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The value of TSO-DSO coordination in re-dispatch with flexible decentralized energy sources: Insights for Germany in 2030

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ABSTRACT

As Germany plans to raise the share of energy consumption satisfied by Renewable Energy Sources (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.

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 [1]. 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 to guarantee the security of supply. As Fig. 1 illustrates, the unpredictable nature of RES results in higher risk for congestion. Fig. 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. [2] shows, there is not one ultimate technology providing the needed flexibility capacity, but a wide portfolio of flexibility options is needed.

An option that has a high flexibility potential but is not yet integrated is the use of flexible Distributed Energy Resources (DERs), e.g. load shifting, energy storage, demand response, etc. Their amount and, therefore, their capacity has grown significantly over the last years, and is projected to still exponentially increase over the next decades [3,4]. Currently, some of the reasons for not exploiting their flexibility potentials 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 Transmission Grid (TS) are allowed to feed in their electricity to the system. As flexible DERs are located on the Distribution Grid (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

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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_{el}
$D^{DA}_{s,t}$	Power demand of PHS units on the DA market in MW_{el}
$H^{DA}_{s,t}$	SOC of PHS units on the DA market in MWh_{el}
$P^{DA}_{g,t}$	Generation by all generators on the DA market in MW_{el}
$P^{DA}_{r,t}$	Generation by renewable energy units on the DA market in MW_{el}
$P^{DA}_{s,t}$	Generation by PHS units on the DA market in MW_{el}

Variables Congestion Management (CM)

$\Delta P^{+}_{g,t}$	Upwards adjustment of the DA market generation in MW_{el}
$\Delta P^{-}_{g,t}$	Downwards adjustment of the DA market generation in MW_{el}
$P^{inj}_{n,t}$	Power injection at node n in MW_{el}
$P^{lost}_{n,t}$	Lost load at node n in MW_{el}
$P^{flow}_{n,m,t}$	Line flow from n to m in MW_{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_{el}
$\Delta D^{-}_{n,t}$	Downwards adjustment of the nodal hourly demand in MW_{el}
$L_{n,t}$	Actual, realized load
$D^{re+}_{n,t}$	Hourly increase of demand in the residential sector MW_{el}
$D^{ind+}_{n,t}$	Hourly increase of demand in the industrial sector MW_{el}
$D^{ser+}_{n,t}$	Hourly increase of demand in the service sector MW_{el}
$D^{re-}_{n,t}$	Hourly decrease of demand in the residential sector MW_{el}
$D^{ind-}_{n,t}$	Hourly decrease of demand in the industrial sector MW_{el}
$D^{ser-}_{n,t}$	Hourly decrease of demand in the service sector MW_{el}

Variables DSO optimization

$G_{n,t}$	Electricity taken from network at average market price in MW_{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_{el}
$\mathrm{c}^{\mathrm{VOLL}}$	Value of lost load (VOLL) in MW_{el}
$\mathrm{d}_{n,t}$	Nodal load in MW_{el}
$\mathrm{p}^{\max}_{g}$	Maximum power generation of generator g in MW_{el}
$\mathrm{p}^{\max}_{s}$	Maximum pumping and generating power of PHS unit s in MW_{el}
$\mathrm{p}^{\max}_{l}$	Line capacity in MW_{el}
trm	Transmission reliability margin (trm)
x_{l}	Reactance of line l in MW_{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

the Distribution System Operator (DSO) domain can have to improve Transmission System Operator (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 (Business As Usual (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 the cases on the German power system in 2015 and a future case in 2030, we can compare the performance of the different frameworks in the current system and in the environment they have been designed for.

In the following section, we review recent literature with a focus on the integration of DERs into the power system and related modelling concepts. Afterwards, we describe the methodology and optimization models. Then, we describe the data before discussing the results in Section 5. The paper finishes with conclusions and future research.

2. Related literature

The literature distinguishes different types of DERs connected to the DS. Xu [7] defines DERs as a part of decentralized flexibility options and categorizes them by characteristics concerning technical aspects and field of operation. Eid et al. [8] 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 [9]. In some

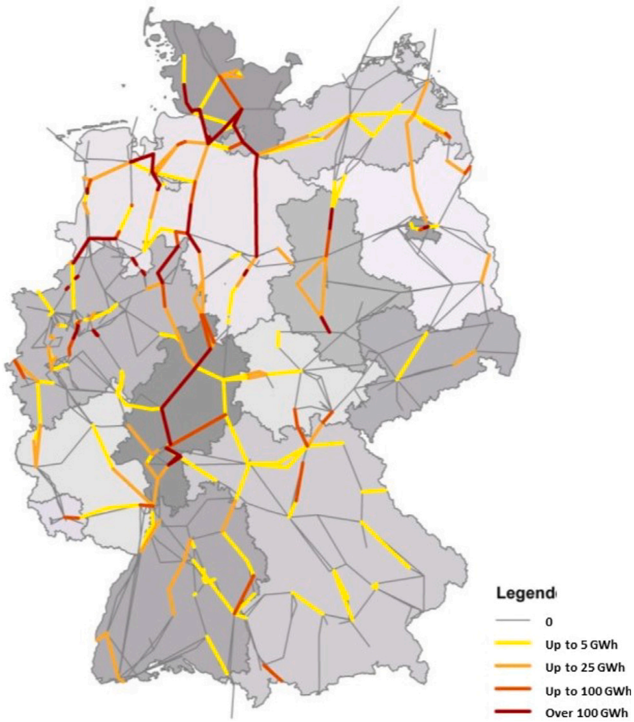

Fig. 1. Transmission line overload index of the German network as planned by the federal network agency with 65% RES in electricity consumption (by BNetzA [1]).

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 [7,10,11]. This tradition is mainly due to existing limits on how much DERs can feed into the grid. Indeed, 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. The fit-and-forget policy can also be interpreted as over-dimensioning the grid to cope with the reverse power flow and congestion. This approach would not be economically and environmentally efficient in the presence of more DERs. Therefore, the DSOs should go beyond this policy by taking advantage of the flexibility from distributed resources and introducing new business models and innovations [12].

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 into existing markets, others elaborate concepts for new emerging markets. ENTSO-E [13] and Eid et al. [8] propose access for aggregated DERs to existing balancing markets, while Savvopoulos et al. [14] use DERs mainly on the DS side and introduce them there either into modified Ancillary Services (AS) markets [14] or newly designed DS markets [7]. Overall, to integrate DERs, there is an agreement that they need to be aggregated to have a tradable amount of flexibility [7,11,15,16].

An active DSO engaged with DERs has emerged as an important enabler in exploiting and rewarding their flexibility [15,17,18]. 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.

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 [8,14]. Others, like Najibi et al. [17] and Givisiez et al. [10], 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. [17] 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 [17] 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 categorization 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. [10] similar to the AS-market models [11,14,19,20] follow different degrees of (de-) centralization. Givisiez et al. [10] 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. [17]. 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. [21], Yuan and Hesamzadeh [15] and Najibi et al. [17] 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. [10] states 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. [11], Rossi et al. [19], Savvopoulos et al. [14] and Givisiez et al. [10] 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 optimizes the whole system taking into account all grid constraints from DS and TS. On the other hand, it is also perceived that a *centralized* management of *distributed* energy resources is becoming more difficult the higher the amount of DERs in the system. However, Xiong et al. [22] found that even such a DER integration approach could improve the system performance. Even though Xiong et al. [22] do not take into account DS grid constraints, its finding corresponds to Najibi et al. [17] 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. [17] also states that the decentralized coordination framework delivers better performance.

Givisiez et al. [10] 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 realized here via the intermediate of this central market. This concept corresponds to the common TSO-DSO AS market approach by Silva et al. [11], SmartNet Consortium [20] and Rossi et al. [19]. According to Rossi et al. [19], 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. [14] 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.

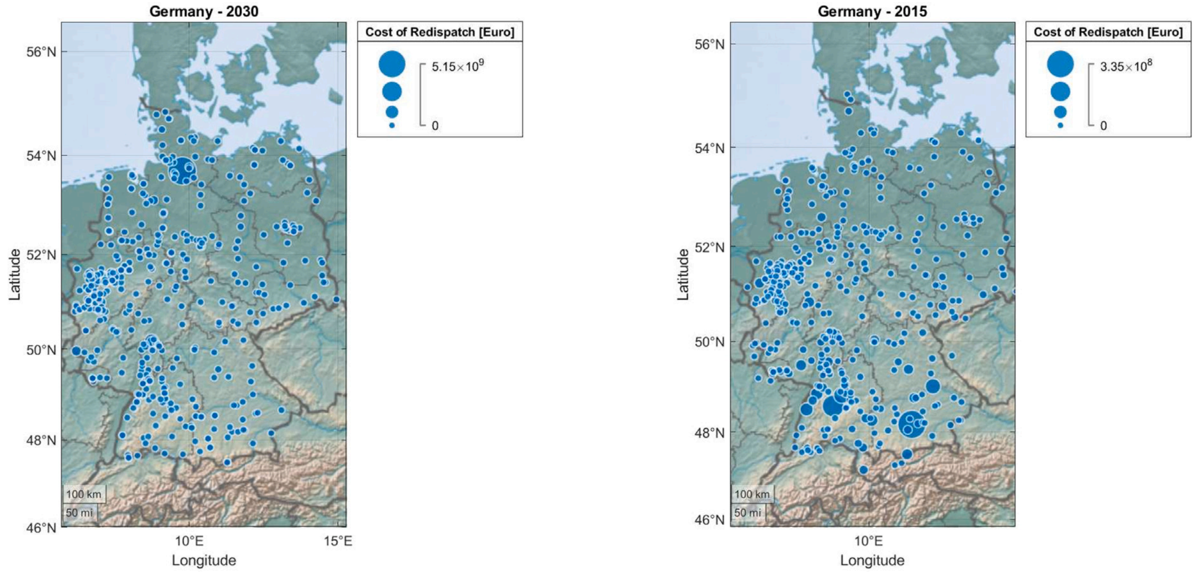

Fig. 2. Spatial distribution of re-dispatch cost over two weeks in Germany in 2015 (right) and 2030 (left) based on own calculations and data by Kunz et al. [5] (for 2015) and vom Scheidt et al. [6] (for 2030).

The DSO-managed approach by Givisiez et al. [10] could be such a more realistic concept. It requires by far more communication between the TSO and the DSOs than the centralized one but less than the common market idea. Similar to Najibi et al. [17] and Givisiez et al. [10] 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 [15] created the generalized bid function as communication tool between DSO and TSO that similar to Najibi et al. [17] 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. [21]. The second approach by Givisiez et al. [10] is a more distributed one, where all available DERs can be pursued on either DS- or TS-level. Savvopoulos et al. [14],SmartNet Consortium [20] and Rossi et al. [19] adapt this concept to AS market design and introduce the local AS market coordination scheme that features parallels to Silva et al. [11] local and global flexibility market concept. While Savvopoulos et al. [14], SmartNet Consortium [20] and Rossi et al. [19] propose an existing AS-market but with a hierarchical structure, Silva et al. [11] 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. [11] 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. [10]. Nevertheless, both of those AS-market concepts are addressed quite frequently in the literature. They are perceived as the simplest coordination scheme with the least optimization effort while still allowing the DSOs to control their grid and resources and preserving the information barrier between the two system operators [11]. Even though Givisiez et al. [10] 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. [19] 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.

2.2. TSO-DSO modelling approaches

According to Givisiez et al. [10] 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. [22], Yuan and Hesamzadeh [15] and Najibi et al. [17] 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. [14], Najibi et al. [17], Yuan and Hesamzadeh [15] and Mahboubi-Moghaddam et al. [23]. 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. [14] models the local AS market as described in [20] based on Gerard et al. [24], 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 [15] 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 [15] 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. [14] and Yuan and Hesamzadeh [15] the TSO optimizes in the following step the whole system while using the information about DER-capacities in the different nodes sent by each DSO. The timing of this coordination however is different in the two models as Yuan and Hesamzadeh [15] set up their model for the Economic Dispatch (ED) while Savvopoulos et al. [14] operates later on the AS market.

Unlike Savvopoulos et al. [14], Yuan and Hesamzadeh [15], Najibi et al. [17] and Mahboubi-Moghaddam et al. [23] 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

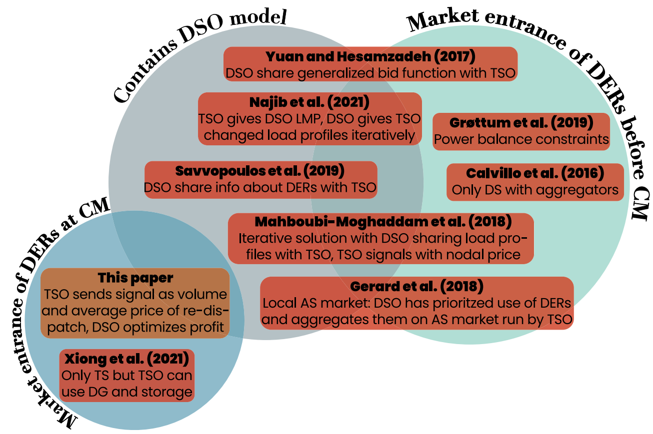

Fig. 3. Comparison of TSO-DSO coordination mechanisms in the literature concerning DER integration approaches with an active DSO with the model and concept of this paper.

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. [25]. Their model aggregates the DERs on DS-level and the aggregator can participate in the Day Ahead (DA) market. Unlike the other models that aim to minimize the system costs, Calvillo et al. [25] aims to maximize 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 are aiming 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. [22] 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. [22] nor one of the models discussed above consider re-dispatch services coming from a TSO-DSO coordination.

2.3. Contribution

There are few approaches including a DSO model, even though most of them assume the DSOs participating actively in the process. Fig. 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 optimization (see Fig. 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
- analyse 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, the contribution of this paper consists of

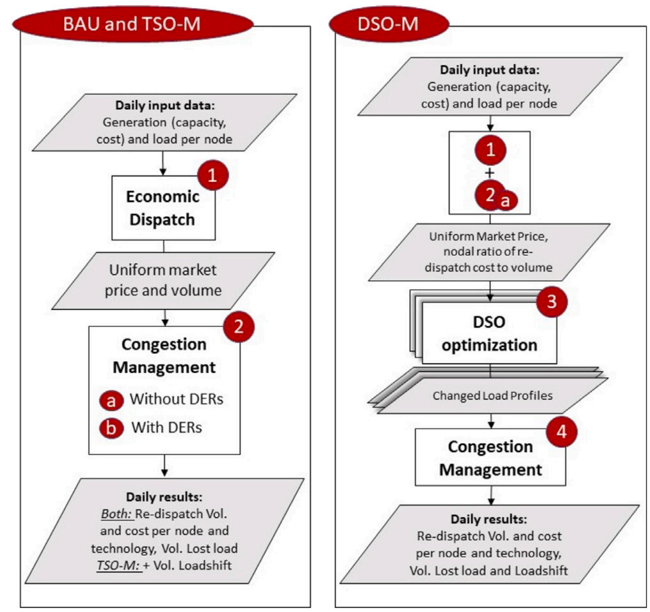

Fig. 4. Program flow chart for one day all cases (Left: Business As Usual (BAU) (Step 1 + 2a) and TSO managed (TSO-M) (Step 1 + 2b), Right: DSO managed (DSO-M)).

formulating possible coordination frameworks, their implementation, i.e., the optimization models used, 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 the models. 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. 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 Fig. 4.

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. [22] in a slightly modified version, calculating the minimal system-wide cost of re-dispatch necessary not to violate transmission constraints.

As we show in Fig. 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 Congestion Management (CM) optimization (step 2a for BAU). The BAU case only involves those two steps. Xiong et al. [22] chose a sequential model to simulate this process. With each sequence being 24 h long, this approach allows us to analyse the 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 DA transfers the uniform market price $\overline{\Psi}_t$ and volume $\overline{P}_{g,t}^{DA}$ 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 [26,27]. 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.

3.2. 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 Fig. 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, 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. 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. The 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. Load profiles are changed by shifting load between time steps according to the constraints regarding load shifting potential (Eqs. (23); (25)–(37)), with the demand in each node aggregating to the same amount over each period of 24 h. 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 Fig. 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 $\overline{\Phi}^{RD}_{n,t}$ to the correspondent DSOs. Those parameters are the input information for each DSO optimization (Step 3 in Fig. 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.

3.4. 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. [22][1]).

3.4.1. 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 [28]. Hence, ramping constraints become non-binding. Therefore, we neglect ramping constraints, also because this reduces the computational complexity of all models we use.

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 paper'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 study scope.

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% [29]. As they are rather low and we focus on the congestion on the transmission lines, we neglect those losses in the optimization.

Sectoral load shifting. We assume that each sector in the 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 [30], 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).

3.4.2. ED model (Step 1)

The ED as the result of the day-ahead (DA) market 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:

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

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. (1)).

$$\min_{P^{DA}_{g,t}} \sum_t \sum_g \mathrm{c}^{\mathrm{mc}}_g P^{DA}_{g,t} \tag{1}$$

Market clearing. The sum of generation from all sources must be equal to the sum of demand in all nodes at all times (Eq. (2)).

$$\sum_g P^{DA}_{g,t} - \sum_n \mathrm{d}^{\mathrm{load}}_{n,t} = 0 \quad , t \in \mathcal{T} \tag{2}$$

Power generation. The power generation by all generators cannot exceed their maximum power output (Eq. (3)). Since we assume

$$P^{DA}_{g,t} \leq \mathrm{p}^{\mathrm{max}}_g \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{3}$$

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 (Eqs. (4), (5)). They can only store energy up to their maximum capacity (Eq. (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. (7)) and we ensure there is no simultaneous charge and discharge decisions by introducing a very small (negligible) penalty in the objective function to their respective variables.

$$D^{DA}_{s,t} \leq \mathrm{p}^{\mathrm{max}}_s \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{4}$$

$$P^{DA}_{s,t} \leq \mathrm{p}^{\mathrm{max}}_s \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5}$$

$$H^{DA}_{s,t} \leq \mathrm{l}^{\mathrm{max}}_s \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{6}$$

$$H^{DA}_{s,t} = H^{DA}_{s,t-1} - P^{DA}_{s,t-1} + \eta_{\mathrm{s}} D_{s,t-1} \quad , s \in \mathcal{S}, t \in \mathcal{T} : t > 1 \tag{7}$$

Non negativity. Eqs. (9)–(11) ensure that the power output of all generators and storages, demand for power by PHS units and storage level can never be negative.

$$P^{DA}_{g,t} \geq 0 \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{8}$$

$$P^{DA}_{s,t} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{9}$$

$$D^{DA}_{s,t} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{10}$$

$$L^{DA}_{s,t} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{11}$$

3.4.3. 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. (2)).

Objective function. We follow the formulation of Xiong et al. [22], based on Kunz and Zerrahn [31]. 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. Tolerating lost load in the model assures physical feasibility in case of insufficient capacity connected to a node in the used data. However, unavoidable lost load has a large influence on the cost of re-dispatch. In order to not overestimate its effect on the possible value of load shifting, we retain the conservative Value of Lost Load (VOLL) of 1000 € per MWh as previously used by Xiong et al. [22] in our own calculations (Eq. (12)).

$$\min_{\Delta P^+_{g,t}, \Delta P^-_{g,t}} \sum_t \sum_n \left[\sum_g \left(\mathrm{c}^{\mathrm{mc}}_g \Delta P^+_{g,t} + (\overline{\Psi}_t - \mathrm{c}^{\mathrm{mc}}_g) \Delta P^-_{g,t} \right) + \sum_s \frac{\overline{\Psi}_t}{\eta_{\mathrm{s}}} \Delta P^+_{s,t} + \mathrm{c}^{\mathrm{VOLL}} P^{lost}_{n,t} \right] \tag{12}$$

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. (13)).

$$P'_{g,t} = \overline{P}^{DA}_{g,t} + \Delta P^+_{g,t} - \Delta P^-_{g,t} \tag{13}$$

Nodal balance and power injection. Eq. (14) ensures that the market clearing constraint holds true at each node. As shown in Eq. (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.

$$\sum_g P'_{g,t} - \mathrm{d}_{n,t} = P^{inj}_{n,t} \quad , n \in \mathcal{N}, t \in \mathcal{T} \tag{14}$$

$$\sum_m b_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{inj}_{n,t} \quad , n \in \mathcal{N}, t \in \mathcal{T} \tag{15}$$

Line power flow. The power flow in the model is calculated by using the line reactance and voltage angles at the from-node and the to-node in Eq. (16). To avoid line damaging, their thermal capacity limit including the Transmission Reliability Margin (TRM) must not be exceeded (positive or negative) at all times. This constraint is expressed by Eqs. (17) and (18) and holds true in both flow directions. The TRM is defined as a value between 0 and 1 and effectively reduces the capacity of all transmission lines by reserving a relative share of the capacity for security reasons. As Xiong et al. [22] and Weibezahn and Kendziorski [32], 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.

$$x^{-1}_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{flow}_{n,m,t} \quad , n, m \in \mathcal{N} : n \neq m, t \in \mathcal{T} \tag{16}$$

$$P^{\mathrm{flow}}_{l,t} \leq p^{\mathrm{max}}_l (1 - \mathrm{trm}) \quad , l \in \mathcal{L}, t \in \mathcal{T} \tag{17}$$

$$-\left[p^{\mathrm{max}}_l (1 - \mathrm{trm})\right] \leq P^{\mathrm{flow}}_{l,t} \quad , l \in \mathcal{L}, t \in \mathcal{T} \tag{18}$$

Power generation. Eqs. (19) and (20) prevent power plants from being simultaneously shifted up and down. Additionally, Eqs. (19)–(21) ensure the new generation profiles to stay within generation limits

$$\overline{P}^{DA}_{g,t} + \Delta P^+_{g,t} \leq \mathrm{p}^{\mathrm{max}}_g \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{19}$$

$$0 \leq \overline{P}^{DA}_{g,t} - \Delta P^-_{g,t} \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{20}$$

$$P^{DA}_{s,t} + \Delta P^+_{s,t} \leq \mathrm{p}^{\mathrm{max}}_s \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{21}$$

Non negativity. All generation after CM calculations must not be negative (Eq. (22)).

$$P'_{g,t} \geq 0 \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{22}$$

3.4.4. 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. (12)) as well as most constraints (Eqs. (13), (15)–(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. (23)).

$$L_{n,t} = d_{n,t} + \Delta D^{+}_{n,t} - \Delta D^{-}_{n,t} \tag{23}$$

Nodal balance. Eq. (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. (24)).

$$\sum_{g} P'_{g,t} - \mathrm{L}_{n,t} = P^{inj}_{n,t} \quad ,n \in \mathcal{N}, t \in \mathcal{T} \tag{24}$$

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 Section 4.3).

$$\Delta D^{+}_{n,t} = D^{ser+}_{n,t} + D^{re+}_{n,t} + D^{ind+}_{n,t} \tag{25}$$

$$\Delta D^{-}_{n,t} = D^{ser-}_{n,t} + D^{re-}_{n,t} + D^{ind-}_{n,t} \tag{26}$$

Aggregated demand balance. Over each calculation period of 24 h, the sum of upwards-shifting must be equal to the sum of downwards-shifting for all nodes and demand sectors. Eqs. (27)–(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.

$$\sum_{t} \left\{ D^{ser+}_{n,t} - D^{ser-}_{n,t} \right\} = 0 \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{27}$$

$$\sum_{t} \left\{ D^{res+}_{n,t} - D^{res-}_{n,t} \right\} = 0 \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{28}$$

$$\sum_{t} \left\{ D^{ind+}_{n,t} - D^{ind-}_{n,t} \right\} = 0 \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{29}$$

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 (Eqs. (30)–(33)). The (albeit higher) shifting potential of the industrial sector is only available during working hours (Eqs. (34)–(37)).

$$D^{ser+}_{n,t} \le a^{ser} \times z^{ser} \times mean(d_{n,t}) \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{30}$$

$$D^{ser-}_{n,t} \le a^{ser} \times z^{ser} \times mean(d_{n,t}) \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{31}$$

$$D^{re+}_{n,t} \le a^{res} \times z^{res} \times mean(d_{n,t}) \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{32}$$

$$D^{re-}_{n,t} \le a^{res} \times z^{res} \times mean(d_{n,t}) \quad ,t \in \mathcal{T}, n \in \mathcal{N} \tag{33}$$

$$D^{ind+}_{n,t} \le a^{ind} \times z^{ind} \times mean(d_{n,t}) \quad ,t \in 9:16, n \in \mathcal{N} \tag{34}$$

$$D^{ind-}_{n,t} \le a^{ind} \times z^{ind} \times mean(d_{n,t}) \quad ,t \in 9:16, n \in \mathcal{N} \tag{35}$$

$$D^{ind+}_{n,t} = 0 \quad ,t \in (1:8) \vee (17:24), n \in \mathcal{N} \tag{36}$$

$$D^{ind-}_{n,t} = 0 \quad ,t \in (1:8) \vee (17:24), n \in \mathcal{N} \tag{37}$$

3.4.5. 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 (Eqs. (23); (25)–(37)).

Auxiliary 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 h 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 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. (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]

$$\min \sum_{t} \left[\overline{\Psi}^{av} G_{n,t} + \overline{\Phi}^{RD}_{n,t} (\Delta D^{+}_{n,t} - \Delta D^{-}_{n,t}) \right] \tag{38}$$

3.4.6. Final CM (Step 4)

After running the DSO-side optimization outlined in Section 3.4.5, 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.

3.5. Computational complexity

The computer used for the calculations is a laptop running Windows 10, using an AMD Ryzen 7 Pro 4750U CPU and 16 GB of RAM. For the BAU case, the time to finish calculating steps 1 and 2a over a time horizon of one year is roughly 2 1/2 h for both the 2015 and 2030 scenarios. The DSO-M case is an extension of the BAU case, adding 35 min for step 3, and another execution of the CM (step 4), adding up to roughly 5 1/2 for the DSO-M case in both scenarios. The TSO-M case (steps 1+2b), featuring a system-wide optimization that includes interdependencies between nodes, is by far the most complex to optimize, requiring over 72 h to calculate one year in the 2015 and over 101 h in the 2030 scenarios using the computer.

[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 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 Section 5.3.

Table 1
Installed capacity and marginal cost for 2015.
Source: Own illustration based on Kunz et al. [5].

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
Pumped Hydroelectric Storage (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 2
Installed capacity and marginal costs for 2030.
Source: Own illustration based on vom Scheidt et al. [6].

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**

4. Data

The implementation of the models uses real-life data from the German power system of 2015 and a 2030 scenario.

4.1. Data for 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. [5]. The related data documentation [33] offers great insight into their data collection method. In this paper, 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 [32] and Xiong et al. [22]. 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 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 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. (39).

$$c_g^{mc} = \frac{c^{fuel} + c^{CO_2}\lambda_g}{\eta_g} + c_g^{OM} \quad , g \in \mathcal{G} \tag{39}$$

4.2. Data for the 2030 scenario

For the 2030 scenario, we use the open-access data set provided by vom Scheidt et al. [6]. It models the German power system in 2030 with 65% of the brute electricity consumption being satisfied by RES. By basing their projections concerning transmission grid topography on the current data provided by Matke et al. [34] and on the development plan of the federal network agency of Germany [1], 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 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. [35,36] 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. [6] did not classify the generators by their fuel or technology, but they created 23 cost classes based on their marginal cost. Table 2 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 24th cost class to simulate that each node has an additional generation capacity of 1000 MW with marginally higher marginal costs than all other conventional power plants (221 €/MWh). vom Scheidt et al. [6] 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 [1], pp. 42–43). The hypothetical 1000 MW generation capacity per node considers these innovations to ensure a feasible grid simulation.

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

We do 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. [6] are formatted differently to our basis data set provided by Kunz et al. [5], we needed to adapt the 2030 data with further assumptions to use the models

The main challenge was the lack of line specifications such as reactance and resistance that the 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. [37] 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 [38]. 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, Eq. (40) shows the relation between the reactances, assuming a symmetrical configuration for the lines.

$$\frac{X_{245}}{X_{490}} = \frac{ln(\frac{d}{r'})}{ln(\frac{d}{\sqrt{r' \times x}})} \tag{40}$$

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.

4.3. DSO-modelling for both scenarios

This paper models 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 [39]. Therefore, there is no uniform data set for medium and low voltage grids.

The technologies that can be used for load shifting purposes differ depending on the sector the electricity is used for. Hence, we divide the demand for electricity into three different sectors. 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 [40]. To avoid overestimating the industry sector's influence, we have chosen to assume a distribution of 40% for the industrial and 30% each for the other two sectors. As the sectoral energy demand is not estimated to change significantly until 2030 [41], this distribution can be used for both scenarios. Further information regarding the sectoral shifting capacities and their mathematical implementation can be found in Sections 3.4.1 and 3.4.4. Regardless of framework of communication between the TSO and the DSOs, the resulting, total shifting capacities need to be communicated to the actor performing the calculations regarding their optimal usage. Using the aforementioned assumptions, we achieve sufficient accuracy while reducing the risk of unrealistically excessive shifting in the industrial sector.

Table 3
Annual key indicators calculated by CM. A price for the DERs is not yet included.

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Million €]	609.86	526.60	574.14
Volume of re-dispatch [TWh]	5.36	4.74	5.33
Volume of RES curtailment [GWh]	993	948	980
Volume of load shifting [TWh]	–	9.04	4.44
2030			
Cost of re-dispatch [Million €]	9396	9089	9242
Volume of re-dispatch [TWh]	44.86	43.23	44.45
Volume of RES curtailment [TWh]	5.65	5.52	5.69
Volume of load shifting [TWh]	–	9.31	6.03

5. Results

5.1. Key indicators

To compare and analyse the results from the different cases and scenarios, we set out four key indicators. 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. 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 analyse 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.

5.2. The value of flexible DERs for the re-dispatch

Knowing the relevant key indicators, we present the results of the cases. We begin with an examination of results on annual level. Table 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 the results regarding the electricity mix in Germany to historic data from 2015 (see See Fig. 5.) shows, that the modelling frameworks we used have the ability to 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. [36] use the dataset for their own re-dispatch calculations, achieving a result of 6.163 billion €. According to the calculations, the dataset features unavoidable lost load in node 14 accumulating to 3.18 TWh. Thus, at the chosen VOLL of 1000 € per MWh of lost load, this is responsible for the difference as vom Scheidt et al. [36] does not consider lost load. Depending on the progress of grid extension, other sources also project (very) high re-dispatch costs in 2030 [42].

[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).

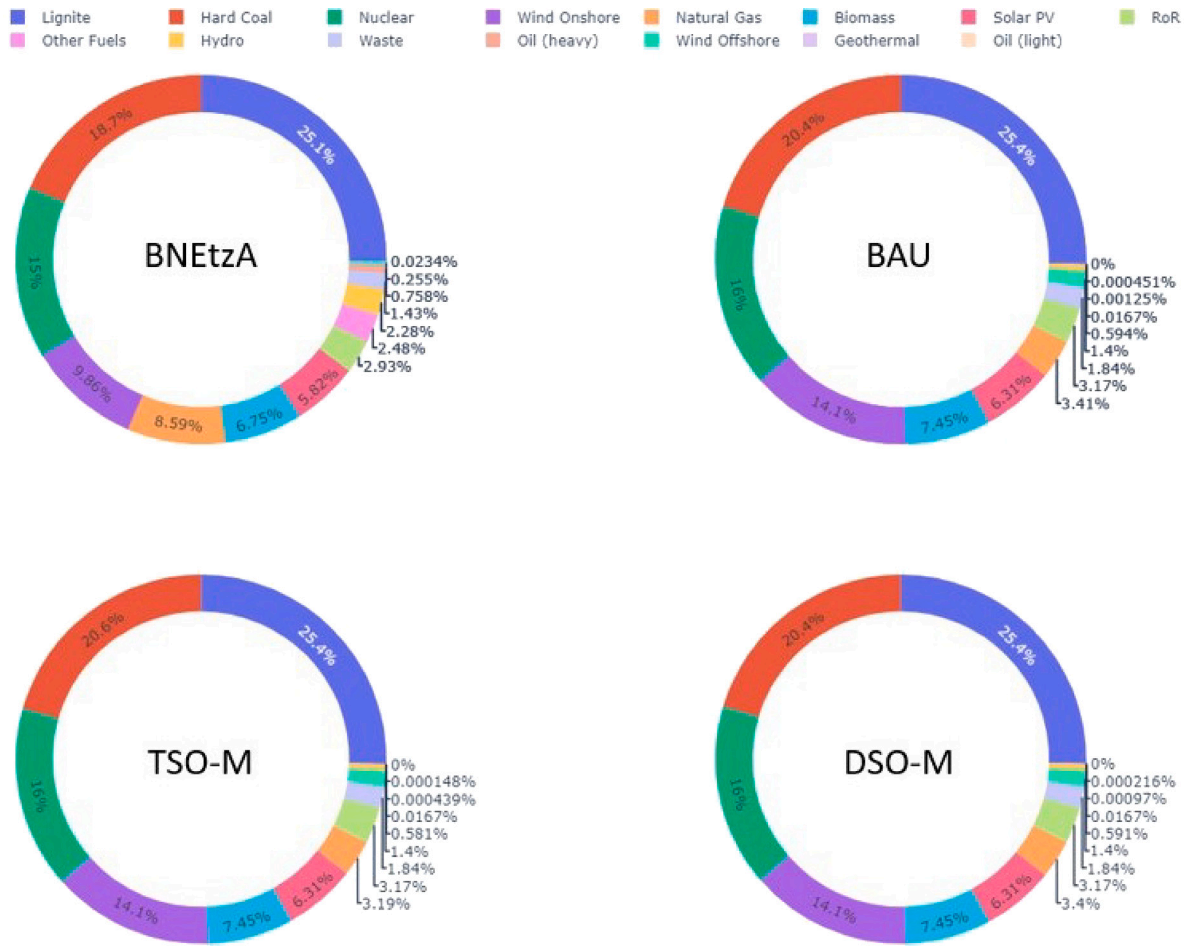

Fig. 5. Generation Mix 2015. Historic data by BNetzA [39] and resulting mix for each case after CM.

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 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 reaching 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 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 of each day is required to be unchanged (Eqs. (27)–(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 the second scenario (plus 0.7%). Consequently, the maximum amount of load shifting potential according to both models 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 5.3.2.

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%).

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

Table 4
Key indicators over days 321–334.

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Million €]	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
2030			
Cost of re-dispatch [Million €]	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

section. We discuss the actual changes to the re-dispatch decisions and load profiles when applying the coordination frameworks we have developed. 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.

5.3.1. A microscopic view

While the annual sums of costs and volumes are good parameters for the comparison of 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 it is our goal 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 the chosen 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 h 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 4.

Fig. 6 shows the aggregated re-dispatch, load shifting decisions 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 very low 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 h in Fig. 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.

Fig. 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.

5.3.2. Further discussion

During the process of the 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 by the two cases to a different extent, explaining their difference in 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 when 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. 6.

In case of DSO-M, 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. Any effect of mechanism 2 that comes into play in the for the decentralized optimization is entirely accidental according to the model, meaning that an actual reduction in re-dispatch *volume* is not certain for case DSO-M.

TSO-M: Conflict of interest. Both 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 do 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.

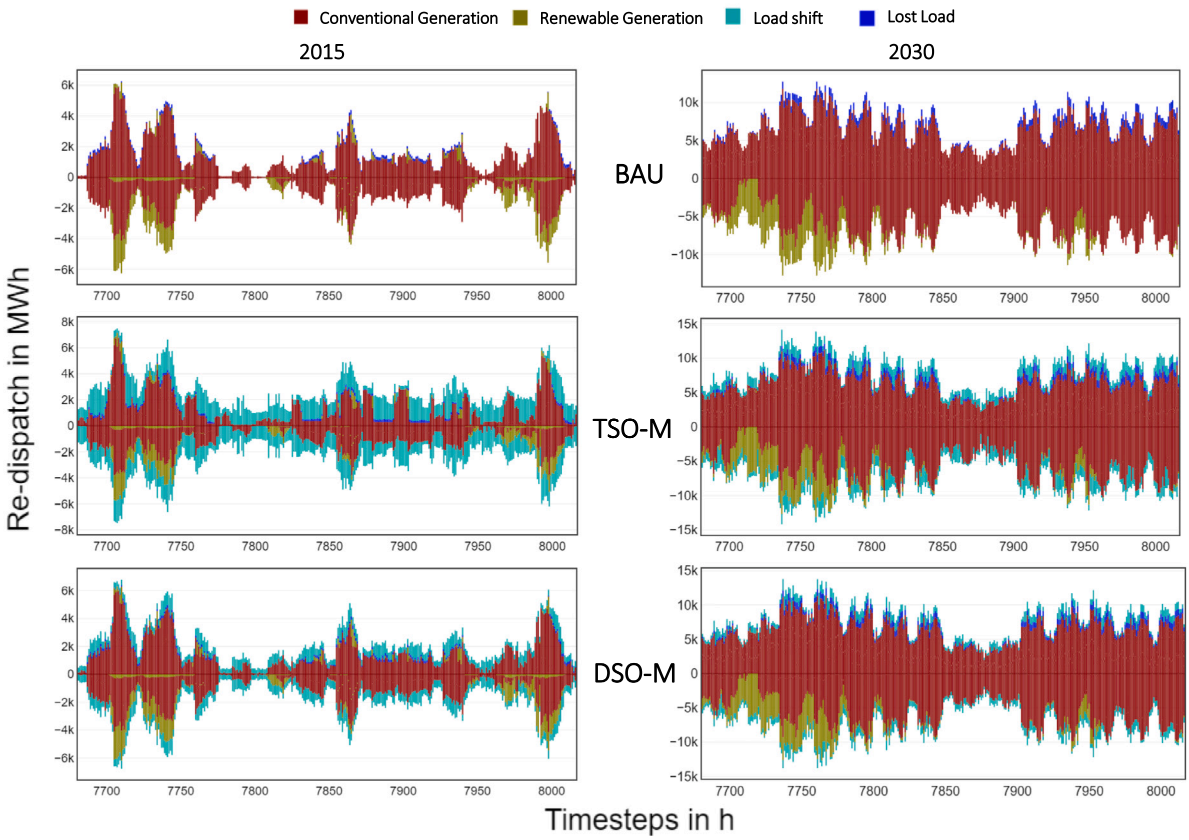

Fig. 6. Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030.

DSO-M: Nodes without re-dispatch. In the DSO-M case, the signal given to the DSOs about the value of load shifting 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. As a consequence, nodes without re-dispatch over any complete period of 24 h 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 price taker at the same, *average market price* over each period of 24 h (Eq. (38)). Indeed, as long as a constant price is assumed during the balancing period for load shifting as implemented in Eqs. (27)–(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 to benefit 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. Any improvement in price, however, 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 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 timestep 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 value are both not close to being high enough to provide realistic incentive for investing in flexible DERs. However, Fig. 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.

5.3.3. Sensitivity analysis

Relative shares of shiftable load are hard to predict and 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 the calculations, we perform

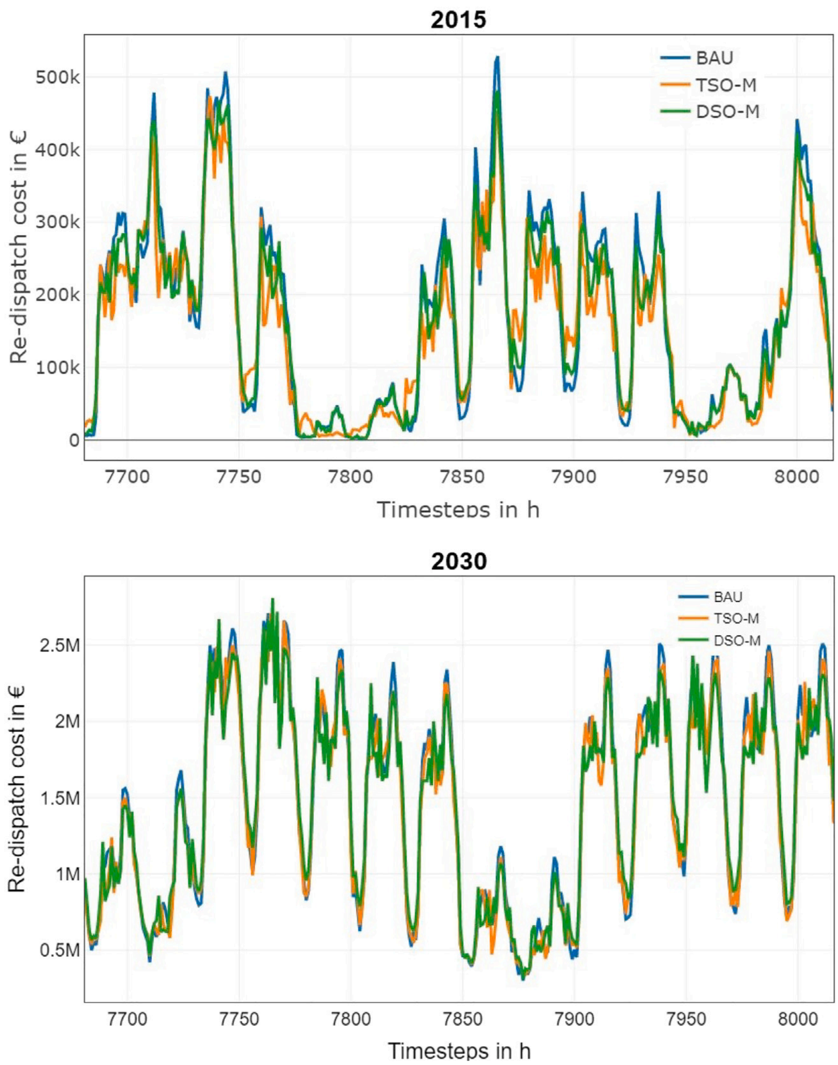

Fig. 7. Re-dispatch cost for all cases over the two most expensive weeks in 2015 (upper graphic) and 2030 (lower graphic).

a sensitivity analysis applying load shifting percentages of one half (2.5/2.5/5%) and one quarter (1.25/1.25/2.5%) their original values to the calculations over the two weeks examined in the previous chapter. We expect the results to be less pronounced than originally, but similar to the 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 5 and 6 provide an overview of the key results, the plotted re-dispatch profiles for the sensitivity analysis are included in Fig. 9 and Fig. 10.

During the 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.

Table 5
Results over days 321–334 for half the shifting capacity.

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Million €]	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 [Million €]	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

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

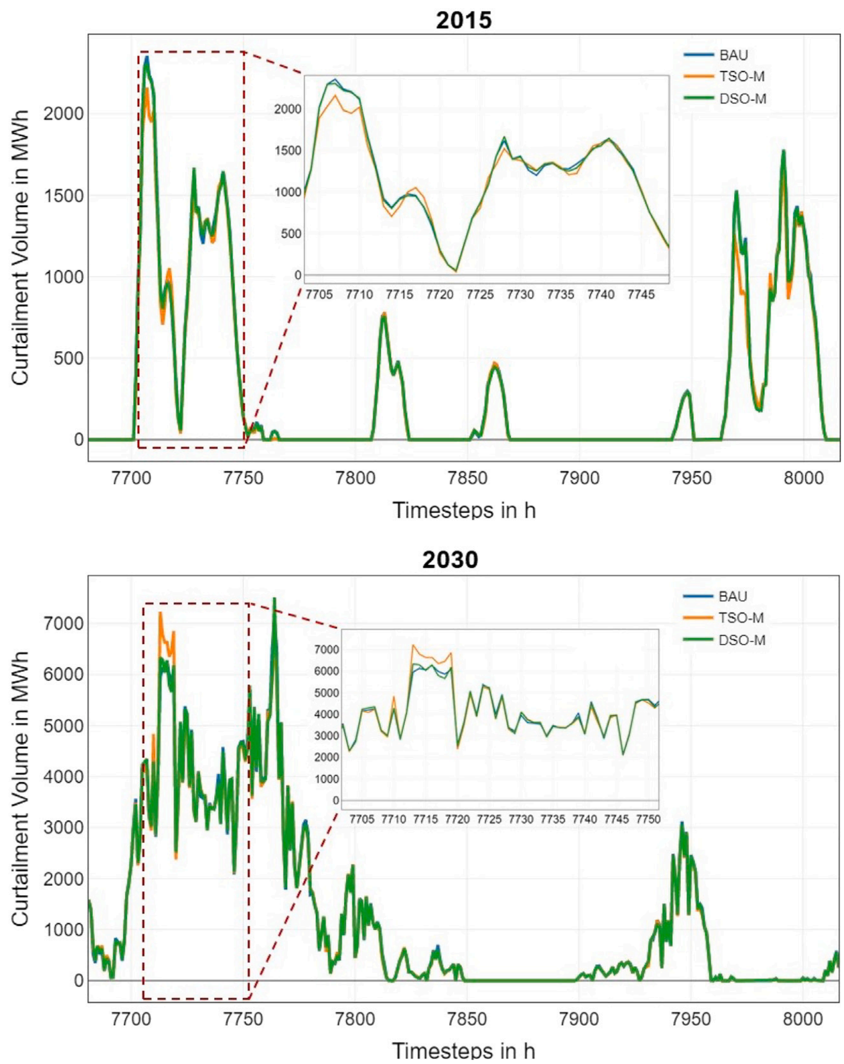

Fig. 8. Volume of RES curtailment for all cases over the two most expensive weeks in 2015 (upper graphic) and 2030 (lower graphic).

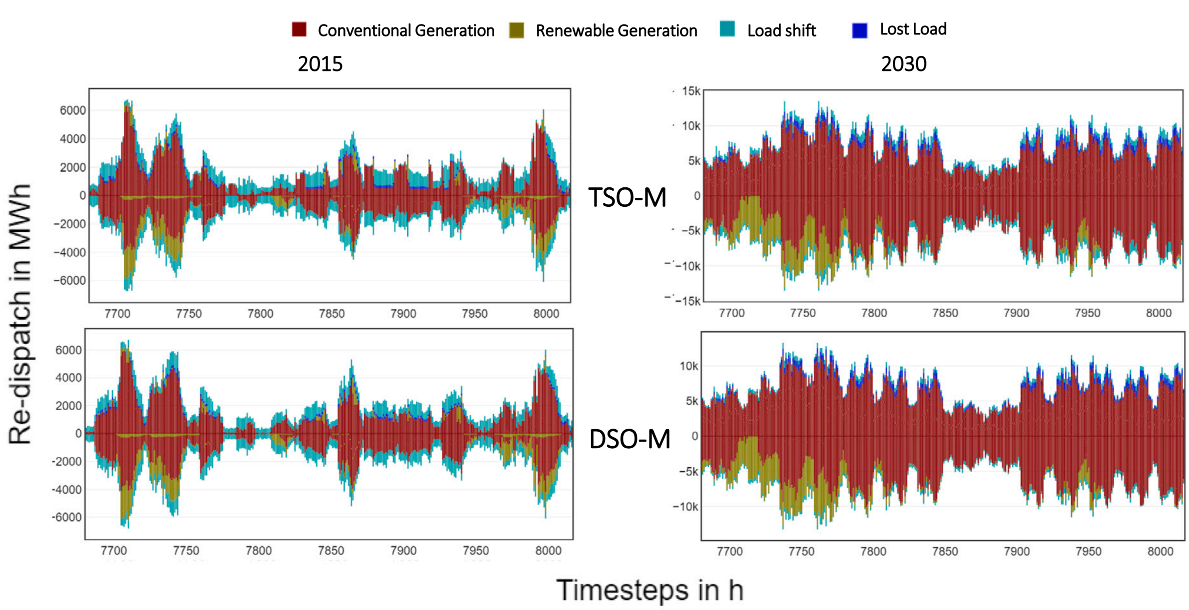

Fig. 9. Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030 with half the original load shifting capacity.

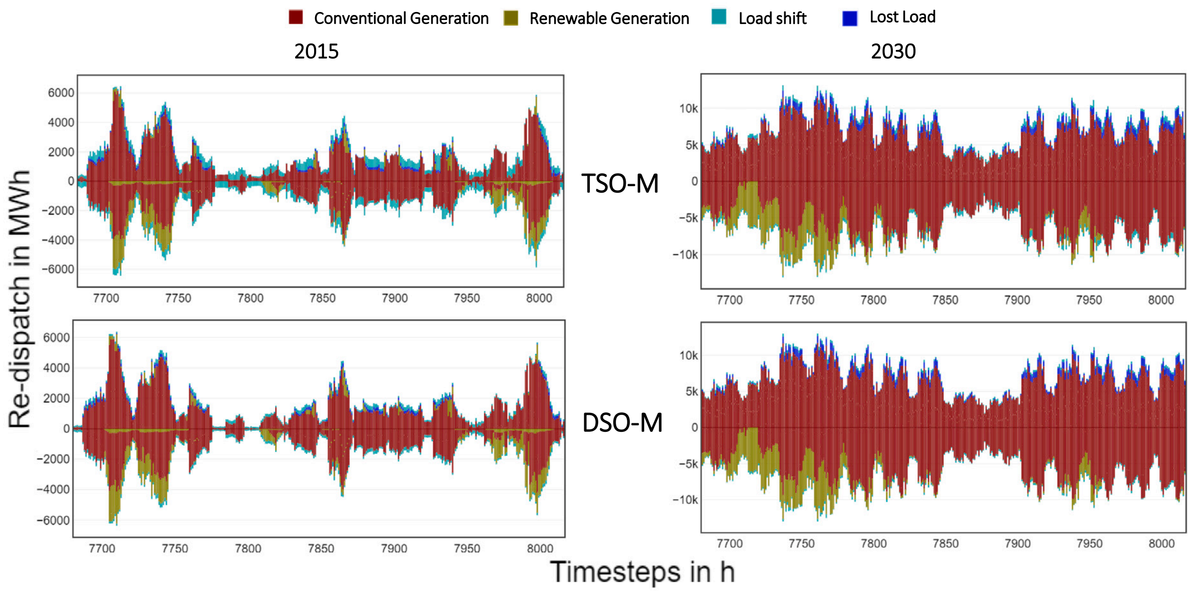

Fig. 10. Re-dispatch volume over the two most expensive weeks for all cases in 2015 and 2030 with a quarter of the original load shifting capacity.

Table 6
Results over days 321–334 for one quarter the shifting capacity.

Indicator	BAU	TSO M	DSO M
2015			
Cost of re-dispatch [Million €]	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 [Million €]	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

power systems, causing increasing risks for congestion and, therefore, increasing re-dispatch cost 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, level of market entrance and, as mentioned, the type of considered DERs. Based on the different ideas, diverse modelling concepts emerged. The concepts perceived as the most promising ones consider an active DSO and a decentralized coordination. Most considered concepts aim to minimize the system cost and therefore chose 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 DA 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 in 2030. However, at a reduction in necessary re-dispatch volume of −11.5% and −3.6% (2015 and 2030), the centralized framework TSO-M aiming for the system welfare yielded more efficient results than the more realistic DSO-M case (−0.5% and −0.9%, respectively) 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 full 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 research area is the development and definition of new marketplaces for DSO side flexibility, i.e., participation in the intra-day market.

CRediT authorship contribution statement

Simon Pearson: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data curation, Writing – original draft, Writing – review & editing. **Sonja Wellnitz:** Conceptualization, Methodology, Validation, Formal analysis, Investigation, Data curation, Writing – original draft, Writing – review & editing, Visualization. **Pedro Crespo del Granado:** Conceptualization, Methodology, Resources, Writing – review & editing, Supervision, Project administration, Funding acquisition. **Naser Hashemipour:** Conceptualization, Methodology, Software, Resources, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

This research has been performed based on open-access data. The model is available in Github under the MIT licence at: https://github.com/simonpea/tsodso_der.

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Most frequent abbreviations

BAU	Business As Usual
CM	Congestion Management
DA	Day Ahead
DER	Distributed Energy Resource
DSO-M	DSO managed
ED	Economic Dispatch
RES	Renewable Energy Sources
TRM	Transmission Reliability Margin
TSO-M	TSO managed
VOLL	Value of Lost Load

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