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THE PARTICIPATION OF SMALL-SCALE VARIABLE DISTRIBUTED RENEWABLE ENERGY SOURCES TO THE BALANCING SERVICES MARKET

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The Participation of Small-scale Variable Distributed Renewable Energy Sources to the Balancing Services Market

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Abstract

The paper considers different market settings for the participation to the balancing services market of small scale variable renewable energy sources connected at the distribution level to the grid. By mixing an economical and a technical approach, it evaluates the efficiency of participation to the market under two opposite settings: a commercial scheme and a technical one. In the former, the supply of the small scale variable distributed renewable energy sources are grouped on a purely commercial basis; in the latter, the DSO is responsible of the imbalances that may possibly arise in the distribution grid. By considering a reference distribution network and designing scenarios for the forecast uncertainty about supply and demand of power profiles, the impact of different market frameworks is assessed. The upward and downward balancing services provided by variable distributed energy resources and controllable units connected to the high voltage grid are both considered. Moreover, the power supply curtailments, that endogenously arise due to the violation of technical constraints of the distribution grid and the random nature of energy supply by renewables, are addressed, for each specific market model. It is shown that the social costs of balancing energy provision can be higher or lower according to the market framework and the specific scenario, depending on the relative share of the different types of distributed renewable energy sources as well as on the amount of reserved energy for balancing services and their cost.

Keywords: small scale variable distributed renewable energy sources; distribution network; market models; aggregator; network externalities and efficiency

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1 Introduction

The diffusion of new energy production plants, especially the non-dispatchable ones, made grid management much more challenging in the past years, for example increasing the costs for the reserve margins provision [1] and giving rise to the risk of unintentional islanding of portions of the power system [2] due to the large diffusion of small scale units, especially at low voltage level [3]. This condition asked for a deep rethinking of energy network functioning, including data communication protocols and rules for the operators [4, 5]. European policy related to the Energy Transition, synthesized in the so called "Clean Energy for all Europeans" package, still fosters investments in the renewable energy production: Europe, indeed, wants to maintain its leadership in the renewable production [6]. Technical improvements and new challenges, however, shall be placed side by side with changes in the energy markets, also re-designing roles for actual and future actors of these markets [7]. In particular, it is necessary to provide a proper market design to efficiently include small scale Variable Distributed Energy Resources (from now onward simply V-DER) and allow all the operators to participate to the balancing service market[1] [8]. Designing new markets is a major issue for the functioning of the energy system as a whole. As the vast majority of new scattered non-dispachable power plants are connected to the medium and low voltage grids (i.e. the distribution network), it is recognized that this power system level shall play a fundamental role in new market design [9]. Distribution System Operators (DSOs) role is particularly interesting: DSOs deeply know the grid they manage in terms of technical features, especially regarding capability and congestions deriving from grid structures, active connections, loads and productions. V-DER typically have a small scale and are connected at the distribution level. Often households invest on them to benefit from the bundle of services they offer such as increasing energy efficiency, improved heating and cooling, higher stability of energy provision. To ease market participation and foster V-DER adoption, new business has emerged from so called *aggregators* that group V-DER and act as intermediaries between households/owners of V-DER and markets to ease V-DER access to market participation. As suggested by the name itself, aggregators are companies that collect and organize small producers or loads in order to supply services to the network: even if each small unit could - in principle - directly participate in the market, the presence of aggregators can be operationally useful for operators, as they cover a part that technically should/could be carried out by DSOs, but for some relevant reasons, e.g. unbundling rules, it is entrusted to another party.

To identify the best way to organize the balancing services market and its regulation, it is necessary to start studying possible ways in which V-DER can participate to it taking into account both the economic implications and the related technical aspects. This work is a first attempt in this sense: through an interdisciplinary approach, we evaluate what are the impacts on the overall cost of the balancing service in the case of different market organizations that can be adopted to allow for V-DER participation. More precisely, we investigate the impact of two different market design for V-DER provision of balancing services. As it is well known, balancing energy is distinguished between upward and downward energy provision[2]. The former is balancing energy needed to cover an equivalent lack of energy supply, i.e. a downward imbalance, and it can be provided by increasing the power produced or decreasing the load. Similarly, downward energy provision refers to the reduction of energy injected or the increase of load and it is needed in case of excess of supply

[1] From now onward we shall refer to the balancing service market as the marketplace where balancing services are exchanged, where the latter are to be understood as energy used to perform balancing and provided by a balancing service provider.

[2] Upward energy provision is also termed as up-regulation, and downward balancing energy as down-regulation.

or demand shortage, i.e., when an upward imbalance arises. We aim at establishing the impact that market design, characterized particularly by different roles played by DSOs, have on upward and downward balancing energy provision and on network externalities. The latter measures the balancing costs and benefits arising from V-DER participation to the balancing market. The evaluation is considered from the standpoint of the whole system, i.e., establishing a social cost function of the balancing service.

Moving from technical studies and from the results obtained by other projects in recent years ([10]; [11] [12]) in the paper we establish the cost effect of two possible market frameworks for balancing energy supplied by V-DER. Under the first type of market participation, that stems form the characteristics of the existing (high voltage) balancing markets and replicates such a market design at the distribution level, aggregators operate grouping V-DER, regardless of any technical feasibility of the load profile supplied by V-DER. The DSO is in charge of keeping grid's technical reliability. Under the second, polar case, the DSO is responsible for keeping an agreed exchange path with the TSO, being thus responsible for local balancing and choosing resources to be called in the market. Balancing energy offered by aggregators is accepted on the basis of both economic and technical feasibility. The two solutions have different implications in the technical management of the grid: the economic analysis aims at identifying the effects of the two alternatives on overall social cost for balancing services. In order to do so, we first setup a theoretical reference model and then perform a simulation using a rich enough reference Low Voltage network, under the two polar market scenarios. This allows establishing the impact that different market rules have on network externalities and social welfare. Different market rules will lead to different levels of system costs (bared by different agents): a careful analysis of the results coming from possible alternatives will help regulators and decision makers in setting the functioning rules.

The analysis we develop here is of particular importance for the evaluation of the contribution that V-DER can play for the Energy Transition, for three reasons. First of all, because a high market share of energy from V-DER can induce a relevant amount of imbalances, due to their limited dispatchability, which can negatively impact the welfare accruing from energy provision. Moreover, because the technical rules that describe how V-DER can participate to the market and the network externalities that derive from their application have an impact also on the possibility that the energy that can be supplied from V-DER is effectively delivered, depending on the technical limits of the power grid, which can limit the full potentiality of V-DER energy supply. Finally, because the these rules impact also on the profitability of both the V-DER and the backup (fully-dispatchable) plants and therefore on the incentives to invest on these sources.

The paper is organized as follows: Section 2 provides a brief review of the main background literature of the work; Section 3 presents the analytical framework in which we are operating, and describes the two market models we analyse. In Section 4 we present the simulation model and in Section 5 we perform simulations regarding the two alternative market organizations. Results are presented and discussed in Section 6, Section 7 concludes. In the Appendix the extension to the multiple aggregators case is discussed.

2 Literature background

Renewable energy sources (RES) participation to the energy markets has been theoretically analysed in a wide literature ([13] [14]; [15]; [16]; [17]; [18], among others), showing that real-time energy markets can be worth to participate in for RES plants. RES to ancillary and balancing markets is one relevant aspect of their integration in the electricity system ([19]), but there is a need for modifications in both design and rules of current markets to allow renewables' participation ([20]). Despite the great attention to the topic and the political commitment in pursuing new markets to integrate renewables, still a coordinated and effective regulation lacks ([21]). In this sense, main issues are related to how to regulate the sector in presence of high innovation and high uncertainty ([22]). The network needs to be upgraded with new investments that can reduce uncertainties and foster small producers' participation, increasing competition level ([23]). Literature on regulation is also focused on how to design tariffs ([24]) and how to regulate old and new agents: this is particularly true for network operators ([25]; [26]) and aggregators ([27]; [28]; [29]). Medium and low voltage networks see the participation of many renewable energy producers, or prosumers, characterized by small size: in this context, the figure of the aggregator has taken hold as a subject capable of bringing into the market very diversified operators. Aggregators should be able to coordinate different production and consumption patterns connected to a specific local grid, and organize and manage network services to be sold to DSOs and (or) to TSOs. [30] revised the role of aggregators under an economic perspective, identifying the conditions under which these subjects can create value for the system and suggesting policy solutions to eliminate potentials for economic inefficiencies deriving from opportunistic behaviours. The authors underlined that most important advantages deriving from the presence of aggregators are economies of scale, scope and uncertainty management. In the design of future energy markets, the effects that new market frameworks have on power systems shall be clearly analysed and evaluated. Attempts to welfare analysis of RES integration ([31] pave the way to a deeper evaluation on local electricity markets. This is the purpose of the present work.

3 Analytical framework

3.1 Balancing services market frameworks

We build a model representing system balancing costs in a scenario where V-DER participate to the balancing market: depending on the market framework, different cost levels are reached. The target for a properly designed regulation is to choose the market model that minimizes the overall cost of balancing. Starting from what has already been proposed in the literature [32] we consider two polar solutions for participation of small scale V-DER to balancing markets, a *commercial* aggregation and a *technical* one[3]. The balancing process modelled in this work relies on three main actors categories:

- the Transmission System Operator (TSO), in charge of managing the transmission system through the selection of offers from the balancing services market;
- the Distribution System Operator (DSO), in charge of managing the distribution network;
- aggregator/s of distributed resources that forecast and publish a consumption profile on day D−1 and offer balancing products on day D exploiting the V-DER availability.

Flexible resources connected at High-Voltage (HV) level are also present in the environment, but they are external to the model. In the model, only one distribution network managed by a DSO

[3] In the literature there is no agreed terminology to define different types of V-DER market participation to balancing markets. We refer here to *commercial* and *technical* to highlight the emphasis on the shift of balancing responsibility between the two models, fully described in the following paragraph.

is considered in the relationship with the transmission network (and the TSO). Our focus here is on the impact that market rules have on overall costs, net of any strategic interaction. Therefore, we do not model neither the interplay between aggregators and DSO nor between aggregators and single power producers/investor, and assume for simplicity that a single aggregator exists. In the appendix, we report the comparative static result when there is more than one aggregator (yet without any strategic interaction).

We distinguish between Model 1, i.e. market model organized with *commercial* aggregation and Model 2, i.e. market model organized with *technical* aggregation. Model 1 foresees a commercial aggregation of V-DERs, meaning that the aggregator gathers the energy provided by V-DERs for balancing services provision without caring about the physical location of V-DER, but just on commercial basis, i.e. to make a competitive price/quantity offer to the TSO. Both the aggregators and the HV flexible resources submit bids directly to the TSO in the balancing services market. Once the aggregator has his offer accepted in the market, it will dispatch its units (connected at distribution level) such as to provide the required service. In this model, the DSO only has a technical role in managing the distribution network. Its objective is just to ensure the safe operation of this portion of the power system, therefore it will allow V-DERs dispatching as long as it meets the technical constraints of the distribution network. In case of biting technical constraints, the DSO, who has no commercial function, is forced to disconnect V-DER to prevent the violation (e.g. over-voltage issue or congestion of a distribution line). Due to this, the balancing service by the aggregator cannot be provided, plus there is a reduction of energy supply due to disconnection, which causes a further imbalance to be covered with other resources in the market. Furthermore, since no information is provided by the aggregator on the composition of V-DER aggregated, upon refusal of the dispatching order by the DSO, the TSO is forced not to accept the whole offer by the aggregator[4]. Summarizing the phases involved in model 1 implementation:

1. the aggregator/s collects all the V-DER availability and presents a single offer for upward and a single offer for downward balancing service;
2. the TSO can select an offer by the aggregator and then submits the updated dispatching order to the DSO for technical feasibility check;
3. the DSO applies the new dispatching order to the distribution network model. In order to ensure the safe operation of the distribution network, it can force the disconnection of V-DER to prevent the violation;
4. the TSO covers its residual demand for balancing services by selecting offers by HV-connected resources.

On the contrary, Model 2 implements a technical aggregation of V-DER. In this case, the DSO is responsible of keeping the distribution network balanced, while the TSO is only concerned with balancing the power system at HV level. With these premises, in this model, the DSO has both a commercial role, since it selects the balancing offers by V-DER, and a technical role, since it

[4]This is an extreme assumption that aims at making clear the asymmetric information that agents have under the commercial market design: the aggregator has no information about network operations; the DSO does not know details about individual contractual relationships between the aggregator and the V-DER and thus treats the aggregators' offers as a whole.

dispatches the distribution network according to its technical constraints. The target of the DSO is to keep the profile agreed with the TSO the day ahead[5].

In model 2, the DSO dispatches V-DER in order to keep the distribution network balanced up to the V-DER availability. In this model, the role of aggregator and DSO coincide, in the sense that regardless of whether they are two distinct bodies or not, the entity that is responsible to the balancing of the distribution grid has full information about V-DER balancing services. For the sake of simplicity, we shall refer to this agent as the DSO, regardless of whether it is vertically integrated with the aggregator of if has written a full contract with the latter that forces it to share all the information about V-DER. The residual unbalance to the scheduled power exchange at the interface with the HV grid that might arise are covered by the TSO by selecting bids from other flexible resources in the HV grid. Summarizing the phases involved in model 2 implementation:

1. the aggregator/s collects the availabilities of V-DER for upward and downward services, specifying the composition of the aggregate and transmit it in real time to the DSO;
2. an optimal power flow calculation is performed by the DSO with the objective of compensating deviations from the scheduled power exchange at the interface with the HV grid, selecting the energy contributions from V-DER, up to the network's technical limits;
3. the TSO selects offers presented by HV flexible resources in order to cover the residual imbalance.

In this model, the DSO solves the balancing needs as much as possible at distribution level.

3.2 The model

The two market models imply different costs of the balancing services and a different supply/demand of balancing energy, with the possible supply curtailment by the DSO due to technical constraints.

The research question is which one is the preferable market setting from the standpoint of a social planner that wants to minimize overall system costs.

In general, the balancing process simulated in this work develops as follows:

1. in day D−1, the aggregator communicates the scheduled consumption and generation profiles to the TSO. As it will be further specified in section 4, each load type is assumed to have a scheduled power absorption from the grid, while a production pattern is scheduled by each V-DER owner for the upcoming day;
2. the TSO calculates an energy exchange profile between the HV grid and the distribution network based on the load/generation profiles, scheduling the energy flow at the interface transformer in each time interval for day D, denoted by the array $\mathbf{P_{ex}^{(0)}}$. Based on the demand and generation patterns, this flow can be directed in both ways, either from or to the HV grid;
3. during day D, forecasting errors on demand and generation schedules originate a new aggregated profile, denoted as $\mathbf{P_{ex}^{(1)}}$, so that the need for balancing services in each time period t is contained in the array:

$$\mathbf{P_B}(t) = \mathbf{P_{ex}^{(0)}}(t) - \mathbf{P_{ex}^{(1)}}(t)\,,\ \forall t \in (1, 24) \tag{1}$$

[5] It should be noticed that this paper does not frame the game played between DSO and third-party aggregators, but rather focuses on the impact that different market frameworks have on the total cost for power system balancing at distribution level.

4. The aggregators managing the V-DER connected to the distribution network offer two flexibility products: upward service and downward service. The former consists in voluntarily reducing the availability in the scheduling stage (day D−1), in order to offer the generation surplus in the balancing market. This can be done by assuming that V-DER capacity, at the scheduling stage, is de-rated, so that the residual capacity is kept as reserve and the corresponding energy can be offered as upward balancing energy. We assume that the de-rating percentage is constant throughout day D, so the generation schedule will be just reduced by a given factor for all generators. Downward service consists in offering a generation reduction in the balancing market. We denote the offered energies for the two services by a generic aggregator i as L_i^+ and L_i^- (integral of the hourly energy amounts over one day). At the end of one day of operation, the amount of energy for upward and downward services provided by the V-DER as resulting after the offers acceptance in each day of operation, is indicated by L_A^+ and L_A^- such that:

$$L_A^+ \leq L_i^+ \tag{2}$$

$$L_A^- \leq L_i^- \tag{3}$$

   It shall be noted that, according to the balancing services market model, technical constraints in the distribution network influence the selection of energy offered in a different way, as specified in the following;

5. Depending on the technical constraints of the distribution network, it may happen that the DSO is forced to disconnect V-DER to preserve the safe operation of the grid, as a result of congestions or overvoltage issues. This action results in an unbalance in the power exchange, since it modifies the production schedule and it generates the need to buy upward services. In the model, this energy is addressed with the variable Z that measures the energy curtailments which are endogenously generated depending on the technical constraints of the distribution network;

6. The TSO needs to maintain the whole system balanced, so it might need to accept balancing energy offered from HV power producers in order to integrate the energy provided by aggregators of V-DER, possibly substituting offers rejected due to technical issues. The amount of energy for upward and downward services that the TSO acquires from other sources in the transmission grid is:

$$L_{AS}^+ = \sum_{t=1}^{24} \max\left[\mathbf{P_B}(t), 0\right] - L_A^+ \tag{4}$$

$$L_{AS}^- = \sum_{t=1}^{24} \min\left[\mathbf{P_B}(t), 0\right] - L_A^- \tag{5}$$

Considering all the energy terms introduced above, the overall cost for balancing is evaluated taking into account a reference price for each service, both from aggregators and from other flexible HV resources in the market, as:

$$C = p_*^+ \cdot E[L_{AS}^+] + p_*^- \cdot E[L_{AS}^-] + p_A^+ \cdot E[L_A^+] + p_A^- \cdot E[L_A^-] + p_Z \cdot E[Z] \tag{6}$$

where all balancing energy services as well as the curtailments are to be understood as random variables, $E[\cdot]$ denotes the expected value operator and

- p_*^+ and p_*^- are the prices for upward and downward services provided by HV flexible resources;
- p_A^+ and p_A^- are the prices for upward and downward services provided by aggregators of V-DER;
- p_Z is the opportunity cost associated to the V-DER energy curtailment due to technical constraints in the distribution network.

The latter parameter can be interpreted as measuring the average cost of having wrongly incentivised V-DER, for the amount of energy that was not dispatched due to technical curtailments. Such a cost could be fully attributed to V-DER producers or, alternatively, they could be compensated for the amount of energy that they could have been producing and have not for reasons independent on their wills. From a theoretical point of view, compensating producers for curtailment is just a way to insulate producers from market risks shifting the cost to the TSO (i.e., end consumers). In the real world examples there are several possible compensation scheme for RES curtailments[6]. In Europe, for instance, there are very different approaches about compensation, ranging from null to full compensation, at a price that can be administratively set or emerge from competitive auctions; moreover, different caps are set in various markets[7]. Given that there are very different approaches, in our analyses we compare the results under a null value hypothesis for p_Z with the case of a positive value for it.

Energy quantities are defined with sign, while prices are always positive. Through this choice, by accepting a downward service, the network operator is - in principle - entitled of receiving a cash flow from the service provider. The social planner has the objective of minimising the cost for balancing.

In the following section, a case study is introduced to discuss the results in terms of the energy needed. Then in the subsequent section, the social cost is calculated and discussed under different scenarios.

4 Case study

We start by introducing the electrical network layout. Then the simulation parameters involved in the analysis are recalled. Finally, a detailed simulation example is reported in order to clarify the meaning of the variables involved in the modelling methodology discussed in section 2.

4.1 Distribution network layout

Since the focus of this work is on the provision of balancing services by V-DER, the analysis focuses on a power system layout that consists of a distribution network connected to the high voltage grid as shown in Figure 1. In this case study, the only imbalance on power supply and demand derives from the distribution network itself and can be simulated by assuming perturbation factors to the end-user power profiles, as discussed in the following.

Figure 1 reports a graphical representation of the IEEE 33-bus reference distribution network, connected to the high voltage grid through a 132/12.66 kV, 6 MVA transformer [34]. Reference data have been used to define the rated load power, while the power profiles in Figure 2a have been

[6]We refer here to Renewable Energy Sources in general and not just to V-DER.

[7]For a review to RES compensation schemes, see [33]

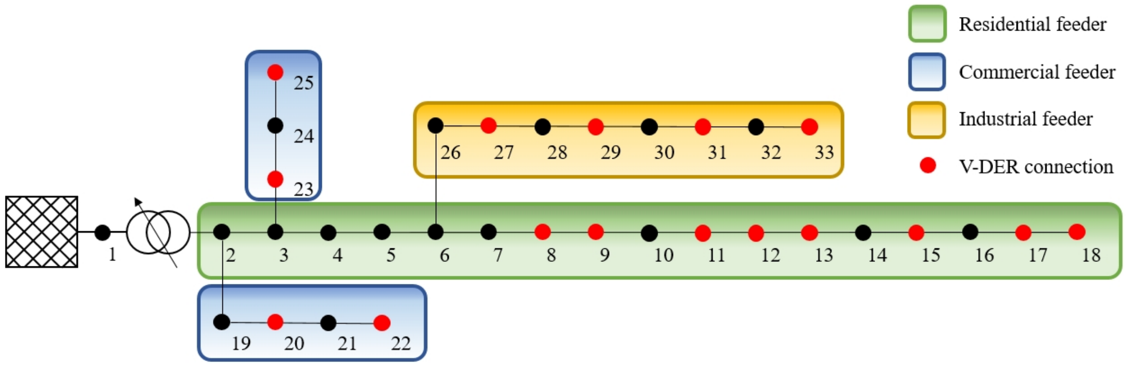


Figure 1: IEEE-33bus reference distribution network.

assumed to represent the day-ahead forecast for residential, industrial and commercial load types, as proposed in [35].

Concerning distributed generators, 16 V-DER are considered, with a total installed capacity of 6.528 MW. In the analysis, several scenarios are designed, assuming that V-DER are either Photovoltaic (PV) or Wind installations and considering different shares of the two sources. The day-ahead production forecasts for PV and Wind are reported in Figure 2b.

4.2 Simulation parameters

Along with the network layout introduced in the previous paragraph, there are other relevant parameters to be considered.

First of all, once the supply and demand schedules are determined through the power profiles in 2, the real-time power profiles for a 24 hours period are obtained by applying perturbation

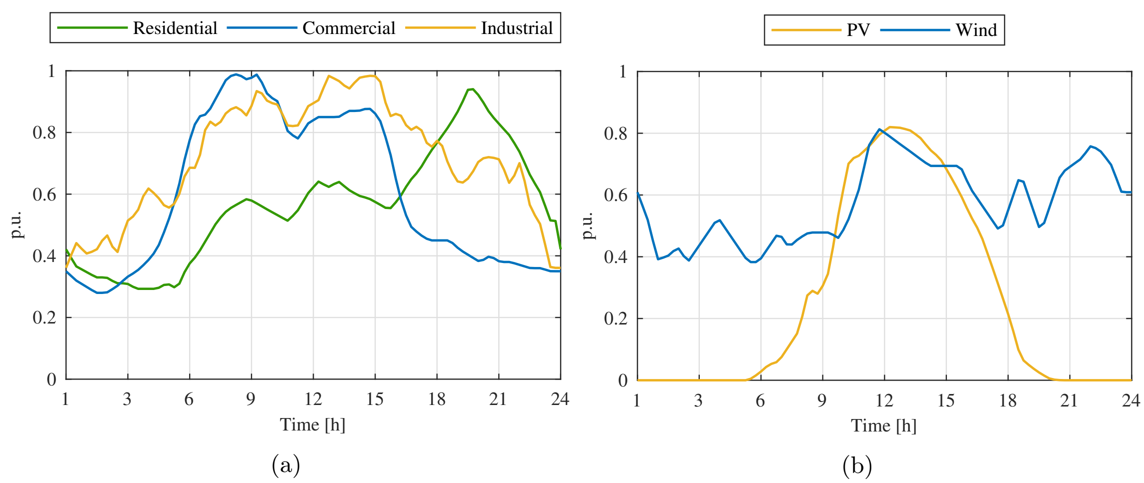


Figure 2: Load (a) and generation (b) daily power profiles.

coefficients. These coefficients are drawn from Gaussian distributions obtained considering the day-ahead schedule, in each hour, as the mean and assuming different standard deviation between generation and demand, which represents possible forecast errors, as follows.

A forecast error of 3.5% is assumed for demand profiles, as indicated in literature [36]. Concerning generation profiles, forecast errors are assumed to stem from a standard deviation of 20%. Wind generators are considered completely uncorrelated from one another, although connected to the same distribution grid. This represents the idea that wind actual production depends on many factors such as wind direction and presence of obstacles [37]. On the contrary, geographical location plays a more significant role in the case of PV units [38], therefore a different approach is used in this case. Perturbation coefficients for PV units are drawn from the Gaussian distribution for each hour, resulting in the real-time pattern. Then, a uniformly distributed noise in the range of 10% around the perturbed profile is applied, simulating the variation associated to the real distribution of PV units in the area.

Through this process, the real-time power exchange at the primary substation (i.e. the interface with the high voltage grid) will differ from the scheduled one, originating a demand for balancing energy. According to the specific market model, either the TSO or the DSO will select the balancing offers in order to cover this demand.

Two other important parameters influencing the simulations outcomes are the distributed resources type and their availability for the upward and downward services. To consider several possible cases, we construct five scenarios in the simulations about the distribution of type of generation source. Keeping the same total installed power, mentioned in section 4.1, the share of wind and PV units' capacity is made varying between 0 and 100% with steps of 25%. For what concerns the availability of V-DER to provide the balancing service, it is necessary to distinguish between downward and upward balancing services. Since both the V-DER technologies considered in this work (Wind and PV) are non-programmable, they can always offer downward balancing service (i.e. generation cut), up to the actual power output in each time interval. On the other hand, in order to provide upward service, the V-DER need to be de-rated. Multiple scenarios for de-rating are designed, varying the reserve range between 5 and 20% of the producible energy, with steps of 5%.

Concerning the number of aggregators, as discussed in section 3.1, we consider here offers presented by a single aggregator of V-DER. It should be noticed that assumptions about the number of aggregators matter only under model 1 (commercial), since in model 2 (technical) it is assumed that the DSO is able to control each individual offer from V-DER. Therefore, the number of aggregators implies the possibility that the network operator accepts $1/n$ of the balancing energy offered by V-DER in each time instant, where n is the number of aggregators. When n coincides with the number of V-DER connected to the grid, Model 1 converges to Model 2. In the appendix, a case for multiple aggregators (three) is described.

Concerning the prices for the provision of balancing energy, we distinguish between upward and downward services. For V-DER, we suppose that they can provide upward service at a price that is not lower than the one in DA market, but lower than that offered by programmable sources in the balancing market. This reflects the assumptions that the lower boundary of the opportunity cost of upward energy offered by V-DER is given by the opportunity cost due to the missed day-ahead price not gained by the energy de-rated and therefore not offered in the scheduling stage. On the other hand, the upward boundary of the opportunity cost of providing energy through V-DER can be meaningfully assumed to be lower than the cost of providing upward balancing services by programmable power plants since V-DER have no fuel costs compared to the latter. About downward service, the provision of downward energy by programmable resources typically foresees a payment to the system operator (i.e. the equivalent of an offer with negative price). The price offered by renewable energy fuelled V-DER can be meaningfully assumed to be null since there is no cost reduction involved in the offer of downward service.

For the simulation we consider meaningful reference levels for the parameters. To provide intuitive examples, we take as an example figures that are close to the Italian day-ahead and balancing services market, as reported in [39]. In that paper the authors report average figures for upward balancing energy provided by programmable sources connected to the high voltage grid that span from the day-ahead level to twice that value, with average day-ahead prices for the Italian continental zones of about 50 €/MWh (See [39], Table 2). For downward services, the Italian balancing market rules prescribe that downward services are remunerated at a price that spans from null to the corresponding day-ahead one as the upper bound. Therefore, an intermediate reference price of 25 €/MWh (i.e. half the day-ahead one) can be meaningfully assumed.

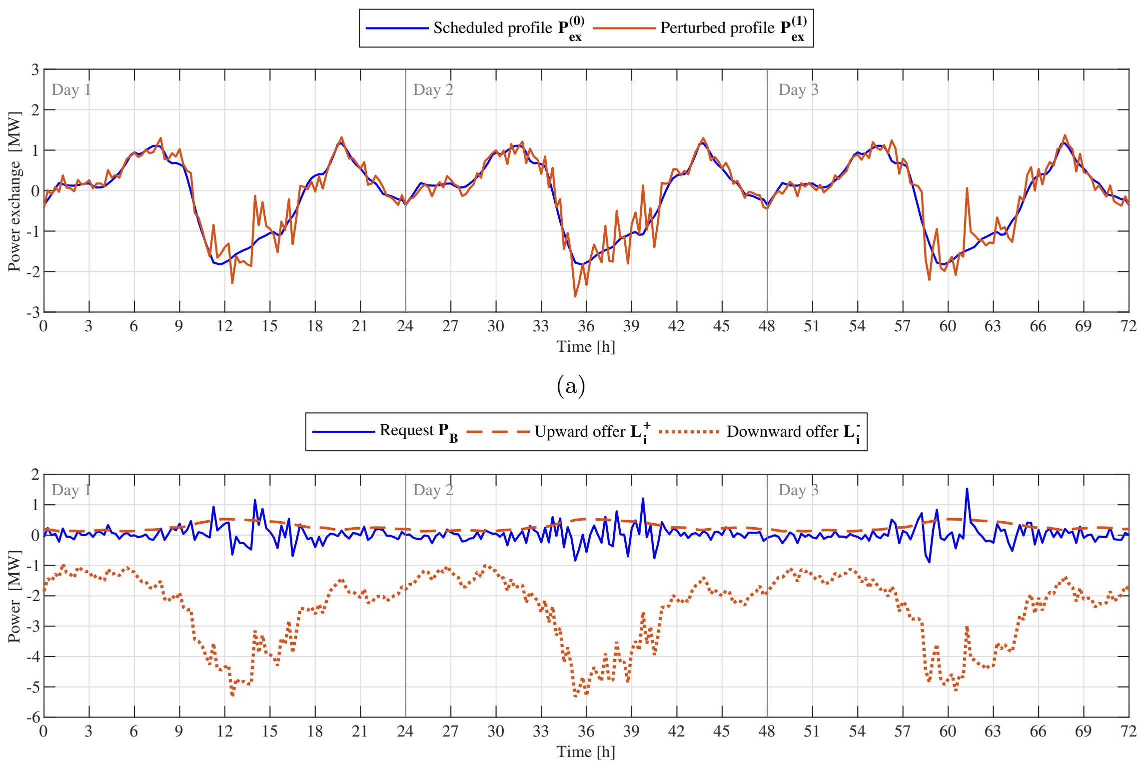
4.3 Detailed simulation example

A three-days numerical example is presented here to show the energy amounts involved in the model presented in section 3.2. The simulation outcomes of the two market models are discussed starting from the same initial conditions about the share of V-RES technologies (Wind and PV) and the upward reserves given by the de-rating coefficients. For the former, we suppose that PV and Wind sources each have 50% share of the overall V-RES capacity. In this way, it is possible to detect the effects of the wind generation throughout the day as well as the concentration of PV generation in few central hours of the day. Concerning the upward reserve, a 10% de-rating of the V-RES scheduled capability is assumed.

Following the procedure outlined in section 3.2, in step 1, scheduled profiles for loads and generators are defined as a result of DA trading, corresponding to those shown in Figure 2, while step 2 consists of the aggregation of scheduled load and generation profiles (i.e. the outcomes of DA market trading) at the interface between high voltage and distribution grids, resulting in the scheduled profile $\mathbf{P_{ex}^{(0)}}$.

In step 3, by adopting the assumptions introduced in the previous section about forecast uncertainty, the actual power exchange profile $\mathbf{P_{ex}^{(1)}}$ is obtained by aggregating the actual load and generation in each time interval. Considering the trends $\mathbf{P_{ex}^{(0)}}$ and $\mathbf{P_{ex}^{(1)}}$ shown in Figure 3a, power exchange is displayed as positive when directed from the high voltage grid to the distribution network. Given that the only imbalance in the simulation is associated to the distribution network by assumption, the demand for balancing power is calculated as in (1): it arises because of the discrepancy between the two power exchange profiles, as reported in blue in Figure 3b. Positive $\mathbf{P_B}(t)$ values indicate the need for upward balancing energy, negative ones correspond to the need for downward services. In particular, it should be noted that, as expected, during the central hours of each day, the forecast error's amplitude is magnified by the PV generation given its bell shaped profile (see for instance that for three times, in the three day span, $\mathbf{P_B}(t)$ is above 1 MW, as shown in blue line in Figure 3b).

In step 4 of the simulation, energy offers by the aggregator are collected, in each day, in two categories: an upward balancing offer L_i^+ (integral, in each 24-hours period, of the red dashed trend in Figure 3b) and a downward balancing offer L_i^- (integral, in each 24-hours period, of the red dotted trend in Figure 3b). It should be noted that, according to the scenario, a different generation mix in V-DER causes differences both in the balancing demand and in the composition



(a)

(b)

Figure 3: a) Scheduled and real exchange profile b) Aggregator offers and balancing request

of these offers. For example, increasing the PV share, a positive correlation among perturbations causes a higher demand in middle hours of each day, whereas V-DER offers tend to concentrate in that same period (8 am - 6 pm, according to the scheduled production). On the other hand, a prevalence of wind generation tends to reduce the demand for balancing energy, as forecast errors are uncorrelated, while flattening the offer curves.

Once the initial scenario has been outlined in the form of a balancing request $\mathbf{P_B}$ and the bids submitted, upward and downward services are selected by the system operator (either TSO or DSO) according to the rules specified in each market model, as discussed in section 3.1. Figure 4a shows the accepted offers sourcing from the aggregator in each time instant for models 1 and 2, whose integral in each day yields L_A^+ and L_A^-. Comparing the two results, it clearly appears that the aggregator is only called to provide downward service in model 2, in which the DSO is responsible for balancing, since in model 1 the TSO selects always the more convenient high voltage flexible resources. Concerning upward service, in model 1 the TSO, not knowing the composition of the aggregator's offer, is forced either to accept the whole offer (if below the request) or to reject it. This happens whenever the blue trend in Figure 4a is below the red dashed line, reflected in a missed L_A^+ activation in Figure 4a.

As mentioned in section 3.1, in model 1 the TSO selects aggregator's offers with no knowledge of the distribution network structure, so it may happen that, once the service is activated, the DSO detects a violation of technical constraints forcing the disconnection of some V-DER units. An example is a group of PV generators whose production at peak is not matched by load (residential load is typically ramping in the evening), causing overvoltage issues and, possibly, congestions in the distribution network. In model 2, the DSO has balancing responsibility so it selects V-DER offers with knowledge of the distribution system's structure, avoiding disconnections for constraints violations. As a result, in Figure 4c it can be seen that, in Model 2, Z is always null.

Finally, in step 6 of the procedure, the residual demand for balancing energy (i.e. integrating accepted offers by the aggregator or substituting the rejected ones) is fulfilled by selecting offers presented by high voltage programmable sources, resulting in the energies L_{AS}^+ and L_{AS}^-, as defined in equations (4-5). Accepted offers for each time interval are reported in Figure 4b for the two models. In model 1, low quantities of L_A^+ (accepted upward energy supplied by V-DER, integral of the positive part of the blue dashed trend in Figure 4a) correspond to high quantities of $L_{AS}^+(t)$ (upward balancing energy needed from high voltage sources, integral of the positive part of the blue dashed trend in Figure 4b). Vice versa, in model 2, high quantities of ${L_A}^+$ correspond to low quantities of L_{AS}^+ (orange lines).

5 Results

In this section, we present the results of the simulations conducted over the case study network, considering the power system data and the parameters recalled in section 4. Following the approach detailed in section 4.3, the amounts of the energies involved in the balancing process are calculated for both Model 1 and Model 2, considering 100 days in the simulation.[8] The expected values for each energy amount, as for equation (6), are computed as the average of daily values of L_A^+, L_A^-, L_{AS}^+, L_{AS}^- and Z over the 100 days. In Table 1, expected energies are reported for the two market models, considering four de-rating percentages for upward service reservation (5%; 10%;15% and

[8]The reliability of this statistical basis has been checked by extending the simulation to one thousand days with negligible differences in the outcomes. Results are available from the authors upon request.

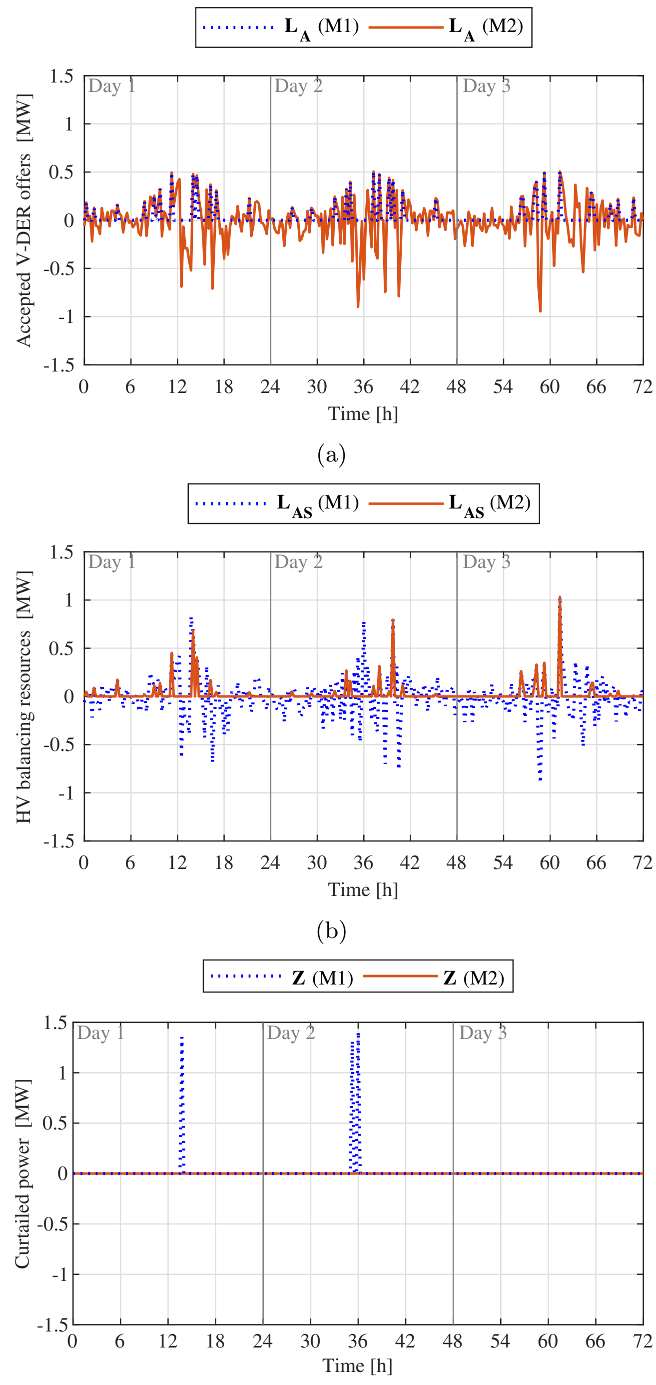


Figure 4: a) Accepted aggregator offers, b) Residual high voltage balancing resources, c) Curtailed power due to congestions. By separating positive and negative parts of the trends in a) and b) and integrating them, we can obtain L_A^+ and L_A^- in a) and L_{AS}^+ and L_{AS}^- in b).

20%) and five V-DER sources mix (shares PV-Wind), with Wind going from 0% to 100%, increasing by 25 points each scenario; PV covers complementary shares.

Table 1: Parametric analysis results: energy amounts [MWh] in model 1 (a) and model 2 (b).

a)

Model 1																									
De-rating	100% PV - 0% Wind					75% PV - 25% Wind					50% PV - 50% Wind					25% PV - 75% Wind					0% PV - 100% Wind				
	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z
5%	3.35	-1.59	0.81	0.00	2.42	2.49	-1.96	0.93	0.00	1.30	1.98	-1.99	0.97	0.00	0.78	1.89	-1.78	0.92	0.00	0.89	1.51	-1.79	0.81	0.00	0.41
10%	2.46	-1.87	1.25	0.00	1.64	1.89	-2.29	1.22	0.00	0.63	1.74	-2.18	0.93	0.00	0.30	1.86	-1.89	0.54	0.00	0.36	1.78	-1.82	0.29	0.00	0.13
15%	2.05	-2.26	1.42	0.00	0.98	1.88	-2.57	1.05	0.00	0.14	1.97	-2.27	0.55	0.00	0.05	2.02	-1.96	0.15	0.00	0.06	1.95	-1.85	0.03	0.00	0.02
20%	2.09	-2.67	1.28	0.00	0.45	2.10	-2.66	0.80	0.00	0.03	2.26	-2.30	0.25	0.00	0.01	2.12	-1.98	0.02	0.00	0.01	1.97	-1.86	0.00	0.00	0.00

b)

Model 2																									
De-rating	100% PV - 0% Wind					75% PV - 25% Wind					50% PV - 50% Wind					25% PV - 75% Wind					0% PV - 100% Wind				
	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z	L^+_{AS}	L^-_{AS}	L^+_A	L^-_A	Z
5%	2.40	-0.06	0.91	-3.15	0.00	1.75	0.00	1.12	-2.78	0.00	1.18	0.00	1.30	-2.40	0.00	0.71	0.00	1.41	-2.07	0.00	0.49	0.00	1.48	-1.99	0.00
10%	1.70	-0.06	1.62	-3.15	0.00	0.99	0.00	1.88	-2.78	0.00	0.48	0.00	1.99	-2.41	0.00	0.16	0.00	1.95	-2.08	0.00	0.07	0.00	1.87	-2.00	0.00
15%	1.16	-0.06	2.16	-3.14	0.00	0.53	0.00	2.34	-2.78	0.00	0.17	0.00	2.30	-2.41	0.00	0.02	0.00	2.07	-2.08	0.00	0.00	0.00	1.91	-1.99	0.00
20%	0.77	-0.06	2.55	-3.14	0.00	0.26	0.00	2.60	-2.77	0.00	0.05	0.00	2.41	-2.40	0.00	0.00	0.00	2.08	-2.08	0.00	0.00	0.00	1.91	-1.98	0.00

5.1 Market model 1 - *commercial* aggregation

About downward service, an increase of de-rating percentage leads to a higher need for balancing downward service in all generation scenarios. These downward services are provided by high voltage plants since they are more convenient than offers form V-DER (remember that downward offers are gained by the TSO and they are made at positive prices from high voltage plants and null prices from V-DER by assumption). As a consequence, L_A^- is always equal to zero in model 1. Note that the higher the de-rating of V-DER, the reduced the probability of line congestions and therefore the lower is Z.

Looking at upward balancing service, offers accepted from high voltage resources and aggregators are significantly influenced by the different scenarios considered (i.e., the de-rating percentage and the generation mix). The prevalence of PV installations with low de-rating percentage causes a high probability of incurring in technical constraints violations. This implies higher L_{AS}^+ quantities. In the case with 100% PV and 5% de-rating, the highest Z is detected, 2.42 MWh. However, the amount of upward balancing energy gathered from aggregators L_A^+ is not influenced significantly by this phenomenon, which entails only periodical offers rejections. Given the positive correlation in PV units forecast errors, the overall amount of upward balancing energy activated (sum of L_{AS}^+ and L_A^+) tends to decrease as the wind share increases. For instance, considering 5% de-rating and decreasing the PV share from 75% to 50% the overall need for upward balancing energy reduces from 3.42 MWh to 2.95 MWh (-13.7%). By combining this effect with the growing size of upward service offers as the de-rating percentage increases, it can be seen that L_A^+ amounts tend to decrease while reducing the PV share and increasing the de-rating percentage.

5.2 Market model 2 - *technical* aggregation

As mentioned in section 3.1, in model 2 the DSO aggregates the V-DER offers in order to match the distribution network's power exchange with respect to the scheduled profile, while taking technical constraints into account. As a result, as already mentioned in the detailed case study discussion, Z

is always equal to zero and both upward and downward balancing services are sourced from V-DER primarily, with the only residual request being fulfilled through high voltage resources.

About downward service, V-DER are supposed to be available to decrease their entire production in all intervals, therefore the whole downward service request is fulfilled by L_A^-, the only exception being the case of 100% PV share, when no offers are presented by V-DER during off-production periods (since obviously PV does not generates at night).[9] As a consequence, these distributed downward services allow the DSO to avoid generation curtailments Z.

As for upward services, since the aggregation of each V-DER is made on a technical basis a larger amount of offers is selected since the offer indivisibility constraint of model 1 is removed. As a consequence, L_A^+ grows as the de-rating percentage rises, in all the generation scenarios. At the same time, decreasing amounts of L_{AS}^+ are acquired as V-DER availability grows.

5.3 Balancing cost comparison

Once the expected energy results have been obtained for the two market models, it can be evaluated the social cost for balancing, according to equation (6). As mentioned, we consider the following reference values: $p_{AS}^+ = 100$ €/MWh; $p_{AS}^- = 25$ €/MWh; $p_A^- = 0$ €/MWh; $p_A^+ = 75$ €/MWh. For the curtailment opportunity cost p_Z, [33] shows that there are very different figures for ex post compensation prices (calculated as the ratio of the overall cost derived from RES curtailments and volumes of curtailed RES electricity). Across European markets, for instance, in year 2017 it ranged from null (in several countries) to 144 €/MWh in Norway; in Italy it was 37 €/MWh[10] Given such a high range, we consider here the results under the assumption of $p_Z = 0$ €/MWh, (Table 2) and compare it with the case of $p_Z = 50$ €/MWh (Table 3). Clearly, the higher p_Z the higher the social cost of model 1.

Looking at the balancing cost results reported in Table 2, in both models lower costs are found as the Wind penetration increases at the expenses of the PV share, as a consequence of the uncorrelation in production forecast errors and lower balancing needs. Furthermore, cost savings are associated to larger shares of V-DER availability for upward service, obtained through higher derating, in particular in the cases in which the demand for upward balancing is high due to positive correlation among forecast errors on the supply (i.e. large penetration of PV). This has the effect of containing Z and the amount of upward activated offers from high voltage resources. Comparing the social costs of the two models we see that they can be higher or lower according to the scenario. They are higher in model 1, when the limited de-rating of V-DER implies that relatively more high voltage upward energy is purchased under model 1 than for model 2. However, the result depends also on the relative share of Wind and the cost of curtailments. When the latter is null (or low) as reported in Table 2, the fact that a high de-rating induces also a higher need of downward energy in model 1 and that less costly (more convenient) offers from high voltage are accepted compared to model 2 (where V-DER balancing is prioritized) more than compensates the higher curtailments of model 1. As a consequence, the social cost of model 1 becomes lower compared to the one of model 2. Clearly, as the cost of curtailments rise, the relative advantage of model 2 (which shows no curtailment) over model 1 implies that the former becomes less costly under all scenarios, as it can be observed comparing Tables 2 and 3, where in the latter the cost of model 1 rises as p_Z increases.

[9] It is worth noticing that we do not consider in this paper the existence of distributed storage sources.

[10] It is worth noticing that these figures refer to very different rules and types of compensation schemes. Moreover, they do not refer specifically to V-DER. Therefore, they are just used here to derive plausible reference values.

Table 2: Social cost C in Model 1 and Model 2 with p_A^+=75 €/MWh and p_Z= 0 €/MWh.

Model 1					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	356.55	270.06	220.68	212.85	167.69
10	293.14	223.04	189.32	179.51	154.11
15	255.17	202.17	181.47	164.43	151.03
20	238.13	203.27	186.70	164.46	151.00

Model 2					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	306.86	258.78	215.71	176.97	159.88
10	289.85	240.04	197.86	162.15	147.10
15	276.46	228.15	189.03	157.54	143.87
20	266.63	221.11	185.39	156.40	143.38

Table 3: Social cost C in Model 1 and Model 2 with p_A^+=75 €/MWh and p_Z=50 €/MWh.

Model 1					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	477.72	335.18	259.90	257.43	188.42
10	375.37	254.44	204.55	197.62	160.36
15	304.28	209.35	184.19	167.51	151.90
20	260.67	204.61	187.20	165.14	151.18

Model 2					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	306.86	258.78	215.71	176.97	159.88
10	289.85	240.04	197.86	162.15	147.10
15	276.46	228.15	189.03	157.54	143.87
20	266.63	221.11	185.39	156.40	143.38

In order to evaluate the impact of the cost of upward energy provided by V-DER, we analyse also how costs change across the two models, when the price p_A^+ varies between the day-ahead level (50 €/MWh) and the price offered by high voltage resources (100 €/MWh), for each of the generation mix scenaros, in the case of a 10% de-rating. Figure 5 reports the values of the social cost under the two models with the mentioned assumptions.

It is interesting to note that when PV prevails, the two models yield similar results in terms of overall balancing costs, even at low values of p_A^+. This is due to the high amount of downward energy purchased from high voltage resources in Model 1 which helps containing the cost, regardless of the higher needs of high voltage upward balancing. Reducing the share of PV units, model 1 results in a flattened cost trend due to the prevalence of upward services sourced from high voltage resources. Model 2 remains sensitive to the cost of V-DER upward energy due to its relative more

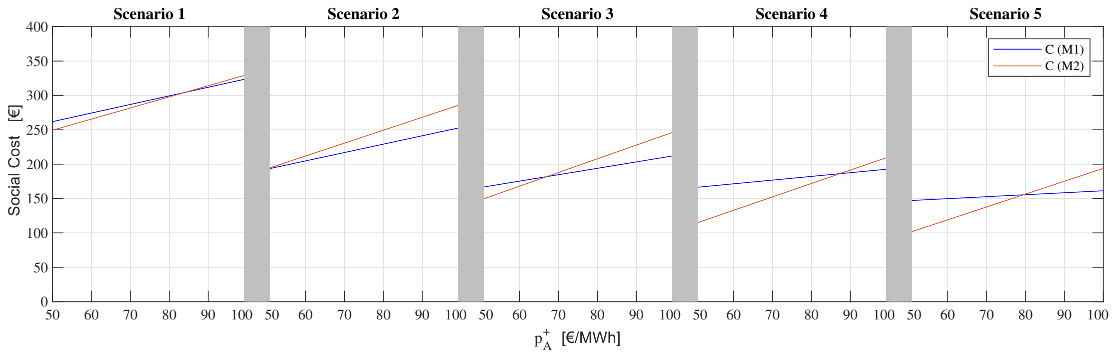


Figure 5: Social cost of Model 1 and Model 2 with 10% de-rating percentage

importance in the balancing market. Model 2 is cheaper until the offered price overcomes 80-85 €/MWh (1.6-1.7 times the market price).

6 Conclusions

In this work we presented two possible models for local electricity markets, where distributed energy sources connected to local distribution grid can participate to the balancing services market. We proposed a model to calculate overall social cost of balancing, also including a parameter (Z) that represents the energy curtailment connected to the violation of technical network boundaries in the market functioning, possibly accounted as a specific cost figure. Starting from this model, we analysed the realizations of two different market alternatives, i.e. a *commercial* solution, where the DSO is responsible only for the grid operational management and a *technical* solution, where the DSO manages V-DER and is committed in keeping an agreed exchange profile with the TSO.

Looking at the simulations, we noticed that there are substantial differences between the two market frameworks with respect to the occurrences of the curtailments. The first model can lead to curtailments of V-DER supply in case there is a possible violation of technical constraints: this causes a cost of curtailments that represents the missing value of integration, since when a violation of technical constraints occurs all V-DER in the balancing market are curtailed. Moreover, there is an increase in balancing needs, as the curtailed energy must be balanced with high voltage resources. This result is due to the fact that balancing offers do not take into account network limitations, a somehow unavoidable outcome, taking into account that the operator that is responsible for operations and knows the technical boundaries (the DSO) is left outside the market. The second model, on the contrary, calls for a wider role of the DSO: the operator must solve the local imbalances using first all the V-DER connected to its grid in order to keep the agreed profile at the connection point with the transmission line. In this case, Z falls to zero, because the operator has the possibility to include technical boundaries in the evaluation of the offers. It is possible to say that model 2 allows for the internalization of the curtailments in the cost function of the DSO, in case it is responsible for balancing. However, model 2 is not necessarily always preferable to model 1. Even though it reduces the curtailments, it forces the market operator to do so by making use of some sources, in particular downward energy from V-DER, that are more costly (or less convenient) than the corresponding sources provided by high voltage producers. This can make the commercial aggregation of model 1 preferable. *Ceteris paribus*, this occurs when there are more available reserves (due to a higher de-rating of capacity) and when there is a higher volatility of V-DER balancing services due to the prevalence of PV. The rationale is that the *commercial* model does not impose ex-ante the obligation to give priority to V-DER but leaves free the balancing operator to chose the more convenient sources at every point in time and this can more than compensate the higher curtailments that are ex-post created.

Overall, the results of our simulations show that the *commercial* aggregation is preferable when the penalty price for curtailments is null or low, the share of PV is high and the V-DER reserve capacity is high too. On the contrary, as the share of wind prevails and for low levels of V-DER de-rated capacity or with high explicit penalties for curtailments the *technical* aggregation that attributes to the DSO the responsibility of balancing V-DER is to be preferred.

Clearly, our results are just a first tentative to explicitly take into account the impact of market regulation of the efficiency of V-DER balancing energy provision, and depend on several assumptions.

We have focused on two polar models. There can be other intermediate possible models. For instance a regulation could be set that introduces a limit to balancing services that can be offered or accepted by V-DER, or to acceptable levels of curtailment Z. The result would therefore depend on such limits. Still, we think the two alternatives we described in the paper can represent a good starting point to further develop a strategy to increase renewable integration in the grid and to determine how to regulate electricity networks, especially considering different policies to pursue renewable integration. We have not discussed as well the impact that market regulations might have on investment incentives, both on V-DER and on the distribution grid itself. In model 1, for example, it seems to be hard to find an interest for the DSOs in investing in grid reinforcing, as they are not involved in local balancing nor penalized for the failure in renewable integration. Moreover, in case of an increase of RES presence on the local grid without upgrading of the infrastructure, there will also be an increase in curtailments because of congestions. It is reasonable to assume that this situation will lead to a decrease in V-DER investments in the specific grid, as they will not be able to fully exploit their market's participation (on the other hand, this could also be a way to guide new V-DER investments to other portions of the network); similarly, aggregators will have less convenience in working in areas with poor infrastructures. In this sense, an active regulation to foster investments for grid renovation and upscale is needed in case of market model 1: only with adequate investments the grid will be able to actively integrate renewables; guarantee market access to further V-DER producers (thus fostering competition); create market conditions for the role of aggregators.

Although model 2 allows the disappearing of Z, the reduced need of high voltage balancing services might lower the incentives to invest in high voltage controllable plants, which overtime might hinder security of supply by providing less high voltage balancing energy that can be needed regardless of the amount of V-DER capacity because of the availability of the renewable primary energy source (as it occurs for instance for the case of PV energy provision at night). These aspects, together with the issues posed by storage, for instance, represent an interesting starting point for future research.

Further researches shall consider also dynamic market interactions among players and their effects on market equilibria, especially on prices. V-DER are price takers, but aggregators could put in place strategic behaviours across them or with the DSO. This is even more true in case of several distribution grids that interact at system level and when there are learning curves and cost evolution. In terms of our models, this could imply that aggregated offers in model 1 change overtime, or that available V-DER capacity evolves overtime because of market entrance or exit. Again, we have not considered these dynamic effects here.

Nevertheless, we believe the paper provides a first insight of how different market models for V-DER participation at distribution level could impact on the services supplied and the efficiency of the power system. We show that there is no best model to be chosen. The choice depends on the relative cost of the provision of the balancing service as well as the structure of V-DER supply and on the amount of available V-DER reserves. Our model can be of guidance to implement balancing market reforms. It points out that the straight adoption of the actual market design for controllable (high voltage) balancing service to the V-DER might not lead to an efficient outcome. It shows how this depends on the structure of the system and the relative share of V-DER. We welcome future researches along these lines which will further provide useful insights to fully exploit all the potentiality stemming from V-DER integration in the power system, without introducing undue inefficiencies.

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Appendix

We report the results of the cost simulation for the case of three aggregators. For the reasons explained in the text, the different results refer just to Model 1. When more than one aggregator is allowed, the TSO is no more forced to make full use of the balancing service offered or refuse it entirely; it can accept a fraction corresponding to the offer of one or more aggregators, up to the full offer. Table 4 presents the result under the same assumptions used to derive the figures presented in Table 3 but with 3 aggregators.

Table 4: Social cost C in Model 1 and Model 2 with p_A^+=75, p_Z =0, 3 aggregators.

Model 1					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	355.04	267.25	215.86	205.70	158.13
10	287.57	213.28	173.69	159.27	133.06
15	243.47	183.02	156.27	138.58	129.16
20	218.00	177.36	157.12	140.98	134.12
Model 2					
Derating [%]	**Share PV - Share Wind [%]**				
	100 - 0	**75 - 25**	**50 - 50**	**25 - 75**	**0 - 100**
5	306.86	258.78	215.71	176.97	159.88
10	289.85	240.04	197.86	162.15	147.10
15	276.46	228.15	189.03	157.54	143.87
20	266.63	221.11	185.39	156.40	143.38

We can see that the only changes refer to Model 1. The social cost reduces compared to the one presented in Table 3 since now the TSO has a higher flexibility in accepting offers from the individual aggregator, and this implies a lower need of upward balancing energy from high voltage (since now partial offers can be accepted from V-DER). The limit case of Model 1, as the number of aggregator rises, is Model 2, since the latter could be interpreted as the case in which each individual V-DER is a single aggregator and the DSO knows all of them. Therefore as the number of aggregator rises, figures of Model 1 converge towards the ones of Model 2.