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Strategic bidding of distributed energy resources in coupled local and central markets

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ABSTRACT

This paper explores a revenue maximization problem for distributed energy resources in a local day-ahead and balancing market. The local market creates opportunities for competition among distributed energy resources, however it may also lead to exercising market power. In the day-ahead market, the strategic revenue maximization of the distributed energy resources is modelled through a bi-level optimization. The upper-level in the bi-level optimization is from the strategic distributed energy resource's perspective and the lower-level problem is from the local market operator's perspective. The balancing market (where there is perfect competition) is modelled by the shrinking rolling horizon approach. A wind farm with a storage system is considered as a case study of a strategic distributed energy resource to evaluate its profitability within the proposed revenue maximization problem. The revenue of the wind farm in the local market is compared with the one in a (business-as-usual) centralized market where it cannot exercise market power. Sensitivity analysis regarding the effect of changing the distribution system parameters e.g. the branch resistances and the loads, on the revenue of the wind farm and its bidding behaviour is performed. Moreover, the role of the storage system on the revenue of the wind farm is studied. Results show that an overloaded or weak distribution system will positively influence the strategic position of the wind farm. Finally, it is shown that depending on the existence of market power, a storage system can bring extra revenues for the wind farm, by hedging against its uncertain output.

1. Introduction

The integration of distributed energy resources (DERs) such as electrical storage systems, small wind farms, PV systems, etc. are increasing in the distribution system. High penetration of DERs brings benefits and opportunities for power systems, among others, increasing the affordability and reliability and decreasing system costs [1]. However, in the current electricity markets, there are some challenges for the participation of the DERs in markets, among others, scalability issues and complexity of many DERs in one central market, a high bid size requirement for market participants, and a high market transaction fee [2]. To deal with these challenges, the concept of the local electricity market has emerged [3–7]. In these local electricity markets DERs participate directly within a market. What the bidding strategy of these DERs should be to maximize their profit within the specific case of a local market is still an open question.

Generally speaking, the bidding behaviour of market players in power systems can be classified into strategic bidding and non-strategic bidding. Non-strategic bidding means market players can only solve a self-scheduling problem to determine their most beneficial actions for given prices. In contrast, strategic bidding is behaviour by which a market player can affect market prices and as a result, increase its revenue [8]. There are several ways for a market player to perform market power in the electricity market. These ways, according to [9] are: using price bidding strategies to raise market prices independently of changes in underlying supply and demand conditions; exploiting market power resulting from local transmission network constraints; capacity withholding to increase market prices, in particular by manipulating the capacity payment mechanism under the existing trading arrangements; and manipulation of complex market rules to increase prices and earn excessive profits. Ref. [10] summarizes the market power behaviour of generating companies in three strategies: financial withdrawal (price increase), physical withdrawal (volume reduction), and physical withdrawal with free bilateral contracts. Ref. [11] classifies the exercise of market power in electricity markets in two broad strategies which a generator can use to artificially increase electricity market prices;

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economic withholding and capacity withholding. In the capacity withholding, a strategic market participant can influence the market price by withdrawing its cheaper units [12]. In the economic withholding, a strategic market player can maximize its revenue mainly due to the system constraints [13]. DERs participating in local electricity markets can have market power despite their small size, as the market size is still smaller and location matters for economic withholding. Therefore, local electricity markets can create good opportunities for DERs to exercise market power [1]. Moreover, it is important to understand strategic bidding behaviour by the DERs in local markets, as the market power leads to unwanted consequences for social welfare and unfair income distribution [14]. However, there is yet limited amount of literature in which the strategic behaviour of DERs in the local electricity market is studied. Strategic bidding of market players in the centralized electricity market, however, has been studied thoroughly in the literature. Some of them are reviewed here.

The existing literature is classified in terms of a different strategic approach. In [15], the bidding behaviour of the storage system which acts strategically through economic withholding is studied. Ref. [16] is another example where the storage system is exercising market power, however, by withholding its capacity. In some literature, "capacity" refers to generation capacity expansion which can also be seen as a strategic behaviour by generating companies in imperfectly competitive power markets. For example, in [17], the strategic behaviour of companies facing generation capacity expansion decisions are studied through different game-theoretic models. Ref. [18] is another example in which different models of investments in generation capacity in an oligopolistic market are studied. However interesting, long-term investment decisions are out of scope of this paper, where we focus on day-ahead operational decisions. In the published literature in this area, mainly exercising market power by generators which are participating in the wholesale market is studied. However, the effect of transmission constraints on strategic bidding of market players mostly is discarded such as [19]. Ref. [20] also proposes a profit maximization problem for a wind turbine operating in a traditional wholesale market without considering system constraints. However, there is some literature such as [21] and [22] where transmission system constraints are considered through DC and AC power flow, respectively. Ref. [23] is another example that proposes a problem with mathematical programming with equilibrium constraints-based procedure for calculating oligopolistic price equilibria for an electric power market while taking into account transmission constraints. Ref. [24] studies the strategic behaviour of a wind turbine through a bi-level model for the jointly cleared wholesale energy and reserve markets where the transmission system is modelled through the DC power flow. This bi-level approach is also used in [25] which addresses the optimal bidding strategy problem of a commercial virtual power plant seeking to maximize its profit in the day-ahead market. Another example is [15] in which the bi-level optimization is used to maximize the profit of a storage system in the day-ahead and balancing markets without considering the transmission constraints. In [23], also the bi-level optimization is applied for profit maximization of dominant firms in an electric power network modelled through DC power flow. In recent years, there has been a growing interest in bi-level approaches to model many operational and planning problems in power systems. More information about the bi-level and its application in power systems can be found in [26].

In this paper, the bi-level approach is applied to the local electricity market to study the possibility of market power for a DER represented by a combination of wind farm and storage system. A local market model based on the coupled market concept introduced in [6] is selected. In this market, there is a local market for the participation of DERs which is operated by a distribution market operator. The distribution market operator can be considered as the distribution system equivalent of the market operator, which is responsible for managing the electricity market and scheduling power transfers to achieve the secure operation of the distribution system. This local market engages in an exchange of information and power with the central market, both in the day-ahead and real-time balancing time frames.

The reason for choosing this market model is as follows. Since the main research question of this paper is to address whether DERs are capable of exercising market power, a market model with certain characteristics should be chosen. When a local market is connected to a larger market, capacity withholding is a less feasible strategy for the DERs due to their small size and the risk of such a strategy backfiring by triggering imports of cheaper energy from the upstream transmission system. The distribution network constraints should, therefore, be taken into account in the market clearing process, so that a realistic picture can be obtained of any remaining possibilities for exercising market power, in particular economic withholding.

Next to that, a local balancing market needs to be included to fully model the behaviour of market participants, and uncover the possibility for exercising market power in this market as well. With a high level of DER penetration, the participation of DERs in the balancing market becomes non-negligible. However, the scalability issue for the TSO with regards to managing all the balancing resources which are available still exists. Therefore, DERs need to be aggregated in some way to allow participation in the central balancing market. In the proposed coupled market, the local balancing market acts as this aggregator. Note that the DMO participates in the central balancing market, and balancing remains a system-wide service. Lastly, the coupled market can belong to a future with a lot of (renewable-based) DERs in the distribution system, and there can be that balancing in distribution systems becomes part of the responsibility of the local market. It means that in the future, the local market can go towards being more independent of the upstream system. There is research on local balancing and its importance in the future, for example in [27]. Therefore, the coupled market design is chosen, because it enables both modelling of the distribution system constraints and the inclusion of a balancing market, both of which are essential ingredients for studying the possibilities of exercising market power by DERs.

To model the participation of the wind farm with the storage system in the balancing market a shrinking rolling horizon approach is used. In a shrinking rolling horizon approach, instead of having a horizon of fixed length, the endpoint of the horizon is fixed, leading to a shorter time window (horizon) for each solution performed at consecutive times t, after starting time t_0 [28]. This shrinking rolling horizon is applied in several pieces of literature, for example, in [29] which addresses the demand side management problem for smart grids where the users have energy generation and storage capabilities. In [30] also, a shrinking rolling horizon is used in unit commitment formulations to quantify the uncertainty in wind power generation.

With the behaviour of the wind farm with the storage system modelled, several questions about the exercising of market power in a local electricity market can be answered: Can the wind farm raise its revenue in the day-ahead market compared to a centralized market model? How do the distribution system parameters, e.g. resistance and loads, affect the use of the market power of the wind farm? How would the inclusion of the storage system affect the revenue of the wind farm? In short, the contributions of this paper are:

- Formulating a revenue maximization problem for a wind farm with a storage system in a local day-ahead market.

Table 1
Sets and indices.

$c(C)$	Index(set) of combined wind farm and energy storage systems.
$e(E)$	Index(set) of energy storage systems.
$g(G)$	Index(set) of generators.
$i(I)$	Index(set) of sending nodes.
$j(J)$	Index(set) of receiving nodes.
$l(L)$	Index(set) of line.
L_D	Set of distribution lines.
L_T	Set of transmission lines.
N_D	Set of distribution nodes.
N_T	Set of transmission nodes.
N_{D-T}	Set of interface nodes in distribution system.
N_{T-D}	Set of interface nodes in transmission system.
$s(S)$	Index(set) of scenarios.
$t(T)$	Index(set) of time steps.
$w(W)$	Index(set) of wind farms.

- Showing that a wind farm with a storage system can exercise its market power in a local market to generate a higher revenue than in a centralized (business-as-usual) market.
- Demonstrating the effect of the distribution system parameters on the ability to exercise market power by DERs in local markets.

The paper is organized as follows. In Section 2, the main nomenclature used in this paper is listed. In Section 3, the coupled market model is explained. In Section 4, the steps for the revenue maximization of the DERs in the day-ahead and balancing markets of the coupled market model are described. In Section 5, the corresponding mathematical formulation is presented. In Section 6, input data and case studies are explained. The result of simulations on the case studies is shown in Section 7. Finally, conclusions are summarized in Section 8.

2. Nomenclature

The main nomenclature used in this paper is listed in Tables 1–3. Other symbols and abbreviations are defined where they first appear.

3. Coupled market model

In this section, the proposed coupled market model in [6] is described. In this market model, there is a local day-ahead and balancing market where DERs that are connected to the distribution system level can participate. The local market for DERs is operated by the distribution market operator (DMO) which can be an independent entity or be a part of the distribution system operator (DSO) (if the local regulatory framework allows). In any case, there should be information exchange between DSO and DMO regarding the dispatching of DERs and the security of the system constraints. The DMO aggregates bids from DERs and participates in the central market on behalf of them. The central market is operated by the transmission market operator (TMO) which is equivalent to a power exchange in Europe (e.g. EPEX or Nordpool) or an independent system operator in the US. Note that for example, in Europe, the transmission system operator (TSO) is responsible for balancing and is a different entity than the power exchange which operates the day-ahead market. It could have been that in the coupled market, one TMO could be assigned for the day-ahead market operation and one other entity for the balancing market, separately. However, for the sake of simplicity, one TMO is introduced which clears both the balancing and day-ahead markets. Having one TMO in the market scheme does not affect results in comparison with the situation of two separate TMO organizations. In this market model, the TSO is responsible for managing the transmission system and guarantees the security and stability of its operation. The TSO and the TMO should, therefore, exchange information regarding the dispatching and the security of the transmission system. The DMO and bulk generators and consumers at the transmission system participate in this TMO-operated central market.

The DMO can be defined as the distribution level equivalent of the market operator, which is responsible for managing the electricity market and scheduling power transfers to achieve the optimal operation of the distribution system. The DMO serves as an intermediate entity between the TMO-operated central market and the DERs and is a separate entity from the DSO.

In Fig. 1, the time sequence of the coupled DMO–TMO market model is shown in the grey colour flowchart. In total there are six steps in Fig. 1: Step I is preliminary scheduling for the local day-ahead joint energy and reserve capacity market. This step happens in D-1, the day before the delivery time and at a time, before the clearing time of the day-ahead wholesale market. The day-ahead market at the local and national level is a joint energy and reserve market and is cleared every hour in a 24-hour time-horizon. The reasons for introducing a reserve capacity market and including this as part of a joint energy and reserve capacity market is as follows. Firstly, in the coupled market, the TSO relies on the DMO market for the balancing market. As the TSO does not have control over DERs and the distribution system, there is a chance that in the balancing market, there will be a lack of resources. To avoid this situation, the reserve market should be created to guarantee that there will be enough energy available for the balancing phase. Secondly, the European regulators are paying more attention to the reserve market and the simultaneous alignment of energy provision and reserve capacity as a more efficient market design [31]. Through this step, the DMO solves an optimization problem for determining the local day-ahead energy and reserve market prices and an initial limit for the power flow over the transmission-distribution interface transformer. Step II is the TMO day-ahead joint energy and reserve market and clears in D-1 with the time resolution of one hour and in a 24-hours time-horizon. The results for this step are the scheduled power of bulk generators which will be sent to the central balancing market (step V) and a final value of the power flow over the transmission-distribution interface transformer which will be sent back to the DMO. Right after clearing the day-ahead wholesale market, the local day-ahead joint energy and reserve market is cleared by the DMO in step III. The results of this market will be sent to the local balancing market in step IV.

The procedure in the balancing market is similar to that of the day-ahead market. The difference is the duration of the scheduling interval which is 15 min for the balancing market. Step IV which happens in D, the day of the delivery time, is preliminary scheduling for the local balancing market and happens near real-time. Through this step, the local balancing market price and an initial value for the power flow over the interface transformer are estimated. In step V (real-time), the TMO clears the central real-time balancing market according to the scheduled energy and reserve of market players. The TMO will send back the final value for the interface transformer power to the DMO. Finally, in step VI, the local balancing market is cleared by the DMO, based on the updated interface power flow from step V and the DER scheduled energy and reserve from step III. As mentioned in Section 1, the algorithm applied in the balancing market clearing is based on the shrinking rolling horizon which is explained further in Section 5.2.

Calculating the market clearing price in both day-ahead and balancing markets is based on marginal pricing. The reason for choosing this pricing mechanism is, firstly, because in Europe most countries apply marginal pricing as shown in [32]. Secondly,

Table 2
Parameters.

b_i	Nodal susceptance [p.u.].
B_l	Line shunt susceptance of transmission line l [p.u.].
E_e^{ini}	Initial energy value for the energy storage system [MWh].
E_e^{max}	Maximum ESS state-of-charge [MWh].
E_e^{min}	Minimum ESS state-of-charge [MWh].
G_i	Distribution nodal admittance [p.u.].
M	A large positive number.
$O_{e,t}^{Edis/Ech}$	Energy (upward/downward) offer price by the storage in the balancing market [€/MWh].
$O_{g,t}^{E}$	Energy offer price of generators in day-ahead market [€/MWh].
$O_{g,t}^{RUP}$	Upward reserve offer price of generators [€/MW].
$O_{g,t}^{RDN}$	Downward reserve offer price of generators [€/MW].
$O_{g,t}^{EUP/EDN}$	Energy (upward/downward) offer price of generators in balancing market [€/MWh].
$P_e^{ch,max}$	Maximum charging power of ESS [MW].
$P_e^{dis,max}$	Maximum discharging power of ESS [MW].
$P_{i,t}^{load}/Q_{i,t}^{load}$	Active/reactive power load demand [MW/MVAr].
$P_{w,t,s}^{Wact}$	Actual wind farm power production [MW].
P_w^{Wmax}	Installed wind farm power [MW].
$P_{g,t}^{gmax}/P_{g,t}^{gmin}$	Maximum/minimum active power of generator g [MVAr]
$Q_{g,t}^{gmax}/Q_{g,t}^{gmin}$	Maximum/minimum reactive power of generator g [MVAr]
r_l	Resistance of a distribution line.
$S_{g,t}$	Rated apparent power of generator g [MVA].
$S_{l,t}$	Rated apparent power of line l [MVA].
$SI_{t,s}$	Total system imbalance in scenario s and time t [MW].
TC_l	Transmission line capacity.
V_i^{max}/V_i^{min}	Maximum/minimum voltage of bus i $\in N_D$
x_l	Reactance of a distribution line.
α_{Imb}	Coefficient for total system imbalance in distribution system.
α_T	Coefficient for total reserve capacity requirement in transmission system.
η^{ch}/η^{dis}	Charging/discharging efficiency of the ESS [p.u.].
$\lambda_{t,s}^{TD}$	Wholesale day-ahead market price in scenario s and time t [€/MWh].
$\lambda_{t,s}^{+/-}$	Forecasted positive/negative imbalance prices [€/MWh].
π_s	Scenario probability.

for the most common alternative which is the pay-as bid mechanism, strategic behaviour of the other generators in the system cannot be ignored. By contrast, for marginal pricing, the assumption that each generator (which does not behave strategically) bids its marginal cost is tenable. Therefore, marginal pricing is used in this paper. The interested reader is referred to [33] for a more in-depth comparison on the effect of pricing mechanism on the exercise of market power.

4. Revenue maximization problem of DERs in the coupled market

In this section, the revenue maximization of the DERs in day-ahead and balancing markets in the coupled market model is described. The dark and light green bars in Fig. 1 – underneath the grey flowchart – are showing the steps taken by the DERs to bid into the day-ahead and balancing markets, respectively. These steps are explained as follows.

4.1. Day-ahead market

As it has been mentioned in Section 3, the day-ahead market is a joint energy and reserve capacity market in which the wind farm with a storage system (WF-ESS) actively bids. However, due to the uncertain nature of the wind, the wind farm alone can only actively bid into the day-ahead energy market and cannot participate in the reserve market.

As mentioned earlier, in the day-ahead market in the coupled market model, the WF-ESS can behave strategically. The reason is that in the coupled market, the DERs participate in the local market which has relatively small in size. Therefore, the chance for the DERs to act strategically will increase. Moreover, in the coupled market model, the distribution system constraint is taken into account in market-clearing. DERs knowing that they might be called due to the power flow limits are provoked to exercise market power. In the coupled market due to the system constraint in the market clearing, the market power can be performed through economic withholding. Capacity withholding is an unsafe strategy for market players. Because, in the coupled market, the local market is not independent and is in exchange for power with the wholesale market. Therefore, there is always a chance that cheaper energy from the higher-level becomes imported to the local market. In this situation, if DERs apply capacity withholding strategy, their chance of being dropped out of the market will rise. Note that, the other generators of the distribution system are price-takers.

The bidding process in the day-ahead market contains three steps, as shown by the dark green bar in Fig. 1. In step 1, the WF-ESS tries to generate its strategic bids in terms of price and quantities in the day-ahead market. This strategic bidding of the WF-ESS in the day-ahead market is modelled through a bi-level optimization shown in Fig. 2. The bi-level optimization contains two levels in which the upper-level problem is from the WF-ESS's perspective and the lower-level problem is from the DMO market clearing's perspective. Through this bi-level optimization, the

Table 3
Decision variables.

$E_{e,t}$	Energy stored (state-of-charge) in the ESS [MWh].
$f^{p}_{l,t}/f^{q}_{l,t}$	Active/reactive power over line l [MW/MVAr].
$I_{l,t}/I_{l,t,s}$	Square current over line l [A].
$\widehat{o}^{E}_{c,t}$	Energy offer price of WF-ESS [€/MWh].
$\widehat{o}^{Rech}_{e,t}$	Downward reserve offer price of ESS [€/MW].
$\widehat{o}^{Redis}_{e,t}$	Upward reserve offer price of ESS [€/MW].
$P^{ch/dis}_{e,t}$	Charging/discharging rate of ESS in day-ahead energy market [MW].
$\widehat{P}^{ch/BL}_{e,t}$	Energy quantity bid/offer ESS in balancing market (downward regulation) [MW].
$\widehat{P}^{dis/BL}_{e,t}$	Energy quantity bid/offer ESS in balancing market (upward regulation) [MW].
$P^{ch/BL}_{e,t}$	Charging rate of ESS in balancing market(downward regulation) [MW].
$P^{dis/BL}_{e,t}$	Discharging rate of ESS in balancing market (upward regulation) [MW].
$\widehat{P}^{DA}_{c,t}$	Energy quantity bid/offer by WF-ESS at time t, [MW].
$P^{DA}_{c,t}$	Scheduled energy from the WF-ESS in day-ahead energy market [MW].
$P^{DT/DN}_{i,t}/P^{DT/UP}_{i,t}$	Downward/upward regulation in the balancing market at N_{D-T} node at the distribution system [MW].
$P_{g,t}/Q_{g,t}$	Scheduled active/reactive power output from generator g [MW/MVAr].
$P^{w}_{w,t}$	Scheduled wind power in day-ahead market [MW].
$P^{TD}_{i,t}/Q^{TD}_{i,t}$	Real/reactive power injection in T-D interface node i [MW/MVAr].
$P^{DT}_{i,t}$	Real power injection in interface node i$\in N_{D-T}$ [MW].
$P^{DN/UP}_{g,t}$	Downward/upward regulation from generator g in balancing market [MW].
$P^{Totalrealtime}_{c,t,s}$	Actual power produced by the WF-ESS in scenario s and time t [MW].
$R^{DN/UP}_{g,t}$	Scheduled downward/upward reserve capacity of the generator g [MW].
$R^{ch/dis}_{e,t}$	Charging/discharging rate of ESS in reserve market (downward/upward reserve) [MW].
$\widehat{R}^{ch/dis}_{e,t}$	Upward/ downward reserve bid/offer by storage system e at time t, [MW].
$R^{DT/DN}_{i,t}$	Aggregated upward reserve at node i$\in N_{D-T}$ [MW].
$R^{DT/UP}_{i,t}$	Aggregated downward reserve at node i$\in N_{D-T}$ [MW].
$R^{DER}_{i,t}$	Aggregated reserve capacity from DERs at T-D node [MW].
$u_{e,t}$	Binary variable related to the charging state of storage.
$V_{i,t}$	Square bus voltage [p.u.] at node i$\in N_{D}$
$y_{t,s}$	Binary variable defines the positive and negative imbalance of WF-ESS.
$z_{t,s}$	Binary variable related to the imbalance direction of WF-ESS.
$\Delta_{c,t,s}$	Imbalance of WF-ESS in scenario s and time t [MW].
$\Delta^{+}_{c,t,s}$	Positive imbalance of WF-ESS and time t [MW].
$\Delta^{-}_{c,t,s}$	Negative imbalance of WF-ESS and time t [MW].
$\Delta_{w,t,s}$	Imbalance of wind farm and time t [MW].
$\Delta^{+}_{w,t,s}$	Positive imbalance of wind farm and time t [MW].
$\Delta^{-}_{w,t,s}$	Negative imbalance of wind farm and time t [MW].
$\lambda^{DA}_{i,t}$	Local day-ahead energy market price [€/MWh].
$\lambda^{DN/UP}_{t}$	Downward/upward reserve market price [€/MW].
$\lambda^{BL}_{i,t}$	Balancing market price [€/MWh].
$\theta_{i,t}$	Transmission bus angle.

WF-ESS makes its offering decisions in the upper-level while anticipating the market behaviour of other market players which is modelled in the lower-level within the day-ahead market clearing by the DMO.

In step 2, the day-ahead market is cleared by the DMO. The reason for having this step – even though the day-ahead market clearing by the DMO is taking into account in the lower-level problem in step 1 – is that there is uncertainty in how much power flow over interface transformer between distribution and transmission system is. Therefore, the lower-level problem in step 1, cannot reflect the real market, and therefore, step 2 is needed. Step 2, the day-ahead market-clearing, contains all three steps (I–III) in the day-ahead market shown in the grey flowchart in Fig. 1 which are explained in Section 3. The output of step 2 is the cleared local market prices and the scheduled energy and reserve capacities for the DERs including the WF-ESS.

Finally, step 3 is the remuneration phase in which the WF-ESS calculates its day-ahead revenue based on the cleared market prices and its scheduled energy and reserve capacity obtained in step 2. The corresponding mathematical formulations are presented in Section 5.1.

4.2. Balancing market

Unlike the day-ahead market, in the balancing market, it is more difficult to exercise market power by the DERs. The reason is that first of all, the amount of MWh energy traded in the balancing market is significantly smaller than in the day-ahead market. Secondly, since in the balancing market, the exact location for the required imbalances is not known by the DERs, it can be risky to perform market power. As DERs would get their market power from possible congestion which arising from the imbalances or the reserve activation, the chance that they will not be called in the balancing market is significantly higher then

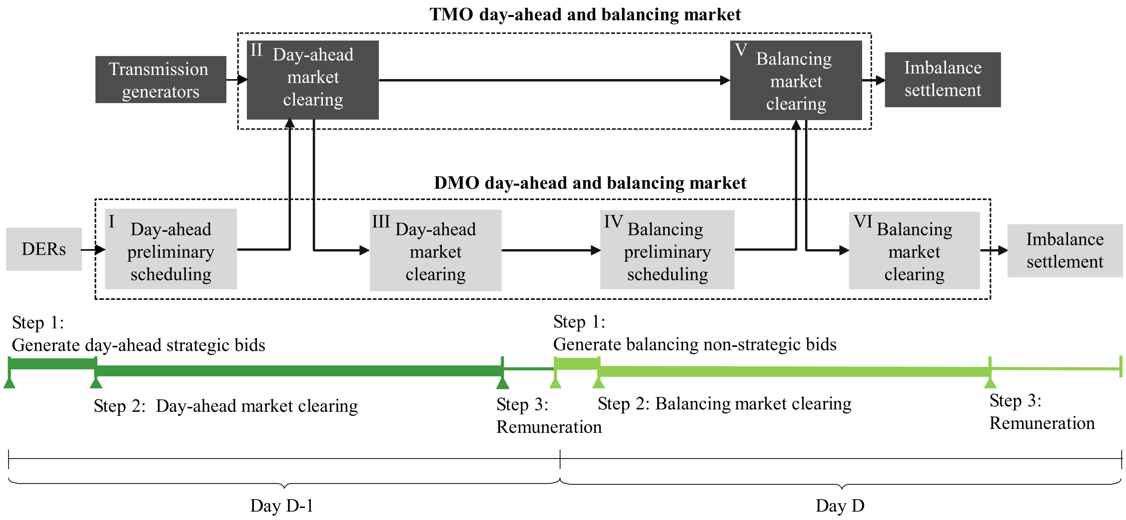

Fig. 1. Coupled market model and DER's bidding steps in day-ahead and balancing markets.

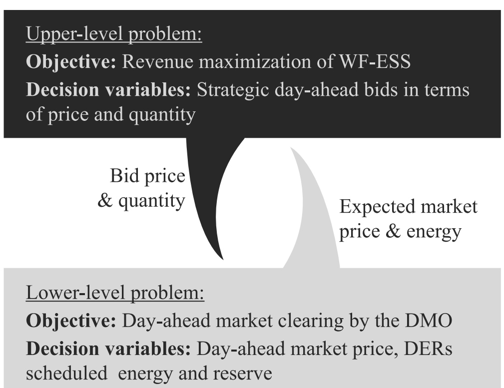

Fig. 2. Step 1: Generate day-ahead strategic bids through a bi-level optimization.

in the day-ahead market. Therefore, the revenue maximization problem for the WF-ESS in the balancing market is the same as the WF-ESS being non-strategic, i.e. a price-taker. Moreover, the balancing market clearing is modelled through a shrinking rolling horizon due to having a storage system, since the energy or the state of charge of the storage system at time t depends on its energy at the previous time $t-1$. The starting rolling time is reset to each time the day-ahead market is cleared. This period includes 96 intervals in 24 h. At the start of each interval, a new forecast becomes available. At each step inside the rolling horizon, the horizon is shrunk by one time-step and the balancing market is solved over the remaining horizon. Each of these shrinking horizon problems gives the bid for the current time. The last assumption is regarding the pricing mechanism in imbalance settlements. In this paper, the dual pricing is applied. The Ref. [34] explains the feature for the dual versus single pricing mechanism, in detail. The dual-pricing mechanism is more complicated than the single-pricing, therefore, to have a broader formulation, the dual-pricing mechanism has been chosen in this paper. However, the approach can easily be adapted for the single-pricing mechanism too.

The storage system of the WF-ESS can actively bid into the balancing market. However, the wind farm alone cannot participate in the balancing market, instead, it can only pay or being paid in the imbalance settlement depending on its imbalance direction with respect to the total system imbalance. The bidding in the balancing market also contains three steps shown in the light green bar in Fig. 1. Step 1 is generating non-strategic bids in terms of price and quantities. Therefore, the WF-ESS solves a self-scheduling problem to determine its most beneficial actions (bids) for given prices. Step 2, is the balancing market-clearing which contains all three steps (IV–VI) in the balancing market. The results of this step are local balancing market prices and quantities and imbalances. Finally, step 3 is the remuneration in the imbalance settlement phase based on the dual-pricing mechanism. if Wf-ESS's imbalance is in the opposite direction of the system imbalance, he has to pay the price equal to the day-ahead market price. But if its imbalance is in the same direction with the total system imbalance, he has to pay the price based on the marginal cost of the last balancing unit deployed, which is usually higher than the day-ahead market price. The corresponding mathematical formulations are presented in Section 5.2.

5. Mathematical formulations

In this section, the mathematical formulations for the revenue maximization of the WF-ESS are presented. The mathematical formulations are for the WF-ESS case, as this is a more complicated case study than the wind farm alone. However, the formulations can easily be adapted for the wind farm case by setting the storage system size equal to zero. Section 5.1 shows the mathematical formulation regarding the strategic optimization of the WF-ESS in the day-ahead market and Section 5.2 describes the mathematical formulation for the non-strategic optimization of the WF-ESS in the balancing market.

5.1. Mathematical formulations: Revenue maximization in the day-ahead market

As it has been explained, the revenue maximization problem of the WF-ESS in the day-ahead market consists of three steps. The mathematical formulation for steps 1–3 is described as follows.

- **Step 1. Generate day-ahead strategic bids**
  In step 1, through a bi-level optimization shown in Fig. 2, the WF-ESS tries to generate its strategic bidding in terms of price and quantities. The upper and lower levels of the bi-level optimization are formulated as follow:

    1. Upper-level problem:

The upper-level is from the WF-ESS's perspective which is maximizing the revenue of the WF-ESS and its objective function is shown in (1):

$$\text{Maximize} \sum_{t}[\sum_{c}\lambda^{DA}_{c\in i,t}\cdot P^{DA}_{c,t}+\sum_{e}\lambda^{UP}_{t}\cdot R^{dis}_{e,t}+\lambda^{DN}_{t}\cdot R^{ch}_{e,t}] \tag{1}$$

The objective function in (1) consists of several parts. The first part is the day-ahead energy bidding revenue of the WF-ESS. The expected day-ahead market price, $\lambda^{DA}_{c\in i,t}$, is the Lagrangian multiplier of the power balance equation in the lower-level problem. The second part is the revenue from selling upward and downward regulations by the storage in the reserve market. The expected reserve prices, λ^{UP}_{t} and λ^{DN}_{t}, are the Lagrangian multipliers belong to constraints (A.4) and (A.5) in the lower-level problem.
Following constraints need to be enforced:

$$\widehat{P}^{DA}_{c,t}=\sum_{w\in c}P^{w}_{w,t}+\sum_{e\in c}(P^{dis}_{e,t}-P^{ch}_{e,t}),\ \forall c,t \tag{2}$$

$$0\le P^{w}_{w,t}\le P^{Wmax}_{w},\ \forall w,t \tag{3}$$

$$-\sum_{e\in c}P^{ch,max}_{e}\le\widehat{P}^{DA}_{c,t}\le\sum_{e,w\in c}(P^{Wmax}_{w}+P^{dis,max}_{e}),\ \forall c,t \tag{4}$$

$$0\le\widehat{R}^{ch}_{e,t}\le P^{ch,max}_{e},\ \forall e,t \tag{5}$$

$$0\le\widehat{R}^{dis}_{e,t}\le P^{dis,max}_{e},\ \forall e,t \tag{6}$$

$$0\le P^{ch}_{e,t}\le u_{e,t}\cdot P^{ch,max}_{e},\ \forall e,t \tag{7}$$

$$0\le P^{dis}_{e,t}\le(1-u_{e,t})\cdot P^{dis,max}_{e},\ \forall e,t \tag{8}$$

$$0\le P^{ch}_{e,t}+\widehat{R}^{ch}_{e,t}\le P^{ch,max}_{e},\ \forall e,t \tag{9}$$

$$0\le P^{dis}_{e,t}+\widehat{R}^{dis}_{e,t}\le P^{dis,max}_{e},\ \forall e,t \tag{10}$$

$$\widehat{o}^{Redis}_{e,t},\widehat{o}^{Rech}_{e,t},\widehat{o}^{E}_{c,t}\ge 0,\ \forall c,e\in c,t \tag{11}$$

$$E^{min}_{e}\le E_{e,t}\le E^{max}_{e},\ \forall e,t \tag{12}$$

$$E_{e,1}=E^{ini}_{e},\ \forall e \tag{13}$$

$$E_{e,t}=E_{e,t-1}+(P^{ch}_{e,t}+\widehat{R}^{ch}_{e,t})\cdot\eta^{ch}-\frac{(P^{dis}_{e,t}+\widehat{R}^{dis}_{e,t})}{\eta^{dis}},\ \forall e,1<t \tag{14}$$

Constraint (2) defines the total energy bid by the WF-ESS in the day-ahead market which is a combination of the energy from the wind farm and the storage system. Constraint (3) limits the bidding by the wind farm in the day-ahead market to its installed capacity and (4) limits the total energy bids by the WF-ESS to the summation of the installed capacity of the wind farm and the storage system. Constraints (5) and (6) enforce limits for the downward and upward reserves by the storage system, $R^{ch}_{e,t}$ and $R^{cdis}_{e,t}$, respectively. Similarly, (7) and (8) limit the bidding by the storage system in the day-ahead energy market. Constraints (9) and (10) show that the total charging and discharging of the storage in the reserve and energy markets should be less than the charging and discharging capacity of the storage system, respectively. Constraint (11) shows the offer prices of the WF-ESS in the day-ahead energy and reserve markets should be more than zero. Finally, (12)–(14) enforce limits to the state of charge for the storage system.

2. Lower-level problem:
   The lower-level is from day-ahead market clearing by the DMO. This local day-ahead market is cleared by solving the optimization problem defined by constraints (15)–(A.16). The primal variable is set $\{P_{g,t}, Q_{g,t}, R^{UP}_{g,t}, R^{DN}_{g,t}, P^{DA}_{c,t}, R^{ch}_{e,t}, R^{dis}_{e,t}, V_{i,t}, I_{l,t}, f^{p}_{l,t}, f^{q}_{l,t}\}$. All dual variables are given in a parentheses in front of constraints.

$$\begin{aligned}\text{Minimize} &\sum_{t\in T}\sum_{g\in G_D}(O^{E}_{g,t}\cdot P_{g,t}+O^{RUP}_{g,t}\cdot R^{UP}_{g,t}+O^{RDN}_{g,t}\cdot R^{DN}_{g,t})\\ &+\sum_{t\in T}[\sum_{c}\widehat{o}^{E}_{c,t}\cdot P^{DA}_{c,t}\\ &+\sum_{e\in c}(\widehat{o}^{Rech}_{e,t}\cdot R^{ch}_{e,t}+\widehat{o}^{Redis}_{e,t}\cdot R^{dis}_{e,t})]\\ &+\sum_{t}\sum_{i\in N_{D-T}}\sum_{s}\pi_{s}\cdot\lambda^{TD}_{t,s}\cdot P^{TD}_{t,i}\end{aligned} \tag{15}$$

   The objective function in (15) minimizes the total energy and reserve capacity costs from DERs (shown in the first line), and the energy and the reserve capacity cost form the WF-ESS (shown in the second line) in the joint day-ahead market. The objective function is subjected to the constraints which are mainly distribution system constraints. The distribution system is represented through a second-order cone programming (SOCP) relaxation, which is tight for radial distribution systems [35]. Through the SOCP relaxation, the distribution system constraints become convex which is a necessary condition for solving the bi-level optimization problems. The constraints are shown in Appendix A.
3. Solving the bi-level optimization problem:
   To solve the bi-level problem, first, the lower-level problem of DMO-market-clearing including Eqs. (15)–(A.16) are replaced by their Karush–Kuhn–Tucker (KKT) conditions. Note that these KKT conditions provide the optimality conditions since the lower-level problem is convex. Then, the KKT equations of the lower level problem will be added to the upper-level problem including Eqs. (1)–(14). The resulting single-level optimization model is a mathematical problem with equivalent constraints (MPEC). This problem, however, is non-linear. There are two sources of non-linearity that can be linearized as described below:

- The first source of non-linearity is the set of complementarity conditions that are within the KKT conditions. Each complementarity condition can be linearized using a "Big-M" approach [36].
- The second source of non-linearity comes from the bilinear terms in the objective function (1). Inspired from [37], we linearize those bilinear terms.

After solving the aforementioned non-linearity in the MPEC model, it turns into a mixed integer linear problem which its output is the strategic bidding prices ($\widehat{o}^{E}_{c,t}$, $\widehat{o}^{Redis}_{e,t}$, $\widehat{o}^{Rech}_{e,t}$) and quantities ($\widehat{P}^{DA}_{c,t}$, $\widehat{R}^{ch}_{e,t}$, $\widehat{R}^{dis}_{e,t}$) by which WF-ESS participates in the day-ahead market in step 2.

- **Step 2. Day-ahead market clearing**
In this step, the day-ahead market is cleared. As it is explained in Section 3, the day-ahead market in the coupled market model consists of three steps. The first step is the preliminary scheduling, the second step is the wholesale market clearing and the third step is the local day-ahead market clearing. A complete mathematical formulation for the day-ahead market in the coupled market model is explained in [6]. However, to clarify the inputs and outputs of this step, a short explanation together with a simplified formulation is presented below.

1. Step I: Day-ahead preliminary scheduling by the DMO:
The DMO first aggregates all the bids and offers from the DERs by solving a preliminary scheduling problem where the objective function is minimizing the total cost of energy and reserve capacity. The objective function is shown in (16).

$$\begin{aligned} Minimize \sum_{t\in T}\sum_{g\in G_D}&(O^{E}_{g,t}\cdot P_{g,t}+O^{RUP}_{g,t}\cdot R^{UP}_{g,t}+O^{RDN}_{g,t}\cdot R^{DN}_{g,t})\\ &+\sum_{t\in T}[\sum_{c}\widehat{o}^{E}_{c,t}\cdot P^{DA}_{c,t}\\ &+\sum_{e\in c}(\widehat{o}^{Rech}_{e,t}\cdot R^{ch}_{e,t}+\widehat{o}^{Redis}_{e,t}\cdot R^{dis}_{e,t})]\\ &+\sum_{t}\sum_{i\in N_{D-T}}\sum_{s}\pi_s\cdot\lambda^{TD}_{t,s}\cdot P^{TD}_{t,i} \end{aligned} \tag{16}$$

Eq. (16) minimizes the total cost of generation and reserve capacity of the DERs in the local market plus the expected cost of buying/selling energy and reserve from/to the TMO market. The cost of this energy is the day-ahead price in the wholesale market. This price has to be estimated by the DMO and is therefore based on a set of scenarios and their associated probabilities of occurrence. Note that $\widehat{o}^{E}_{c,t}$, $\widehat{o}^{Rech}_{e,t}$ and $\widehat{o}^{Redis}_{e,t}$ in (16) are no longer decision variables, but parameters which are the output of the bi-level optimization in step 1. Constraints of the objective function in (16) are similar to the ones in (A.1)–(A.16).
Through this preliminary scheduling, the local market price for energy and reserve will be determined. The energy price ($\lambda^{DA}_{i,t}$) is the Lagrange multiplier of the power balance equation at the interface node between the TSO and DSO, which can be determined by deriving the KKT conditions of the above convex optimization problem. Moreover, the Lagrangian multiplier of (A.4) and (A.5) symbolized with λ^{UP}_{t} and λ^{DN}_{t}, are the price for the upward and downward reserve capacity in the distribution system. The power injected at the interface node ($\widetilde{P^{TD}_{i,t}}$), total reserve capacity of DERs ($\widetilde{R^{UP/DN}_{g,t}}$), energy price ($\lambda^{DA}_{i,t}$) and reserve price ($\lambda^{UP/DN}_{t}$) are outputs of this step by which the DMO participates in the wholesale market.
2. Step II: Day-ahead market clearing by the TMO:
In this step, the wholesale day-ahead joint energy and reserve capacity market is cleared by the TMO. The DMO and transmission generators participate in this market. The objective of this market is maximizing social welfare. However, since in this paper the demand is considered to be inelastic, the social welfare is equivalent to minimizing the total generation cost.

$$\begin{aligned} Minimize \sum_{t\in T}\sum_{g\in G_T}&(O^{E}_{g,t}\cdot P_{g,t}+O^{RUP}_{g,t}\cdot R^{UP}_{g,t}+O^{RDN}_{g,t}\cdot R^{DN}_{g,t})\\ &+\sum_{t\in T}\sum_{i\in N_{T-D}}(\lambda^{DA}_{i,t}\cdot P^{DT}_{i,t}\\ &+\lambda^{UP}_{t}\cdot R^{DT/UP}_{i,t}-\lambda^{DN}_{t}\cdot R^{DT/DN}_{i,t}) \end{aligned} \tag{17}$$

The first line in (17) consists of the cost of energy and reserve capacity procured by the transmission generators. The second line accounts for the total costs of energy and reserve capacity procured by the DERs. The objective function is subjected to the transmission system constraints. In a transmission system, the error in the DC power flow is less than in the distribution system, therefore a DC power flow can be used to model the transmission system constraints. The constraints can be found in Appendix B. After clearing this market, the DMO is informed about the allocated power flow over the interface transformer ($\widetilde{P^{DT}_{i,t}}$) and the required reserve capacity from DERs ($\widetilde{R^{DT/UP}_{i,t}}$ and $\widetilde{R^{DT/DN}_{i,t}}$).
3. Step III: Day-ahead market clearing by the DMO:
In this step, the DMO clears the day-ahead joint energy and reserve capacity market based on the updated information from step II. This local day-ahead market is cleared with the objective function shown by (18):

$$\begin{aligned} Minimize \sum_{t\in T}\sum_{g\in G_D}&(O^{E}_{g,t}\cdot P_{g,t}+O^{RUP}_{g,t}\cdot R^{UP}_{g,t}+O^{RDN}_{g,t}\cdot R^{DN}_{g,t})\\ &+\sum_{t\in T}[\sum_{c}\widehat{o}^{E}_{c,t}\cdot P^{DA}_{c,t}\\ &+\sum_{e\in c}(\widehat{o}^{Rech}_{e,t}\cdot R^{ch}_{e,t}+\widehat{o}^{Redis}_{e,t}\cdot R^{dis}_{e,t})] \end{aligned} \tag{18}$$

The objective function in (18) is minimizing the total generation cost of DERs in the distribution system. The constraints in this step are mostly similar to the preliminary scheduling. The differences are in the power balance equation in (19) and the required upward and downward reserves in (20) and (21) which are written as follows:

$$\begin{aligned} &\sum_{l=(j,i)}(f^{p}_{l,t}-I_{l,t}\cdot r_l)+\sum_{g\in G_D}P_{g,t}+\sum_{c\in i}P^{DA}_{c,t}-\widetilde{P^{DT}_{i,t}}\\ &\quad=P^{load}_{i,t}+\sum_{l=(i,j)}f^{p}_{l,t}+G_i\cdot V_{i,t},\forall i\in N_D,t \end{aligned} \tag{19}$$

$$\sum_{g\in G_D} R^{UP}_{g,t} + \sum_{e} R^{dis}_{e,t} \geq \widetilde{R^{DT/UP}_{i,t}}, \forall i \in N_{D-T}, t \tag{20}$$

$$\sum_{g\in G_D} R^{DN}_{g,t} + \sum_{e} R^{ch}_{e,t} \geq \widetilde{R^{DT/DN}_{i,t}}, \forall i \in N_{D-T}, t \tag{21}$$

In (19), $\widetilde{P^{DT}_{i,t}}$ is a parameter symbolizing the power flow injected at the interface node of the distribution system. In (20) and (21), $\widetilde{R^{DT/UP}_{i,t}}$ and $\widetilde{R^{DT/DN}_{i,t}}$ are parameters symbolizing the required upward and downward reserves in the distribution system, respectively, which are generated in step II. The rest of the constraints are similar with the ones in (A.1), (A.3), and (A.6)–(A.16) shown in Appendix A. The outputs of this step, regarding the upward and downward reserve capacity ($\widetilde{R^{UP/DN}_{g,t}}$ and $\widetilde{R^{dis/ch}_{e,t}}$) and the scheduled energy of dispatchable generators ($\widetilde{P_{g,t}}$ and $\widetilde{P^{DA}_{c,t}}$), are inputs for the balancing market which is explained further in Section 5.2.

- **Step 3. Remuneration**
  In this step, according to the cleared day-ahead market price ($\lambda^{DA}_{i,t}$ and $\lambda^{UP/DN}_{t}$) and quantities ($\widetilde{P^{DA}_{c,t}}$ and $\widetilde{R^{dis/ch}_{e,t}}$) obtained in step 2, the day-ahead revenue of the WF-ESS is calculated as shown in (22):

$$\sum_{t}[\sum_{c} \lambda^{DA}_{c\in i,t} \cdot \widetilde{P^{DA}_{c,t}} + \sum_{e} \lambda^{UP}_{t} \cdot \widetilde{R^{dis}_{e,t}} + \lambda^{DN}_{t} \cdot \widetilde{R^{ch}_{e,t}}] \tag{22}$$

5.2. Mathematical formulations: Revenue maximization in the balancing market

As explained earlier in Section 4.2, the bidding of the WF-ESS in the balancing market is non-strategic. The revenue calculations of the WF-ESS in the balancing market has three steps. Step 1 is to generate the bids through a self-optimization problem. Step 2 is the balancing market clearing process including three steps (4–6) of the coupled market model explained in Section 3. Lastly, step 3 is the remuneration phase in which the WF-ESS calculates its balancing revenue based on a dual-pricing mechanism.

These three steps need to be performed through a shrinking rolling horizon approach. The balancing market is cleared every 15 min in a time window of 24 h. At each time interval inside the rolling horizon, the horizon is shrunk by a one time step and the optimization is solved over the remaining horizon with the new forecasts of the current day. The forecast is for the uncertain parameters which are dependent on scenarios. Wind output ($P^{Wact}_{w,t,s}$), the imbalance prices ($\lambda^{+/-}_{t,s}$), and the total system imbalance ($SI_{t,s}$) are the uncertain scenario-based parameters in step 1. Indeed, there is no uncertainty in steps 2 and 3 which happen in real-time. Each of these shrinking horizon solutions gives the current variable outputs and at the current time. Mathematical formulations belong to steps 1–3 are described as follows.

- **Step 1: Generate balancing-non-strategic bids**
  In step 1, the WF-ESS solves a self-scheduling problem to determine its most beneficial actions in the balancing market in terms of its bidding volume for a given price and for the time-horizon of 24 h.

$$\begin{aligned}&\sum_{t}[\sum_{e\in c}\sum_{s} \pi_s \cdot ((\lambda^{+}_{t,s} \cdot P^{dis/BL}_{e,t,s} - \lambda^{-}_{t,s} \cdot P^{ch/BL}_{e,t,s})\\ &+ \sum_{c}(\lambda^{DA}_{c\in i,t} \cdot (1-z_{t,s}) \cdot \Delta_{c,t,s})\\ &+ \sum_{c}(\lambda^{+}_{t,s} \cdot z_{t,s} \cdot y_{t,s} \cdot \Delta^{+}_{c,t,s} + \lambda^{-}_{t,s} \cdot z_{t,s} \cdot (1-y_{t,s}) \cdot \Delta^{-}_{c,t,s}))]\end{aligned} \tag{23}$$

The objective function in (23) consists of three parts. The first term is the revenue obtained by the storage system due to actively bidding in the balancing market. The second and the third terms belong to the imbalance settlement in which the storage system pays or is being paid, depending on whether or not its imbalance is in the opposite direction with the total system imbalance. As the dual-pricing mechanism is applied, in the case in which the deviation is in the same direction with the total system imbalance, the WF-ESS has to pay with a price equal to the $\lambda^{DA}_{c\in i,t}$, otherwise, it is being paid by a price equal to $\lambda^{+}_{t,s}$ or $\lambda^{-}_{t,s}$ depending on having a short or long imbalance, respectively. As mentioned earlier, this step happens before the real-time, hence the wind power and imbalance prices and the total imbalance of the system are scenario-dependent. Constraints Eqs. (24)–(39) need to be enforced.

$$\Delta_{c,t,s} = P^{Totalrealtime}_{c,t,s} - \widetilde{P^{DA}_{c,t}}, \forall c, t, s \tag{24}$$

$$\Delta_{c,t,s} \cdot SI_{t,s} \leq z_{t,s} \cdot M, \forall c, t, s \tag{25}$$

$$\Delta_{c,t,s} \cdot SI_{t,s} \geq -(1-z_{t,s}) \cdot M, \forall c, t, s \tag{26}$$

$$P^{Totalrealtime}_{c,t,s} = \sum_{w\in c} P^{Wact}_{w,t,s} + \sum_{e\in c}(\widehat{P}^{dis/BL}_{e,t,s} - \widehat{P}^{ch/BL}_{e,t,s}), \forall c, t, s \tag{27}$$

$$\Delta_{c,t,s} = \Delta^{+}_{c,t,s} - \Delta^{-}_{c,t,s}, \forall c, t, s \tag{28}$$

$$0 \leq \Delta^{+}_{c,t,s} \leq y_{t,s} \cdot (\sum_{w\in c} P^{Wact}_{w,t,s} + \sum_{e\in c} P^{dis,max}_{e}), \forall c, t, s \tag{29}$$

$$0 \leq \Delta^{-}_{c,t,s} \leq (1-y_{t,s}) \cdot \widetilde{P^{DA}_{c,t}}, \forall c, t, s \tag{30}$$

$$\widehat{P}^{ch/BL}_{e,t,s} + \widetilde{P^{ch}_{e,t}} \leq P^{ch,max}_{e}, \forall e, t, s \tag{31}$$

$$\widehat{P}^{dis/BL}_{e,t,s} + \widetilde{P^{dis}_{e,t}} \leq P^{dia,max}_{e}, \forall e, t, s \tag{32}$$

$$0 \leq \widehat{P}^{ch/BL}_{e,t,s} \leq u_{e,t,s} \cdot P^{ch,max}_{e}, \forall e, t, s \tag{33}$$

$$0 \leq \widehat{P}^{dis/BL}_{e,t,s} \leq (1-u_{e,t,s}) \cdot P^{dis,max}_{e}, \forall e, t, s \tag{34}$$

$$\widehat{P}^{ch/BL}_{e,t,s} \leq \widetilde{R^{ch}_{e,t}}, \forall e, t, s \tag{35}$$

$$\widehat{P}^{dis/BL}_{e,t,s} \leq \widetilde{R^{dis}_{e,t}}, \forall e, t, s \quad (36)$$

$$E^{min}_{e} \leq E_{e,t} \leq E^{max}_{e}, \forall e, t, s \quad (37)$$

$$E_{e,1} = E^{ini}_{e}, \forall e \quad (38)$$

$$E_{e,t} = E_{e,t-1} + \sum_{s} \pi_s \cdot (P^{ch/BL}_{e,t,s} \cdot \eta^{ch} - \frac{P^{dis/BL}_{e,t,s}}{\eta^{dis}}), \forall e, t > 1 \quad (39)$$

Constraints (24) and (27) are related to the amount of the imbalances caused by the WF-ESS. Constraints (25) and (26) define the direction of the imbalance of the WF-ESS with respect to the total system imbalance. $SI_{t,s}$ indicates the total system imbalance and is scenario-based. Constraints (28)–(30) define the positive and negative imbalance by WF-ESS. Constraints (31) and (32) limit the upward and downward energy of the storage system in the balancing market. Constraints (33)–(36) limit the charging an discharging of the storage system with respect to the scheduled energy of the storage in the day-ahead market ($\widetilde{P^{dis}_{e,t}}$ and $\widetilde{P^{ch}_{e,t}}$). Finally, (37)–(39) depict the state of the charging of the storage systems. The output of this optimization is an estimated bidding energy of the WF-ESS by which it will participate in the balancing market.

- **Step 2: balancing market clearing**
This step includes steps IV–VI in the coupled market model shown in Fig. 1 and explained in Section 3. In [6], the formulation for each step is described in detail, but for clarity, each step is formulated briefly here as well. Note that, τ in the equations below is the time unit of the balancing market in the shrinking rolling horizon.

1. Step IV: Balancing preliminary scheduling:
In this step, the DMO estimates the local balancing market price by which it participates in the central real-time balancing market. The objective function is minimizing the expected cost of balancing services at the distribution system shown in (40).

$$\begin{aligned} Minimize\{ & \sum_{g \in G_D} (O^{EUP}_{g,\tau} \cdot P^{UP}_{g,\tau} - O^{EDN}_{g,\tau} \cdot P^{DN}_{g,\tau}) \\ & + \sum_{e} (O^{Edis}_{e,\tau} \cdot P^{dis/BL}_{e,\tau} - O^{Ech}_{e,\tau} \cdot P^{ch/BL}_{e,\tau}) \\ & + \sum_{i \in N_{D-T}} \sum_{s} \pi_s \cdot (\lambda^{+}_{\tau,s} \cdot P^{DT/UP}_{i,\tau} - \lambda^{-}_{\tau,s} \cdot P^{DT/DN}_{i,\tau})\} \end{aligned} \quad (40)$$

The first and the second term in (40) is the cost of the balancing services procured from the DERs and the third term belongs to the cost of balancing services procured by the transmission system. The following constraints need to be imposed:

$$\begin{aligned} (\lambda^{DBL}_{i,\tau}): \quad & \sum_{l=(j,i)} (f^{p}_{l,\tau} - I_{l,\tau}.r_l) + \sum_{g \in i} (\widetilde{P_{g,\tau}} + P^{UP}_{g,\tau} - P^{DN}_{g,\tau}) \\ & + (\widetilde{P^{DA}_{c,\tau}} + P^{dis/BL}_{e,\tau} - P^{ch/BL}_{e,\tau}) \\ & + \sum_{i \in N_{D-T}} (P^{DT/UP}_{i,\tau} - P^{DT/DN}_{i,\tau}) = \alpha_{Imb} \cdot SI_{\tau,s} \\ & + P^{load}_{i,\tau} + \sum_{l=(i,j)} f^{p}_{l,t} + G_i.V_{i,t}, \forall i \in N_D \end{aligned} \quad (41)$$

$$\widetilde{P_{g,\tau}} + P^{UP}_{g,\tau} \leq P^{gmax}_{g}, \forall g \in G_D \quad (42)$$

$$\widetilde{P_{g,\tau}} - P^{DN}_{g,\tau} \geq P^{gmin}_{g}, \forall g \in G_D \quad (43)$$

$$-\widetilde{R^{UP/DN}_{g,\tau}} \leq P^{UP/DN}_{g,\tau} \leq \widetilde{R^{UP/DN}_{g,\tau}}, \forall g \in G_D \quad (44)$$

Constraint (41) is the power balance equation. α_{Imb} is the fraction of the total imbalance system which belongs to the distribution system. Constraints (42)–(44) limit the upward and downward balancing regulations. The rest of the constraints are related to the system constraint which is similar with the ones in (A.1), (A.3), and (A.6)–(A.16) shown in Appendix A. The output of this step is the local balancing market price ($\lambda^{DBL}_{i,\tau}$: the Lagrangian multiplier of (41)) and quantities ($P^{DT/UP}_{i,\tau}$ and $P^{DT/DN}_{i,\tau}$), by which the DMO participate in the TMO-balancing market in step V.

2. Step V: Balancing market clearing by the TMO:
In this step, the TMO clears the real-time central balancing market. Generators connected to the transmission system and the DMO with aggregated bids from the DERs participate in this market (see Fig. 1). This is the objective function:

$$\begin{aligned} Minimize & \sum_{g \in G_T} (O^{EUP}_{g,\tau} \cdot P^{UP}_{g,\tau} - O^{EDN}_{g,\tau} \cdot P^{DN}_{g,\tau}) \\ & + \sum_{i \in N_{T-D}} \lambda^{DBL}_{i,\tau} \cdot (P^{DT/UP}_{i,\tau} - P^{DT/DN}_{i,\tau}) \end{aligned} \quad (45)$$

The first term is related to the cost of balancing services from the transmission generators. In the second term, $\lambda^{DBL}_{i,\tau}$ is the price of balancing services form aggregated the DERs by the DMO. The system constraints of the transmission system are enforced as shown in (B.1)–(B.10) in Appendix B. The results of this step, which will be passed on to the DMO, is indicating the deployed energy from transmission to the distribution system.

3. Step VI: Balancing market clearing by the DMO:
In this step, the DMO clears the local balancing market. The objective function is minimizing the balancing service cost deployed by the DERs:

$$\begin{aligned} Minimize\{ & \sum_{g \in G_D} (O^{EUP}_{g,\tau} \cdot P^{UP}_{g,\tau} - O^{EDN}_{g,\tau} \cdot P^{DN}_{g,\tau}) \\ & + \sum_{e} (O^{Edis}_{e,\tau} \cdot P^{dis/BL}_{e,\tau} - O^{Ech}_{e,\tau} \cdot P^{ch/BL}_{e,\tau})\} \end{aligned} \quad (46)$$

The power balance equation is as follow:

$$\begin{aligned} (\lambda^{DBL}_{i,\tau}): \quad & \sum_{l=(j,i)} (f^{p}_{l,\tau} - I_{l,\tau}.r_l) + \sum_{g \in i} (\widetilde{P_{g,\tau}} + P^{UP}_{g,\tau} - P^{DN}_{g,\tau}) \\ & + (\widetilde{P^{DA}_{c,\tau}} + P^{dis/BL}_{e,\tau} - P^{ch/BL}_{e,\tau}) \\ & + \sum_{i \in N_{D-T}} (\widetilde{P^{DT/UP}_{i,\tau}} - \widetilde{P^{DT/DN}_{i,\tau}}) = P^{load}_{i,\tau} \\ & + \sum_{l=(i,j)} f^{p}_{l,\tau} + G_i.V_{i,\tau}, \forall i \in N_D \end{aligned} \quad (47)$$

In the power balance equation in (47), $\widetilde{\Delta P^{DT}_{i,\tau}}$ is the scheduled adjustment from transmission level to the distribution level which has been calculated in step V. The rest of the constraints are similar with the system constraints shown in Appendix A. The output of this step is the cleared balancing market price ($\lambda_{i,\tau}^{DBL}$) and quantities ($\widetilde{P_{e,\tau}^{dis/BL}}, \widetilde{P_{e,\tau}^{ch/BL}}$) by which the WF-ESS calculates its revenue in step 3.

- **Step 3: Remuneration**
This step, which happens at the imbalance settlement phase, calculates the revenue of the WF-ESS by the cleared balancing market price and quantities obtained in step VI of step 2. As explained in Section 3, in the imbalance settlement of the balancing market, the dual pricing mechanism is applied. Therefore, the revenue calculation is as follow:

$$\sum_{e\in c}(\lambda_{\tau}^{DBL}\cdot\widetilde{P_{e,\tau}^{dis/BL}}-\lambda_{\tau}^{DBL}\cdot\widetilde{P_{e,\tau}^{ch/BL}}) \\ -\sum_{c}(\lambda_{\tau}^{DA}\cdot a\cdot\widetilde{\Delta_{c,\tau,s_r}^{+}}+\lambda_{\tau}^{DA}\cdot b\cdot\widetilde{\Delta_{c,\tau,s_r}^{-}}) \\ +\sum_{c}(\lambda_{\tau}^{DBL}\cdot c\cdot\widetilde{\Delta_{c,\tau,s_r}^{+}}+\lambda_{\tau}^{DBL}\cdot d\cdot\widetilde{\Delta_{c,\tau,s_r}^{-}}) \tag{48}$$

where a, b, c, d are binary parameters which at each moment only one of them is equal to one and the rest are zero. For example, $a = 1$ means that in the real-time the imbalance caused by the WF-ESS is positive ($Delta_{c,\tau,s_r}^{+}$) and is in-line with the direction of the total system imbalance. Therefore, the WF-ESS should pay for causing this imbalance in the system at the rate of the day-ahead market price. The definitions of $\widetilde{\Delta_{c,\tau,s_r}^{+}}$, $\widetilde{\Delta_{c,\tau,s_r}^{-}}$ are based on the (24)–(30). However, the difference is that in (48) , $\widetilde{\Delta_{c,\tau,s_r}^{+}}$ and $\widetilde{\Delta_{c,\tau,s_r}^{-}}$ do not depend on the scenario, since this step is after scenario realizations. Note that s_r is one realized scenario. $\widetilde{P_{e,\tau}^{dis/BL}}$ and $\widetilde{P_{e,\tau}^{ch/BL}}$ are cleared charging and discharging of storage system in the balancing market obtained in step VI of step 2.

6. Input data and case studies

In this section, the input data and main case studies which have been used for the simulations are described.

6.1. Input data

The proposed coupled TMO–DMO market model is tested using a radial 30-bus medium voltage Dutch distribution system and the IEEE-24 bus transmission system [38] as shwon in Fig. 3. The data for the offer prices of distributed generators are from [39]. Tables 4 and 5 summarize the data for generators at transmission and distribution network level, respectively. The WF-ESS is located at bus number 19 (at the end of the feeder) of the distribution system with a wind farm with an installed capacity of 6 MW. The storage system has 5 MW charging and discharging capacity with an efficiency of 80%. The wind speed data are from the Royal Netherlands Meteorological Institute (KNMI) [40]. The day-ahead and imbalance market prices and total system imbalances are for the Netherlands and obtained from the ENTSO-e transparency platform [41]. The residential loads in the distribution system are generated with the method described in [42]. For the industrial loads, the data for the Netherlands from the NEDU profiles [43] has been used. To generate the scenarios an Artificial Neural Network modelling approach is applied in order to obtain a set of scenarios of wind power generation, day-ahead, and imbalance market prices. The time resolution of the day-ahead market is one hour with a time horizon of 24-hours and the balancing market is 15 min. α_T is considered as 30% of the total installed generation at the transmission system and α_{Imb} is the ratio of the total installed DERs to the total load of the system. The mathematical models are formulated in the General Algebraic Modelling System (GAMS) and solved with the solvers CPLEX and MOSEK on a computer with CPU E5-2697 v3@2.6 GHz. The computational time for the participation of the WF-ESS in one time-step of the day-ahead market (i.e. 1 h) and the balancing market (i.e. 15 min) of the coupled market model is 34 s and 16 s, respectively.

Table 4
Data for transmission generators.

Gens. bus no.	P_g^{gmax} MW	P_g^{gmin} MW	$O_{g,t}^{E}$ €/MWh	$O_{g,t}^{RUP/DN}$ €/MW
1	15.2	3,4	90.58	50
2	15.2	3,4	90.58	50
7	30	7.5	130.63	70
13	59.1	20,85	130.27	70
15	60	12	210	120
15	15.5	5,25	60.75	40
16	15.5	5,25	60.75	40
18	40	40	30.39	20
21	40	40	30.39	20
23	31	10,5	60.75	40
23	35	14	70.03	50

Table 5
Data for distribution generators.

Gens. bus no.	P_g^{gmax} MW	$O_{g,t}^{E}$ €/MWh	$O_{g,t}^{RUP/DN}$ €/MW
3	1.96	25	12
4	0.98	20	10
5	1.96	15	7.5
17	0.98	30	15
19	5	15	7.5
26	1.96	22	12
29	0.98	18	9
31	0.98	18	9

6.2. Case studies

In this section, the case studies which are going to be analysed in the results section are introduced. The first one is regarding the market model and the second one is about different sorts of DERs.

6.2.1. Market model case studies

In this paper, in addition to the coupled market model which is explained earlier, a centralized market is also considered as the benchmark. This market model is more compatible with the current electricity market regulation. More detailed information about the centralized market and its mathematical formulation can be found in Appendix A.

As the WF-ESS is relatively small compared with the size of the market, the WF-ESS cannot behave strategically in the centralized market and therefore his behaviour does not affect the market price. Consequently, the WF-ESS is a price-taker in both day-ahead and balancing markets hence, it solves a self-scheduling problem to determine its most beneficial actions for given prices in day-ahead and/or balancing markets.

6.2.2. DER case studies

In the WF-ESS case, the storage system participates in the energy and reserve capacity market and actively bids into the balancing markets. The wind farm alone, however, is limited in how it can participate in the market. Due to the stochastic nature of wind power, the wind farm alone is considered unable to

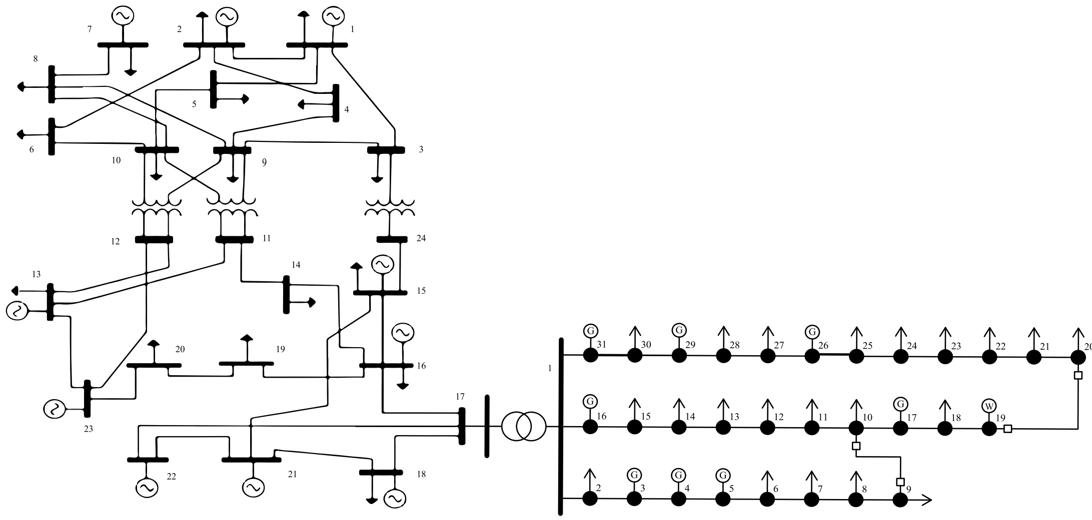

Fig. 3. Connected transmission and distribution system diagram for the case studies.

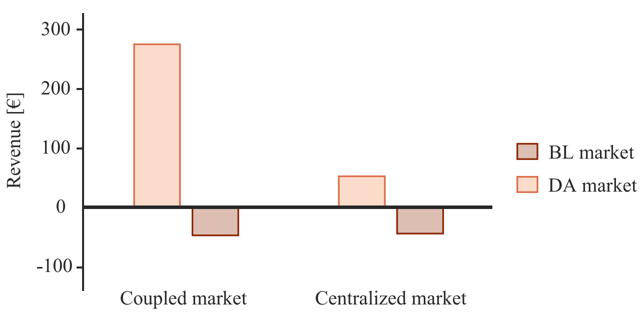

Fig. 4. The revenue of the wind farm in the coupled versus the centralized market.

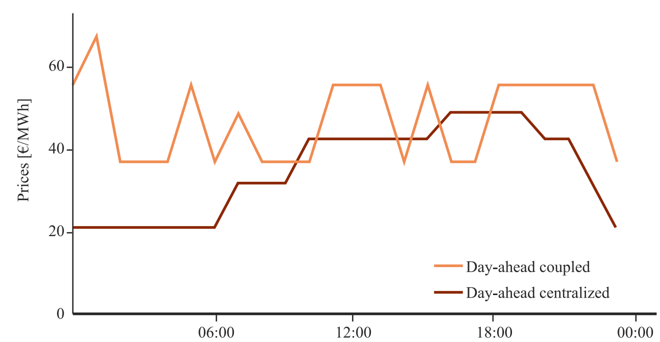

Fig. 5. The DA market price in the coupled versus centralized market.

participate in the reserve capacity market and/or actively bid into the balancing market, so it can only actively bid into the day-ahead energy market. However, in the balancing market, the wind farm may have to be paid or pay the market imbalance price (based on the assumed dual pricing scheme), depending on its real-time deviation with respect to the total system imbalance.

Because of higher complexity in the WF-ESS compared with the wind farm case, the mathematical formulations have been presented for the WF-ESS case. However, these formulations can be easily adapted for the wind farm alone, if one sets the capacity of the storage system equal to zero.

7. Results and discussion

In this section, the numerical results of the simulation are shown. In Section 7.1, the results of the wind farm's revenue in the coupled versus the centralized market are presented. In Section 7.2, the results of sensitivity analysis for changing the distribution system parameter, e.g. resistance and loads, and their effects on the day-ahead revenue and bidding wind energy by the wind farm are presented. In Section 7.3, the wind generation of the wind farm at different resistance rates in the coupled market is compared with the one in the centralized market model. Finally, in Section 7.4, the revenue of the wind farm is compared with the case in which the wind farm is equipped with a storage system. Therefore, the results of the performance of the WF-ESS in the coupled and centralized market is shown in this section.

7.1. Wind farm's revenues in the coupled versus centralized market

Fig. 4 shows the revenues of the wind farm in day-ahead and balancing markets for different market models. As this figure shows, in the coupled market model, the day-ahead revenue is significantly higher compared to the one in the centralized market model. The reason is indeed the strategic behaviour of the wind farm in the day-ahead coupled market which leads to higher market prices. For the comparison, Fig. 5 shows the day-ahead market prices in the coupled versus centralized market models and is showing a relatively higher value for day-ahead market prices in the coupled market.

As expected, the revenue in balancing markets is lower than the revenue in the day-ahead market for both market models. Moreover, for both market models, the balancing market revenue is negative which means that the wind farm has to pay the imbalance penalty cost to the system. Compared to the day-ahead market, there is not that much of a difference between the balancing revenue of coupled and centralized markets. The reason is that, as explained in Section 4.2, in the balancing market of the coupled market model, the wind farm cannot exercise market power. However, the difference is significantly higher in the day-ahead revenue of the wind farm when it participates strategically in the coupled market in comparison with its non-strategic day-ahead revenue in the centralized market.

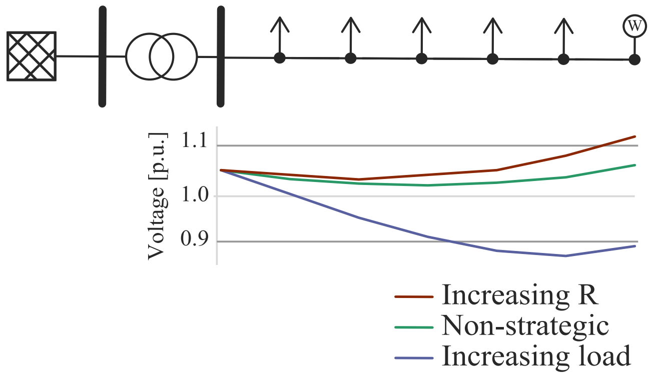

Fig. 6. The effect of increasing resistance and loads on the voltage through the feeder.

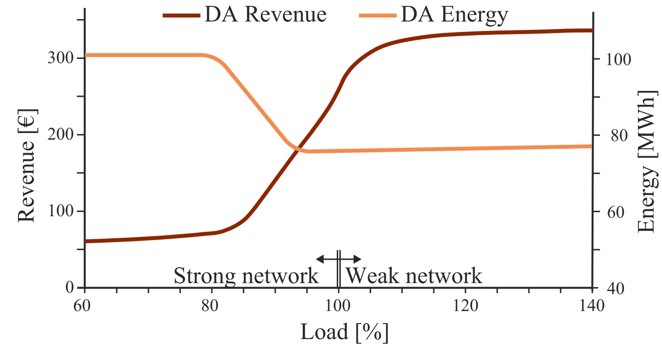

Fig. 7. The effect of increasing loads on the day-ahead energy and revenue of wind farm.

7.2. The effect of distribution system parameters on exercising market power by the strategic wind farm

To see the effect of distribution system parameters on the revenue of strategic market players, two parameters are being changed, loads, and the resistance of branches. In the distribution systems, cables are usually being used and their reactant compared with the resistance have smaller values. Therefore, changing the resistance of cables can be sufficient for studying the effect of branch parameters on the strategic biding of DERs. Performing this sensitivity analysis helps to understand whether or not changing loads and resistances, effects on the bidding volume and the revenue of the strategic wind farm. Before answering this question, one needs to study the effect of varying the resistance or loads on the security element of the distribution system, i.e. the voltage. To a better understanding of this effect, an example in Fig. 6 has been demonstrated. This figure shows a feeder where at its end, there is a generator, and in the middle, there are some loads. The generator's situation is almost comparable to the wind farm. In the diagram in Fig. 6, there are three curves showing voltage magnitude through the feeder in three different cases. The green curve in the middle is related to the normal situation where there is not increasing loads or resistance, hence the voltage along the feeder is always in the secure range. The red curve is related to the case where the resistance is increasing. As it is shown, the voltage along the feeder is increasing too, so that at the end of the feeder, there is an over-voltage. In contrast, by increasing the loads, the voltage along the feeder is decreasing in such a way that at the end of the feeder an under-voltage happens. This is shown by the blue curve in the diagram. Therefore, in both cases, i.e. either increasing the loads or increasing the resistance, the voltage at the end of the feeder-where the generator is located can be higher or lower than the security limits. Hence, the generator reacts differently to each of the two cases. In the case where the resistance is increasing, to counteract the over-voltage, the generator has to reduce its generation. This prevents the generator to exercise the market power because the generator knows that its power is not required by the system. In contrast, in the case where the loads are increasing, to counteract the under-voltages, the generator should inject more power to raise the voltage. Therefore, in this case, the generator by knowing this fact that its power is being required by the system operator might exercise market power. This market power is performed through an economic withholding which leads to a higher bidding price and a lower bidding quantity.

Now, back to the case study for the wind farm, the effect of increasing loads and resistance are being investigated. First starting with the loads. The effect of increasing the loads on the bidding behaviour of the wind farm is presented in Fig. 7. In the horizontal axis, a different percentage of the load is shown. When the load in the distribution system is decreasing with respect to the base-case, the system is indicated as strong and when the load is increasing, the system is indicated as weak. The red curve in the figure shows the day-ahead revenue of the wind farm in the coupled market model. As it is shown in Fig. 7, by increasing the loads, the day-ahead revenue has an overall increase. However, the revenue stays the same up to the point where the load is 80%. After this point, the revenue starts rising, since the wind farm realizes that it is required by the system operator thanks to its geographical location and the under-voltage which is happened there. Therefore, the wind farm raises the offer prices. On the other hand, at the point where the revenue is increasing, the energy bid by the wind farm is decreasing as it is shown by the orange curve in Fig. 7. In short, Fig. 7 depicts an exercising market power by the wind farm when the loads are increasing. The exercising of the market power by the wind farm is shown through a higher revenue for a lower amount of energy bid into the day-ahead market, which means a higher day-ahead price. As it has been mentioned earlier, this phenomenon is the basis of the economy withholding by which a strategic market player increases its revenue.

Fig. 8 shows an increase in the resistance and its effect on the bidding wind energy and the day-ahead prices. The horizontal axis is the difference percentage of the resistance of the cables. When the resistance of the cables is decreasing, the system is indicated as strong and when the resistance of the cables is increasing with respect to the base-case, the system is indicated as weak. As it is explained by Fig. 6, increasing the resistance will cause an over-voltage at the end of the feeder and therefore, the wind farm has to decrease its power. This is shown by the orange curve in Fig. 8 which has a downward trend. On the other hand, the day-ahead market prices — indicated by the red curve in Fig. 8, is also decreasing as the resistance is increasing. This, therefore, leads to a downward trend in the revenue of the winds farm as well. Therefore, it can be seen that by increasing the resistance, the wind farm cannot perform market power.

7.3. Renewable generation in the coupled versus centralized market

In this part, the difference between the bidding energy by the wind farm in the coupled versus centralized markets with different resistance rates is studied. In the centralized market, as it is explained in Appendix C, distribution system constraints are not taken into account during market clearing. This means that in the centralized market, the feasibility of the distribution system constraints when the DERs are getting dispatched is not considered, and therefore, there might be the chance that they

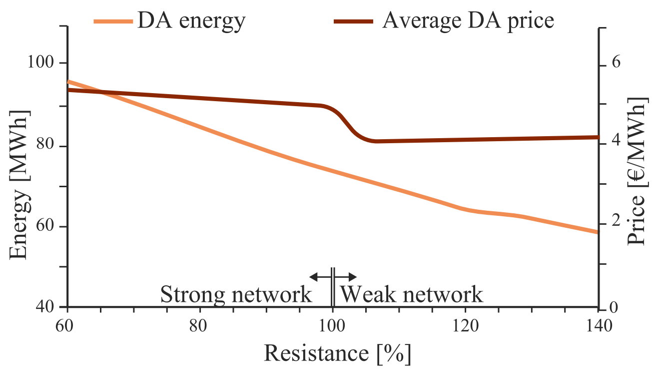

Fig. 8. The effect of increasing cable resistances on the day-ahead energy and revenue of the wind farm.

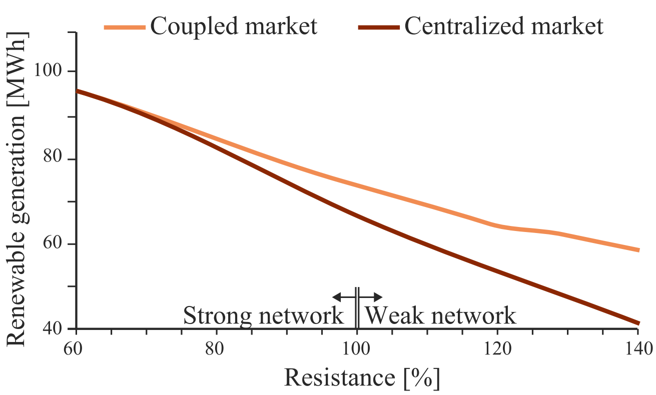

Fig. 9. Wind generation in the coupled and the centralized market.

cause system disturbances. To avoid this, a power flow for the distribution system with different resistance rates is performed, to determine the maximum energy allowed by the wind farm which does not cause disturbances in the distribution system. Then, the maximum energy allowed by the wind farm is getting compared with its bidding energy in the centralized market. If the bidding energy, in the centralized market and at a certain resistance rate, is lower than the maximum allowed energy, there will not be any wind curtailment, otherwise, there will be wind curtailments to reduce the bidding energy to the amount of the maximum allowed energy by the wind farm at that resistance rate.

Fig. 9 shows the bidding wind energy into the day-ahead market in the coupled versus the centralized market. The red curve shows the wind generated by the wind farm in the centralized market and the orange curve shows the one in the coupled market. As is expected, the wind generation in the centralized market has a downward trend by increasing the resistance, the same as that in the coupled market. However, at any resistance rate, the wind generation in the coupled market is higher than the wind generation in the centralized market. In other words, in the coupled market the distribution system is dynamically checked at each moment while in the centralized market, the distribution system is taken into account statically. Therefore, in a weak system where the resistance is higher and the distribution system is more often in danger of disturbance, the renewable-based DERs such as wind farms are more likely to be curtailed. In the coupled market, however, dynamically checking the distribution system let the wind farm to generate at a higher rate. This can be seen in Fig. 9 where for example at 140% resistance, the wind generation in the coupled market is almost 50% higher than the one in the centralized market.

7.4. Effect of storage system on the wind farm's revenue

In this section, the results for the difference between the wind farm alone and the WF-ESS, in terms of their revenues, are presented. These results want to show whether or not being equipped with a storage system is affordable for the wind farm. This comparison is performed for both market models.

Fig. 10 shows the revenues of the WF-ESS in day-ahead and balancing markets for different market models. To make the figure more readable, the results in Fig. 4 are added to Fig. 10 as well. As the figure shows, in the coupled market model, the day-ahead revenue either at the wind farm alone or the WF-ESS case is significantly higher compared to the ones in the centralized market model. The reason is indeed the strategic behaviour of the wind farm and the WF-ESS in the day-ahead coupled market which leads to higher market prices. As expected, Fig. 10 shows that the revenue in balancing markets, for both cases and at both market models are lower than the revenues in day-ahead markets. However, in the case where the wind farm is alone, at both market models, the balancing market revenue is negative which means that the wind farm has to pay the imbalance penalty cost to the system. In contrast, as the storage system can actively bid into the balancing market, the revenue in the balancing market for the WF-ESS either at coupled or centralized market models has positive values which means the WF-ESS can earn some revenue in the balancing market. There is slightly a higher balancing market revenue in the coupled compared to the

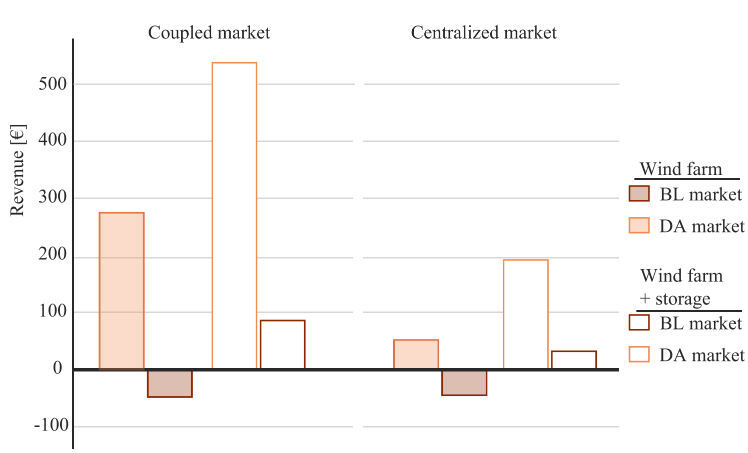

Fig. 10. Revenue of the wind farm and the WF-ESS in the coupled and the centralized market.

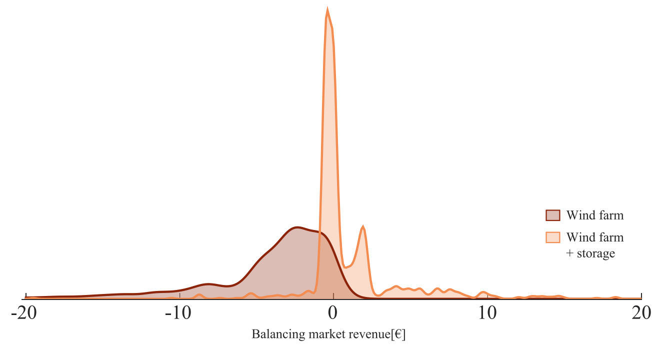

Fig. 11. The probability density function of the revenue in the balancing market for the wind farm and the WF-ESS.

centralized market but comparing this difference with the one in the day-ahead market, this difference is not very significant due to the non-strategic behaviour of market players in the balancing market.

To compare the balancing market revenues for different scenario realizations in two cases of wind farm versus WF-ESS, the probability density function (PDF) of balancing market revenues has been figured. Fig. 11 shows the PDFs for the wind farm versus WF-ESS case in the coupled market which are the results of 960 points consists of 10 scenarios realization for each of the 96-time intervals in the balancing market. The PDF belongs to the WF-ESS case has been shifted to the right in comparison with the one for the wind farm case and shows an increase in the balancing market revenue for the WF-ESS. This means that when the wind farm is provided with a storage system, for different scenario realization, there is a higher revenue compared with the case where the wind farm solely bid into the market and consequently has to pay a penalty cost due to its imbalances caused by the real-time wind power deviated from the bidding energy in the day-ahead market.

It should be mentioned here that to have a better comparison in terms of revenues between the wind farm case and the WF-ESS case, it is also important to take into account the cost of the storage system as well. If for the electrical storage system, a Li-ion battery is being considered, the Levelized cost of storage (LCOS) may be equal to 388 €/MWh. In this case the WF-ESS in the coupled market, with the deducted LCOS from its total revenue, results in a 227 €/MWh net revenue which is equal to the 227 €/MWh revenue of the case where the wind farm is alone. On the other hand, in the centralized market, deducting the LCOS from the total revenue requires a LCOS of 217 €/MWh to have an equal profit to a wind farm without a storage system. Therefore, depending on the market model and whether or not there is market power, a combined wind and storage unit can be an affordable or a non-affordable option in comparison with a case where the wind farm is alone and cannot act strategically.

8. Conclusions

This paper proposes a novel strategic bidding method for the revenue maximization of distributed energy resources (DERs) in a coupled market model. In a coupled market, as described in our earlier work [6], there is – in addition to a central market – a local market operated by the distribution market operator (DMO) to facilitate the participation of DERs. The size of the local market is relatively small, and this increases the chance of some DERs to act strategically. The coupled market consists of day-ahead and balancing markets on two geographical levels. The revenue maximization problem has been modelled through a bi-level shrinking rolling horizon optimization where its upper-level problem is from the strategic DER's perspective and the lower-level problem is from the market operator's (DMO's) perspective. In this paper, a wind farm is considered as the strategic DER, showing that under certain assumptions, also intermittent resources can exercise market power by economic withholding.

The first research question was to quantify the proposed strategic revenue maximization of the wind farm in the coupled market model. To answer this question, the results for the coupled market were compared with the ones for a state-of-art centralized market model where DERs cannot employ strategic behaviour. The results confirm the applicability of the proposed revenue maximization problem and they show that, in general, the wind farm earns higher revenues in the coupled market where it can exercise market power, as compared with the centralized market.

The second research question was whether or not changing the distribution system parameters can affect the revenue of the wind farm and its bidding strategy in the coupled market. Results show that a weak system, with longer feeders and thus higher branch resistances, leads to higher revenues for the wind farm, and lower amounts of energy cleared in the day-ahead market, while a stronger system has a reverse effect. In other words, a strategic market player in a weak system can increase its market power and therefore earn a higher income. In contrast, a strong system prevents exercising market power by market players. Note that these results have to do with the presence of the wind farm at the end of a feeder, therefore having a positive effect on the voltage profile. Moreover, it is seen that in a weak system, wind generation is significantly higher in the coupled market compared with the amounts cleared in the centralized market. This means that the coupled market can better unlock the potential of the renewable-based DERs which want to participate in the market.

The last research question was to see whether or not adding a storage system is affordable for the wind farm. Results show that in both coupled and centralized markets, the combined wind and storage system (WF-ESS) has a higher income compared with the case of the wind farm alone. However, taking into account the Levelized Cost of the Storage and deducting it from the revenue can lead to different net revenue for the wind farm with the storage system in coupled and centralized markets.

Finally, it is important to mention that exercising market power by market players leads to a higher end-user electricity price and consequently a higher social cost. Since in the coupled market design, this market power exists due to the presence of system constraints, the distribution system operator must also investigate the cost of upgrading the system to avoid the occurrence of market power.

CRediT authorship contribution statement

Mana Farrokhseresht: Conceptualization, Ideas, Methodology, Software, Formal analysis , Writing - original draft. **Han Slootweg:** Writing - review & editing, Supervision, Project administration. **Madeleine Gibescu:** Investigation, Writing - review & editing, Supervision, Project administration, Funding acquisition.

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.

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Appendix A. Distribution system constraints

In this section, the constraints that need to be enforced for the distribution system are explained. Given a distribution node $i \in N_D$, j refers to its unique ancestor.

$$(\theta_{i,l,t}): \quad V_{i,t} = V_{j,t} + 2(r_l \cdot f^p_{l,t} + x_l \cdot f^q_{l,t}) + r_l^2 \cdot I_{l,t} + x_l^2 \cdot I_{l,t}, \quad \forall i \in N_D, l \in L_D, t \tag{A.1}$$

$$(\lambda^{DA}_{i,t}): \sum_{l=(j,i)} (f^p_{l,t} - I_{l,t} \cdot r_l) + \sum_{g \in G_D} P_{g,t} + \sum_{w \in i} P^{DA}_{c,t} + P^{TD}_{i,t} = P^{load}_{i,t} + \sum_{l=(i,j)} f^p_{l,t} + G_i \cdot V_{i,t}, \forall i \in N_D, t \tag{A.2}$$

$$(\mu_{i,t}): \quad \sum_{l=(j,i)} (f^q_{l,t} - I_{l,t} \cdot x_l) + \sum_{g \in i} Q_{g,t} + Q^{TD}_{i,t} = Q^{load}_{i,t} + \sum_{l=(i,j)} f^q_{l,t} - b_i \cdot V_{i,t}, \forall i \in N_D, t \tag{A.3}$$

$$(\lambda^{UP}_t): \sum_{g \in G_D} R^{UP}_{g,t} + \sum_{e \in i} R^{dis}_{e,t} \geq 0, \forall t \tag{A.4}$$

$$(\lambda^{DN}_t): \sum_{g \in G_D} R^{DN}_{g,t} + \sum_{e \in i} R^{ch}_{e,t} \geq 0, \forall t \tag{A.5}$$

$$(\varphi^+_{g,t}): \quad P_{g,t} + R^{UP}_{g,t} \leq P^{gmax}_g, \forall g \in G_D, t \tag{A.6}$$

$$(\varphi^-_{g,t}): \quad P_{g,t} - R^{DN}_{g,t} \geq P^{gmin}_g, \forall g \in GD, t \tag{A.7}$$

$$(\xi_{l,t}): \quad (f^p_{l,t})^2 + (f^q_{l,t})^2 \geq I_{l,t} \cdot V_{i,t}, \forall i \in N_D, l = (i,j) \in L_D, t \tag{A.8}$$

$$(\zeta_{l,t}): \quad (f^p_{l,t})^2 + (f^q_{l,t})^2 \leq S^2_{l,t}, \forall i \in N_D, l = (i,j) \in L_D, t \tag{A.9}$$

$$(\phi_{g,t}): \quad (P_{g,t})^2 + (Q_{g,t})^2 \leq S^2_{g,t}, \forall g \in G, t \tag{A.10}$$

$$(\sigma^+_{i,t}, \sigma^-_{i,t}): \quad V^{min}_i \leq V_{i,t} \leq V^{max}_i, \forall i \in N_D, t \tag{A.11}$$

$$(\delta^+_{g,t}, \delta^-_{g,t}): \quad Q^{gmin}_i \leq Q_{g,t} \leq Q^{gmax}_i, \forall g \in G, t \tag{A.12}$$

$$(\beta^+_{g,t}, \beta^-_{g,t}): \quad P^{gmin}_g \leq P_{g,t} \leq P^{gmax}_g, \forall g \in G, t \tag{A.13}$$

$$(\gamma^+_{c,t}, \gamma^-_{c,t}): \quad 0 \leq P^{DA}_{c,t} \leq \widehat{P}^{DA}_{c,t}, \forall c \in C, t \tag{A.14}$$

$$(\psi^+_{e,t}, \psi^-_{e,t}): \quad 0 \leq R^{dis}_{e,t} \leq \widehat{R}^{dis}_{e,t}, \forall e \in E, t \tag{A.15}$$

$$(\vartheta^+_{e,t}, \vartheta^-_{e,t}): \quad 0 \leq R^{ch}_{e,t} \leq \widehat{R}^{ch}_{e,t}, \forall e \in E, t \tag{A.16}$$

Constraint (A.1) accounts for the voltage difference which is induced by the power flow over a line. Constraints (A.2) and (A.3) are active and reactive power balance equations of the distribution system, respectively. In (A.4) and (A.5) the required upward and downward reserves procured from DERs are defined. This constraint guarantees that a certain amount of the total installed capacity from dispatchable generators is available for the balancing purpose. Constraints (A.6) and (A.7) are limits for the reserve capacity of generators. Constraints (A.8) shows the relation between voltage and current and active and reactive power flow over a line and is the conic equation of the distribution system. Constraint (A.9) imposes the congestion limit for the distribution lines. Constraint (A.10) is related to the generation capability curves and is linearized by the method explained in [44]. Constraints (A.11)–(A.16) impose limits on the involved decision variables.

Appendix B. Transmission system constraints

In this section, the constraints that need to be enforced for the transmission system are explained.

$$f^p_{l,t} = B_l(\theta_{i,t} - \theta_{j,t}), \forall (i,j) \in l, l \in L_T, t \tag{B.1}$$

$$-TC_l \leq f^p_{l,t} \leq TC_l, \forall l \in L_T, t \tag{B.2}$$

$$\sum_{g \in G_T} P_{g,t} + P^{DT}_{i,t} + \sum_{(j,i) \in l} f^p_{l,t} = P^{load}_{i,t} + \sum_{(i,j) \in l} f^p_{l,t}, \forall i \in N_T, l \in L_T, t \tag{B.3}$$

$$(R^{DT/UP}_{i,t} - R^{DT/DN}_{i,t}) + \sum_{g \in G_T} (R^{UP}_{g,t} - R^{DN}_{g,t}) \geq \alpha_T . \sum_{g \in G_T} P^{gmax}_g, \forall i \in N_{T-D}, t \tag{B.4}$$

$$P_{g,t} + R^{UP}_{g,t} \leq P^{gmax}_g, \forall g \in G_T, t \tag{B.5}$$

$$P_{g,t} - R^{DN}_{g,t} \geq P^{gmin}_g, \forall g \in G_T, t \tag{B.6}$$

$$P^{gmin}_g \leq P_{g,t} \leq P^{gmax}_g, \forall g \in G_T, t \tag{B.7}$$

$$0 \leq P^{DT}_{i,t} \leq \widetilde{P^{TD}_{i,t}}, \forall i \in N_{T-D}, t \tag{B.8}$$

$$0 \leq R^{DT/UP}_{i,t} \leq \sum_{g \in G_D} \widetilde{R^{UP}_{g,t}}, \forall i \in N_{T-D}, t \tag{B.9}$$

$$0 \leq R^{DT/DN}_{i,t} \leq \sum_{g \in G_D} \widetilde{R^{DN}_{g,t}}, \forall i \in N_{T-D}, t \tag{B.10}$$

Constraint (B.1) considers the power flow over a transmission line and (B.2) imposes a limit on this power flow to the transmission line capacity. In (B.3), the power balance equation is shown. Constraint (B.4) is the required reserve capacity in the transmission system level which is a ratio of the totalled generation directly connected to the transmission system. Constraints (B.5)–(B.6) correspond to limits for the reserve capacity procured from generators in the transmission system. Constraints (B.7) and (B.8) impose limits for the energy from transmission generators and the DMO, respectively. Eqs. (B.9) and (B.10) limit the reserve capacity from the DMO.

Appendix C. Centralized market model

A scheme consisting of centralized day-ahead and balancing markets is considered as the benchmark which has the most compatibility with the current electricity market regulation. The centralized market model is shown in the grey flowchart in Fig. C.12. As it is shown in the figure, there are no DMO-operated local markets, and distribution system constraints are not taken into account. DERs are considered to be connected at the interface node of the transmission system and the TMO operates both day-ahead and balancing markets for all DERs and generators in the transmission system. Same as the coupled market, the day-ahead market is the joint energy and reserve capacity market and there is a similar approach regarding the time resolution, time horizon, and market clearing. To avoid disturbing the distribution system, due to activating the DERs, after market clearing, a power-flow for the distribution system is performed by the distribution system operator, to determine the maximum energy allowed by the DERs which does not cause problems in the distribution system. The centralized market model merely consists of Step 2 and Step 5 (shown in Fig. 1) in the coupled market model. A more detailed explanation for the clearing process in the centralized market can be found in [6]. Below, the revenue maximization problem of the WF-ESS in the centralized market is explained.

C.1. Revenue maximization problem of DERs in the centralized market model

The steps and their sequences in the WF-ESS's bidding in centralized day-ahead and balancing markets are shown in the green bar in Fig. C.12. Relatively speaking, day-ahead and balancing markets in the centralized market model are much bigger than the WF-ESS, hence the WF-ESS cannot behave strategically and exercise market power in the day-ahead market nor the balancing market. The balancing market is also modelled through the rolling shrinking horizon in case of having a storage system, the same as the one in the coupled market model. The dual pricing mechanism is also applied in the imbalance settlement phase.

In both day-ahead and balancing markets, there are three steps. In step 1, generating the non-strategic bids, the WF-ESS solves a self-scheduling problem for given scenario-based market prices to determine its most beneficial actions in terms of bidding volume. Thereafter, in step 2, the unit participates in the day-ahead or balancing markets and the centralized market becomes clear. Finally, in step 3, according to the cleared price and quantities in step 2, the day-ahead or balancing revenue of the WF-ESS is calculated. The corresponding mathematical formulations of WF-ESS revenue in day-ahead and balancing markets are presented below.

C.2. Mathematical formulations: WF-ESS's revenue in the day-ahead market

In this section, the mathematical formulation for the revenue maximization of the WF-ESS in the day-ahead market is presented. As shown in Fig. C.12, there are three steps in day-ahead bidding which are as follows:

- **Step 1: Generate day-ahead non-strategic bids**
  In this step, the WF-ESS solves the following optimization to determine its most optimum bidding volume in the day-ahead market.

$$\begin{aligned} Maximize \sum_{t}[\sum_{c}\sum_{s}\pi_s\cdot\lambda^{TD}_{t,s}\cdot P^{DA}_{c,t} \\ +\sum_{e}\sum_{s}\pi_s\cdot(\lambda^{UP}_{t,s}\cdot R^{dis}_{e,t}+\lambda^{DN}_{t,s}\cdot R^{ch}_{e,t})] \end{aligned} \tag{C.1}$$

  The objective function in Eq. (C.1) consists of the revenue of WF-ESS in day-ahead energy market and the in the reserve market. The constraints for Eq. (C.1) are the same as the ones in Eqs. (2)–(14). The output of this step are the energy ($\widetilde{P^{DA}_{c,t}}$) and reserve ($\widetilde{R^{dis/ch}_{e,t}}$) bidding volume of WF-ESS in the day-ahead market.
- **Step 2: day-ahead market clearing**
  The day-ahead joint market of the centralized model is quite similar to the day-ahead market clearing by the TMO in the coupled market model. The difference is that, for the objective function in the centralized model, $\lambda^{DA}_{i,t}$ and $\lambda^{UP/DN}_{t}$ in (17) are equal to zero. Moreover, $P_{g,t}$ and $R^{UP/DN}_{g,t}$ represent energy and reserve for all generators including DERs and generators at the transmission system. Therefore, the objective function and constraints are as follows:

$$\begin{aligned} Minimize \sum_{t\in T}[\sum_{g\in(G_T\cup G_D)} O^{E}_{g,t}\cdot P_{g,t}+O^{E}_{c,t}\cdot P^{DA}_{c,t}+O^{RUP}_{g,t}\cdot R^{UP}_{g,t} \\ +O^{RDN}_{g,t}\cdot R^{DN}_{g,t} \\ +O^{RUP}_{e,t}\cdot R^{dis}_{e,t}+O^{RDN}_{e,t}\cdot R^{ch}_{e,t}] \end{aligned} \tag{C.2}$$

  The system constraints are quite similar with the constraints in the step of wholesale market clearing by the TMO in the coupled market model shown in Appendix B. The only difference is in the power balance equation in (B.3) where $P^{load}_{i,t}$ belongs to the loads of the transmission and distribution systems. The output of this step is cleared market prices ($\lambda^{DA}_{i,t}$, $\lambda^{UP/DN}_{t}$) and dispatching of energy and reserve of generators ($\widetilde{P_{g,t}}$, $\widetilde{P^{DA}_{c,t}}$, $\widetilde{R^{UP/DN}_{g,t}}$, $\widetilde{R^{dis/ch}_{e,t}}$).
- **Step 3: Remuneration**
  In this step, the revenue of the WF-ESS is calculated based on the cleared day-ahead market price and quantities obtained in step 2:

$$Revenue=\sum_{t}[\sum_{c}\lambda^{DA}_{c\in i,t}\cdot\widetilde{P^{DA}_{c,t}}+\sum_{e}(\lambda^{UP}_{t}\cdot\widetilde{R^{dis}_{e,t}}+\lambda^{DN}_{t}\cdot\widetilde{R^{ch}_{e,t}})] \tag{C.3}$$

C.3. Mathematical formulations: WF-ESS's revenue in the balancing market

As the light green bar in Fig. C.12 shows, the revenue maximization of WF-ESS in the balancing market consists of three steps, the same as the one in the day-ahead market. These steps are explained below.

- **Step 1: Generate balancing non-strategic bids**
  In this step, same as the one in the coupled market, the WF-ESS tries to calculate its energy bidding in the balancing market based on scenario-based positive and negative imbalance prices and the cleared day-ahead market prices:

$$\begin{aligned} \sum_{t}[\sum_{e\in c}\sum_{s}\pi_s\cdot(\lambda^{+}_{t,s}\cdot P^{dis}_{e,t}-\lambda^{-}_{t,s}\cdot P^{ch}_{e,t})+\sum_{c}(\lambda^{DA}_{t}\cdot(1-z_t)\cdot\Delta_{c,t} \\ +\sum_{s}\pi_s.(\lambda^{+}_{t,s}\cdot z_t\cdot y_t\cdot\Delta^{+}_{c,t}+\lambda^{-}_{t,s}\cdot z_t\cdot(1-y_t)\cdot\Delta^{-}_{c,t}))] \end{aligned} \tag{C.4}$$

  The formulation of the objective function in (C.4) is similar with the one in (23) hence its constraints are also the same as in (24)–(39). The output of this step is the bidding volume ($\widetilde{P^{dis/ch}_{e,t}}$) of the unit in the balancing market.

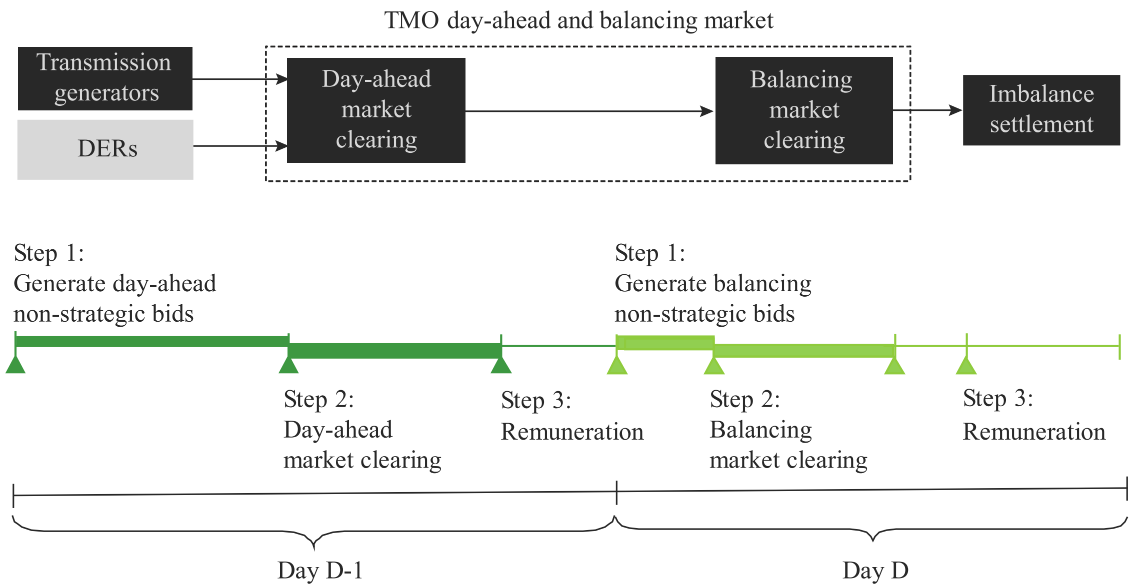

Fig. C.12. Centralized market model.

- **Step 2: balancing market clearing**
  In this step, the balancing market is cleared. The shrinking rolling horizon approach is applied here as well to clear the balancing markets. The objective function is minimizing the total balancing service by the TMO as shown in (C.5):

$$\begin{aligned} Minimize \sum_{g\in G_T \cup G_D} (O^{EUP}_{g,\tau}.P^{UP}_{g,\tau} - O^{EDN}_{g,\tau}.P^{DN}_{g,\tau}) \\ + \sum_{e} (O^{Edis}_{e,\tau} \cdot P^{dis/BL}_{e,\tau} - O^{Ech}_{e,\tau} \cdot P^{ch/BL}_{e,\tau}) \end{aligned} \tag{C.5}$$

  Following constraints need to be enforced:

$$\begin{aligned} (\lambda^{BL}_{i,\tau}): \quad & \sum_{g\in G_T \cup G_D} (\widetilde{P_{g,\tau}} + (P^{UP}_{g,\tau} - P^{DN}_{g,\tau})) \\ & + \sum_{c,e\in c} (\widetilde{P^{DA}_{c,\tau}} + P^{dis/BL}_{e,\tau} - P^{ch/BL}_{e,\tau}) \\ & + \sum_{(j,i)\in l} f^{p}_{l,\tau} = SI + P^{load}_{i,\tau} \\ & + \sum_{(i,j)\in l} f^{p}_{l,\tau}, \forall i \in N_T/N_{T-D}, l \in L_T, t \end{aligned} \tag{C.6}$$

$$P^{ch/BL}_{e,\tau} \leq \widetilde{P^{ch/BL}_{e,\tau}}, \forall e, \tau \tag{C.7}$$

$$P^{dis/BL}_{e,\tau} \leq \widetilde{P^{dis/BL}_{e,\tau}}, \forall e, \tau \tag{C.8}$$

  The rest of the constraints are similar as the ones in Appendix B. The output of this step is the cleared balancing market price ($\widetilde{\lambda^{BL}_{i,\tau}}$) and the cleared upward and downward energy ($\widetilde{P^{dis/BL}_{e,\tau}}$, $\widetilde{P^{ch/BL}_{e,\tau}}$) in the balancing market.
- **Step 3: Remuneration**
  Finally, at the imbalance settlement phase, the WF-ESS calculates its revenue based on dual pricing mechanism and cleared balancing market prices ($\widetilde{\lambda^{BL}_{i,\tau}}$) and the cleared upward and downward energy ($\widetilde{P^{dis/BL}_{e,\tau}}$, $\widetilde{P^{ch/BL}_{e,\tau}}$), obtained in step 2.

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