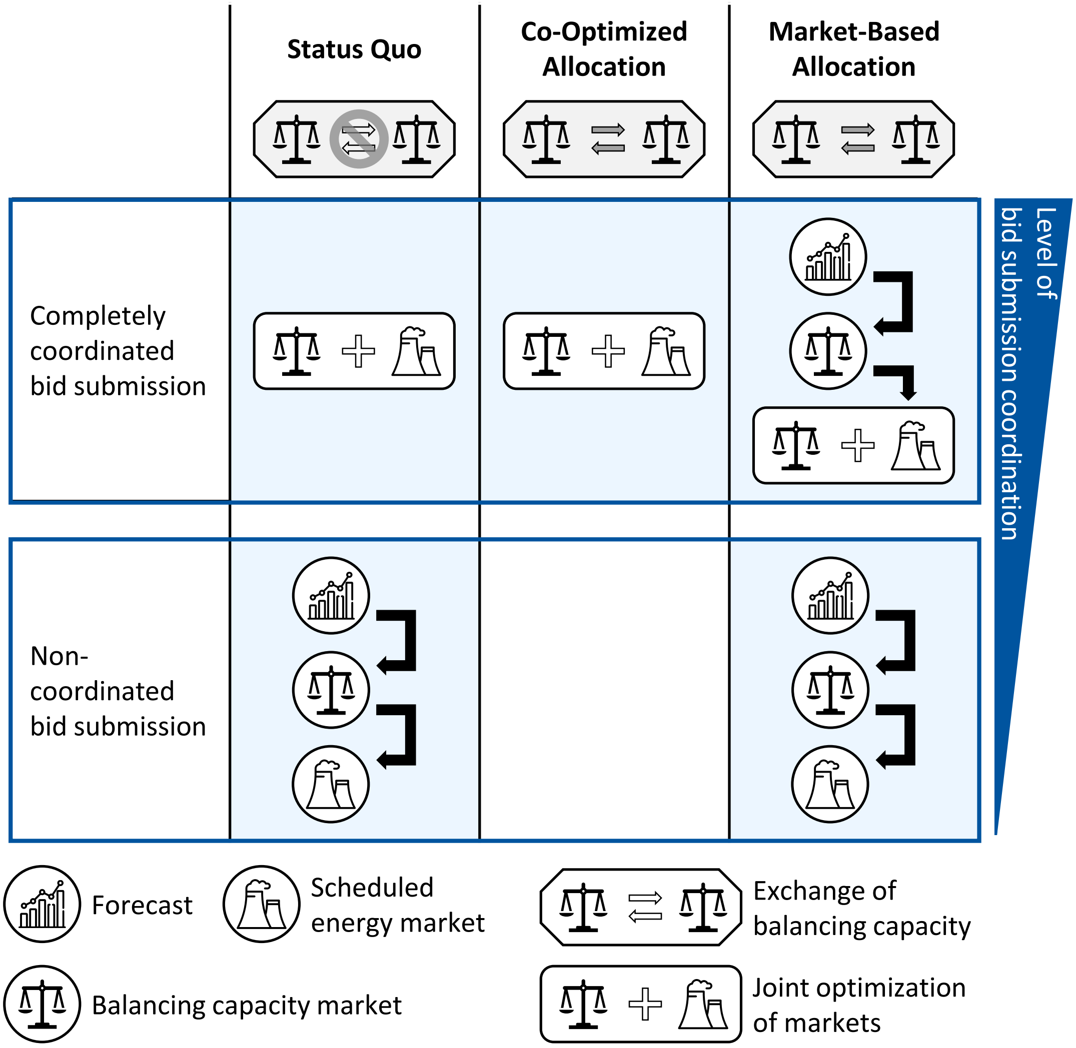

Figure 2.3 Overview of performed simulations

2.2.1 Market Optimization and Price Forecast

Scheduled Energy and Balancing Capacity Market Optimization

The joint optimization of the markets, representing the complete coordination of bid submission of all generation units in a bidding zone, determines the cost-minimal coverage of the demand for SE and BC requirements while considering the costs for electricity generation. For BC, the primary focus is on the markets for Frequency Restoration Reserve (FRR). Frequency Containment Reserve (FCR) is included in the market model but not emphasized, while Replacement Reserve (RR) is not considered in the market model. aFRR and mFRR are considered as separate products. The joint simulation determines the dispatch of generation units, storages and demand-side response (DSR) units, BC provision of each unit, SE exchange, BC exchange, renewables curtailment and energy or BC not served in each bidding zone in hourly resolution. The market simulation model includes linear unit commitment constraints that account for minimum up and down times, minimum load and power plant outages.

When both markets are simulated sequentially, the set of fixed input data, optimization variables and constraints changes compared to the joint simulation.

When simulating only the BC market, variables and constraints inherent to the SE market are not incorporated. However, opportunity costs based on the forecasted electricity prices are considered in the objective function for each unit that can deliver FRR. Section A.2.3 of the annex describes the opportunity costs. Furthermore, in the case of permitted BC exchange, this exchange is priced with the forecasted market value of CZC for SE exchange to consider the possibility of SE exchange in concurrence with BC exchange. This ensures that BC is only exchanged if the added value is greater than the added value for the exchange of SE. The results of the optimization include the BC provision of all units, the CZCA for the balancing market, the BC exchange (if permitted) and BC not served in each bidding zone in hourly resolution.

If only simulating the SE market, BC provision resulting from prior BC market optimization is fixed for all units. For the *MBO* approach, the CZCA from the BC market is part of the input data and the exchange of SE is limited on this basis. The results of the optimization include the dispatch of generation units, storages and DSR units, the SE exchange, renewables curtailment and energy not served in each bidding zone in hourly resolution.

A detailed description of the models is provided in Annex A.2.

Price and CZC Market Value Forecast

When applying *MBO* or the *non-coordinated* approach a forecast of the SE market prices and market value of CZC for the SE market is necessary. The forecast method is based on a collection of data of historic forecast errors for renewable energy generation and electrical load. Based on publicly available data (smard.de) on day-ahead forecasts for Germany, a probability distribution for forecast errors for photovoltaics, wind, other renewables and load is determined. On the assumption that relative forecast accuracy remains the same in the future, the probability distributions are used to draw normally distributed relative forecast errors for each renewable energy source and load for each simulation time step. The moving average is implemented for the purpose of autocorrelation, and the correlation between error time series is established via a Cholesky transformation. The forecast errors are finally added to the scenario time series to generate forecasted time series for RES generation and load. With the forecasted time series, a market simulation with joint optimization without BC exchange is carried out. The resulting dual variables of the load coverage restriction correspond to the forecasted electricity prices. The market value for CZC corresponds to the value of the dual variable of the flow-based constraint of each line. Since the simulation with the forecasted time series does not allow for BC exchange, the market value for CZC is determined for the case that the full CZC is available for the exchange of SE. The forecast method is used for both the electricity prices and the CZC market values. Furthermore, it is assumed that all market participants have the same price forecast and only one price for each bidding zone is forecasted.

Balancing Energy Market Optimization

A separate optimization of the balancing energy (BE) market is done as a last step, to estimate the costs for BE activation. The BE market optimization is based on the market results of SE and BC markets. It is assumed that all resources including units and available CZC that are not used for SE can be used for BE. This means that units which did not participate in the BC market can still participate in the BE market. The costs for BE are based on the electricity generation costs or its potential savings in case of activation. For thermal power plants, this results in positive BE costs being the electricity generation costs and negative BE costs being the saving of electricity generation costs. Based on the costs of all units, a BE merit order for all BC products and directions can be derived. In accordance with the principle of merit order, it can be deduced that the lower the balancing energy price, the higher the activation probability. A frequency distribution is derived from historical data of BE activations, representing the historical activation frequency of a certain percentage of the reserve requirement. In order to determine the average costs for BE activation, the costs of each unit in the BE merit order are multiplied with the relative frequency of activation of the corresponding share of the requirement. To determine the assessed yearly costs for BE the sum over all units in the merit order and all time-steps is calculated.

2.2.2 Completely coordinated bid submission

Considering the completely coordinated bid submission in the simulation, all three CZCA approaches are modelled.

To model the *Status Quo*, a joint simulation of the SE and BC market is executed without the possibility to exchange BC. Thus, all the available CZC can be used for the exchange of SE.

CO and the *Status Quo* only differ in the possibility to exchange BC in the market simulation. By using the joint simulation (cf. 2.2.1), the BC and SE market both compete for the limited available CZC, and the allocation is based on the market values for CZC, implicitly derived in the market simulation.

The modelling of the *MBO* contains three steps:

Firstly, forecasting of the SE market in order to determine the opportunity costs for the provision of BC and CZC market values for SE (cf. 0).

Secondly, simulating the BC market (cf. 2.2.1) thus determining the CZCA for the exchange of BC based on the forecast from the first step.

Thirdly, CZCA is fixed implying that the CZC available for the SE market is reduced. A joint simulation of both markets is carried out to obtain the final dispatch and BC provision, as well as the final cross-zonal trade of the SE market.

2.2.3 Non-coordinated bid submission

When assuming no coordination in the bid submission process, the BC and SE markets have to be simulated separately.

Given the *Status Quo*, forecasting SE market prices is the first step to subsequently determine the opportunity costs for providing BC. This is followed by the simulation of the BC market, which defines the BC provision by all units, with no exchange of BC allowed. In this simulation, the forecasted opportunity costs for BC provision are considered. However, for hydro storage and battery units, the forecasted SE market dispatch – rather than opportunity costs – acts as a constraint on BC provision. Once the outcome of the preceding market is determined, it is fixed for all units and remains unchanged in the subsequent market. The subsequent market is the SE market having the full CZC available for the exchange of SE. The dispatch of generation units and the cross-zonal exchange of SE are results of the final market simulation.

In contrast, *MBO* allows the exchange of BC and therefore the CZC has to be split between both markets. Hence, when simulating the BC market, the CZCA is conducted simultaneously, based on the results of the SE market forecast, as in the *MBO* with complete coordination. The difference is that the result of the BC market is held constant and includes not only the CZCA but also the BC provision. In the following SE market simulation, the CZC available for the exchange of SE is reduced and the dispatch of generation units and the cross-zonal exchange of SE are determined accordingly.

2.3 Welfare Effects of Combining or Coordinating Portfolio-Based Markets for Scheduled Energy and Balancing Capacity

The methodology is applied to a case study of the 2030 European electricity market. Section 2.3.1 outlines the scenario framework based on the ERAA 2023 scenario, along with the data and assumptions utilized. Sections 2.3.2 to 2.3.5 present the results of the different approaches and provide a comparative analysis of the welfare effects.

2.3.1 Scenario Framework

The scenario data for the 2030 case study is derived from the openly available European Resource Adequacy Assessment (ERAA) 2023[3], published by ENTSO-E. The modeled countries are shown in Figure 2.4. Balancing capacity exchange is only considered for the CORE region.

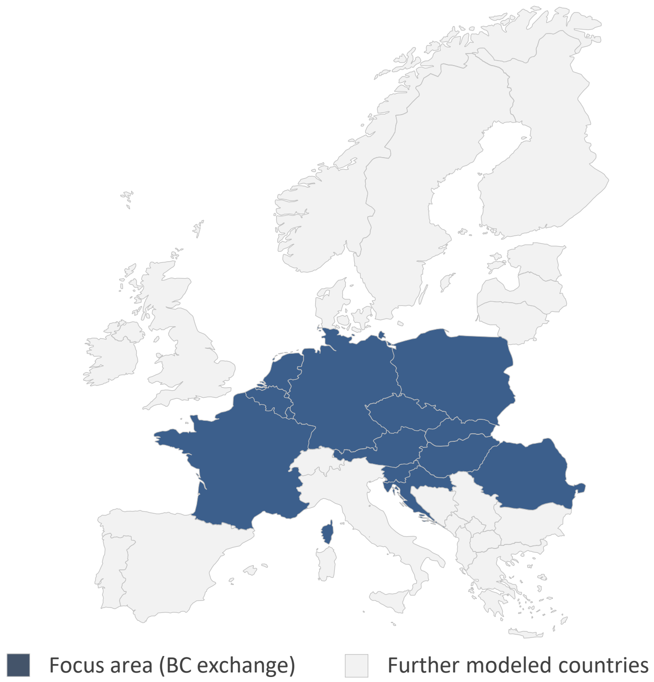

Figure 2.4 Countries included in the market model (blue and gray) and countries for which BC exchange is investigated (blue)

This scenario aligns with the European objective of reducing emissions by 55% by 2030. The scenario data used from ERAA 2023 includes installed capacities by fuel type and renewable energy sources (RES), feed-in timeseries for RES, annual electricity demand and load time series, installed flexibility capacities, as well as key technical and economic parameters (e.g. fuel prices). The time series for RES and load are based on meteorological data from the year 2012. Figure 2.5 illustrates the installed generation capacities for all bidding zones in the CORE region. Since this study does not focus on resource adequacy, as the ERAA does, the installed capacities of

[3] ENTSO-E - European Resource Adequacy Assessment 2023 Edition

gas-fired generation units in the German, Danish, and Belgian bidding zones are expanded based on the results of the Economic Viability Assessment from the ERAA 2023.

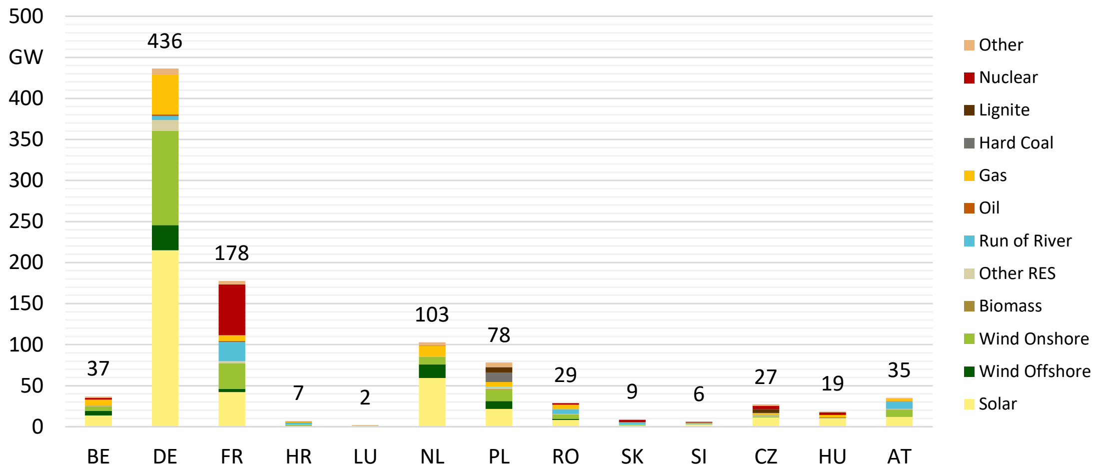

Figure 2.5 Installed capacities per country in the CORE region in the 2030 scenario

Figure 2.6 shows the installed capacities of flexibilities in each country of the CORE region.

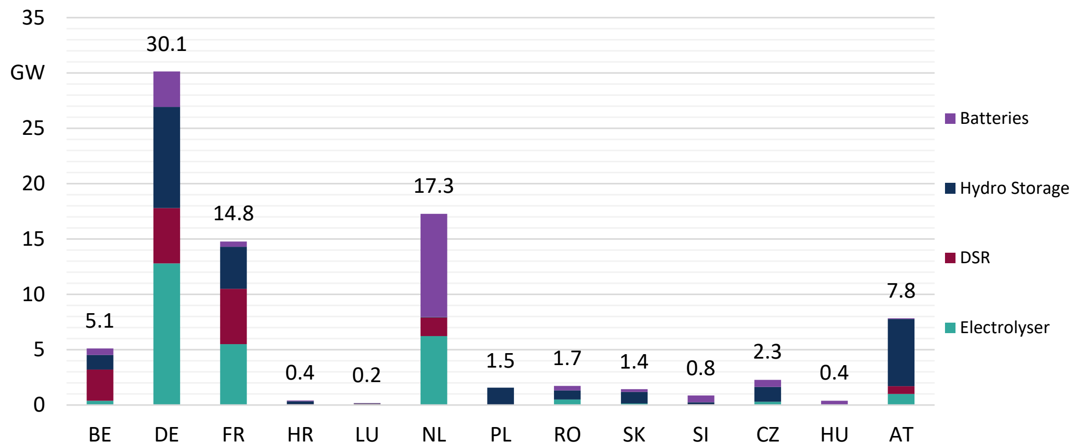

Figure 2.6 Installed capacities of flexibilities in the CORE region in the 2030 scenario

The IAEW maintains a comprehensive generation unit database that combines publicly available and non-public sources and contains information on thermal and hydroelectric generation units with a capacity exceeding 10 MW. The database is regularly updated and adjusted to align with the underlying scenario data. To achieve the required installed capacities of the scenario, an addition and removal heuristic developed by IAEW is applied. Furthermore, to account for planned and unplanned power plant outages, an existing IAEW model[4] is adapted to meet the parameters defined within the ERAA framework.

An independent determination of flow-based market coupling (FBMC) parameters was done for the case study. To derive suitable FBMC parameters, the national installed capacities are

[4] K. Pacco, "Einfluss unterschiedlicher Ansätze zur Generierung von Ausfallzeitreihen auf die Kenngrößen zur Resource Adequacy", 2024, *https://www.tugraz.at/fileadmin/user_upload/tugrazExternal/f560810f-089d-42d8-ae6d-8e82a8454ca9/files/lf/Session_B2/222_LF_Pacco.pdf*

regionalized, and the underlying grid model is updated to incorporate planned grid expansion measures for the target year 2030. The regionalization methods and the grid model applied are described in Annex A.3.

The balancing reserve requirements in the case study are also based on the ERAA 2023 and are visualized in Figure 2.7. Notably, due to the relatively high reserve requirements in the Hungarian bidding zone, the FRR requirements of Hungary are halved. To differentiate between aFRR and mFRR, a ratio is established. For Germany, it is based on publicly available data. The aFRR-to-mFRR ratio is 0.74:0.26 for positive FRR and 0.83:0.17 for negative FRR for Germany. For other market areas, a ratio of 0.33:0.66 is applied. These assumptions are based on expert input from the involved TSOs and serve as simplified, theoretical assumptions. They do not aim to fully reflect the diverse and complex structure of balancing requirements across European balancing markets but rather provide a consistent basis for comparison within the scope of this study.

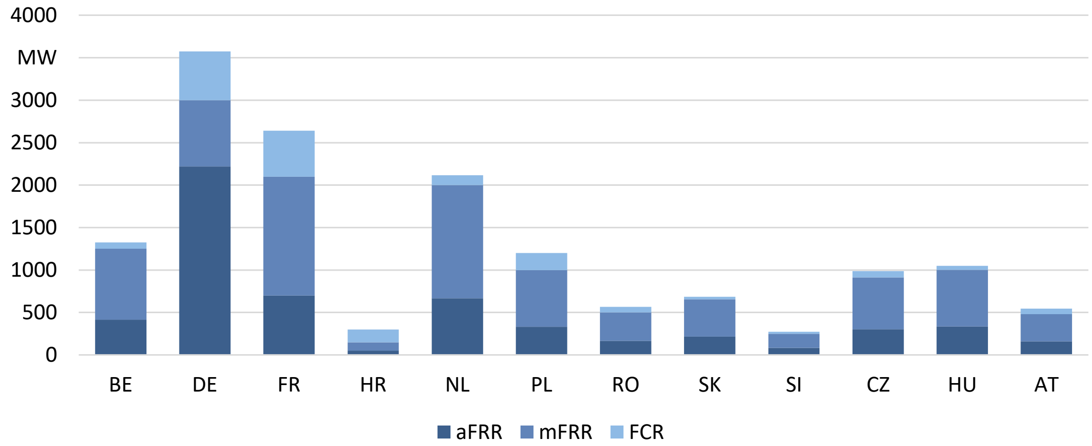

Figure 2.7 Reserve requirements per country in the CORE region in the 2030 scenario

The participation of generation technologies in the balancing reserve market is subject to specific technical constraints, as outlined in Table 1.

Table 1 Participation of generation technologies in the balancing reserve market

Technology	FCR	aFRR	mFRR
Thermal power plants (including biomass)	✓	✓	✓
Electrolysis	×	✓	✓
Hydro power plants	✓	✓	✓
DSR	✓	✓	✓
Batteries	✓	✓	✓
RES (onshore, offshore, PV)	×	✓	✓
Other RES	×	×	×

RES units are restricted to providing only negative FRR, with a maximum participation of 10% of their installed capacity. This percentage was based on expert expectations regarding RES participation in balancing markets by 2030. Biomass generation units are eligible to participate but are constrained by limited fuel availability. Gas-fired power plants are assumed to be able to provide mFRR even when offline through quick-start mechanisms.

Since the provision of BC is not explicitly priced in the model, an exogenous merit order with minimal costs is implemented to account for differences in the actual costs of BC provision and to ensure the model is not indifferent to different technologies.

The cost hierarchy for positive balancing reserves is as follows

pump storage < batteries < thermal power plants < electrolysers < DSR.

For negative balancing reserves, the order is

pump storage < batteries < thermal power plants < electrolysers < RES < DSR.

To prevent unnecessary loop and ring flows, the exchange of BC is also assigned a small cost factor, comparable in magnitude to the costs in the merit order. During the course of the study, different levels of these cost parameters were tested. The selected price level was found to have only a minor influence on both the overall results as well as the total system cost.

2.3.2 Results for Status Quo (completely coordinated)

The *completely coordinated Status Quo* approach can be regarded as a reference case against which all other approaches will be compared. The resulting annual electricity generation and consumption are illustrated in Figure 2.8.

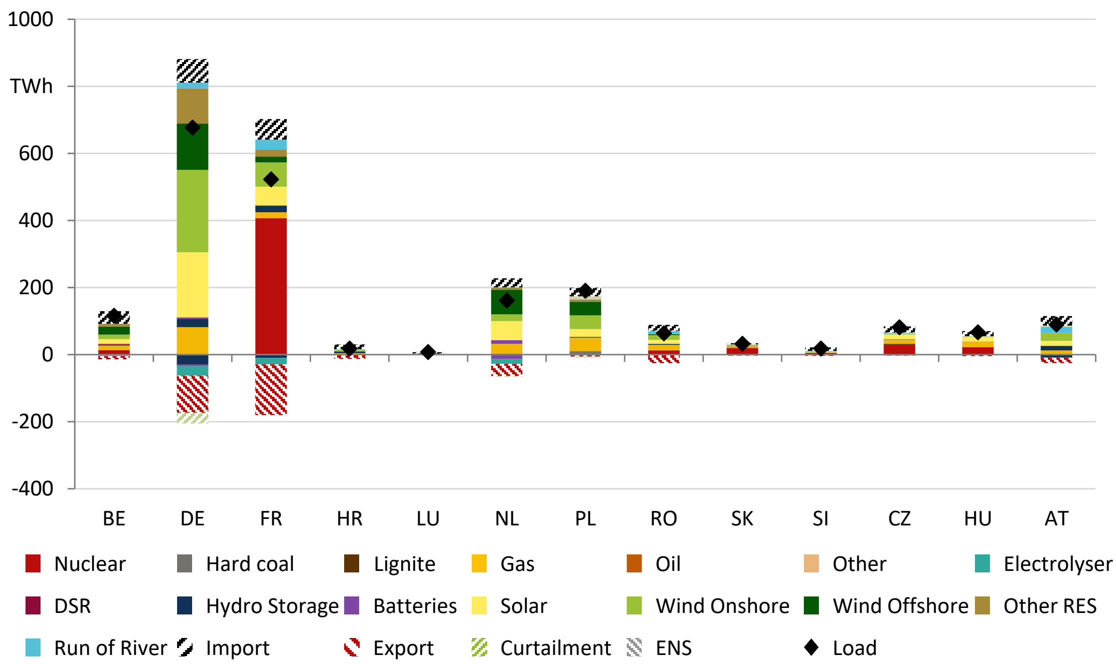

Figure 2.8 Annual electricity generation and consumption of the completely coordinated Status Quo approach

It is evident that over 60% of the electricity generation in the CORE region is provided by RES, which aligns with the scenario assumptions. In France, there is a high share of nuclear power.

During periods of reduced RES provision, gas-fired power plants are utilized. Germany, France, the Netherlands, and Romania are net exporters, while all remaining bidding zones are net importers.

Figure 2.9 shows the average provision of aFRR.

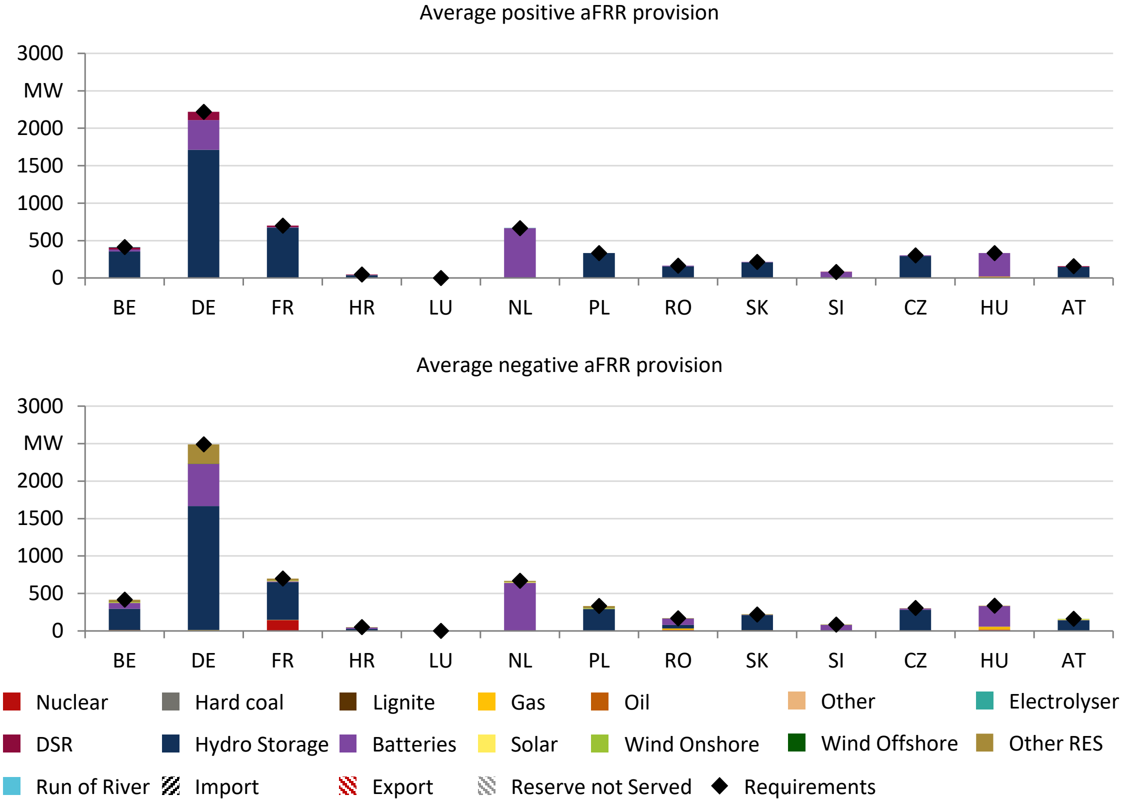

Figure 2.9 Average provision of positive (top) and negative (bottom) aFRR of the completely coordinated status quo approach

The provision of positive aFRR is dominated by hydro storage and batteries. In Germany, there are also some hours in which positive aFRR is provided by DSR. In the Netherlands as well as in Hungary, no hydro power plants are installed. Therefore, positive aFRR is provided only by batteries. The negative aFRR provision is also dominated by hydro power plants and batteries, but there is more variation with other technologies. In Germany, the negative aFRR is partly provided by RES, mainly by technologies classified as 'Other RES' which includes biomass. In France, negative aFRR is partly provided by nuclear power plants.

Analogously, the average provision of mFRR is shown in Figure 2.10.

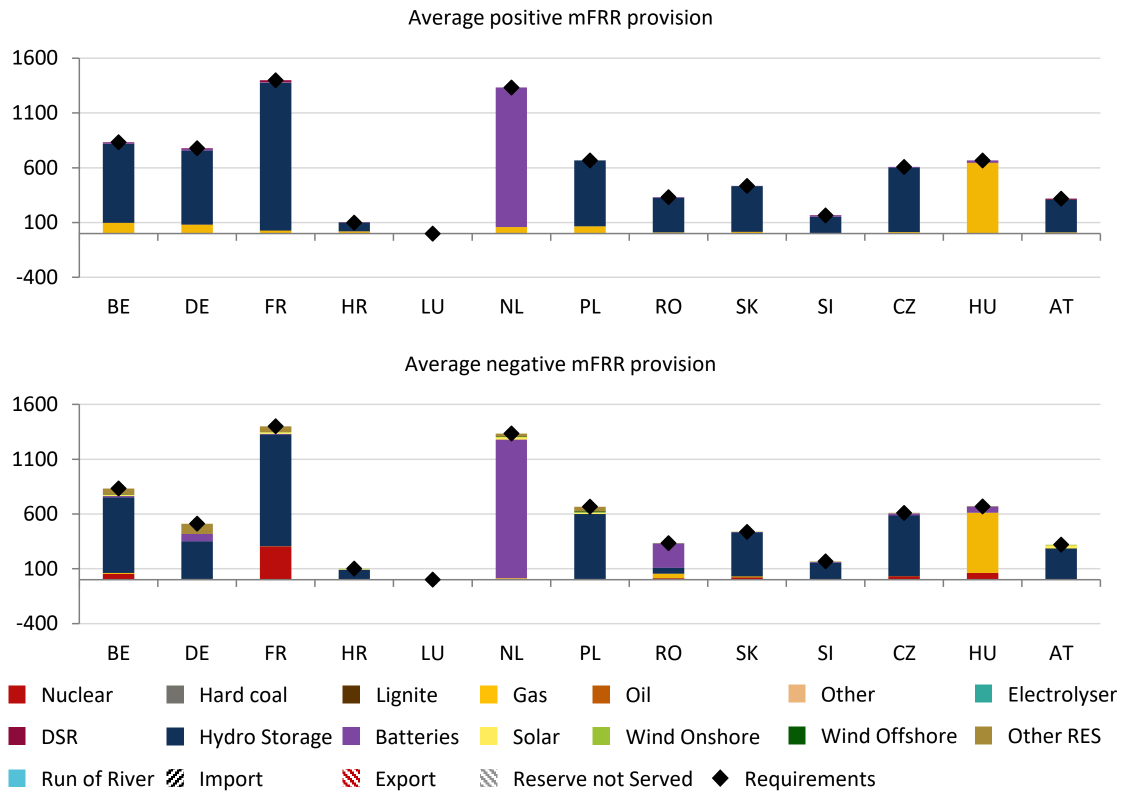

Figure 2.10 *Average provision of positive (top) and negative (bottom) mFRR of the completely coordinated Status Quo approach*

Overall, the technologies used are similar to those for the provision of aFRR. Gas-fired power plants are utilized more, as they are capable of providing mFRR even when they are offline. For negative mFRR, also nuclear and RES (especially biomass and PV) are employed. The longer activation time of mFRR allows a larger amount of power to be supplied by thermal power plants with the same ramp-up or ramp-down gradient.

2.3.3 Cost Comparison

The difference in annual electricity generation costs of the CORE region compared to the *Status Quo (completely coordinated)* is shown in Figure 2.11.

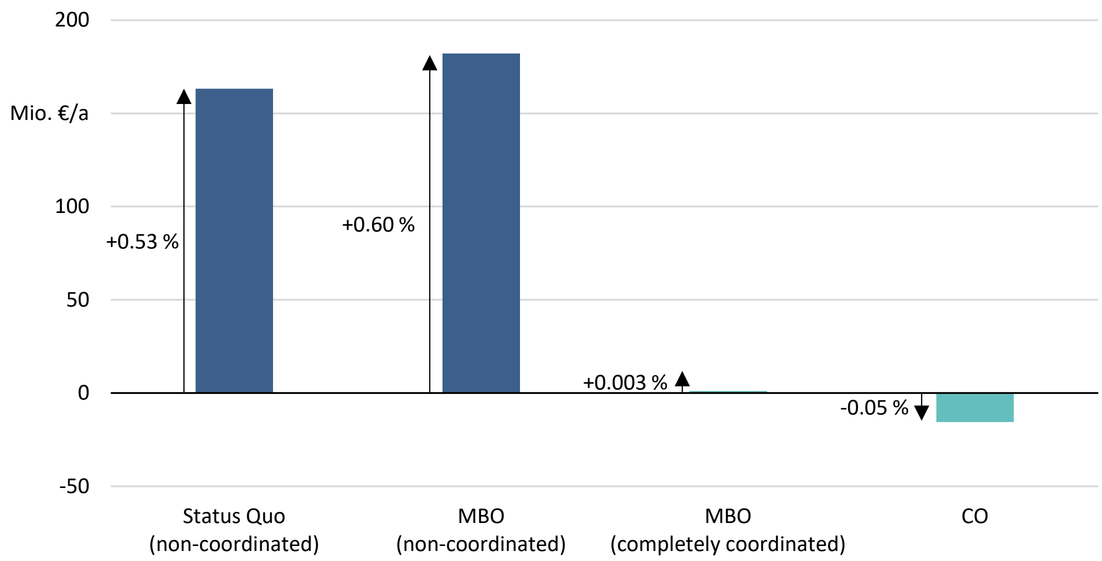

Figure 2.11 Annual electricity generation costs in the CORE region compared to Status Quo (completely coordinated)

The results indicate a significant range between the *completely coordinated* and the *non-coordinated* approaches. Since these represent the two extreme cases considering the coordination of bid submission between the SE and BC market, the actual market outcome—where partial coordination exists—falls within this range.

Depending on the specific method used to simulate the *Status Quo*, the cost reduction achieved through *CO* ranges from EUR 15.5 million (0.05%) to EUR 179 million (0.58%) per year for the CORE region. This highlights that when comparing *Status Quo* to *CO*, the assumed level of coordination between the generation units participating in the SE and BC markets in the *Status Quo*, in conjunction with the applied modeling methodology, has a large impact on the results. Notably, the range between the *completely coordinated* and the *non-coordinated* approach is significantly larger than the differences observed among *Status Quo*, *MBO* and *CO* under complete coordination. This suggests that efficiency gains from improved bid submission coordination between generation units participating in the SE and BC markets are greater than those achieved solely by BC exchange.

When applying the same comparison as in the NTUA/UC Louvain study, comparing *CO* to the non-coordinated *Status Quo*, this study finds lower efficiency gains from *CO*. While the NTUA/UC Louvain study identified gains of approximately 2.1%, this study reports only 0.58%. The main reasons for this difference are the higher forecast accuracy applied here and the focus on a future scenario rather than a historical case. With improved forecast quality, the *Status Quo*, despite being modeled with no bid submission coordination, performs relatively close to the *CO* scenario. Moreover, in the future scenario considered here, many of the factors contributing to large efficiency gains in the NTUA/UC Louvain study, such as fixed costs and technical minimums of thermal power plants, play a much smaller role. This is due to the reduced reliance on thermal generation in FRR capacity provision (cf. Figure 2.9 and Figure 2.10).

For *MBO*, both under the *completely coordinated* and the *non-coordinated* approach, annual electricity generation costs slightly increase compared to *Status Quo*. This outcome can be attributed to several factors related to modeling and scenario assumptions. In the *MBO* approach, CZCA for FRR capacity exchange is based on a forecast of the SE market. Since this forecast deviates from the actual market outcome, it can lead to an over- or underestimation of the market value of CZC for SE. In this study, the forecast is derived from a market simulation without BC exchange (cf. section 2.2.1), leading to a systematic underestimation of the market value of CZC, as it assumes full CZC availability for SE exchange. Although the forecast method aims to replicate a realistic level of accuracy, comparable to historical forecasts, this simplification can lead to suboptimal allocation. Specifically, in the optimization of the BC market, more BC is exchanged than would be economically optimal, reducing the available CZC for the SE market. This reduction limits SE exchange in the next modelling step and ultimately leads to a slight increase in generation costs. However, this outcome is highly dependent on the forecasting approach, and alternative approaches in practice may not necessarily underestimate market values. In real-life market operations, allocating CZC for balancing capacity could also reduce available CZC for later market stages such as the intraday market, potentially introducing additional inefficiencies, but this affects both *MBO* and *CO*. Additionally, the simulation considers not only electricity generation costs, but also high penalty costs for unserved energy. In the *Status Quo*, there are small volumes of unserved energy (0.77 TWh in the CORE region). Under the *MBO* approach, these volumes are reduced (by 0.04 TWh), leading to lower combined costs for generation and unserved energy compared to the *Status Quo*. While generation costs increase slightly, the total system cost still improves due to the reduction in unserved energy. This effect is primarily a result of the specific simulated scenario and is unlikely to occur in practice. Accordingly, the lower performance of *MBO* is mainly caused by specific modelling assumptions and the chosen scenario and may not occur in practice.

Since the costs of BC provision are only implicitly modeled, they cannot be directly analyzed. However, to approximate the relative cost levels of BC provision across scenarios, the dual values of the reserve requirement fulfillment constraints can be used. These dual values represent the marginal costs of providing BC in the model. By multiplying the marginal costs per bidding zone by the respective reserve requirement volumes and summing across all zones, an indicative cost level can be derived. This provides an estimate for comparing BC costs across scenarios. In the *non-coordinated* approaches, however, BC provision is fixed for all units. Therefore, the dual values are not meaningful and cannot be used for cost estimation in those cases.

Accordingly, *Figure 2.12* presents the difference of the indicative cost levels of BC provision of *MBO (completely coordinated)* and *CO* compared to the *Status Quo (completely coordinated)*. As shown, the highest cost level is observed in the *Status Quo* scenario without BC exchange, while both the *MBO* and *CO* approaches result in significantly lower costs. The greatest reduction—52.8%—is achieved in the *CO* scenario. These findings indicate that, despite a slight increase in SE costs under *MBO*, the facilitation of BC exchange can still significantly reduce the cost level of the BC market.

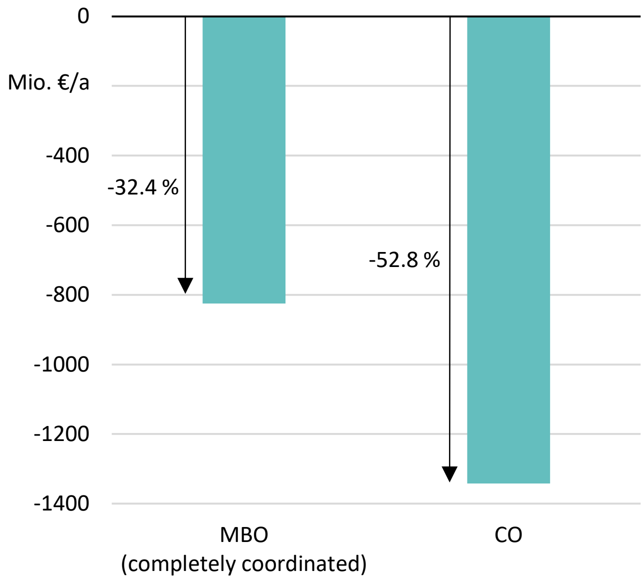

Figure 2.12 Difference of indicative cost level of BC provision in the CORE region compared to Status Quo (completely coordinated)

The estimation of BC activation costs was performed using the methodology described in section 2.2.1 and with detailed results presented in Figure in the appendix. These costs were generally several orders of magnitude lower than total electricity generation costs, and the differences between scenarios were likewise smaller in absolute terms. Nevertheless, when comparing scenarios with complete coordination relative to one another, the highest activation costs are observed in the completely coordinated *Status Quo*, while all other approaches yield lower cost levels. Interestingly, *MBO* performs best in terms of estimated BC activation costs, which can be attributed to a greater allocation of CZC for BC exchange. This results in higher volumes of balancing energy being exchanged, contributing to the improved cost efficiency in the balancing energy market.

2.3.4 Market Outcome Comparison

The cost differences between the various approaches can be analyzed and explained by comparing the market outcomes across the different approaches. In this comparison, the results of the *completely coordinated Status Quo* approach (cf. section 2.3.2) serve as the reference against which all other results are compared. Therefore, the difference of annual electricity generation and consumption as well as the difference of the average FRR capacity provision, i.e., the sum of aFRR and mFRR, are shown for the CORE region. Thus, for generation units, DSR and import, a value greater than zero indicates a higher value than in the *Status Quo* and a negative value indicates a lower value. Conversely, for electrolysis, curtailment and export, a value greater than zero indicates a lower value than in the *Status Quo* and a negative value indicates a higher value. For a more detailed comparison of each approach with the *Status Quo (completely coordinated)* by country, see Figure to Figure in the appendix.

Figure 2.13 illustrates the sum of the difference of the annual electricity generation and consumption across all zones in the CORE region. The respective data can be found in Table 2 in the annex.

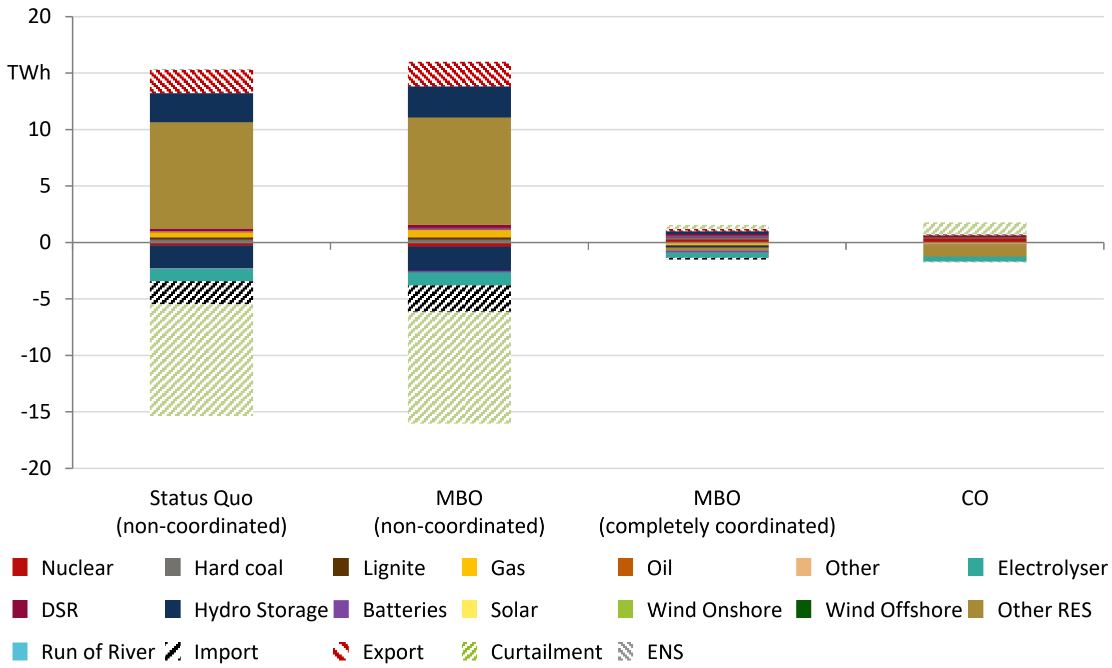

Figure 2.13 Difference of annual electricity generation and consumption in the CORE region compared to Status Quo (completely coordinated)

The results indicate minimal to no changes for the *completely coordinated MBO* and *CO* approaches. Similarly, for the *non-coordinated* approaches, overall changes remain low, below 15 TWh for the entire CORE region, but are slightly more pronounced. However, many of these changes are cost-neutral, e.g., a shift from biomass generation to increased curtailment resulting from indifferences in the model. The *non-coordinated* approaches show a slight increase in generation of gas-fired power plants and the use of DSR, accompanied by a reduction in generation from nuclear power plants. This shift contributes to the higher overall generation costs observed in these approaches. Conversely, for *CO*, costs are reduced by substituting the use of DSR with an increased share of gas-fired and nuclear power plants. Additionally, a reduction in SE exchange compared to the *Status Quo* is observed in both non-coordinated approaches and the completely coordinated *MBO* approach.

The difference of the average FRR capacity provision is illustrated in Figure 2.14. The respective data can be found in Table 3 and Table 4 in the annex.

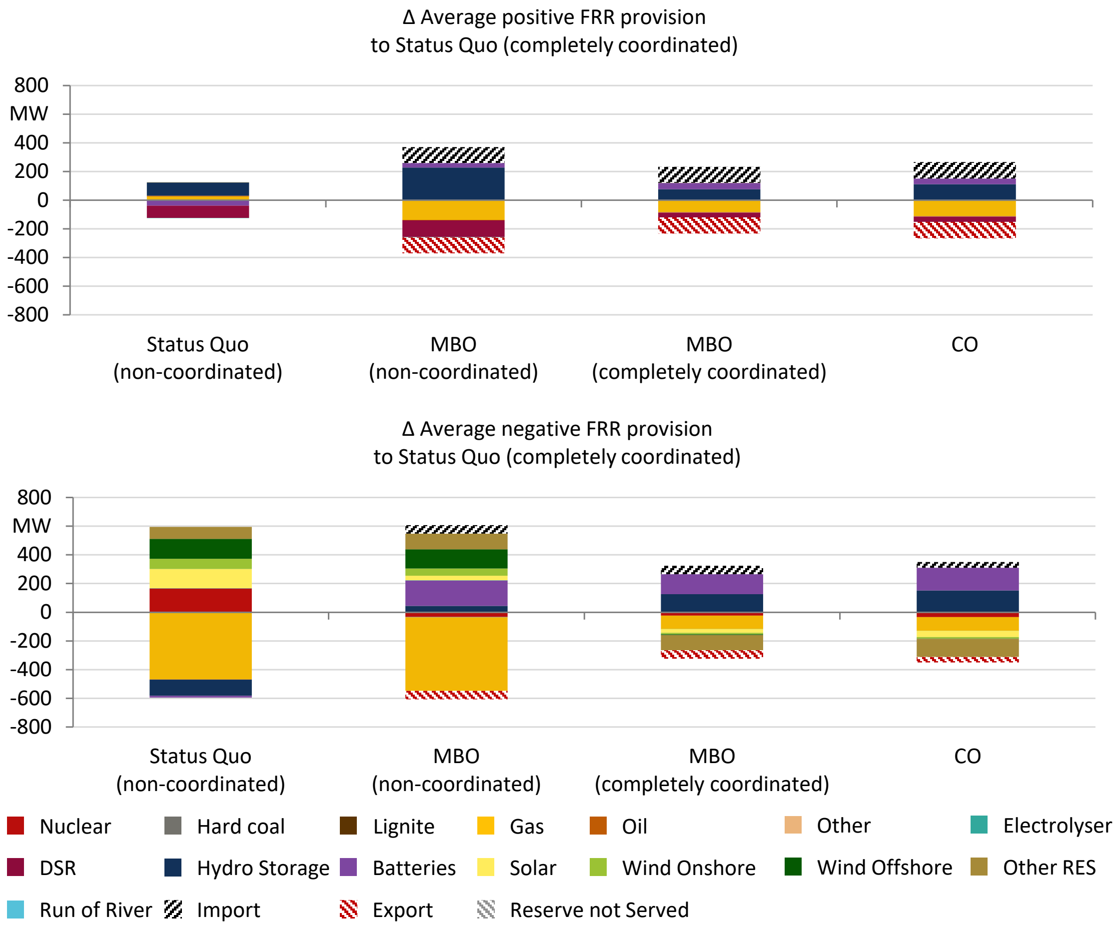

Figure 2.14 *Difference of average positive (top) and negative (bottom) FRR capacity provision in the CORE region compared to Status Quo (completely coordinated)*

The analysis of the differences in average positive FRR capacity provision shows that, except for the *non-coordinated Status Quo* approach, all approaches allow for an increased positive FRR capacity provision from hydro storages and batteries to replace positive FRR capacity provision from gas-fired power plants and DSR. This outcome directly results from the applied cost order (cf. section 2.3.1) and does not necessarily lead to a reduction in electricity generation costs within the SE market. However, a slight decrease in aFRR capacity provision from gas-fired power plants is observed, which prevents certain plant start-ups solely for FRR capacity provision, thereby achieving actual cost savings in both start-up and generation costs. For the *CO* approach, FRR capacity exchange allows thermal capacities in certain zones to be freed up, as they no longer need to provide positive FRR. This enables these plants to replace the more costly use of DSR, resulting in reduced overall costs. In contrast, for the *MBO* approach, FRR capacity exchange proves inefficient in some hours, leading to reduced SE exchange. Consequently, this increases reliance on expensive DSR, thereby driving up costs. For the *MBO* approach, both variations have the same exchange volumes, as the CZCA is the same for both approaches.

Across all approaches, the provision of negative FRR capacity shows a reduced use of gas-fired generation units. Additionally, utilization of nuclear generation decreases in all cases except for the *non-coordinated Status Quo*. This is primarily because, in the *non-coordinated Status Quo*, nuclear generation units in Hungary provide more negative FRR capacity than gas-fired generation units. Consequently, for all cases, except for the *non-coordinated Status Quo*, hydro storage and battery deployment increase to compensate. In some cases, this shift does not result in actual cost reductions, as it is driven by the applied cost order (cf. section 2.3.1). However, in cases where gas-fired or nuclear power plants would otherwise operate solely for negative FRR capacity provision, their replacement by hydro power plants or batteries leads to real cost savings. In the non-coordinated approaches, the use of RES for negative FRR capacity provision increases, whereas in the completely coordinated approaches, there is a slight decrease. In the latter case, this is mainly due to a shift from other RES (primarily biomass) to batteries in Germany, which again results from the cost order applied (cf. section 2.3.1). The increased use of RES for negative FRR capacity provision corresponds to the observed decrease in curtailment, as reflected in the differences between annual electricity generation and consumption. While in Germany, the provision of negative FRR capacity from other RES decreases in the non-coordinated approaches as well, it increases in Belgium and France as a substitute for nuclear power. Furthermore, the exchange volumes for negative FRR capacity provision are slightly lower in the *CO* approach compared to *MBO*. For *MBO*, both variations exhibit identical exchange volumes, as the CZCA remains the same in both cases.

2.3.5 Exchange of FRR capacity and CZC Allocation

As shown in the previous market outcome comparison, the possibility for BC exchange is used for the *MBO* and *CO* approaches mostly to allow for a more cost-effective provision of BC but can also lead to real cost reductions on the SE market. In order to provide a better understanding of the BC exchanges, they are analyzed in more detail below. Therefore, both the magnitude and the frequency of the exchanges of the zones are considered.

Co-Optimized Allocation

Figure 2.15 illustrates the average hourly net position of FRR capacity for all zones within the CORE region under the *CO*.

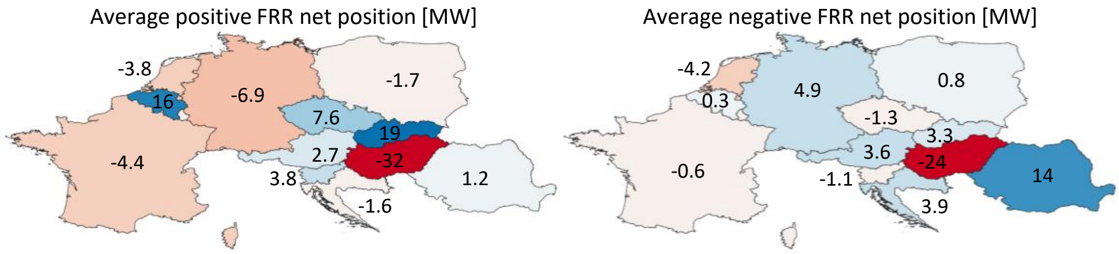

Figure 2.15 Average net positions of positive (left) and negative (right) FRR capacity for CO in MW

Overall, the absolute average net positions for both positive and negative FRR capacity are relatively low, with the highest value of 32 MW observed in Hungary. Hungary primarily imports positive FRR capacity from neighboring countries to reduce its reliance on gas-fired power plants for provision, resulting in positive average net positions for these countries. Notably, Belgium has a relatively high average net position and acts as an exporter of positive FRR capacity. This is largely due to Belgium being a net importer of SE, which means that CZC towards Belgium is predominantly allocated for this purpose. As a result, the CZC in the opposite direction remains available most of the time, enabling Belgium to export positive FRR capacity to countries such as Germany, the Netherlands, and France. To facilitate these exports, Belgium increases its provision of FRR capacity from hydro power plants and DSR, thereby reducing the positive FRR capacity provision from gas-fired power plants in other zones.

For negative FRR capacity, the average net positions indicate a lower overall exchange compared to positive FRR capacity. This is primarily due to the lower theoretical provision costs, as thermal power plants incur no opportunity costs for negative FRR capacity when they are already online. Most negative FRR capacity exchange occurs around Hungary, where imports are used to replace provision from gas-fired power plants.

While the previous analysis focused on the total volume of FRR exchange, it is also informative to differentiate between aFRR and mFRR to better understand their relative contribution and value. The results indicate that the exchange of positive aFRR appears to be more economically valuable than that of positive mFRR. Although mFRR reserve requirements are higher in most bidding zones, the average exchanged volume of positive aFRR capacity in the CORE region (80 MW) exceeds that of positive mFRR capacity (21 MW). This suggests a higher marginal value for aFRR capacity exchange compared to mFRR capacity. A key reason for this difference lies in the underlying assumptions. While positive aFRR capacity can only be provided by online thermal power plants, positive mFRR capacity is assumed to be also deliverable by gas-fired power plants in offline (standing reserve) mode, which expands the pool of available resources and reduces scarcity in the mFRR market. For negative FRR capacity, the difference in exchange volumes is less pronounced. In the CORE region, the average exchange volume is 17 MW for aFRR and 21 MW for mFRR. mFRR capacity exchange volumes are slightly higher, which aligns with the fact that mFRR requirements exceed those of aFRR in most bidding zones. Nonetheless, the relatively high level of aFRR capacity exchange, despite its smaller share in reserve requirements, still indicates a notable role for aFRR in facilitating efficient cross-zonal balancing.

To illustrate the frequency of exchanges, Figure 2.16 exemplarily presents the import and export duration curve for positive FRR capacity in Germany, considering only exchanges exceeding 0.1 MW. The figure demonstrates that exchanges occur during a limited number of hours throughout the year. However, when they do occur, the exchanged volumes are relatively high. Additionally, the figure confirms that Germany participates in both importing and exporting positive FRR capacity. Export predominantly takes place in February and November, periods characterized by low renewable energy generation and a relatively high reliance on gas-fired generation units to meet demand. Imports also occur primarily during such periods but are distributed more evenly throughout the year. The unsorted exchange patterns are illustrated in Figure in the appendix.

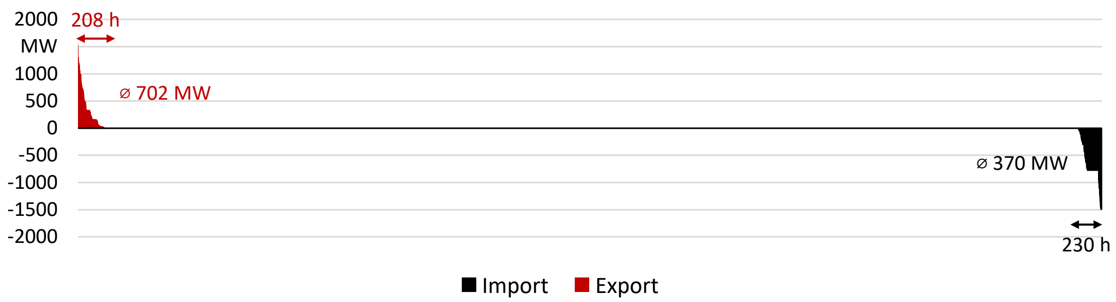

Figure 2.16 Positive FRR capacity import/export duration curve for Germany in CO

Figure 2.17 provides the corresponding duration curve for negative FRR capacity. In contrast to positive FRR, negative FRR capacity exchanges occur less frequently, as Germany rarely imports negative FRR. Moreover, the exchanged volumes for negative FRR are generally lower than those observed for positive FRR. The unsorted exchange pattern in Figure in the appendix illustrates that negative FRR capacity exports predominantly take place in February.

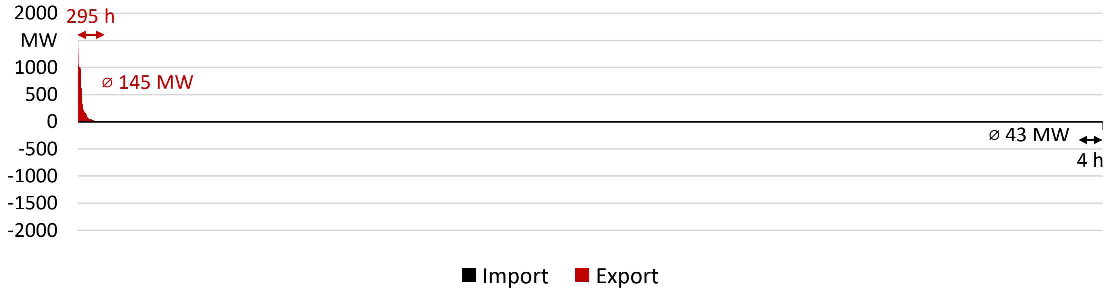

Figure 2.17 Negative FRR capacity import/export duration curve for Germany in CO

Similar to Germany, many other bidding zones engage in FRR capacity exchange during only a limited number of hours. However, some participate more frequently—for example, Hungary imports positive FRR capacity in a substantial number of hours, with Slovakia correspondingly exporting during these periods. The exchange of negative FRR capacity remains limited for many zones as well. Romania and Hungary are notable exceptions, as they engage in negative FRR capacity exchanges more frequently. Table 5 and Table 6 in the appendix provide a summary of the number of hours with exchange and the average exchange volume when it occurs for all zones within the CORE region.

Market-Based Allocation

For *MBO*, the average hourly net positions of FRR capacity for all zones are presented in Figure 2.18.

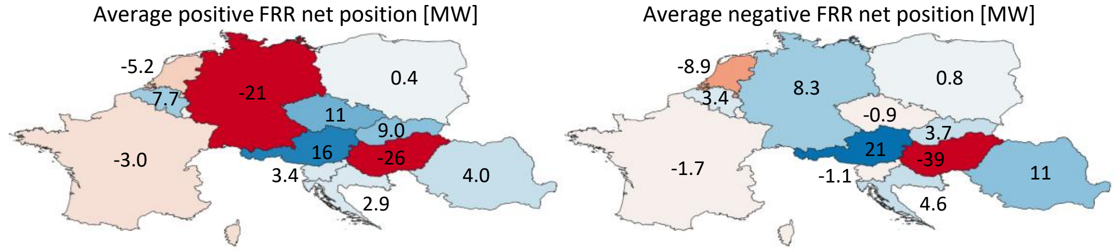

Figure 2.18 Average net positions of positive (left) and negative (right) FRR capacity for MBO in MW

The results indicate that the overall volume of FRR capacity exchange is higher in *MBO* compared to *CO*. However, the direction of the average net positions remains largely consistent with those observed in *CO*.

Figure 2.19 presents the import/export duration curve of positive FRR capacity for Germany under *MBO*. This shows that exports occur in approximately the same number of hours as in *CO*, whereas import takes place more frequently and with a higher average volume. The unsorted results in Figure in the appendix show that the export pattern differs quite significantly from *CO*. This divergence arises because, in *CO*, exports predominantly occur during exceptional periods of low renewable generation, which are difficult to forecast. The forecasting method used in this study exhibits the largest errors during such periods. However, the findings also show that while peak export volumes are lower, the exchange volume is more evenly distributed across all the hours with exports. The import pattern remains largely unchanged in *MBO* compared to *CO*.

Figure 2.19 Positive FRR capacity import/export duration curve for Germany in MBO

For negative FRR capacity, both imports and exports occur more frequently in Germany under *MBO* compared to *CO*. However, imports remain rare. The exchange volumes are lower than those observed for positive FRR capacity. The unsorted exchange pattern, presented in Figure in the appendix, shows that the overall exchange pattern for negative FRR capacity remains largely unchanged, with lower peak volumes due to the 10% limit applied in *MBO*.

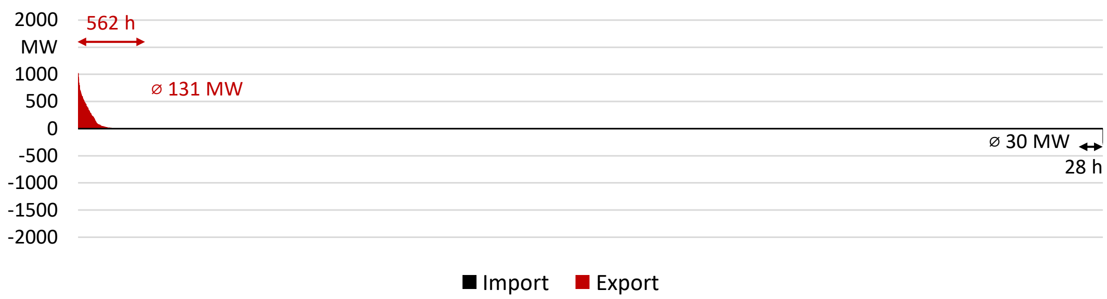

Figure 2.20 Negative FRR capacity import/export duration curve for Germany in MBO

Cross-zonal Capacity Allocation

The average share of CZC utilized for FRR capacity exchange is presented in Figure 2.21.

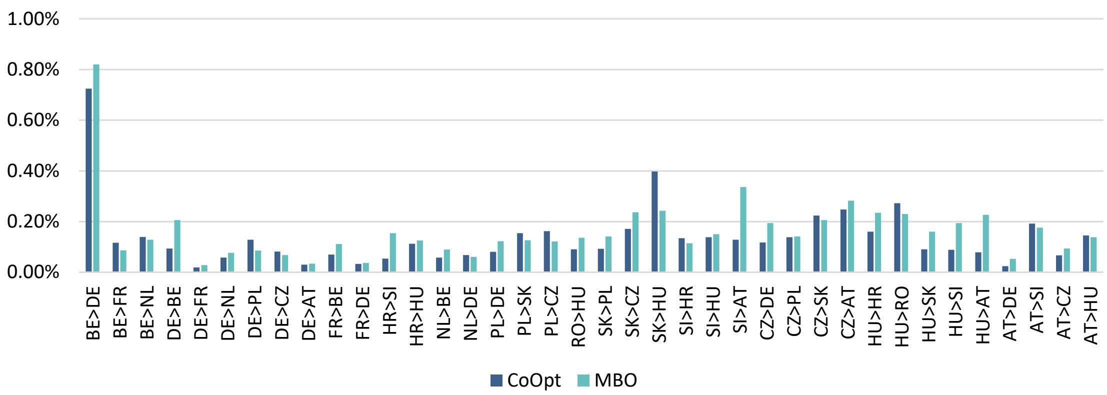

Figure 2.21 Average share of CZC used for FRR capacity exchange

The results indicate that the average share remains relatively low, staying below 1% for all borders within the CORE region. In many cases, the share is higher for *MBO* approach compared to *CO*.

Figure 2.22 illustrates the maximum CZC utilization.

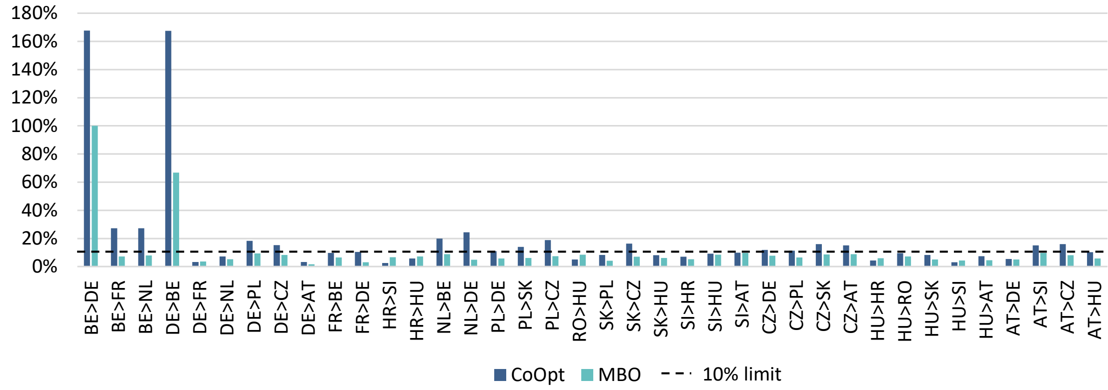

Figure 2.22 Maximum share of CZC used for FRR capacity exchange

The use of CZC for FRR capacity exchange is constrained by 10% in the *MBO* approach, except for DC interconnectors. The figure shows, however, that the maximum use generally does not exceed 30% in the *CO* approach as well. An exception is observed on the German-Belgian border, where the maximum share surpasses 100% due to the utilization of CZC in the opposite direction of scheduled energy exchange. However, the total CZC between Germany and Belgium is relatively low, which can result in a high utilization percentage even with moderate exchange volumes.

2.4 Summary of the Quantitative Assessment

The objective of this quantitative assessment was to evaluate different approaches to CZCA through detailed quantitative modeling. It aimed to analyze the impact of the specific modelling approach and assumptions to provide a more contextualized interpretation of the results presented in the NTUA/UC Louvain study published by ACER. The key modeling assumptions investigated include the level of bid submission coordination of generation units participating in the SE and BC market in the *Status Quo* and *MBO* approaches (where the NTUA/UC Louvain study assumes limited coordination), the price forecasting methodology (as the NTUA/UC Louvain study employs a very simplistic approach), and the choice of case study (where NTUA/UC Louvain rely on historical data).

To estimate the impact of bid submission coordination in sequential market approaches, two scenarios were considered: *complete coordination* and *no coordination* of the units participating in both the SE and BC markets. This approach provides a range within which the actual, portfolio-based market outcome is expected to fall. The used price forecasting methodology incorporates historical forecast errors of renewable energy generation and load, and the investigated case study includes a European market scenario for the year 2030.

The estimated cost savings from *CO* relative to the *Status Quo* vary significantly, depending on the assumed level of bid submission coordination of generation units across the SE and BC market in the *Status Quo*, ranging from 15.5 to EUR 179 million per year for the CORE region. This large range shows the sensitivity of such a comparison to the modeling assumptions for the *Status Quo*, indicating that the real market outcome could fall anywhere within this spectrum.

Compared to the estimated savings of EUR 678 million per year of the NTUA/UC Louvain study, the results of this study suggest that when using a future case study — where thermal power plants play a smaller role — and employing a more sophisticated forecasting method, the expected savings from *CO* are considerably lower. While efficiency gains are still observed through the exchange of BC, as it allows for replacing the generation of thermal power plants that would otherwise run solely for BC provision, this effect is less pronounced in a scenario where hydro power plants and batteries are already the dominant BC providers in most bidding zones.

Furthermore, the results demonstrate that under the assumption of *complete coordination* between the units participating in the SE and BC markets, cost differences between the *Status Quo*, *MBO*, and *CO* are relatively small. More importantly, these differences are significantly smaller than those observed between the *completely coordinated* and *non-coordinated* approaches. This suggests that improving coordination of units participating in the relevant markets generates greater efficiency gains than BC exchange itself. The results for *MBO* indicate a slight increase in the generation costs. However, this outcome is highly dependent on the methodology used to forecast the market value of CZC for SE exchange and the chosen scenario. If the forecast systematically underestimates this value, excessive CZC is allocated to BC exchange at the expense of SE, leading to increased overall generation costs. Nevertheless, this effect is model-dependent and could manifest differently in real-world conditions.

Although total BC exchange volumes remain small in all modeled approaches, the results indicate that when exchange does occur, it is concentrated in a limited number of hours, often with relatively high volumes. This suggests that BC exchange is particularly beneficial in specific situations, such as periods of low renewable energy generation, when most available generation capacity is already utilized in the SE market. However, as exchange takes place in only a very small fraction of the hours in a year, it raises the question whether the added complexity and effort required to implement a full *CO* is justified.

Apart from the modelled quantitative effects, an implementation of *CO* would involve substantial changes to market design and operational processes. While *CO* may yield efficiency gains under certain conditions, its overall necessity and proportionality should be critically assessed. These broader market effects and implementation considerations will be analyzed in more detail in the following chapter.

3 Qualitative Assessment

3.1 Scope and Approach of Qualitative Assessment

The approaches for allocating limited CZC will not only have a quantifiable impact on social welfare which is analyzed in the previous chapter but will also come with other effects (including additional non-quantifiable impacts on social welfare). In order to fully evaluate the different CZCA approaches, those effects must also be included in the evaluation in addition to the comparison of social welfare calculated by the quantitative analyses, as most of those aspects cannot be captured by the simulations or can only be captured partly. The qualitative assessment is focused on three main aspects that complement the quantitative results:

> ***Implementation and practicability:*** The introduction, maintenance and servicing of the systems underlying a CZCA methodology will be associated with costs. These must be compared with the welfare gains for a fair assessment of the benefits of the CZCA methodology. These **implementation costs** cannot be modeled but have to be assessed by experts in the places where implementation and maintenance cost will be incurred. Further elements of this aspect include the **risk of failure** and the **increase in complexity**. Due to the higher complexity of co-optimization that results from linking BC and SE markets compared to the current market design, a higher risk of failure or decoupled clearing is to be expected. These complexities include but are not limited to amendments to the market coupling algorithm, the design of fallback mechanisms and the bid structure. The benefits achieved through co-optimization should be set against the likely costs or missed benefits associated with this risk.
>
> Another aspect to consider is that the introduction of a CZCA approach does not happen in a vacuum. The **dependencies with other projects** aiming at expanding and further developing the market coupling have to be taken into consideration. The TSOs, while coordinating closely with the NEMOs, are continuously developing the market design, including projects outside of the CZCA. At present, other implementations are already being implemented and discussed, such as the introduction of quarter-hourly products in the SDAC or the review of bidding zones. As with the adaptation of the CZCA, such further developments are fundamental amendments to the market coupling algorithm that on the one hand lead to adaptations and additional features for all players, but on the other hand also require resources, especially on the side of the TSOs. As resources tied up in this way cannot be used for other projects, it is necessary to weigh which projects to implement first. In terms of welfare gains to be achieved, the projects promising the greatest benefit – taking into account the resources committed – should be prioritized. In this context, the assessment includes the consequences of using the **computing power** required for co-optimization for processes that already exist today.
>
> In the analysis of the implementation of a new approach **missed efficiency gains** and **inefficient clearing** have to be considered. Even today, the SDAC algorithm cannot guarantee an optimal solution, and different runs of the same problem may lead to different results. It cannot be ruled out that the same problem applies to the different approaches of CZCA, especially the co-optimization. With the increasing complexity due to co-optimization, it is still unclear whether adequate optimality can be achieved in a reasonable time. We therefore discuss potential developments regarding optimality of the solution found by the SDAC algorithm when coupled with the clearing of BC demand. The

discussion includes the question of the required **bid structures** and complexity of bids for co-optimization purposes.

Challenges for CZCA for Reserves: In the co-optimization process, stakeholders can specifically influence the CZCA by submitting a bid. When carrying out the quantitative simulations, it is assumed that the market players act rationally under the assumption of perfect competition, which leads to the welfare optimum. In practice, however, distortions in the allocation process can result from the behavior of powerful market players. This is particularly true if the SE and BC markets have different competitive structures and **market power** can be abused. The fact that the markets for BC can be categorized as comparatively narrow is particularly critical.

Another challenge is the risk of an inefficient CZCA due to **forecast errors**. In the currently envisaged market design, the allocation of CZC between BC and SE is carried out once a day in advance so that the allocation of CZC determined in this process is binding until the time of fulfilment. Possible intraday changes, such as updated forecasts, which would otherwise lead to an adaptation of the bids by the players and thus lead to another optimal CZCA, cannot be taken into account. This can significantly limit the benefits of the intraday market and lead to inefficiencies. The potential gains of CZCA are therefore determined by the forecasting quality of the players with a lead time of roughly one day.

The co-optimization process can also have disadvantageous **effects for market players**. In the current market design, markets are conducted in a strictly sequential manner. This means that if a player is unsuccessful in one market, it can offer its unutilized flexibility in another market (often the market with technically lower requirements). In co-optimization, market players may have to choose beforehand on which market they want to offer their flexibility. Their success depends on the decisions of other market players. In case of unsuccessful bidding, market players will have to face the risks accordingly. We also discuss whether such problems could be overcome by the introduction of more complex bid structures and combinatorial auctions and what this would mean for the complexity of the auctions.

Limits of quantitative assessment: In quantitative simulations, some idealized assumptions are made, such as rational actor behavior, abstraction from forecasting errors or from portfolios and market shares that exist in practice. In practice, however, it is to be expected that such and other effects will occur and influence the social welfare gain of CZCA in BC markets. The welfare gains determined by such analyses therefore represent a theoretical optimum that is likely to be difficult to achieve in practice due to the lack of idealized framework conditions in a real-world scenario. We therefore identify possible influences overestimating the welfare gains so that they can be taken into account in the discussion on CZCA mechanisms

This aspect also includes an **assessment of the NTUA/UC Louvain** on the comparative assessment of social welfare gains when introducing co-optimization and market-based allocation. The study concludes that the introduction of co-optimization is clearly more advantageous than the market-based approach. The study does not include a critical appraisal of the calculation results or an assessment of the impact of typical assumptions. We therefore discuss the limitations of the study (which are unavoidable when carrying out simulations) and assess their impact on the results and the conclusions of the study.

For these reasons, in addition to our own simulations, our study also provides a qualitative assessment to complement the consideration of quantitative welfare analyses.

The scope of the qualitative analyses can only be meaningfully addressed with the help of highly specialized expert knowledge of the numerous processes that would be affected by the introduction of a CZCA approach. Our assessment is therefore based on interviews with several experts:

- Experts from TSOs (50Hertz, Amprion, TenneT and TransnetBW) who specialize in European electricity markets, the CORE region and system operations and balancing (co-operations),
- Two representatives from NEMOs and Power exchanges (including EPEX SPOT) for expertise on market coupling and SDAC/EUPHEMIA
- Two market participants on electricity and balancing markets

Based on a broad spectrum of expert knowledge and considering different perspectives, it is possible to draw a set of balanced assessments and conclusions on the aspects listed above. These findings will be summarized in the following section.

3.2 Conclusions from the Qualitative Assessment

The evaluation of the interviews revealed a high degree of agreement between the experts on several points. Although expert interviews only ever represent a sample of all perspectives on a topic, the experts' opinions considered in the qualitative assessment provide a good range and a valuable assessment of the consequences resulting from co-optimization. For the most part, the introduction of CO is met with skepticism. This is mainly due to the concern that it will lead to a significant increase in the complexity of the overall system far beyond the balancing markets as the introduction of CO could mean a preliminary decision in favor of a general change in the market structure.

There are considerable doubts about the efficiency gains postulated in the NTUA/UC Louvain study. Additionally, the timing of introduction CO into a system that is currently undergoing fundamental changes towards a decarbonized and far more decentralized system is questioned. Therefore, the implementation of CO, if it is considered feasible at all, is viewed as more of a future topic rather than an urgently needed additional change.

3.2.1 Implementation and practicability

Currently there is neither a comprehensive study nor an estimation on the implementation costs for introducing any co-optimization, therefore the feedback consisted of qualitative estimates of the additional effort.

Implementation cost

The experts consulted emphasized that the implementation effort is highly contingent on the degree of sophistication with which CO is introduced, given that numerous conceptual and practical questions remain unresolved at this stage. There is, however, a broad consensus that the

Market Coupling Algorithm would have to be significantly adapted to the CO.[5] This included processing more complex bids as well as implementing priority rules among balancing products as well as between SE and BC products. Additionally, increased complexity requires rules for managing indeterminacy conditions[6] and non-convexity (paradoxical rejections of orders).

Beyond the adaptation of the algorithm the NEMO trading system and the interfaces between NEMOs and TSOs would become more complex. Market participants would also have to update their IT-infrastructure and their interfaces which could require some investment. Currently the interfaces of market participants are tailored to today's market design. Should the market design undergo substantial changes, a corresponding adaptation of system interfaces becomes necessary which in turn entails implementation costs to the same extent. Apart from the Market Coupling Algorithm, the introduction of CO necessitates additional methodical and implementation work in the capacity calculation and validation processes including the interaction with minRAM requirements.[7] Adaptations in these processes are regarded as being complex and time-consuming to implement and design.

Effects on computing power/interaction with other projects

While there was a single opinion that the current project pipeline for SDAC implementation projects fills only around three years and after that point CO could be implemented without offsetting other, potentially more promising projects, the majority opinion was more skeptical. One concern was that the further potential for adding additional features to EUPHEMIA could be limited by the introduction of CO because of increased complexity and computation demand required for CO. It was acknowledged, however, that the effects on the algorithm will depend on the complexity of the bid structure, i.e. the degree of granularity and sophistication to which CO is implemented. Regarding further foreseeable projects that also require implementation effort and could compete with CO for scarce development and computation resources, interviewees mentioned the introduction of the 15 Minute Market Time Unit (MTU) in mid-2025 that is already seen as a significant change to the algorithm with regard to computing power.[8] Another development in European electricity market design that has not yet materialized but would mean significant implementation effort would be an increase in the number of bidding zones in case any bidding zone reconfiguration should happen.[9] In the view of the consulted experts, this could necessitate significant resources for the adaption of the processes. Additionally, there are further projects with varying implementational effort such as the extension of Flow-based market coupling, geographical expansion, a potential closer integration of UK into SDAC, advanced hybrid coupling and the Offshore-bidding zones. The changes caused by new projects are not confined to the algorithm but all related processes on the parts of the TSOs, NEMOs and the market participants also require resources for design and implementation.

All changes do not only cause implementation effort but also require additional computing power which is a scarce resource (although some interviewees were optimistic that constraints

---

[5] See also: *https://www.acer.europa.eu/news/acer-amends-methodology-electricity-market-coupling-algorithm-mandate-research-co-optimisation*

[6] Indeterminacy conditions occur when there are multiple possible solutions that could satisfy the market's clearing conditions, but no unique or definite solution can be determined based solely on the given information.

[7] This also holds for the MBO.

[8] Current information on the introduction of the 15 Minute MTU is published here: *https://www.nemo-committee.eu/sdac*

[9] A bidding zone review report is expected for spring 2025: *https://www.entsoe.eu/network_codes/bzr/#timeline-for-the-bzr*

could be relieved over time). If resources for development and implementation are limited and computing power is a constraint, which most interviewees considered to be true, they also tended to conclude that the introduction of CO should be no priority. The problem of CZCA for SE and BC markets could be solved with significantly reduced efforts and limited reductions in welfare gains. This could be achieved if an alternative approach to CO is chosen while other changes in the market design must be implemented in the EUPHEMIA/SDAC algorithm and seem to be more pressing. The implementation effort and the potential effects on computing power should therefore be carefully weighed against potential welfare gains which in the quantitative part of our study have shown to be limited in total as well as limited in the hours in which they occur.

Alternative: Market-based optimization

In the study, NTUA/UC Louvain concludes that the introduction of CO is clearly more advantageous than the market-based approach (both methods are outlined in section 2.2). Currently, MBO is a regional solution in the Nordic[10] and Baltic[11] region that is not implemented across Europe. Some interview partners identified it as a noteworthy alternative option.

One of the main advantages of MBO is that, looking at implementation effort which is not considered at all by the NTUA/UC Louvain study, the experts consulted estimated it to be significantly lower for MBO than the one required for CO. This can be attributed to the fact that no changes in bid formats, bid submission processed or the EUPHEMIA/SDAC algorithm was needed for MBO. The only changes necessary would be a predictor developed for the value of CZC in SE market and the extension of the BC clearing algorithm to take into account cross-border bids if the welfare gain achieved by their acceptance is higher than this predictor. The feedback indicated that a likely sufficient level of forecasting accuracy could be achieved with manageable resources and that the implementation effort required to extend the BC market clearing would be limited and significantly lower than one associated with a methodically much more complex implementation of CO in SDAC: Hence, implementation of MBO could be considered as a "low-hanging fruit" compared to the more complex CO. Moreover, relevant experience from European markets may serve as a useful reference. However, some interviewees still see significant implementation effort caused by the inclusion of an additional market stage that might not be justified by the efficiency gains achieved.

Apart from the lower implementation effort, some of the experts consulted also considered MBO to be preferable from a more general perspective as it would allow market participants greater degrees of freedom in optimizing their portfolios. Consequently, they argue that results, even from a welfare perspective, could be better than with a low-level, moderately sophisticated level of CO.

However, both options, CO and MBO, entail specific drawbacks. They allocate a certain share of CZC to BC at the day-ahead stage. Because of the nature of BC markets, this allocation needs to be firm and cannot be revised until delivery time. This is a significant difference compared to SE markets at day-ahead stage where there is actually only an initial allocation of capacity which can be revised and adapted within intraday trading. If any further allocation of capacity should turn out to deliver higher welfare gains during intraday trading, e.g. due to fundamental changes

[10] For information on the Nodic Balancing Market see: *https://nordicbalancingmodel.net*

[11] For information on the Baltic Balancing Market see: *https://www.litgrid.eu/index.php/electricity-market/balancing-market/proposal-for-the-cross-zonal-capacity-allocation-methodology-for-balancing-capacity-/3251*

in availability of generation, a complete reallocation of CZC remains possible. For CZC allocated to the exchange of BC this is no longer possible, nor is there any netting of countervailing flows. From an economic perspective this means that allocating CZC to SE markets has an option value because this allocation is not fixed and can be changed later in the process, namely in the intraday market. It is beyond the scope of this study to quantify this option value. But the experts consulted agreed that a CZCA, which is solely based on bid values for SE and BC and does neglect this option value, does not lead to efficient results.

Therefore, some of the experts argued in favor of the probabilistic method (ProbM) - an approach for taking CZC into account that does not explicitly reserve CZC ex-ante for the purposes of BC exchange.

Fallback mechanisms

Even though any new implementation in the market coupling algorithm is tested vigorously before go-live, there remains a risk that with increasing complexity due to CO the risk of de-coupling events increases. For such events fallback mechanisms are already in place, however they would have to be adapted as with the implementation of CO the BC and SE markets are linked. Given that day-ahead processes which normally happen after market clearing like DACF are on a very tight schedule already today, the overall schedule of all processes would become even tighter if emergency procedures to procure BC in case of a decoupling would have to be organized after the decoupling event. Although some experts deem the procurement of BC manageable even in this case, sufficient time is needed and might even require a backward shift of gate-closure times. Again, the design requirements for the fallback mechanisms depend on the design choices made for the introduction of CO. By linking market stages more parties will have to be involved in the fallback mechanisms.

The quantitative efficiency gains calculated in simulations do not account for the inefficiencies from additional fallback mechanisms that occur in the event of decoupling. These must, however, be weighed against any postulated efficiency gains.

Effect on bid structure and dispatch

A recurring topic in all interviews was the complexity of the bid structure required for CO which is closely linked with the level of sophistication needed. The implementation effort for the Market Coupling Algorithm closely depends on how bids would be submitted to the co-optimization algorithm and which decisions would be made by this algorithm. Trade-offs exist but might look different from the perspective of the market coupling algorithm and of market participants. Today's bid formats only include one dimension for BC (EUR/MW) and SE (EUR/MWh) each which is fine for a sequential clearing of these markets as market participants can adapt their bids for the subsequent market stage based on the outcome of the previous stage. However, these bid formats are not suited for including technical constraints (such as start-up costs, minimum downtimes etc.). Nor can they adequately represent cost structures (including opportunity cost) or interdependencies between markets and within large portfolios, factors that a comprehensive CO approach involving the simultaneous clearing of BC and SE markets would need to account for. In general, there seem to be two very different approaches to deal with that requirement. In the first approach, market participants would have to model above-mentioned constraints by some kind of bid linkages, marking them mutually exclusive, depending on each other or only to be accepted jointly and combining these linkages with individual opportunity costs/bid value modifiers. From the perspective of the market coupling algorithm this would not systematically change the nature of the optimization problem, but (vastly) increase the number of integer constraints and therefore complexity to solve the optimization problem. From the market participants perspective, however, the complexity of bid calculation and submission would multiply as permutations of bid acceptances would have to be simulated and evaluated in advance. On the other hand, one could imagine a radically different bid structure where market participants would not submit somehow linked BC and SE bids but would rather submit modelling the technical and economic properties of the providing units allowing the market clearing algorithm not only to match and accept bids but to actually solve the unit commitment problem. Such an approach, which could be considered as the only true CO as applied in some US markets, e.g., would require some form of unit-based bidding and complex bid structures allowing bids to include all necessary technical constraints, allowing for a central dispatch (an exemplary bid format is depicted in Figure 3.1). It would also require a completely different approach for the EUPHEMIA/SDAC algorithm.

Generation and DRR-Type II Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Economic Offer Data				
Energy Offer Curve	MW, $/MWh	Hourly	Hourly	
No-Load Offer	$/hr	Hourly	Hourly	4
Regulating Reserve Capacity Offer	$/MWh	Hourly	Hourly	1.5
Regulating Reserve Mileage Offer	$/MW	Hourly	Hourly	1
Spinning Reserve Offer	$/MWh	Hourly	Hourly	1.5
On-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	1,2,5
Off-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	3,5
Off-Line Short-Term Reserve Offer	$/MWh	Hourly	Hourly	1,5
Hot Start-Up Offer	$	Daily	Daily	4
Intermediate Start-Up Offer	$	Daily	Daily	4
Cold Start-Up Offer	$	Daily	Daily	4
Self-Scheduled Regulation	MW	Hourly	Hourly*	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly*	1
Self-Scheduled On-Line Supplemental Reserve	MW	Hourly	Hourly*	1,2
Self-Scheduled Off-Line Supplemental Reserve	MW	Hourly	Hourly*	3
Self-Scheduled Energy	MW	Hourly	Hourly*	

Note 1: If qualified
Note 2: If not Spin Qualified
Note 3: Quick-Start Resources only
Note 4: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets
Note 5: DRRs-Type II may submit up to three MW/Price pairs for reserve offers
Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval

Figure 3.1 Bid format in a US market with co-optimization (source: MISO Business Practices Manual – Energy and Operating Reserve Markets)[12]

To our understanding, CO according to EB Regulation, would still rely on portfolio-based bidding and self-dispatch (which in Europe, e. g. in Germany, is not only common for SE but also for BC). The Market Coupling Algorithm would have to follow the first approach described above, managing CO by implementing priority rules among balancing products as well as between energy and balancing products. Additional rules for managing indeterminacy conditions and non-convexity (paradoxical rejections of orders) would also be required. The experts we spoke to emphasized that the implementation effort depends largely on the extent to which CO is introduced, as there are still many unanswered questions at this stage. An adapted bid format for co-optimization would face the challenge of ideally being designed for all asset structures while capturing all the information required by the algorithm. This includes, for example, the explicit

[12] MISO Business Practices Manual - Energy and Operating Reserve Markets. *https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/*

bidding of opportunity costs since products like heat (CHP) require explicit consideration of these costs in the optimization.

While acknowledging that such approach might be feasible from the perspective of the EUPHEMIA/SDAC algorithm, market participants and NEMOs interviewed for this study agreed that the complexity of the resulting bid structure could not be managed in a way by market participants that would actually allow them to submit optimal bids. Instead, market participants suggested they would aim at submitting bids which actually pre-determine decisions to be made by the market coupling algorithm on the allocation between BC and SE provision and limit the degrees of freedom for the algorithm (e.g. by adapting opportunity costs in bids or including restrictive bid linkages). Thus, interviewees argued that the outcome of the CO process might be optimal with respect to the submitted bids but still not result in an efficient utilization of resources for SE and BC provision. Several interviewees argued that they would even expect a reduction of social welfare as a consequence of such implementation of CO because optimizations within portfolios which happen today could no longer be done by market participants while the level of accuracy necessary to calculate an efficient dispatch could not be achieved by the CO algorithm.

There was a widespread sentiment that such an outcome would not be sustainable and therefore, there would soon be a discussion to pursue the second of the approaches described above resulting in CO only to be a precursor towards a unit-based bidding scheme with central dispatch further down the line.

As a conclusion, almost all interviewees agreed that in today's market structure, CO will lead to a substantial increase in complexity that could endanger manageability for market participants Any reduction of complexity by a limited degree of sophistication with the market coupling or by a deliberate decision of market participants not to submit optimal bids (i.e. those which would cover all technical constraints, costs and opportunity costs for the entire portfolio and model them by bid linkages), however, bears a risk of not realizing any of the intended welfare gains (or even cause welfare losses, especially considering implementational efforts and transaction costs which would increase with more complex bids). Complexity could in theory be overcome by having bids that reflect the actual technical constraints and cost structure of single units instead of bids for particular products. This, however, would effectively lead to a unit-based central dispatch model and would constitute an entirely different market design. Such a design would resemble e.g. US ISO Markets that actually have a CO of SE and BC products which is applied across all market timeframes and unit commitment decisions, not only for DA markets. This comes at a cost as it precludes both portfolio bidding and continuous trading. Such a market design is often described as a theoretical benchmark. However, it should be mentioned that this is mainly true for systems with large, centralized generation, but there is no evidence of how such market design will interact with requirements from decentralized flexibility providers and in markets with major shares of RES generation.

As expected, market participants confirmed their preference for portfolio bidding and self-dispatch. They argue that the intelligence and innovation of market participants can only be rewarded in portfolio bidding. They stress that CO would pose a particular hurdle for the participation of flexibilities and decentralized generation in the markets.

The need for more complex bid formats and the potential path towards central dispatch raise the issue of whether a development in the realm of balancing capacity markets, which stems from the EB Regulation, is intended or even supposed to trigger such a fundamental reorganization of the current market design. The European system is currently undergoing major transformation towards a decentralized system with a large share of RES and a significant role of flexibilities. This raises the question of whether central dispatch, which becomes increasingly like the more completely CO is introduced, constitutes an appropriate approach to address these developments.

At least, there should be an awareness that introducing CO without significantly changing the entire structure of the EU electricity market design, according to our interviewees, it is unlikely to deliver significant welfare gains, if any at all. If CO is introduced to a limited extent, in order not to completely change today's bidding formats, portfolio bidding and self-dispatch, the desired welfare gains might not materialize, and a partial implementation might even lead to reduced social welfare. A fundamental change of market structures, however, was widely considered to be beyond the scope of the EB Regulation implementation.

Linking of markets and effects on price transparency

CO effectively means that day-ahead markets (DA) for BC and SE that previously operated separately would be combined. The effects of linking the day-ahead markets influences the decisions of market participants regarding their choice in which markets to participate and require even market participants which mainly focus on SE provision to develop models and forecasts for the BC markets. Market participants which dislike those limitations or consider bidding in co-optimized markets to be too complex could potentially decide to only engage in intraday markets (ID) unless bidding in day-ahead markets becomes compulsory. To effectively enhance overall efficiency, ID markets would have to be part CO. However, this would entail a significant increase in complexity and the loss of continuous trading.

Linking SE and BC markets would additionally imply that prices in scheduled energy markets are determined not only by the bids for SE and capacity constraints, but also on opportunity costs from bids for BC markets. This might reduce the risk of ex-post-regrets regarding the market outcome but decreases the transparency of price formation. A lack of transparency particularly affects smaller market participants and thereby potentially increases the risk of market concentration.

It should be emphasized that CO links markets of significantly different sizes. The SDAC has a much greater commercial impact compared to the balancing markets. The price predictability on SE markets directly affects the behavior of market participants. Financial players that are active in these markets crucially depend on price transparency. The effects on price transparency could also have repercussions on liquidity of forward markets with an even higher commercial impact compared to SDAC since forward markets use SDAC prices as underlying. If price transparency is insufficient, financial participants might eventually retire from these markets. Stability as well as explainability of prices are the basis for investment decisions into assets with long-term planning horizons.

Beyond energy markets, electricity prices have significant implications for political decision-making. Even after the energy price crisis of recent years has eased, the level of electricity prices remains a highly politicized issue. If the transparency and explainability are decreasing, this could potentially pose a potential risk for European integration of energy markets.

The effects of reduced price-transparency cannot be quantified but should be considered when weighing the expected benefits of CO against the potential risks and additional cost.

3.2.2 Challenges for Balancing Reserves

Quantitative simulations assuming perfect competition, assume rational behavior of market players, leading to the welfare optimum. The actual behavior of powerful market players, however, can cause distortions in the allocation process. With regard to CO this could be worrisome, as the SE and BC markets have different competitive structures and market power can be a concern. As the markets for BC are comparatively narrow this issue should be considered when analyzing the effects of the introduction of CO on reserves.

When bids submitted by market participants are used to allocate CZC between SE and BC markets, the resulting allocation yields an efficient – that is, welfare-maximizing – outcome if the bids reflect true costs and are made within a sufficiently competitive market environment.

In today's SE markets, most observers agree that market power does not play a major role. Bids are usually based on variable costs, including estimated opportunity costs especially for storage technologies. However, this does not hold for BC markets. Due to technical requirements and more complex products, there are fewer active participants and less market depth. As a result, BC prices often cannot be explained by standard market models, which should be considered in the evaluation of the indicative cost levels of BC provision in the quantitative assessment of this study.

Therefore, there is a clear risk that BC bids include markups above actual variable costs. This means that simply comparing bid values to decide whether scarce transmission capacity should be used for SE or BC might not lead to a welfare-optimal outcome. In fact, it could even reduce overall welfare compared to a case where the capacity is only used for SE.

Inefficiency can occur anytime CZC is allocated to markets that are not fully competitive. The risk is especially high with CO, because it allows the entire transmission capacity to be used for BC – without limits.

3.2.3 Limits of quantitative assessment

Section 2.1 already provides an overview of the method used by NTUA/UC Louvain and its limitations. Our interviews have revealed considerable doubts about the study's postulated efficiency gains. It must be concluded that these efficiency gains are only achievable under perfect conditions. Additionally, the study assumes limited coordination which reduces the possibilities of portfolio optimization and results in an underestimation of the efficiency of *MBO* and *Status Quo*. Refining quantitative analysis as was done in the quantitative part of this study can provide additional insights into the potential efficiency gains. Notably, this study models two extremes of bid submission coordination - complete coordination and no coordination. Complete coordination provides an upper bound for the efficiency of *MBO* and *Status Quo*. Although it is not possible to determine with certainty how close real-world market outcomes are to this upper bound, the presence of portfolio optimization in actual markets suggests that outcomes likely align more closely with full coordination than with the absence of coordination.

However, there are effects that fundamental market models are simply not able to incorporate. Many of these effects such as implementation effort, the welfare losses in case of increasing decoupling events and decreasing price transparency have been discussed in the qualitative part of this study. An additional inefficiency results from the fact that allocating CZC based on a comparison of bid values between BC and SE bids fundamentally ignores the loss of option value of CZC if used for BC instead of SE exchanges, as explained above.

Models cannot capture reactions of market participants to the market design. As already discussed, assuming portfolio bidding and self-dispatch are maintained, bid structure and bid preparation would become much more complex than in today's sequential markets to account for interdependencies between (multiple) BC and SE products. These complexities are less manageable for smaller market participants compared to bigger players, favoring concentration and lack of competition. Market participants also might want to "pre-determine" outcome of optimization and allocation of their assets to BC vs. SE, i.e. maintaining their freedoms in portfolio optimization. Such behavior may lead to distorted bids and there pose a risk of inefficiencies as CO is interfered with. Market participants might also react by focusing on single market segments (SE, in particular), resulting in BC markets with even lower liquidity and higher concentration ratios than today.

We therefore conclude that any model analyzing the impact of CO which does not account for the significant differences in complexity of a co-optimized market and potential adverse effects discussed above, is likely to significantly overestimate the achievable welfare gains.

4 Conclusions

The quantitative assessment evaluates different approaches of CZCA to add a more comprehensive analysis to the results from the NTUA/UC Louvain study. A key distinction lies in the choice of case study: while the NTUA/UC Louvain analysis is based on historical data, this study employs a 2030 scenario to reflect expected developments in the energy system. Other key factors being investigated include the level of coordination between the SE and BC markets and the forecasting methodology. By modelling cases of complete and no coordination, the quantitative assessment identified a large bandwidth of potential cost savings for CO compared to the Status Quo, highlighting the sensitivity of results to assumptions about market coordination.

Compared to the estimated EUR 678 million savings per year from CO according to NTUA/UC Louvain, this study finds significantly lower values ranging from EUR 15.5 to 179 million per year when using a future case study year and a more sophisticated forecasting approach. While BC exchange can improve efficiency by reducing inefficient commitment of thermal power plants, its impact is smaller when hydro power plants and batteries are the dominant BC providers. Additionally, the study shows that increased bid submission coordination of market participants in both SE and BC markets yields greater efficiency gains than BC exchange itself. For MBO, the quantitative analysis indicates negligible effects on scheduled energy markets, with the direction of the impact being highly scenario-dependent. An estimation of BC costs demonstrates notable savings for both CO and MBO approaches.

Although total BC exchange volumes remain low, the quantitative assessment showed that exchange is concentrated in specific periods, particularly when renewable generation is low, indicating that BC exchange can provide benefits in such periods.

When weighing the qualitative aspects that cannot be captured by fundamental models the introduction of CO is viewed with skepticism for the most part by the experts from TSOs, NEMOs and market participants that were interviewed as part of the qualitative assessment. Considerable doubts remain regarding the postulated efficiency gains, specifically as the bid structure would need to become more complex to fully implement CO and therefore fully reap its benefits. This increasing complexity paves the way towards unit-based bidding, and in the longer term, suggests that a development toward a central dispatch system does not appear unlikely. These potential changes raise the question whether a development in the realm of balancing power markets, which stems from the GLEB, is intended or even supposed to trigger such a fundamental reorganization of the current market design.

Practical CO implementations can be found in markets with large, centralized generation units that are better suited for unit-based bidding and central dispatch. In contrast, the European system is currently undergoing major transformation toward a decentralized system with a large share of RES and a significant role of flexibilities. It is therefore subject to debate whether a central dispatch with unit-based bidding – whose implementation becomes increasingly likely as CO is more comprehensively introduced – constitutes an appropriate approach to address these developments. If on the other hand a system is introduced with only some feature of CO, it is consistency and may fail to deliver the intended welfare gains.

In addition to the anticipated efficiency gains, the discussion on the introduction of CO should consider the number of effects that it would cause, ranging from implementation efforts and increasing complexity in large parts of the system that might trigger a whole new market design, to the reaction of market participants and the transparency of electricity prices. In that discussion it should be made clear that a partial introduction can only partially achieve the calculated welfare gains, if at all, but may even generate disadvantages. A full implementation of CO, on the other hand, requires a fundamental change in the current market design – a process in which all relevant stakeholders should be involved as it is not limited to BC markets.

A Annex

A.1 Nomenclature

Sets

$\mathcal{C}$	Set of CNEC
$\mathcal{D}$	Set of DSR units
$\mathcal{E}$	Set of electrolysis units
$\mathcal{G}$	Set of generation units
$\mathcal{R}$	Set of balancing reserve types
$\mathcal{S}$	Set of storages
$\mathcal{T}$	Set of time steps
$\mathcal{Z}$	Set of bidding zones
$\mathcal{Z}_{Core}$	Set of bidding zones of the CORE CCR

Variables

E	Storage level
H^{daily}	Daily aggregated load reduction
$EX^{BC,-/+}$	Exchange of BC (-: negative direction, +: positive direction)
EX^{SE}	Exchange of SE
NP^{SE}	Net position of SE
P^{SE}	Power for SE market
$P^{BC,-/+}$	Power for BC market (-: negative direction, +: positive direction)
P^{on}	Help variable for linear dynamic constraints: online power
P^{up}	Help variable for linear dynamic constraints: ramped up power
$P^{up,max}$	Help variable for linear dynamic constraints: max. ramp up power
P^{down}	Help variable for linear dynamic constraints: ramped down power
$P^{down,max}$	Help variable for linear dynamic constraints: max. ramp down power

Subscripts

$cnec$	Critical Network Element and Congestion (CNEC)
d	DSR unit
e	electrolysis unit
g	Generation unit
r	Balancing reserve type
s	Storage unit

t	Time step
z	Bidding zone

Parameters

η	Efficiency
c	Marginal cost
c^{start}	Start-up cost
mv^{CZC}	Market value of CZC
oc	Opportunity cost
δ	Availability
D	Electricity demand
MAT	Maximum activation time for balancing capacity
m^{Import}	Maximum import limit for balancing capacity (FRR: 50%, FCR: 70%)
p_{H_2}	Hydrogen price
P^{max}	Technical maximum power
P^{min}	Technical minimum power
PR	Power generation from RES
$PTDF$	Zonal Power Transfer Distribution Factor
NTC	Net Transfer Capacity
$R^{-/+}$	Reserve requirement (-: negative direction, +: positive direction)
RAM	Remaining available margin (sfd: standard flow direction, nsfd: non-standard flow direction)
T_{up}^{min}	Minimum up time
T_{down}^{min}	Minimum down time
$\Delta^{up,rel}$	Relative upward power gradient
$\Delta^{down,rel}$	Relative downward power gradient
T_{dec}^{max}	Maximum daily load reduction time

A.2 Modelling Details

A.2.1 Completely coordinated model

The completely coordinated model is formulated as follows:

$$\min \sum_{t\in\mathcal{T}} \left(\sum_{g\in\mathcal{G}} \left(c_g \cdot \frac{P_{g,t}^{SE}}{\eta_g} + c_g^{start} \cdot P_{g,t}^{up} \right) + \sum_{d\in\mathcal{D}} c_d \cdot P_{d,t}^{SE} + \sum_{e\in\mathcal{E}} -p_{H_2} \cdot P_{e,t}^{SE} \cdot \eta_e + \sum_{z\in\mathcal{Z}} c^{ENS} \cdot P_{z,t}^{ENS} + \sum_{z\in\mathcal{Z}} \sum_{r\in\mathcal{R}} c^{RNS} \cdot P_{z,r,t}^{RNS,-/+} \right) \tag{4.1}$$

$$\sum_{g\in\mathcal{G}_z} P_{g,t}^{SE} + \sum_{s\in\mathcal{S}_z} P_{s,t}^{SE,out} + PR_{z,t} - P_{z,t}^{curtail.} + NP_{z,t}^{SE} = D_{z,t} + \sum_{s\in\mathcal{S}_z} P_{s,t}^{SE,in} - \sum_{d\in\mathcal{D}_z} P_{d,t}^{SE} + \sum_{e\in\mathcal{E}_z} P_{e,t}^{SE} - P_{z,t}^{ENS} \tag{4.2}$$

$$\sum_{g\in\mathcal{G}_z} P_{g,r,t}^{BC,-/+} + \sum_{s\in\mathcal{S}_z} P_{s,r,t}^{BC,-/+} + \sum_{d\in\mathcal{D}_z} P_{d,r,t}^{BC,-/+} + \sum_{e\in\mathcal{E}_z} P_{e,r,t}^{BC,-/+} + P_{renewables,t}^{BC,-/+} + \sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{x\to z,r,t}^{BC,-/+} = R_{z,r}^{-/+} + \sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{z\to x,r,t}^{BC,-/+}, \forall z \in \mathcal{Z}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.3}$$

$$RAM_{cnec,t}^{nsfd} \le \sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} \cdot PTDF_{cnec,z} \le RAM_{cnec,t}^{sfd} \tag{4.4}$$

$$\sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} = 0, \forall t \in \mathcal{T} \tag{4.5}$$

$$\sum_{x\in\mathcal{Z}\backslash\{\mathcal{Z}_{Core},z\}} EX_{z\to x,t}^{SE} \le NTC_{z\to x}, z \in \mathcal{Z}\backslash\mathcal{Z}_{Core},, \forall t \in \mathcal{T} \tag{4.6}$$

$$\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}>0}} EX_{x\to z,r,t}^{BC,+} \cdot PTDF_{cnec,x\to z} + \sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} \cdot PTDF_{cnec,z} \le RAM_{cnec,t}^{sfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.7}$$

$$\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}<0}} EX_{x\to z,r,t}^{BC,-} \cdot -PTDF_{cnec,x\to z} + \sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} \cdot PTDF_{cnec,z} \le RAM_{cnec,t}^{sfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.8}$$

$$\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}<0}} EX_{x\to z,r,t}^{BC,+} \cdot -PTDF_{cnec,x\to z} - \sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} \cdot PTDF_{cnec,z} \le RAM_{cnec,t}^{nsfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.9}$$

$$\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}>0}} EX_{x\to z,r,t}^{BC,-} \cdot PTDF_{cnec,x\to z} - \sum_{z\in\mathcal{Z}_{Core}} NP_{z,t}^{SE} \cdot PTDF_{cnec,z} \le RAM_{cnec,t}^{nsfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.10}$$

$$\sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{x\to z,r,t}^{BC,-/+} \le m^{Import} \cdot R_{z,r}^{-/+}, \forall z \in \mathcal{Z}_{Core}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.11}$$

$$P_{g,t}^{on} \le P^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.12}$$

$$P_{g,t}^{SE} - \sum_{r\in\mathcal{R}} P_{g,r,t}^{BC,-} \ge \frac{P_g^{min}}{P_g^{max}} \cdot P_{g,t}^{on}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.13}$$

$$P_{g,t}^{SE} + \sum_{r\in\mathcal{R}} P_{g,r,t}^{BC,+,slow} \le P_{g,t}^{on}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.14}$$

$$P_{g,t}^{SE} + \sum_{r \in \mathcal{R}} P_{g,r,t}^{BC,+,slow} + P_{g,r,t}^{BC,+,fast} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.15}$$

$$P_{g,t}^{up,max} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.16}$$

$$P_{g,t}^{up} \leq P_g^{up,max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.17}$$

$$P_{g,t}^{down,max} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.18}$$

$$P_{g,t}^{down} \leq P_{g,t}^{down,max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.19}$$

$$P_{g,t}^{on} = P_{g,t-1}^{on} + P_{g,t}^{up} - P_{g,t}^{down}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t = 0\} \tag{4.20}$$

$$P_{g,t}^{up,max} = P_{g,t-1}^{up,max} - P_{g,t-1}^{up} + P_{g,t-T_{up,g}^{min}}^{down}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t \leq T_{up,g}^{min}\} \tag{4.21}$$

$$P_{g,t}^{down,max} = P_{g,t-1}^{down,max} - P_{g,t-1}^{down} + P_{g,t-T_{down,g}^{min}}^{up}, , \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t \leq T_{down,g}^{min}\} \tag{4.22}$$

$$P_{g,r,t}^{BC,+} \leq \Delta_g^{up,rel} \cdot P_g^{max} \cdot MAT_r, \forall g \in \mathcal{G}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.23}$$

$$\sum_{r \in \mathcal{R}} \frac{P_{g,r,t}^{BC,+}}{MAT_r} \leq \Delta_g^{up,rel} \cdot P_g^{max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.24}$$

$$P_{g,r,t}^{BC,-} \leq \Delta_g^{down,rel} \cdot P_g^{max} \cdot MAT_r, \forall g \in \mathcal{G}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.25}$$

$$\sum_{r \in \mathcal{R}} \frac{P_{g,r,t}^{BC,-}}{MAT_r} \leq \Delta_g^{down,rel} \cdot P_g^{max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.26}$$

$$P_{s,t}^{SE,out} \leq P_s^{max,out}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.27}$$

$$P_{s,t}^{SE,in} \leq P_s^{max,in}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.28}$$

$$P_{s,t}^{SE,out} + \sum_{r \in \mathcal{R}} P_{s,r,t}^{BC,+} \leq P_s^{max,out} + P_{s,t}^{SE,in}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.29}$$

$$P_{s,t}^{SE,in} + \sum_{r \in \mathcal{R}} P_{s,r,t}^{BC,-} \leq P_s^{max,in} + P_{s,t}^{SE,out}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.30}$$

$$E_{s,t} \leq E_s^{max}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.31}$$

$$E_{s,1} \leq E_{s,8760}, \forall s \in \mathcal{S} \tag{4.32}$$

$$E_{s,t} = E_{s,t-1} + P_{s,t}^{SE,in} \cdot \eta_s^{in} - \frac{P_{s,t}^{SE,out}}{\eta_s^{out}} + P_{s,t}^{inflow} - P_{s,t}^{overflow}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \backslash \{t = 0\} \tag{4.33}$$

$$P_{d,t}^{SE} + \sum_{r \in \mathcal{R}} P_{d,r,t}^{BC,+} \leq P_d^{max}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \tag{4.34}$$

$$\sum_{r\in\mathcal{R}} P^{BC,-}_{d,r,t} \leq P^{SE}_{d,t}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \tag{4.35}$$

$$H^{daily}_{d,y} = \sum_{t=y}^{y+24} P^{SE}_{d,t}, \forall d \in \mathcal{D}, \forall y \in \mathcal{T}: y \bmod 24h = 0 \tag{4.36}$$

$$H^{daily}_{d,y} \leq P^{max}_{d} \cdot T^{max}_{dec}, \forall d \in \mathcal{D},, \forall y \in \mathcal{T}: y \bmod 24h = 0 \tag{4.37}$$

$$P^{SE}_{e,t} + \sum_{r\in\mathcal{R}} P^{BC,-}_{e,r,t} \leq P^{max}_{e}, \forall e \in \mathcal{E}, \forall t \in \mathcal{T} \tag{4.38}$$

$$\sum_{r\in\mathcal{R}} P^{BC,+}_{e,r,t} \leq P^{SE}_{e,t}, \forall e \in \mathcal{E}, \forall t \in \mathcal{T} \tag{4.39}$$

$$P^{BC,-}_{renewables,t} \leq 10\,\% \cdot PR_t \tag{4.40}$$

Eq. *(4.1)* defines the objective function of the completely coordinated model. The objective function minimizes operative system costs, which comprise the marginal costs of generation units (including fuel and CO_2 costs), start-up costs of generation units (both fixed and fuel-related), costs associated with DSR, the negated value of electrolysis based on hydrogen prices, and penalties for energy not served (ENS) and reserve not served (RNS)[13]. Eq. *(4.2)* defines the SE net position. Eq. *(4.3)* ensures that reserve requirements are met by contributions from all generation units, storages, DSR and electrolysis units as well as imports and exports. For bidding zones outside the CORE region, imports and exports are set to zero. Furthermore, when the completely coordinated model is used to simulate the *Status Quo*, cross-zonal exchange of BC is also set to zero within the CORE region. For *MBO (completely coordinated)*, cross-zonal BC exchanges are fixed based on the results of the previous simulation step. Eq. *(4.4)* constrains cross-zonal SE exchange in the CORE region using PTDF and RAM. Eq. *(4.5)* ensures that the internal trade within the CORE region is balanced. Eq. *(4.6)* restricts electricity trading with non-CORE bidding zones and outside of the CORE region using Net Transfer Capacity (NTC) constraints. Eq. *(4.7)-(4.10)* constrain BC exchanges and consider only those exchanges that have a positive sensitivity on a CNEC. This ensures that trading constraints are respected, even when not all BC is activated. Eq. *(4.11)* imposes limitations on BC imports as prescribed in the System Operation Guideline. Eq. *(4.12)-(4.15)* limit the power output and BC provision of generation units based on their maximum capacity, and—if online—their minimum stable generation levels. A distinction is made between slow and fast units: only the former must be online to provide positive BC. Eq. *(4.16)-(4.22)* linearly model minimum up and down times for generation units. Eq. *(4.23)-(4.26)* constrain BC provision by the ramping capability of units within the maximum activation time required for each reserve type. Equations *(4.27)-(4.30)* govern the maximum power injection, generation, and BC provision of storage units. Eq. *(4.31)* constrains their maximum energy capacity, while eq. *(4.32)* ensures the storage level is equal in the first and last simulation time step. Eq. *(4.33)* models the storage continuity constraint considering natural inflows. For closed-loop pumped hydro and battery storages, these inflows are zero. Eq. *(4.34)* and *(4.35)* limit the maximum load reduction of DSR units and their associated BC provision. Eq. *(4.36)* and *(4.37)* additionally ensure that daily load reduction is within acceptable bounds. Eq. *(4.38)* and *(4.39)* constrain the maximum load and BC provision of electrolysis units. Finally, Eq. *(4.40)* restricts

[13] The cost for energy not served is set to 3000€/MWh and for reserve not served to 5000€/MW.

the BC provision from RES by 10% of its available supply. All variables are continuous and non-negative.

A.2.2 Non-coordinated model

In the non-coordinated model, the first step is the BC market. This is modeled as follows:

$$\min \sum_{t\in\mathcal{T}} \left(\sum_{g\in\mathcal{G}} \left(\sum_{r\in\mathcal{R}} \widehat{oc_{g,t}} \cdot P_{g,r,t}^{BC,-/+} + c_g^{start} \cdot P_{g,t}^{up} \right) + \sum_{d\in\mathcal{D}} \sum_{r\in\mathcal{R}} \widehat{oc_{d,t}} \cdot P_{d,r,t}^{BC,-/+} + \sum_{e\in\mathcal{E}} \sum_{r\in\mathcal{R}} \widehat{oc_{e,t}} \cdot P_{g,e,t}^{BC,-/+} + \sum_{z\in Z} \sum_{r\in\mathcal{R}} c^{RNS} \cdot P_{z,r,t}^{RNS,-/+} + \sum_{cnec\in\mathcal{C}} \left(mv_{cnec}^{\widehat{CZC,sfd}} \cdot P_{cnec,t}^{BC,flow,max,sfd} + mv_{cnec}^{\widehat{CZC,nsfd}} \cdot P_{cnec,t}^{BC,flow,max,nsfd} \right) \right) \tag{4.41}$$

$$\sum_{g\in\mathcal{G}_z} P_{g,r,t}^{BC,-/+} + \sum_{s\in\mathcal{S}_z} P_{s,r,t}^{BC,-/+} + \sum_{d\in\mathcal{D}_z} P_{d,r,t}^{BC,-/+} + \sum_{e\in\mathcal{E}_z} P_{e,r,t}^{BC,-/+} + P_{renewables,t}^{BC,-/+} + \sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{x\to z,r,t}^{BC,-/+} = R_{z,r}^{-/+} + \sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{z\to x,r,t}^{BC,-/+}, \forall z \in \mathcal{Z}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.42}$$

$$\max\left(\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}>0}} EX_{x\to z,r,t}^{BC,+} \cdot PTDF_{cnec,x\to z}, \sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}<0}} EX_{x\to z,r,t}^{BC,-} \cdot -PTDF_{cnec,x\to z} \right) = P_{cnec,t}^{BC,flow,max,sfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.43}$$

$$\max\left(\sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}>0}} EX_{x\to z,r,t}^{BC,-} \cdot PTDF_{cnec,x\to z}, \sum_{r\in\mathcal{R}} \sum_{\substack{x,z\in\mathcal{Z}_{Core} \\ PTDF_{cnec,x\to z}<0}} EX_{x\to z,r,t}^{BC,+} \cdot -PTDF_{cnec,x\to z} \right) = P_{cnec,t}^{BC,flow,max,nsfd}, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.44}$$

$$P_{cnec,t}^{BC,flow,max,sfd} \leq RAM_{cnec,t}^{sfd} \cdot 10\,\%, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.45}$$

$$P_{cnec,t}^{BC,flow,max,nsfd} \leq RAM_{cnec,t}^{nsfd} \cdot 10\,\%, \forall cnec \in \boldsymbol{\mathcal{C}}, \forall t \in \mathcal{T} \tag{4.46}$$

$$\sum_{x\in\mathcal{Z}_{Core}\backslash z} EX_{x\to z,r,t}^{BC,-/+} \leq m^{Import} \cdot R_{z,r}^{-/+}, \forall z \in \mathcal{Z}_{Core}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.47}$$

$$P_{g,t}^{on} \leq P^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.48}$$

$$P_{g,t}^{SE} - \sum_{r\in\mathcal{R}} P_{g,r,t}^{BC,-} \geq \frac{P_g^{min}}{P_g^{max}} \cdot P_{g,t}^{on}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.49}$$

$$P_{g,t}^{SE} + \sum_{r\in\mathcal{R}} P_{g,r,t}^{BC,+,slow} \leq P_{g,t}^{on}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.50}$$

$$P_{g,t}^{SE} + \sum_{r\in\mathcal{R}} P_{g,r,t}^{BC,+,slow} + P_{g,r,t}^{BC,+,fast} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.51}$$

$$P_{g,t}^{up,max} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.52}$$

$$P_{g,t}^{up} \leq P_g^{up,max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.53}$$

$$P_{g,t}^{down,max} \leq P_g^{max} \cdot \delta_{g,t}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.54}$$

$$P_{g,t}^{down} \leq P_{g,t}^{down,max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.55}$$

$$P_{g,t}^{on} = P_{g,t-1}^{on} + P_{g,t}^{up} - P_{g,t}^{down}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t = 0\} \tag{4.56}$$

$$P_{g,t}^{up,max} = P_{g,t-1}^{up,max} - P_{g,t-1}^{up} + P_{g,t-T_{up,g}^{min}}^{down}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t \leq T_{up,g}^{min}\} \tag{4.57}$$

$$P_{g,t}^{down,max} = P_{g,t-1}^{down,max} - P_{g,t-1}^{down} + P_{g,t-T_{down,g}^{min}}^{up},, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \backslash \{t \leq T_{down,g}^{min}\} \tag{4.58}$$

$$P_{g,r,t}^{BC,+} \leq \Delta_g^{up,rel} \cdot P_g^{max} \cdot MAT_r, \forall g \in \mathcal{G}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.59}$$

$$\sum_{r\in\mathcal{R}} \frac{P_{g,r,t}^{BC,+}}{MAT_r} \leq \Delta_g^{up,rel} \cdot P_g^{max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.60}$$

$$P_{g,r,t}^{BC,-} \leq \Delta_g^{down,rel} \cdot P_g^{max} \cdot MAT_r, \forall g \in \mathcal{G}, \forall r \in \mathcal{R}, \forall t \in \mathcal{T} \tag{4.61}$$

$$\sum_{r\in\mathcal{R}} \frac{P_{g,r,t}^{BC,-}}{MAT_r} \leq \Delta_g^{down,rel} \cdot P_g^{max}, \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \tag{4.62}$$

$$P_{s,t}^{\widehat{SE,out}} + \sum_{r\in\mathcal{R}} P_{s,r,t}^{BC,+} \leq P_s^{max,out} + P_{s,t}^{\widehat{SE,in}}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.63}$$

$$P_{s,t}^{\widehat{SE,in}} + \sum_{r\in\mathcal{R}} P_{s,r,t}^{BC,-} \leq P_s^{max,in} + P_{s,t}^{\widehat{SE,out}}, \forall s \in \mathcal{S}, \forall t \in \mathcal{T} \tag{4.64}$$

$$P_{d,t}^{SE} + \sum_{r\in\mathcal{R}} P_{d,r,t}^{BC,+} \leq P_d^{max}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \tag{4.65}$$

$$\sum_{r\in\mathcal{R}} P_{d,r,t}^{BC,-} \leq P_{d,t}^{SE}, \forall d \in \mathcal{D}, \forall t \in \mathcal{T} \tag{4.66}$$

$$H_{d,y}^{daily} = \sum_{t=y}^{y+24} P_{d,t}^{SE}, \forall d \in \mathcal{D}, \forall y \in \mathcal{T}: y \bmod 24h = 0 \tag{4.67}$$

$$H_{d,y}^{daily} \leq P_d^{max} \cdot T_{dec}^{max}, \forall d \in \mathcal{D},, \forall y \in \mathcal{T}: y \bmod 24h = 0 \tag{4.68}$$

$$P_{e,t}^{SE} + \sum_{r \in \mathcal{R}} P_{e,r,t}^{BC,-} \leq P_e^{max}, \forall e \in \mathcal{E}, \forall t \in \mathcal{T} \tag{4.69}$$

$$\sum_{r \in \mathcal{R}} P_{e,r,t}^{BC,+} \leq P_{e,t}^{SE}, \forall e \in \mathcal{E}, \forall t \in \mathcal{T} \tag{4.70}$$

$$P_{renewables,t}^{BC,-} \leq 10\ \% \cdot PR_t \tag{4.71}$$

The objective function, described in eq. *(4.41)*, consists of the forecasted opportunity cost of reserving BC in the BC market, start-up costs (incurred when a unit must be started to provide BC), and the valuation of BC exchange based on the forecasted market value of CZC for SE exchange. The determination of the opportunity costs of the different technologies is described in the next section. Eq. *(4.42)* ensures that total reserve requirements are met through domestic BC provision and cross-zonal imports and exports. Eq. *(4.43)* and *(4.44)* introduce help variables representing the maximum possible flow on a CNEC, considering the worst-case positive or negative activation of BC. These flows are constrained in Eq. *(4.45)* and *(4.46)* to remain within the RAM, incorporating the 10% CZC limit imposed under the *MBO* approach. When the non-coordinated model is used to simulate the *Status Quo* scenario, all cross-zonal BC exchanges are set to zero. Eq. *(4.47)* constrains the import of BC to the maximum permissible level as defined in the System Operation Guideline. Eq. *(4.48)* to *(4.62)* model the technical characteristics of generation units, including constraints on minimum and maximum power output as well as minimum up- and down-times. These formulations are consistent with those used in the completely coordinated model. SE variables are also included to ensure that the resulting BC provision remains within all operational limits. Eq. *(4.63)* and *(4.64)* limit BC provision from storage units based on their forecast SE dispatch. Eq. *(4.65)* to *(4.68)* govern the provision of BC from DSR units, ensuring compliance with SE market constraints. Eq. *(4.69)* and *(4.70)* apply similar restrictions to electrolysis units. Eq. *(4.71)* constrains the BC provision from RES. As with the completely coordinated model, all variables are continuous and non-negative, and the entire formulation remains within the scope of linear programming.

In the next stage of the non-coordinated approach, the SE market is simulated. This model largely mirrors the structure of the completely coordinated model; however, the provision of BC by all units is treated as fixed, based on the outcomes of the previous optimization step. Specifically, this applies to Eq. *(4.3)*, *(4.13)-(4.15)*, *(4.29)-(4.30)*, *(4.34)-(4.35)* and *(4.38)-(4.40)*, where BC-related variables are no longer decision variables but parameters. Similarly, in the case of the *MBO* approach, the cross-zonal exchange of BC—defined in Eq. *(4.7)-(4.11)*—is also fixed to the values obtained in the preceding BC market simulation.

A.2.3 Determination of Balancing Capacity Provision Costs

The costs for balancing capacity provision are primarily composed of opportunity costs, representing foregone revenue from other markets, particularly the SE market. In order to model the BC market separately from the SE market in the non-coordinated approaches in this study, price forecasts are used to estimate the opportunity costs for all units.

Each unit's operating point P_{op} is constrained by its minimum and maximum output P_{min} and P_{max}. To provide positive balancing capacity, a unit must withhold part of its upward capacity $P_{BC,up}$. For negative balancing capacity, it must operate at a higher output level to ensure sufficient downward reserve $P_{BC,down}$. The opportunity costs for the provision of balancing capacity depend on the (forecasted) market price p_{el} and the variable costs of the unit c_{var}, as illustrated in Figure A.1.

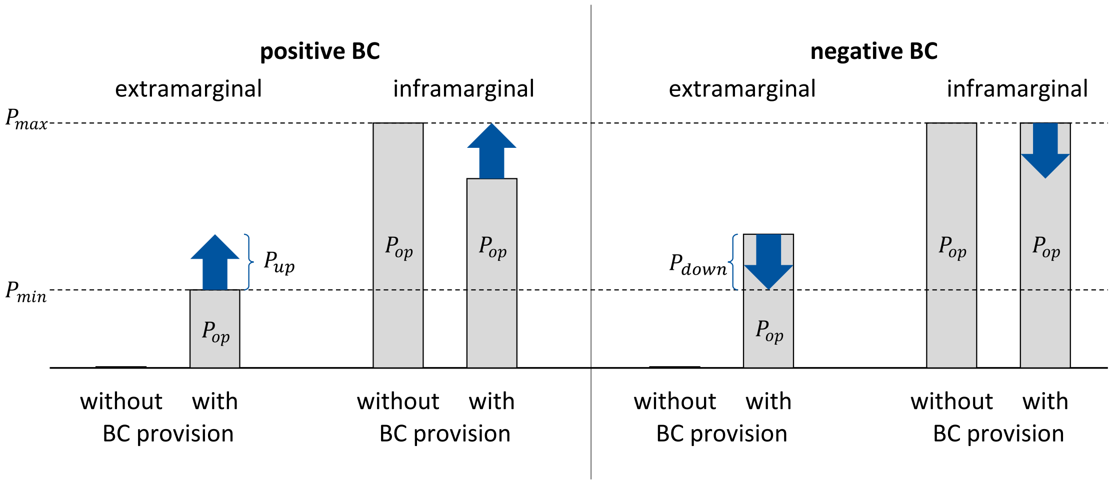

Figure A.1 Provision of balancing capacity for different market price situations

If a unit is expected to be extramarginal ($c_{var} > p_{el}$), its operation is not economically viable. If it has to be online solely for providing balancing capacity, it needs to sell electricity below marginal costs, resulting in a financial loss. If a unit is expected to be inframarginal ($c_{var} < p_{el}$), it will aim to maximize energy sales. In this case, withholding capacity for positive balancing leads to lost revenue from energy sales and therefore incurs an opportunity cost. However, providing negative balancing capacity does not reduce profits and thus involves no costs.

Based on this, for each unit and simulation time step, the model calculates BC provision costs depending on whether the unit is inframarginal or extramarginal, depending on the forecasted price. The marginal cost for positive BC provision in the extramarginal case is given by equation (4.72).

$$c_{BC,pos}^{ex} = (c_{var} - p_{el}) \cdot \frac{P_{min}}{P_{up}} \tag{4.72}$$

The cost for positive BC provision in the inframarginal case is given by equation (4.73).

$$c_{BC,pos}^{inf} = (p_{el} - c_{var}) \tag{4.73}$$

The cost for negative BC provision arises only in the extramarginal case, as formulated in equation (4.74).

$$c_{BC,neg}^{ex} = (c_{var} - p_{el}) \cdot \frac{P_{min} + P_{down}}{P_{down}} \tag{4.74}$$

For thermal power plants, a distinction is made between spinning and standing reserves. Spanning reserves require the plant to be online to provide balancing capacity, whereas standing reserves can be activated for balancing from an offline state. In this study, only gas-fired power plants are considered as standing reserves for the provision of mFRR capacity. For these plants therefore, the provision of positive mFRR capacity incurs no costs in the extramarginal case.

For renewable generation units, which are assumed only to be able to provide negative BC, no opportunity costs are incurred as their marginal costs are considered negligible. For demand-side flexibility, including demand side response (modeled as load reduction potential) and electrolysis (modelled as load increase potential), opportunity costs are modeled similarly to standing reserves. However, these units do not have a minimum output constraint.

For storage units, including hydro power plants and batteries, several approaches for modeling opportunity costs were analyzed in the course of this study. Their opportunity costs primarily result from restricting their ability to engage in temporal arbitrage in the SE market. However, due to the diversity of technical characteristics (e.g., turbine-to-pump power ratio, round-trip efficiency) and the variability in operators' optimization strategies and horizons, accurately modeling their cost structures and price formation process for BC proved challenging. As none of the tested approaches provided a reliable estimation of opportunity costs, the provision of BC by storage units was constrained based on their forecasted dispatch in the SE market. The same forecast used for electricity prices was applied to determine this dispatch, and it is interpreted as the expected operation of storage units under those price assumptions.

A.3 Grid Model and Regionalization

All grid expansion measures planned for commissioning up to and including 2030 were integrated into the IAEW European transmission grid model used in this study. For the German grid, the expansion measures from the national grid development plan published by the four German TSOs were considered. For neighboring European countries, grid expansion projects from the TYNDP 2022 were incorporated. Grid expansion measures with commissioning dates beyond 2030, for which the timeline remains uncertain, were not included. Figure 6 provides an overview of the underlying grid model.

The installed capacities for RES are allocated to grid nodes based on potential areas in Europe, as shown in Figure A.2.

The national annual electricity demand is regionalized based on socioeconomic data and divided into static and flexible demand. Static demand follows a time series derived from the 2012 weather year. Flexible demand includes electrolysers, DSR, and large-scale battery storages. The locations of battery storages are determined based on PV generation and load distribution. Half of the installed electrolyser capacity (on-site) and DSR potential are allocated according to the load at each grid node, while the other half of the electrolyser capacity (off-site) is distributed based on offshore and onshore wind generation sites.

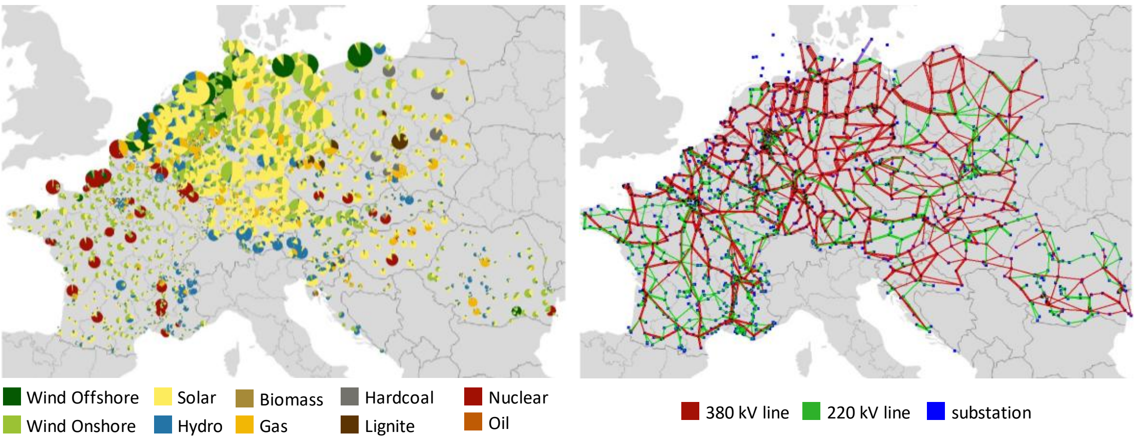

Figure A.2 Regionalization of the installed capacities (left) and the underlying grid model (right)

A.4 Results

A.4.1 Estimated Average Costs for Balancing Capacity Activation

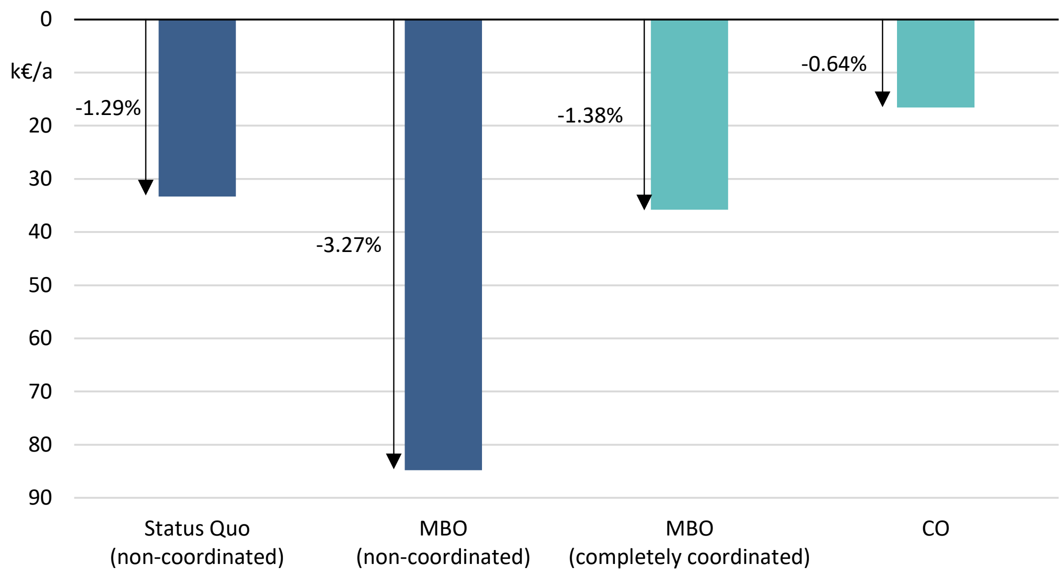

Figure A.3 Difference of annual estimated average BC activation costs in the CORE region compared to Status Quo (completely coordinated)

A.4.2 Data of Market Outcome Comparison

Annual electricity generation and consumption

Table 2 Difference of annual electricity generation and consumption in the CORE region compared to Status Quo (completely coordinated)

	Status Quo (non-coordinated)	MBO (non-coordinated)	MBO (completely coordi-nated)	CO
Nu-clear	-0.24	-0.36	0.27	0.35
Hard coal	0.25	0.26	0.10	0.07
Lignite	0.18	0.17	0.09	0.07
Gas	0.45	0.64	-0.23	-0.16
Oil	0.07	0.07	-0.04	-0.04
Other	0.00	0.00	0.00	0.00
Elec-tro-lyser	-1.11	-1.14	-0.47	-0.44
DSR	0.23	0.26	0.14	0.13
Hydro (gen.)	-2.05	-2.15	-0.19	0.00
Hydro (load)	2.60	2.77	0.24	-0.01

Batteries (gen.)	0.04	0.14	0.16	-0.02
Batteries (load)	-0.04	-0.15	-0.18	0.02
Solar	0.00	0.00	0.00	0.00
Wind Onshore	0.00	0.00	0.00	0.00
Wind Offshore	0.00	0.00	0.00	0.00
Other RES	9.40	9.51	-0.26	-1.02
Run of River	0.00	0.00	0.00	0.00
Import	-2.03	-2.33	-0.15	0.02
Export	2.04	2.15	0.19	0.06
Curtailment	-9.90	-9.91	0.36	1.05
ENS	0.10	0.06	-0.04	-0.09

Difference of average positive FRR capacity provision

Table 3 Difference of average positive FRR capacity provision in the CORE region compared to Status Quo (completely coordinated)

	Status Quo (non-coordinated)	MBO (non-coordinated)	MBO (completely coordinated)	CO
Nuclear	-0.41	-0.61	0.03	0.00
Hard coal	1.17	-1.29	0.26	-0.03
Lignite	-0.04	-0.20	-0.08	-0.05
Gas	24.08	-135.51	-83.42	-111.56
Oil	5.50	-2.90	-2.72	-3.83
Other	0.00	0.00	0.00	0.00
Electrolyser	-0.16	-1.47	-0.55	-0.76
DSR	-84.22	-116.16	-33.94	-35.08
Hydro	92.04	228.08	75.29	111.28
Batteries	-37.96	30.07	44.72	40.05
Solar	0.00	0.00	0.00	0.00
Wind Onshore	0.00	0.00	0.00	0.00
Wind Offshore	0.00	0.00	0.00	0.00
Other RES	0.01	0.00	0.41	0.00
Run of River	0.00	0.00	0.00	0.00
Import	0.00	112.42	112.46	113.71

Export	0.00	-112.42	-112.46	-113.71
Reserve Not Served	0.00	0.00	0.00	0.00

Difference of average positive FRR capacity provision

Table 4 Difference of average negative FRR capacity provision in the CORE region compared to Status Quo (completely coordinated)

	Status Quo (non-coordi-nated)	MBO (non-coordi-nated)	MBO (completely coor-dinated)	CO
Nuclear	166.80	-32.48	-22.60	-33.83
Hard coal	-1.91	-2.00	0.54	0.35
Lignite	-1.65	-1.66	0.13	0.65
Gas	-465.44	-512.16	-94.68	-94.72
Oil	-0.17	0.13	0.01	0.08
Other	0.00	0.00	0.00	0.00
Electrolyser	1.69	2.09	-0.01	-0.02
DSR	0.00	0.00	0.00	0.00
Hydro	-113.68	44.75	125.10	150.40
Batteries	-12.74	177.10	138.51	159.56
Solar	132.56	30.81	-26.69	-43.65
Wind Onshore	71.66	50.50	-10.46	-10.27
Wind Offshore	139.43	134.18	-5.24	-1.68
Other RES	83.45	108.74	-104.62	-126.85
Run of River	0.00	0.00	0.00	0.00
Import	0.00	58.89	58.91	38.45
Export	0.00	-58.89	-58.91	-38.45
Reserve Not Served	0.00	0.00	0.00	0.00

A.4.3 Market Outcomes

Status Quo (non-coordinated)

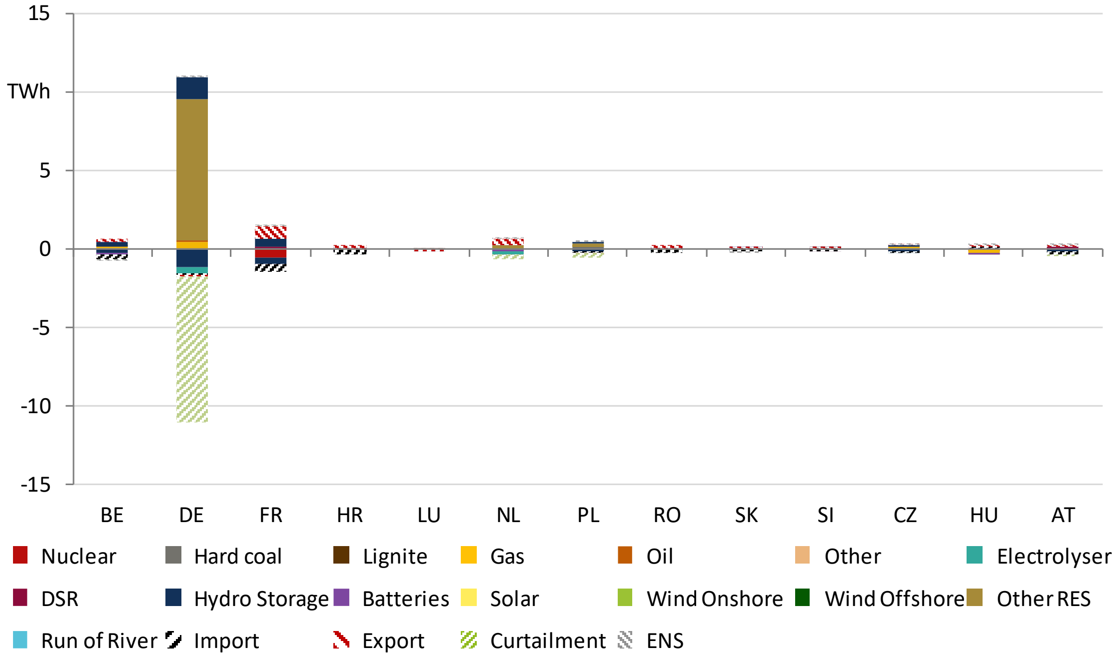

Figure A.4 *Difference of annual electricity generation and consumption of the Status Quo (non-coordinated) approach compared to Status Quo (completely coordinated)*

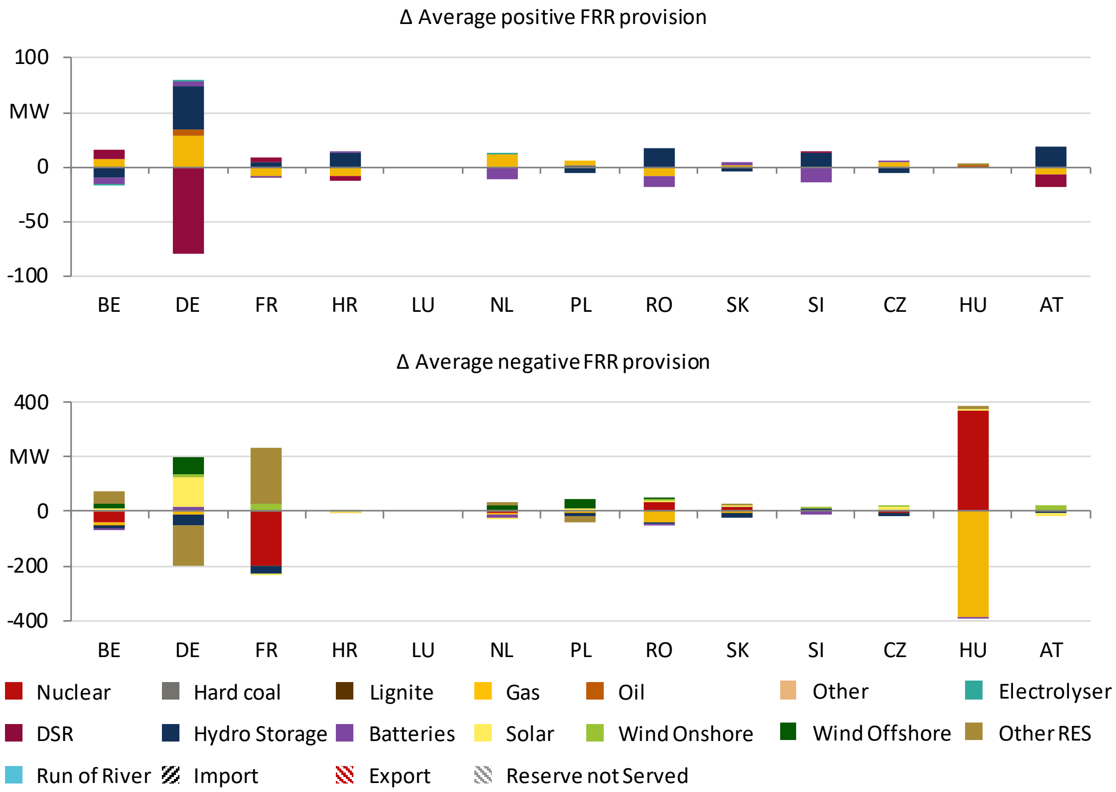

Figure A.5 *Difference of average positive (top) and negative (bottom) FRR capacity provision of the Status Quo (non-coordinated) approach compared to Status Quo (completely coordinated)*

MBO (completely coordinated)

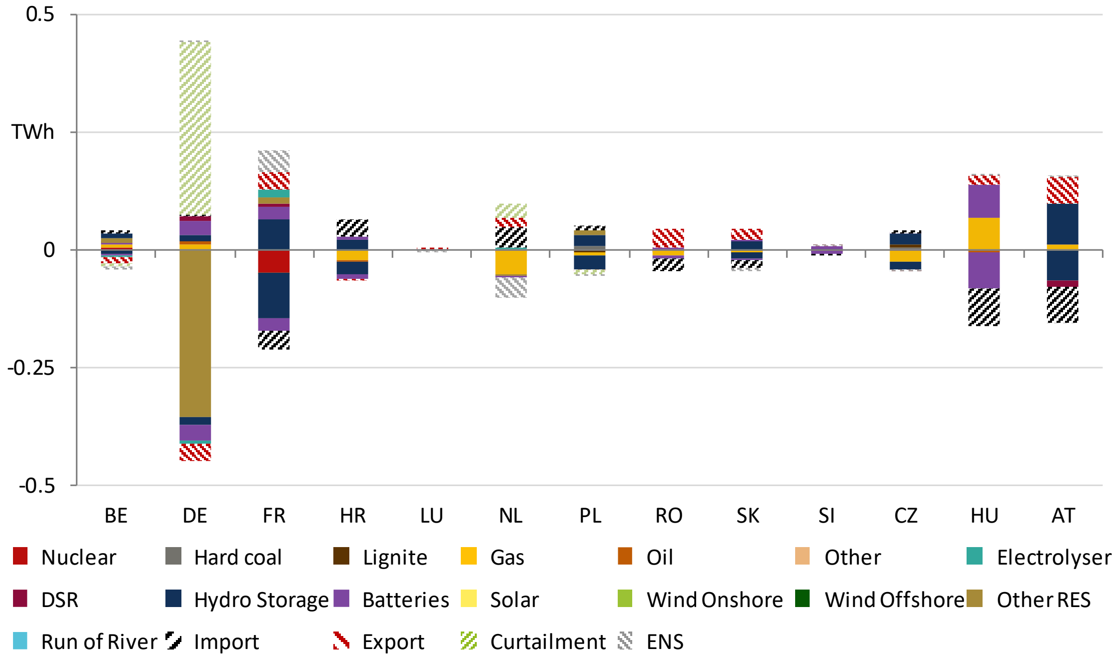

Figure A.6 Difference of annual electricity generation and consumption of the MBO (completely coordinated) approach compared to Status Quo (completely coordinated)

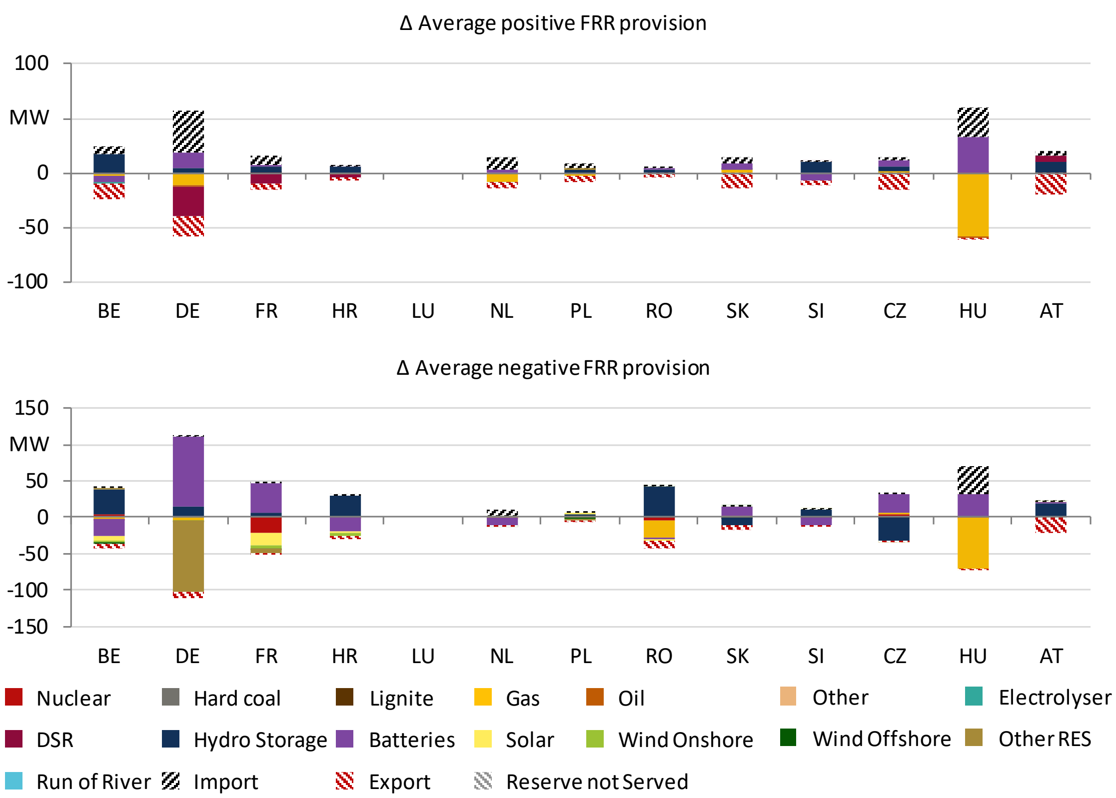

Figure A.7 Difference of average positive (top) and negative (bottom) FRR capacity provision of the MBO (completely coordinated) approach compared to Status Quo (completely coordinated)

MBO (non-coordinated)

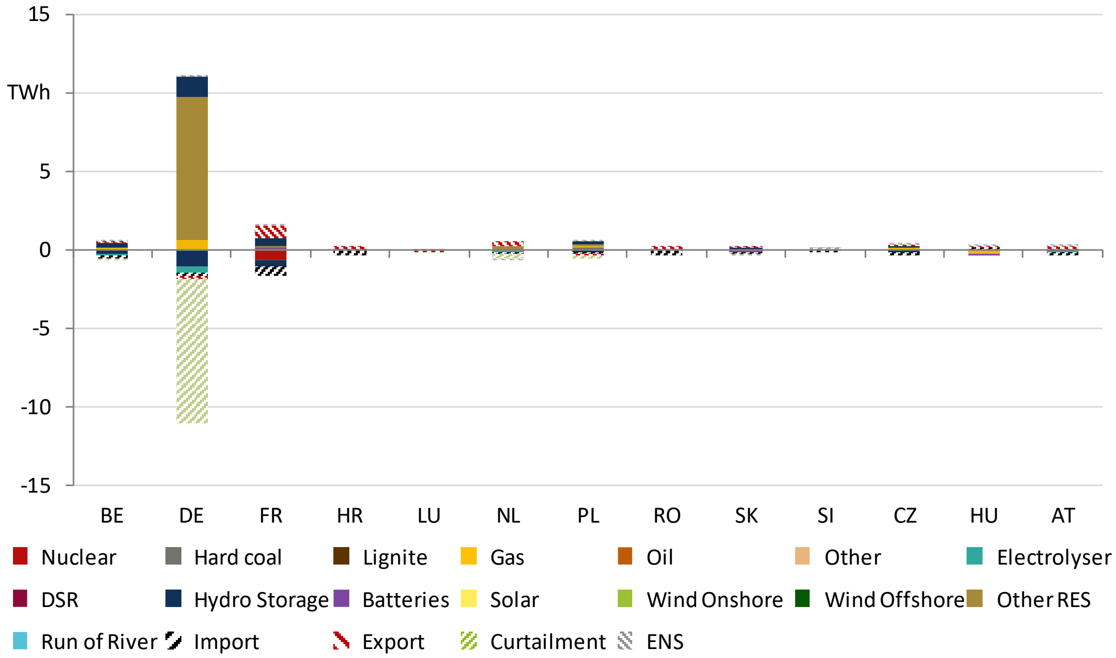

Figure A.8 *Difference of annual electricity generation and consumption of the MBO (non-coordinated) approach compared to Status Quo (completely coordinated)*

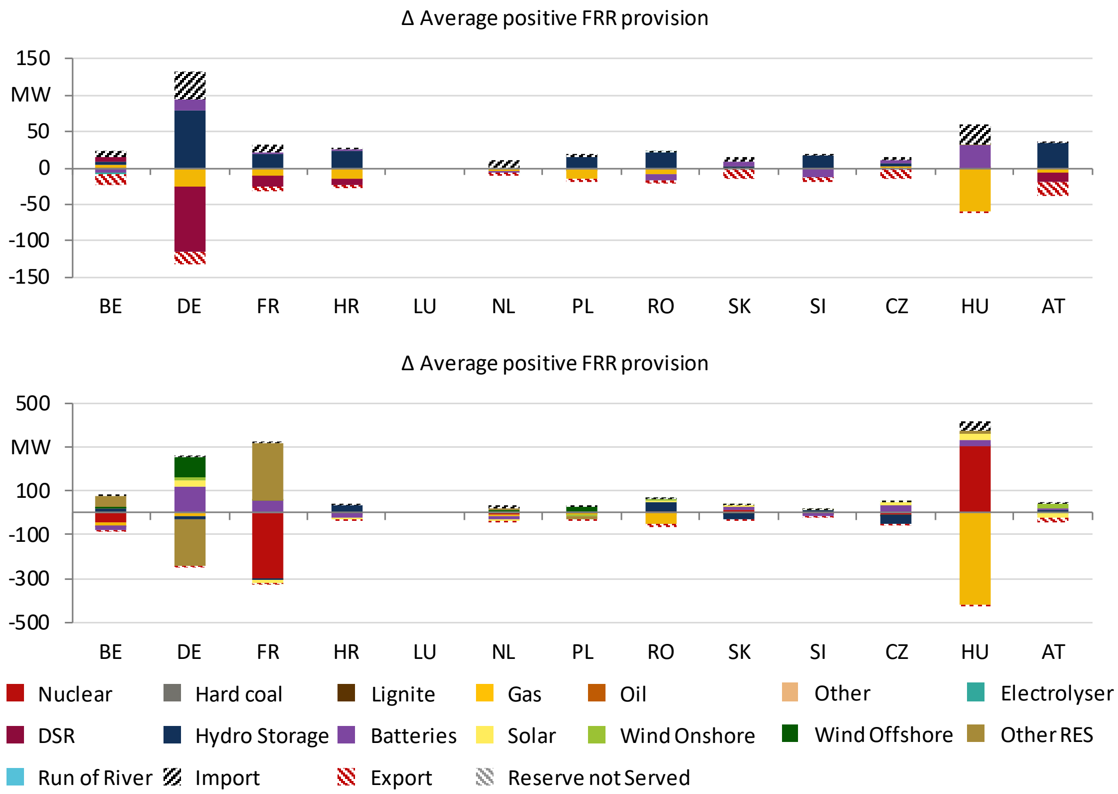

Figure A.9 *Difference of average positive (top) and negative (bottom) FRR capacity provision of the MBO (non-coordinated) approach compared to Status Quo (completely coordinated)*

CO

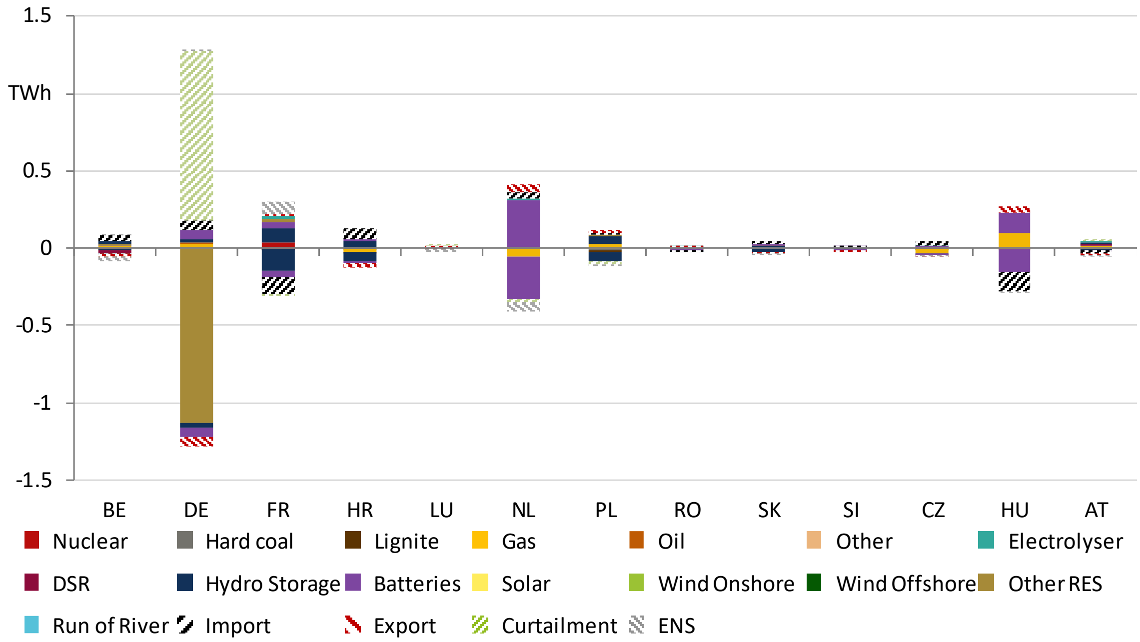

Figure A.10 *Difference of annual electricity generation and consumption of the CO approach compared to Status Quo (completely coordinated)*

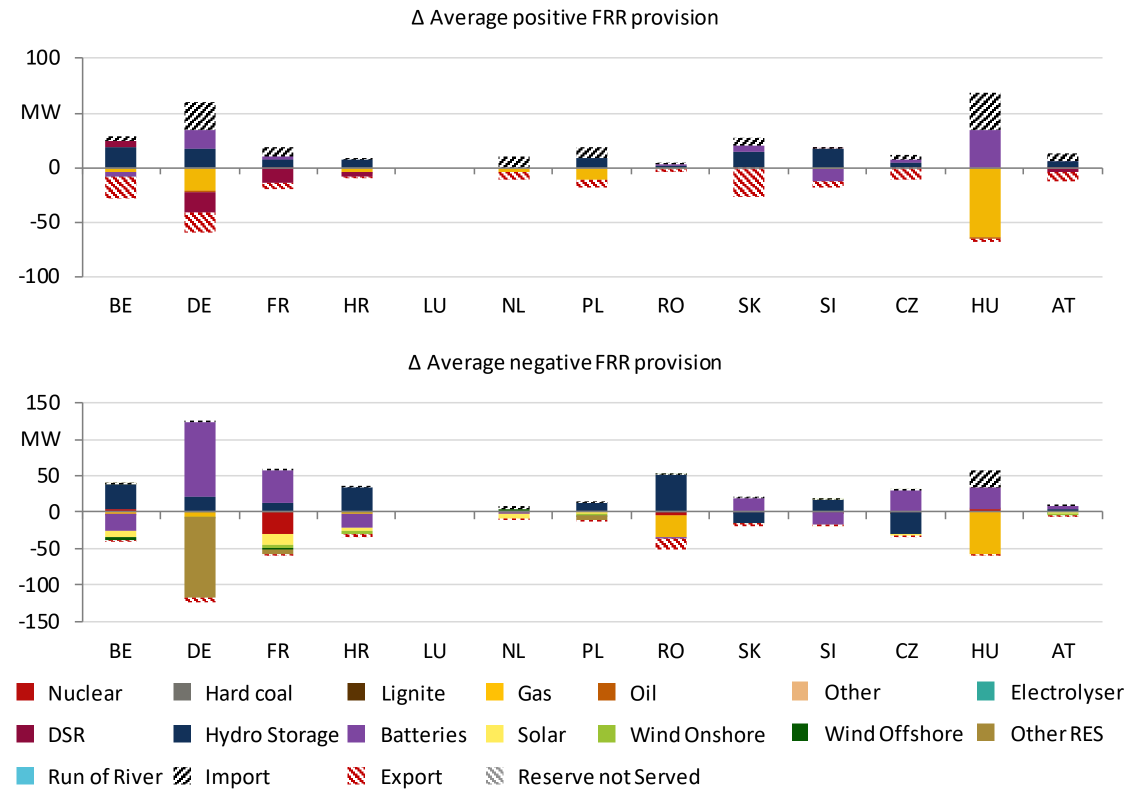

Figure A.11 *Difference of average positive (top) and negative (bottom) FRR capacity provision of the CO approach compared to Status Quo (completely coordinated)*

FRR Capacity Exchange - CO

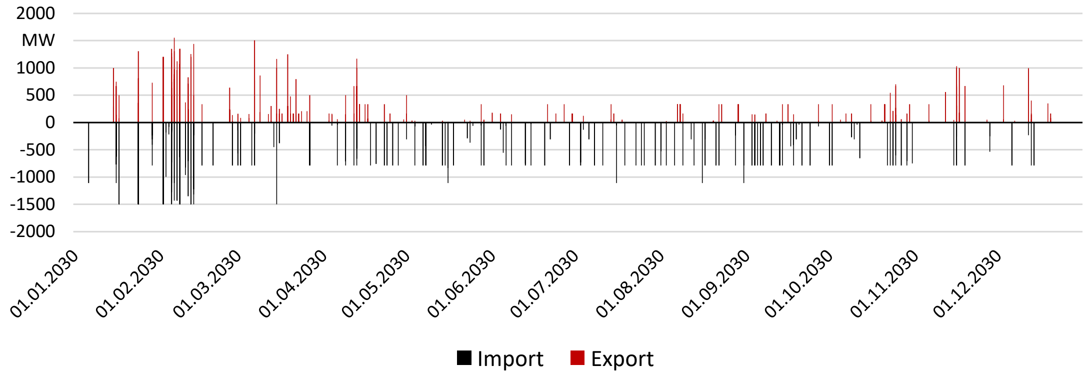

Figure A.12 Import and export of positive FRR capacity in Germany in CO

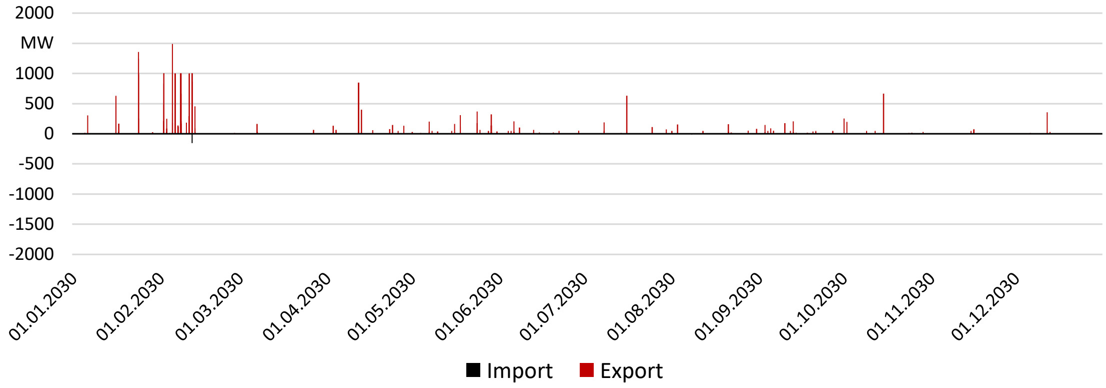

Figure A.13 Import and export of negative FRR capacity in Germany in CO

Table 5 Average exchange volume and number of hours with exchange of positive FRR capacity in CO

Area	⌀ Import [MW]	⌀ Export [MW]	Hours Import [h]	Hours Export [h]
DE	702	370	208	230
SK	274	152	149	1375
BE	266	633	101	261
CZ	214	225	99	388
SI	39	78	175	517
AT	117	374	327	165
RO	75	138	87	121
HR	29	30	645	144
PL	192	422	371	133
NL	385	1286	216	39
FR	668	445	123	97
HU	177	28	1625	334

Table 6 Average exchange volume and number of hours with exchange of negative FRR capacity in CO

Area	⌀ Import [MW]	⌀ Export [MW]	Hours Import [h]	Hours Export [h]
DE	43	145	4	295
RO	28	196	1	636
HR	33	32	354	1426
AT	9	60	3	527
SK	93	115	61	300
PL	39	109	25	75
BE	83	178	208	113
FR	364	73	38	123
SI	40	31	542	386
CZ	100	57	129	23
NL	150	194	272	22
HU	107	38	1957	5

FRR Capacity Exchange - MBO

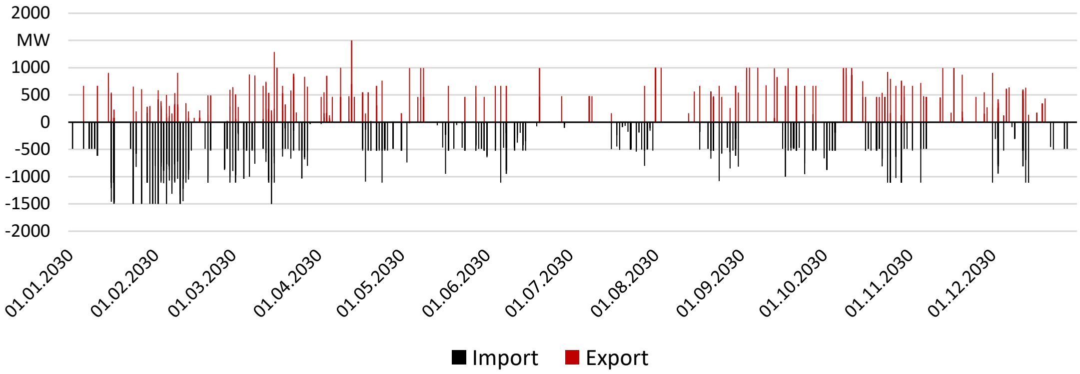

Figure A.14 Import and export of positive FRR capacity in Germany in MBO

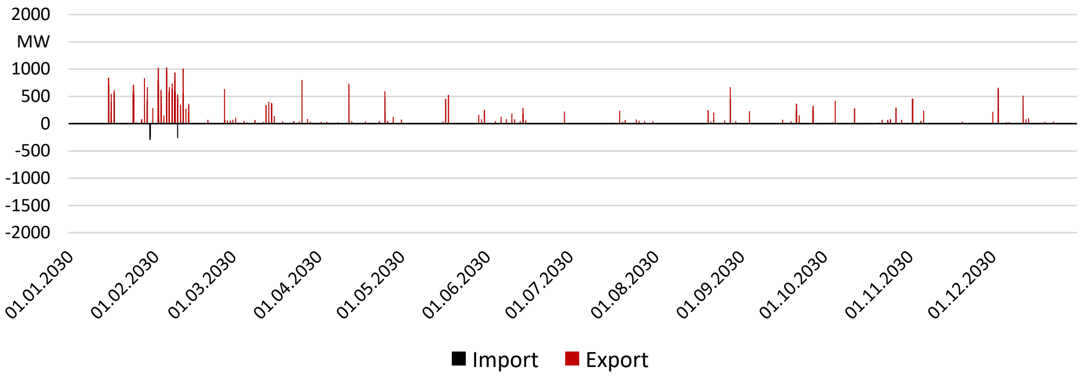

Figure A.15 Import and export of negative FRR capacity in Germany in MBO

Table 7 Average exchange volume and number of hours with exchange of positive FRR capacity in CO

Area	⌀ Import [MW]	⌀ Export [MW]	Hours Import [h]	Hours Export [h]
DE	587	381	440	206
SK	126	60	168	1658
BE	288	437	149	252
CZ	203	234	59	477
SI	47	136	226	297
AT	122	577	180	283
RO	68	69	6	511
HR	37	102	56	270
PL	170	198	247	232
NL	510	395	185	124
FR	593	328	131	157
HU	103	56	2246	15

Table 8 Average exchange volume and number of hours with exchange of negative FRR capacity in CO

Area	⌀ Import [MW]	⌀ Export [MW]	Hours Import [h]	Hours Export [h]
DE	30	131	28	562
RO	24	134	63	695
HR	8	29	10	1382
AT	1	184	5	992
SK	116	75	138	643
PL	21	92	33	79
BE	45	235	272	178
FR	333	65	63	89
SI	43	31	283	83
CZ	168	67	79	74
NL	198	106	403	19
HU	144	44	2417	91