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TSO-DSO interface flow pricing: A bilevel study on efficiency and cost allocation

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ABSTRACT

In the context of increasing distributed flexibility, enhanced TSO-DSO coordination is needed when procuring and activating flexibility. The literature shows that pricing the changes in the power flow over the TSO-DSO interfacing substation leads to optimal flexibility procurement cost in sequential TSO-DSO flexibility markets. This paper proposes a bilevel model, considering a TSO leader which sets interface flow prices freely, and DSO-followers in a Stackelberg game. This game-theoretical approach allows for the identification of regulatory risks and the testing of regulatory mechanisms. Based on two case studies, results show that, if left unregulated, the strategic TSO creates significant cost allocation distortions, creating unwanted financial transfers from DSOs to the TSO. However, when acting strategically, the TSO also activates (or leads to the activation of) economical flexibility providers, having as a reference the first-best option, namely the Common Coordination Scheme (CS). Leveraging on these results, a cap and floor mechanism is proposed, limiting unwanted cost allocation distortions and retaining incentives for efficient flexibility activations. Results showcase that a Fragmented CS with regulated interface flow prices could be an efficient second-best compared to the Common CS, outperforming other regulatory options found in the literature.

1. Introduction

The current efforts to decarbonise power systems and make them more efficient and affordable are reshaping the way consumers, producers, and utilities manage their activities [1,2]. Distribution System Operators (DSOs) are being called to actively manage their grids and, as a result, different flexibility markets and mechanisms are being tested and deployed [3,4]. Distributed Energy Resources (DERs) are also expected to participate in markets run by Transmission System Operators (TSOs) such as balancing markets [5]. In this context, when all System Operators (SOs) may want to activate resources connected at the distribution grid, conflicts may arise. Therefore, enhanced coordination between TSOs and DSOs is needed in order to achieve secure and efficient integration of DERs into current and future markets [6–8].

In recent years, several Coordination Schemes (CSs) have been proposed in the literature in order to allow an enhanced and efficient TSO-DSO coordination. The CSs refer to the market design and activation arrangements for the usage of distributed flexibility by SOs. Several CSs have been proposed by the literature with various nomenclatures and design variations. Among the most recurrent CSs are the Common and disjoint or sequential market models [9]. In the former, the TSO or a third-party market operator is responsible for the joint procurement of flexibility to supply both TSO and DSO needs [10,11]. The latter refers to a market design in which TSO and DSO markets are split. A typical disjoint type of CS is the use of sequential markets, in which one SO clears its market first followed by the next SO. The Multi-Level CS is an example in which the DSO runs a Local Flexibility Market (LFM) and sends unused bids to the TSO [9,10,12]. The DSO could also calculate a flexibility region in terms P/Q and forward that information to the TSO after the LFM [13]. Alternatively, the TSO could calculate the security margins and requesting P/Q setpoints from the DSO [14]. The Fragmented CS is a variation in which each SO can only activate resources connected to their grids, usually maintaining the forecasted power flow at the interfacing substations (e.g. results from a Day-Ahead market).

Both Common and disjoint approaches, however, present advantages and challenges from efficiency and implementation points of view [15]. From a purely techno-economic perspective, the Common CS is the most efficient one. Marques et al. [9] prove that the Common CS will always lead to the least cost of flexibility procurement. The fact that only one optimisation problem is solved taking into account all variables at the same time leads to the most efficient solution. Nevertheless, from an implementation point of view, the Common CS may present additional challenges with respect to other CSs.

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Nomenclature

Indexes

$i, j, ii \in N$	Bus.
$k \in K$	Flexibility Service Provider (FSP).
$s, s' \in S$	System Operator (SO).

Sets

$I^{DSO+}(i)$	Subset of buses i that belong to DSO or is an interface bus (substation).
$I^{DSO}(i)$	Subset of buses i that belong to a DSO s.
$I^{SUBS}(i)$	Subset of buses i that are an interface substation.
$I^{TSO+}(i)$	Subset of buses i that belong to TSO or is an interface bus (substation).
$I^{TSO}(i)$	Subset of buses i that belong to a TSO s.
$IF(i,k)$	Set of FSPs k connected at bus i.
$INTER(s,i,s')$	Set establishing that SO s is connected to SO s' through bus (substation) i.
$IS(i,s)$	Set of buses i belonging to System Operator s.
$K^{DSO}(k,s)$	Subset of FSPs k that are connected to a DSO s.
$K^{TSO}(k,s)$	Subset of FSPs k that are connected to a TSO s.
$L(i,j)$	Set of lines from bus i to bus j.
$S^D(s)$	Subset of SOs s that are DSOs.
$S^T(s)$	Subset of SOs s that are TSOs.
$SLACK^s(i,s)$	Subset of buses i denoting the slack bus for SO s (one slack bus per SO).

Parameters

θ^+/θ^-	Maximum/minimum phase angle θ. (radians)
Bid_k^{dw}	Bid of FSP k for downward activation in the flexibility market(s). (€/MWh)
Bid_k^{up}	Bid of FSP k for upward activation in the flexibility market(s). (€/MWh)
D_i^p	Active power demand at bus i. (MW)
D_i^q	Reactive power demand for bus i. (Mvar)
$DaDSO_s$	Aggregated demand for DSO s. (MW)
$DispatchDA_i$	Total generation cleared in the Day-Ahead market produced at bus i. (MW)
$DSOdemand_s$	Aggregated demand for DSO s at the interface substation. (MW)
$F_{i,j}^{p,+}/F_{i,j}^{p,-}$	Max./min. active power flow of line (i,j). (MW)
$F_{i,j}^{q,+}/F_{i,j}^{q,-}$	Max./min. reactive power flow of line (i,j). (Mvar)
$IntPrice_s^{+,-}$	Upper/lower limit for the interface price for SO s. (€/MWh)
$IntPrice_s$	Interface price for SO s (single level models). (€/MWh)
$LimitFactor^{cap,floor}$	Cap and floor factor for interface price. (p.u.)
M^n	Large enough parameter number n from Big-M implementation.
P_k^+/P_k^-	Maximum/minimum output of FSP k. (MW)
PF	Fixed power factor for all FSPs connected to distribution networks. (p.u.)
$R_{i,j}$	Resistance of line (i,j). (p.u.)
SB	Base Power. (MVA)
$V^{+,-}$	Maximum/minimum voltage limits. (p.u.)
$X_{i,j}$	Reactance of line (i,j). (p.u.)

Variables

$\bar{\mu}^n$	Dual variable of inequality constraint setting an upper bound on variable indicated by n. Indexes according to the constraint.
λ^{Dn}	Dual variable of equality constraint n belonging to the DSO lower level model. Indexes according to the constraint.
λ^{Tn}	Dual variable of equality constraint n belonging to the TSO lower level model. Indexes according to the constraint.
θ_i	Angle θ at bus i. (radians)
$\underline{\mu}^n$	Dual variable of inequality constraint setting a lower bound on variable indicated by n. Indexes according to the constraint.
b^n	Binary variable number n from Big-M implementation. Indexes according to the constraint.
$f_{i,j}^p$	Active power flow over line connecting buses i and j. (MW)
$f_{i,j}^q$	Reactive power flow over line (i,j). (Mvar)
$intprice_s$	Interface price for SO s (bilevel model). (€/MWh)
p_k^{dw}	Quantity of downward flexibility cleared for FSP k. (MW)
p_k^{up}	Quantity of upward flexibility cleared for FSP k. (MW)
q_k	Reactive power generated/consumed by FSP k (Mvar)
$slackQ_{i,j}$	Variable to accommodate the reactive power coming from the transmission network over line (i,j) (Mvar)
w_i	Square of the voltage in bus i. (p.u.)

The Common CS usually assumes that only one Market Operator (MO) exists, which has visibility over the flexibility market and the networks at the same time (both transmission and distribution). This MO could be an independent MO or one of the SOs, usually the TSO [16]. In this context, the SOs which are not the MO would need to transfer or exchange network information. This may represent both a challenge in terms of Information and Communications Technology (ICT) and data privacy [17].

On the one hand, centralising both transmission and distribution grid information for an Optimal Power Flow (OPF)-type of algorithm can be very complex, especially if the Medium-Voltage (MV) and Low-Voltage (LV) are to be represented. Li et al. [18] build a highly detailed synthetic transmission-distribution network located in central Texas, going from 120 V to 230 kV voltage levels. The resulting network includes 307 thousand customers and 1.6 million electric nodes. Li et al. [18] also acknowledge that very few tools are well suited for solving power flows on 1 million-bus networks or more. In the European context, in which one TSO usually operates the transmission of a whole country, having one single OPF, including all distribution and transmission voltage levels, seems unfeasible at the moment. On the other hand, data privacy is also a major concern for SOs, as both TSO and DSO network and customer data are partially or totally private.

In this context, several authors have tried to enable the implementation of a Common CS with reduced information exchange needs. The most common technique proposed is the use of decomposition algorithms. The decomposition algorithm allows for the separation of the optimisation problem into two or more problems, which are solved separately with the exchange of a few coupling variables in an iterative way until convergence towards optimality is achieved. The Alternating Direction Method of Multipliers (ADMM) has been used by several authors to implement the Common TSO-DSO decomposition [9,19–21]. Although the use of a distributed OPF could overcome the data privacy challenge, other data-exchange related issues may still exist. Rodriguez Perez et al. [22] conducted an analysis of the different ICT architectures for TSO-DSO data exchange in Europe and concluded that the implementation of the decentralised Common TSO-DSO market model is considered to be the most challenging from an ICT point of view, requiring seamless real-time synchronisation of different market platforms or processes.

The alternative to overcome data privacy and some ICT issues is the adoption of a sequential or hierarchical CS. Therefore, the Multi-level CS would allow for the TSO and the DSO to access and use distributed flexibility for both local and central needs, such as the Common CS. However, a typical sequential implementation in which a system-agnostic DSO runs an LFM and forward unused bids is proven to lead to a higher cost of flexibility procurement [12,23].

An important source of inefficiencies in disjoint CSs (e.g. Multi-level, Fragmented) is the rebalancing problem. When a DSO has a congestion to solve (e.g. overload), it will most probably procure upward[1] flexibility downstream of the congested element (assuming a radial topology). From a system perspective, this activation leads to an imbalance with respect to original dispatch (e.g. wholesale market results). In a typical Multi-level CS, the DSO may not have an incentive to carry further activation (e.g. downward flexibility upstream of the congested element) to rebalance the system. In fact, this is a market design already in place. The PICLO platform implemented in the United Kingdom (UK), for instance, might procure upward flexibility downstream of the transformer to solve the congestion. Following this procurement, the TSO is only informed about the activation [24]. In a Fragmented CS in which schedule power flow over the interface has to be maintained, on the other hand, the DSO has the obligation to rebalance the system no matter the cost. These two extremes bring inefficiencies, as the most efficient solution may lay in between (e.g. some rebalance activations taking place at the transmission grid and some at the distributions). Moreover, not only does an efficiency detriment arise with respect to a Common CS, but also a cost-allocation issue (e.g. in a Multi-level, the TSO pays to rebalance the system due to a congestion in the distribution network).

In this context, Marques et al. [9] argue that the economic efficiency of the Multi-Level CS can be improved if the variation in the power flow over the interfacing substation is priced properly. In fact, it is proven that if the variation over the power flow is priced optimally, the Multi-level and Fragmented CSs can lead to the same result as the Common CS. In order to compute the interface power flow price, first the authors compute a "virtual" Common CS, and then the Multi-level. Although illustrative, this method is not practical. Therefore, the same authors propose the implementation of a bilevel model with decomposition of the optimisation problem. This allows for the practical implementation of the Multi-level CS in which both SOs have independent markets. Nevertheless, this leads to the same challenges as the distributed Common CS implementation, namely, (i) both markets have to be cleared simultaneously (so the convergence of prices at the interface can be achieved), and (ii) the ICT requirements are higher, as the near real-time information exchange has to take place.

[1] Upward flexibility is here understood as the increase of generation or, equivalently the reduction in consumption. Downward flexibility being the opposite.

This paper proposes an analysis of the situation in which a TSO could set the interface price freely, independent from a "virtual Common CS run" or a decomposed TSO-DSO architecture. It is also assumed that the TSO can act strategically, which might not be entirely realistic, considering that the TSO is a regulated company [25]. However, it allows the research on incentives and regulatory risks, as well as to proposition and testing of eventual regulation.

In the context of conflicting interests between the TSO and DSO, game theory can help identify the dynamics created by each rational player trying to maximise their payoff in anticipation of the actions of other player. Xie et al. [26], for instance, proposes TSO-DSO Nash equilibrium model in the context of wholesale energy trading. Sheikhahmadi et al. [27] proposes a bilevel TSO-DSO model also for wholesale energy markets. Chen et al. [28] more specifically studies the clearing of a local integrated heat and electricity market and a TSO-operated wholesale energy market in a bilevel formulation. These studies, however, focus mostly on coordination for wholesale energy trading, something less applicable in the European context.

In this paper a bilevel optimisation model is introduced, modelling a Stackelberg game in which the TSO sets the interface price first, followed by the DSO's LFM and the TSO Congestion Management markets in a Fragmented CS. The objective of the present study is two-fold. On the one hand, it points out scenarios in which regulatory supervision might be important, considering the asymmetry of information that might exist between a TSO setting interface prices and the regulator. On the other hand, the bilevel model proposed offers an opportunity to test different regulatory mechanisms such as interface price caps and floors, limiting the potential for strategic behaviour by the TSO and offering a quantifiable and implementable second-best to the Common CS.

Two key aspects are analysed when gauging the efficiency of regulatory options. On the one hand, the total cost of procuring flexibility is compared to the Common CS, which leads, by definition, to the least total cost [9]. On the other hand, the cost allocation between TSO and DSO is analysed, comparing it with the Fragmented with optimal interface flow pricing.

Therefore, the main contributions of this paper are:

- The development of a novel bilevel optimisation model to study the behaviours at pricing the TSO-DSO interface.
- The identification of regulatory risks in interface-pricing practice.
- The testing of regulatory mechanisms for efficient limitation of strategic behaviour and comparable efficiency and cost allocation with respect to the Common CS and the Fragmented CS optimally priced.

The remainder of the paper is structured as follows. Section 2 describes the methodology and presents the optimisation models proposed and Section 3 presents the case studies used in this paper and their results. Section 4 discusses the policy and regulatory implications. Finally, Section 5 concludes.

2. Assumptions and methodology

In this paper, we analyse flexibility markets for both the TSO and DSO in a Fragmented CS fashion. This means that the TSO and DSO can use resources connected to their grids only to solve congestions in the network. Congestions are here considered primarily overloads of the network elements. The choice for considering only the Fragmented CS and the product service congestion management is to keep the model and analysis tractable. It is also a typical CS in the academic and as well as real-world implementations [7]. A Common CS implementation, however, is also modelled and used to provide a baseline for optimal flexibility procurement. Additionally, the analysis could be easily expanded to include other disjoint CSs, such as the Multi-level, in which unused bids by the DSO are forwarded to the TSO. In fact, Marques et al. [9] show that the optimal pricing of the substation leads to optimal flexibility procurement in both the Fragmented and Multi-level CSs.

The market sequence modelled in this paper aims to represent a typical European market structure. Wholesale energy markets determine the nominations without considering network constraints.[2] The results of the wholesale energy markets are then passed on to the TSO for feasibility and security verification [29]. Considering the future existence of LFMs, we assume that DSOs will use LFMs in a similar way that TSO today check for network feasibility and apply remedial actions. TSOs in Europe may use several mechanisms to solve internal congestions, such as mandatory redispatch, counter trading or organised congestion management markets [30]. In this paper, we focus on the latter, as implemented in Spain [31].

In order to keep the analysis tractable, we only consider the procurement of flexibility in terms of active power. As a result, congestions are limited to overloads in this paper. Voltage violations and respective services are not considered in this research considering that additional market algorithms could be required, such as reactive power markets [32].

Following the Congestion Management markets, balancing markets would take place in a typical European market sequence [29]. These markets, however, are omitted from the model in this paper, as is the wholesale energy market. An implementation of the full market sequence including a Day-ahead, congestion management and balancing services in several TSO-DSO CSs can be seen in [33].

2.1. Sequential optimisation

The Fragmented CS with interface flow pricing, in this sequential form, is characterised by an LFM run by the DSO followed by a congestion management market run by the TSO. After the LFM, the DSO informs of possible changes in the interface power flow with respect to the original schedule and pays the TSO for the difference in the power flow at the substation, as this difference will have to be rebalanced by the TSO. Different ways of setting this substation price are discussed in the following sections.

2.1.1. DSO's local flexibility market

The LFM formulation in its sequential single-level form is presented in (1). In this model, the DSO minimises their flexibility procurement cost plus the cost for the change in the substation power flow in (1a). Nodal power balance equations for both active and reactive power are presented in (1b) and (1e), respectively. Eq. (1c) computes the final active power flow at the TSO-DSO interfacing substation. Reactive power demand is assumed to be based on a fixed power factor, calculated in (1h). The reactive power flow over the interfacing substation is given by (1f). Eq. (1g) computes active and reactive power flows as well as the square of voltages w_i, while (1d) sets the reference bus.

For the computation of power flows, the choice of an AC OPF relaxation is needed [34]. Therefore, the constraint (1g) is based on a *LinDistFlow* OPF [35]. The *LinDistFlow* is a lossless linear power flow formulation for radial networks capable of accounting for both active and reactive power as well as voltage magnitudes, providing a more precise representation of distribution networks when compared with a DC OPF while maintaining the flexibility of a linear program. Linearity is a desirable feature in this model as it will be later converted in the Karush–Kuhn–Tucker (KKT) conditions. For this reason, the more precise *DistFlow* algorithm is not used.

Moreover, being an OPF-based market algorithm, this formulation also provides Distribution Locational Marginal Prices (DLMPs), given by the dual variable $\lambda^{D1}_{i,s}$ of the power balance constraint (1b). The LFM formulation in this paper is similar to the one proposed in [36].

Eqs. (1i)–(1r) set the upper and lower limits for up and downward flexibility activation, active and reactive power flow, and voltage magnitudes.

$$\min \sum_{s\in S^D,k\in K^{DSO}} \left[\left(Bid^{up}_k \cdot p^{up}_k\right) + \left(Bid^{dw}_k \cdot p^{dw}_k\right)\right] + \sum_{s\in S^D,k\in K^{DSO}} (p^{up}_k - p^{dw}_k)\cdot IntPrice_s \tag{1a}$$

s.t.

$$DispatchDA_i + \sum_{k\in IF} p^{up}_k - \sum_{k\in IF} p^{dw}_k - \sum_j f^p_{i,j} + \sum_j f^p_{j,i} - D^p_i = 0 \quad : \lambda^{D1}_{i,s} \quad \forall i\in I^{DSO}, s\in S^D \tag{1b}$$

$$f^p_{i,j\in I^{SUBS}} + DaDSO_s - \sum_{s\in S^D,i,k} (p^{up}_k - p^{dw}_k) = 0 \quad : \lambda^{D2}_{i,j,s} \quad \forall (i,j)\in L, i\in IS, s\in S^D \tag{1c}$$

$$w_i - 1 = 0 \quad : \lambda^{D3}_{s,i} \quad \forall s\in S^D, i\in SLACK^s \tag{1d}$$

$$+\sum_{k\in IF} q_k - \sum_j f^q_{i,j} + \sum_j f^q_{j,i} - D^q_i = 0 \quad : \lambda^{D4}_{i,s} \quad \forall i\in IS, s\in S^D \tag{1e}$$

$$f^q_{i,j} - slackQ_{i,j} = 0 \quad : \lambda^{D5}_{i,j,s} \quad \forall (i,j)\in L, i\in IS, j\in I^{SUBS}, s\in S^D \tag{1f}$$

$$w_i - w_j - 2\cdot(R_{i,j}\cdot f^p_{i,j} + X_{i,j}\cdot f^q_{i,j}) = 0 \quad : \lambda^{D6}_{i,j,s} \quad \forall (i,j)\in L, i\in IS, s\in S^D \tag{1g}$$

$$q_k - \tan(\arccos(PF)) * (p^{up}_k - p^{dw}_k) = 0 \quad : \lambda^{D7}_{k,i,s} \quad \forall k\in K^{DSO} \tag{1h}$$

$$p^{up}_k - P^+_k \le 0 \quad : \bar{\mu}^{up}_k \quad \forall k\in K^{DSO} \tag{1i}$$

$$-p^{up}_k \le 0 \quad : \underline{\mu}^{up}_k \quad \forall k\in K^{DSO} \tag{1j}$$

$$p^{dw}_k - P^-_k \le 0 \quad : \bar{\mu}^{dw}_k \quad \forall k\in K^{DSO} \tag{1k}$$

$$-p^{dw}_k \le 0 \quad : \underline{\mu}^{dw}_k \quad \forall k\in K^{DSO} \tag{1l}$$

$$f^p_{i,j} - F^{p,+}_{i,j} \le 0 \quad : \bar{\mu}^p_{i,j} \quad \forall (i,j)\in L, i\in I^{DSO} \tag{1m}$$

$$F^{p,-}_{i,j} - f^p_{i,j} \le 0 \quad : \underline{\mu}^p_{i,j} \quad \forall (i,j)\in L, i\in I^{DSO} \tag{1n}$$

$$f^q_{i,j} - F^{q,+}_{i,j} \le 0 \quad : \bar{\mu}^q_{i,j} \quad \forall (i,j)\in L, i\in I^{DSO} \tag{1o}$$

$$F^{q,-}_{i,j} - f^q_{i,j} \le 0 \quad : \underline{\mu}^q_{i,j} \quad \forall (i,j)\in L, i\in I^{DSO} \tag{1p}$$

$$w_i - (V^+)^2 \le 0 \quad : \bar{\mu}^V_i \quad \forall i\in I^{DSO+} \tag{1q}$$

$$(V^-)^2 - w_i \le 0 \quad : \underline{\mu}^V_i \quad \forall i\in I^{DSO+} \tag{1r}$$

2.1.2. TSO's congestion management

The TSO's congestion management model is a redispatch market based on a DC OPF. The DC OPF formulation is chosen given the meshed topology and low estimation error for the voltage levels at the transmission grid, considering the high X/R ratio [37]. The TSO's objective function consists of minimising flexibility activation at the transmission grid minus the transfers received from the DSOs for imbalances after their LFMs (2a). Eqs. (2b) and (2c) calculate the active power flow to be delivered by the TSO at the interfacing substation considering the summation of nodal demands D^p_i, generation $DispatchDA_i$ and flexibility activations from the LFMs $p^{up,*}_k$ and $p^{dw,*}_k$. The nodal

[2] In Europe, cross-bidding zone congestions are considered, but not intra-bidding zones. For the sake of simplicity, only one TSO is considered, which in most European countries is limited to solving congestion in a single bidding zone.

power balance constraint and the DC OPF restrictions are included in (2d)–(2f). Locational marginal prices are given by the dual variable $\lambda^{T3}_{i,s}$. Eqs. (2g)–(2n) set the upper and lower limits for upward and downward flexibility activation, active power flow, and voltage angles.

$$\min \sum_{s\in S^T, k\in K^{TSO}} \left[\left(Bid^{up}_k \cdot p^{up}_k \right) + \left(Bid^{dw}_k \cdot p^{dw}_k \right) \right] - \sum_{s\in S^D, k\in K^{DSO}} (p^{up,*}_k - p^{dw,*}_k) \cdot IntPrice_s \tag{2a}$$

s.t.

$$f^p_{i,j} - DSOdemand_{s'} = 0 \quad : \lambda^{T1}_{i,j,s,s'} \quad \forall (i,j) \in L, \; i \in I^{TSO}, j \in I^{SUBS}, s \in S^T, (s,j,s') \in INTER \tag{2b}$$

$$-\sum_{i\in I^{DSO}} DispatchDA_i - \sum_{k\in K^{DSO}} p^{up,*}_k + \sum_{k\in K^{DSO}} p^{dw,*}_k + \sum_{i\in I^{DSO}} D^p_i - DSOdemand_s = 0 \quad : \lambda^{T2}_s \quad \forall s \in S^D \tag{2c}$$

$$DispatchDA_i + \sum_{k\in IF} p^{up}_k - \sum_{k\in IF} p^{dw}_k - \sum_j f^p_{i,j} + \sum_j f^p_{j,i} - D^p_i = 0 \quad : \lambda^{T3}_{i,s} \quad \forall i \in IS, s \in S^T \tag{2d}$$

$$f_{i,j} - SB \cdot \frac{\theta_i - \theta_j}{X_{i,j}} = 0 \quad : \lambda^{T4}_{i,j,s} \quad \forall (i,j) \in L, i \in I^{TSO}, s \in S^T \tag{2e}$$

$$\theta_i = 0 \quad : \lambda^{T5}_{s,i} \quad \forall s \in S^T, i \in SLACK^s \tag{2f}$$

$$p^{up}_k - P^+_k \le 0 \quad : \bar{\mu}^{up}_k \quad \forall k \in K^{TSO} \tag{2g}$$

$$-p^{up}_k \le 0 \quad : \underline{\mu}^{up}_k \quad \forall k \in K^{TSO} \tag{2h}$$

$$p^{dw}_k - P^-_k \le 0 \quad : \bar{\mu}^{dw}_k \quad \forall k \in K^{TSO} \tag{2i}$$

$$-p^{dw}_k \le 0 \quad : \underline{\mu}^{dw}_k \quad \forall k \in K^{TSO} \tag{2j}$$

$$f^p_{i,j} - F^{p,+}_{i,j} \le 0 \quad : \bar{\mu}^p_{i,j} \quad \forall (i,j) \in L, i \in I^{TSO} \tag{2k}$$

$$F^{p,-}_{i,j} - f^p_{i,j} \le 0 \quad : \underline{\mu}^p_{i,j} \quad \forall (i,j) \in L, i \in I^{TSO} \tag{2l}$$

$$\theta_i - \theta^+ \le 0 \quad : \bar{\mu}^\theta_i \quad \forall i \in I^{TSO+} \tag{2m}$$

$$\theta^- - \theta_i \le 0 \quad : \underline{\mu}^\theta_i \quad \forall i \in I^{TSO+} \tag{2n}$$

2.2. Bilevel model

In order to evaluate the potential strategic behaviours of interface price setting and applicable policies, a bilevel model is derived from the single-level linear programs above. A bilevel model can represent a Stackelberg game, in which a leader (upper level) plays first announcing his strategy, followed by a follower that reacts to the leader's first move [38]. In the proposed model, the TSO sets the interface price first. The choice for the TSO to be the interface price setter is not arbitrary. First, the TSO is the SO that has visibility over all the interfaces with DSOs and, therefore, is the actor with more information to gauge a systemic cost of rebalancing. Second, it is sensible to assume that the TSO publishes the interface prices first so that DSOs have transparency to choose between rebalancing their LFMs or paying the imbalances to the TSO. A similar mechanism is in place in Sweden, in which the TSO sets the price for surpassing a virtual power flow limit at the interface, called subscription cost [39].

Therefore, in this bilevel implementation, we assume the TSO moves first by setting the price for the change of interface flows. According to this game-theoretical approach, the TSO will set the interface price in anticipation of what the reactions of DSOs will be. This, of course, assumes that the TSO has perfect information over DSOs' market, which is not expected to be the case. Nevertheless, considering that we model a one-shot game, the assumption of perfect information can be seen as the result of a repetitive game in which the TSO learns the characteristics of the DSOs' markets, considering that LFMs are expected to be relatively stable and predictable.

Fig. 1 illustrates the overall structure of the bilevel model proposed. The upper level determines the interface prices, which are then passed on to the DSOs at the lower level. After the LFM, the TSO solves the final congestion management market. While the interface prices are sent from the upper level to the DSO's lower level, the quantity imbalanced is passed from the lower level to the upper level. Similarly, the DSO's lower level informs the flexibility activated for the computation of the final substation power flow, as described in single-level implementation. Finally, the lower level of the TSO also shares to the upper level the flexibility activated on the transmission grid. The TSO's congestion management market is modelled as a second lower level to represent the market sequence proposed.

While Fig. 1 highlights the bilevel structure and exchange of variables between models. This type of bilevel formulation containing one upper level and multiple lower levels can be solved as a single optimisation problem by transforming the lower levels into their KKT conditions [40]. In addition, linearisation of complementarity conditions and other bilinear terms may also be required [41,42]. Following these procedures, the formulations for upper and lower levels presented below are solved as a single Mixed Integer Linear Programming (MILP), as described below. The model is implemented in General Algebraic Modeling System (GAMS) language and its source code is publicly available in [43].

2.2.1. Upper level

The upper level's objective function is very similar to (2a), in which the TSO minimises the activation cost while maximising the revenues from the interfacing substation.

Maximising revenues goes, in principle, against common utilities regulation, as TSOs are regulated companies. However, allowing for the TSO to maximise interface revenues could be seen as part of a dedicated incentive, as discussed in more details in Section 4. For the general implementation of this bilevel model, and for the purpose of studying the properties of strategic behaviour, the only restriction for the upper level is a cap for the interface price (3b). This cap is a large enough value to avoid having an unbounded problem, and is set at 1000 €/MWh in the case studies of this paper. More realistic regulatory mechanisms for limiting or defining the interface prices are presented in Section 3.4.

The difference with respect to model (2) is the interface price $intprice_s$ is the decision variable of the upper level, while it was a parameter at the single level. In addition, the flexibility procurement is passed on from the lower to the upper level.

Moreover, one may notice that the objective function of the upper level contains the bi-linear term $(p^{up}_k - p^{dw}_k) \cdot intprice_s$. This term is linearised by the use of the Strong Duality Theorem [40,44]. This linearisation procedure is presented in Appendix A.

$$\min \sum_{s\in S^T, k\in K^{TSO}} \left[\left(Bid^{up}_k \cdot p^{up}_k \right) + \left(Bid^{dw}_k \cdot p^{dw}_k \right) \right] - \sum_{s\in S^D, k\in K^{DSO}} (p^{up}_k - p^{dw}_k) \cdot intprice_s \tag{3a}$$

s.t.

$$0 \le intprice_s \le IntPrice^+_s \tag{3b}$$

2.2.2. Lower level: DSO's LFM

The lower level of the DSO's LFM is converted to the KKT conditions, resulting in the set of restrictions presented in (4). It is also wroth mentioning that the complementarity conditions of the KKTs (4i)–(4r) are linearised by the employment of the Big-M technique, allowing the final model to be solved as a MILP. This linearisation of the complementarity conditions is presented in Appendix B.

(1b), (1c), (1d), (1e), (1f), (1g), (1h), (4a)

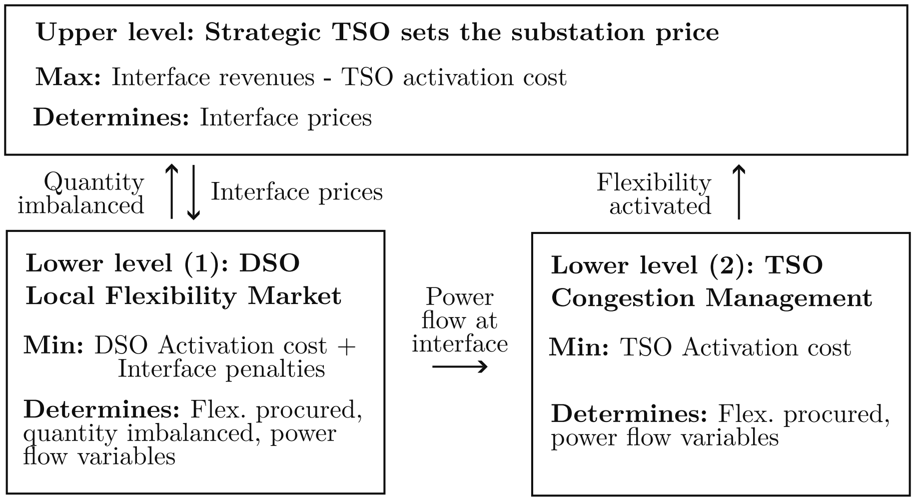

Fig. 1. TSO-DSO bilevel model structure.

$$Bid_k^{up} + \sum_{s\in S^D} intprice_s + \sum_{i\in I^{DSO},s\in S^D} \lambda^{D1}_{i,s} + \sum_{i\in I^{DSO},j,s\in S^D} \lambda^{D2}_{i,j,s} - \sum_{s\in S^D} \lambda^{D7}_{k,s}\cdot \tan(\arccos(PF)) + \bar{\mu}^{up}_k - \underline{\mu}^{up}_k = 0 \quad \forall k \in K^{DSO} \tag{4b}$$

$$Bid_k^{dw} - \sum_{s\in S^D} intprice_s - \sum_{i\in I^{DSO},s\in S^D} \lambda^{D1}_{i,s} - \sum_{i\in I^{DSO},j,s\in S^D} \lambda^{D2}_{i,j,s} + \sum_{s\in S^D} \lambda^{D7}_{k,s}\cdot \tan(\arccos(PF)) + \bar{\mu}^{dw}_k - \underline{\mu}^{dw}_k = 0 \quad \forall k \in K^{DSO} \tag{4c}$$

$$\sum_{i,s\in S^D} \lambda^{D4}_{i,s} + \sum_{s\in S^D} \lambda^{D7}_{k,s} + \bar{\mu}^{q}_k - \underline{\mu}^{q}_k = 0 \quad \forall k \in K^{DSO} \tag{4d}$$

$$-\sum_{s\in S^D} \lambda^{D1}_{i,s} + \sum_{s\in S^D} \lambda^{D1}_{j,s} + \sum_{s\in S^D} \lambda^{D2}_{i,j,s} - \sum_{s\in S^D} [2\cdot \lambda^{D6}_{i,j,s}\cdot R_{i,j}] + \bar{\mu}^{p}_{i,j} - \underline{\mu}^{p}_{i,j} = 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4e}$$

$$-\sum_{s\in S^D} \lambda^{D4}_{i,s} + \sum_{s\in S^D} \lambda^{D4}_{j,s} + \sum_{s\in S^D} \lambda^{D5}_{i,j,s} - \sum_{s\in S^D} [2\cdot \lambda^{D6}_{i,j,s}\cdot X_{i,j}] + \bar{\mu}^{q}_{i,j} - \underline{\mu}^{q}_{i,j} = 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4f}$$

$$+\sum_{s\in S^D} \lambda^{D3}_{s,i\in SLACK^s} + \sum_{s\in S^D,j} \lambda^{D6}_{i,j,s} - \sum_{s\in S^D,j} \lambda^{D6}_{j,i,s} + \bar{\mu}^{V}_{i} - \underline{\mu}^{V}_{i} = 0 \quad \forall i\in I^{DSO} \tag{4g}$$

$$-\sum_{s\in S^D} \lambda^{D5}_{i,j,s} = 0 \quad \forall (i,j)\in L, i\in I^{DSO}, j\in I^{SUBS} \tag{4h}$$

$$0 \le -p^{up}_k + P^+_k \perp \bar{\mu}^{up}_k \ge 0 \quad \forall k\in K^{DSO} \tag{4i}$$

$$0 \le p^{up}_k \perp \underline{\mu}^{up}_k \ge 0 \quad \forall k\in K^{DSO} \tag{4j}$$

$$0 \le -p^{dw}_k + P^-_k \perp \bar{\mu}^{dw}_k \ge 0 \quad \forall k\in K^{DSO} \tag{4k}$$

$$0 \le p^{dw}_k \perp \underline{\mu}^{dw}_k \ge 0 \quad \forall k\in K^{DSO} \tag{4l}$$

$$0 \le -f^p_{i,j} + F^{p,+}_{i,j} \perp \bar{\mu}^{p}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4m}$$

$$0 \le -F^{p,-}_{i,j} + f^p_{i,j} \perp \underline{\mu}^{p}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4n}$$

$$0 \le -f^q_{i,j} + F^{q,+}_{i,j} \perp \bar{\mu}^{q}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4o}$$

$$0 \le -F^{q,-}_{i,j} + f^q_{i,j} \perp \underline{\mu}^{q}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{DSO} \tag{4p}$$

$$0 \le -w_i + (V^+)^2 \perp \bar{\mu}^{V}_{i} \ge 0 \quad \forall i\in I^{DSO+} \tag{4q}$$

$$0 \le -(V^-)^2 + w_i \perp \underline{\mu}^{V}_{i} \ge 0 \quad \forall i\in I^{DSO+} \tag{4r}$$

2.2.3. Lower level: TSO's congestion management

The lower level of the TSO's Congestion Management market is also converted to the KKT conditions presented below. For the final MILP implementation, complementarity conditions are also linearised and presented in Appendix B.

$$(2b), (2c), (2d), (2e), (2f), \tag{5a}$$

$$Bid_k^{up} + \sum_{i\in I^{TSO},s\in S^T} \lambda^{T3}_{i,s} + \bar{\mu}^{up}_k - \underline{\mu}^{up}_k = 0 \quad \forall k\in K^{TSO} \tag{5b}$$

$$Bid_k^{dw} - \sum_{i\in I^{TSO},s\in S^T} \lambda^{T3}_{i,s} + \bar{\mu}^{dw}_k - \underline{\mu}^{dw}_k = 0 \quad \forall k\in K^{TSO} \tag{5c}$$

$$-\sum_{s\in S^T} \lambda^{T3}_{i,s} + \sum_{s\in S^T} \lambda^{T3}_{j,s} + \sum_{s\in S^T,s'\in S^D} \lambda^{T1}_{i,j,s,s'} + \sum_{s\in S^T} \lambda^{T4}_{i,j,s} + \bar{\mu}^{p}_{i,j} - \underline{\mu}^{p}_{i,j} = 0 \quad \forall (i,j)\in L, i\in I^{TSO} \tag{5d}$$

$$-\sum_{s\in S^T,j\in L(i,j)} \frac{SB}{X_{i,j}}\cdot \lambda^{T4}_{i,j,s} + \sum_{s\in S^T,j\in L(j,i)} \frac{SB}{X_{j,i}}\cdot \lambda^{T4}_{j,i,s} + \lambda^{T5}_{s\in S^T,i\in SLACK^s} + \bar{\mu}^{\theta}_{i} - \underline{\mu}^{\theta}_{i} = 0 \quad \forall i\in I^{TSO+} \tag{5e}$$

$$\sum_{s\in S^T,i\in I^{DSO},j} \lambda^{T1}_{i,j,s,s'} - \lambda^{T2}_{s'} = 0 \quad \forall s'\in S^D \tag{5f}$$

$$0 \le -p^{up}_k + P^+_k \perp \bar{\mu}^{up}_k \ge 0 \quad \forall k\in K^{TSO} \tag{5g}$$

$$0 \le p^{up}_k \perp \underline{\mu}^{up}_k \ge 0 \quad \forall k\in K^{TSO} \tag{5h}$$

$$0 \le -p^{dw}_k + P^-_k \perp \bar{\mu}^{dw}_k \ge 0 \quad \forall k\in K^{TSO} \tag{5i}$$

$$0 \le p^{dw}_k \perp \underline{\mu}^{dw}_k \ge 0 \quad \forall k\in K^{TSO} \tag{5j}$$

$$0 \le -f^p_{i,j} + F^{p,+}_{i,j} \perp \bar{\mu}^{p}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{TSO} \tag{5k}$$

$$0 \le -F^{p,-}_{i,j} + f^p_{i,j} \perp \underline{\mu}^{p}_{i,j} \ge 0 \quad \forall (i,j)\in L, i\in I^{TSO} \tag{5l}$$

$$0 \le -\theta_i + \theta^+ \perp \bar{\mu}^{\theta}_{i} \ge 0 \quad \forall i\in I^{TSO+} \tag{5m}$$

$$0 \le -\theta^- + \theta_i \perp \underline{\mu}^{\theta}_{i} \ge 0 \quad \forall i\in I^{TSO+} \tag{5n}$$

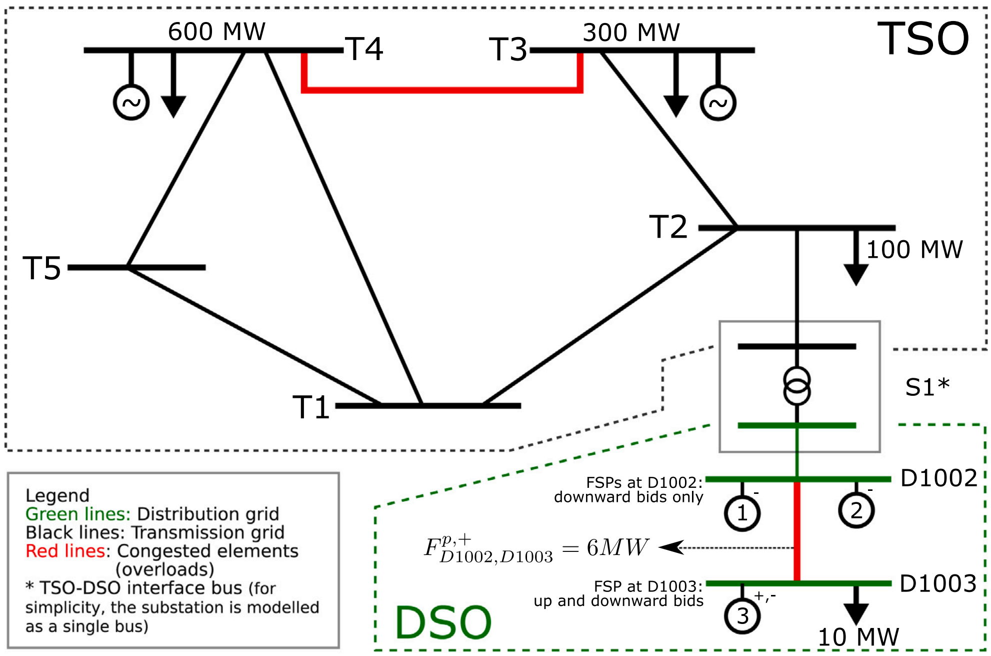

Fig. 2. Stylised case study — network diagram.

Table 1
FSP bids in stylised case study.

FSP	Busbar	Upward bid		Downward bid	
		MW	€/MWh	MW	€/MWh
G3	T3	500	50	500	50
G4	T4	300	20	300	20
FSP 1	D1002	0	10	2	10
FSP 2	D1002	0	30	2	30
FSP 3	D1003	5	60	5	60

3. Case studies

Two case studies are used in this paper to apply the proposed formulation and study strategic behaviours in interface price setting. First, a stylised model with 5 buses on the transmission grid and 2 buses on the distribution network is presented. This model is used primarily to highlight the mechanics in the interface price setting. Second, a larger 102-bus case study is formulated. In this case study, four 18-bus distribution grids are connected to a 30-bus transmission grid. In this second case study, more advanced dynamics involving multiple DSOs can be observed.

3.1. Stylised case study

The transmission grid used in the stylised case study is the PJM 5-bus system [45]. Connected to bus T2, an interfacing substation and a 2-bus radial feeder distribution network are connected. Fig. 2 illustrates the network, indicating that lines T3-T4 and D1002-D1003 are congested. To solve the congestions, the DSO has at its disposal the Flexibility Service Providers (FSPs) 1 to 3, while the TSO has generators connected at buses T3 and T4. The bids offered by each flexibility provider in both upward and downward directions are listed in Table 1.

From a simple analysis, it is clear that the only FSP capable of solving the congestion at line D1002-D1003 is the FSP 3, which is capable of providing upward and downward flexibility. The TSO, on the other hand, has to redispatch generators at T3 and T4 to solve the congestion at the transmission grid. The remaining flexibility activation is with regard to rebalancing the upward activation of FSP 3. Other 4 MW downward are necessary to rebalance the pre-LFM state. This could be done by either activating FSPs 1 and/or 2 at the distribution grid, or G4, considering network constraints.

The most economical way to rebalance the system is achieved by the run of a Common CS. This CS indicates that the 2 MW downward should be activated from FSP 1 and the remaining 2 MW as a redispatch between G3 and G4. On a relaxed Fragmented CS in which the interface price $IntPrice_s = 0$ and the scheduled power flow does not have to be maintained (typical implementation of current LFMs, e.g., PICLO platform), the DSO has no incentive to activate any upward flexibility. In that case, the rebalancing of the 4 MW is done with the flexibility from the transmission grid. The other extreme would be a Fragmented CS in which the expected power flow over S1 has to be preserved. In this scenario, the DSO has to rebalance the system using FSP 1 and 2, necessarily.

In between the unpriced Fragmented and the fixed interface power flow Fragmented CSs, different values for $IntPrice_s$ would lead to different costs for the system (total cost of flexibility procurement for both SOs) as well as different cost allocations. In fact, any interface price between 10 and 30 €/MWh would lead to the least cost of flexibility procurement in this simplified case study. It would incentivise the DSO to activate 2 MW downward from FSP 1 and leave the rest to be rebalanced by the TSO. The difference would be in the cost allocation between the TSO and DSO. Following [9], it is possible to verify which would the optimal interface price by checking the dual variable of the interface power flow constraint on the Common CS. In this case it is the equivalent of $\lambda^{T1}_{i,j,s,s'}$ in the (2b) of the Common CS, which is computed at 18.53 €/MWh. This value is not only a possible optimal solution in terms of total procurement cost but also leads to an optimal cost allocation, meaning the DSO pays to the TSO exactly the necessary for the rebalance to be completed. In other words, the cost for the TSO is the same as in the case of no congestions at the distribution network. Table 2 exemplifies this effect.

When running the bilevel model proposed in Section 2.2, the TSO strategically sets the interface price $intprice_s$ at 30 €/MWh. At this price, the DSO is indifferent at activating the FSP 2 or paying the TSO. Assuming that in this situation the DSO does pay to the TSO (e.g. lower transaction cost to pay the rebalance price than activating an FSP), the TSO would be extracting the highest profit possible. Fig. 3

Table 2
Costs for the TSO for the stylised case study and different interface prices.

		Costs for the TSO			
		No DSO Congestion		With DSO Congestion	
	Interface price	*NA*	*10*	*18.536*	*30*
	Activated Flexibility				
	Upward				
A	Energy (MWh)	211.59	209.79	210.69	210.69
B	Avg. Unit. Cost (€/MWh)	20.00	20.00	20.00	20.00
C	Total Cost Up. (AxB; €)	4,231.82	4,195.86	4,213.84	4,213.84
	Downward				
D	Energy (MWh)	211.59	213.79	212.69	212.69
E	Avg. Unit. Cost (€/MWh)	50.00	50.00	50.00	50.00
F	Total Cost Dw. (DxE; €)	10,579.55	10,689.66	10,634.61	10,634.61
	Interface Settlement				
G	Imbalanced Flexibility (A - D; MWh)	NA	−4.00	−2.00	−2.00
H	Interface Price (€/MWh)	NA	10.00	18.54	30.00
I	Imbalance payment (+) or Revenue (−) (GxH; €)	NA	−40.00	−37.07	−60.00
J	TSO Cost (+) or Profit (−) (C+F+I; €)	14,811.37	14,845.53	14,811.38	14,788.45

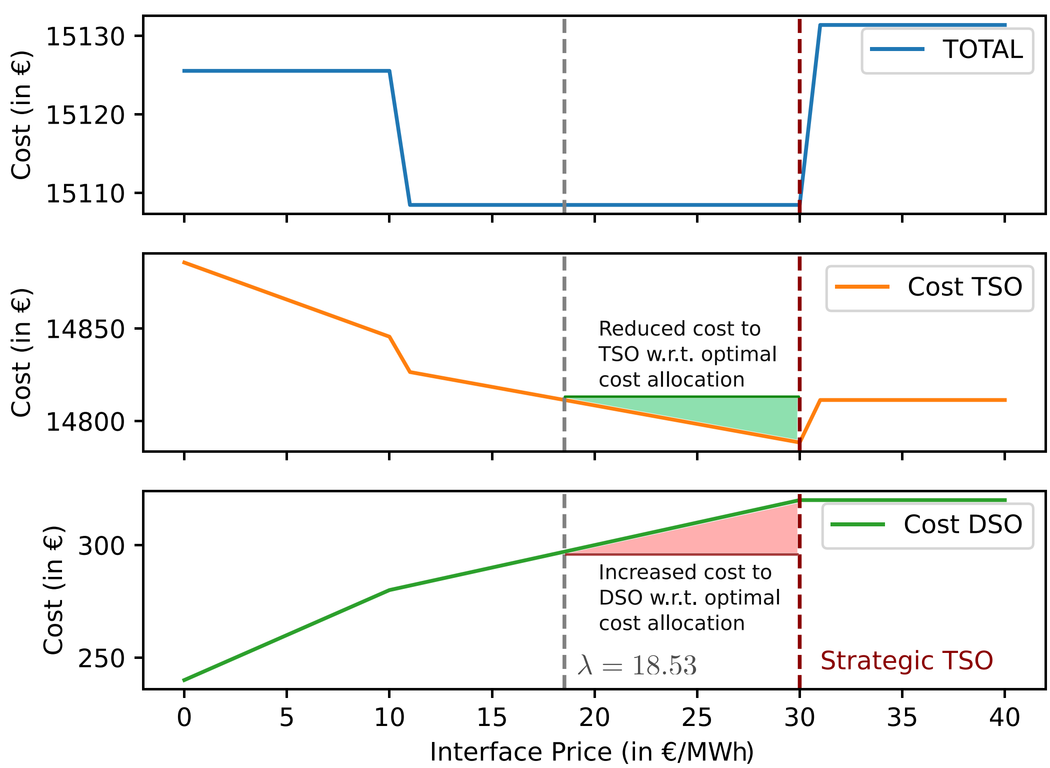

Fig. 3. Results for stylised case study.

presents a sensitivity analysis on the interface price with respect to the costs for the different SOs (considering activation costs and transfers over interface imbalances), as well as the total cost for the system. The highlighted areas show the benefits and losses from cost allocation generated by a strategically set price of 30 €/MWh, in detriment to the optimal 18.53 €/MWh.

3.2. 102-bus Case Study

This case study is composed of one 30-bus transmission network of 135 kV and four 18-bus DSOs of 12.5 kV. The transmission network is based of the IEEE-30 case study, also included in the MATPOWER package for MatLab as *case30* [46–48]. The generators are the flexibility providers for the congestion management market. The four distribution networks are equal in terms of topology, electrical parameters and loads, and are based on the work of Grady et al. [49] and Grady et al. [50]. These networks are also included in the MATPOWER package as *case18*. The original data, however, does not include line ratings, which are considered to be between 1.5 MVA and 6 MVA.[3] The placement of FSPs is randomised for downward providing units (rebalance capability). For upward flexibility, one unit is placed downstream of the distribution congested elements.

Fig. 4 provides the network diagram for the 102-bus Case Study. The congestion occurring at both transmission and distribution networks

[3] The values are chosen so that the power flows from the original data sets are close to the line ratings. In this manner, congestions can be more easily observed or created. Nevertheless, the values are computed from examples of MV cables found in the industry. Line ratings of 1.5 to 6 MVA would correspond to continuous current ratings of 70 and 277 A, respectively, at 12.5 kV. These values are compatible with the ampacity of overhead three-core cables with copper conductor of cross-section ranging from approximately 16 to 95 mm^2, respectively [51].

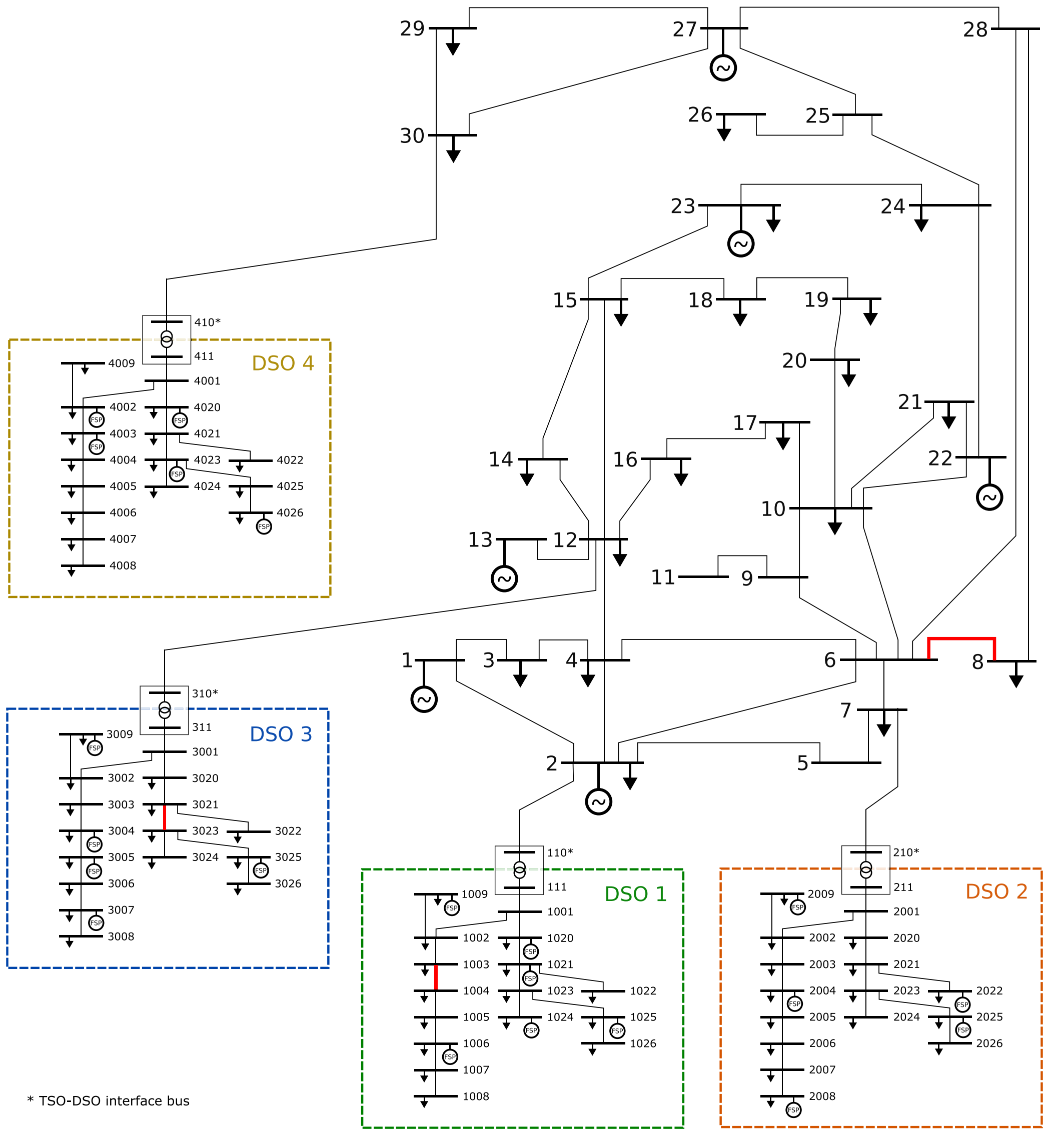

Fig. 4. 102-bus Case Study network representation. Congested lines in red.

are highlighted in red on Fig. 4. At the distribution networks congestions on lines 1003–1004 and 3021–3023 are verified, while line 6–8 on the transmission grid is also overloaded. This congestions are created by lowering the line rating of these elements. In order to chose the overloaded elements, a power flow with the original data is computed, and the lines with closest power flow with respect to line ratings are chosen, therefore minimising the line rating modification. Detailed data for both case studies can be found in [43].

The simulations conducted include not only the base case, but also a sensitivity analysis over two parameters: (i) the bid price from FSPs connected at the transmission level and (ii) the available flexibility from FSPs connected at the distribution network. The objective for these sensitivities is twofold. First, to explore scenarios in which the DSO does not have enough flexibility to rebalance their LFMs. Second, to evaluate how different flexibility prices for the TSO might impact the total cost and cost allocation, going from a flexibility that is always cheaper than the DSOs' to an always more expensive one. Therefore, in each run, the Base Case parameters $P^{-,+}_{k\in K^{DSO}}$ and $Bid^{up,dw}_{k\in K^{TSO}}$ are multiplied by the sensitivity factors S^1 and S^2, respectively. Ranges for S^1 and S^2 are presented in Table 3.

Additionally, two scenarios are considered. First, no congestions at the transmission level occur. Only the congestions in DSOs D1 and D3 take place. Second, the congestion at the transmission level is included (line 6–8, as shown in Fig. 4).

From the CS's perspective, several are simulated. First, the Common CS is simulated to provide the first-best solution in terms of flexibility procurement cost. Moreover, the Common CS is used to compute the optimal interface price. This price is used in a Fragmented CS with optimal interface pricing run. In this CS, the interface price is fixed at the $\lambda^{T1,*}_{i,j,s,s'}$ from the Common CS. This Fragmented-Optimal has important properties for the analysis of the strategic cases: (i) it leads to the same total cost for the system as the Common CS, and (ii) allocates the rebalancing costs optimally among SOs, as argued in Section 3.1. Finally, the Fragmented with Strategic TSO CS is computed. The latter is tested both in its standard case, as well as with additional regulatory mechanisms, as presented in the following subsections.

3.3. No congestion in the transmission network

The scenario in which no congestions occur at the transmission level has an important property for the evaluation of total cost and cost allocation: the cost for the TSO should be zero. From a cost allocation perspective, all flexibility costs should be borne by the DSOs, as no flexibility needs are generated at the transmission grid.

Table 3
Sensitivity factors for the 102-bus Case Study.

Parameter	Sensitivity range	Sensitivity purpose
$P^{+,-}_{k\in K^{DSO}}$	$S^1 = [\ 0.15 \quad 0.20 \quad \dots \quad 0.95 \quad 1.00\ ]$	Study different levels of distributed flexibility provision available to the DSO.
$Bid^{up,dw}_{k\in K^{TSO}}$	$S^2 = [\ 0.25 \quad 0.50 \quad \dots \quad 3.75 \quad 4.00\ ]$	Study the effects of transmission-connected flexibility on total cost and cost allocation.

Table 4
Example of Settlement. CS: Fragmented-Strategic. Sensitivity factors: $S^1 = 0.45$, $S^2 = 3.5$.

		TSO	DSO 1	DSO 2	DSO 3	DSO 4
	Activated flexibility					
	Upward					
A	Energy (MWh)	0.00	1.25	0.00	0.50	0.00
B	Avg. Unit. Cost (€/MWh)	0.00	128.00	0.00	439.00	0.00
C	Total Cost Up. (AxB; €)	0.00	160.00	0.00	219.50	0.00
	Downward					
D	Energy (MWh)	0.00	1.35	0.00	0.20	0.20
E	Avg. Unit. Cost (€/MWh)	0.00	36.00	0.00	38.00	29.00
F	Total Cost Dw. (DxE; €)	0.00	48.60	0.00	7.60	5.80
	Interface settlement					
G	Imbalanced Flexibility (A - D; MWh)	–	−0.10	0.00	0.30	−0.20
H	Interface Price (€/MWh)	–	41.00	41.00	1,000.00	29.00
I	Imbalance Payment (+) or Revenue (−) (GxH[a]; €)	−290.10	−4.10	0.00	300.00	−5.80
J	Total Cost (+) or Profit (−) (C+F+I; €)	−290.10	204.50	0.00	527.10	0.00

[a] Except TSO. For TSO: $-\sum_{DSO}$ I.

At the Base Case (no sensitivity factors applied), the total flexibility procurement cost is 416 € for both the Common and the Fragmented-Optimal CSs. The Fragmented-Optimal shows that both DSOs 1 and 3 activate upward flexibility downstream of their congestions and leave the downward rebalancing to the TSO, as the marginal unit at transmission bids 21 €/MWh, and so is the interface price for both DSOs (as network conditions do not affect these activations, in this case). In this case, the TSO receives the exact amount they need to activate the FSP $KT2$. When analysing the sensitivities results, however, it is possible to observe the case in which the FSPs at transmission are more expensive than the ones at distribution, and therefore, the DSOs are incentivised to activate their own downward flexibility. When the sensitivity factor over the available downward flexibility is also enforced, the DSOs 1 and 3 are not able to individually complete their rebalancing. In this case, the optimal interface pricing from the Fragmented-Optimal CS enables the TSO to receive the imbalance payments from DSOs 1 and 3 and pay this amount to DSO 4 so that the rebalancing is completed using the cheapest units in the system. In this case, the TSO's flexibility cost is still zero. They only act as a settlement party among the DSOs.

When the TSO is allowed to act freely in a strategic way, profits are generated in both the base case and under sensitivity factors. In the case of the latter, the TSO arbitrages the flexibility prices among the different DSOs. Table 4 provides an example of a settlement on the strategic case.

Fig. 5 presents the results for the sensitivity analysis of the scenario with no congestion at transmission. The upper plot shows the absolute values paid by all four DSOs in net terms for the Fragmented-Optimal CS (which in this case is also the total cost for the system), while the lower plot shows the difference in p.u. between the Fragmented-Strategic and the Fragmented-Optimal. In the worst cases, the costs for the DSOs are almost three times higher than the optimal cost and on the best cases, 1.6 times higher.

3.4. Congestion at the transmission network

The case with congestion at transmission is used not only to compute the gap between the Fragmented-Strategic results to the optimal (Common; Fragmented-Optimal), but also to test additional regulatory proposals.

As mentioned in Section 1, modelling a purely strategic TSO is an academic exercise, as TSOs are regulated companies [25]. Therefore, considering a purely strategic TSO is not a realistic assumption but serves to understand potential incentives, identify eventual regulatory risks and allow for the proposal of regulatory mechanisms. In this context, four regulatory proposals are tested on the scenario with transmission and distribution congestions. First, the purely Fragmented-Strategic TSO, in which no policy is applied other than the cap on the interface price enforced by (3b). Second, the unpriced Fragmented CS, as this CS is the simplest implementation and is already being implemented in some countries or pilot projects, as discussed in Section 1. Third, the Fragmented with midpoint interface pricing is tested. The midpoint interface pricing was first proposed by Marques et al. [9] and consists of pricing the interface flow between the most expensive downward flexibility bid and the least expensive upward flexibility bid of each DSO. This proposal is meant to offer a practical solution to interface pricing when optimal pricing is not implementable while retaining some of the benefits of interface pricing. Fourth, a novel regulatory mechanism is proposed and tested, in which the interface price is limited by a cap and floor mechanism. The cap and floor are computed based on the weighted average of all downward bids in the system multiplied by up and down factors (6). The $LimitFactor^{floor}$ is set at 0.5 while $LimitFactor^{cap}$ is set at 1.5.

$$IntPrice^{+,-}_s = \left(\frac{\sum_k Bid^{dw}_k \cdot P^-_k}{\sum_k P^-_k} \right) \cdot LimitFactor^{cap,floor} \tag{6}$$

This would provide a band of possible interface prices according to the downward flexibility markets on the system. The TSO is assumed to be strategic within this band of possible values. Under this proposal, first, the regulatory risk for strategic behaviour is minimised. Second, it considers downward bids from the whole system, allowing, to some extent, for cheap downward bids from one SO to be used by the other, as seen in the scenario with no congestions at transmission. Third, it mitigates a potential risk of midpoint proposal, namely manipulation of interface prices by FSPs. Under the midpoint pricing, the extremes of the merit order lists are used for each DSO. By knowing this, market participants, too, can act strategically (e.g. one unit artificially elevating the interface price by setting a high downward flexibility bid so another unit can be activated). The cap and floor proposal, however,

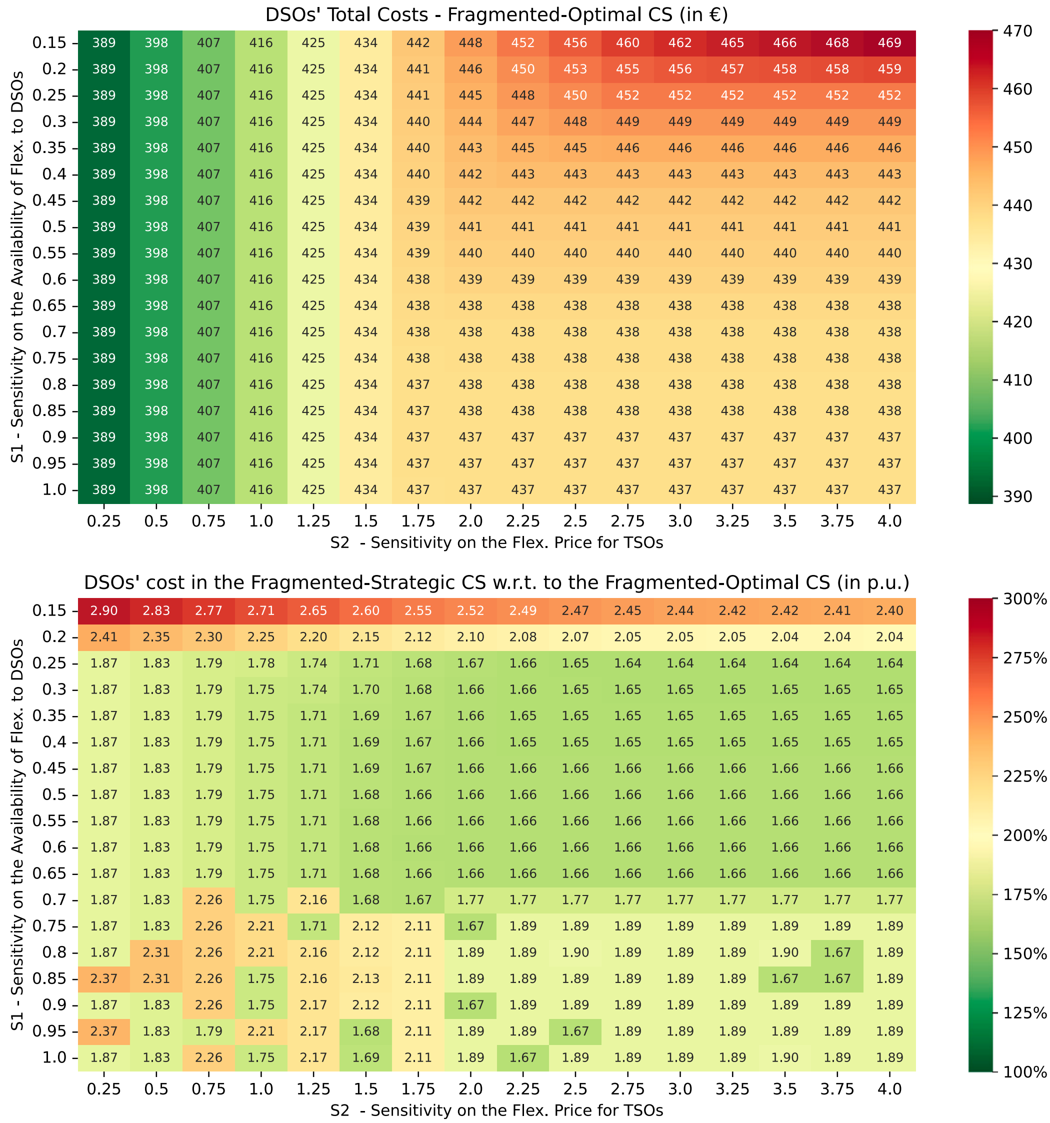

Fig. 5. Results for scenario with no congestion at transmission.

comes at the expense of some information exchange of downward bids, although simplifications are possible (e.g. DSOs only send aggregated weighted average to the TSO or the party responsible for interface pricing calculation).

The Common and Fragmented-Optimal CSs are then used as a baseline for the performance of each of the four policy proposals. In that regard, this research confirms the findings in [9]. In all case studies, when the optimal price for the interface flow is used on a sequential Fragmented CS (models (1) and (2)), the total flexibility procurement cost is equal to the Common CS.

The network scenario with congestions at both transmission and distribution (as depicted in Fig. 4) is simulated for all sensitivity factors proposed in Table 3. Results are presented in Fig. 6. The heat maps illustrate the gap between the specific simulation and the optimal solution (i.e. Common; Fragmented-Optimal) in percentage, according to the colour scale for each case. Results are presented in three columns of plots. The first illustrates the gap between the total flexibility procurement cost of the specific policy proposal to the optimal (i.e. Common;Fragmente-Optimal). The second and third columns show the deviation in cost allocation for the TSO and DSOs, respectively. Numbers presented in the centre of each heat map represent the average of all 288 sensitivity runs on each heat map.

Results show that the purely strategic TSO distorts cost allocation greatly by reducing TSO's cost by 58.8% and increasing the cost to DSOs by 79.6% in relation to the Fragmented-Optimal CSs. However, the total cost in terms of procured flexibility is only increased by 0.44% in relation to the Common CS. Among all four policy proposals, this is the least distorted total cost, demonstrating that a purely strategic TSO has the incentive to price interfaces in a way that the most efficient flexibility units in the system are activated.

The "no interface price" policy, as expected, produces a cost allocation distortion in benefit of the DSOs, reducing their costs by 11%. The imbalance costs are passed on to the TSO, which sees an increase of 11%, while the total cost is increased in 2%. The increase in total and TSO costs is higher on cases in which the cost of transmission-connected flexibility is higher (right side of heat maps).

The Midpoint interface price produces an increase in total cost of 3% while maintaining the cost of the TSO nearly unchanged and increasing the cost for DSOs in 7.5%. The higher increases of cost (both for DSOs and total cost) happen on the region where transmission-connected flexibility is cheap. By setting the interface price only using each DSO's downward flexibility bids, distribution operators cannot benefit when downward flexibility bids at transmission are cheaper.

Finally, the cap and floor mechanism with strategic TSO produces a higher total cost of 0.9%, while cost distortions to TSO and DSO

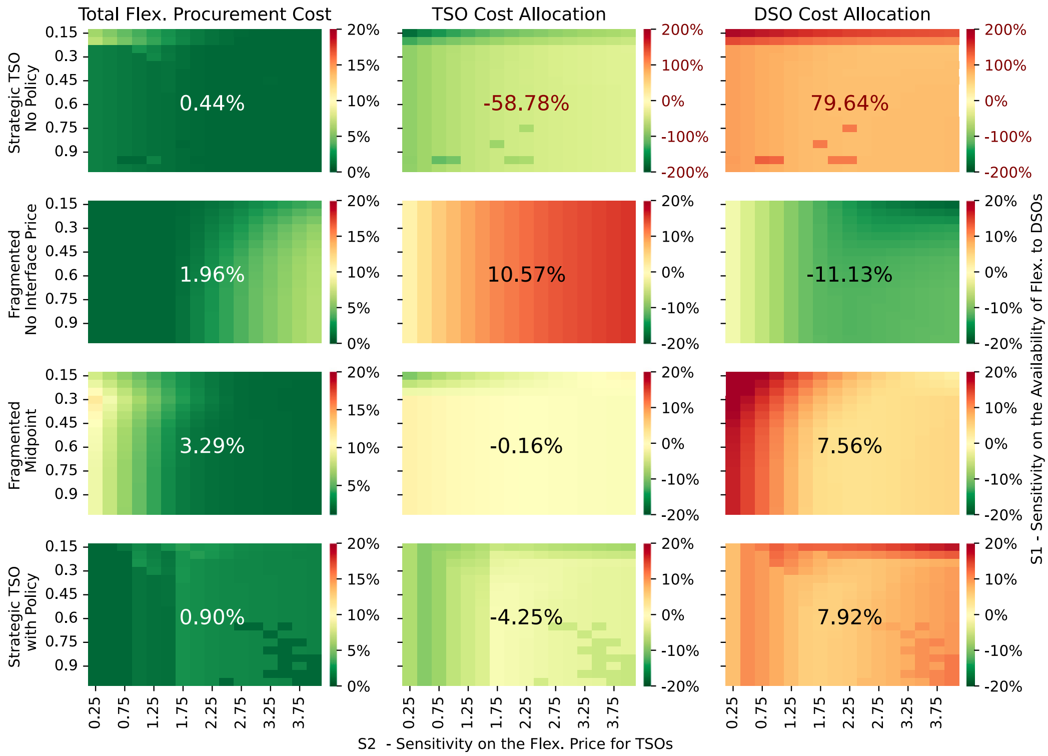

Fig. 6. Results for the scenario with congested at both transmission and distribution and the four policy proposals. Average deviation with respect to the Common CS (for total flex. procurement) and Fragmented-Optimal (for cost allocation) per heat map on the centre.

are −4% and +8%, respectively. This demonstrates that the TSO still exercises its strategical advantages reducing its cost and increasing the ones of DSOs, especially on the region where the flexibility available to DSOs is low (upper rows of heat maps). However, the total cost is increased in 0.9%, second only to the purely strategic TSO, showing that the TSO still retains some incentive to price interfaces so it leads to efficient activations.

4. Policy discussion

While modelling a purely strategic TSO is not a realistic assumption, is worth identifying situations in which strategic behaviours might arise. Even if regulation mandates TSOs to efficiently compute interface prices (efficiency would vary according to the level of information available), a significant asymmetry of information would exist between the TSO and the regulatory authority. Assuming that interface prices could be computed for high time and network granularity (e.g. every hour for tens or hundreds of interfacing substations) and the complexity of calculations, regulators would have a low capability for verification. In this context, we show that distortions are higher in situations where DSOs have a low liquidity in their flexibility markets. This happens both in a purely strategic TSO and when a cap and a floor to interface prices is applied, as the TSO exploit their strategic position to a greater extent, leading to higher cost allocation distortions, as shown in Fig. 6.

Results also show that the current implementation of LFMs in which the DSO does not have any incentive to rebalance their flexibility activations may lead to poor results in terms of total cost as well as cost allocation. However, the results shown are case-dependent, and a trade-off exists between having some cost distortions and introducing a more complex and costly mechanism to solve them. It is possible that at early stages of distributed flexibility usage, when distortions caused by LFMs are not so representative at a system level, introducing complex interface pricing mechanisms could jeopardise the development of these LFMs.

The Midpoint interface pricing is a simple method of easy implementation that has the advantage of not requiring information exchange. However, it also creates cost distortions as shown in the 102-case study results, and therefore, a cost–benefit analysis on its implementation should be conducted on a case-by-case basis.

The cap and floor proposal led to favourable results in the cases analysed. However, results are also case-dependent. Moreover, it assumes a strategic TSO, although strategic behaviour is bounded. This means that, intrinsically, a cost allocation distortion in favour of the TSOs is to be expected. On the other hand, it illustrates that a TSO that has incentives to efficiently price substations could lead to lower total costs in terms of flexibility activation. It is important to notice that the actual cost to the system is the activated flexibility (e.g. the sum of C and F on Table 4). The settlement for interface pricing (e.g. I on Table 4) is a financial transfer from one SO to the other.

Although the TSO benefits by exploring potential gains on interface pricing, the TSO is also the one enabling the coordination of efficient flexibility procurement among all SOs in a given control zone. A case could be made that this coordination is a service to the system and that this could be remunerated in some form. The cap and floor mechanism proposed in this research is primarily a proof of concept that illustrates a form of dedicated incentive for TSO-DSO coordination. Dedicated incentives are a known and widely used regulatory mechanism used for specific purposes, on top of general incentive regulation schemes (e.g. RPI-X). An example is the use of dedicated incentives for the development of offshore grids, a riskier and newer type of investments to be done by TSOs [52].

From the DSO's perspective, actions could be taken in order to minimise cost allocation distortions. Considering that the regulatory mechanism proposed does not require intensive supervision, regulatory authorities could focus eventual supervision efforts on situations in which distortions are potentially higher, i.e., when liquidity in the DSO's LFM is low, as shown in Fig. 6. Moreover, expected distortions could be offset by including them in the set of incentives DSOs are expected to have in order to procure flexibility, as mandated by European regulation [53].

5. Conclusions

In this paper, a bilevel model is proposed to evaluate how a strategic TSO would act in a Stackelberg game environment in which the interface flow price is set first and freely by the transmission operator. Although assuming a purely strategic TSO is not a realistic assumption, it provides important benefits to the investigation of possible regulatory implementations.

First, it identifies the situations in which potential distortions would be greater, namely in situations with low liquidity at the LFMs of the DSOs. This can be used by regulatory authorities to direct eventual verification in a context of high asymmetry of information and limited regulatory resources.

Second, it provides a research environment for the testing of different policy alternatives. While the purely strategic TSO is an unrealistic extreme, different regulatory mechanisms can be tested and compared. The results obtained demonstrated that a strategic TSO has the incentive to activate or price interfaces so that the most efficient flexibility providers are activated. Leveraging on these results, a cap and floor regulatory mechanism is proposed. This mechanism poses bounds to strategic behaviours by the interface price setter, but still gives an incentive for the activation of economical FSPs. This mechanism compared favourably against other options. It was the realistic mechanism that led to the least distortion of total cost. On a sensitivity analysis of 288 simulations on a 102-bus cases study, the cap and floor mechanism led to an average increase by 0.90% in total cost with respect to the first-best reference (i.e. a Common CS), against 1.96% and 3.29% for the vanilla-Fragmented and the Midpoint options, respectively.

While providing a modelling sandbox for regulatory mechanisms, this paper also indicates that indirect sharing of resources through interface pricing is an efficient and implementable way of achieving TSO-DSO coordination for distributed flexibility procurement. Moreover, it indicates that mechanisms that are low in regulatory supervision can lead to efficient second-best options in terms of total cost and cost allocation, when compared to the first-best but technically complex Common CS.

The proposed cap and floor on interface prices is an example that requires future research. More elaborate mechanisms could be proposed, such as a bonus-malus, which is already a typical type of dedicated incentive for TSOs and DSOs. Moreover, meshed-to-meshed topologies should be considered, representing the typical typologies adjacent to TSO-DSO interfaces in Europe. Finally, this study could be expanded to include voltage violations in addition to overloads. This could require the adaptation of the model to include reactive power flexibility procurement or other voltage control techniques.

CRediT authorship contribution statement

Leandro Lind: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Rafael Cossent:** Writing – review & editing, Supervision. **Pablo Frías:** Writing – review & editing, Supervision.

Declaration of competing interest

• We have no conflicts of interest to disclose.
• This manuscript has not been published and is not under consideration for publication elsewhere.
• This work did not receive external funding.

Data availability

The data is available publicly as explained in the documents submitted.

Appendix A. Linearisation of the upper level's objective function

According to the Strong Duality Theorem, if x is an optimal solution to the primal problem and λ is an optimal of the dual problem, then $c^T x = \lambda^T b$. Therefore, a possible linearisation technique for $(p_k^{up} - p_k^{dw}) \cdot intprice_s$ is to verify if a linear term exists in the equality between the primal objective function (1a) and its dual counterpart. Therefore,

$$\begin{aligned}
&\sum_{s\in S^D,k\in K^{DSO}} \left[\left(Bid_k^{up}\cdot p_k^{up}\right)+\left(Bid_k^{dw}\cdot p_k^{dw}\right)\right] \\
&+\sum_{s\in S^D,k\in K^{DSO}} (p_k^{up}-p_k^{dw})\cdot IntPrice_s \\
&= \\
&+\sum_{i\in I^{DSO},s\in S^D} DispatchDA_i\cdot\lambda_{i,s}^{D1}-\sum_{i\in I^{DSO},s\in S^D} D_i^p\cdot\lambda_{i,s}^{D1} \\
&+\sum_{i\in I^{DSO},j\in I^{SUBS},s\in S^D} DaDSO_s\cdot\lambda_{i,j,s}^{D2}-\sum_{i\in SLACK^s,s\in S^D}\lambda_{i,s}^{D3} \\
&-\sum_{i\in I^{DSO},s\in S^D} D_i^q\cdot\lambda_{i,s}^{D4} \\
&-\sum_{k\in K^{DSO}} P_k^+\cdot\bar{\mu}_k^{up}-\sum_{k\in K^{DSO}} P_k^-\cdot\bar{\mu}_k^{dw}-\sum_{i\in I^{DSO},j} F_{i,j}^{p,+}\cdot\bar{\mu}_{i,j}^p \\
&+\sum_{i\in I^{DSO},j} F_{i,j}^{p,-}\cdot\underline{\mu}_{i,j}^p \\
&-\sum_{i\in I^{DSO},j} F_{i,j}^{q,+}\cdot\bar{\mu}_{i,j}^q+\sum_{i\in I^{DSO},j} F_{i,j}^{q,-}\cdot\underline{\mu}_{i,j}^q-\sum_{i\in I^{DSO+}} (V^+)^2\cdot\bar{\mu}_i^V \\
&+\sum_{i\in I^{DSO+}} (V^+)^2\cdot\underline{\mu}_i^V
\end{aligned} \tag{A.1}$$

resulting in the following linear objective function for the upper level:

$$\begin{aligned}
\min &\sum_{s\in S^T,k\in K^{TSO}} (Bid_k^{up}\cdot p_k^{up})+(Bid_k^{dw}\cdot p_k^{dw})+\sum_{s\in S^D,k\in K^D} (p_k^{up}-p_k^{dw}) \\
&-\sum_{i\in I^{DSO},s\in S^D} DispatchDA_i\cdot\lambda_{i,s}^{D1}+\sum_{i\in I^{DSO},s\in S^D} D_i^p\cdot\lambda_{i,s}^{D1} \\
&-\sum_{i\in I^{DSO},j\in I^{SUBS},s\in S^D} DaDSO_s\cdot\lambda_{i,j,s}^{D2}+\sum_{i\in SLACK^s,s\in S^D}\lambda_{i,s}^{D3} \\
&+\sum_{i\in I^{DSO},s\in S^D} D_i^q\cdot\lambda_{i,s}^{D4} \\
&+\sum_{k\in K^{DSO}} P_k^+\cdot\bar{\mu}_k^{up}+\sum_{k\in K^{DSO}} P_k^-\cdot\bar{\mu}_k^{dw}+\sum_{i\in I^{DSO},j} F_{i,j}^{p,+}\cdot\bar{\mu}_{i,j}^p \\
&-\sum_{i\in I^{DSO},j} F_{i,j}^{p,-}\cdot\underline{\mu}_{i,j}^p \\
&+\sum_{i\in I^{DSO},j} F_{i,j}^{q,+}\cdot\bar{\mu}_{i,j}^q-\sum_{i\in I^{DSO},j} F_{i,j}^{q,-}\cdot\underline{\mu}_{i,j}^q+\sum_{i\in I^{DSO+}} (V^+)^2\cdot\bar{\mu}_i^V \\
&-\sum_{i\in I^{DSO+}} (V^+)^2\cdot\underline{\mu}_i^V
\end{aligned} \tag{A.2}$$

Appendix B. Linearisation of the lower levels' complementarity conditions

In order to linearise the complementarity conditions, the Big-M technique is employed. Therefore, the complementarity conditions of the DSO's lower level (4i)–(4r) and TSO's lower level (5g)–(5n) are substituted by the formulation below. It is worth mentioning that some complementarity conditions are shared by both models, only changing the subsets applicable. These complementarity conditions can be unified in one single constraint. This is done in (B.1a)–(B.1x).

$$-p_k^{up}+P_k^+\geq 0 \quad \forall k \tag{B.1a}$$

$$\bar{\mu}_k^{up}\geq 0 \quad \forall k \tag{B.1b}$$

$$-p_k^{up}+P_k^+\leq b_k^{01}\cdot M^{01} \quad \forall k \tag{B.1c}$$

$$\bar{\mu}_k^{up} \leq (1-b_k^{01}) \cdot M^{01} \quad \forall k \tag{B.1d}$$

$$p_k^{up} \geq 0 \quad \forall k \tag{B.1e}$$

$$\underline{\mu}_k^{up} \geq 0 \quad \forall k \tag{B.1f}$$

$$p_k^{up} \leq b_k^{02} \cdot M^{02} \quad \forall k \tag{B.1g}$$

$$\underline{\mu}_k^{up} \leq (1-b_k^{02}) \cdot M^{02} \quad \forall k \tag{B.1h}$$

$$-p_k^{dw} + P_k^- \geq 0 \quad \forall k \tag{B.1i}$$

$$\bar{\mu}_k^{dw} \geq 0 \quad \forall k \tag{B.1j}$$

$$-p_k^{dw} + P_k^- \leq b_k^{03} \cdot M^{03} \quad \forall k \tag{B.1k}$$

$$\bar{\mu}_k^{dw} \leq (1-b_k^{03}) \cdot M^{03} \quad \forall k \tag{B.1l}$$

$$p_k^{dw} \geq 0 \quad \forall k \tag{B.1m}$$

$$\underline{\mu}_k^{dw} \geq 0 \quad \forall k \tag{B.1n}$$

$$p_k^{dw} \leq b_k^{04} \cdot M^{04} \quad \forall k \tag{B.1o}$$

$$\underline{\mu}_k^{dw} \leq (1-b_k^{04}) \cdot M^{04} \quad \forall k \tag{B.1p}$$

$$-f_{i,j}^p + F_{i,j}^{p,+} \geq 0 \quad \forall (i,j) \in L \tag{B.1q}$$

$$\bar{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{B.1r}$$

$$-f_{i,j}^p + F_{i,j}^{p,+} \leq b_k^{05} \cdot M^{05} \quad \forall (i,j) \in L \tag{B.1s}$$

$$\bar{\mu}_{i,j}^p \leq (1-b_k^{05}) \cdot M^{05} \quad \forall (i,j) \in L \tag{B.1t}$$

$$-F_{i,j}^{p,-} + f_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{B.1u}$$

$$\underline{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{B.1v}$$

$$-F_{i,j}^{p,-} + f_{i,j}^p \leq b_k^{06} \cdot M^{06} \quad \forall (i,j) \in L \tag{B.1w}$$

$$\underline{\mu}_{i,j}^p \leq (1-b_k^{06}) \cdot M^{06} \quad \forall (i,j) \in L \tag{B.1x}$$

$$-f_{i,j}^q + F_{i,j}^{q,+} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1y}$$

$$\bar{\mu}_{i,j}^q \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1z}$$

$$-f_{i,j}^q + F_{i,j}^{q,+} \leq b_k^{07} \cdot M^{07} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1aa}$$

$$\bar{\mu}_{i,j}^q \leq (1-b_k^{07}) \cdot M^{07} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1ab}$$

$$-F_{i,j}^{q,-} + f_{i,j}^q \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1ac}$$

$$\underline{\mu}_{i,j}^q \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1ad}$$

$$-F_{i,j}^{q,-} + f_{i,j}^q \leq b_k^{08} \cdot M^{08} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1ae}$$

$$\underline{\mu}_{i,j}^q \leq (1-b_k^{08}) \cdot M^{08} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{B.1af}$$

$$-w_i + (V^+)^2 \geq 0 \quad \forall i \in I^{DSO+} \tag{B.1ag}$$

$$\bar{\mu}_i^V \geq 0 \quad \forall i \in I^{DSO+} \tag{B.1ah}$$

$$-w_i + (V^+)^2 \leq b_k^{09} \cdot M^{09} \quad \forall i \in I^{DSO+} \tag{B.1ai}$$

$$\bar{\mu}_i^V \leq (1-b_k^{09}) \cdot M^{09} \quad \forall i \in I^{DSO+} \tag{B.1aj}$$

$$-(V^-)^2 + w_i \geq 0 \quad \forall i \in I^{DSO+} \tag{B.1ak}$$

$$\underline{\mu}_i^V \geq 0 \quad \forall i \in I^{DSO+} \tag{B.1al}$$

$$-(V^-)^2 + w_i \leq b_k^{10} \cdot M^{10} \quad \forall i \in I^{DSO+} \tag{B.1am}$$

$$\underline{\mu}_i^V \leq (1-b_k^{10}) \cdot M^{10} \quad \forall i \in I^{DSO+} \tag{B.1an}$$

$$-\theta_i + \theta^+ \geq 0 \quad \forall i \in I^{TSO+} \tag{B.1ao}$$

$$\bar{\mu}_i^\theta \geq 0 \quad \forall i \in I^{TSO+} \tag{B.1ap}$$

$$-\theta_i + \theta^+ \leq b_k^{11} \cdot M^{11} \quad \forall i \in I^{TSO+} \tag{B.1aq}$$

$$\bar{\mu}_i^\theta \leq (1-b_k^{11}) \cdot M^{11} \quad \forall i \in I^{TSO+} \tag{B.1ar}$$

$$\theta^+ + \theta_i \geq 0 \quad \forall i \in I^{TSO+} \tag{B.1as}$$

$$\underline{\mu}_i^\theta \geq 0 \quad \forall i \in I^{TSO+} \tag{B.1at}$$

$$\theta^+ + \theta_i \leq b_k^{12} \cdot M^{12} \quad \forall i \in I^{TSO+} \tag{B.1au}$$

$$\underline{\mu}_i^\theta \leq (1-b_k^{12}) \cdot M^{12} \quad \forall i \in I^{TSO+} \tag{B.1av}$$

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Glossary

ADMM: Alternating Direction Method of Multipliers
CS: Coordination Scheme
DER: Distributed Energy Resource
DLMP: Distribution Locational Marginal Price
DSO: Distribution System Operator
FSP: Flexibility Service Provider
GAMS: General Algebraic Modelling System
ICT: Information and Communications Technology
KKT: Karush–Kuhn–Tucker
LFM: Local Flexibility Market
LV: Low-Voltage
MILP: Mixed Integer Linear Programming
MO: Market Operator
MV: Medium-Voltage
OPF: Optimal Power Flow
SO: System Operator
TSO: Transmission System Operator
UK: United Kingdom