Masteroppgave

NTNU
Norges teknisk-naturvitenskapelige universitet
Fakultet for økonomi
Institutt for industriell økonomi og teknologiledelse

Sonja Wellnitz
Simon Pearson

Marketplaces for DSO side flexibility providers: Insights regarding future TSO-DSO coordination mechanisms in Germany

Masteroppgave i Sustainable Energy Systems and Markets
Veileder: Pedro Crespo del Granado & Naser Hashemipour
Juni 2022

NTNU
Kunnskap for en bedre verden

Sonja Wellnitz
Simon Pearson

Marketplaces for DSO side flexibility providers: Insights regarding future TSO-DSO coordination mechanisms in Germany

Masteroppgave i Sustainable Energy Systems and Markets
Veileder: Pedro Crespo del Granado & Naser Hashemipour
Juni 2022

Norges teknisk-naturvitenskapelige universitet
Fakultet for økonomi
Institutt for industriell økonomi og teknologiledelse

NTNU
Kunnskap for en bedre verden

Preface

This master's thesis was written by Sonja Wellnitz and Simon Pearson as the final submission in the dual degree program "Sustainable Energy Systems and Markets" (SESAM) between the Technical University of Berlin (TUB) and the NTNU in Trondheim, Norway. The master-level study program consists of one year at each student's home university (in our case the TUB), followed by one year abroad including the submission of the thesis. This thesis accounts for 30 and 24 credits at NTNU and TUB, respectively.

When offered the opportunity, we took the invaluable chance to base our thesis on the publication of two scientific papers and to contribute to a scientific field that is just starting to be researched. We are proud to announce that we have already submitted our first paper to a special issue of the journal *Applied Energy*. It has recently finished the reviewing stage, and we are awaiting feedback from the publishers with great interest. Our second paper is also planned for submission at a later time. This would not have been possible without the help of others.

We express our deepest gratitude to our two supervisors, Dr. Pedro Crespo del Granado and Dr. Naser Hashemipour. They have provided us with inspiration, assistance, and a much-appreciated forum for discussion. They taught us both how to develop ideas for scientific modeling frameworks and how to implement them. They also improved our scientific writing to a great extent. We are especially thankful for Pedro's assistance finding prediction methods for the intra-day market prices used for our case study in paper 2. Naser provided invaluable help in developing the framework of our DSO-managed case in our first paper and calculating the transmission line parameters for the future scenario. We acknowledge the FME CINELDI center (2016–2024) funded by the Norwegian Research Council.

Furthermore, we thank other fellow members of the scientific community for their publications laying the foundation for our research:

Dr. Jens Weibezahn and Mario Kendziorski, who developed and published the *Joulia* package for the *Julia* programming language, a large-scale model for the Germany-wide economic dispatch. We thank Johannes Predel and Bobby Xiong, who, as part of their own thesis in a previous year of the SESAM program, developed a framework for the congestion management and made their code publicly available through *GitHub*. They provided us with inspiration and a modeling framework to further develop and gave us a much-appreciated head start. It is a matter of course that we also publish the code used for both our research projects. We would be honored if our frameworks were used for further research in a similar manner.

We thank Prof. Ruud Egging-Bratseth for being the omnipresent contact person for organizational matters long before the start of our time abroad, making our stay in Norway possible even during times of COVID-19. Furthermore, we thank both him and Prof. Anne Neumann for teaching and guiding us during our time at the NTNU.

Finally, we thank our fellow SESAM students Curd Schade, Jakob Heilmann, Marthe Wensaas, Jasper Specht and Victor Lestrade for the mutual emotional and scientific support.

Abstract

Like many European countries, Germany plans to increase the share of renewable electricity generation within its power system to mitigate the effects of the anthropogenic climate change. However, the intermittent nature and the spatial allocation of the Renewable Energy Sources (RES) all over Germany pose a challenge as they will lead to an increased need for flexibility options and increased congestion in the transmission grids. In this thesis, we research the integration of a powerful yet largely untouched flexibility resource: Distributed Energy Resources (DERs) connected to the Distribution System Operator (DSO) grid. The thesis is written following a paper-based format. Therefore, we investigate two different approaches to this topic.

In the first paper, in which we extend the research we have conducted as part of our specialization project in the fall semester of 2021, we explore possible integration mechanisms for these flexibility options. Currently, there is no advanced regulatory system for including the large-scale use of DERs into the established electricity markets. We investigate the application of load flexibility DERs can provide for assisting the re-dispatch necessary in electricity markets that employ a zonal pricing mechanism. Using a deterministic techno-economic optimization model, we implement two different Transmission System Operator (TSO)-DSO coordination schemes with varying levels of involvement of the DSOs and compare their performance with a business-as-usual case in one historical scenario from 2015 and one prediction for 2030. Findings include that while both cases improve the system-wide re-dispatch concerning volume and cost, the centralized framework outperforms the decentralized one. However, we find the decentralized framework to be more realistic to implement as it preserves the interests of the different stakeholders. Furthermore, we find the average value of optimal load-shifting to not be high enough in 2015 to incentivize investment in this area. However, at the higher percentages of generation from RES in the future scenario, this value becomes promising and using DERs for this purpose may provide long-term benefits to the system operators and owners of assets alike.

In the second paper, we expand our focus and research possible methods and additional applications to improve the value of load shifting further while considering the insights from the first paper. We investigate how using the DSO side flexibility not only for the re-dispatch but also for the intraday market improves the financial incentives to provide this flexibility service to the system. To do so, we enhance the model from the first paper to a two-stage stochastic techno-economic optimization model adopting the principle of coordinated bidding. Regarding the flexibility integration into the re-dispatch, we use a decentralized TSO-DSO coordination framework. We found that, on the one hand, accessing more than one market results in a higher value of the DSO side flexibility. On the other hand, it also allows the DSO side flexibility providers connected to nodes without re-dispatch in the respective time step to offer their service to the system. Therefore, the multi-market access improves the reward potential of this flexibility option.

Contents

List of Figures

List of Tables

Abbreviations

AS Ancillary Services

BAU Business As Usual

CM Congestion Management

CTS Commerce, Trade and Services

DAM Day Ahead Market

DER Distributed Energy Resource

DG Distributed Generation

DR Demand Response

DS Distribution System

DSO Distribution System Operator

DSO-M DSO managed

ED Economic Dispatch

IDM Intraday Market

MC Marginal Cost

OPF Optimal Power Flow

PHS Pumped Hydroelectric Storage

RES Renewable Energy Sources

TRM Transmission Reliabiliy Margin

TS Transmission System

TSO Transmission System Operator

TSO-M TSO managed

VOLL Value of Lost Load

Chapter 1

Introduction

1.1 The future of European power systems

The anthropogenic climate change and the attempts taken by countries in Europe and all over the world to slow its effects influence not only the environment but also lead to changes in the power systems. The European countries agreed to measures aiming to limit global warming to a maximum of 2 °C, preferably 1.5 °C, compared to pre-industrial levels (UN (2015)). In order to reach this goal, several carbon reduction targets concerning different sectors have been set. Concerning the power sector, these measures induce an increase of Renewable Energy Sources (RES) within the electricity generation.

As Bloomfield et al. (2021) show, the increasing share of RES in European power systems leads to a higher sensibility of the supply to meteorological conditions. Therefore, the electricity generation of the future will be increasingly intermittent and consequently more difficult to forecast. Another implication is the shift from a system of centralized power producers toward a network of decentralized units. Hence, the nature of RES poses several challenges to the current power system.

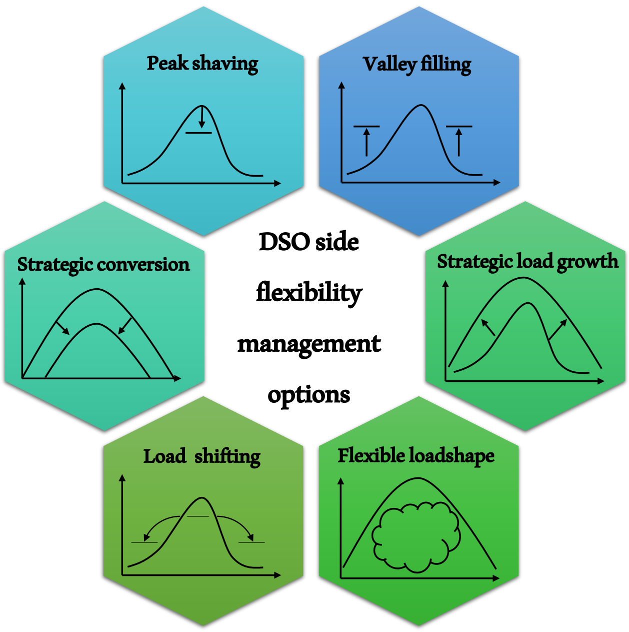

Figure 1.1: The versatility of demand side flexibility resources based on Sharda et al. (2021)

The intermittent aspect of RES calls for more flexibility options to cope with the uncertainty of their generation. Current sources of flexibility are traded on the balancing reserve and on the Intraday Market (IDM). To this day, those flexibility options are mainly connected to the high voltage transmission grid and consist, for example, of gas turbines. However, the capacity of the current flexibility providers is not sufficient to ensure system security with a high share of RES within the generation. Therefore, other flexibility-providing resources must be considered while designing stable future power systems harmonizing with the climate goals.

One such resource has been growing over the recent past as part of the medium- and low-level voltage grids. With an increasing public interest in climate preservation and the progressing electrification worldwide, more and more Distributed Energy Resources (DERs) are connected to the Distribution System (DS). As Figure 1.1 illustrates, this demand-side flexibility can offer various services to the system. Each of those can be used to deal with the uncertainty of renewable generation and ensure supply and system security. The most applicable of these six services are the peak-clipping and the load-shifting (Sharda et al. (2021)). As the potential flexibility capacity of this DSO side flexibility is expected to increase further over the upcoming years and already has a significant volume today, this resource is valuable for the European power systems of the future. Nevertheless, there are several challenges to their integration into the current system. Due to these obstacles, which are further discussed in the next section, this growing flexibility resource remains mainly untouched to date.

1.2 The challenging integration of demand side resources

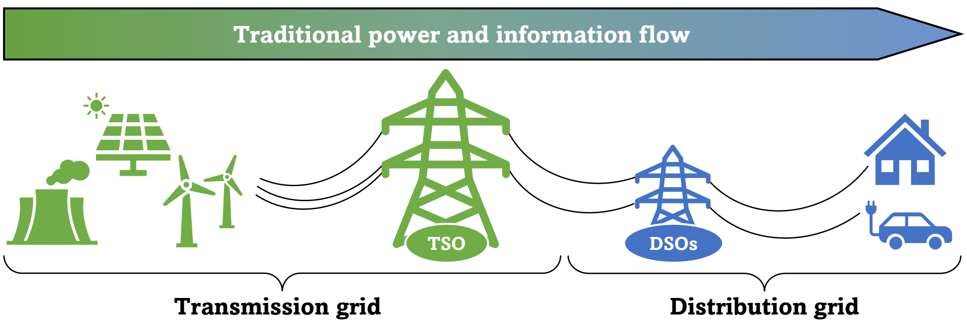

Figure 1.2: Traditional European power system set up

The integration of the flexibility potential offered by DERs connected to the DS features various challenges. Some of them concern physical issues, while others are more market-based. However, there is substantial ongoing research aiming to exploit their potential for the future.

The first challenge to their implementation concerns the current structure of the European power systems. As Figure 1.2 shows, they are designed as unidirectional networks regarding power and information. Most European systems follow this top-down approach, which relies on centralized power producers, commanding Transmission System Operators (TSOs) and mainly passive Distribution System Operators (DSOs). Within this setup, the TSO receives the power schedules from the producers and coordinates them according to physical grid constraints. Afterward, the TSO transmits the electricity on a high voltage level towards the nodes connecting the Transmission System (TS) and the DS. From there,

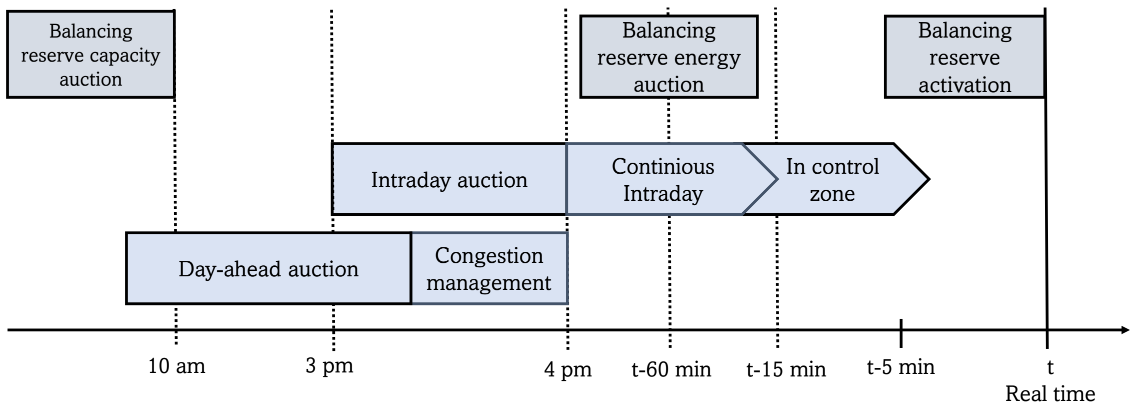

Figure 1.3: German power market structure based on Kraft et al. (2021)

the DSOs delivers it to the end consumers. This approach was designed for the largely fossil-based and, therefore, centralized electricity generation of the past.

This unidirectional design cannot support a future where larger power volumes can also be injected on the distribution side. Currently, the DERs are treated according to the "fit-and-forget" approach. This approach only allows power injection into the DS up to a certain level to ensure that it neither endangers the system security nor causes congestion. However, this approach hinders the efficient exploitation of the flexibility potential of DERs. Therefore, the communication between the operators of the transmission and distribution grids needs to be improved in order to make this valuable resource visible and useful for the whole system.

The introduction of coordination between the TSO and the DSOs would develop the unidirectional to a bidirectional power system. Even though this coordination needs to be accompanied by infrastructural adaptations in both grids, the basis to enable this development is enhanced communication between the responsible system operators.

However, the lack of standardized implementation schemes is not the only obstacle to the DSO side flexibility integration. Aside from technical challenges such as the measurability of the flexibility potential, there are also economic issues. As the operating principle shown in Figure 1.3 is mainly designed for centralized producers, there are entrance barriers for DSO side flexibility providers. Many markets require a minimum capacity size to participate, which is usually hardly achieved by the aggregators and would only allow large consumers to participate. Another obstacle found by Forouli et al. (2021) are prequalifying requirements from Ancillary Services (AS) markets like a high run duration. Furthermore, they find that even for markets allowing these flexibility providers to trade, the competition is too high and the remuneration too low or too complex to provide incentives for investing in this flexibility. Some European countries also feature regulatory obstacles, such as forbidden real-time prices in Belgium or complicated and non-transparent market structures.

1.3 Objectives of the thesis

With the research conducted in this thesis, we target some obstacles mentioned above and investigate possible solutions. However, as discussed in section 1.1, the versatile nature of the demand-side flexibility enables them to offer multiple services. Some of these services, such as AS and balancing services, are already a matter of ongoing research. Therefore, in order to maintain a reasonable focus and contribute to the current research in this field, we concentrate on a less investigated service: support for the re-dispatch.

Our research considers the two main challenges from the previous section: i) the lack of clear and adequate integration and coordination schemes and ii) the lack of market-based incentive for investment in flexibility-providing resources. We investigate these challenges in the two subsequent papers of this thesis.

The first paper aims to find suitable coordination frameworks between the TSO and the DSOs to enable the DERs to support the re-dispatch. The objective of the two elaborated coordinated frameworks is to research the value of this flexibility source for the system. Furthermore, we compare the different approaches concerning their ability to efficiently exploit and integrate this resource.

While the first paper focuses on the coordination-based flexibility integration mechanisms, the second paper considers the second main challenge mentioned beforehand: the lack of adequate remuneration and, therefore, lack of incentive to invest in this flexibility resource. Considering the variety of possible products DSO side flexibility providers can offer, we research their opportunities when given the chance to trade their flexibility for more than one purpose. Due to the promising results from our first paper, we retain their option to trade flexibility for CM purposes while giving them additional access to the Intraday Market (IDM). The latter is attractive for the flexibility providers due to its high price volatility. Within this approach, we take the provider's perspective and investigate their optimal strategy regarding monetary benefits when considering these two trading options.

1.4 Structure of the thesis

After this introduction into the topic of our thesis, we provide a description of the targeted problems in Chapter 2. As this master thesis has a paper-based format, the remaining structure follows this approach by presenting the two papers corresponding to our work. Therefore, we present our first paper titled "The value of TSO-DSO coordination in re-dispatch with flexible Decentralized Energy Sources: Insights for Germany in 2030" in Chapter 3. The focus of this paper are TSO-DSO coordination frameworks enabling the integration of DERs into the re-dispatch process. The second paper, titled "Multi-market bidding for DSO-side flexibility providers: Value from Re-dispatch and Intraday Market participation", follows in Chapter 5 after a short transition section. The focus of the second paper expands the one from the first one by including the point of view of the flexibility providers and researches how multiple trading options increase their incentives to participate in the power system. Finally, we make some concluding remarks and provide an outlook into further interesting research in this direction.

Chapter 2

Problem description

This chapter provides an overview of the scope of the thesis and the methods we use to approach it. It provides a brief explanation of the idea we base our optimization model on and sets it into a greater context.

Starting with the scope of this thesis, we research the integration of flexibility resources connected to the DS into the power system. We refer to those resources as DERs or DSO-side flexibility. While researching possible integration mechanisms, we follow a market-based rather than electrotechnical approach: We investigate the structural issues and opportunities for the integration of flexibility. Infrastructural aspects are not within the scope of our research. As mentioned in the previous chapter, this field of research is increasingly interesting with the development of growingly decentralized and renewable power systems. Within this field, we initially focus on a less investigated service DERs can offer to the system: providing flexibility for the re-dispatch.

The topic can be approached from different perspectives, focusing on different stakeholders. Within this thesis, we investigate the integration of DSO side flexibility from two points of view: Firstly, we aim for TSO-DSO coordination frameworks allowing the systematic implementation of this growing flexibility source into the system without endangering the system security. Secondly, we take the position of the flexibility providers and analyse possible incentives for them to participate in the power system.

However, we do not present a solely theoretical approach, but implement our frameworks into a power market model. In the following sections, we firstly present the basis model, setting the context of the German power system to our work. Afterwards, we provide an overview on the methodology used to approach the flexibility implementation from the system's and the provider's point of view.

2.1 Power system model

We base our work on the model developed by Xiong et al. (2021). They simulated the German power system and its Day Ahead Market (DAM) alongside with the re-dispatch process. As Figure 2.1 illustrates, this model basis reflects the current top-down approach in Germany. After the clearing of the DAM, the information concerning the clearing price and the nodal generation schedules are passed towards the TSO. The TSO adjusts the results of the Economic Dispatch (ED) from the DAM with the physical transmission grid constraints neglected in the first process within the CM. At the end of this process, the TSO sends out up- and down regulation commands towards the generators.

This model, to which we also refer as the Business As Usual (BAU) case, considers

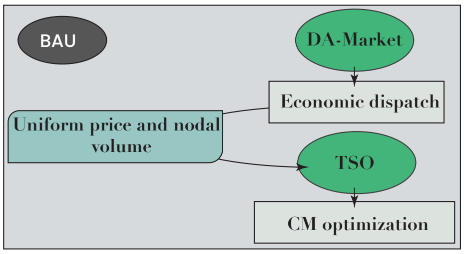

Figure 2.1: Model basis referred to as Business As Usual (BAU) case

only the TS level and takes no note of DS resources. Therefore, it does not implement the potential flexibility from the DSO side.

2.2 Coordinated DER integration frameworks

The DER integration approach we follow in Chapter 3 focusses on implementation frameworks from the system's perspective. Identifying the most important actors within this issue as the TSO and the DSOs, we elaborate different coordination schemes between these two parties. As Figure 2.2 shows, we build up our TSO-DSO coordination frameworks on the current top-down approach, as described in the previous section. Our focus lies on the exploitation of the DERs flexibility potential to increase the efficiency of the re-dispatch process.

We address the topic guided by the following research questions:

- To what extent can flexible DERs contribute to a more efficient re-dispatch?
- How does the coordination between TSO and DSO contribute towards rewarding the flexibility potential of DERs?

To answer these questions, we follow a two-case approach by elaborating two different TSO-DSO coordination frameworks: the TSO managed (TSO-M) and the DSO managed (DSO-M) case. These frameworks differ in their degree of (de)centralization and the amount of responsibility given to the DSOs.

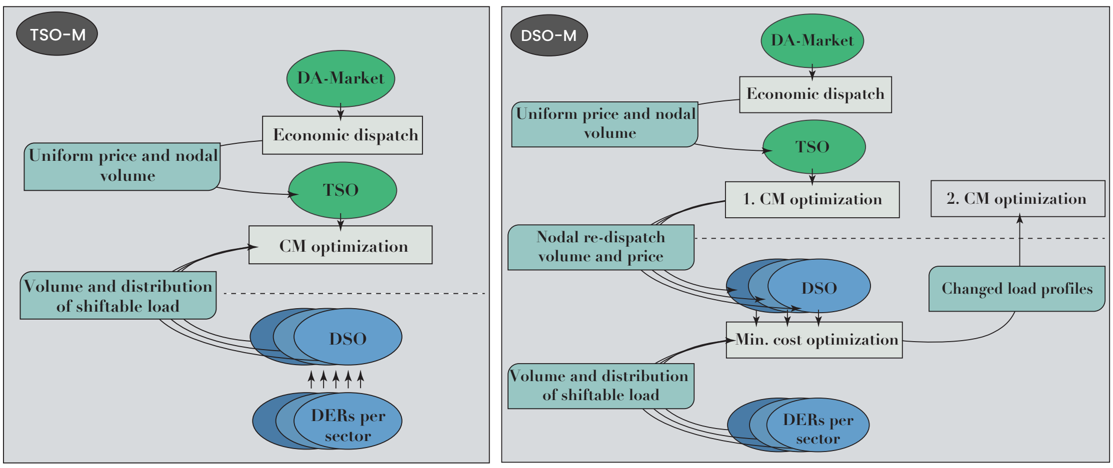

Figure 2.2: TSO-DSO coordination framework approaches: TSO-Managed case (left) and DSO-Managed case (right)

2.2.1 The TSO-Managed Case

The TSO-M case is a centralized TSO-DSO coordination framework. Within this framework, the TSO is still in charge of calculating the re-dispatch. However, the potential load shifting capacities of the DERs are now visible and accessible to the TSO. As illustrated by the left side of Figure 2.2, the DSOs gather the information about their related DERs and forward them towards the TSO. Therefore, the TSO can consider them as a flexibility option in the congestion management and dictate their actions. Being so omniscient and omnipotent towards the DERs, the TSO optimizes the whole system within the re-dispatch process.

However, even though the flexibility potential of the DER can now be exploited, this centralized approach to implementing decentralized flexibility options bears some weaknesses when facing reality. Even though it aims for the overall system welfare, the assumption of fully cooperative DSOs is not realistic. As the information barrier between the TSO and the DSOs is not preserved, it prevents the DSO from representing their interests.

2.2.2 The DSO-Managed Case

The DSO-M case picks up the aforementioned weakness of the TSO-M case. It features a decentralized, nodal optimization for each DSO, allowing each of them to act according to its respective interests. The right side of Figure 2.2 illustrates the more active role assigned to the DSOs in this coordination framework. It shows that each DSO is provided the information about the re-dispatch cost and volume in its respective area by the TSO. For this case, the initial CM corresponds to the one in the BAU case. As the DSOs act as aggregators of their related DERs, they also get the information about the flexibility potential from the DERs. Using this input, each DSO optimizes the cost for the DER owners, considering the cost of electricity taken from the system and the profits generated by providing their flexibility. The result of this optimization is transferred to the TSO in the form of changed load profiles. Using those, the TSO then runs the CM one additional time. In this case, the DERs are used for facilitating the necessary re-dispatch without the necessity of an omniscient TSO.

Within this framework, the information barrier between the system operators is preserved. Therefore, the DSOs are given the opportunity to act according to the interests of its aggregated DERs. It is a more realistic framework than the previous one. However, as there is no information about the decisions of the other DSOs available to the individual one, the scope of the operators can no longer be the system welfare. Furthermore, in this case, precise information about congested transmission lines is no longer part of the calculations.

2.3 Providing incentive for DSO side flexibility

In Chapter 5, where we present the second paper written as part of this thesis, we shift our focus towards the DSO side flexibility providers. While the coordination frameworks in Chapter 3 enable them to participate in the power system, the possible average benefits of using their flexibility potential are limited. Therefore, in the second part of our thesis, we investigate possible methods to improve their gains and further incentivize their participation.

The already mentioned versatile nature of flexibility-providing resources enables their owners to use them for more than one service. Even though we find load flexibility to be

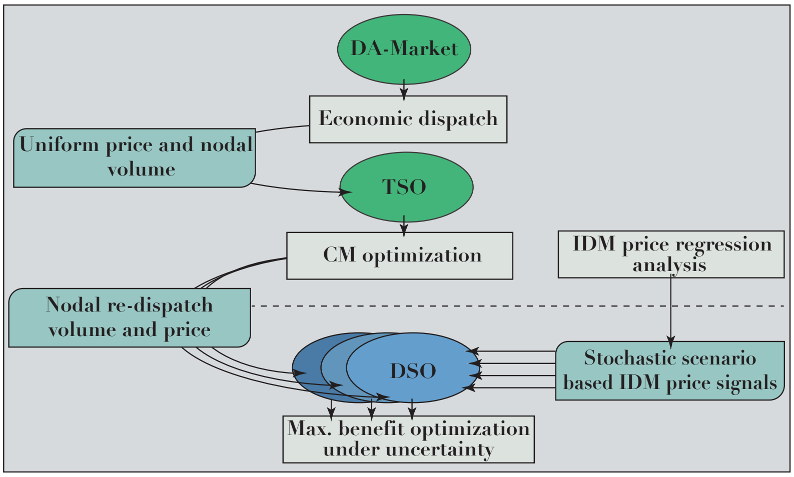

Figure 2.3: DSO side flexibility integration approach from the providers perspective

relatively valuable when used for re-dispatch, the possibility of trading it for other services may increase possible benefits. In Chapter 5, we investigate the impact of multiple trading options on the profitability of providing DSO side flexibility. As the second trading option, we offer the providers access to the IDM, which is attractive for them because of its high price volatility. Our research aims to answer the following questions:

- Where can DSO flexibility providers profitably participate in power markets?
- What is the optimal strategy to allocate this flexibility within the two trading options CM and IDM?

As Figure 2.3 illustrates, the approach to these questions is based on the DSO-M case from Chapter 3. Since the results of our DSO-M case have shown that using load flexibility for CM purposes can provide financial benefits, we retain this as one possible trading option.

However, as we want to offer the providers a second trading option, we expand the DSO-M framework by including the price signals from the IDM. Within this new framework, the DSO still function as aggregators of the flexibility providers and represents their interest toward other parties. Therefore, each DSO still executes its individual optimization, with the adjusted objective of maximizing its financial gains. Within this optimization, the DSO considers the price signals from the CM and the IDM.

The strategy for the allocation of flexibility as optimized by each DSO is based on coordinated bidding and, therefore, considers the subsequent markets by the time a decision needs to be made for the first market. As the IDM opens only after the execution of the CM, we create a stochastic IDM price signal to consider the uncertainty of this market. Therefore, we conduct a regression analysis to predict the IDM price development using researching several possibly influencing factors. We implement a total number of four different scenarios regarding possible proceedings on the IDM. Unlike in Chapter 3, we obtain a two-stage stochastic model to analyze the impact of two trading options on the potential revenue of DSO side flexibility providers.

Paper 1

The value of TSO-DSO coordination in re-dispatch with flexible Decentralized Energy Sources - Insights for Germany in 2030 -

Manuscript submitted to Applied Energy Elsevier: VSI SmartDemandResponse2021, and if accepted it will be published in Applied Energy.

Chapter 3

The value of TSO-DSO coordination in re-dispatch with flexible Decentralized Energy Sources: Insights for Germany in 2030

Abstract

As Germany plans to raise the share of energy consumption satisfied by RES up to 65%, congestion in the transmission grids will drastically increase in the power system unless the grids are substantially upgraded or new flexibility options are considered. In this paper, we explore possible integration mechanisms of a potentially powerful source of flexibility: Distributed Energy Resources (DERs). Currently, there is no advanced regulatory system for including them into the established electricity markets. We investigate the application of load flexibility DERs can provide for assisting the re-dispatch necessary in electricity markets that employ a zonal pricing mechanism. We implement two different cases with varying levels of involvement of the DSOs and compare their performance with a business-as-usual case in one scenario from 2015 and one prediction for 2030. Findings include that while both cases facilitate the system-wide re-dispatch concerning volume and cost, the average value of optimal load-shifting is not high enough in 2015 to incentivize investment in this area. However, at the higher percentages of generation from RES in the future scenario, this value becomes promising and using DERs for this purpose may provide long-term benefits to the system operators and owners of assets alike.

3.1 Introduction

Until 2030, Germany plans to generate 65 % of their gross electricity demand from Renewable Energy Sources (RES) according to their network development plan from the federal network agency (BNetzA (2019)). Even though the realization of this plan would be a great step towards a low-carbon power system, it also imposes major challenges to the current system. These arise mainly from the intermittent generation of RES that causes issues in guaranteeing the security of supply. As Figure 3.1 illustrates, the decentralized availability of RES results in higher risk for congestion. Figure 3.2 shows that this leads to higher re-dispatch volume and cost and a shift of the congestion to different parts of the network. The German power system will require more flexibility options than it currently has to ensure high standards on power quality and supply security. However, as a study by Zöphel et al. (2018) shows, there is not one ultimate technology providing the needed flexibility capacity, but a wide portfolio of flexibility options is needed.

An option with a high flexibility potential but that is not yet integrated is the use of flexible Distributed Energy Resources (DERs), e.g., load shifting, energy storage, demand response. Their amount and, therefore, their capacity has grown significantly over the last years and is projected to still increase exponentially over the next decades (Facchini (2017); Crespo Del Granado et al. (2020)). Currently, some of the reasons for not exploiting their flexibility potential is the actual design of the German power system. It is designed as a unidirectional power flow system, where only units connected to the high voltage TS are allowed to feed in their electricity to the system. As flexible DERs are located on the DS, the current grid design does not allow them to offer their full potential of flexibility as it would create congestion in the DS. Therefore, a new design of the power system structure is needed to adapt the grid to future conditions and enable the integration of new flexibility providers such as DERs. The most important change needed concerns the communication between the grid operators, as only when those set up suitable coordination, it is possible to realistically implement DERs to the system.

In this regard, this paper explores possible TSO-DSO coordination frameworks to integrate the DERs into the system and exploit their flexibility potential for a more efficient and sustainable re-dispatch process. The central idea is to understand the value DERs located under the DSO domain can have to improve TSO operations for re-dispatch under different scenarios and TSO-DSO frameworks. In the literature, this has received very limited attention. Concretely, the objective of this paper is to address the following research questions:

- To what extent can flexible DERs contribute to a more efficient re-dispatch in TSO-operation?
- How does the coordination between TSO and DSO contribute towards rewarding the flexibility potential of DERs?

In order to answer them thoroughly, we approached them with a three-case approach. Each case contains its own coordination framework. While the first one (BAU) represents the current setup and serves as a benchmark to reality, the other two cases contain coordination frameworks with varying degrees of (de)centralization and information flow between the system operators. By implementing data about the German power system from 2015 and 2030, we can compare the performance of the different frameworks in the current system and in the environment they have been designed for.

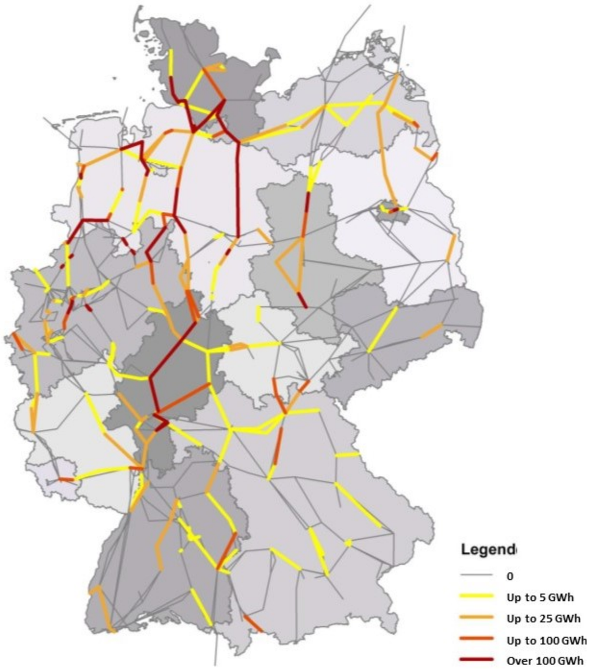

Figure 3.1: Transmission line overload index of the German network as planned by the federal network agency with 65 % RES in electricity consumption (by BNetzA (2019))

In the following section, we give an insight into recent literature with a focus on the integration of DERs into the power system and related modelling concepts. Afterward, we describe our methodology and optimization models. In the next step, we present our case study before discussing the results in section 5.5. Ultimately, we finish the report with a conclusion.

3.2 Related literature

The literature distinguishes different types of DERs connected to the DS. Xu (2019) defines DERs as a part of decentralised flexibility options and categorises them by characteristics concerning technical aspects and field of operation. Eid et al. (2016) define three categories of DERs: electrical consumption, bidirectional DERs and distributed generation. Each category offers different variants of flexibility to the grid and, therefore, requires special handling. While electrical consumption can offer only downward flexibility through demand-side management and DG can only provide changes upwards, bidirectional DERs such as electrochemical energy storages (e.g., batteries) have a broader field of application. Although the three types of DERs offer different variants of flexibility, these potentials are not exploited sufficiently (Sia Partners (2014)). In some countries, DERs are allowed to feed in their generation into the DS. Currently, their total resulting power does not cause congestion in the DS, but in the next decades, their incoming capacity growth might induce a higher risk for congestion. This upcoming challenge requires new management mechanisms to integrate DERs. The traditional way to deal with increasing DER-input is the fit-and-forget approach (Givisiez et al. (2020), Silva et al. (2021), Xu (2019)). This tradition is mainly due to existing limits on how much DERs can feed into the grid.

In the literature, various paths for the integration of DERs take into account the impact DERs have on the modus operandi of TSOs and DSOs. Some of them seek to introduce DERs

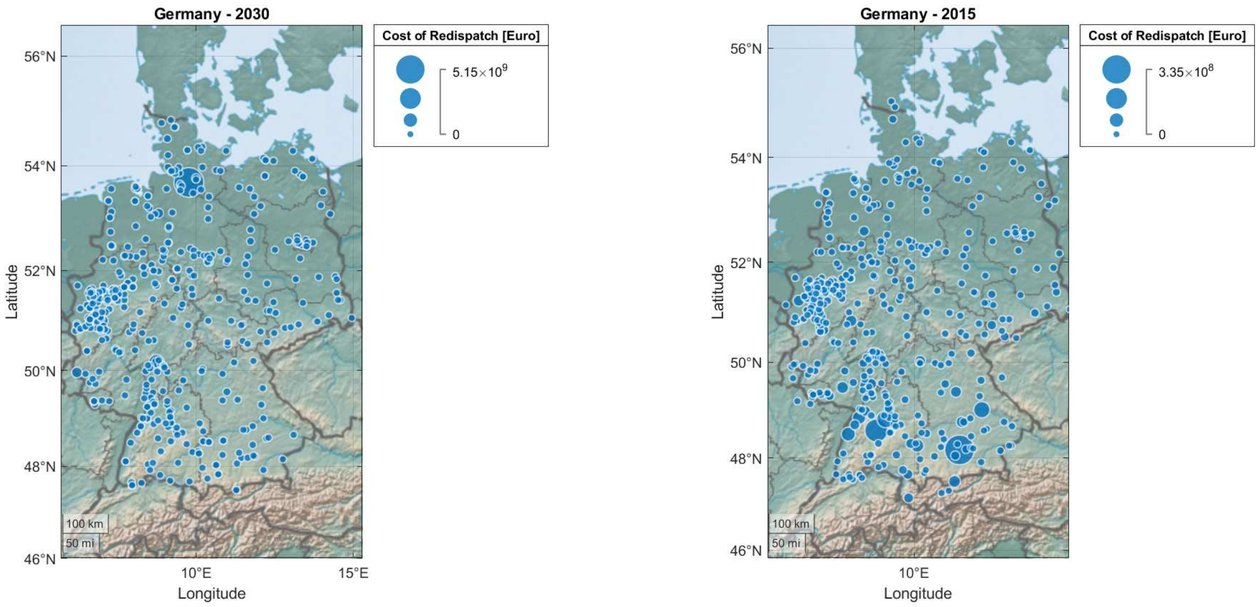

Figure 3.2: Spatial distribution of re-dispatch cost over two weeks in Germany in 2015 (right) and 2030 (left) based on own calculations and data by Kunz et al. (2017b) (for 2015) and vom Scheidt et al. (2020) (for 2030)

into existing markets, others elaborate concepts for new emerging markets. ENTSO-E (2018) and Eid et al. (2016) propose access for aggregated DERs to existing balancing markets, while Savvopoulos et al. (2019) use DERs mainly on the DS side and introduce them there either into modified AS markets (Savvopoulos et al. (2019)) or newly designed DS markets (Xu (2019)). Overall, to integrate DERs, there is an agreement that they need to be aggregated to have a tradable amount of flexibility (Yuan and Hesamzadeh (2017), Xu (2019), Silva et al. (2021), Burger et al. (2016)).

An active DSO engaged with DERs has emerged as an important enabler in exploiting and rewarding their flexibility (Yuan and Hesamzadeh (2017), Najibi et al. (2021), Zhu et al. (2021)). However, the prospects of a more active DSO entail a redesign of current information and coordination mechanisms between TSO and DSO. Decisions of DSOs in sync with local DERs operations should be aligned with the centralized flexibility needs of the power system, i.e., the TSO-DSO coordination.

3.2.1 TSO-DSO coordination mechanisms - An overview

Different approaches for the structure of TSO-DSO coordination are explored in related literature. Some focus on specific markets like the AS or the balancing market Eid et al. (2016); Savvopoulos et al. (2019). Others, like Najibi et al. (2021) and Givisiez et al. (2020), approach the coordination from a more conceptual point of view and do not consider market designs to trade DER-flexibility. However, both approaches lead to similar mechanisms regarding the coordination of TSO and DSO. Najibi et al. (2021) differentiate the coordination schemes primarily by their amount of active operators. Therefore, the authors distinguish between centralized and decentralized TSO-DSO coordination. Within decentralized schemes Najibi et al. (2021) further differentiates between hierarchical and distributed models. While hierarchical models have a leader-follower structure, all DERs in distributed models can be selected to meet the demand. This categorisation applies to most models in the field, as they all vary the amount and the nature of information exchanged between TSO and DSO to use DERs efficiently. The three conceptual models identified by Givisiez et al. (2020) similar to the AS-market models (Savvopoulos et al. (2019), Silva et al. (2021), Rossi et al. (2020), SmartNet Consortium (2019)) follow different degrees of (de-) centralization. Givisiez et al. (2020) extracts the following three approaches from the literature: i) TSO-managed, ii) hybrid approach, iii) DSO-managed.

The TSO-managed approach is a centralized one as defined by Najibi et al. (2021). Its core is a TSO to whom the DERs bid directly and who therefore can dispatch over the whole system using both traditional generating units and DER capacities. The DSOs only provide operational real-time DS data. Many authors such as Grøttum et al. (2019), Yuan and Hesamzadeh (2017) and Najibi et al. (2021) present in first place a centralized model in which the TSO is the sole purchaser of DER-flexibility and optimizes the whole system while possessing all information about DERs, TS and DS. Givisiez et al. (2020) state that within this TSO-managed model, the TSO can use his know-how on dispatching and expand the existing platforms. Alongside with Silva et al. (2021), Rossi et al. (2020) and Savvopoulos et al. (2019), Givisiez et al. (2020) sets up this model as the closest to the current situation. They agree upon the fact that this model requires a high computational effort on the one hand as it optimises the whole system taking into account all grid constraints from DS and TS. On the other hand, it is also perceived that a *centralised* management of *distributed* energy resources is becoming more difficult the higher the amount of DERs in the system. However, Xiong et al. (2021) found that even such a DER integration approach could improve the system performance. Even though Xiong et al. (2021) do not take into account DS grid constraints, its finding corresponds to Najibi et al. (2021) who elaborate one centralized and one decentralized coordination framework. For both scenarios, they found the operational costs for TSO and DSO decreasing, congestion to be relieved, and the share of accessible DERs increasing. Indeed, Najibi et al. (2021) also states that the decentralised coordination framework delivers better performance.

Givisiez et al. (2020) proposes a hybrid coordination scheme requiring a higher communication level and more activity from DSO-side. The DSO prequalifies the DER-bids in terms of DS constraints before allowing them to participate in a central market where both system operators purchase flexibility. The TSO-DSO coordination is realised here via the intermediate of this central market. This concept corresponds to the common TSO-DSO AS market approach by Silva et al. (2021), SmartNet Consortium (2019) and Rossi et al. (2020). According to Rossi et al. (2020), it would theoretically be the most efficient coordination scheme. However, as it requires a high level of cooperation and much effort in communication, it causes conflicts between the system operators. Another issue outlined by Savvopoulos et al. (2019) is the access of commercial parties to this market that would reclassify the priority access for the system operators who then see their system operation ability compromised. Hence, this approach is not realistic for the communication between TSO and DSO.

The DSO-managed approach by Givisiez et al. (2020) could be such a more realistic concept. It requires far more communication between the TSO and the DSOs than the centralised one but less than the common market idea. Similar to Najibi et al. (2021) Givisiez et al. (2020) distinguish between two approaches in the decentralized scheme. The first one is hierarchical, where no market on the distribution side exists. The DSO awaits the dispatch command from the TSO to transmit it to its aggregated DERs and meet the requirement. Such a framework requires less information exchange than the previous one. Yuan and Hesamzadeh (2017) created the generalized bid function as communication tool between DSO and TSO that similar to Najibi et al. (2021) gets a price from the TSO as input and returns a net load from DS-side to the TSO. A similar approach is pursued conceptually by Grøttum et al. (2019). The second approach by Givisiez et al. (2020) is a more distributed one, where all available DERs can be pursued on either DS- or TS-level. Savvopoulos et al. (2019), SmartNet Consortium (2019) and Rossi et al. (2020) adapt this concept to AS market design and introduce the local AS market coordination scheme that features parallels to Silva et al. (2021) local and global flexibility market concept. While Savvopoulos et al. (2019), SmartNet Consortium (2019) and Rossi et al. (2020) propose an existing AS-market but with a hierarchical structure, Silva et al. (2021) adds a possibility of direct DER-trade with the TSO and has therefore a more distributed market concept. The local AS market concept considers a market-clearing on DS-level before it is cleared on TS-level. The DSO then sends the remaining DER bids to the TSO-AS market. The possibility added by Silva et al. (2021) enables the DERs not to be aggregated by the DSO on the TS-level market but to bid there directly after the first market clearing. Hence, this approach corresponds more to the distributed concept by Givisiez et al. (2020). Nevertheless, both of those AS-market concepts are frequently addressed in the literature. They are perceived as the simplest coordination scheme with the least optimisation effort while still allowing the DSOs to control their grid and resources and preserving the information barrier between the two system operators (Silva et al. (2021)). Even though Givisiez et al. (2020) see this coordination scheme as the one with potential for the most efficient facilitation of DERs, they also state some major challenges for those concepts like the lacking know-how on markets by the DSO and its upcoming problems with the complexity of modelling and running them. Rossi et al. (2020) add that DS-side markets are likely subject to scarcity and illiquidity. However, most of the mentioned challenges concern the initial set-up of this coordination and could be mastered in the long run. Therefore, this form of coordination is seen as the most promising one.

3.2.2 TSO-DSO modelling approaches

According to Givisiez et al. (2020) there are three main solution techniques to model TSO-DSO coordination: distributed, hierarchical and centralized optimization.

While the TSO-managed frameworks such as described by Xiong et al. (2021), Yuan and Hesamzadeh (2017) and Najibi et al. (2021) follow similar modelling approaches considering the lack of information barrier, an omnipotent TSO and using the centralized optimization, the models proposed for a DSO-managed coordination differ more from each other.

Most of the optimization problems based on the DSO-managed scheme use a hierarchical solution technique (Savvopoulos et al. (2019), Najibi et al. (2021),Yuan and Hesamzadeh (2017), Mahboubi-Moghaddam et al. (2018),). Almost all those solutions implement a TSO and a DSO sub-problem and are therefore bi-level optimizations. However, the models vary in their handling and timing of the different sub-problems. While Savvopoulos et al. (2019) models the local AS market as described in SmartNet Consortium (2019) based on Gerard et al. (2018), they let the DSOs clear their markets before the actual realization on system imbalances occur, i.e. before the TSO clears the balancing market. This model is similar to Yuan and Hesamzadeh (2017) where the DERs send their bids not to a local market but to the DSO who gathers them in a generalized bid function. The generalized bid function is a communication tool introduced by Yuan and Hesamzadeh (2017) that implicitly contains all DER bids to one DSO but lowers the data transfer volume between the system operators. In the models of Savvopoulos et al. (2019) and Yuan and Hesamzadeh (2017) the TSO optimizes in the following step the whole system while using the information about DER-capacities in the different nodes sent by each

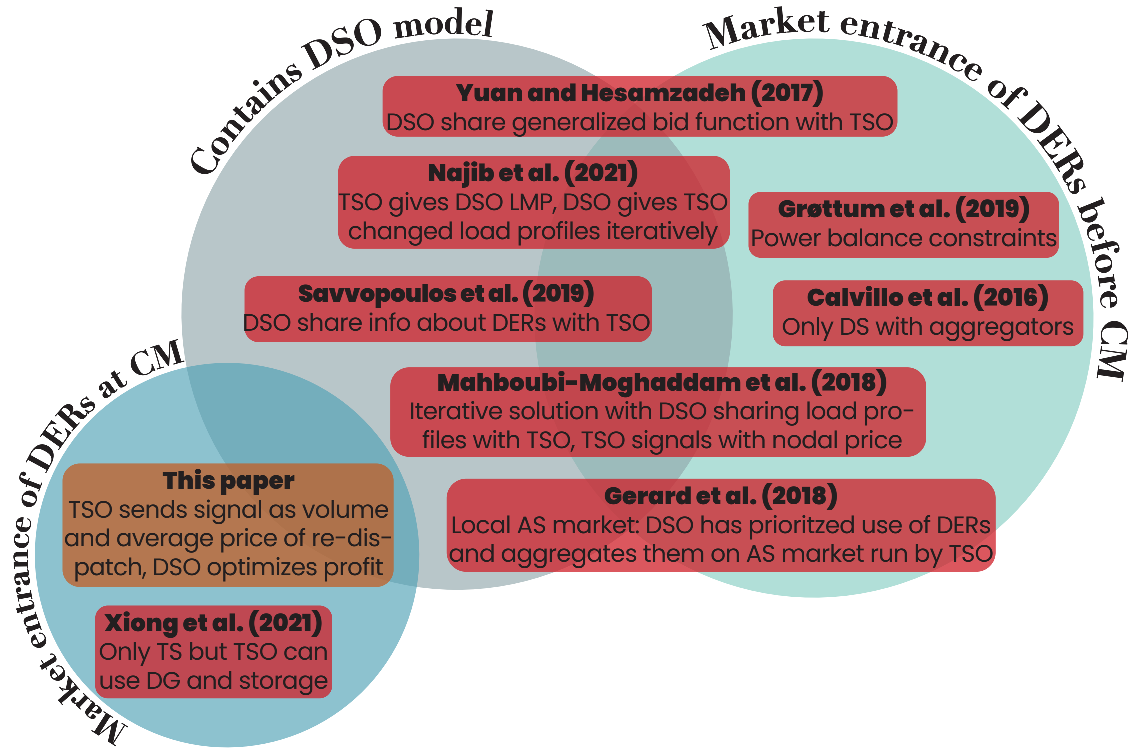

Figure 3.3: Comparison of TSO-DSO coordination mechanisms in the literature concerning DER integration approaches with an active DSO with the model and concept of our project

DSO. The timing of this coordination however is different in the two models as Yuan and Hesamzadeh (2017) set up their model for the ED while Savvopoulos et al. (2019) operates later on the AS market.

Unlike Savvopoulos et al. (2019) and Yuan and Hesamzadeh (2017), Najibi et al. (2021) and Mahboubi-Moghaddam et al. (2018) handle the sub-problems in a different order. They first let the TSO optimize the TS while meeting the DS load entirely with TS resources and ignoring DERs. As they assume a nodal pricing system the model takes place in the ED and the TSO calculates a locational marginal price that is his signal to the DSOs. Each DSO then solves its own cost-minimizing optimization taking into account its DERs and sends a changed load profile to the TSO. The TSO then considers it again in its optimization. Hence, it is an iterative solution technique that converges to a near optimal solution which is also timed to the ED.

A somewhat different DS-side approach is offered by Calvillo et al. (2016). Their model aggregates the DERs on DS-level and the aggregator can participate in the DAM. Unlike the other models that aim to minimise the system costs, Calvillo et al. (2016) aims to maximise the benefit of the DER-owners and the aggregator. As the aggregator can be either an independent company or the DSO, this approach adds an interestingly different perspective to the other models.

Few solutions aim to integrate DERs into the re-dispatch as most are either integrating them in the dispatch process or in the AS market. Xiong et al. (2021) propose a model that introduces DER-capacities to the re-dispatch but locates the DERs on TS-level. Therefore, it does not include a DSO-model and ignores the DS. Hence, neither Xiong et al. (2021) nor one of the models discussed above consider re-dispatch services coming from a TSO-DSO coordination.

3.2.3 Contribution

There are few approaches including a DSO model, even though most of them assume the DSOs participating actively in the process. Figure 3.3 illustrates that most models integrate the DER-potential either in the dispatch process or introduce it to the balancing or AS market. Few models include DERs into the re-dispatch process. Even within those that consider the re-dispatch, there are barely any models that integrate the DSO within its own sub-problem in the optimisation (see Figure 3.3). Based on this review, the contribution of this paper in comparison with related literature is as follows:

- provide original TSO-DSO coordination frameworks and models considering the interests of DSOs
- demonstrate the integration of flexibility potentials from DERs connected to the DS
- analyze TSO-DSO coordination in the re-dispatch of power generating units in a uniform pricing system
- and evaluate the performance of the frameworks in the current system as well as in a future scenario (2030).

The literature does not discuss whether DSOs and their connected, flexible DERs can contribute to the re-dispatch. This paper provides groundwork for the research in this specific field by describing and modelling possible frameworks for an efficient DSO-TSO coordination in this process. Therefore, our contribution consists of formulating possible coordination frameworks, their implementation, i.e., our optimization models, and the frameworks' performance comparison from 2015 to 2030. Unlike other papers, we provide a real-life country-wide scope to test the validity of our model. Such high-scaled models are not broadly available in the literature (especially in a TSO-DSO context). The models including their respective mathematical formulations may also contribute to further research, as they are easy to scale and expand. With increasing insight and understanding of this research domain, this model can serve as an implementation framework. It is beneficial for this purpose, as it considers a possibility to calculate the load profiles and shifting on behalf of DERs in the context of re-dispatch.

3.3 Methodology

To measure the impact of flexible DERs on the re-dispatch process, we implement three cases: i) Business as Usual, ii) TSO-Managed, and iii) DSO Managed. The cases are elaborated in the following sub-sections and overall framework depicted in Figure 3.4.

3.3.1 Business as usual case (BAU)

The BAU case reflects the current system structure and serves both as a benchmark and as a foundation to both the TSO-M and DSO-M cases. Here, we use the model as formulated by Xiong et al. (2021) in a slightly modified version, calculating the minimal system-wide cost of re-dispatch necessary not to violate transmission constraints.

As we show in Figure 3.4, the first stage of all three cases is about modelling the ED (step 1) whose results are then transferred to the second stage where the TSO executes its CM optimization (step 2a for BAU). The BAU case only involves those two steps. Xiong

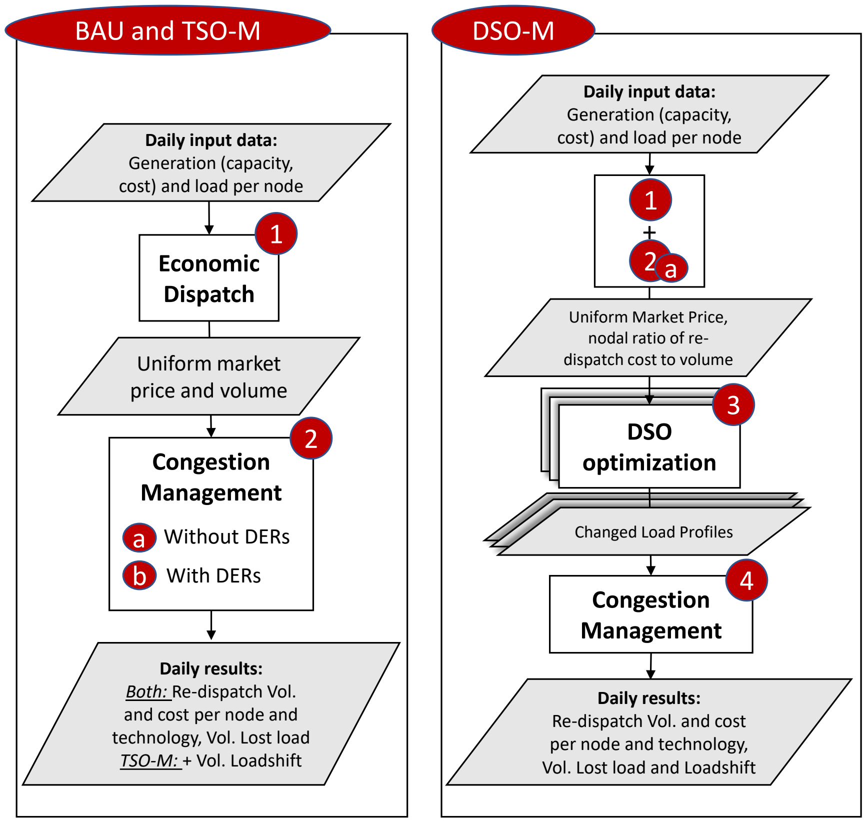

Figure 3.4: Program flow chart for one day all cases
(Left: Business As Usual (BAU) (Step 1 + 2a) and TSO managed (TSO-M) (Step 1 + 2b), Right: DSO managed (DSO-M))

et al. (2021) chose a sequential model to simulate this process. With each sequence being 24 h long, this approach allows us to analyse our results over longer periods (in this case one year) day by day. Every sequence starts with the ED that minimizes the overall system cost for generation. As the ED assumes a single copper plate, its input and output information are economical. Therefore, the DAM transfers the uniform market price $\overline{\Psi}_t$ and volume $\overline{P}^{DA}_{g,t}$ to the TSO on hourly basis for it to perform the second stage. As the BAU case reflects the current situation, the TSO does not have information about the location or flexibility potential of connected DERs and therefore does not use them for the re-dispatch. Hence, the TSO executes the CM to calculate the system-wide cost-minimal redispatch for the assigned volume while considering physical grid constraints of the transmission grid. Adjusted power plants, curtailed RES and lost load lead to financial compensation. The remuneration is based on current schemes and describes a profit neutral re-dispatch concept for power plants (Connect (2018), BDEW (2018)). The resulting up- and downward regulation volumes, as well as the total nodal volumes, are communicated to the generators and DSOs by commands sent by the TSO.

3.3.2 The TSO managed case (TSO-M)

Here, we model a fully cooperative TSO-DSO coordination that does not take into account their different interests nor preserves the information barrier. However, unlike the BAU case, it implements the load shifting potential of the DERs. Those are visible to the TSO in this framework because the fully cooperative DSOs provide the TSO all the necessary information concerning location and load shifting capabilities about connected DERs. This corresponds to step 2 variant (b) in Figure 3.4. Not only are demand response potentials of DERs in this case visible for the TSO, he can also access and dispatch them. Therefore, the TSO can perform the re-dispatch by using both TS generators and DER flexibility. To keep computational effort reasonable for this project, the TSO does not consider physical DS constraints.

This solution would maximize the welfare and the all-over efficiency of the power system. However, it is not realistic, as it neglects the interest conflicts between the different system operators and the high computational effort in the CM if it would also consider the DS-constraints.

3.3.3 The DSO managed case (DSO-M)

Aside from the TSO-M case aiming for the whole system welfare, we set up the DSO-M case as a second coordinated framework that takes into account the individual interests of the participants by preserving the information barrier between the TSO and the DSOs. In this case, the DSOs have a more active part than in the previous ones. Each DSO has the opportunity to profit from providing their flexibility options to the TSO. Our model assumes that there is no inter- or intra-node competition between different DSOs. Therefore, it models only one DSO per node and does not contain a market model to coordinate bids between DSOs. Therefore, each DSO focuses on a nodal level to minimize the cost of electricity taken from the system and to maximize benefits from changing load profiles to reduce the necessary re-dispatch of generators. The DSOs are assumed to aggregate the providers of DERs in their node and have, therefore, an interest in reducing the nodal electricity costs.

As this case requires a more bidirectional information flow between the TSO and the DSOs than the previous cases, the DSO-M model contains two more steps than the BAU and TSO-M case. As the right part of Figure 3.4 shows, the first two steps correspond to the BAU case, as the TSO has no information about DERs connected to the DS. Unlike in the previous cases, the TSO transmits information about the uniform market price $\overline{\Psi}_t$ and the nodal ratio of re-dispatch cost to volume $\overline{\Phi}_{n,t}^{RD}$ to the correspondent DSOs. Those parameters are the input information for each DSO optimization (Step 3 in Figure 3.4). The output of each DSO optimization is a new load profile that is sent to the TSO. In step 4 of the model, the TSO optimizes the whole system with these new load profiles.

Based on the outcome of this second re-dispatch calculation, the TSO sends the usual redispatch commands to the generators connected to the TS. Therefore, in this case, the TSO cannot dispatch the DERs, and the DSOs keep control over their grid and their resources.

3.3.4 Model formulation

The mathematical formulation and the implementation is based on the *Julia* programming language for the ED and CM optimization (initial code by Xiong et al. (2021)[1]). The nomenclature containing denominations for sets, variables and parameters is available in the appendix (see Appendix A).

[1]The original source code is openly available at `http://github.com/bobbyxiong/redispatch-ptg`

Model assumptions

No Ramping. Rotating generation units achieve ramp rates between 2% and 15% per minute of their maximum output, which makes it possible for a model with an hourly resolution to have ramping rates from 100 % per hour of the maximum output (Gonzalez-Salazar et al. (2018)). Hence, ramping constraints become non-binding. Therefore, we neglect ramping constraints, also because this reduces the computational complexity of our model.

No cross-border exchange. The cross-border exchanges can either be modelled by including them as fixed parameters based on historical data or considering the related exchange equations in the clearing process. However, the former approach is not realistic since export is equivalent to a higher load, leading to a higher market-clearing price. Moreover, the latter approach requires more information about the neighbouring countries and more computational efforts beyond the project's technical and contextual scope. Therefore, cross-border exchanges are not considered.

Inter-DSO competition. It is assumed that there is no more than one DSO connected to a node of the transmission grid. This assumption eliminates the need to model the competition between the nodal DSOs since such a competition is not within the scope of this paper.

DER actions. Due to the lack of real data set about the demand and existing DER capacity, the aggregated behaviour of DERs has been modelled as a change in the load pattern of each DSO.

No transmission losses. Due to the nature of transmission lines, losses are ignored, and DC load flow is employed to calculate the flow of power in the grid. Those transmission losses range in Europe between 1.7 and 3.4 % (CEER (2020)). As they are rather low and we focus on the congestion on the transmission lines, we neglect those losses in our optimization.

Sectoral load shifting. We assume that each sector in our model formulations can shift its demand within a certain relative range, as only parts of the demand with DERs are flexible. As stated by Gils (2014), especially the large-scale, highly energy-consuming industry sector features considerable mechanisms to provide load shifting. Hence, we include higher load shifting capacities for this sector. To avoid overestimating how much load shifting can be realistically achieved, we choose to implement 5% of the daily average for the residential and trade, and service sectors. We assume 10% for the industrial sector, which are only available during working hours (hours 9 to 16 of each day).

ED model (Step 1)

The Economic Dispatch (ED) as the result of the Day Ahead Market (DAM) is the basis for all three cases. It is responsible for efficiently allocating generating resources. It aims to meet the global demand of all nodes at the lowest system costs possible. Here, we assume a *copper plate*, i.e., we allow for unlimited transmission with no losses between all generators and nodes. The model formulation is as follows:

Objective function. The objective function of the ED minimizes the global cost of all dispatched generation, i.e. the sum of the marginal cost times the used generation capacity for all generators and timesteps within the optimization period (Eq. 3.1).

$$\min_{P^{DA}_{g,t}} \sum_t \sum_g \mathrm{c}^{\mathrm{mc}}_g P^{DA}_{g,t} \tag{3.1}$$

Market clearing. The sum of generation from all sources must be equal to the sum of demand in all nodes at all times (Eq. 3.2).

$$\sum_g P^{DA}_{g,t} - \sum_n \mathrm{d}^{\mathrm{load}}_{n,t} = 0 \quad ,t \in \mathscr{T} \tag{3.2}$$

Power generation. The power generation by all generators cannot exceed their maximum power output (Eq. 3.3). Since we assume

$$P^{DA}_{g,t} \leq \mathrm{p}^{\mathrm{max}}_g \quad ,g \in \mathscr{G}, t \in \mathscr{T} \tag{3.3}$$

Pumped Hydroelectric Storage (PHS). The units for pumped hydroelectric storage (PHS) used in the models have upper bounds for the maximum pumping and generating power (Eq. 3.4, 3.5). They can only store energy up to their maximum capacity (Eq. 3.6). Furthermore, their hourly state of charge (SOC) is calculated using the SOC from the prior time-step minus pumping and plus storing power. Additional storage is subject to efficiency losses (Eq. 3.7).

$$D_{s,t} \leq \mathrm{p}^{\mathrm{max}}_s \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.4}$$

$$P^{DA}_{s,t} \leq \mathrm{p}^{\mathrm{max}}_s \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.5}$$

$$H_{s,t} \leq \mathrm{l}^{\mathrm{max}}_s \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.6}$$

$$H_{s,t} = H_{s,t-1} - P^{DA}_{s,t-1} + \eta_{\mathrm{s}} D_{s,t-1} \quad ,s \in \mathscr{S}, t \in \mathscr{T} : t > 1 \tag{3.7}$$

Non negativity. Eq. (3.9-3.11) ensure that the power output of all generators and storages, demand for power by PHS units and storage level can never be negative.

$$P^{DA}_{g,t} \geq 0 \quad ,g \in \mathscr{G}, t \in \mathscr{T} \tag{3.8}$$

$$P^{DA}_{s,t} \geq 0 \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.9}$$

$$D^{DA}_{s,t} \geq 0 \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.10}$$

$$L^{DA}_{s,t} \geq 0 \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.11}$$

CM model (Step 2a)

Auxiliary parameters. The auxiliary parameters we use in this iteration of the calculations are the *market clearing price for electricity* $\overline{\Psi}_t$ and the economically optimal, hourly generation per generating unit $\overline{P}^{DA}_{g,t}$. As no binary or otherwise non-linear equations or constraints are used, the price is obtained as the dual value of the market clearing constraint of the ED (Eq. 3.2).

Objective function. We follow the formulation of Xiong et al. (2021), based on Kunz and Zerrahn (2016). Re-dispatch is profit-neutral, so any affected unit is reimbursed for additional costs or lost profits: Power-output increasing re-dispatch is compensated at marginal cost, power-decreasing re-dispatch at the lost profit, PHS storage units at the efficiency-adjusted market price and demand that cannot be delivered at the cost of lost load. The Value of Lost Load (VOLL) is set to 1000 in our calculations (Eq. 3.12).

$$\min_{\Delta P^{+}_{g,t},\Delta P^{-}_{g,t}} \sum_{t}\sum_{n} \left[\sum_{g}\left(\mathrm{c}^{\mathrm{mc}}_{g}\Delta P^{+}_{g,t} + (\overline{\Psi}_{t} - \mathrm{c}^{\mathrm{mc}}_{g})\Delta P^{-}_{g,t}\right) + \sum_{s}\frac{\overline{\Psi}_{t}}{\eta_{\mathrm{s}}}\Delta P^{+}_{s,t} + \mathrm{c}^{\mathrm{VOLL}}P^{lost}_{n,t}\right] \tag{3.12}$$

The re-dispatch effectively changes the scheduled power output of generating units. As such, we introduce the variables $P'_{g,t}$ for the adjusted generation schedules after CM calculations (Eq. 3.13).

$$P'_{g,t} = \overline{P}^{DA}_{g,t} + \Delta P^{+}_{g,t} - \Delta P^{-}_{g,t} \tag{3.13}$$

Nodal balance and power injection. Eq.3.14 ensures that the market clearing constraint holds true at each node. As shown in Eq. 3.15, the nodal power injection is calculated as the net difference between all connected generation (positive) and load (negative). The voltage angles are linked to this injection by using the susceptance entry on the admittance matrix.

$$\sum_{g} P'_{g,t} - \mathrm{d}_{n,t} = P^{inj}_{n,t} \quad ,n \in \mathscr{N}, t \in \mathscr{T} \tag{3.14}$$

$$\sum_{m} b_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{inj}_{n,t} \quad ,n \in \mathscr{N}, t \in \mathscr{T} \tag{3.15}$$

Line power flow. The power flow in our model is calculated by using the line reactance and voltage angles at the from-node and the to-node in equation 3.16. To avoid line damaging, their thermal capacity limit including the Transmission Reliabiliy Margin (TRM) must not be exceeded (positive or negative) at all times. This constraint is expressed by equation 3.17 and 3.18 and holds true in both flow directions. The TRM is defined as a value between 0 and 1. As Xiong et al. (2021), we chose a TRM value of 0.25 for the 2015 scenario. To ensure physical feasibility of the model, no TRM was assumed for the future scenario.

$$x^{-1}_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{flow}_{n,m,t} \quad ,n,m \in \mathscr{N} : n \neq m, t \in \mathscr{T} \tag{3.16}$$

$$P^{\mathrm{flow}}_{l,t} \leq p^{\max}_{l}(1 - \mathrm{trm}) \quad ,l \in \mathscr{L}, t \in \mathscr{T} \tag{3.17}$$

$$-\left[p^{\max}_{l}(1 - \mathrm{trm})\right] \leq P^{\mathrm{flow}}_{l,t} \quad ,l \in \mathscr{L}, t \in \mathscr{T} \tag{3.18}$$

Power generation. Eq. 3.19 and 3.20 prevent power plants from being simultaneously shifted up and down. Additionally, Eq. 3.19-3.21 ensure the new generation profiles to stay within generation limits

$$\overline{P}^{DA}_{g,t} + \Delta P^{+}_{g,t} \leq \mathrm{p}^{\max}_{g} \quad ,g \in \mathscr{G}, t \in \mathscr{T} \tag{3.19}$$

$$0 \leq \overline{P}^{DA}_{g,t} - \Delta P^{-}_{g,t} \quad ,g \in \mathscr{G}, t \in \mathscr{T} \tag{3.20}$$

$$P^{DA}_{s,t} + \Delta P^{+}_{s,t} \leq \mathrm{p}^{\max}_{s} \quad ,s \in \mathscr{S}, t \in \mathscr{T} \tag{3.21}$$

Non negativity. All generation after CM calculations must not be negative (Eq. 3.22).

$$P'_{g,t} \geq 0 \quad ,g \in \mathscr{G}, t \in \mathscr{T} \tag{3.22}$$

TSO-M: CM extension. (Step 2b)

In the TSO-M case, the TSO is responsible for including the flexibility options provided by DERs into its calculations to achieve the globally minimized cost of re-dispatch. In order to simulate this, we apply a number of changes to the previously introduced model formulation for the CM. The objective function (Eq. 3.12) as well as most constraints (Eq. 3.13, 3.15-3.22) remain unchanged. However, for implementing flexible loads, the nodal demand for the respective nodes is no longer treated as exogenously determined. Instead, we allow the TSO to change the hourly demands, according to the respective constraints. Additionally, constraints are required to limit the amount of load shifting.

Load. We introduce the variables $L_{n,t}$ to depict the actually realized demand for electricity as the sum of the previously constant demand and the changes in all sectors (Eq. 3.23).

$$L_{n,t} = d_{n,t} + \Delta D^{+}_{n,t} - \Delta D^{-}_{n,t} \tag{3.23}$$

Nodal balance. Eq. 3.14 is modified to accommodate for variable load profiles. Still, the nodal power injection must equal the difference between re-dispatched generation and shifted load (Eq. 3.24).

$$\sum_{g} P'_{g,t} - \mathrm{L}_{n,t} = P^{inj}_{n,t} \quad ,n \in \mathscr{N}, t \in \mathscr{T} \tag{3.24}$$

Aggregated load shifting. The aggregated load shifting in a node - upwards and downwards, respectively, both denoted by positive values - is comprised of the three sectors (further explained in chapter 3.4.3).

$$\Delta D^{+}_{n,t} = D^{ser+}_{n,t} + D^{re+}_{n,t} + D^{ind+}_{n,t} \tag{3.25}$$

$$\Delta D^{-}_{n,t} = D^{ser-}_{n,t} + D^{re-}_{n,t} + D^{ind-}_{n,t} \tag{3.26}$$

Aggregated demand balance. Over each calculation period of 24 hours, the sum of upwards-shifting must be equal to the sum of downwards-shifting for all nodes and demand sectors. Eq. 3.27-3.29 ensure that the daily demand for power by each sector aggregates to the same amount as before the introduction of flexibility. Since the total demand is the sum of the three sectors, these implicitly include the demand balance for each node.

$$\sum_t \{D^{ser+}_{n,t} - D^{ser-}_{n,t}\} = 0 \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.27}$$
$$\sum_t \{D^{res+}_{n,t} - D^{res-}_{n,t}\} = 0 \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.28}$$
$$\sum_t \left\{D^{ind+}_{n,t} - D^{ind-}_{n,t}\right\} = 0 \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.29}$$

Maximum shifting capacity. We split the previously exogenously determined load profiles into the sectors and assign upper bounds for both upwards and downwards load shifting. These bounds are constant for the residential and the service sectors at their average demand for energy times the relative load shifting capacity (Eq. 3.30-3.33). The (albeit higher) shifting potential of the industrial sector is only available during working hours (Eq. 3.34-3.37).

$$D^{ser+}_{n,t} \leq a^{ser} \times z^{ser} \times mean(d_{n,t}) \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.30}$$
$$D^{ser-}_{n,t} \leq a^{ser} \times z^{ser} \times mean(d_{n,t}) \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.31}$$
$$D^{re+}_{n,t} \leq a^{res} \times z^{res} \times mean(d_{n,t}) \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.32}$$
$$D^{re-}_{n,t} \leq a^{res} \times z^{res} \times mean(d_{n,t}) \quad ,t \in \mathscr{T}, n \in \mathscr{N} \tag{3.33}$$
$$D^{ind+}_{n,t} \leq a^{ind} \times z^{ind} \times mean(d_{n,t}) \quad ,t \in 9:16, n \in \mathscr{N} \tag{3.34}$$
$$D^{ind-}_{n,t} \leq a^{ind} \times z^{ind} \times mean(d_{n,t}) \quad ,t \in 9:16, n \in \mathscr{N} \tag{3.35}$$
$$D^{ind+}_{n,t} = 0 \quad ,t \in (1:8) \vee (17:24), n \in \mathscr{N} \tag{3.36}$$
$$D^{ind-}_{n,t} = 0 \quad ,t \in (1:8) \vee (17:24), n \in \mathscr{N} \tag{3.37}$$

DSO-M: Load shifting (Step 3)

In the DSO-M case, the TSO no longer performs the calculations controlling the load shifting decisions. Instead, as an aggregator of flexibility provided by the owners of DERs, the DSO runs a cost minimization attempting to reduce the amount that needs to be paid for the electricity as much as possible. For this calculation, we define a new objective function while using all constraints from the TSO-M case regarding limits to load shifting capacities (Eq. 3.23; 3.25-3.37).

Auxillary Parameters. For this optimization step, we use two auxiliary parameters from the first calculation of CM without load shifting. For minimizing their cost, the end-consumers connected to a node need to pay a price for their electricity demand. To examine the effect of utilizing DERs for re-dispatch and to prevent the influence of volatile market prices, we assume them to be price-takers at the *average market price* over the 24 hours of each day. For this purpose, we introduce the daily average electricity price $\overline{\Psi}$ that is no longer volatile.[2] Furthermore, we assume them to receive a signal $\overline{\Phi}^{RD}_{n,t}$ about the

[2]We acknowledge that assuming a constant price for taking electricity from the TS for a certain time period makes the price itself irrelevant to the load shifting decisions as long as each nodal demand aggregates to its original value over the same period. Hence, we could also assume a price of zero and remove the

hourly *average cost of re-dispatch*, obtained from the non-extended CM and influencing their decisions. Calculated for every node and hour of calculation, we obtain it as the nodal ratio of the *total cost of re-dispatch* divided by the *total volume of re-dispatch*. We define it to be zero for nodes with no active re-dispatch.

Objective function. The purpose of the objective function (Eq. 3.38) is minimizing the overall cost of all participants connected to a node. Using the uniform market price given by the ED, the cost for the end-consumers is comprised of price multiplied by the energy that is actually taken from the electric network. They reduce their cost by shifting their load according to signals sent by the TSO regarding the profitability of positive or negative load shifting (both negative and positive values are possible for $\overline{\Phi}^{RD}_{n,t}$).[3]

$$\min \sum_t \left[\overline{\Psi}^{av} G_{n,t} + \overline{\Phi}^{RD}_{n,t} (\Delta D^{+}_{n,t} - \Delta D^{-}_{n,t}) \right] \tag{3.38}$$

Final CM (Step 4)

After running the DSO-side optimization outlined in section 3.3.4, the resulting load profiles are returned to the TSO for a final iteration of the CM optimization, finalizing the re-dispatch commands sent to generators.

This calculation follows the mathematical formulation of the CM with a minor modification: The forecast demand profiles $d_{n,t}$ are replaced by the auxiliary parameters $\overline{L}_{n,t}$ as the nodal, changed demand profiles returned by the DSO optimization.

3.4 Case study

We apply our model to real-life data from the German power system of 2015 and a German 2030 scenario with 65 % RES.

3.4.1 The 2015 scenario

For the 2015-scenario, we use an open-access reference data set (version 1.0.0), which reflects the whole German energy sector (electricity, heat, natural gas) at the state of late 2015 provided by Kunz et al. (2017b). The related data documentation (Kunz et al. (2017a)) offers great insight into their data collection method. In the context of this project, we extract data on electric load, installed capacities of conventional and RE generation units, transmission line capacities, resistance, and reactance. The extraction is based on the preparation of Weibezahn and Kendziorski (2019) and Xiong et al. (2021). The extracted data are the input for our model of the ED and subsequent CM.

The transmission grid provided by the data set includes 724 multi-circuit AC transmission lines connected to 451 national nodes. Across those nodes, the annual load of

first term entirely. However, we include it on purpose as it would be very simple to replace it by the *actual, volatile* market prices for further research.

[3]The signal $\overline{\Phi}^{RD}_{n,t}$ could be interpreted as a *price* for the load shifting by itself that is then paid to the involved parties. However, it is not its actual dimension that is important for the load shifting decisions, but its absolute and relative *change* over the course of one day. Indeed, multiplying all hourly values over the course of one day - or dividing them - by any non-negative number has absolutely no effect on the load shifting decisions resulting from this optimization step. Hence, the pricing of load shifting is its own topic we discuss in chapter 3.5.3.

Fuel	Marginal Cost (MC) [€/MW]	Installed capacity in [GW]
Wind onshore	0	41.2
Wind offshore	0	3.3
Solar PV	0	39.3
Run of River	0	3.7
PHS	0	8.8
Geothermal	0	0.03
Biomass	< 1	8.1
Total RES		**104.4**
Natural gas	40 - 135	23.6
Nuclear	9.09	12.1
Lignite	20 - 36	20.9
Hard coal	29 -52	28.6
Oil (light)	120 - 157	3.1
Oil (heavy)	61 -71	0.6
Other fuels	102 -139	2.5
Waste	0	1.6
Total Non-RES		**93**
Total		**197.4**

Table 3.1: Installed capacity and marginal cost for 2015 based on Kunz et al. (2017b)

540.339 TWh is distributed at hourly resolution. Concerning the generation, 613 individual thermal power plants and 33 PHS units are included and associated with nodes. The data set also considers RES units but aggregates them on a nodal level. At the time frame of the data set, a total generation capacity of 197,4 GW is installed in Germany. 47% of the capacity is provided by conventional thermal power plants, 11% by flexible RES power plants and 42% by intermittent RES generation units. Table 3.1 shows the exact distribution of generation capacity.

This table also shows the range of MC for the different technologies used in the 2015 scenario that are the basis to the calculation of the market price and the re-dispatch cost. While the MC for RES technologies are set to zero, the components of MC of conventional power plants are the fuel cost c^{fuel}, a technology specific price and factor for CO_2 (c^{CO_2}, λ_g), cost for operation and maintenance c_g^{OM} and the efficiency η_g. The model computes the MC from those components with eq. (3.39).

$$\mathrm{c}_g^{\mathrm{mc}} = \frac{\mathrm{c}^{\mathrm{fuel}} + \mathrm{c}^{\mathrm{CO_2}} \lambda_g}{\eta_g} + \mathrm{c}_g^{\mathrm{OM}} \quad , g \in \mathscr{G} \tag{3.39}$$

3.4.2 The 2030 scenario

For the 2030 scenario, we use the open-access data set provided by vom Scheidt et al. (2020). It models the German power system in 2030 with 65 % of the brute electricity consumption satisfied by RES. By basing their projections concerning transmission grid topography on the current data provided by Matke et al. (2016) and on the development plan of the federal network agency of Germany (BNetzA (2019)), they give a realistic impression of the power system in 2030. This development plan also lays the basis for the data set concerning generation and demand (in high spatial and temporal resolution). The

MC [€/MW]	**Installed capacity [GW]**
0	190
30	0.681
40	1.337
50	6.411
60	2.146
70	33.829
80	7.414
90	2.854
100	9.543
110	2.434
120	0.242
130	1.693
140	0.853
150	0.498
160	0
170	0
180	0
220	0.036
Total	**259.975**

Table 3.2: Installed capacity and marginal costs for 2030 based on vom Scheidt et al. (2020)

documentation [4] provides greater insight into their data collection method and assumptions made to create a future data set. Up to today, this data set has been used by vom Scheidt et al. (2021) and vom Scheidt et al. (2022) to analyse the effects of integrating hydrogen in the German power system and how this would affect the hydrogen supply chain. However, as it provides a realistic and applicable simulation of the German power system in 2030, we chose to use this data set to apply our frameworks to a power system with higher RES generation share as it could be in eight years. The described transmission grid consists of 663 lines connecting 485 nodes and transmitting 543.9 TWh per year. Compared to 2015, its capacity is increased by 18.76 %. On the generation side, it includes only wind and solar as RES with an annual generation of 247.4 TWh and 86.7 TWh. This capacity corresponds to an increase of RES generation of 109.81 % compared to 2015. For the conventional power plants, it considers 718 units with a total annual capacity of 70,175 MW. It excludes nuclear power as Germany plans to shut down all nuclear units by the end of 2022. Unlike in the 2015 data set, vom Scheidt et al. (2020) did not classify the generators by their fuel or technology, but they created 23 cost classes based on their marginal cost. Table 5.1 shows the total amount of installed capacity (both for dispatchable and non-dispatchable generation) per cost class. The authors of the data set included a 24^{th} cost class to simulate that each node has an additional generation capacity of 1,000 MW with marginally higher marginal costs than all other conventional power plants (221 €/MWh). vom Scheidt et al. (2020) did so, as the network development plan does not provide a power system free of bottlenecks. Quite the contrary is the case, as they intentionally allowed those bottlenecks to encourage technological innovations that can compensate for the shortages in the grid (BNetzA (2019), pp.42-43). The hypothetical

[4] available on `https://bwdatadiss.kit.edu/dataset/254#headingFileList`

1,000 MW generation capacity per node considers these innovations to ensure a feasible grid simulation. We consider this theoretical capacity, as we found that the amount of lost load becomes unreasonably high without this capacity.

As the data of vom Scheidt et al. (2020) are formatted differently to our basis data set provided by Kunz et al. (2017b), we needed to adapt the given data with further assumptions to apply them to our model.

The main challenge was the lack of line specifications such as reactance and resistance that our model needs to perform a DC Optimal Power Flow (OPF) calculation. We had to make some assumptions to approximate those values as follows:

- Since the data set does not imply information about the length of the lines, we had to assume that each line connects its start and endpoint in a straight line. This assumption enabled us to approximate the length using the provided coordinates of the nodes and the line incidence matrix.

- We assumed the line type and voltage level based on the capacity of each line. Indeed, lines with capacities divisible by 490 MW and 1700 MW are considered in 220 kV and 380 kV levels, respectively. Egerer et al. (2014) provide the specifications of lines with 490 MW and 1700 MW capacity. It should be noted that the dataset contains a few lines that are not divisible by 490 MW and 1700 MW. These lines are rounded to the closest higher capacity.

- Finally, some lines have a capacity of 245 MW, i.e., half of 490 MW lines which are typically configured with a bundle of 2 wires per phase (Openmod Initiative (2022)). So, it is assumed that the only difference between 245 MW and 490 MW lines is the number of wires per phase. Therefore, the resistance per length per phase of each 490 MW is half of the 245 MW lines. However, equation 3.40 shows the relation between the reactances, assuming a symmetrical configuration for the lines.
$$\frac{X_{245}}{X_{490}} = \frac{ln(\frac{d}{r'})}{ln(\frac{d}{\sqrt{r' \times x}})} \tag{3.40}$$
d is the distance between the lines, r' is the effective radius of the wires, and x is the distance between wires in the bundled phase. Based on some typical values for d, r', and x, the reactance per length of the 245 MW line is 29 percent higher than the impedance of the 490 MW line.

3.4.3 DSO-modelling for both scenarios

In our project, we want to model the TSO as well as several DSOs. While real transmission network data are available (like the data sets we use), DSOs usually do not publish data about their networks. Furthermore, the significant number of DSOs also causes problems for mapping the DSs. In Germany, more than 880 DSOs are operating (BNetzA (2016)). Therefore, there is no uniform data set for medium and low voltage grids.

To avoid the lack of real data but still get a realistic picture, we did not model a different electricity demand distribution between the sectors for each DSO but applied the same distribution to all nodes across Germany. At 45% (large scale industry), 27% (trade and services), and 26% (residential), those three sectors were responsible for almost all electricity demand in Germany in 2020 (BDEW (2021)). To avoid overestimating the industry sector's influence, we have chosen to assume a distribution of 40% for the

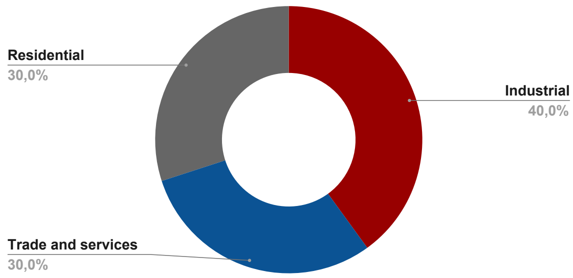

Figure 3.5: Sectoral load distribution per node based on BDEW (2021)

industrial and 30% each for the other two sectors. As the sectoral energy demand is not estimated to change significantly until 2030 (Matthes et al. (2007)), this distribution can be used for both scenarios. Using this assumption, we achieve sufficient accuracy while reducing the risk of unrealistically excessive shifting in the industrial sector. Furthermore, this method enables us to run our model in the macroscopic setting we are aiming for.

3.5 Results

3.5.1 Key Indicators

We set out four key indicators to compare and analyze the results from the different cases and scenarios. The first indicator reflects the system-wide cost of re-dispatch. Related to the first indicator, we take a look at the global volume of re-dispatch as the second indicator. The value of comparison for this parameter are the aggregated re-dispatch commands reducing the power output of all generators, including the curtailment of RES [5]. The third indicator depends on the mentioned load profile adaption, as we analyze the volume of total shifted load in the system. This parameter indicates the intensity of use of the DER flexibility potential and is, therefore, an efficiency indicator for their integration. The fourth and last indicator was chosen to measure the efficiency of the frameworks for a power system with increasing RES generation share: the volume of curtailment. The less energy generation from renewable sources is curtailed, the more the frameworks support the green shift. Another aspect of this indicator is of economic nature. As curtailment is one of the most expensive forms of power-reducing re-dispatch, the frameworks are generally more cost-efficient with a lower share of curtailment.

3.5.2 The value of flexible DERs for the re-dispatch

Knowing our key indicators, we present the results of our cases. We begin with an examination of results on an annual level. Table 3.3 provides a summary of the key indicators resulting from all three cases and the two scenarios over the course of one year.

A comparison of our results regarding the electricity mix in Germany to historic data from 2015 (see Appendix B) shows that our modeling frameworks have the ability to

[5] It would also have been possible to aggregate the re-dispatch increasing the power output of generators, in this case excluding RES with a marginal cost of zero, as they will always be fully utilized as long as the demand exceeds their availability. However, by choosing the power-decreasing re-dispatch, lost load is inherently included in the parameter. Both scenarios feature a certain amount of lost load, with the majority occurring in node 272 (87% of global lost load in the 2015 scenario) and node 14 (100% of global lost load in the 2030 scenario).

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Mio € /a]	609.86	526.60	574.14
Volume of re-dispatch [TWh/a]	5.36	4.74	5.33
Volume of RES curtailment [GWh/a]	993	948	980
Volume of load shifting [TWh/a]	-	9.04	4.44
2030			
Cost of re-dispatch [Mio € /a]	9,396	9,089	9,242
Volume of re-dispatch [TWh/a]	44.86	43.23	44.45
Volume of RES curtailment [TWh/a]	5.65	5.52	5.69
Volume of load shifting [TWh/a]	-	9.31	6.03

Table 3.3: Annual key indicators calculated by CM. A price for the DERs is not yet included.

provide an insight close enough to reality. For the future scenario, a comparison with empiric data is impossible. Furthermore, the annual, system-wide cost for re-dispatch of over 9 billion €, being over 15 times the result from 2015, may seem exaggerated. However, vom Scheidt et al. (2022) use the dataset for their own re-dispatch calculations, achieving a result of 6.163 billion €. According to our calculations, the dataset features unavoidable lost load in node 14 accumulating to 3.18 TWh. Thus, at our VOLL of 1,000 € per MWh of lost load, this is responsible for the difference as vom Scheidt et al. (2022) does not consider lost load. Depending on the progress of grid extension, other sources also project (very) high re-dispatch costs in 2030 (von Schemde et al. (2020)).

Since all models minimize costs, it is expected that both the DSO-M and TSO-M cases manage to reduce the annual cost for the re-dispatch. Caused by the significantly higher total amount of necessary re-dispatch, the relative decrease in cost is substantially lower for the 2030 scenario, despite the actual savings being higher. For the 2015 scenario, the savings of roughly 83 and 35 Million € translate to a relative reduction of cost of 13.65 % and 5.86 %, respectively. Using the future data, we achieve a reduction of roughly 300 and 150 Million Euros (3.26 and 1.63 %, TSO-M and DSO-M case, respectively). We emphasize that no pricing or compensation for the DERs is included at this point. Concerning the DSO-M case, the parameter $\overline{\Phi}_{n,t}^{RD}$ as implemented in the objective function of the DSOs is only considered a signal for how useful load-shifting in a certain time step is. In the TSO-M case, the load shifting capacities, as included in the constraints, can be freely utilized up to their respective bounds and with no associated costs.

We also expect the related indicator of global volume of re-dispatch to decrease in both coordinated frameworks and for both scenarios. As Table 3.3 shows, our expectation holds true, even though the increase in performance is significantly more substantial for the TSO-M case: The DSO-M case decreases this indicator by only 0.5 % in 2015 and by 0.9 % in 2030. Caused by the much larger total amount of necessary re-dispatch, the relative reduction for the TSO-M case reaches only 3.6 % in 2030 compared to 11.5 % in 2015 despite its absolute value being 1.63 TWh over the course of the year.

In summary, the decrease in the overall *cost* of re-dispatch is significantly higher than the decrease in the overall *volume* of re-dispatch for the 2015 scenario, with the change in *volume* being even negligible for the DSO-M case. Using the predicted data for 2030, the relative indicators reach similar dimensions in both cases.

We calculate the volume of load shifting as the annual sum of all shifting decisions reducing the hourly nodal power demand. The aggregated power demand over the course

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Mio €]	57.4	52.5	56.0
Volume of re-dispatch [GWh]	548.8	501.6	543.4
Volume of RES curtailment [GWh]	109.5	104.2	108.4
Volume of load shifting [GWh]	-	402.6	199.0
Value of load shifting [€ /MWh]	-	12.17	7.04
2030			
Cost of re-dispatch [Mio €]	492.6	481.2	487.2
Volume of re-dispatch [TWh]	2.374	2.299	2.350
Volume of RES curtailment [GWh]	430.5	429.5	428.8
Volume of load shifting [GWh]	-	400.9	270.7
Value of load shifting [€ /MWh]	-	28.39	19.97

Table 3.4: Key indicators over days 321-334

of each day is required to be unchanged (eq. 3.27-3.29). As such, this value equals the sum of power-increasing decisions over the course of each day and thus over the year. The system-wide demand for power is only increased marginally in our second scenario (plus 0.7 %). Consequently, according to our models, the maximum amount of load shifting potential is similar in both scenarios. This can be easily observed with the TSO-M cases reaching a total amount of 9.04 TWh (2015) and 9.31 TWh (2030) of shifted load over the course of the entire years. In the DSO-M cases, the load shifting is less pronounced, aggregating to 4.44 TWh (2015) and 6.03 TWh (2030). We discuss the main reason for this difference in section 3.5.3.

Concerning the volume of curtailment, both coordinated frameworks improve the outcome in 2015. However, the TSO-M case outperforms the DSO-M case again at a relative reduction of 4.75 % and 1.32 %, respectively. In 2030, the TSO-M case is still able to reduce curtailment by a small margin (2.4 %) while applying the DSO-M case slightly increases the amount of curtailed generation from RES (0.7 %).

3.5.3 Discussion and sensitivity analysis

For further analysis of the results, we take a close look at one single period of two consecutive weeks for both scenarios in the following section. When applying our coordination frameworks, we discuss the changes to the re-dispatch decisions and load profiles. Furthermore, we explain and discuss other aspects influencing the outcome and possible model limitations before performing a sensitivity analysis regarding the percentage of shiftable load.

A microscopic view

While the annual sums of costs and volumes are good parameters for comparing the cases' performance, re-dispatch and its efficiency become increasingly important in the times of the highest congestion. Furthermore, a more microscopic view on the optimal re-dispatch as calculated by the different models provides valuable insight into the mechanisms behind the improvement in performance when using the newly developed models. Consequently, in addition to investigating the annual model outcomes, we take a closer look at the *two weeks with the highest cost of re-dispatch* identified from the results of the 2015 scenario. Since we aim to decrease congestion by finding suitable mechanics to reduce the volumes and costs of necessary re-dispatch, we identify these weeks using the congestion management as implemented for the BAU case. Since each week consisting of seven consecutive days features the same number of weekdays with higher expected total loads, we do not require our two-week period to start on a Monday. Instead, we allowed for any period of fourteen consecutive days of operation. We have identified the time frame of reference as the 336 hours starting on the 321st day of the year. For clarity, we chose the same time frame for the 2030 scenario. The key indicators for this period are in Table 3.4.

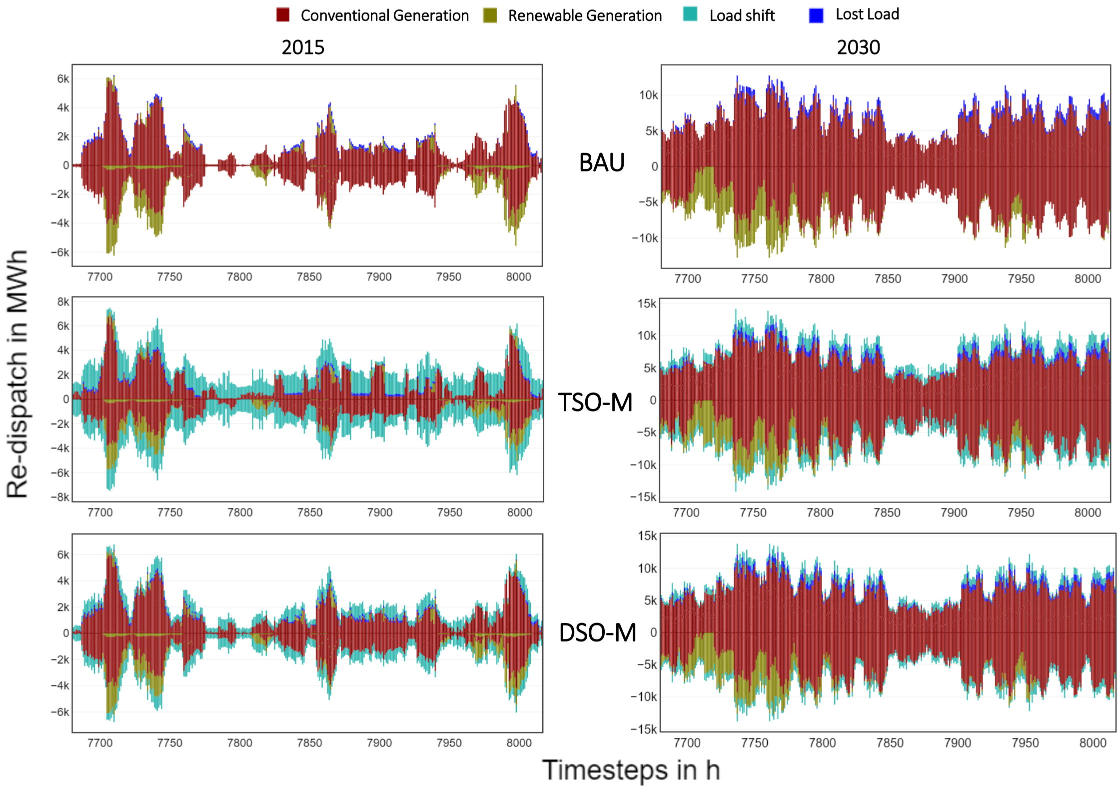

Figure 3.6: Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030

Fig. 3.6 shows the aggregated re-dispatch, load shifting decisions by our frameworks, and unavoidable lost load per case and scenario. For each time step, the sum of generation-increasing re-dispatch, consumption decreasing load shifting, and lost load must equal the sum of generation-decreasing re-dispatch, curtailment of generation from RES, and consumption increasing load shifting. We observe that the relative share of load shifting decisions is much higher in the 2015 scenario (making up more than 80 % of the global volume of re-dispatch using the TSO-M case) due to the much lower amount of necessary global re-dispatch. Furthermore, caused by periods with shallow necessary re-dispatch volumes, the flexibility manages to assist in balancing peaks in both cases while these periods are missing in the 2030 scenario.

We have plotted the hourly cost of re-dispatch over the time period of 336 hours in Fig. 3.7. In the 2015 scenario, the difference in cases is clearly visible, with the TSO-M case achieving the most pronounced decrease in overall cost by efficiently using times of low cost for an increase of re-dispatch. However, in the 2030 scenario featuring much higher overall levels of necessary re-dispatch, both frameworks perform similarly at reducing peaks of re-dispatch cost.

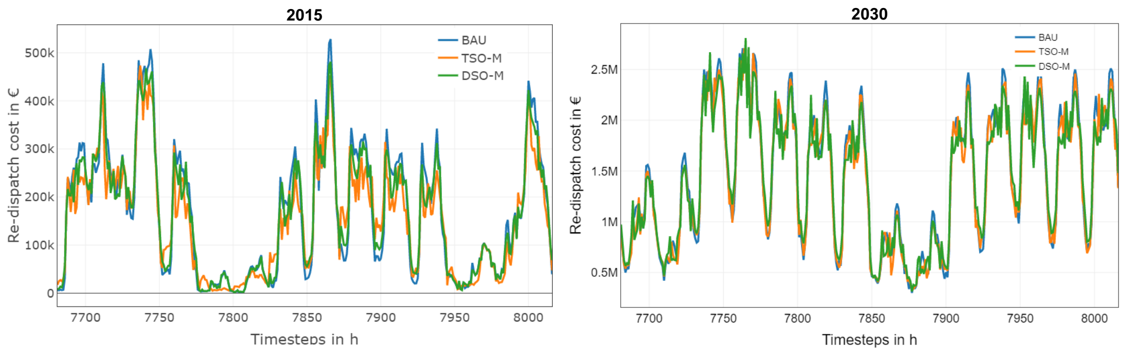

Figure 3.7: Re-dispatch cost for all cases over the two most expensive weeks in 2015 (left) and 2030 (right)

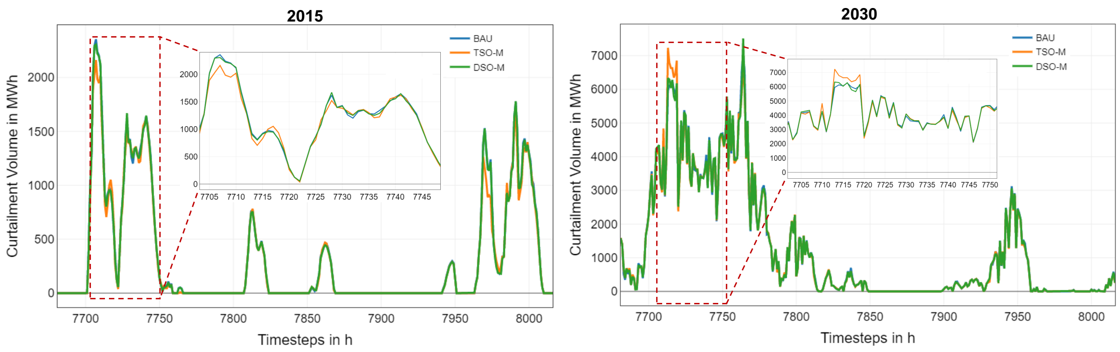

Figure 3.8: Volume of RES curtailment for all cases over the two most expensive weeks in 2015 (left) and 2030 (rigth)

Fig. 3.8 shows the hourly volume of RES curtailment that becomes necessary for each case and scenario during the calendar days 321-334. It becomes apparent that the curtailment of generation from RES is one of the most expensive forms of re-dispatch for the 2015 scenario. As such, the TSO-M case, in particular, is able to reduce its peaks. However, using the large amount of fictional generation capacities at a marginal price of 221 € per MWh of generation in the 2030 scenario, it becomes a relatively cheap option for re-dispatch, and some peaks are increased considerably, especially by the TSO-M case.

Further discussion

During the process of our analysis, we have identified additional aspects of TSO-DSO coordination regarding the usage of DER for re-dispatch purposes that we discuss in the following paragraphs.

Performance improvement in re-dispatch operations. There are two mechanisms by which the two different implementations of DER integration affect the volume and cost of re-dispatch as calculated by the CM.

1. Using the implemented load shifting capacities, necessary re-dispatch is shifted from periods with a high ratio of re-dispatch cost to volume to periods where this value is lower.

2. The shifted load profiles synergize better with transmission constraints. This leads to less congestion and consequently to a lower cost and volume of global re-dispatch.

These two mechanisms are used in the two cases to a different extent, explaining their difference in the outcome. In the TSO-M case, both the load shifting capacities and transmission constraints are included in the optimization. As such, both of the previously mentioned effects can be exhausted: The spatial allocation of nodes and their connecting transmission lines are taken into account, so the model will find the optimal allocation of load shifting to achieve the lowest global cost for necessary re-dispatch. Interdependencies between nodes caused by connections and the physical laws (and constraints) for the flow of electricity are considered. Hence, if a locally sub-optimal solution provides a global optimum, it will be the outcome the model opts for. This reduces the overall volume and thus cost of re-dispatch, explaining the extensive decrease in re-dispatch volume of the TSO-M case compared to the BAU. Furthermore, the load shifting capacities are used to make the remaining unavoidable re-dispatch as cheap as possible. This leads, for example, to the decrease of RES curtailment: At a marginal cost of zero, curtailment needs to be compensated at market price, making it an expensive form of re-dispatch. The effect of shifting re-dispatch towards timesteps when it is overall cheaper can be easily observed when comparing the re-dispatch profiles of cases BAU and TSO-M in the 2015 scenario depicted in Fig. 3.6.

In the DSO-M case, each DSO (as in each node, since we assume one DSO per node) optimizes its own outcome without considering transmission constraints and interdependencies between nodes. As such, they can only directly control the utilization of mechanism 1, i.e., they will shift their load from periods with more expensive re-dispatch towards the cheaper timesteps. According to our model, any effect of mechanism 2 that comes into play in the decentralized optimization is entirely accidental, meaning that an actual reduction in re-dispatch *volume* is not certain for case DSO-M.

TSO-M: Conflict of interest. Our models are already subject to a considerable amount of simplifications. One of the most important assumptions may be the *omniscience* and the *omnipotence* of the TSO: Not only does the TSO have full information about every participant in the market, it can also dictate the load profiles for every provider of load shifting capacities to reach an optimal solution. Both of these assumptions are unrealistic. Even if the DSOs actually assume the role of aggregators, they are unlikely to share information with the TSO that they could utilize for their own benefit. Furthermore, adequate compensation - or other forms of benefit - will need to be provided by the TSO for load-shifting capacities for consumers to follow its suggestions.

DSO-M: Nodes without re-dispatch. In the DSO-M case, the signal given to the DSOs regarding the nodal cost of re-dispatch is calculated as the hourly ratio of re-dispatch cost divided by volume after the first iteration of CM calculations. It is pre-defined to be zero when no re-dispatch occurs in a certain time-step and location. Consequently, nodes without re-dispatch over any complete period of 24 hours after the first calculation of the CM do not receive any incentive to use their load-shifting capacities during this day, explaining the large difference in load-shifting volumes despite the same amount being technically available.

DSO-M: Competition with market prices. To prevent competition with volatile market prices for electricity, the objective function implemented for the DSO-managed case assumes each holder of flexibility-providing DER assets to be a price taker at the same *average* market price over each period of 24 hours (Eq. 3.38). Indeed, as long as a constant price is assumed during the balancing period for load shifting as implemented in Eq.

3.27-3.29, the actual price signal is irrelevant for the resulting shifting decisions. This assumption is necessary for investigating the *best possible* effect of DERs on the re-dispatch, but not realistic: If load shifting capacities are available, it would also be possible to use them for a variety of other purposes, including benefiting from volatile market prices. We go into a little more detail on compensation in the following paragraph.

Both cases: Pricing of DERs. As we have previously shown, both cases are able to reduce global volumes and prices of re-dispatch in both scenarios. However, any price improvement is largely due to the fact that no compensation for the owners of DER assets is implemented. Nevertheless, load-shifting capacities require infrastructure and will thus be linked with considerable investment. To gain an estimate of how much could potentially be paid to the owners of the DER assets providing the flexibility for re-dispatch, we divide the annual volume of load-shifting by the annual decrease in cost for re-dispatch. If this value was paid per amount of electricity shifted from one time step to another, the sum of both prices - for re-dispatch and for load shifting - would aggregate to the same value. Hence, their usage would be profit-neutral, while decreases in re-dispatch and curtailment volume are preserved. Over the course of the year 2015, this value is 9.21 € per MWh (TSO-M) and 8.04 € per MWh (DSO-M). These values are both not close to being high enough to provide a realistic incentive for investing in flexible DERs. However, Fig. 3.6 provides a conclusive explanation for these values being so low: The available load shifting capacities can be used for decreasing expensive re-dispatch such as the curtailment of RES during some periods, providing substantial benefits to the re-dispatch both regarding cost and by including more renewably generated electricity. However, during periods of cheap re-dispatch, both cases still utilize all available load shifting capacities, adding large amounts to load shifting but little to the decrease of global cost of re-dispatch.

It must be noted that the result is very different for the future scenario: At higher levels of necessary re-dispatch and at technologies being used that are relatively more expensive, the TSO-M and DSO-M case reach average values of 33.51 and 25.78 € per MWh of shifted load, respectively.

Sensitivity analysis

Relative shares of shiftable load are hard to predict. In the 2015 scenario, the initial shares of load we allow for shifting result in a global volume of load shifting of over 80% the sum of annual re-dispatch already for the DSO-M case. In TSO-M, the aggregated annual load shifting equals almost double the re-dispatch. These values may be too high to be realistic in the medium term. Even if they are achieved or assumed, assisting re-dispatch decisions is not the only purpose they can be used for. To investigate the effect smaller shares of shiftable load have on the outcome of our calculations, we perform a sensitivity analysis applying load shifting percentages of one half (2.5/2.5/5%) and one quarter (1.25/1.25/2.5%) of their original values to the calculations over the two weeks examined in the previous chapter. We expect the results to be less pronounced than initially but similar to our original scenario in that the TSO-M case outperforms the DSO-M case for all scenarios. However, we especially expect the average value of load shifting (i.e., the ratio of cost decrease by volume of shifted load) to increase with each reduction of shifting percentage, as at lower shifting volumes, more expensive re-dispatch remains to be shifted. Tables 3.5 and 3.6 provide an overview of the key indicators resulting from our examinations. The plotted re-dispatch profiles for our sensitivity analysis are included in the appendix.

Indicator	**BAU**	**TSO M**	**DSO M**
2015			
Cost of re-dispatch [Mio €]	57.4	54.4	56.6
Volume of re-dispatch [GWh]	548.8	501.6	543.4
Volume of RES curtailment [GWh]	109.5	106.8	108.8
Volume of load shifting [GWh]	-	204.2	99.5
Value of load shifting [€ /MWh]	-	14.76	8.66
2030			
Cost of re-dispatch [Mio €]	492.6	486.1	489.3
Volume of re-dispatch [TWh]	2.374	2.330	2.361
Volume of RES curtailment [GWh]	430.5	429.7	429.9
Volume of load shifting [GWh]	-	208.5	135.4
Value of load shifting [€ /MWh]	-	31.50	24.89

Table 3.5: Results over days 321-334 for half the shifting capacity

Indicator	**BAU**	**TSO M**	**DSO M**
2015			
Cost of re-dispatch [Mio €]	57.4	55.7	56.9
Volume of re-dispatch [GWh]	548.8	533.1	547.1
Volume of RES curtailment [GWh]	109.5	107.8	109.1
Volume of load shifting [GWh]	-	103	49.8
Value of load shifting [€ /MWh]	-	16.60	9.54
2030			
Cost of re-dispatch [Mio €]	492.6	489.1	490.8
Volume of re-dispatch [TWh]	2.374	2.349	2.367
Volume of RES curtailment [GWh]	430.5	430.1	430.5
Volume of load shifting [GWh]	-	105.6	67.7
Value of load shifting [€ /MWh]	-	33.68	27.05

Table 3.6: Results over days 321-334 for one quarter the shifting capacity

During our sensitivity analysis, both cases continue to prove beneficial in both scenarios. However, at lower percentages of available load for shifting, the aggregated volume of shifted load drops faster than the saves from the decrease in re-dispatch. Consequently, our second expectation holds true as well: At lower availability of shifting capabilities, the value per shifted amount of load increases, bringing this values from 12.20 to 14.76 and 16.60 € per MWh (TSO-M) / from 7.09 to 8.66 and 9,54 € per MWh (DSO-M) for the 2015 scenario. For the future scenario, the already much more promising values of 28.39 (TSO-M) and 19.97 € per MWh (DSO-M) increase further to 31.50 / 33.68 € per MWh and 24.89 / 27.05 € per MWh, respectively.

3.6 Conclusion

The domain for researching new coordination mechanisms between TSO and DSOs is relatively new and of high interest. The novelty of the domain, caused by the recently increasing DER potential all over the world, leaves many opportunities for new concepts and discussion. The high interest derives from the ongoing implementation of RES into power systems, causing increasing risks for congestion and, therefore, increasing re-dispatch costs as we saw in the 2030 scenario.

We have seen various paths explored to find feasible solutions to integrate and exploit the potential of DERs for a higher power system efficiency with RES. Models in related literature present different approaches for the various types of DERs and often focus on just one type. The approaches vary in the level of integration, the form of aggregation, the level of market entrance, and, as mentioned, the type of considered DERs. Based on the different ideas, diverse modeling concepts emerged. The concepts perceived as the most promising ones consider an active DSO and decentralized coordination. Most considered concepts aim to minimize the system cost and therefore choose economic efficiency indicators. This corresponds to the current practice of evaluating those systems.

In this paper, we have researched the application of load flexibility DERs can provide for assisting the re-dispatch necessary in electricity markets that employ a zonal pricing mechanism and that do not consider transmission constraints before the closure of the DAM markets. We have developed two coordination frameworks (TSO-M and DSO-M) and used a BAU case as a benchmark in one empiric and one future scenario.

We have found that both coordinated frameworks outperform the BAU in 2015 and 2030. However, the centralized framework TSO-M aiming for the system welfare yielded more efficient results than the more realistic DSO-M case both in 2015 and 2030. Despite this finding, TSO-M is not likely to be applied (in this form) as it assumes the TSO to have complete information and the DSOs owners of DER assets to be fully cooperative. The DSO-M case is more likely to be accepted as it preserves the information barrier and the cost-minimizing interest of the DSOs. However, this framework does not offer a system-wide perspective to the system operators and has, therefore, lower performance than the TSO-M case.

Further research could include the development of a coordination framework combining the preservation of the information barrier, i.e., taking both the different interests of the participants and the system-wide perspective for TSO and DSOs into account. Other approaches could be to develop remuneration schemes to incentivize investment in the area of DERs or to investigate whether using the flexibility provided by them for more than just one purpose could prove beneficial.

3.7 Appendices

Appendix A

Nomenclature

Sets

$\mathcal{G}$	Set of all generators: g
$\mathcal{L}$	Set of transmission lines: $l \in (n, m)$
$\mathcal{N}$	Set of nodes: n, m
$\mathcal{R}$	Subset of $\mathcal{G}$, Renewable energy units: r
$\mathcal{S}$	Set of all PHS units: s
$\mathcal{T}$	Set of time slices in hours: t

Variables Economic Dispatch (ED)

Ψ_t	MCP in €/MWh$_{\mathrm{el}}$
$D^{DA}_{s,t}$	Power demand of PHS units on the DA market in MW$_{\mathrm{el}}$
$H^{DA}_{s,t}$	Storage level of PHS units on the DA market in MWh$_{\mathrm{el}}$
$P^{DA}_{g,t}$	Generation by all generators on the DA market in MW$_{\mathrm{el}}$
$P^{DA}_{r,t}$	Generation by renewable energy units on the DA market in MW$_{\mathrm{el}}$
$P^{DA}_{s,t}$	Generation by PHS units on the DA market in MW$_{\mathrm{el}}$

Variables Congestion Management (CM)

$\Delta P^{+}_{g,t}$	Upwards adjustment of the DA market generation in MW$_{\mathrm{el}}$
$\Delta P^{-}_{g,t}$	Downwards adjustment of the DA market generation in MW$_{\mathrm{el}}$
$P^{inj}_{n,t}$	Power injection at node n in MW$_{\mathrm{el}}$
$P^{lost}_{n,t}$	Lost load at node n in MW$_{\mathrm{el}}$
$P^{flow}_{n,m,t}$	Line flow from n to m in MW$_{\mathrm{el}}$
$\Theta_{n,t}, \Theta_{m,t}$	Node angle at n and m in rad

Variables CM extension

$\Phi^{RD}_{n,t}$	Ratio of nodal re-dispatch cost to volume
$\Delta D^{+}_{n,t}$	Upwards adjustment of the nodal hourly demand in MW$_{\mathrm{el}}$
$\Delta D^{-}_{n,t}$	Downwards adjustment of the nodal hourly demand in MW$_{\mathrm{el}}$
$L_{n,t}$	Actual, realized load
$D^{re+}_{n,t}$	Hourly increase of demand in the residential sector MW$_{\mathrm{el}}$
$D^{ind+}_{n,t}$	Hourly increase of demand in the industrial sector MW$_{\mathrm{el}}$
$D^{ser+}_{n,t}$	Hourly increase of demand in the service sector MW$_{\mathrm{el}}$
$D^{re-}_{n,t}$	Hourly decrease of demand in the residential sector MW$_{\mathrm{el}}$
$D^{ind-}_{n,t}$	Hourly idecrease of demand in the industrial sector MW$_{\mathrm{el}}$
$D^{ser-}_{n,t}$	Hourly decrease of demand in the service sector MW$_{\mathrm{el}}$

Variables DSO optimization

$G_{n,t}$	Electricity taken from network at average market price in MW$_{\mathrm{el}}$

Parameters

a^{ser}	nodal share of service sector load
a^{ind}	nodal share of industrial sector load
a^{res}	nodal share of residential sector load
$\mathrm{b}_{n,m}$	Susceptance entry (n, m) on the admittance matrix
$\mathrm{c}^{\mathrm{mc}}_{g}$	Marginal cost of generator g in €/MWh$_{\mathrm{el}}$
$\mathrm{c}^{\mathrm{VOLL}}$	Value of lost load (VOLL) in MW$_{\mathrm{el}}$
$\mathrm{d}_{n,t}$	Nodal load in MW$_{\mathrm{el}}$
$\mathrm{p}^{\max}_{g}$	Maximum power generation of generator g in MW$_{\mathrm{el}}$
$\mathrm{p}^{\max}_{s}$	Maximum pumping and generating power of PHS unit s in MW$_{\mathrm{el}}$
$\mathrm{p}^{\max}_{l}$	Line capacity in MW$_{\mathrm{el}}$
trm	Transmission reliability margin (trm)
x_{l}	Reactance of line l in MW$_{\mathrm{el}}$
z^{ser}	share of load from the service sector that can be shifted
z^{ind}	share of load from the industrial sector that can be shifted
z^{res}	share of load from the residential sector that can be shifted
η_{s}	Storing efficiency of PHS unit s

Appendix B

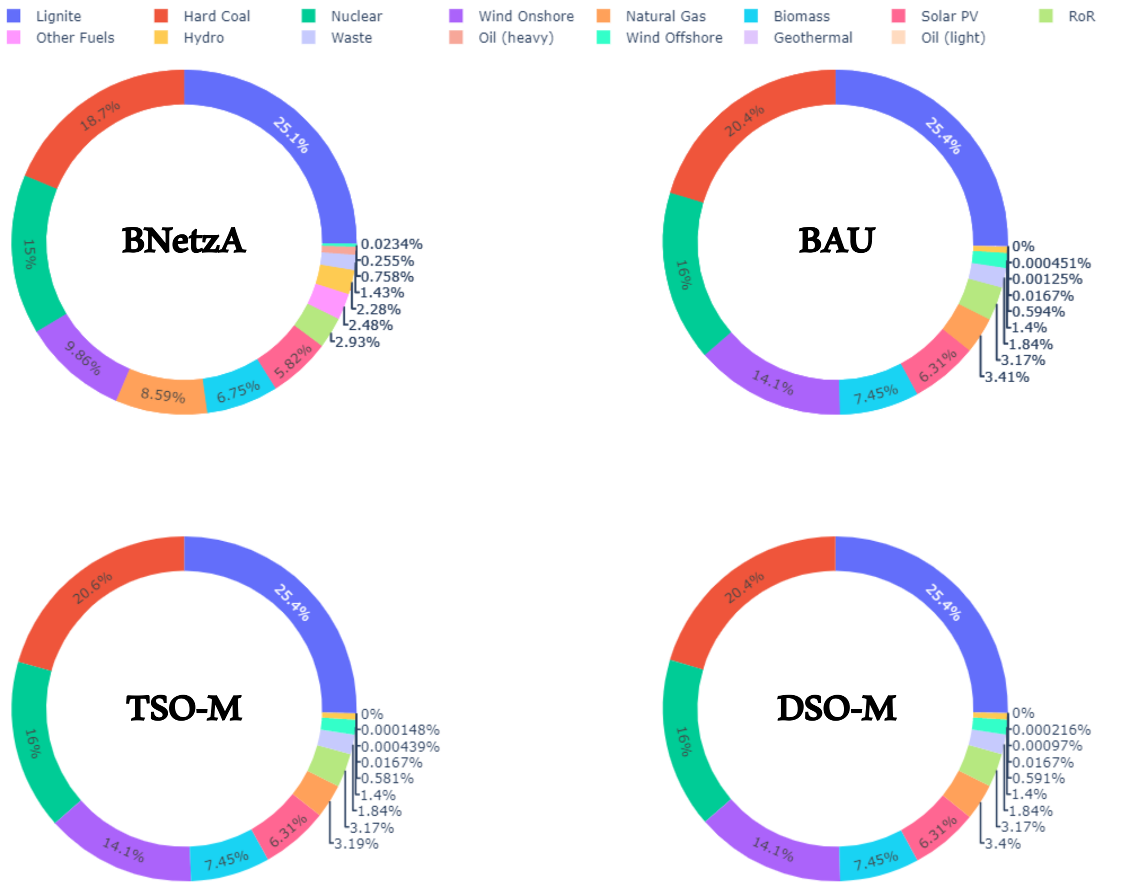

Figure 3.9: Generation Mix 2015. Historic data by BNetzA (2016) and resulting mix for each case after CM

Appendix C

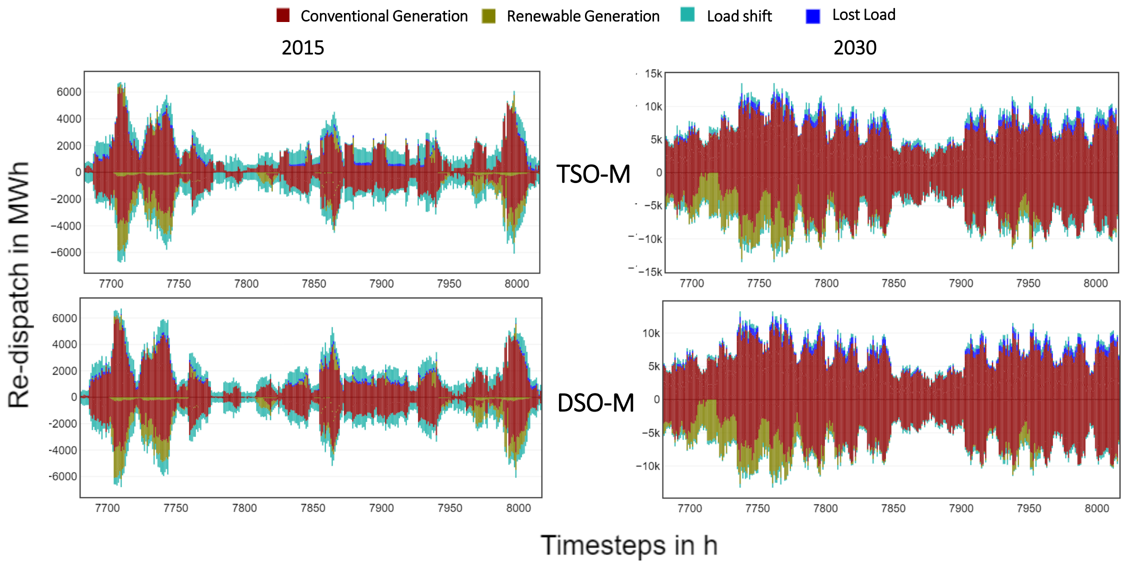

Figure 3.10: Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030 with half the original load shifting capacity

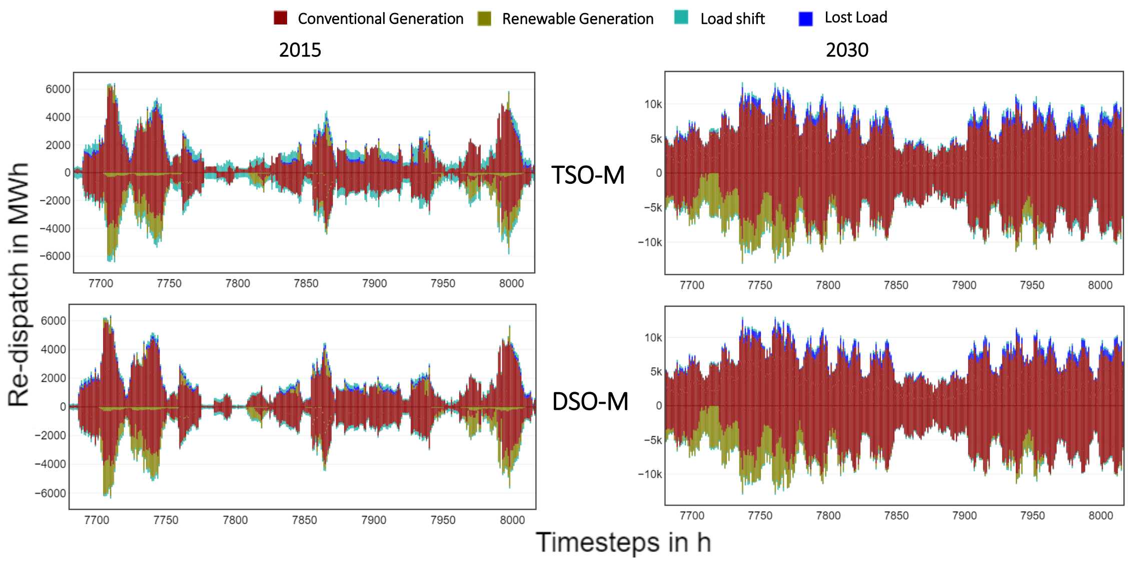

Figure 3.11: Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030 with a quarter of the original load shifting capacity

Model framework

We provide our model (Julia) under the MIT licence on GitHub: `https://github.com/simonpea/tsodso_der`.

Chapter 4

Towards a more realistic value for DSO side flexibility

4.1 Reflections of the first paper

Within this section, we review the methodology and the results of the first paper. Here, we consider both: their strengths and limitations. The research of the first paper aimed to set up possible TSO-DSO coordination frameworks to exploit the potential of DERs within the power system. More precisely, we investigated their value to lessen the cost and volume of the CM. We developed two coordinated frameworks (TSO-M and DSO-M) and one reference case (BAU) to benchmark them. Furthermore, we considered that the flexibility of DERs becomes more crucial in future power systems with a higher share of RES and, therefore, higher uncertainty concerning generation. Hence, we applied our frameworks to two scenarios: the German power system in 2015 and 2030.

In the following sections, we assess some limitations and the general perspective of the frameworks in Chapter 3. We have already discussed some of those limitations in the discussion part of the previous chapter. However, we set a particular focus on some of them in order to point out the relation to our second paper.

4.1.1 The realization potential of the coordinated frameworks

The frameworks in Chapter 3 are designed to measure the impact of integrating DERs on the whole power system. However, as discussed previously, some assumptions influence the likelihood of their realization. Even though the TSO-M case outperforms the DSO-M case, several factors make the DSO-M case more realistic. Firstly, a centralized approach to managing growing, decentralized flexibility resources is highly demanding in terms of computational complexity. This is especially true if these calculations occur while calculating the large-scale CM. Our decision to exclude the DS-level constraints from our model prevented our analysis from reflecting this challenge. Secondly, the assumption of the benevolence of the DSOs towards the system welfare by sharing all necessary information disregards the interests of the flexibility providers aggregated by the DSOs. The TSO is allowed to utilize their flexibility assets without providing immediate, adequate compensation to benefit the system's welfare. The DSO-M case does consider those interests and is, as a decentralized approach to an increasingly decentralized power system, more likely to be accepted. However, the DSO-M case also has some limitations. As the incentive to provide flexibility is a price signal from the CM, the DSOs on nodes without necessary re-dispatch get no signal and have no incentive to use their assets. Therefore, the potential of DERs is not exhausted, and the DSO-M case fails at fully integrating them into the power system.

4.1.2 Static market prices

Both of the coordinated frameworks assume the CM to be the only possibility for the DER owners to profit from participation in the power system. As our focus in Chapter 3 was the systems benefit from an integration of the flexibility potential of the DERs, we prevented competition between the CM and other markets for the DERs. The versatile nature of DERs allows them to use their potential for different purposes and theoretically take advantage of other trading options. However, our decision to only consider the average market price over 24 hours as DAM price prevents the providers of flexibility from profiting from any volatility in electricity price. Meanwhile, the results in Chapter 3 showed that the value of load shifting if considered as revenue for the flexibility providers is not high enough by itself to incentivize investment into demand side flexibility assets.

4.1.3 The two scenarios

The use of two scenarios enabled us, on the one hand, to calibrate the model with empirical data and to get an insight into the future value of demand-side flexibility on the other. While the 2015 scenario shows a potential value of DSO side flexibility already for current power systems, it also proves the lack of investment incentives. The 2030 scenario, however, illuminates a growing potential for these flexibility providers in the future. With more uncertain generation in the system, flexibility such as provided by DERs becomes increasingly valuable and their participation more beneficial for their owners. It is, therefore, interesting from the perspective of the providers to investigate the incentives arising in the future.

4.1.4 Value of load shifting

The price signal from the CM to the flexibility providers in the first paper is not yet an actual remuneration for the providers. However, even if they would be recompensated at this value, at between 8.04 €/MWh and 9.21 €/MWh in 2015, this does not provide enough incentive to invest in this flexibility resource. Even at the significantly higher values for the future scenario (25.78 €/MWh (DSO-M) and 33.51 €/MWh (TSO-M)), the incentive for new DSO side flexibility investments may be relatively low.

4.2 Transition to the subsequent paper

The second paper in this thesis continues the research based on the reflections in Section 4.1. They aroused our interest in investigating a more realistic approach to the topic. Instead of searching for the system's most beneficial way to exploit the potential of DSO side flexibility, we are now searching for methods to improve the potential monetary benefits that can be gained by investing in load flexibility. Consequently, our focus expands and considers the following aspects.

The main extension of the second paper consists of the addition of other possibilities DSOs aside from the CM as trading options. As seen in Chapter 1, DSO-side flexibility providers could potentially access many existing electricity markets. We decided to offer the providers the opportunity to trade on the IDM additionally to the CM because of the high price volatility of that market. The flexibility providers can exploit this volatility to maximize their revenue.

From the modeling perspective, the most critical development is the step from a deterministic toward a two-stage stochastic model. The stochastic model extension copes with the uncertainty regarding the price development on the IDM: The decision regarding the allocation of flexibility to the precedent CM needs to be made before the IDM comes into play. Unlike in the first paper, we now expect that the DSO flexibility providers will exploit the price volatility. Therefore, we do not assume the IDM price to be constant over the course of 24 hours. Instead, we make a prediction for different possible developments of the IDM price, each assigned with a certain probability of occurrence. We investigate the optimal expected revenue the DSO side flexibility providers could expect when allocating their potential to these two trading options.

Paper 2

Multi-market bidding for DSO side flexibility providers: Value from Re-dispatch and Intraday Market participation

Manuscript to be submitted to an international peer reviewed journal.

Chapter 5

Multi-market bidding for DSO side flexibility providers: Value from Re-dispatch and Intraday Market participation

Abstract

As the share of renewable electricity generation increases in most power systems, their intermittent nature will lead to an increased demand for flexible technologies to balance fluctuations in power supply. Furthermore, the spatial distribution of the different sources of renewable energy will cause increased congestion of the affected transmission lines. DSO-side flexibility may prove beneficial regarding both of those challenges. However, to this day, this flexibility resource remains largely unused. Besides missing integration frameworks, the remuneration for the DSO side flexibility providers is not high enough to incentivize investment in this flexibility resource. We investigate how using the DSO side flexibility not only for the re-dispatch but also for the intraday market improves the financial incentives to provide this flexibility service to the system. In order to do so, we set up a two-stage stochastic techno-economic optimization model adopting the principle of coordinated bidding. Regarding the flexibility integration into the re-dispatch, we use a decentralized TSO-DSO coordination framework. We find that allowing access to more than one market results in a significantly higher value of the DSO side flexibility than when used solely for CM purposes. Furthermore, it allows more DSO side flexibility providers to effectively offer their service. Consequently, this improves the integration of this potentially crucial future flexibility resource.

5.1 Introduction

The energy-related climate goals set by governments all over the world pose significant challenges to their power systems. Designed for receiving energy from centralized generators and distributing it top-down towards the end consumer, the systems are not yet ready for an increasing share of intermittent generation from Renewable Energy Sources (RES). Alongside the higher share of RES in the system comes an increasing electricity demand originating from climate-friendly electrification policies. Higher electricity demand and a growingly uncertain and decentralized generation call for more flexibility options to ensure system and supply security.

As Sánchez-Jiménez et al. (2015) claims, alongside with others (see section 5.2), an important yet largely unexploited source of flexibility is located on the DSOs side of the grid. The research about possible DSO side flexibility integration is a rather new but fascinating and important field of research. As Figure 5.1 shows, there are, on the one hand, various possibilities to introduce DSO side flexibility into existing electricity markets. On the other hand, the figure also shows that significant research has been done already to work out integration programs.

However, besides the research progress on this topic, Figure 5.1 illustrates as well the limitations of current literature. The versatile nature of the DSO flexibility qualifies them to offer their products also for other services. Even though some authors consider designing new markets for this flexibility resource, some services such as help within the Congestion Management (CM) are less researched. Another issue that is only touched by recent literature is the missing incentives for investment into DSO side flexibility through their integration into the power system. The main focus lies on the systematic implementation and not on adequately incentivizing the DSO side flexibility providers to participate. As Figure 5.1 shows, there are price and incentive-based participation programs. However, currently, those incentives are not strong enough.

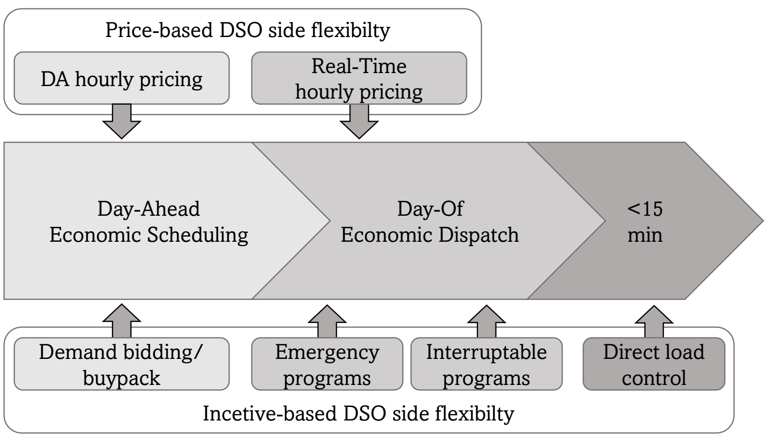

Figure 5.1: Possibilities to integrate DSO-side flexibility into the power system based on Shivakumar et al. (2017)

A possibility to provide adequate incentives is offering the possibility of providing flexibility not only in one but also in several of the pictured programs and beyond. However, little research in this area has been done so far as we know, especially with a consideration of the CM. Therefore, we want to contribute to this research with this paper guided by the following questions:

- Where can DSO flexibility profitably participate in power markets?

- What is the optimal strategy to allocate this flexibility within the two trading options CM and IDM?

We approach these questions within this paper as follows: After a review of current related literature, we explain our methodology and lay out our model formulation in section 5.3. Once we clarified our approach, we give insight into the case study we apply the methodology onto. Ultimately, we state and discuss the results in section 5.5 before giving some concluding remarks in section 5.6.

5.2 Related literature

The flexibility providers located at the DS have been increasing over the years in number and variety. Within the literature, those flexibility options are described as decentralized flexibility options and, based on technical characteristics like, among others, response time, duration, and delivering time, categorized as follows: electrical consumption, bidirectional flexibility, and Distributed Generation (DG) (Xu (2019); Eid et al. (2016)). Within the scope of this paper, we focus on the Demand Response (DR) potential for load shifting, towards which all the three categories can contribute. To date, the amount of this DSO side flexibility is already considerable and is expected to further increase in the future (Sia Partners (2014),Vartanian et al. (2018)).

However, the current power market design does not support the integration of this growing resource. While in our previous work (Pearson et al. (2022)), we investigated their integration from a system perspective, we research in the following sections what markets are attractive for the flexibility providers and how their bidding strategies can be modeled when they access more than one market.

5.2.1 Attractive markets and perspectives for DSO side flexibility providers

While Xu (2019) and Eid et al. (2016) distinguish between different physical flexibility assets, Villar et al. (2018) identifies three flexibility products that can be offered with those assets: ramping capacity (power), energy and capacity. As products of the exact nature are traded on the different electricity markets, the versatility of DSO side flexibility gives their providers the opportunity to participate in those trades.

However, the current power system design hinders the participation of DS flexibility resources. Integrating this resource into the system is a matter of ongoing research. Authors like SmartNet Consortium (2019), Rossi et al. (2020), Savvopoulos et al. (2019), Silva et al. (2021), Xu (2019) and Eid et al. (2016) investigate possible integration frameworks and, while agreeing on some findings, take rather different approaches. They all agree on the need for a change in the coordination of TSOs and DSOs to enable market participation of DSO side flexibility. The authors also agree that with increasing RES in the system, the integration of those flexibility resources becomes crucial for supply security. However, there is no agreement on the level or type of their market entrance.

SmartNet Consortium (2019), Rossi et al. (2020), Silva et al. (2021) and Savvopoulos et al. (2019) see the greatest potential for those flexibility options on the AS market. They propose different integration frameworks that focus on the TSO-DSO coordination to manage their structural implementation. One of their main findings is the importance of a more active DSO role that takes more responsibilities in an increasingly bidirectional power and communication flow. Another finding is the need for an aggregator that represents the interests of several DSO side flexibility providers to participate in any market.

While Eid et al. (2016) and Xu (2019) agree with the other authors on the need for an aggregator, they find more potential for DSO side flexibility on the balancing market. Villar et al. (2018) agree to this finding by defining two of their three market-orientated flexibility products as balancing flexibility that is either sold at the TS or the DS.

Unlike the previous authors, Newman and MacDougall (2021) and IRENA (2019) state that real-time market signals, such as from the balancing market, do not offer flexibility providers enough response time to reschedule their flexibility optimally. Especially for DSO side flexibility as in the context of this paper, these authors find that an integration in medium- to long-term wholesale markets and, more precisely, in the IDM is exploiting their potential more efficiently. Newman and MacDougall (2021) further explore the benefits of such an integration for the IDM and sees increasing trading volumes and a more cost-effective market with higher liquidity.

Less research has been conducted so far about the benefits of distributed flexibility for the CM. The results of Xiong et al. (2021) and our previous work Pearson et al. (2022) showed that using this flexibility for this purpose can improve the all-over system performance. However, it also revealed that the remuneration for the provision of this flexibility is only high enough to incentivize their providers when the share of RES in the system is higher than it is now. This result correlates with Ostergaard et al. (2021) stating in the context of a study about demand side flexibility in Denmark that to date the financial benefit for DSO side flexibility providers is not sufficient to engage them into the power system.

Indeed, most of the literature considered so far does not take the point of view of the flexibility providers but seeks to preserve the interests of the TSO, DSOs, and of a functioning system. Fewer authors took the position of flexibility providers and aggregators. Calvillo et al. (2016) proposes a framework for DSO side flexibility aggregators operating on the DAM, aiming to maximize their benefit. With the increasing size of the aggregator, it turns out to be economically beneficial for the flexibility providers to participate in the DAM. This correlates with the findings of Ottesen et al. (2016) who analysed possible bidding strategies for DSO side flexibilities on the DAM, considering penalities for imbalances but excluding the IDM. Madlener and Ruhnau (2021) and Bichler et al. (2021) expand this investigation by including the IDM. While comparing the strategies of demand-side flexibility on those two markets, especially DR, Madlener and Ruhnau (2021) and Bichler et al. (2021) found the IDM more promising due to higher price volatility than on the DAM that will even increase with a growing share of RES.

So far, the literature mainly focuses on one market to integrate DSO side flexibility. However, the European Network for Transmission System Operators (ENTSO-E) suggests the participation of DSO side flexibility in as many electricity markets as possible to exploit their potential the most efficient way (Chabanne et al. (2014)). From the perspective of the flexibility providers, it is also attractive to participate in more than one market, as shown by Ottesen et al. (2018) and Roos et al. (2014). The latter found that an aggregator allowed to participate in the DAM and the tertiary reserve market can maximize its outcome by trading simultaneously on both. Ottesen et al. (2018) even makes the aggregator participate in three electricity markets: an options market (like the balancing reserve capacity market), a spot market (like the DAM), and a flexibility market (like the balancing energy market). The multi-market participation leads to a significant increase in the benefit for the flexibility aggregator and the providers.

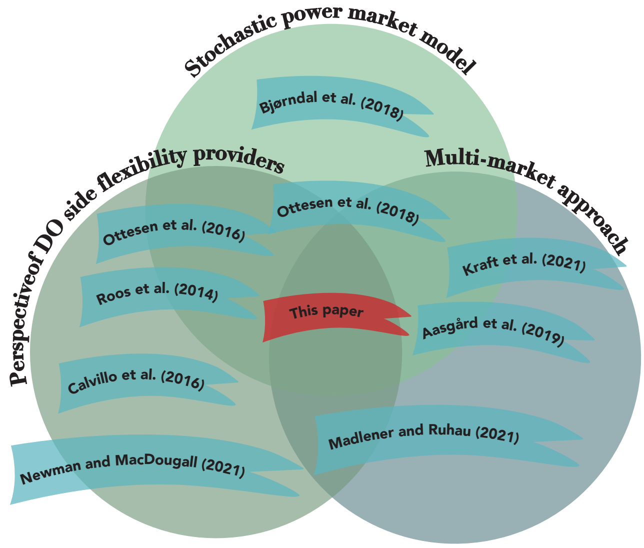

Figure 5.2: Graphic summary of the reviewed literature concerning DSO side flexibility perspective and market modelling

5.2.2 Multi-market bidding strategies

The investigation of optimal bidding strategies for an actor in more than one electricity market is not a new topic. As Klaboe and Fosso (2013) show, there have been several investigations about optimal participation in subsequent markets. However, those strategies have been developed and tailored to conventional power producers. Moreover, as DSO side flexibility providers have a different structure than those actors, these strategies need adjustments to allow an optimal DSO side flexibility allocation between subsequent markets.

Nevertheless, the concepts and procedures from conventional research provide a good basis for developing flexibility allocation strategies. Klaboe and Fosso (2013) differentiates two different bidding types: coordinated and separated bidding. While the latter does not take into account the opportunities in following markets before the closure time of the first market the actor participates in, the coordinated bidding does so. The concept of coordinated bidding also implies a decision for all related markets before the closure time of the first one. Research such as by Faria and Fleten (2011) and Boomsma et al. (2014) showed that the coordinated bidding slightly outperforms the separate bidding concerning the profit, even though currently it has a limited profit potential (Aasgård et al. (2019)). However, Klaboe and Fosso (2013) and Aasgård et al. (2019) points out the lack of comparing literature and states that coordinated bidding becomes more important with higher price differences between markets.

In a future with higher RES generation share, the conditions become more favorable for coordinated bidding. Therefore, most authors developing multi-market bidding strategies for DSO side flexibility aggregators such as Roos et al. (2014) and Ottesen et al. (2018) adopt this principle in their research. Even though Aasgård et al. (2019) are not researching multi market participation of DSO side flexibility, they also find this principle valuable for the flexibility, reservoir hydropower producers can offer on multiple markets. In doing so, the authors encounter the issue of uncertain information about the subsequent market. While Roos et al. (2014) chose a deterministic approach, Ottesen et al. (2018) and Aasgård et al. (2019) saw an interest in integrating these uncertainties via a stochastic model based on different price scenarios for its participating markets. Even though Roos et al. (2014) also explores possible bidding strategies with their approach, Talari et al. (2018)and Bjørndal et al. (2018) point out the importance of stochastic modeling in power markets, especially regarding analyses of future scenarios, to yield higher accuracy of the results and get a better impression of the market participants' opportunities. This statement is reinforced by Kraft et al. (2021) who developed sequential market trading strategies for a RES portfolio. Ottesen et al. (2016) even quantified the value of stochastic planning and found higher revenue for the flexibility providers when considering uncertainties in their planning than when basing their decisions on expected values. Furthermore, Aasgård et al. (2019) highlight the competitive advantage for producers of considering and managing the uncertainty of subsequent markets in a future power system.

Whether using a stochastic or a deterministic model, both Roos et al. (2014) and Ottesen et al. (2018) chose similar markets for their frameworks. While Roos et al. (2014) lets the aggregator participate explicitly in the DAM and the tertiary regulation reserve market, Ottesen et al. (2018) chose a more general approach. Within their framework, the aggregator can allocate its flexibility between three markets, as mentioned before. Therefore, they only distinguish between different types of markets without analyzing specific market designs. Both Roos et al. (2014) and Ottesen et al. (2018) chose a relatively small scope for their research and physical modeling of participating flexibility assets.

5.2.3 Contribution

Current literature concerning the integration of DSO side flexibility only knows few authors considering the benefit of their providers from this integration. Among those considering it, most research concentrates on one market even though the official recommendation from ENTSO-E encourages their integration in all possible markets. Alongside the research about the single market integrations, the IDM turned out to be the most profitable within the existing electricity markets for the DSO side flexibility as defined for this paper. Besides the existing markets, we found this flexibility valuable for the CM both for the system and, if remunerated with the price signal, the providers. The latter applies especially for a future scenario with a higher share of RES.

This paper contributes to the existing literature by investigating the possible benefit for DSO side flexibility providers by providing their service simultaneously for two different purposes. Based on our previous work (Pearson et al. (2022)) we continue investigating the value of these flexibility services for the CM with a suitable TSO-DSO coordination scheme. However, now we give the flexibility providers with the DSOs as aggregators the chance to optimally allocate their products between the CM and the market, which is the most suitable for the DSO side flexibility as defined in this paper: the IDM. In correlation with the literature, we model the uncertainties concerning the IDM stochastically while deciding the allocation at the CM. Unlike current literature, we analyze the effect of this dual trading option not on a small but a country-wide scale. Furthermore, we set this analysis into the context of the German power system in 2030.

5.3 Methodology

In this paper, we want to measure the impact multiple trading options have on the revenue and the behavior of DSO side flexibility providers. In the following, we describe the decision process about the flexibility allocation between the two trading opportunities we focus on: CM and IDM. As this decision is based on price signals, we explain the calculation methods and origin of the respective signals. The IDM price is not known in advance and cannot be calculated from other input data. Hence, we then explain our prediction method for three different possible price developments on the IDM.

5.3.1 DSO side flexibility participation at CM

In our previous work (Pearson et al. (2022)), we set up two TSO-DSO coordination schemes to exploit the potential of DSO side flexibility for a more efficient re-dispatch. The TSO-M, centralized framework considered interdependencies between nodes caused by transmission constraints and resulted in a higher value of load shifting. However, unlike its alternative, the decentralized DSO-M scheme considered the interests of DSO side flexibility providers with the DSOs as their aggregators. Therefore, we build up on our research and design the participation of the flexibility providers as a modification and extension of the DSO-M. Figure 5.3 provides a graphic explanation of the framework used in our previous paper.

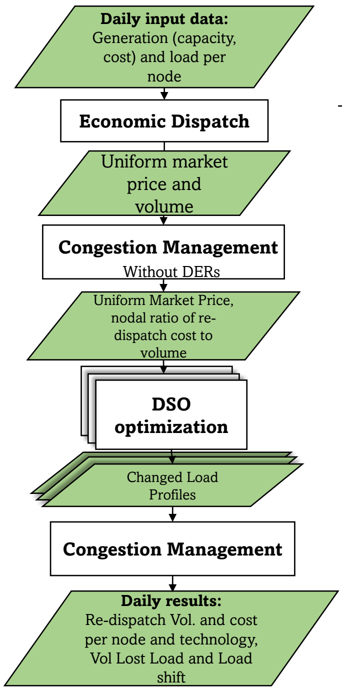

Figure 5.3: The DSO managed framework from Pearson et al. (2022)

As the Figure shows, the first two steps take place on the TSO level. First, we run an economic dispatch simulating the DAM to result in the uniform market price and the market volume. In the second step, the responsible TSO executes the CM without considering the DSO side flexibility to generate the nodal cost and volume of re-dispatch per node. In this model, we assume only one TSO operating in Germany. The results of the CM and the uniform market price are the signals on which the DSOs as flexibility aggregators base their cost minimization. During this process, no information about the other DSOs is available; therefore, the decisions of the DSOs do not influence each other. The adjusted nodal load profiles as results of this optimization are, in turn, sent back to the TSO to enable a second CM including the DSO flexibility. In Pearson et al. (2022) we analyzed the changes in re-dispatch cost and volume and load shifting value as caused by our framework in various ways.

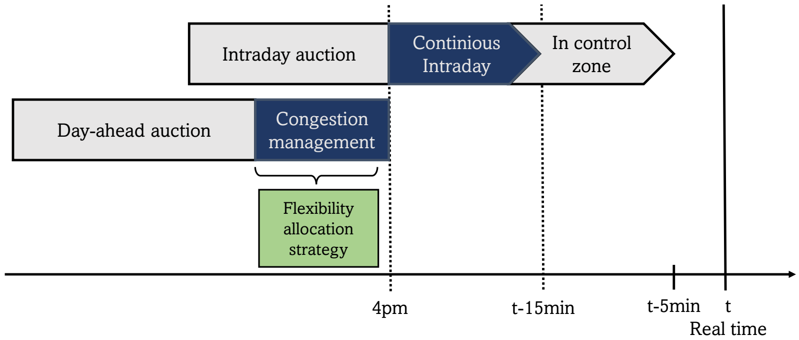

Figure 5.4: The German wholesale electricity market based on Kraft et al. (2021) with the timing of the DSO side flexibility allocation decision

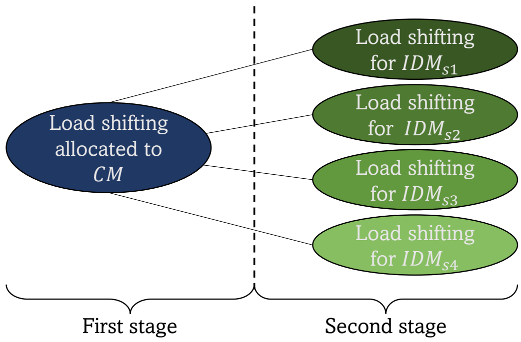

Figure 5.5: Two stage stochastic DSO optimization

However, as we are now not only analyzing the impact and opportunities for DSO flexibility in the CM, we adapt this framework to our expanded focus. Similar to the DSO-M scheme, we are still basing our DSO individual optimization on price signals, and we preserve the first two steps of the model. The third step will be modified in order to optimize considering not only one but two price signals. As we are now interested in the potential revenue of the DSOs as flexibility aggregators, we eliminate the second CM (Step 4). The modifications after the CM price signal generation are further explained in 5.3.3.

5.3.2 DSO side flexibility participation at IDM

In our model, we use the principle of coordinated bidding. Therefore, we consider the IDM during the DSOs decision about the flexibility volume used for the CM. However, as Figure 5.4 shows, no certain information about the IDM is available to the DSOs by the time they have to decide about the allocation of load shifting potential for CM purposes. We represent this by including three possible scenarios for the price development on the IDM, each assigned a specific probability of occurrence. Furthermore, unlike the DAM, the real IDM does not feature uniform prices and bid acceptance is not guaranteed. For our calculations, we assume uniform prices based on the historical IDM-Index-Price and its high and low prices[1], which are not available upfront. Thus, a prediction is needed regarding the future IDM and the development of its respective prices over each day. We represent the lack of a guarantee for bid acceptance by adding a fourth scenario where the amount of trading on the IDM is forced to zero.

[1]The index price used is the average price of all accepted bids for each period of 15 minutes. For our calculations, we, in turn, average it over each hour. The high and low prices are the highest and lowest accepted bids during the hour before realization.

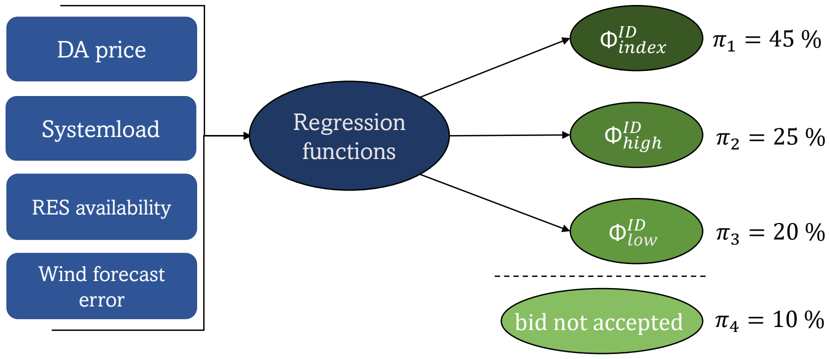

Figure 5.6: Intraday price signal scenarios

Within the related literature, a common approach to predict IDM prices is to perform a regression analysis (Ottesen et al. (2016); Shinde and Amelin (2019); Pape et al. (2016); Hagemann (2013)). Regarding the possible influences on the IDM price, Pape et al. (2016) points out that the DAM price is one of the most important factors for an accurate prediction. Other authors like Shinde and Amelin (2019) additionally highlight the influence RES like wind and solar energy have on the IDM price. The related investigation by Hagemann (2013) showed that especially the forecast errors of wind generation also impact the price of the IDM.

Based on these findings, we performed a regression analysis considering the following factors: DAM price, system load, wind and solar generation on the DAM, wind forecast error. Additionally, we analyzed the impact of the daytime and season (hour and month). We retrieved historical data for the regression inputs from the four German TSOs (50 Hertz, Amprion, Tennet, and TransnetBW) and from EEX, ENTSO-E, and EPEX for the years 2019-2021.[2]

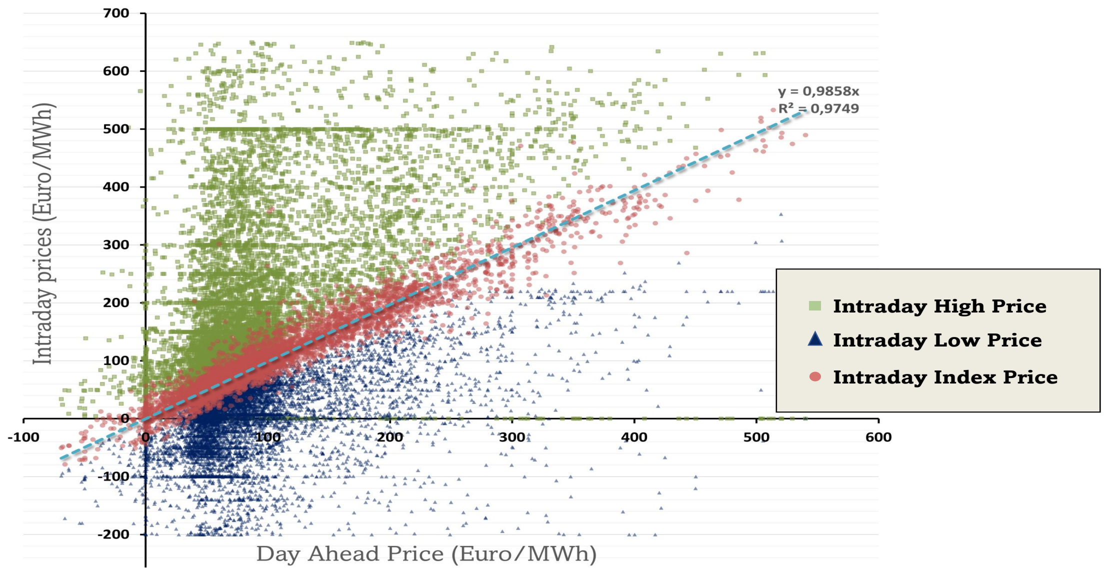

Figure 5.7: Intraday price (high, index and low) correlation to the Day Ahead price

In order to consider the uncertainty of the IDM price realization by the time of the load shifting allocation decision for the CM, we decided to create four different IDM price

[2]For a graphic representation of the respective data sets see `https://energy-charts.info/?l=de&c=DE`

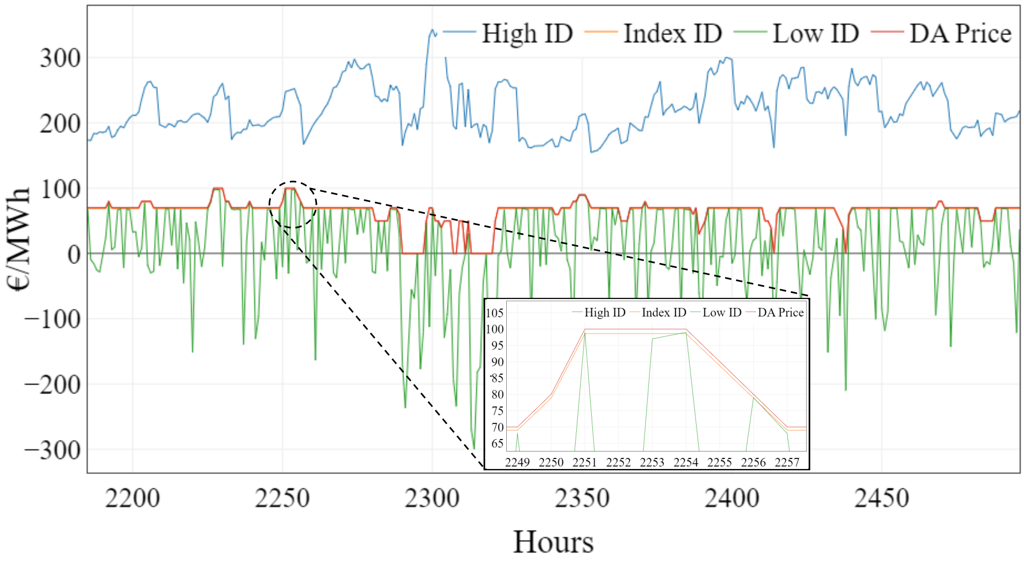

Figure 5.8: Intraday price scenarios and day-ahead price development

scenarios. Therefore, we use a two-stage stochastic model as illustrated by Figure 5.5. In one, we predict the IDM index price, two others consider the IDM high and the low price, while the fourth represents the possibility that the provider's bid on the IDM is not accepted (see Figure 5.6). We executed a regression analysis for the first three scenarios to predict each of these prices. As illustrated by Figure 5.7, the intraday index price has a strong correlation to the DAM price. In fact, the analysis showed that the DAM price has a strong correlation and high statistical significance to explain and predict the intraday index price. That is, a simple linear regression (without a constant for the intercept) would be as follows to predict the intraday index price:

$$\Phi^{ID}_{index,t} = 0.9858 \cdot \Phi^{DA}_{t} \tag{5.1}$$

Due to these regression results, the IDM index price is always close to the DAM price, as Figure 5.8 illustrates.

However, for the intraday high and low prices, Figure 5.7 illustrates that those do not have such a strong correlation only to the DAM price. In fact, through various regression analyses, we determine that the intraday high price is sufficiently significant depending on the DAM price, the daytime (hour of the day (t)), and the wind and solar generation. The high intraday price as a function of these dependent variables is as follows:

$$\Phi^{ID}_{high,t} = 2.293998 \cdot t + 1.54556 \cdot \Phi^{DA}_{t} + 0.000402 \cdot Gen_{solar,t} + 0.003225 \cdot Gen_{wind,t} \tag{5.2}$$

We provide the detailed results of the regression analyses in a tabular format within the appendix. Note that we have removed outliers or extreme values.

The intraday low price did not show a significant correlation to any independent variables and a low R^2 in relation to the DAM price. Therefore, performing a regression for the low price was not a meaningful approach. Instead, the low price scenario was determined by: i) comparing the average of the low prices and the index price, ii) observing the variability and standard deviation for the time of the day, and iii) creating a random function with a uniform distribution that can simulate sudden jumps in the price. That is, the DAM price serves as the basis to have a trend, so as the low price follows the hourly price tendencies to which we add two random functions. The scenario of the low price in short:

$$\Phi^{ID}_{low,t} = 0,6 * \Phi^{DA}_{t} + RandFunctions \tag{5.3}$$

Various empirical testing on different randomized parameters were done to ensure the projected $\Phi^{ID}_{low,t}$ has a similar mean and resemblance to the historical data (see Appendix B).

As the IDM high and low price do not have such a strong correlation to the DAM price as the index price, their likelihood and variation are harder to predict. Figure 5.8 illustrates these variations when calculating the three prices. In addition, it shows the relation between the IDM high/ low price. Therefore, we assume that the probabilities assigned to each scenario should represent to some degree the likelihood (based on correlation) of the respective IDM price with the DAM price, see in Figure 5.6. This is based on a statistical analysis of the historical data, where we observed normality plots and other measures to deduct that the ID index price is the one with the largest likelihood.

5.3.3 Optimal decision of the DSOs

Figure 5.9 summarizes the development and the influence of the two price signals on the optimal decision of the DSOs. Unlike in the DSO-M framework described in our previous work, the flexibility allocation is decided based on a profit maximization conducted by the DSOs as aggregators for the DSO side flexibility providers. Due to the timing of the allocation decision, the signals, as explained above, are of deterministic nature for the CM and stochastic for the IDM. Therefore, the optimization in step 4 differs from the DSO-M scheme by not giving an overall optimal result, but only suggesting an optimal strategy under uncertainty. Nevertheless, this optimal strategy allows us to analyse the potential revenue incentivizing the DSO side flexibility providers to trade their product.

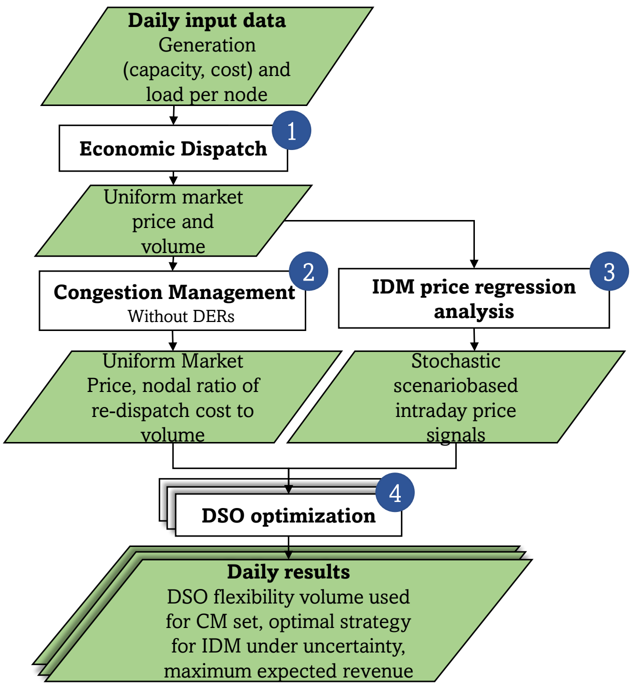

Figure 5.9: Program Flow Chart of the Flexibility Allocation within two trading options

5.3.4 Mathematical Formulation

The nomenclature containing denominations and descriptions of sets, variables and parameters is available in the appendix.

Model assumptions

IDM volume. For our model, we assume that the load shifting capacities allocated to the IDM do not exceed its market volume at any time. As such, no upper bounds for this purpose are necessary in the mathematical formulation of our model. We go more into detail about this in chapter 5.5.3, section *The IDM and CM volumes.*

Inter-DSO competition. In a similar way to our previous paper, we assume that there is no more than one DSO connected to a node of the transmission grid. This assumption eliminates the need to model competition between the nodal DSOs since such a competition is not within the project scope.

Sectoral load shifting. Like in our previous work, we assume that each sector in our model formulations can shift its demand within a certain relative range. We describe our method regarding sector distribution and relative shifting potential in section 5.4.2.

The model

Objective function. We use an objective function that maximizes the expected profits gained by load shifting in each node (Eq. 5.4). The total load shifting potential available to each DSO acting as aggregators of nodal flexibility assets can be used for allocation to either the CM or the IDM. Load can be reduced in return for the current prices or increased for the respective negative values. Since negative prices are a possibility for both the CM and IDM, reducing or increasing the load can lead to both compensation or additional cost.

At the time each actor needs to make a decision, the actual price development of the IDM is uncertain. We represent this uncertainty as a stochastic 2-stage problem including a set of scenarios and formulate the objective function in its extensive form.

$$\max_{\Delta CM^-_{n,t},\Delta CM^+_{n,t},\Delta ID^-_{s,n,t},\Delta ID^+_{s,n,t}} \sum_n \sum_t \sum_s \left[\overline{\Phi}^{CM}_{n,t} (\Delta CM^-_{n,t} - \Delta CM^+_{n,t}) + \pi_s \overline{\Phi}^{ID}_t (\Delta ID^-_{s,n,t} - \Delta ID^+_{s,n,t}) \right] \tag{5.4}$$

Load shifting capacities. We assume identical upwards and downwards load shifting potential for the respective sectors and formulate eq. 5.5-5.12 to provide upper and lower bounds for the resulting demand. Using this formulation, we also prevent unwanted simultaneous upwards- and downwards- shifting without the use of binary variables. Furthermore, eq. 5.9-5.12 ensure that shifting capacities by the industrial sector are only available during working hours.

$$d_{n,t} * a^{res} + \Delta CM^{res+}_{n,t} + \Delta ID^{res+}_{s,n,t} \leq mean(d_{n,t}) * a^{res} * (1 + z^{res}) \quad ,s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.5}$$

$$mean(d_{n,t}) * a^{res} * (1 - z^{res}) \leq d_{n,t} * a^{res} - \Delta CM^{res-}_{n,t} - \Delta ID^{res-}_{s,n,t} \quad ,s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.6}$$

$$d_{n,t} * a^{cts} + \Delta CM^{cts+}_{n,t} + \Delta ID^{cts+}_{s,n,t} \leq mean(d_{n,t}) * a^{cts} * (1 + z^{cts}) \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.7}$$

$$mean(d_{n,t}) * a^{cts} * (1 - z^{cts}) \leq d_{n,t} * a^{cts} - \Delta CM^{cts-}_{n,t} - \Delta ID^{cts-}_{s,n,t} \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.8}$$

$$\begin{gathered} d_{n,t} * a^{ind} + \Delta CM^{ind+}_{n,t} + \Delta ID^{ind}_{s,n,t} \leq mean(d_{n,t}) * a^{ind} * (1 + z^{ind}) \\ , s \in \mathscr{S}, n \in \mathscr{N}, t \in [9:16] \end{gathered} \tag{5.9}$$

$$\begin{gathered} mean(d_{n,t}) * a^{ind} * (1 - z^{ind}) \leq d_{n,t} * a^{ind} - \Delta CM^{ind-}_{n,t} - \Delta ID^{ind-}_{s,n,t} \\ , s \in \mathscr{S}, n \in \mathscr{N}, t \in [9:16] \end{gathered} \tag{5.10}$$

$$\Delta CM^{ind+}_{n,t}, \Delta CM^{ind-}_{n,t} = 0 \quad , n \in \mathscr{N}, t \in [1:8] \vee [17:24] \tag{5.11}$$

$$\Delta ID^{ind+}_{s,n,t}, \Delta ID^{ind-}_{s,n,t} = 0 \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in [1:8] \vee [17:24] \tag{5.12}$$

Total CM and IDM shifting. The aggregated load shifting increasing and decreasing demand and used for CM or IDM purposes is calculated as the sum of each sector's shifting decisions.

$$\Delta CM^{+}_{n,t} = \Delta CM^{res+}_{n,t} + \Delta CM^{cts+}_{n,t} + \Delta CM^{ind+}_{n,t} \quad , n \in \mathscr{N}, t \in \mathscr{T} \tag{5.13}$$

$$\Delta CM^{-}_{n,t} = \Delta CM^{res-}_{n,t} + \Delta CM^{cts-}_{n,t} + \Delta CM^{ind-}_{n,t} \quad , n \in \mathscr{N}, t \in \mathscr{T} \tag{5.14}$$

$$\Delta ID^{+}_{s,n,t} = \Delta ID^{res+}_{s,n,t} + \Delta ID^{cts+}_{s,n,t} + \Delta ID^{ind+}_{s,n,t} \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.15}$$

$$\Delta ID^{-}_{s,n,t} = \Delta ID^{res-}_{s,n,t} + \Delta ID^{cts-}_{s,n,t} + \Delta ID^{ind-}_{s,n,t} \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.16}$$

Total load shifting. We calculate the aggregated amount of load increasing and decreasing shifting decisions as the sum of the respective CM and IDM oriented values (eq. 5.17 and 5.18). Since the IDM-related decisions are based on the factual scenario realization, the total load shifting depends on the scenario.

$$\Delta D^{+}_{s,n,t} = \Delta CM^{+}_{n,t} + \Delta ID^{+}_{s,n,t} \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.17}$$

$$\Delta D^{-}_{s,n,t} = \Delta CM^{-}_{n,t} + \Delta ID^{-}_{s,n,t} \quad , s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.18}$$

Unsuccessful bid scenario. In scenario 4, we simulate the market participants' bids on the IDM not being successful. Eq. 5.19 and 5.20 ensure that the IDM-oriented load shifting is set to zero for this scenario.

$$\Delta ID^{+}_{s,n,t} = 0 \quad , s = 4, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.19}$$

$$\Delta ID^{-}_{s,n,t} = 0 \quad , s = 4, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.20}$$

Aggregated demand balance. Over each calculation period of 24 hours, the sum of upwards-shifting must be equal to the sum of downwards-shifting for all nodes, demand sectors and scenarios. Eq. 5.21-5.23 ensure that the daily demand for power by each sector aggregates to the same amount as before the introduction of flexibility. Since the total demand is the sum of the three sectors, these implicitly include the demand balance for each node.

$$\sum_t \left[\Delta CM^{res+}_{n,t} - \Delta CM^{res-}_{n,t} + \Delta ID^{res+}_{s,n,t} - \Delta ID^{res-}_{s,n,t}\right] = 0 \quad ,s \in \mathscr{S}, n \in \mathscr{N} \tag{5.21}$$

$$\sum_t \left[\Delta CM^{cts+}_{n,t} - \Delta CM^{cts-}_{n,t} + \Delta ID^{cts+}_{s,n,t} - \Delta ID^{cts-}_{s,n,t}\right] = 0 \quad ,s \in \mathscr{S}, n \in \mathscr{N} \tag{5.22}$$

$$\sum_t \left[\Delta CM^{ind+}_{n,t} - \Delta CM^{ind-}_{n,t} + \Delta ID^{ind+}_{s,n,t} - \Delta ID^{ind-}_{s,n,t}\right] = 0 \quad ,s \in \mathscr{S}, n \in \mathscr{N} \tag{5.23}$$

New load profiles. The load shifting decisions influence the load profiles in each node. Eq. 5.24 defines the new, CM-relevant load profile which is sent back to the TSO for recalculation of the CM. Eq. 5.25 calculates the final load profiles depending on the actual scenario.

$$L^{CM}_{n,t} = d_{n,t} + \Delta CM^{+}_{n,t} - \Delta CM^{-}_{n,t} \quad ,n \in \mathscr{N}, t \in \mathscr{T} \tag{5.24}$$

$$L_{s,n,t} = d_{n,t} + \Delta D^{+}_{s,n,t} - \Delta D^{-}_{s,n,t} \quad ,s \in \mathscr{S}, n \in \mathscr{N}, t \in \mathscr{T} \tag{5.25}$$

Model implementation

We wrote the code for the model and for processing its results in the programming language *Julia* in version 1.5.4. We implemented the linear program using the Julia for Mathematical Programming (*JuMP*) package in version 0.20.1 and solved it using the academic license of the Gurobi solver in version 9.0.3.

5.4 Case Study

The implementation of the power system model is calibrated with an open-access reference data set about the German power system of 2015 as collected and edited by Kunz et al. (2017b). In our previous work Pearson et al. (2022) we showed, on behalf of this data, that the model yields a sufficient accuracy to return a realistic impression of the system. However, in the present paper, we are interested in the revenue opportunities for DSO side flexibility providers within a future scenario with a higher share of RES than in the actual system.

5.4.1 German power system in 2030

We decided to set up our case study in 2030 using the open-access data set provided by vom Scheidt et al. (2020). This data set pictures the German power system in 2030, featuring 65 % of the brute electricity consumption covered by RES. As vom Scheidt et al. (2020) base their projection on data about the current transmission grid topography as provided by Matke et al. (2016) and on the development plan of the federal network agency of Germany (BNetzA (2019)), they provide a realistic vision of the German power system in eight years. The authors also hold onto the network development plan to elaborate their data about generation and demand in a high spatial and temporal resolution. Further insight into their methods and assumptions is provided in their documentation [3].

The data set has been so far applied to studies such as vom Scheidt et al. (2021) and vom Scheidt et al. (2022). They analyse the integration of hydrogen into the German

[3] available on `https://bwdatadiss.kit.edu/dataset/254headingFileList`

MC [€/MW]	Installed capacity [GW]
0	190
30	0.681
40	1.337
50	6.411
60	2.146
70	33.829
80	7.414
90	2.854
100	9.543
110	2.434
120	0.242
130	1.693
140	0.853
150	0.498
160	0
170	0
180	0
220	0.036
Total	**259.975**

Table 5.1: Installed capacity and marginal costs for 2030 based on vom Scheidt et al. (2020)

power system and its effects on the hydrogen supply chain. We, therefore, use a tested scenario data set for our case study and can apply our model to these data.

The transmission grid described by vom Scheidt et al. (2020) consists of 663 lines connecting 485 nodes and transmitting 543.9 TWh per year. It only considers wind and solar energy as RES with an annual generation of 247.4 TWh and 86.7 TWh. Regarding conventional generation, 718 units with a total annual capacity of 70,175 MW are included in the data set. However, it does not consider nuclear power as Germany plans to fade out of nuclear by the end of 2022. The generators, conventional and renewable, are not classified by technology, but the authors of the data set created 23 cost classes based on their marginal cost. Table 5.1 shows the total amount of installed capacity per cost class. The 24^{th} cost class displayed in the table was created because the network development plan does not provide a power system free of bottlenecks but intentionally implies them to incentivize technological innovations that can compensate for the shortages in the grid (BNetzA (2019), pp.42-43). The 24^{th} cost class creates an additional generation of 1,000 MW at each node with marginally higher marginal costs than the most expensive conventional power plants (221 €/MWh) to simulate the existence of those innovations. This hypothetical generation also ensures a feasible grid solution to the model and keeps the volume of lost load reasonable.

As the data of vom Scheidt et al. (2020) are formatted differently to our basis data set provided by Kunz et al. (2017b), we needed to adapt the given data with further assumptions to apply them to our model. These adaptions, mainly concerning the transmission lines, are documented in our previous work (Pearson et al. (2022)).

5.4.2 DSO simulation

Our research, both in our previous work and in the paper at hand, considers both TSOs and DSOs and attempts to find future frameworks and trading options providing benefits on a local scale while preserving and aiding in the stability of the electricity system. However, the data set used for our case study only includes information on the TS level and lacks data about the DS. Indeed, there are more than 880 DSOs currently operating in Germany (BNetzA (2016)), and there is no uniform data set about the DS available. Hence, we need to make assumptions about the allocation and distribution of load shifting possibilities and about how to simulate the DSOs throughout Germany. In this context, we follow the approach from our previous work (Pearson et al. (2022)).

Firstly, we assume one DSO per node that is not constrained by limits to the DS-level transmission network. Going in-depth in this regard would provide little benefit to our global-scale case study and go beyond our research scope. Each DSO in our model aggregates the interest of all connected owners of flexibility-providing assets.

Secondly, we divide the electricity demand assigned to each DSO into three sectors, assuming an identical distribution of demand for all nodes. In 2020, almost the entire electricity demand of Germany was distributed into 3 sectors: 45% large scale industry, 27% Commerce, Trade and Services (CTS) and 26% residential (BDEW (2021)). Matthes et al. (2007) estimate that this distribution is not likely to change significantly until 2030. Hence, and to not overestimate the influence of the industry, we decided to opt for demand shares of 40% for the large scale industry, 30% for CTS, and 30% for the residential sector.

Thirdly, as stated by Gils (2014), especially the large-scale, highly energy-consuming industry sector features considerable mechanisms to provide load shifting. We therefore include higher load shifting capacities for this sector. We implement an hourly shifting potential of 5% of the respective load averaged over each period of 24 hours for the residential and the CTS sectors. We assign the industrial sector a higher shifting potential of 10%, which we assume to be only available during working hours (from 08:00 until 16:00, represented by hours 9 to 16 of each optimization period in our model). With this assumption, our model provides sufficient accuracy while reducing the risk of overestimating the influence of the industrial sector.

5.5 Results

5.5.1 Key Indicators

To analyze our results and to assess the performance of our model, especially when compared to our previous paper (Pearson et al. (2022)), we have identified a number of suitable key indicators. One of the main factors for the future implementation of flexible loads is their extensive use: A high reward for a certain amount of load shifting only provides incentive for investment if it is available more than a few times per year. This is reflected in our results by the *volume of load shifting*, split by its purpose - either the use for CM or IDM purposes - and its total sum over the year. We use the same relative, and, since the data set is identical, also the same absolute values of load shifting potential as in our previous paper. However, since there are more options to utilize the potential than in our previous work, we expect this value to be higher both for the majority of our scenarios and for the expected value as the weighed sum of each scenario. Another main factor is the amount of profit generated by the use of load flexibility options, reflected by the yearly sum of *revenue* generated by using this potential. We also split this value by markets, depending on whether the revenue is generated by facilitating CM or by trading on the IDM, and calculate their sum over the whole year. The third, and possibly most important, key indicator we investigate is the *average value of load shifting*, which we calculate as the total revenue divided by the total volume of load shifting, in turn for each market and for the global system This indicator is the fundamental value to assess the future potential of our modeling framework and to answer our research questions.

	Expected Value	Scenario 1	Scenario 2	Scenario 3	Scenario 4
ID Price	NA	Index	High	Low	NA
Volume used for CM (TWh)	**2.82**	2.82	2.82	2.82	2.82
Volume used for IDM (TWh)	**6.95**	4.83	10.63	10.61	0
Total Load Shifting (TWh)	**9.77**	7.65	13.45	13.45	2.82
Revenue by CM (Mio. €)	**169.4**	169.4	169.4	169.4	169.4
Revenue on IDM (Mio. €)	**346.3**	121.7	404.3	953.3	0
Total Revenue (Mio. €)	**515.7**	291.1	573.7	1 121.7	169.4
Av. Value of LS for CM (€/MWh)	**60.03**	60.03	60.03	60.03	60.03
Av. Value of LS for IDM (€/MWh)	**49.82**	25.21	38.03	89.77	/
Av. Total Value of LS (€/MWh)	**52.77**	38.06	42.65	83.52	60.03

Table 5.2: Global, annual Key Indicators (expected values and per scenario)

We emphasize, that the expected value as the weighted sum of all scenarios is substantial for interpreting the results of our 2-stage stochastic model: For each calculation period of 24 hours, each scenario has a probability of occurrence. As such, the values for each scenario are useful for the interpretation of our results, but it is highly unlikely for the same scenario to happen over the entire year.

5.5.2 The value of load flexibility for multiple purposes

After the identification of the key indicators we present the results to our calculations before discussing key aspects of our modeling framework. Table 5.2 summarizes the key indicators, should a certain scenario be realized for the entire year and the expected values given the chosen probabilities for each scenario. We emphasize once more that the factual realization of only one scenario over the whole year is in practice highly unlikely.

For the analysis of our results, we initially take a look at the volumes of load shifting. We find that for every scenario and either market, the decisions for increasing and decreasing the original load profiles are equal to each other over each calculation period. This is a consequence of the combination between the implementation of the unsuccessful-bid-scenario (Eq. 5.19 and 5.20) and the requirement for an aggregated demand balance (Eq. 5.21-5.23). The sum of all nodal load shifting decisions must equal zero over each period of 24 hours. Therefore, implementing a scenario where no IDM-oriented trading is possible implies that this balance must also prove true for each trading market. A distinction between upwards- or downwards- oriented trading volumes for each market is therefore not necessary.[4] We furthermore find that the highest volumes of load shifting for IDM purposes occur in the scenarios featuring the more extreme IDM price developments. Those volumes reach very similar levels of a little more than 10.6 TWh over the course of the whole year for scenarios 2 and 3 featuring the predicted high and low IDM prices, respectively. These values are more than twice the value of our scenario 1 at 4.83 TWh. Scenario 1 features the more average IDM-Index-Price which is closely correlated with the uniform price of the DAM. Fig. 5.10 provides the load shifting profiles of each scenario over an exemplary period of 2 weeks (hours 2184-2496). We plot the original load profiles and the ones after each stage of the stochastic model in Fig. 5.11. Especially the large influence of the industrial sector (it makes up more than half the shifting potential during the hours 9 to 16, adding 4 percentage points to the 3 % of average load available during the rest of the day) becomes immediately apparent when comparing the two plots. This is especially true for the high- and low- price scenarios: Upon reaching the 9$^{\text{th}}$ time step of

[4] We discuss the consequences of removing the unsuccessful-bid-scenario from the model in our critical reflection, section *Allowing Arbitrage*.

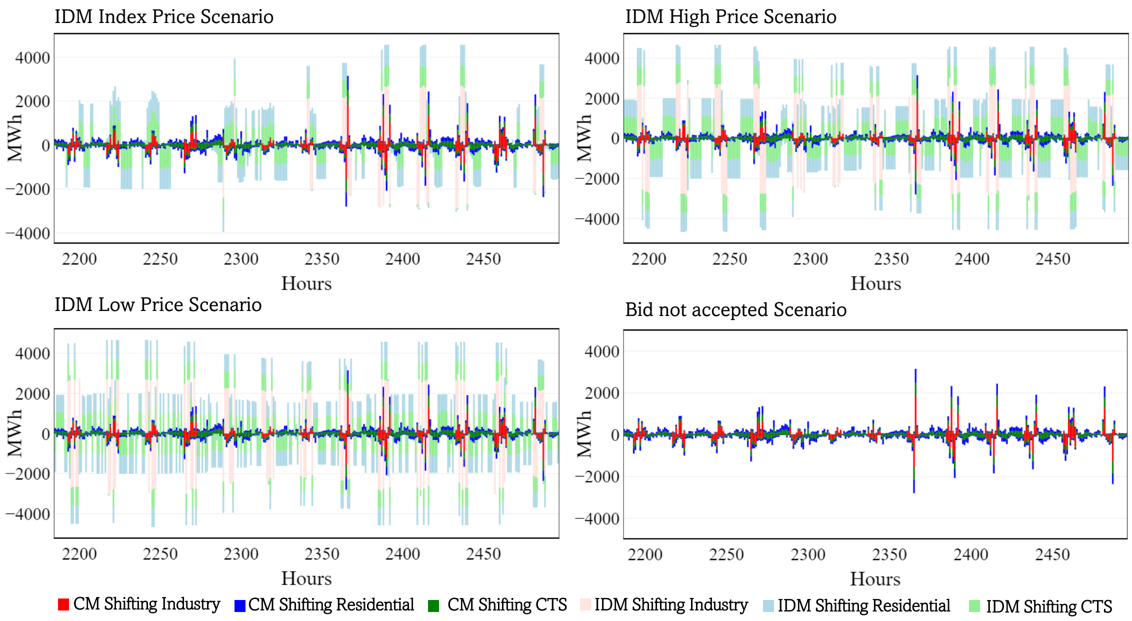

Figure 5.10: Volume of load shifting split by market and sector for each IDM price scenario

one day, lower prices on the IDM are immediately used for increased consumption. This is then balanced out during later time steps, when profit can be generated due to higher momentary IDM prices.

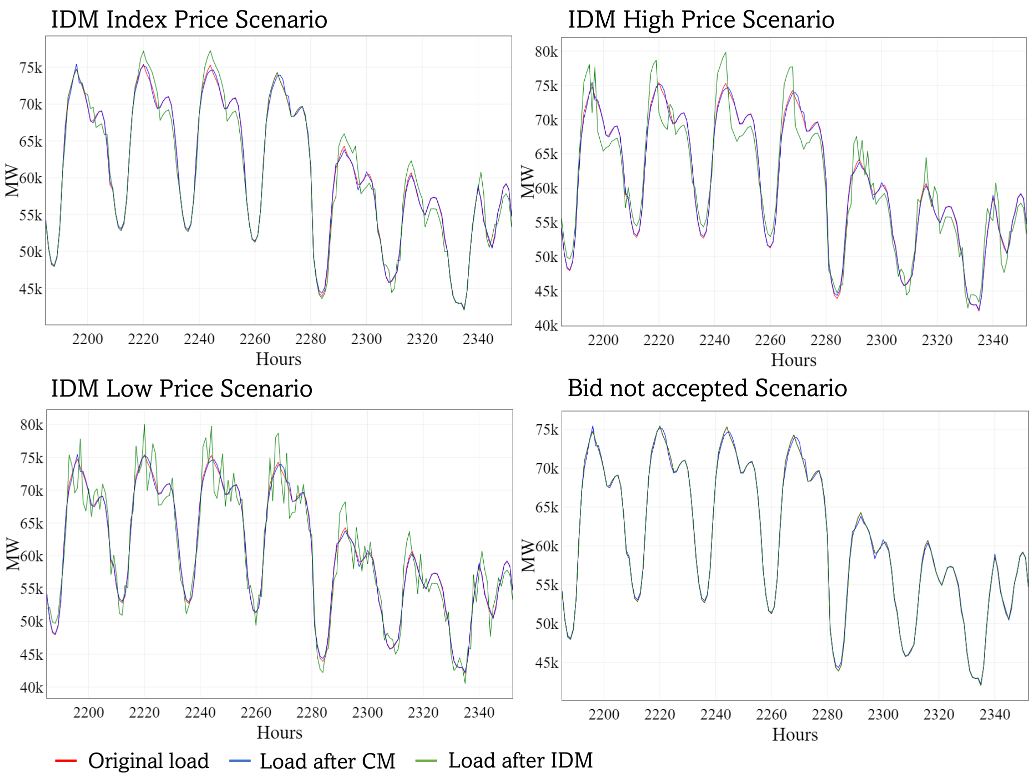

Figure 5.11: Changing load profiles after each market clearing for each IDM price scenario over the same week

The second set of parameters for the analysis of our results is the revenue generated

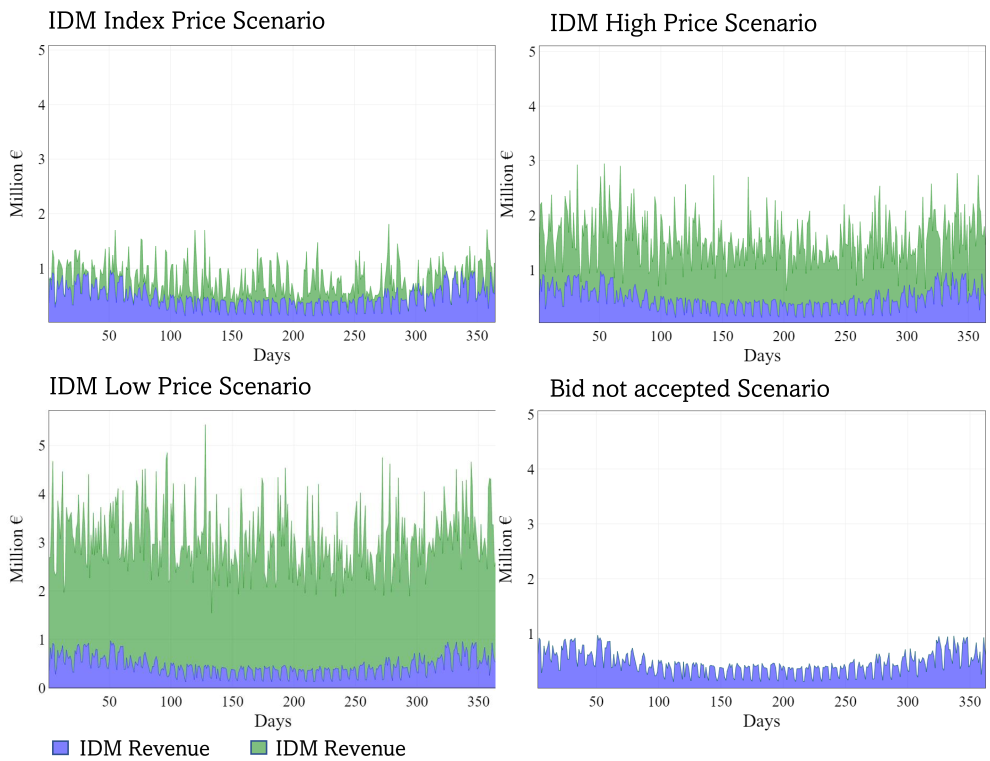

Figure 5.12: System-wide daily DSO side flexibility providers revenue distinguished by market for each IDM price scenario

by the respective shifting decisions over the whole year. We calculate the revenue for each market as the sum of the hourly cash flows. They are then aggregated to obtain the global value. Because the CM-related load shifting decisions are equal in all scenarios, this is also true for the revenue generated by the CM, reaching a final value 169.4 Mio. €. Regarding the revenue generated on the IDM, scenario 3 (featuring the low price development) outperforms the others by far, reaching profits generated only on this market of 953.3 Mio. €. This does not come as a surprise, since the low IDM price development features frequent negative prices. At negative prices, a node is able to increase its profits through increased consumption. This never occurs for any other scenario. Consequently, scenario 1 and 2 feature lower values of 121.7 Mio. € and 404.3 Mio. €, while it is not possible to generate profits from the IDM in scenario 4. We plot the total, daily revenue per scenario over the whole year in Figure 5.12, which also shows the division of the total revenue into its source markets. Especially for the revenue, the expected value is more essential for the assessment of our results. In total, the expected value of the revenue generated over the whole year (i.e., the weighted sum of all possible outcomes) aggregates to 515.7 Mio. €. We depict the development of the global expected daily profits in Fig. 5.13. The figure is especially useful to prove how important the participation in the IDM is for the overall revenue: The expected revenue generated by participation on the IDM contributes more than two thirds to the optimal, global and annual profits from applying our framework.

The final key indicator for the assessment of our results is the average value of load shifting, calculated as the revenue divided by the volume of load shifting. Like the other key indicators, it can be calculated for either market and for the whole system altogether. Even though we use a different approach to calculating this value in the paper at hand, we have also calculated it in our first paper (Pearson et al. (2022)), concluding that CM

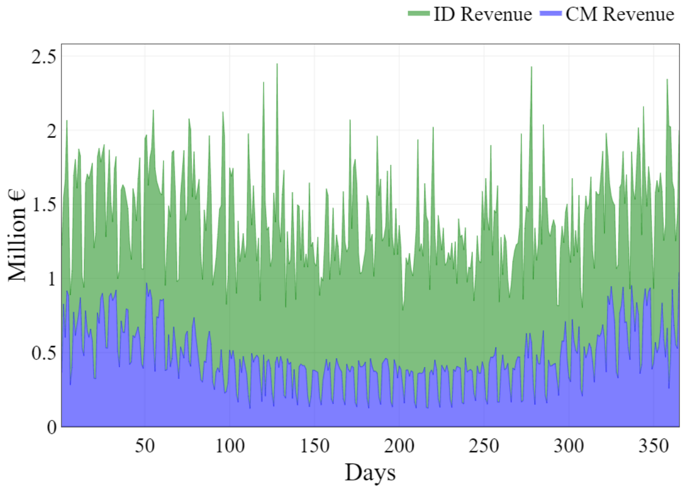

Figure 5.13: System-wide, daily expected DSO side flexibility providers revenue distinguished by market

alone is not sufficiently profitable for the more-than-marginal utilization of load shifting. We therefore consider this parameter the most essential result of our calculations. The volumes of load shifting used for CM purposes are the same throughout all scenarios. Consequently, the optimal value of load shifting for the CM is the same throughout all scenarios and for the expected values, reaching 60.03 € per MWh of shifted load. Caused by the scenario-specific volumes traded on the IDM and the varying amounts of revenue generated thereby, the average value of load shifting for the IDM varies strongly by scenario, ranging from 25.21 € per MWh in scenario 1 to 89.77 € per MWh in scenario 3. Note that this indicator does not exist for scenario 4 since it does not feature IDM trading. The expected global value of load shifting and traded on the IDM throughout the year reaches a value of 49.82 MWh.

Finally, we calculate the average value of load shifting. It ranges from 38.06 € per MWh for scenario 1 to 83.52 € for scenario 4, with an expected value at the given probabilities of occurrence of 52.77 € per MWh of shifted load.

5.5.3 Discussion and critical reflection

In the following section, we discuss our results further. In order to do so, we examine the differences in the origin of the profits of different nodes before performing a sensitivity analysis regarding the effects of a higher chance for the unsuccessful-bid-scenario. We then critically reflect the limitations to our model and its results and point out possible areas of further research.

Nodes with little necessary re-dispatch.

Unlike the pricing mechanism applied in Germany for the DAM and unlike the pricing mechanism we simulate for the IDM, congestion and its related cost are not a global, but a nodal issue. Not every transmission line has to deal with capacity issues. Consequently, not every node is assigned a re-dispatch cost and volume at all times. Indeed, this was one of the main issues we found when attempting to use load flexibility *only* for CM purposes: When the use of load flexibility is optimized locally using the average cost of re-dispatch as the sole deciding parameter, only the nodes featuring re-dispatch efforts have an incentive to use their potential at all. As such, giving nodes that are unaffected

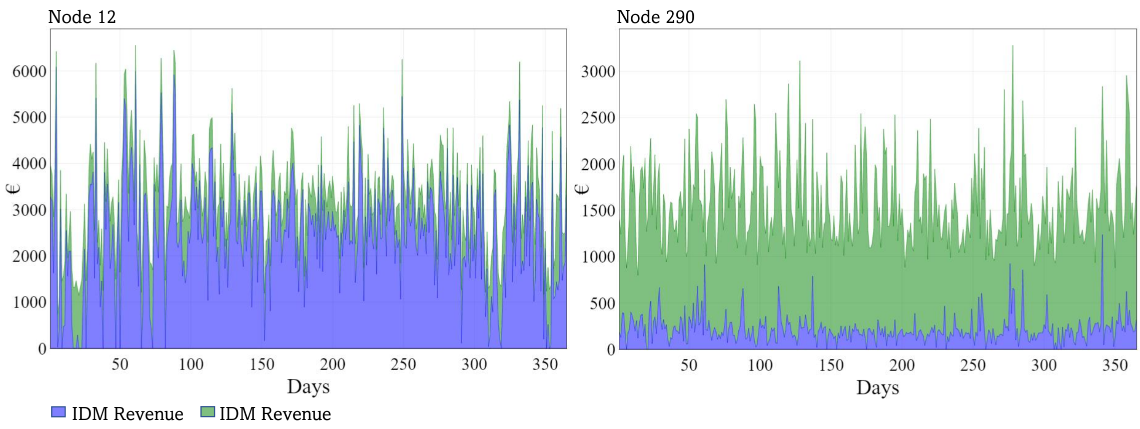

Figure 5.14: Daily expected revenue for the most and the least profiting nodes (no. 12 at 83.4 € /MWh and no. 290 at 34.9 € /MWh p.a.)

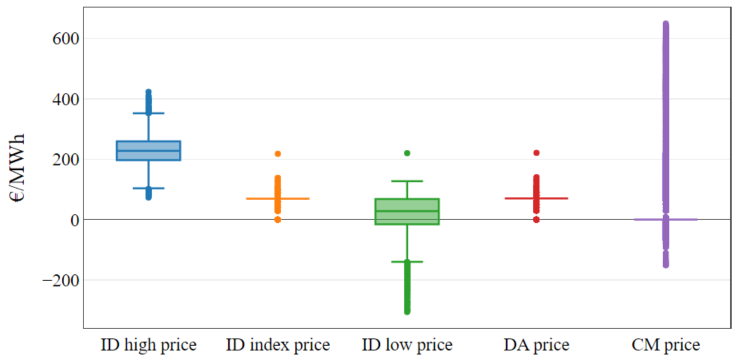

Figure 5.15: Distribution of the IDM, DA and CM prices over the year

by the CM at least some of the time an option to utilize their own potential for benefit was one of our goals for this research.

In order to show the difference between the profit generation in nodes with high and low amounts of necessary re-dispatch, we have identified the nodes 12 and 290 as the nodes with the highest and lowest expected ratio of revenue to load shifting over the course of the whole year.[5] Fig. 5.14 shows the composition of their daily expected revenue. We find that the nodal, hourly values for the cost of re-dispatch have a substantial influence on the optimal distribution between profits from each of the two markets. This can be explained with Fig. 5.15 depicting the distribution of the different price signals: While all nodes share the same, global prices on the IDM, the cost for re-dispatch varies greatly in a bigger range than any of the IDM price signal developments. Consequently, especially nodes with a large spread in CM cost benefit primarily from using their flexibility for this purpose, whereas the IDM is responsible for the majority of revenue in others.

Sensitivity analysis.

While very promising, our results are based on a number or assumptions. One of the assumptions is the probability related to scenario four, which simulates the DSO's bids to the IDM not getting accepted. This forces the respective load shifting to zero for the calculation period of 24 hours. We have initially assigned this scenario a 10% chance of

[5] We have excluded node 14: It does feature an even higher value, but this is caused by extreme amounts of lost load contributing to its re-dispatch cost.

	Expected Value	Scenario 1	Scenario 2	Scenario 3	Scenario 4
ID Price	NA	Index	High	Low	NA
Volume used for CM (TWh)	**2.94**	2.94	2.94	2.94	2.94
Volume used for IDM (TWh)	**6.90**	4.80	10.57	10.51	0
Total Load Shifting (TWh)	**8.55**	7.74	13.51	13.45	2.94
Revenue by CM (Mio. €)	**171.8**	171.8	171.8	171.8	171.8
Revenue on IDM (Mio. €)	**270.3**	121.0	401.8	943.5	0
Total Revenue (Mio. €)	**442.1**	292.8	573.6	1 115.3	171.8
Av. Value of LS for CM (€/MWh)	**58.44**	58.44	58.44	58.44	58.44
Av. Value of LS for IDM (€/MWh)	**48.17**	25.21	38.01	89.79	/
Av. Total Value of LS (€/MWh)	**51.71**	37.83	42.45	82.94	58.44

Table 5.3: Global Key Indicators for the sensitivity analysis (25 % chance for scenario 4)

occurrence.

This value may be too low to reflect reality. As such, we chose to perform a sensitivity analysis with the same data and assumptions, but while increasing the probability for this scenario to 25%[6] we decrease the chance of the others by 5 percentage points each. We are aiming to see what changes in behavior and in expected outcome are caused by a significantly higher chance of being unable to participate in the IDM. We are expecting a decrease in expected total revenue and in volume of load shifting traded on the IDM but an increase in load shifting used for CM purposes.

At 442.1 Mio. € of expected revenue over the course of the entire year, our first expectation holds true, translating to a decrease of 73.6 Mio. € (14.3 % of the original value). Our second expectation is also fulfilled: The volumes used for CM and IDM increase by 117.6 GWh (4.2 %) and decrease by 1.34 TWh (19.3 %), respectively. Overall, the changes lead to an average expected value of load shifting of 51.71 € per MWh, which is only 1.06 € per MWh lower than in the original results. It must be noted, however, that a considerably higher share of load shifting potential remains unused. All key indicators for our sensitivity analysis can be found in table 5.3.

Allowing arbitrage.

As we previously mentioned, the existence of a scenario with no possible load shifting used for IDM purposes limits trading between the two different markets to a great extent: Eq 5.19 and 5.20 set the value for the IDM-related volumes to zero while the constraints for shift balancing (eq. 5.21-5.23) still need to be satisfied. Hence, at the end of the day, the same volume of energy that was previously bought from or sold to the CM must be compensated. Without this scenario, it would be possible to buy larger volumes of generation on one market and sell it on the other, as it will always be possible to compensate for any imbalance after the CM-related shifting decision has been made. We examine this by running our calculations one additional time with a few modifications: We use only the first three scenarios (assigning them exemplary probabilities of 50%, 25%, and 25% respectively) and remove eq. 5.19 and 5.20 from the model. We expect to see considerable changes to the result, including disparities between the upwards- and downwards-shifting measures on the CM and a more or less substantial increase in expected revenue. This

[6]While we have changed variables and constraints to implement the stochastic differentiation of the model and the IDM as an additional trading option, we point out that increasing this value to 100% while removing the other scenarios would in fact lead to identical load shifting decisions as we have calculated for the DSO-M case in our previous paper. This is due to the fact that our assumptions regarding general shifting potential and the values passed on from the TSO-operated CM to the DSOs remained the same.

will be caused by the possibility to benefit from a form of arbitrage, with the exact benefit being uncertain and depending on the actual price development on the IDM.

Our expectations for the results of these calculations - which we perform only for discussion purposes - do not only hold true, but are exceeded considerably. At an aggregated expected revenue of over 2.2 billion €, the profits when allowing trading between markets are more than 4 times as high as when this mechanism is prevented. Meanwhile, the expected overall volume of load shifting increases to almost 22 TWh over the course of the year, representing an increase of over 100%. The joint changes in shifting volume and revenue lead to an average value of load shifting of over 101 € per MWh of shifted load. For these calculations, scenario 2 featuring the high IDM-price-development becomes by far the most profitable of all scenarios: Without the necessity of balancing the trade on each market over 24 hours, the price signal for the CM of zero that is caused by the absence of necessary re-dispatch becomes a free source of additional generation. This additional generation can then be used for any purpose, including the immediate selling at high IDM prices. This mechanism provides a chance for excessive profits associated with very little risk and is a prime example how unregulated arbitrage can be dangerous for a market's stability. The complete results of this calculation are available in Table 5.7 in the appendix.

Prediction of the IDM price.

Our prediction of the IDM prices and our approach to using this prediction are both based on a number of assumptions and highly simplified. They differ substantially from the actual operating principle of the IDM: In reality, the IDM does not feature a uniform price. Instead, the IDM is cleared pay-as-bid, meaning each actor is rewarded or charged according to its individual bid. As such, there is never a guarantee to successfully buy or sell at any price, regardless of its value. We attempt to simulate this by including a scenario for unsuccessful bidding on the IDM. Our approach is suitable for our purposes and in order to answer our research question. However, modeling this market in a more realistic way will require a much more complicated simulation of the bidding process. Furthermore, if market regulations are changed and the IDM is opened to DS-level providers of load flexibility, this will much likely lead to changes in the price development itself. If a large number of new actors, featuring large amounts of aggregated load shifting potential, join this market, this may more or less frequently lead to an imbalance between supply and demand. This risk is increased if many of those actors follow a similar strategy to gain the highest possible advantage from the market. Another possible consequence of high levels of supply may be generally lower and less volatile prices - which would reduce the opportunity to generate financial gains when using a framework such as the one we have developed.

The IDM and CM volumes.

One type of parameter we do not feature in our calculations are the *volumes* of both the global IDM and the re-dispatch necessary in a certain node. We initially made the assumption that the IDM volume will be sufficient for the amounts of load shifting according to our calculations. According to EPEX SPOT, the empiric values for the year 2021 very rarely go below 4 000 MW and 2 000 MW during the day and night, respectively, while they are usually considerably higher. For comparison, we have plotted the hourly, global volume of load shifting used for IDM purposes in the low price scenario in Figure 5.16.

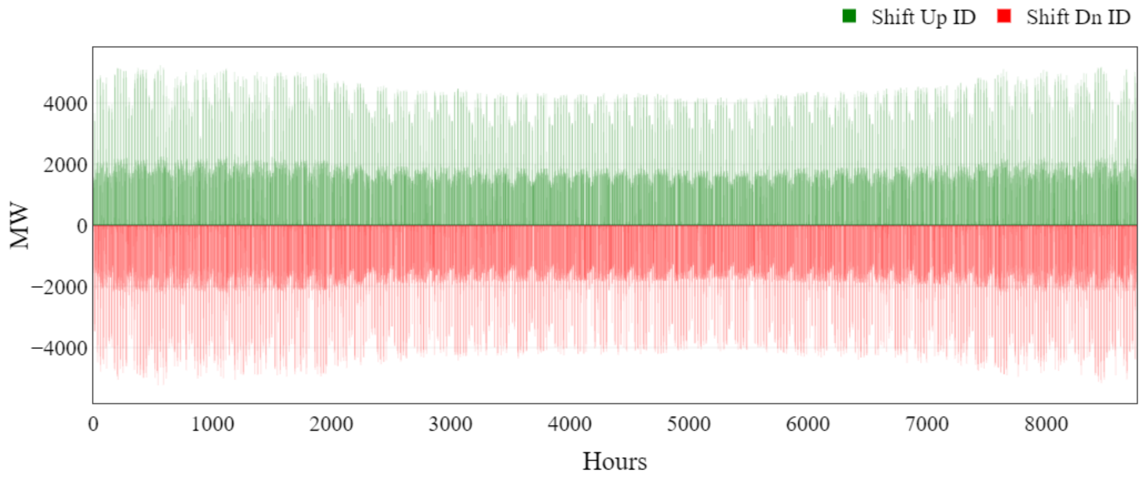

Figure 5.16: Load shifting volume on the IDM over the year for the IDM low price scenario

We find that even for one of the scenarios featuring the highest amounts of load shifting assigned to the IDM, the empiric market volumes from 2021 are already sufficient during the majority of time steps. Since Newman and MacDougall (2021) expect a continuing growth of these volumes for the future, the assumption can be safely made that they will be sufficient in 2030 at all times. Nevertheless, their implementation would add to the dependability of the results of this optimization. The volumes of re-dispatch are another challenge: Our model assumes constant remuneration for load shifting used for CM purposes regardless of total volumes. This is somewhat imprecise: In case a node's need for additional or reduced generation is fully satisfied, further load shifting should not pose a threat to the stability of the transmission lines anymore. However, remunerating any excess supply of load shifting and adding these costs onto the grid charges would make the power system less efficient.

In summary, including specific volumes for necessary re-dispatch and for the IDM would be an opportunity for further research.

Other uses for load flexibility.

The list of purposes we are using load flexibility - containing only the simplification of the CM and the trade on the IDM - is by no means exhaustive. There are many more possible uses for load shifting potential. Their application for balancing or other types of AS, for peer-to-peer trading, for detailed simulation of energy storage or other forms of DERs may prove worthwhile and are possibly equally or even more promising than the potential we have found in this paper. All these may improve the possible benefits to future power systems and the profits for the owners of flexibility providing assets even further. As such, there is considerable remaining further research to be done regarding other applications of load flexibility.

5.6 Conclusion

In this paper, which we wrote as the second part of our master's thesis, we have continued our previous research regarding the application of load flexibility to simplify re-dispatch efforts after the closure of the DAM. After we had proven that their application is possible for this purpose, albeit at average values of load shifting that are comparably low, we have decided to search for other markets where load flexibility can be applied and found the IDM as an especially suitable option: It features generally volatile prices, no need for near-instantaneous availability and a market volume that should be sufficient enough that a reasonable amount of load shifting potential could be used without exceeding its market volume. However, the IDM does not feature uniform prices, and both simulating its operation and estimating different price developments are not easy tasks. In order to assess the potential value flexible loads might have when having the option to be used for both purposes, we have developed a method to predict three different scenarios for the IDM price development. We have added a fourth scenario to simulate unsuccessful bids and assigned each of those suitable probabilities of occurrence. Since the realized price development is not known in advance, we have then used these four scenarios to model a two-stage stochastic linear program, calculating the possible value of load shifting that can be achieved by using our framework.

We have found the results of our calculations to be very promising. Reaching a total volume of shifted load of 9.77 TWh over the course of the year, the expected total revenue generated over the entire electricity system amounts to 515.7 Mio. €. Of this amount 169.4 and 346.3 Mio. € account for the CM and IDM, respectively. At an expected global average value of load shifting of 52.77 € per MWh of shifted load, we reach more than twice the value from the decentralized (DSO-M) scenario in our previous paper (25.78 €/MWh). We reached this value when using the shifting potential exclusively for CM purposes.

We conclude that the research we conducted for this paper was not only successful, but exceeded our expectations. Using load flexibility for the two purposes we consider and a similar methodology as the one we propose, the owners of flexibility providing assets may gain compensation sufficient enough to incentivize investment in this area.

However, we note that regulatory frameworks for comparable application do not yet exist in the power system used in Germany. In order to allow for the profitable usage of load flexibility, extensive changes need to be made to the operating principles of power markets. An exchange of information must be implemented between different actors to communicate information relevant to its optimal use. Furthermore, we emphasize that the framework we developed is a fundamental working principle. There is extensive need for further research for the actual implementation of DS-side flexibility assets and other forms of DERs, and the two scopes of application we assess in this paper are far from being the only possibilities.

As such, we suggest further research in a number of areas, including but not limited to:

- A more detailed exchange of information between markets and their involved actors, including a mechanism to include the market volumes into the calculations. As we pointed out in our first paper, especially the CM-related decisions could be improved considerably by including specific information about congested transmission lines into the calculations;

- A detailed model of the DS, including the possibility for multiple DSOs in one node or DSOs spanning more than one node. Like the TS, the DS can suffer from congestion, so the unlimited provision of flexibility may be associated with further challenges; and

- Other markets, where the application of load flexibility could prove beneficial.

5.7 Appendices

Appendix A

Nomenclature

Sets

$\mathcal{N}$ Set of nodes: n

$\mathcal{S}$ Set of scenarios: s

$\mathcal{T}$ Set of time slices in hours: t

Variables

$\Delta CM^{res+}_{n,t}$ Hourly, sectoral increase of demand in the residential sector used for CM purposes in MW_{el}

$\Delta CM^{res-}_{n,t}$ Hourly, sectoral decrease of demand in the residential sector used for CM purposes in MW_{el}

$\Delta CM^{cts+}_{n,t}$ Hourly, sectoral increase of demand in the cts sector used for CM purposes in MW_{el}

$\Delta CM^{cts-}_{n,t}$ Hourly, sectoral decrease of demand in the cts sector used for CM purposes in MW_{el}

$\Delta CM^{ind+}_{n,t}$ Hourly, sectoral increase of demand in the industrial sector used for CM purposes in MW_{el}

$\Delta CM^{ind-}_{n,t}$ Hourly, sectoral decrease of demand in the industrial sector used for CM purposes in MW_{el}

$\Delta ID^{res+}_{s,n,t}$ Hourly, sectoral increase of demand in the residential sector used for IDM purposes in scenario s in MW_{el}

$\Delta ID^{res-}_{s,n,t}$ Hourly, sectoral decrease of demand in the residential sector used for IDM purposes in scenario s in MW_{el}

$\Delta ID^{cts+}_{s,n,t}$ Hourly, sectoral increase of demand in the cts sector used for IDM purposes in scenario s in MW_{el}

$\Delta ID^{cts-}_{s,n,t}$ Hourly, sectoral decrease of demand in the cts sector used for IDM purposes in scenario s in MW_{el}

$\Delta ID^{ind+}_{s,n,t}$ Hourly, sectoral increase of demand in the industrial sector used for IDM purposes in scenario s in MW_{el}

$\Delta ID^{ind-}_{s,n,t}$ Hourly, sectoral decrease of demand in the industrial sector used for IDM purposes in scenario s in MW_{el}

$\Delta CM^{+}_{n,t}$ Aggregated hourly increase of demand used for CM purposes in MW_{el}

$\Delta CM^{-}_{n,t}$ Aggregated hourly decrease of demand used for CM purposes in MW_{el}

$\Delta ID^{+}_{s,n,t}$ Aggregated hourly increase of demand used for ID purposes in scenario s in MW_{el}

$\Delta ID^{-}_{s,n,t}$ Aggregated hourly decrease of demand used for ID purposes in scenario s in MW_{el}

$\Delta D^{+}_{s,n,t}$ Aggregated hourly increase of demand in scenario s in MW_{el}

$\Delta D^{-}_{s,n,t}$ Aggregated hourly decrease of demand in scenario s in MW_{el}

$L^{CM}_{n,t}$ CM-relevant load profile in MW_{el}

$L_{s,n,t}$ Aggregated load in scenario s in MW_{el}

Parameters

$\Phi^{RD}_{n,t}$ Ratio of nodal re-dispatch cost to volume

Φ^{ID}_{t} Global expected IDM price

$d_{n,t}$ Nodal load forecast in MW_{el}

π_s Probability of occurence of scenario s

a^{cts} Load share of cts sector

a^{res} Load share of residential sector

a^{ind} Load share of industrial sector

z^{cts} Relative load shifting potential of the cts sector

z^{res} Relative load shifting potential of the residential sector

z^{ind} Relative load shifting potential of the industrial sector

Appendix B - Results of the regression analysis

Regression statistics	
Multiple R	0.895373067
R^2	0.80169293
Adjusted R^2	0.801498309
Standard Error	120.0889257
Observations	8199

Table 5.4: Regression statistics for the Intraday High Price

	df	SS	MS	F	Significance F
Regression	4	4.78E+08	119444110.6	8282.44998	0
Residual	8195	118182963.9	14421.35007		
Total	8199	595959406.4			

Table 5.5: ANOVA Intraday High Price

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0	NV	NV	NV	NV	NV	NV	NV
Hour	2.293997797	0.174713658	13.13004273	5.47362E-39	1.951514737	2.636480858	1.951514737	2.636480858
Day-ahead Price [€/MWh]	1.545560142	0.016966583	91.09436532	0	1.512301338	1.578818947	1.512301338	1.578818947
Solar generation (MW)	0.000402263	0.000150819	2.667195885	0.00766374	0.00010662	0.000697906	0.00010662	0.000697906
Wind generation (MW)	0.003225331	0.000115098	28.02258301	4.3477E-165	0.002999711	0.003450951	0.002999711	0.003450951

Table 5.6: Influence factors Intraday High Price

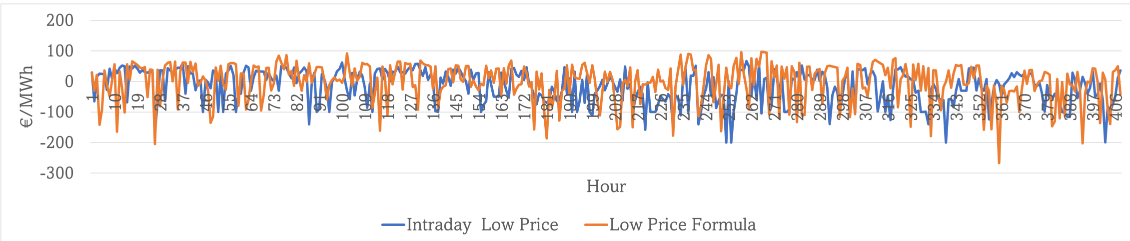

Figure 5.17: Comparison IDM low price formula to historical data

Appendix C

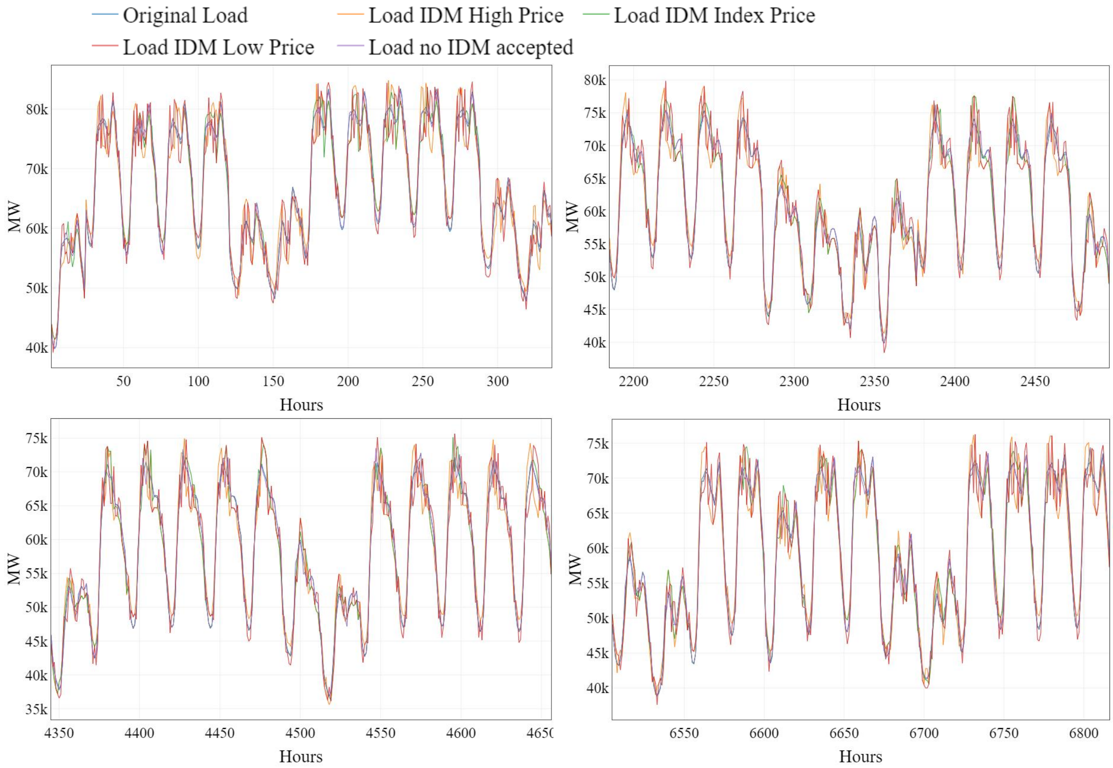

Figure 5.18: Final load for each scenario over two weeks per season

Appendix D

	Expected Value	Scenario 1	Scenario 2	Scenario 3
ID Price	NA	Index	High	Low
Upshifting volume used for CM (TWh)	**19.44**	19.44	19.44	19.44
Downshifting volume used for CM (TWh)	**2.06**	2.06	2.06	2.06
Upshifting volume used for IDM (TWh)	**2.45**	2.24	2.59	2.73
Downshifting volume used for IDM (TWh)	**19.84**	19.63	19.97	20.11
Total Load Shifting (TWh)	**21.89**	21.69	22.03	22.17
Revenue by CM (Mio. €)	**445.6**	445.6	445.6	445.6
Revenue on IDM (Mio. €)	**1770.3**	1211.8	4108.7	548.8
Total Revenue (Mio. €)	**2215.8**	1657.4	4554.2	994.4
Av. Total Value of LS (€/MWh)	**101.21**	76.42	206.72	44.85

Table 5.7: Global, annual Key Indicators for the analysis of the behaviour without the risk of unaccepted bids on the IDM

Model

We provide the code written for our model and for the analysis of its results (written in the *Julia* programming language in version 1.5.4) under the MIT license on GitHub: `https://github.com/simonpea/cm_idm_flexibility`

Chapter 6

Concluding remarks

Within this master thesis, we researched the integration of distributed energy resources as a flexibility option for the congestion management into an increasingly renewable power system. Therefore, we used and expanded a techno-economic optimization model as provided by Xiong et al. (2021).

In the first part of the thesis, we assessed the present and future value of this flexibility resource for the efficiency of the re-dispatch process. By reviewing the related literature, we found the degree of efficiency when using DERs to depend on the type of coordination set up between two of the main actors: the TSO and the DSOs. Therefore, we developed one centralized and one decentralized TSO-DSO coordination framework to allow for an efficient exploitation of the DER flexibility potential for the CM. We found that both of the coordinated frameworks were able to improve the volume and the cost of the re-dispatch for the applied 2015 and 2030 scenarios. Even though the relative decrease in re-dispatch cost changes from 2015 to 2030 from 13.65 % to 3.26 % for the centralized and from 5.68 % to 1.63 % for the decentralized framework, the absolute savings increase by 217 Million € and 115 Million € as the total re-dispatch becomes more expensive the more RES are participating.

As can be deduced from the mentioned cost of re-dispatch in either scenario, the centralized framework outperforms the decentralized one. However, as the decentralized case preserves the interest of all participants, the DSO-M framework is more realistic to implement. Considering the outcome under the aspect of the actual implementation of the frameworks, we also found that the values of load shifting as a result of our optimizations are insufficient to incentivize investment in this resource. However, the value of load shifting flexibility almost triples from 2015 to 2030. Therefore, we conclude that DS-side flexibility assets gain relevance with an increasing share of RES in the global power generation. Nevertheless, the frameworks developed in the first paper of the thesis and focussing only on the CM are unlikely to provide enough incentive to engage the flexibility providers even for our future scenario.

Based on these findings, in the second part of this thesis, we investigated possible methods to increase potential benefits for the providers of DS-side load flexibility in the future. Following the recommendations of ENTSO-E, we searched for other possible applications of flexibility to offer the providers more than one trading option. We considered peer-to-peer trading, balancing markets, more realistic modeling of energy storage located on the DS-level or other DERs, and more. We found the IDM to be the most attractive second market for more than one reason: The volatile prices of this market already provide considerable incentive. Furthermore, the IDM is expected to increase in volume and importance under the influence of decarbonization for more than one reason. It is especially suitable for DERs and load flexibility since, unlike balancing markets, it does not require fast or even close-to-instantaneous reaction times.

To simulate the DSO side flexibility providers' participation on two subsequent markets, we developed our deterministic decentralized case model from the first paper to a two-stage stochastic model using the principle of coordinated bidding. The providers aggregated by the DSOs decided upon their strategy to allocate their flexibility on the two markets considering the uncertain information about the IDM. The results of this opening towards another market showed higher remuneration opportunities: The expected value of load shifting increased from 25.78 €/MWh in the future DSO-M case from paper 1 to 52.77 €/MWh when applying our stochastic model. Furthermore, the access to two markets increased the expected volume of shifted load over the year by ca. 60 % compared to the DSO-M case in the first paper. This increase is primarily caused by eliminating one of the essential weaknesses of the DSO-M case from paper 1: Adding another trading option provides even the nodes without a need for re-dispatch with an area of application for their flexibility. Hence, by including the IDM, we can improve the efficient use of flexibility potential considerably.

However, the methods we use in this thesis are subject to some assumptions that pose limitations: We are assuming exactly one DSO in each node that aggregates the interest of all the flexibility potential within its area. Furthermore, in order to maximize the potential benefits by using load flexibility, we are not yet including any marginal or fixed cost for the use of flexibility potential. In addition, assuming the same sectoral distribution - and identical sectoral shifting potentials across Germany - is a significant simplification. We could continue this list. The main challenge, however, is that the resulting values for the benefits from using the flexibility potential are highly dependent on the assumptions concerning the IDM price.

Nevertheless, we have successfully provided insights into the potential DSO-side flexibility has to secure and improve the power system of the future. It can aid in decarbonization by reducing the necessary curtailment of RES by increasing the demand during times of their highest availability. And it can provide substantial financial benefits to its providers when more than one market is open for its application. With our research, we have contributed to a better understanding of possible effective integration mechanisms for the system operators and for the DSO side flexibility providers. Based on our work, future research can - and, considering the novelty of the issue - should follow various different paths to gain further comprehension of this relevant topic. Possible directions are:

- Releasing the assumption of only one DSO per node and re-evaluate our results with intra- and maybe also inter-nodal competition and trading of flexibility;

- Including operational cost to the provision of DSO side flexibility and research the benefit this resource has for the re-dispatch and the improvements offered by a multi-market access;

- Accounting for the physical medium- and low-voltage grid constraints to investigate if the physical network structure can cope the participation of the DSO side flexibility without endangering its system security;

- Setting the subject matter into a larger context and investigate how a nodal pricing system instead of the current zonal pricing could improve the integration and remuneration of flexibility resources connected to the DS;

- Shifting the focus from existing energy markets toward the development of new market places especially designed and suited for DSO side flexibility and investigating the changes necessary for power systems for their implementation;
- Conducting further investigation in market entrance barriers relevant for DSO side flexibility and in regulatory mechanisms to overcome those obstacles to actually grant the providers access to the interesting markets.

Bibliography

Aasgård, E., Fleten, S., Kaut, M., 2019. Hydropower bidding in a multi-market setting. Energy Syst 10, 543–565. URL: https://doi.org/10.1007/s12667-018-0291-y.

BDEW, 2018. Branchenleitfaden: Vergütung von redispatch Maßnahmen. Bundesverband der Energie und Wasserwirtschaft URL: https://www.bdew.de/media/documents/Branchenleitfaden_Verguetung-von-Redispatch-Massnahmen.pdf.

BDEW, 2021. Stromverbrauch in deutschland nach verbrauchergruppen 2020. URL: https://www.bdew.de/media/documents/Nettostromverbrauch_nach_Verbrauchergruppen_2020_online_o_jaehrlich_Ki_02092021.pdf.

Bichler, M., Bojung, C., Buhl, H., Fridgen, G., Gretschko, V., Hanny, L., Knörr, J., Maldonado, F., Neuhoff, K., Neumann, C., Ott, M., Richstein, J., Rinck, M., Schoepf, M., Schott, P., Sitzmann, A., Wagner, J., Weibelzahl, M., 2021. Electricity spot market design 2030-2050 doi:10.24406/fit-n-621457.

Bjørndal, E., Bjørndal, M., Midthun, K., Tomasgard, A., 2018. Stochastic electricity dispatch: A challenge for market design. Energy 150, 992–1005. URL: https://www.sciencedirect.com/science/article/pii/S0360544218302834, doi:https://doi.org/10.1016/j.energy.2018.02.055.

Bloomfield, H., Brayshaw, D., Troccoli, A., Goodess, C., De Felice, M., Dubus, L., Bett, P., Saint-Drenan, Y.M., 2021. Quantifying the sensitivity of european power systems to energy scenarios and climate change projections. Renewable Energy 164, 1062–1075. URL: https://www.sciencedirect.com/science/article/pii/S0960148120315500, doi:https://doi.org/10.1016/j.renene.2020.09.125.

BNetzA, 2016. Monitoringbericht 2016. Bundesnetzagentur, https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Monitoringberichte/Monitoringbericht2016.pdf.

BNetzA, 2019. Bestätigung des netzentwicklungsplans strom f¨ur das zieljahr 2030 Bundesnetzagentur, Retrieved from https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/NEP2019-2030_Bestaetigung.pdf.

Boomsma, T.K., Juul, N., Fleten, S.E., 2014. Bidding in sequential electricity markets: The nordic case. European Journal of Operational Research 238, 797–809. URL: https://www.sciencedirect.com/science/article/pii/S0377221714003695, doi:https://doi.org/10.1016/j.ejor.2014.04.027.

Burger, S., Chaves-Ávila, J.P., Batlle, C., Pérez-Arriaga, I.J., 2016. The Value of Aggregators in Electricity Systems. MIT - Center for Energy and Environmental policy research .

Calvillo, C., Sánchez-Miralles, A., Villar, J., Martín, F., 2016. Optimal planning and operation of aggregated distributed energy resources with market participation. Applied Energy 182, 340–357. URL: https://www.sciencedirect.com/science/article/pii/S030626191631217X, doi:https://doi.org/10.1016/j.apenergy.2016.08.117.

CEER, 2020. 2nd CEER Report on Power Losses. Ref: C19-EQS-101-03.

Chabanne, C., Dietz, T., Hirvonen, R., Janssen, A., Munthe, K., Smolira, K., Sullivan, J.O., Foresti, M., Dusolt, A., 2014. Market design policy paper. https://eepublicdownloads.entsoe.eu/clean-documents/Publications/Position%20papers%20and%20reports/140915_Market_Design_Policy__web.pdf.

Connect, 2018. Konzepte für Redispatchbeschaffung und Bewertungskriterien URL: https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/konzepte-fuer-redispatch.pdf?__blob=publicationFile&v=6.

Crespo Del Granado, P., Resch, G., Holz, F., Welisch, M., Geipel, J., Hartner, M., Forthuber, S., Sensfuss, F., Olmos, L., Bernath, C., et al., 2020. Energy transition pathways to a low-carbon europe in 2050: the degree of cooperation and the level of decentralization. Economics of Energy & Environmental Policy 9, 121–136.

Egerer, J., Gerbaulet, C., Ihlenburg, R., Kunz, F., Reinhard, B., von Hirschhausen, C., Weber, A., Weibezahn, J., 2014. Electricity sector data for policy-relevant modeling: Data documentation and applications to the German and European electricity markets. DIW Data Documentation 72. Berlin. URL: http://hdl.handle.net/10419/95950.

Eid, C., Codani, P., Perez, Y., Reneses, J., Hakvoort, R., 2016. Managing electric flexibility from distributed energy resources: A review of incentives for market design. Renewable and Sustainable Energy Reviews 64, 237–247. URL: https://www.sciencedirect.com/science/article/pii/S1364032116302222, doi:https://doi.org/10.1016/j.rser.2016.06.008.

ENTSO-E, 2018. Electricity balancing in europe: An overview of the european balancing market and electricity balancing guideline .

Facchini, A., 2017. Distributed energy resources: Planning for the future. Nat Energy 2, 17129. URL: https://www.nature.com/articles/nenergy2017129#citeas, doi:https://doi.org/10.1038/nenergy.2017.129.

Faria, E., Fleten, S.E., 2011. Day-ahead market bidding for a nordic hydropower producer: Taking the elbas market into account. Computational Management Science 8, 75–101. doi:10.1007/s10287-009-0108-5.

Forouli, A., Bakirtzis, E.A., Papazoglou, G., Oureilidis, K., Gkountis, V., Candido, L., Ferrer, E.D., Biskas, P., 2021. Assessment of demand side flexibility in european electricity markets: A country level review. Energies 14. URL: https://www.mdpi.com/1996-1073/14/8/2324.

Gerard, H., Puente, E.I.R., Six, D., 2018. Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework. Utilities Policy 50, 40–48. URL: https://www.sciencedirect.com/science/article/pii/S0957178717301285, doi:https://doi.org/10.1016/j.jup.2017.09.011.

Gils, H.C., 2014. Assessment of the theoretical demand response potential in europe. Energy 67, 1–18. URL: https://www.sciencedirect.com/science/article/pii/S0360544214001534, doi:https://doi.org/10.1016/j.energy.2014.02.019.

Givisiez, A.G., Petrou, K., Ochoa, L., 2020. A review on tso-dso coordination models and solution techniques.

Gonzalez-Salazar, M.A., Kirsten, T., Prchlik, L., 2018. Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables. Renewable and Sustainable Energy Reviews 82, 1497–1513. URL: https://www.sciencedirect.com/science/article/pii/S1364032117309206, doi:https://doi.org/10.1016/j.rser.2017.05.278.

Grøttum, H.H., Bjerland, S.F., del Granado, P.C., Egging, R., 2019. Modelling tso-dso coordination: The value of distributed flexible resources to the power system. International Conference on the European Energy Market 16.

Hagemann, S., 2013. Price determinants in the german intraday market for electricity: An empirical analysis. Journal of Energy Markets, 2015 URL: https://ssrn.com/abstract=2352854, doi:http://dx.doi.org/10.2139/ssrn.2352854. eWL Working Paper No. 18/2013.

IRENA, 2019. Innovation landscape brief: Market integration of distributed energy resources. International Renewable Energy Agency URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Market_integration_distributed_system_2019.pdf?la=en&hash=2A67D3A224F1443D529935DF471D5EA1E23C774A.

Klaboe, G., Fosso, O., 2013. Optimal bidding in sequential physical markets — a literature review and framework discussion, pp. 1–6. doi:10.1109/PTC.2013.6652371.

Kraft, E., Russo, M., Keles, D., Bertsch, V., 2021. Stochastic Optimization of Trading Strategies in Sequential Electricity Markets. Technical Report. Karlsruher Institut für Technologie (KIT). doi:10.5445/IR/1000134346.

Kunz, F., Kendziorski, M., Schill, W.P., Weibezahn, J., Zepter, J., von Hirschhausen, C.R., Hauser, P., Zech, M., Möst, D., Heidari, S., Felten, B., Weber, C., 2017a. Electricity, heat, and gas sector data for modeling the German system. DIW Data Documentation 92. Berlin. URL: http://hdl.handle.net/10419/173388. doi:10.5281/zenodo.1044463.

Kunz, F., Weibezahn, J., Hauser, P., Heidari, S., Schill, W.P., Felten, B., Kendziorski, M., Zech, M., Zepter, J., von Hirschhausen, C., Möst, D., Weber, C., 2017b. Reference Data Set: Electricity, Heat, and Gas Sector Data for Modeling the German System URL: https://doi.org/10.5281/zenodo.1044463, doi:10.5281/zenodo.1044463.

Kunz, F., Zerrahn, A., 2016. Coordinating cross-country congestion management. DIW Berlin Discussion Paper No. 1551 URL: http://hdl.handle.net/10419/129208.

Madlener, R., Ruhnau, O., 2021. Chapter 13 - variable renewables and demand flexibility: Day-ahead versus intraday valuation, in: Sioshansi, F. (Ed.), Variable Generation, Flexible Demand. Academic Press, pp. 309–327. URL: https://www.sciencedirect.com/science/article/pii/B9780128238103000054, doi:https://doi.org/10.1016/B978-0-12-823810-3.00005-4.

Mahboubi-Moghaddam, E., Nayeripour, M., Aghaei, J., Khodaei, A., Waffenschmidt, E., 2018. Interactive robust model for energy service providers integrating demand response programs in wholesale markets. IEEE Transactions on Smart Grid 9, 2681–2690. doi:10.1109/TSG.2016.2615639.

Matke, C., Medjroubi, W., Kleinhans, D., 2016. Scigrid - an open source reference model for the european transmission network (v0.2). Retrieved from http://www.scigrid.de.

Matthes, D.F.C., Harthana, R.O., Groscurth, D.H.M., Boßmann, T., 2007. Klimaschutz und stromwirtschaft 2020/2030 technologien, emissionen, kosten und wirtschaftlichkeit eines klimafreundlichen stromerzeugungssystems URL: https://www.arrhenius.de/fileadmin/redaktion/pdf/WWF-DUH-Szenario-01-07-2007.pdf.

Najibi, F., Apostolopoulou, D., Alonso, E., 2021. Tso-dso coordination schemes to facilitate distributed resources integration. Sustainability 13. URL: https://www.mdpi.com/2071-1050/13/14/7832, doi:10.3390/su13147832.

Newman, J., MacDougall, P., 2021. Increasing DER integration through discrete intraday settlements. The Electricity Journal 34, 106932. URL: https://www.sciencedirect.com/science/article/pii/S1040619021000233, doi:https://doi.org/10.1016/j.tej.2021.106932.

Openmod Initiative, 2022. Typical electrical parameters for transmission infrastructure. https://wiki.openmod-initiative.org/wiki/Transmission_network_datasets#Typical_electrical_parameters_for_transmission_infrastructure.

Ostergaard, J., Ziras, C., Bindner, H.W., Kazempour, J., Marinelli, M., Markussen, P., Rosted, S.H., Christensen, J.S., 2021. Energy security through demand-side flexibility: The case of denmark. IEEE Power and Energy Magazine 19, 46–55. doi:10.1109/MPE.2020.3043615.

Ottesen, S., Tomasgard, A., Fleten, S.E., 2016. Prosumer bidding and scheduling in electricity markets. Energy 94, 828–843. URL: https://www.sciencedirect.com/science/article/pii/S0360544215015972, doi:https://doi.org/10.1016/j.energy.2015.11.047.

Ottesen, S., Tomasgard, A., Fleten, S.E., 2018. Multi market bidding strategies for demand side flexibility aggregators in electricity markets. Energy 149, 120–134. URL: https://www.sciencedirect.com/science/article/pii/S0360544218302159, doi:https://doi.org/10.1016/j.energy.2018.01.187.

Pape, C., Hagemann, S., Weber, C., 2016. Are fundamentals enough? explaining price variations in the german day-ahead and intraday power market. Energy Economics

54, 376–387. URL: https://www.sciencedirect.com/science/article/pii/S0140988316000037, doi:https://doi.org/10.1016/j.eneco.2015.12.013.

Pearson, S., Wellnitz, S., del Granado, P.C., Hashemipour, N., 2022. The value of TSO-DSO coordination in re-dispatch with flexible Decentralized Energy Sources: Insights for Germany in 2030. Preprint submitted to Applied Energy Elsevier: VSI SmartDemandResponse2021.

Roos, A., Ottesen, S., Bolkesjø, T.F., 2014. Modeling consumer flexibility of an aggregator participating in the wholesale power market and the regulation capacity market. Energy Procedia 58, 79–86. URL: https://www.sciencedirect.com/science/article/pii/S1876610214017792, doi:https://doi.org/10.1016/j.egypro.2014.10.412. renewable Energy Research Conference, RERC 2014.

Rossi, M., Migliavacca, G., Viganò, G., Siface, D., Madina, C., Gomez, I., Kockar, I., Morch, A., 2020. Tso-dso coordination to acquire services from distribution grids: Simulations, cost-benefit analysis and regulatory conclusions from the smartnet project. Electric Power Systems Research 189, 106700. doi:10.1016/j.epsr.2020.106700.

Savvopoulos, N., Konstantinou, T., Hatziargyriou, N., 2019. Tso-dso coordination in decentralized ancillary services markets, pp. 1–6. doi:10.1109/SEST.2019.8849142.

von Schemde, A., Eriksrud, A.L., Hentsche, J., von Schemde, A., 2020. Redispatch and countertrade costs the impact of german bidding zones final report.

Sharda, S., Singh, M., Sharma, K., 2021. Demand side management through load shifting in iot based hems: Overview, challenges and opportunities. Sustainable Cities and Society 65, 102517. URL: https://www.sciencedirect.com/science/article/pii/S2210670720307344, doi:https://doi.org/10.1016/j.scs.2020.102517.

Shinde, P., Amelin, M., 2019. A literature review of intraday electricity markets and prices, in: 2019 IEEE Milan PowerTech, pp. 1–6. doi:10.1109/PTC.2019.8810752.

Shivakumar, A., Anjo, J., Miller, M., Pye, S., Rouelle, P.B., Martin Densing, T.K., 2017. Smart energy solutions in the eu: State of play and measuring progress. INSIGHT_E URL: http://www.insightenergy.org/system/publication_files/files/000/000/068/original/INSIGHT_E_PR_SES_30-01-2017.pdf?1507713619.

Sia Partners, 2014. Demand response: A study of its potential in europe. Insight Energy and Environment .

Silva, R., Alves, E., Ferreira, R., Villar, J., Gouveia, C., 2021. Characterization of tso and dso grid system services and tso-dso basic coordination mechanisms in the current decarbonization context. Energies 14.

SmartNet Consortium, 2019. Smartnet: Tso-dso coordination for acquiring ancillary services from distribution grids—the smartnet project final results Available online: http://smartnet-project.eu/wp-content/uploads/2019/05/SmartNet-Booktlet.pdf (accessed on 7.12.2021).

Sánchez-Jiménez, M., Stamatis, K., Kollau, M., Stantcheva, M., Busechian, E., Hermans, P., Guzeleva, D., Abrandt, G.E., Friedl, W., Mandatova, P., Stromback, J., 2015. Regulatory recommendations for the deployment of flexibility.

Talari, S., Shafie-khah, M., Osório, G.J., Aghaei, J., Catalão, J.P., 2018. Stochastic modelling of renewable energy sources from operators' point-of-view: A survey. Renewable and Sustainable Energy Reviews 81, 1953–1965. URL: https://www.sciencedirect.com/science/article/pii/S1364032117309437, doi:https://doi.org/10.1016/j.rser.2017.06.006.

UN, 2015. Paris agreement. United Nations Treaties URL: https://unfccc.int/sites/default/files/english_paris_agreement.pdf.

Vartanian, C., Bauer, R., Casey, L., Loutan, C., Narang, D., Patel, V., 2018. Ensuring system reliability: Distributed energy resources and bulk power system considerations. IEEE Power and Energy Magazine 16, 52–63. doi:10.1109/MPE.2018.2863059.

Villar, J., Bessa, R., Matos, M., 2018. Flexibility products and markets: Literature review. Electric Power Systems Research 154, 329–340. URL: https://www.sciencedirect.com/science/article/pii/S0378779617303723, doi:https://doi.org/10.1016/j.epsr.2017.09.005.

vom Scheidt, F., Müller, C., Staudt, P., Weinhardt, C., 2020. The german electricity system in 2030 - data on consumption, generation, and the grid URL: https://bwdatadiss.kit.edu/dataset/254#headingFileList.

vom Scheidt, F., Qu, J., Staudt, P., Mallapragada, D., Weinhardt, C., 2021. The effects of electricity tariffs on cost-minimal hydrogen supply chains and their impact on electricity prices and redispatch costs. Proceedings of the 54th Hawaii International Conference on System Sciences URL: http://hdl.handle.net/10125/71016, doi:10.24251/HICSS.2021.401.

vom Scheidt, F., Qu, J., Staudt, P., Mallapragada, D.S., Weinhardt, C., 2022. Integrating hydrogen in single-price electricity systems: The effects of spatial economic signals. Energy Policy 161, 112727. URL: https://www.sciencedirect.com/science/article/pii/S0301421521005930, doi:https://doi.org/10.1016/j.enpol.2021.112727.

Weibezahn, J., Kendziorski, M., 2019. Illustrating the benefits of openness: A large-scale spatial economic dispatch model using the julia language. Energies 12. URL: https://www.mdpi.com/1996-1073/12/6/1153, doi:10.3390/en12061153.

Xiong, B., Predel, J., del Granado, P.C., Egging-Bratseth, R., 2021. Spatial flexibility in redispatch: Supporting low carbon energy systems with power-to-gas. Applied energy 283.

Xu, Z., 2019. The electricity market design for decentralized flexibility sources. Oxford institute for energy studies.

Yuan, Z., Hesamzadeh, M.R., 2017. Hierarchical coordination of tso-dso economic dispatch considering large-scale integration of distributed energy resources. Applied Energy 195, 600–615. URL: https://www.sciencedirect.com/science/article/pii/S030626191730274X, doi:https://doi.org/10.1016/j.apenergy.2017.03.042.

Zhu, Z., Wing Chan, K., Bu, S., Zhou, B., Xia, S., 2021. Real-time interaction of active distribution network and virtual microgrids: Market paradigm and data-driven stakeholder behavior analysis. Applied Energy 297, 117107. URL: https://www.sciencedirect.com/science/article/pii/S0306261921005511, doi:https://doi.org/10.1016/j.apenergy.2021.117107.

Zöphel, C., Schreiber, S., Müller, T., Möst, D., 2018. Which flexibility options facilitate the integration of intermittent renewable energy sources in electricity systems?, in: Curr Sustainable Renewable Energy Rep. Springer Link. chapter 5, pp. 37–44. URL: https://doi.org/10.1007/s40518-018-0092-x.

NTNU

Kunnskap for en bedre verden