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Quantitative Assessment of Flexibility at the TSO/DSO Interface Subject to the Distribution Grid Limitations †

Nicola Natale, Fabrizio Pilo , Giuditta Pisano and Gian Giuseppe Soma *

Department of Electrical and Electronic Engineering, University of Cagliari, 09123 Cagliari, Italy; nicola.natale@unica.it (N.N.); fabrizio.pilo@unica.it (F.P.); giuditta.pisano@unica.it (G.P.)

* Correspondence: giangiuseppe.soma@unica.it

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Abstract: In the last years, renewable energy sources have been changing the power system by making it more challenging to balance the generation and demand at every single point in time. The increasing penetration of distributed generation represents another trend at the distribution level that impacts the exploitation of existing distribution assets. In this context, the flexibility of distributed energy resources connected to the distribution systems may play an important role. The flexibility products are represented by variations in the scheduled/expected active and reactive power setpoints. Recently, regulatory bodies suggested many proposals and undertook actions for enabling new players, such as the distributed energy resources connected to the distribution systems, to provide both system and local services. However, currently, there are still barriers that might limit their effective involvement. Market schemes have been proposed for opening the participation of distributed energy resources in the service markets. This paper proposes an analytical quantification of how much the use of flexibility by the transmission system operator can influence the distribution system operator activities and the expected costs. The final goal is quantifying the flexibility that the transmission system operator can procure from the distribution system without a harmful impact on the distribution network operation. The paper investigates the expected interactions between the use of flexibility for power system balancing and security and the operation of distribution systems. The application of the methodology to a significant Case Study showed that even though the fit and forget approach causes a hypertrophic development of distribution systems to host distributed generation, the transmission system operator cannot obtain the required flexibility services or has to pay extra costs for bottlenecks caused by distribution system operational issues.

Keywords: transmission system operators (TSO); distribution system operators (DSO); flexibility; distributed energy resources; ancillary service market

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1. Introduction

Transmission system operator (TSO) and distribution system operator (DSO) interactions become essential for avoiding unnecessary bottlenecks in opening market participation and will be strengthened due to the expected energy transition. One trend towards the energy transition is the increasing connection of renewable energy sources (RES)—intrinsically intermittent and not programmable—to reducing CO_2 emissions and reaching climate goals. In the last 5–10 years, RES have been changing the power system by making it more challenging to balance the generation and demand at every single point in time. The increasing penetration of distributed generation (DG) and new electric loads with high coincident peaks (e.g., electric vehicles, heat pumps, induction cookers, etc.) that impact the exploitation of existing distribution assets represent another trend at the distribution level. In this context, the flexibility of distributed energy resources (DERs) connected to the distribution systems may play an important role. DERs, as RES-based generators, fuel generators (e.g., combined heat and power, CHP), energy storage systems, as well as active users, can offer flexible products to the TSO to ensure reliable system operation and to the DSOs, to better operate their networks. Purposes related to such flexibility may be avoiding massive infrastructural investments for network reinforcement, not jeopardising the achieved high levels of system stability and security of supply, system balancing, voltage regulation and power congestion relieving, etc.

Flexibility is usually defined as the possibility of modifying generation and/or consumption patterns in reaction to an external signal (price or activation signals) to contribute to the power system stability cost-effectively [1]. The flexibility products from DERs are represented by variations in their scheduled/expected active and reactive power setpoints. By considering the transmission grid point of view, these variations in the scheduled/expected working points of DERs result in bids of flexibility services that, if awarded in the ancillary service (AS) market, produce a variation in the power profile at the first point of common coupling (PCC) of the distribution system with the transmission grid. Such a PCC is the HV/MV (high voltage/medium voltage) transformer located in the primary substations (PSs), where the MV distribution system, managed by the DSOs, is connected to the HV transmission system and, thus, it represents the interface between the two operators. At the same time, the DERs can offer flexibility to the DSOs for fixing distribution network issues, such as voltage regulation or local power congestion management.

Nevertheless, when using flexibility to cope with one grid operation challenge, this might impact other grid operation issues. For instance, the activation of distribution-connected flexibility for system balancing might cause congestion on the distribution grid or local voltage regulation issues. Theoretically, the activation of distribution-connected flexibility to mitigate congestion on the distribution grid may also affect system balancing. However, in practice, this impact can be expected to be small when assuming that the activation for distribution grid purposes would not be simultaneous for different parts of a distribution grid. Nonetheless, a mutual impact exists.

Recently, regulatory bodies suggested many proposals and undertook actions for enabling new players, as the DERs connected to the distribution systems, to provide both system and local services. However, currently, there are still barriers that might limit their effective involvement. Market schemes have been proposed for opening the participation of DERs in the service markets. The main drawbacks that arise from this opening are related to the significant modification in the role of the DSO and, indeed, in the interactions between system operators. With [2], the Italian Regulator had opened the AS market participation to the DERs connected to the distribution networks by starting pilot projects that included DERs in service market participation. From the early stages of the pilot projects, the Italian TSO publicised the results, and they seemed to be profitable for the entire power system [3,4]. More recently, the focus has been turned to the use of flexibility by the DSO that can purchase flexible products from aggregators and producers [5,6] for fixing distribution network issues. The TSO/DSO interactions have been investigated in many recent papers [7–11], proposing new market schemes. Several approaches promote the DSO participation, introducing local market schemes that need to be coordinated with the traditional AS markets [12,13]. A review of coordination schemes between local and central markets is presented in [14], in which the most common information exchanges between operators are analysed. Different approaches for coordinated optimal power flow (OPF) calculations are reported in [15–17]. The mentioned methods cannot guarantee feasibility due to the limited applicability and the extensive communication requirements.

In the distribution networks, the number of DER can be very large: for this reason, some aggregation approaches and flexibility resources modelling can become more attractive. For example, in [18,19], some models to aggregate the flexibility of distributed residential loads are presented. The participation of an aggregator in the energy market is proposed in [20], modelled through a bi-level mixed-integer linear programming (MILP) problem. The optimal management of consumers' flexibility for aggregators in the day-ahead market was addressed in [21] by formulating a MILP model. The authors of [22] propose a set of bidding optimisation models that support the participation of EV aggregators in multiple market sessions, such as energy and tertiary reserves.

All the mentioned works proposed do not consider the technical distribution network constraints in the optimisation models. They assume that the DSO must be capable of solving all the eventual network problems that may arise from the flexibility offered. On the contrary, only more recent approaches [23–25] aggregating the DERs flexibility preserve the secure and reliable operation of the distribution network. In particular, in [23], an efficient grid-congestion management power flow algorithm with flexible assets is proposed. The paper [24] formulates an algorithm capable of providing flexibility to DSOs. The approaches suggested in [25] assume that the DSO quantifies the flexibility needed to solve the grid problem following their operating costs as a separate problem, and the aggregator assists it. Finally, Refs. [26–30] solve an OPF problem to estimate flexibility. OPF-based approaches seem to accurately identify the flexibility curve and, therefore, will be adopted in the proposed paper.

As well as the research studies, some operative solutions, already implemented in real applications, have been proposed around the EU Countries. There are examples dealing with flexible products for distribution with other interactions between TSOs and DSOs. In the United Kingdom, an independent software company has recently developed a market platform on which DSOs can purchase, via long-term bilateral contracts, local flexibility services. Up to now, this platform has enabled over 300 flexibility providers with a flexibility volume of over 10 GW, and over 1200 competitions have been advertised by the platform users [31]. In Germany, market operators and energy service providers are collaborating on the ENergyERA (ENERA) project to develop a platform that efficiently allocates the local flexibility sources based on price signals. The market platform will be available, after the demonstration phase, to the system operators and the flexibility providers of the project consortium [32]. In the Netherlands, the already launched Grid Operators Platform for Congestion Solutions (GOPACS) implements cooperation between the Dutch TSO and several DOSs to solve congestion in the electricity grid [33]. The differences between such platforms are related to both the TSO and DSOs participation and the need for new market creation.

This paper proposes an analytical quantification of how much the use of flexibility by the TSO can influence the DSO activities and the expected costs. The final goal is quantifying the flexibility that the TSO can procure from the distribution system without a harmful impact on the distribution network operation. Recently, the authors developed a methodology that, starting from public data on the energy consumption of a region or wider area, is capable of obtaining reasonable load and generation profiles at the TSO/DSO interfaces and also building a realistic representation of the grid below such an interface [34]. The obtained models are the synthetic networks of the real distribution networks. In this paper, the synthetic networks built with the developed procedure are used to calculate possible outbound conditions (e.g., excessive voltage variations, critical power flows, etc.), and, finally, to propose the optimal operation of networks to fix any issue that can arise when flexibility products are offered to the TSO by the DERs. The paper investigates the expected interactions between the use of flexibility for power system balancing and security and the operation of distribution systems.

The paper's main contribution is the methodology for modelling the role of distribution systems in providing flexible services. The paper aims at answering the following questions:

- To what extent can the TSO exploit flexibility without causing issues at the distribution level?
- What are the main issues caused by flexibility?
- Are there operational actions that enable flexibility at the distribution level?
- What are the expected costs to enable flexibility?

TSOs can use the methodology to know in advance the expected level of flexibility services that the distribution system can offer and the relevant prices. DSOs can use the method to predict the exploitation of flexibility for operational and planning analysis. Market players can assess the expected impact of new flexibility providers. Finally, aggregators can simulate operative conditions to define better prices and quantities of services that their portfolio of customers could offer.

The structure of the paper is as follows: Section 2 deals with flexibility services; Section 3 describes the main regulatory framework implemented in most important countries; Section 4 is devoted to the proposed approach; Section 5 describes the Case Study adopted. Finally, Section 6 is about the results and discussion.

2. Flexibility Services

The present Section aims to highlight the reasons that demonstrate the validity of the flexible approach and the possible way that it can be used.

The services associated with the flexibility products offered by DERs can be helpful for services as a reserve, black start for participation in the recovery of the electricity system, reactive power support for reducing losses and voltage regulation, active power support for voltage regulation, local congestion mitigation, demand response and load modulation, etc. [35,36].

Some of them can be considered global system services (e.g., frequency regulation, reserve, etc.), offered to the TSO in the AS market; others are local services provided to the DSO for managing issues that occurred in some networks at a given time or for allowing the participation of DERs in the AS market [36,37].

The global services can be aggregated in at least two use cases of the distribution flexibility available for the TSO [38]:

T1. Balancing—The TSO uses flexibility for system balancing purposes: frequency containment reserve, automatic frequency restoration reserve and manual frequency restoration reserve.

T2. Reactive Power Management in Transmission Networks—Flexible DERs are used for reactive power management to minimise grid losses or support the voltage on the transmission network.

From the DSO point of view, the flexible services offered by the DERs may be expended for more use cases:

D1. Local Congestion Management in Distribution Networks—This use case refers to the use of flexibility to relieve one or more congested lines.

D2. Congestion Avoidance at TSO/DSO Interface—For countries where the transformers at the TSO/DSO interface are owned and operated by the DSOs, transformer congestions can be avoided using flexibility from the distribution grid.

D3. Voltage Control in Distribution Network (active power modulation)—In this use case, the DSO uses flexibility to control the voltage via active power management.

D4. Voltage Control in Distribution Network (reactive power support)—In this use case, the DSO activates one or several flexible units connected to its distribution network to perform voltage control in its network via reactive power flows support.

Based on the use cases, an assessment concerning general technical requirements for the coordinated use of flexibility can be made. The paper focuses on the use cases T1 and the relevant interdependency between TSO and DSO. The expected block of the activation of flexible units because of local congestion issues in the distribution system or the reduction in expected balancing capacities caused by the activation of flexible units for voltage or congestion management is analysed in the paper on a large scale. The methodology can also be used for assessing possible blocks of flexibility provision concerning D1–D3.

3. Regulatory Framework

Depending on the market framework, the bids to the AS market can be aggregated at the PS level or offered by a single DER or a group of DERs, enabling market participation.

Italy has an ancillary services market (MSD), where the TSO (i.e., Terna) operates as a single counterparty to procure the resources needed to ensure system security, adequacy and quality of supply. MSD is a pay as bid market where all programmable production units with a minimum installed capacity of 10 MVA and the needed technical requirements are requested to participate by offering all their upward and downward regulation intervals. On the MSD, some ancillary services are procured with a mechanism of remuneration (i.e., infra-zonal congestion relief, frequency restoration reserve with automatic activation—aFRR, tertiary reserve, subdivided into ready, spinning, and replacement reserve, and real-time balancing). Furthermore, a series of services are provided without remuneration, as their provision is mandatory (i.e., primary reserve, which is comparable to the frequency containment reserve—FCR, primary and secondary voltage control).

The DER involvement in the distribution network's management implies the development of local markets. The most promising regulatory framework is a local flexibility market where the DSO first solves the local distribution network security issues and then aggregates the remaining flexibility for the centralised TSO. The local markets are where local "products of flexibility" can be purchased from aggregators and producers by the DSOs for fixing distribution network issues. Their models result in an optimisation problem of which the solution is the economic optimum of the market and respects its rules and principles.

Different market models for the flexibility products for local and system services have been recently proposed in Italy and other European Countries. Among the other differences, they differ from one to the other for the role assumed by the involved system operators and the other market players. Although each EU Country proposed many variants for service market schemes, recent projects elaborated the subject and reached the following definitions [8–10]:

1. *Extended centralised dispatching:* all participants, from transmission and distribution, offer system services to the global market. The TSO is the only buyer of flexibility.
2. *Local Ancillary Service market:* DERs may participate in a new local AS market managed by the DSO. In this market, local services for solving distribution network operation issues are directly purchased by the DSO that, in turn, offers system services to the global AS market managed by the TSO by aggregating the remaining bids from the same or other DERs that participate in the local market.
3. *Shared balancing responsible model:* TSOs and DSOs handle the flexibility offered by only the resources connected to the networks that they manage. DERs connected to the distribution system cannot provide system services to the TSOs. Still, the DSOs have the new role of balancing the demand and the production at its voltage level according to a schedule defined in advance with the TSO and based on the day-ahead energy market results or historical data.
4. *Common TSO–DSO market model:* TSOs and DSOs can purchase services from flexible resources connected to the transmission and distribution grid. Both operators buy products from the joint-operated marketplace. There is no priority for the TSO or DSO, but the service is allocated by considering the highest need in terms of increasing social welfare. There are two variants of this market model. In the first, bids for system and local services are cleared in the same session, considering both transmission and distribution constraints. The DSO operates a local market that runs earlier than the common session but with participants' commitment in the second variant. Then, in the common market, the optimisation of the bid allocation considers the results of the first local market.
5. *Integrated flexibility market model:* This new market for flexibility allows DSOs, TSOs and other non-regulated players to buy flexible products from all resources independently from the connection point. The services are allocated to the party willing to pay more than the others.

Each model has its strengths and must overcome barriers due to its weaknesses, described in Table 1.

Table 1. Strengths, barriers and weaknesses of the proposed market models.

Market Model	Strengths	Barriers and Weaknesses
Extended centralised dispatching	- extension of existing markets with a unique buyer (TSO); - easy implementation; - immediately feasible in sufficiently robust distribution networks.	- too limited role of DSO; - small interaction between TSO and DSO; - minimum bid size for enabling the participation; - harmful impacts on distribution network operation disregarded.
Local Ancillary Service market	- local dimension can reduce the minimum bid size; - the DSO knows its distribution networks; - the DSO can act as a facilitator of the participation of DERs in the global market.	- implementation of new small and distributed markets; - risk of higher costs.
Shared balancing responsible	- TSOs can foresee the demand of the distribution systems with a very low level of uncertainty (smaller error in the forecast of the residual load demand); - reduced costs of balancing services; - DSOs gain an active role according to the specifications of the European Commission [33].	- the schedule should be determined at each TSO/DSO interface; - implementation of new small and distributed markets (as the previous model); - the DSOs and the DERs do not offer services to the TSOs; - fewer flexibility options are available for TSOs.
Common TSO–DSO market (first variant)	- unique optimisation (possibility of identifying the least cost solution); - DSO is a buyer of flexibility in the same market of the TSO; - TSO and DSO share the responsibility for operating the market; - both grid constraints are taken into account in the same timeframe;	- the computational effort for the optimisation of the bid allocation can become high due to the large dimension of the market; - it could be necessary for a third party other than the DSO and TSO for supervision.
Common TSO–DSO market (second variant)	- less communication between TSO and DSO.	- the DSO has no priority in the use of local resources.
Integrated flexibility market	- direct competition between regulated and non-regulated operators; - high liquidity due to the presence of additional buyers of flexibility; - possibility for TSO and DSO of reselling non-used flexibility to the market at the same conditions on which it was purchased.	- introduction of an independent market operator to guarantee neutrality; - additional interaction between system operators and other market players; - the lowest costs not necessarily obtained; - possible negative impacts on the operation of the other network; - unnecessary grid costs; - balancing could be problematic to the TSO.

4. Proposed Approach: Quantitative Assessment of the Flexibility

Two complementary and interconnected main tasks constitute the proposed approach:

- The first task builds the distribution network model in terms of lines, topology, conductors, demand and production exchanged with the bulk grid using open data only. The results are helpful for the TSO and for the stakeholders that do not know the distribution grid in detail.

- The second task aims at quantifying the availability of flexible products and the relevant costs by using local market models that optimise the DERs dispatching.

4.1. Modelling the Distribution Systems

Estimating distribution grid flexibility must consider the grid technical constraints that can be calculated only with a detailed knowledge of the distribution grids. This information is usually unavailable for different reasons (e.g., security reasons) and confined within the DSO databases. However, publicly available open data on the energy consumption and production of a region or broader area, opportunely processed, allow realistic load and generation profiles for each distribution network to be obtained, i.e., each TSO/DSO interface, in a given region/area. In [34], the authors proposed a methodology that, by combining these profiles with geo-spatial and socio-economic data, can build accurate *synthetic* models of the distribution grid with all data necessary for power flow analyses (e.g., number of lines, type of conductors, loads and generators). The results of the whole procedure proposed in [34] are (i) the exchange power profiles at the TSO/DSO interface that characterise an equivalent generator at the PCC with a four-quadrant capability curve (i.e., in import or export mode, from/to the bulk grid), and (ii) for each real distribution network of which the specific data of the grid are unknown, a synthetic network model that can be used for all the studies that need to check the grid limitations. The method is applicable even when the information on the distribution grid is open since the distribution networks are continuously reconfigured. It is much more efficient for high-level operational planning studies to refer to a good representation of the distribution system instead of the distribution system trying to follow the reconfigurations.

4.2. Flexibility Providers

Once the distribution network is modelled, several scenarios can be applied to model the flexibility provisions. For instance, typical scenarios can reproduce the existing or the expected level of distributed generation (DG), demand response and electric vehicles, which are the DERs involved in the market as flexibility providers. As well as these kinds of DERs, an important role in flexibility provision can be played by energy storage systems (ESSs). They, due to their inherent operational characteristics, may favour the transition towards more flexible and "smarter" distribution systems. ESSs, behaving as a four-quadrant generator, can provide several services to the DSOs related to voltage regulation, energy losses reduction, continuity and power quality improvement, etc. Indeed, if installed close to the TSO/DSO interfaces, they may offer flexibility services also to the TSO. However, the current European regulatory framework (starting from the "Clean Energy Package" [39]), despite giving a new role to the DSOs, considers storage operations as a competitive activity in the framework of European market design, and therefore, in principle, not allowed for monopolistic grid operators. For this reason, to avoid obstacles in market competitivity that may arise in the considered extended centralised market model, in this paper, ESSs owned and managed by the DSOs are not contemplated in the evaluation of the distribution's potential flexibility. In truth, an exception exists where under specific strict conditions, and only with the approval of the national regulatory authority, ESSs may be owned and managed by DSOs, especially if the implemented market model is the *shared balancing responsible* model, but this possibility is not considered in this paper [39–41]. In the proposed application, only private ESSs may be included to increase the potential bids of the DER owners. In this case, the added new flexibility quantity would be comprised in their offers in the market. However, it is worth noticing that this scenario can be expected only when the flexibility market is well-consolidated, and the DER owners envisage the ESSs as a possible source of extra income.

Starting from the known or estimated production of a distribution network, generators can be allocated in the representative feeders that compose the passive model of the synthetic network until it achieves the supposed real DG penetration. As well as the active customers agreeing to participate in demand response programs, a DERs scenario may include different combinations of non-programmable RES (i.e., solar or wind-based generators), programmable energy sources (i.e., CHP or biomass generators) for modelling the realistic DG penetration derived from the public data used for defining the power profiles at the TSO/DSO interface.

The proposed approach starts from the defined profiles at the PCC, locates the production plants along with the feeders of a real or a model of the distribution network, and hypothesises the participation profiles of the DERs (production plants, storages and active loads) involved in offering flexibility products, to estimate the market potential of DERs connected to a distribution network.

The DERs behaviour in the market is described in terms of pairs price/quantity of flexibility, and the bids are differentiated between upward and downward offers. It is assumed that such new market players behave rationally (i.e., by trying to maximise their profits), and the bid prices can be defined according to any model. For instance, a PV producer may offer in downward even reducing to zero the injection of power into the grid, and increase the injection if he has derated the production of his plant from the perspective of offering flexibility services in upward (e.g., especially if the plant is equipped by an energy storage system). Such upward bids are generally small in quantity because, if not awarded, they can represent a complete loss of revenue for the DG owner (i.e., neither for selling energy to the grid nor for possible incentives).

4.3. Assessment of Price/Quantity Curves at the TSO/DSO Interfaces

Figure 1 shows the flow chart of the second task of the proposed approach. For a given distribution network (e.g., one single feeder) and for each considered time interval ($t = t_0 \cdots T$), the quantitative assessment of the distribution system market potential is obtained by performing the following steps:

1. Calculate the maximum variations in upward and downward offers of the expected working point at the TSO/DSO interface by considering the hypothesised participation profile of each DER (i.e., maximum/minimum local generation and the minimum/maximum demand). Thus, the most extensive range of potential bids of the virtual power plant at the TSO/DSO interface is defined.
2. Represent the range of the upward and downward offers with a fair number of points.
3. Perform power flow (PF) calculations to verify the compliance of the distribution grid operation with the technical constraints by applying the generation/load conditions corresponding to the points obtained in the previous step 2. The PF calculation is performed on the given real distribution network if the data are known or, otherwise, on its synthetic model.
    a. If no violations are found, the relevant flexibility can be used by TSO with no adjunctive cost than the one correspondent to the price of the bids times the quantity purchased (i.e., *pay as bid*, they will receive a green traffic light).
    b. If operational issues are found (e.g., voltage regulation and power congestions), an OPF calculation is performed to identify the optimal setpoints of local resources required to fix such distribution issues. In the early phase of the local flexibility market, only reactive power support can be used to solve the distribution system operational issues (i.e., the reactive support is used for voltage regulation issues, and it is more effective in networks with a high X/R ratio). The OPF aims at minimising the distribution system operation costs that have to be added to the price of the active power bids that, if awarded, can be accepted with reserve by the DSO (i.e., they will receive an orange traffic light).

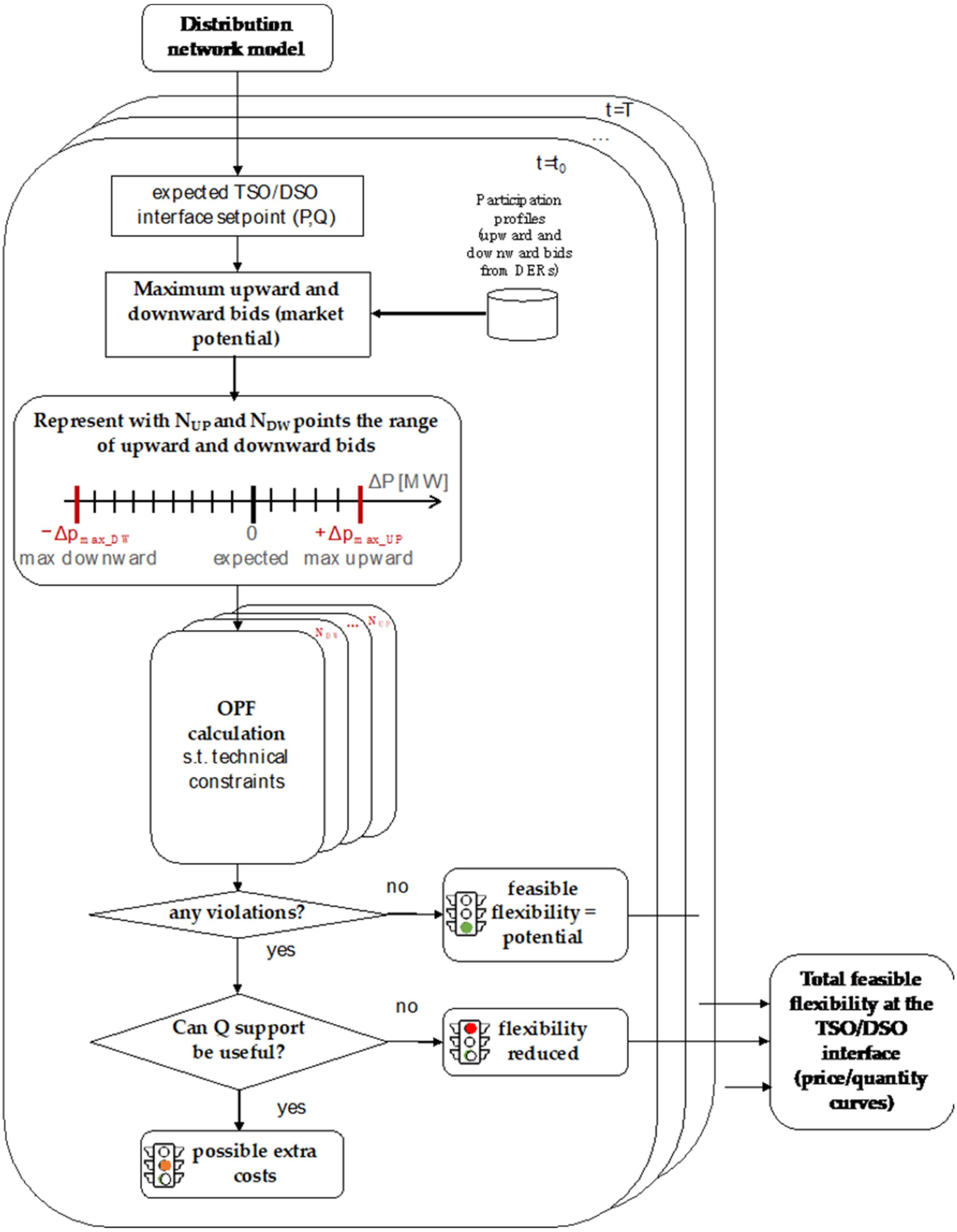

Figure 1. Flowchart of the quantitative assessment of the distribution system flexibility.

In particular, the optimal exploitation of the available flexibility is attained by solving a linearised optimal power flow (LOPF) with a linear programming (LP) approach that minimises a cost function expressed as the weighted sum of the flexibility services subject to network constraints [42]. The flexibility services considered are the active power from MV generators, the reactive power provided by the MV generators and the active power from the electricity consumption of MV customers involved in the demand response programs. The weights are proportional to the purchasing costs of the related flexibility services. The network constraints, corresponding to the nodal voltage and the ampacity limits, are linearised by using suitable sensitivity coefficients for each nodal voltage and each line current concerning the unitary active (reactive) power variation from each single flexibility provider [42]. Additional constraints are the maximum flexibility that each DER can provide.

c. It may happen that, in particularly critical distribution networks close to their hosting capacity, some operational issues (e.g., overvoltages, power congestions, excessive voltage drops) cannot be solved by resorting to the local resources. In such cases, the flexibility that can be offered to the TSO is limited by the distribution constraints. The difference between the potential bids calculated in step 1 and that resulting from eliminating the critical working points represents the measure of the non-feasible bids. DERs can bid such offers to the service market, but, if awarded, they will be blocked by the DSO (i.e., they will receive a red traffic light).

The result of this methodology is the price/quantity curves for upward and downward offers from a distribution network portion for each time interval considered. The extra costs possibly sustained for the flexibility products or the blocks imposed by the DSO for avoiding harmful impacts on the distribution network operators are also outcomes of the methodology. The extra costs depend on the hypothesised regulatory and market frameworks, while the possible harmful impacts on the distribution network operation depend on the defined location of the DERs along the network lines. Thus, for obtaining general validity results, different scenarios of DER location should be simulated to assess the expected maximum and minimum feasible flexibility.

5. Case Study

The proposed approach for quantitatively assessing the market potential of a given distribution network has been applied to a single primary substation (40 MVA transformer), sited in Sardinia (Italy), that has been modelled by a synthetic network with the approach proposed by the authors in [34]. The resulting model, provided in [34], is constituted of five feeders, two of rural ambit (feeder R1 and R2), one dedicated feeder that connects the biggest PV and CHP power plants (feeder D3) and two urban feeders (feeders U4–U5), one of them passive (Figure 2). The annual energy demand of loads of the network is 81.4 GWh/y. The total installed DG capacity power is aimed at reproducing the realistic scenario of DG derived from the analysis of open data concerning the real territory served by the PS. In fact, since the vast majority of DG is based on RES or high-efficiency CHP, open data exist on the position and size of those generators due to public incentive programs. Thus, the production by the local generation has been associated with each territorial portion, according to such information, by considering the rated power capacity of the generators and the production potential of the site. In the proposed case, about 26 MW of PV, 2.5 MW of WIND and 5.2 MW of CHP have been estimated to be installed along the network. The DG position is chosen and distributed for creating a critical scenario: the PVs are located at the end of only one rural feeder. The WIND turbines are connected at the end of the two rural feeders. The CHPs are supposed to be concentrated at the beginning of one rural and one urban feeder. Furthermore, the dedicated feeder includes two known existing plants, one 9.6 MW PV and one 2.7 MW CHP. Twelve typical day profiles for each kind of customer (i.e., residential, commercial, industrial and agricultural) and production technology (i.e., PV, CHP and WIND) are used for the daily demand and production representation, differentiated between weekdays, Saturdays and holidays and by season. In particular, typical production profiles are derived by combining the technical skills of the specific power plants with the historical meteorological data of the region/area on which is located the network. The PV production has been correlated to the latitude that strongly impacts solar radiation. The wind production profiles, derived by historical data, have been differentiated between coastal and mountain installations, and the CHP production profiles have been related, as the demand, to the climatic zone subdivision. The PV, WIND and CHP power plants connected to the test network produce 35.03 GWh/y, 3.87 GWh/y and 20.35 GWh/y, respectively. More details about the feeders' data and the load and generation profiles can be found in [34].

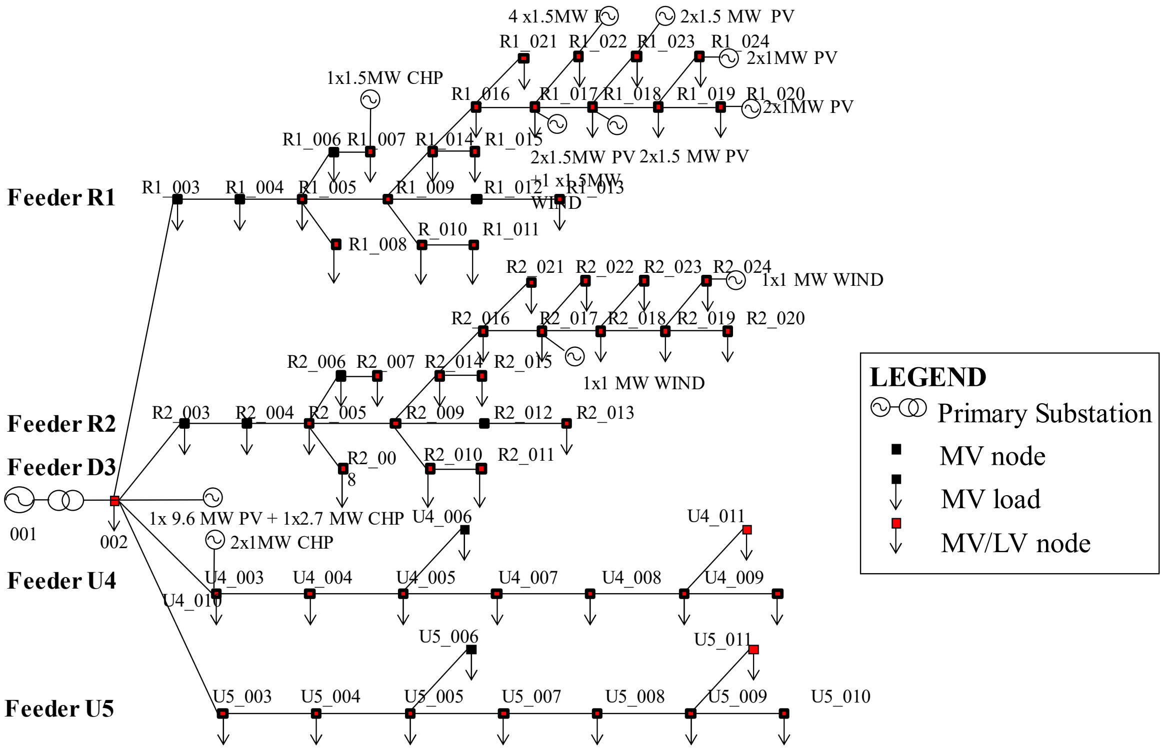

Figure 2. Case Study.

In the proposed approach, the network behaviour in the market is described in terms of flexibility and bids differentiated between upward and downward. Table 2 reports the quantity/price pairs considered in the simulations for all DERs involved in the market in the Case Study.

Table 2. DER participation in the market: quantity/price pairs.

DER	Participation Level	Downward Reserve		Upward Reserve	
		Quantity (%)	Price (EUR/MWh)	Quantity (%)	Price (EUR/MWh)
RES	All	−100%	0	+10%	$2 \cdot P_s$
CHP	All	−20%	$0.9 \cdot P_p$	+20%	P(fuel)
End-Users	25% of industrial customers	−5%	$0.9 \cdot P_p$	+5%	$1.1 \cdot P_p$

The Italian regulation subdivides the national territory into market zones. Considering the zonal selling price in the Italian Power Exchange Market (IPEX), hour-by-hour pricing for the energy exported to the grid is defined. On the other hand, the energy purchasing price for importing from the grid is based on the energy national single price (PUN). PUN varies hourly, daily and monthly, and, in Italy, is influenced by renewable production concentrated in the middle hours of the day (e.g., photovoltaic). The hourly PUN values and the zonal selling prices, available on the website of the Italian energy market operator (GME [43]), have been averaged for finding purchasing P_p and selling P_s price profiles for the typical days (i.e., three days for season) to be used in this application (i.e., selling price in the range 17.80 EUR/MWh ÷ 78.67 EUR/MWh, and purchasing price in the range 24.60 EUR/MWh ÷ 74.83 EUR/MWh).

The RES owners bid with prices greater than the day-ahead clearing price P_s for upward reserve because these bids require a voluntary derating of generators (10%) for creating upward margins with an immediate economic loss for producers. Regarding the downward bids, they might bid at zero or even negative prices if allowable by the regulatory framework. A zero price bid means that the producer will receive the money corresponding to the energy curtailed at the market clearing price. The zero price bids are the most convenient for fuel power plants, but they are non-convenient for RES that do not have operational fuel costs such as thermal power plants.

Conventional plants (e.g., CHP) that use fuel, offer a limited upward reserve at a price dependent on the fuel price P(fuel), which represents the most significant part of the production costs. CHPs have the priority to produce heat for the served thermal load, and thus a fluctuation not bigger than 20% of their instantaneous power production is allowed. For the downward reserve, the price should consider that it is necessary to switch on some electrical loads without changing the produced heat to reduce the power production exchanged with the grid. This can be convenient only if the price for purchasing energy in advance may be lower than the current purchasing price (P_p).

Similarly, active end-users realistically may offer minimal quantities (±5%) to modulate their consumption for offering upward and downward reserve. It is worth observing that upward bids mean reducing the consumption of end-users, and downward bids mean increasing it. Reasonable prices for such offers will be low for purchasing energy in advance (i.e., lower than P_p) and extra valuated in case of load postponing (i.e., greater than P_p).

In addition, DG units can support the volt/var regulation by exchanging reactive power with the grid for solving possible voltage violations caused by the variations in the active power setpoints of the DERs (included themselves) involved in the market. Concerning the remuneration for such a service, it is an open matter because, in several countries, the provision of reactive power by DG is considered to be free within the operating limits imposed by the current regulation. In this paper, the service is deemed to be paid at an administrative price of 5% of P_p (EUR/Mvarh) for considering the possible extra cost sustained by the DG owners for equipping their plants with a bigger than necessary inverter. The reactive power limits of DG units are defined according to the Italian technical rules for DG connection in MV networks [44], as allowed by the European standard [45]. The static generators are supposed to be connected through power electronics (i.e., inverters), while the CHPs are supposed to be directly connected. The capability curves used for defining the reactive power limits depend on the technology and size of generators. For instance, concerning the RES-based generators, the considered capability curves are: (i) semi-circular, for static generators greater than or equal to 400 kW (i.e., max reactive power Q_{max} equal to the rated apparent power S_n), (ii) limited semi-circular, for static generators smaller than 400 kW (i.e., $Q_{max} = \pm 0.436\ S_n$, corresponding to a 0.9 power factor); (iii) rectangular, associated to the Doubly Fed Induction Generator (DFIG) and Full Converter (FC) wind turbines (i.e., $Q_{max} = \pm 0.312\ S_n$, corresponding to a 0.95 power factor).

The simulations perform power flow (PF) calculations with a discretisation time of 1 h ($\Delta t = 1$). Since three representative days (working day, semi-holiday and holiday) for each season (winter–spring–summer–autumn) are considered, a total number of $N = 288$ time intervals has been calculated [34]. The simulations have been performed for each feeder included in the Case Study with the approach described in the previous Sections. In particular, the market potential has been calculated for two different cases:

- Case A ("only DG"), where the flexibility is provided only from the DG units, according to the participation level reported in Table 2;
- Case B ("DG + end-users"), with the flexibility offered from all DER available in the feeders, following the indications reported in Table 2.

For the inherent features that characterise the test network (i.e., it is constituted by representative feeders, integrates the real DG installed power, delivers a quantity of energy to the loads according to the open data available to the served territory, uses typical profiles for load demand and production according to the irradiation level of the territory and on historical data of wind production, etc.), it can be considered representative of a real case, and, thus, the results achievable from the application of the proposed approach can be considered representative as well.

6. Results

Table 3 reports the resulting occurrences of the three possible states of the calculated operating points into which are subdivided the maximum hourly range of the upward and downward bids (i.e., the market potential). A "feasible point" identifies an operating point (defined as a pair of active and reactive power for the whole feeder) fully feasible without any violations; a "feasible point with Q control" detects a technical condition where the Q support from DG (with additional costs) is fundamental to solve the electrical violations that happen in the network. Finally, an "unfeasible point" describes a condition where the technical violation cannot be avoided and, for this reason, the DSO will block this offer.

Table 3. Operating point occurrences differentiated for each feeder in the Case Study.

	Case A ("Only DG")			Case B ("DG + End-Users")		
Feeder	**Feasible Points (*Green*)**	**Feasible Points with Q Control (*Orange*)**	**Unfeasible Points (*Red*)**	**Feasible Points (*Green*)**	**Feasible Points with Q Control (*Orange*)**	**Unfeasible Points (*Red*)**
	(%)	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
R1	79.9	2.7	17.4	66.8	5.7	27.5
R2	100.0	0.0	0.0	89.2	5.0	5.8
D3	100.0	0.0	0.0	100.0	0.0	0.0
U4	100.0	0.0	0.0	97.0	0.0	3.0
U5	100.0	0.0	0.0	96.1	0.0	3.9

The first case discussed in the following paragraphs is case A, which involves the DG units only. Therefore, the following comments are referred to in the first columns in Table 3 (case A). Table 3 highlights that, in the first feeder (R1—Figure 3), the reactive support from DG (i.e., their Q control) is mandatory to obtain an adequate flexibility level. By analysing Figure 2, it can be realised that R1 is the feeder with the biggest DG quantity (>50% of the total DG installed capacity in the substation). Consequently, more technical violations (e.g., overvoltages) can be expected in this feeder. On the contrary, the other feeders are fully feasibly capable of giving to the TSO all the flexibility potentially provided by the connected DG units. In the following, more details will be given about the flexibility potential offered by the feeder R1 (case A). In particular, in Figure 3, all the simulated operating points are shown: the different colours follow the definitions adopted in Table 3. Such points represent the operating points into which has been subdivided the market potential of the feeder, calculated as differences in the expected profile in each considered time interval. The (0, 0, t) points of the 3-D graph represent the expected profile without any variations in each time interval t. For the comprehensive analysis of Figure 3, it is important to remark that positive "Delta Active Power" points identify a DG production curtailment, while negative "Delta Active Power" points represent an increase in DG production, which seems feasible for a given extent, 79.9% (green points) around the expected profile, and, for the remaining part of the potential range, become unfeasible (red points 17.4%) or feasible with the reactive support only (orange points, 2.7%).

In detail, Figure 3 highlights that the market potential offered by the DG units can hypothetically reach +6 MW during the year, but this upper limit is unfeasible (red points in Figure 3), with the "feasible flexibility quantity" limited to about +4 MW (green points). As discussed above, positive "Delta Active Power" values detect a generation reduction that is easy to manage (green points—no technical violations). Still, if a large quantity of generation is switched off, some under-voltage conditions happen in the network. This contribution to flexibility becomes unfeasible (red points area in the upper part of Figure 3). In the negative part of the "Delta Active Power" axis (Figure 3), the offers that increase the DG production are represented: according to the availability shown in Table 2, these quantities are lower than the previous ones. Due to the high amount of installed DG in the feeder R1, a further increase in power injection is not suitable (the network suffers from overvoltage issues), and many unfeasible points constitute the potential negative "Delta Active Power" (−1 MW). However, in some conditions, the Q control can avoid the voltage problems, and a few offers can be accepted, taking into account the additional cost needed for the Q contribution (0 ÷ 0.5 MVar). The green points corresponding to negative "Delta Reactive Power" refer to electrical conditions on which the generation injects active power with a non unitary power factor (e.g., wind and CHP units). From another point of view, Figure 4 reports the R1 feeder potential active power profile in all the considered representative days. It shows that, in many time intervals, the feeder has a reverse flow to the main transformer (negative values), but the active power feasible is limited to about 3.8 MW (Figure 4). The majority of unfeasible points are concentrated in the lower part of the profile (increase in power production). Still, some unfeasible points can also be found in the upper part, as discussed in Figure 3. Analysing the differences between the representative days, the unfeasible conditions due to an excessive reduction in the DG production are more frequent in the winter and autumn seasons, according to the load/generation coincidence profiles.

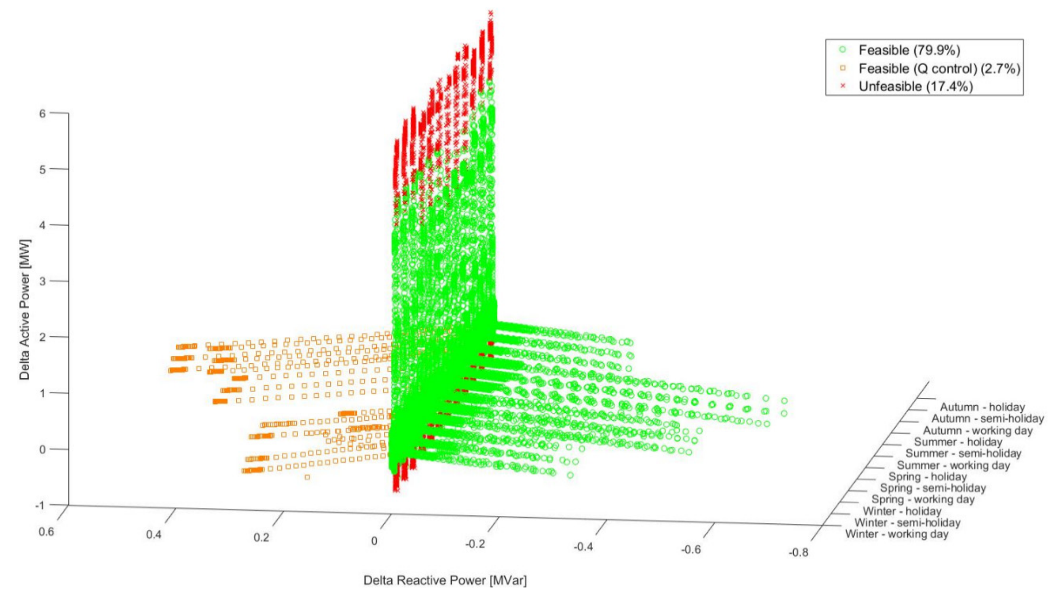

Figure 3. P-Q variations during all the representative days, feeder R1—case A ("only DG").

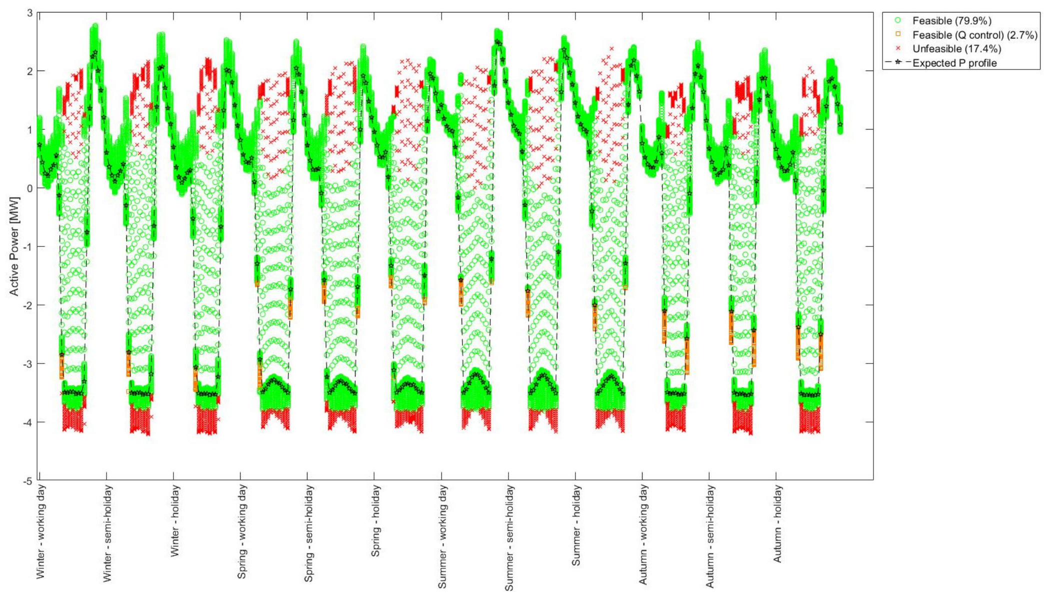

Figure 4. Potential P profile during all the representative days, feeder R1—case A ("only DG").

In the proposed Case Study, only feeder R1 has critical operating points, while the other feeders are completely feasible (Table 3). Therefore, the other feeders are not described in detail. For example, Figure 5 reports the second rural feeder (R2) potential active power profile in all the considered representative days, without reverse flow conditions and fully feasible. In Figure 6 the same shape is shown for the urban feeder (U4—Figure 2): again, it is completely feasible despite some hours of the year in reverse flow.

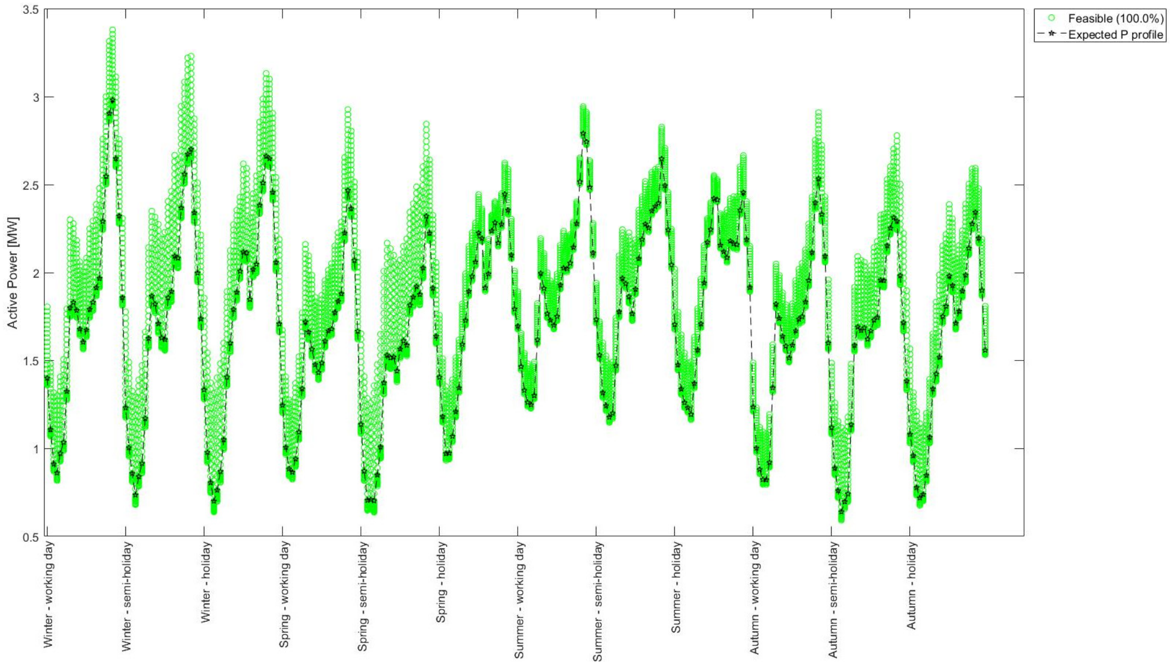

Figure 5. Potential P profile during all representative days, feeder R2—case A ("only DG").

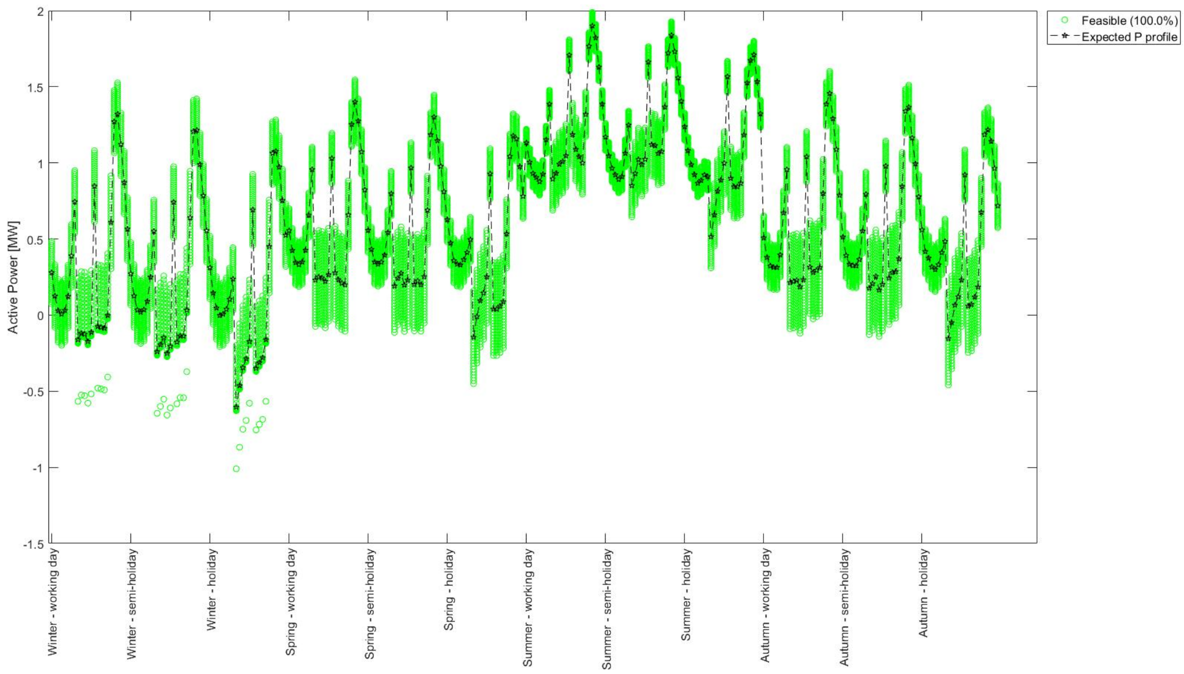

Figure 6. Potential P profile during all representative days, feeder U4—case A ("only DG").

As indicated in Chapter 0 and the first part of this Section, the last columns of Table 3 report the occurrences of the states of the calculated operating points by also considering the contribution of the end-users to the market potential (case B).

First of all, it is worth noticing that the occurrence of Q control feasible (orange) and unfeasible (red) points increases in the case of B in comparison with case A (Table 3). This fact is due to the increased number of operating points on which it is subdivided by the larger range of the market potential due to the added flexibility offered by the end-users. In other words, some operating points in case B have not been analysed in case A because it depends on the end-users' offers. Nevertheless, the end-user engagement allows a more extensive flexibility volume to be obtained compared to the case with only the DG participation. To confirm the last sentence, Figure 7 reports the R1 feeder potential active power profile in all the considered representative days for case B. The comparison between the graph in Figure 7 and the same graph for case A in Figure 3 highlights that the exploitation of end-user flexibility increases the feasible upper limits (>3 MW), while the lower limit (about −3.5 MW) increases the potential flexibility offered to the TSO, but, taking into account only the feasible points, the availability in such a region is not modified between case A and B.

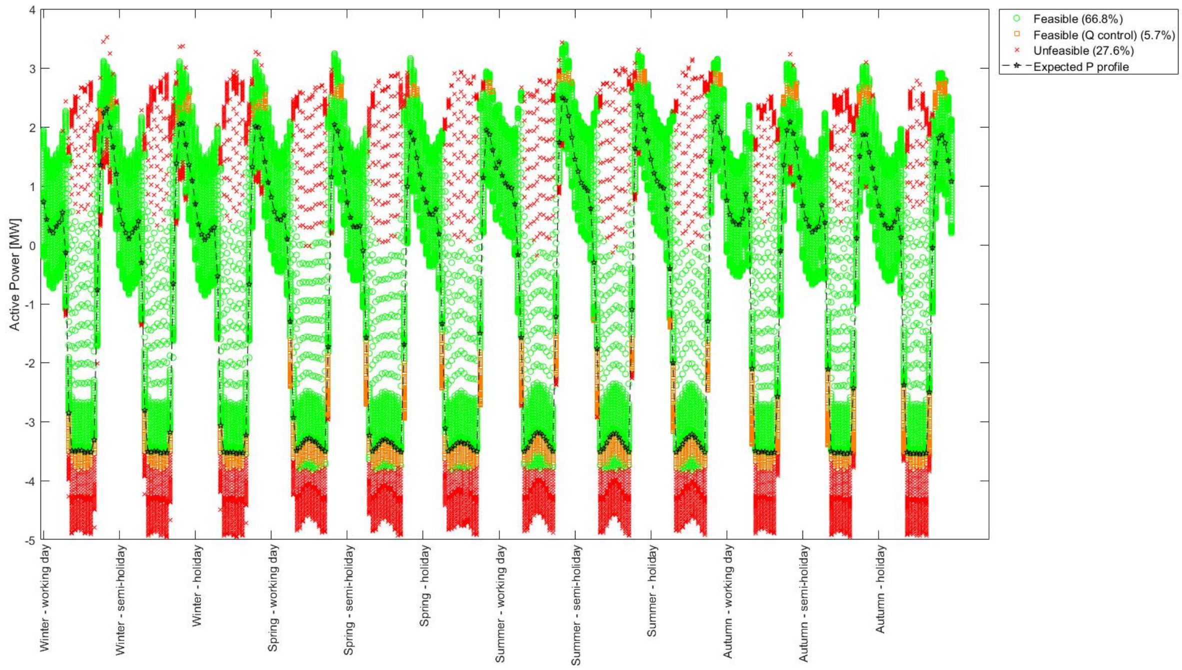

Figure 7. Potential P profile during all representative days, feeder R1—case B ("DG + end-users").

In the other feeders (except the dedicated feeder D3) in case B, a slight increase in the unfeasible point occurrence appears, but it is important to remark again that it depends on the more extensive range of market potential obtainable with the end-user involvement. In other words, with the end-user participation, the potential flexibility volume increases, and, consequently, a bigger number of unfeasible points can be detected. However, the total feasible energy available for the TSO is bigger in comparison with the case with the participation of the DG units only. The comparison of the potential active power profiles of the feeder R2, reported in Figures 5 and 8 for cases A and B, respectively, show that in the last case, the area formed by the (feasible) green points close to the expected profile is bigger than the first one(Figure 8 vs. Figure 5). In addition, in the case of B, the potential active power reaches the +3.5 MW, and some reverse flow conditions (especially in the autumn season—Figure 8) appear. In contrast, in the other case (case A), such potential is limited to 0.6 ÷ 3.4 MW (Figure 5). Figure 8 also shows that the operating points close to +3 MW need reactive support (Q control—orange points) to solve the technical violations. However, over this value, feasible conditions can still be found. The same comments can be made for the other feeders.

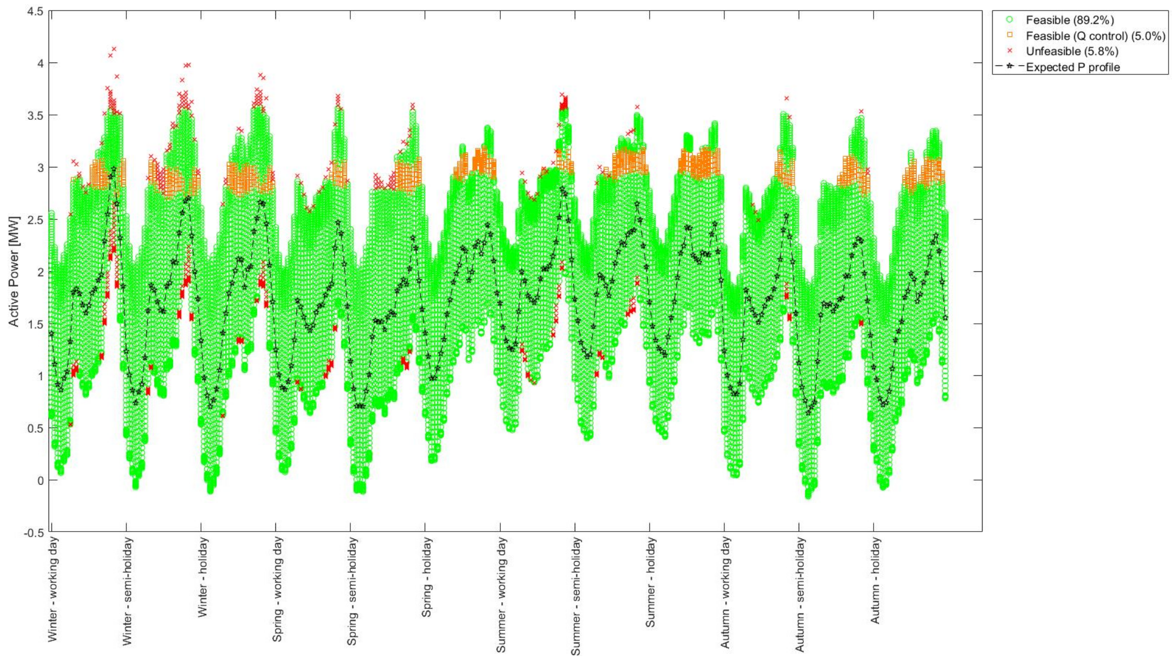

Figure 8. Potential profile during all representative days, feeder R2—case B ("DG + end-users").

Only the single feeders have been discussed regarding the flexibility until this point. However, the entity that offers flexibility products to the TSO is the substation described in Figure 2. Concerning the whole substation, in Table 4, some aggregated results are reported for the two cases (A–B) simulated, differentiated between the upward and downward parts.

Table 4. Flexibility quantities for the whole substation adopted as Case Study (Figure 2).

	UPWARD		DOWNWARD	
	Case A (DG Only)	**Case B (DG + End-Users)**	**Case A (DG Only)**	**Case B (DG + End-Users)**
Market Potential (GWh/year)	9.026	37.271	42.293	70.519
Feasible Flexibility (GWh/year)	8.126 (−10%) [1]	32.503 (−13%) [1]	37.254 (−12%) [1]	60.659 (−14%) [1]
Cost of feasible flexibility (MEUR/year)	0.502	1.849	0.253	1.499
Needed Reactive support (GVarh/year)	29.344	27.900	0.298	3.026
Total extra cost for Reactive support (kEUR/year)	73.3	70.6	0.9	9.2
Unitary cost (without extra cost—feasible) (EUR/MWh)	61.78	56.89 (−8%) [2]	6.79	24.71
Unitary cost (with extra cost—feasible) (EUR/MWh)	70.80	59.06 (−17%) [2]	6.82	24.86

[1]: the percentages refer to the potential quantity for the same case. [2]: the percentages refer to the same quantity in case A, considered as a reference case.

The results show that despite the great potential (i.e., 9 GWh/year in upward and 42 GWh/year in downward—case A), the grid limitations reduce the flexibility that can be offered without incurring in DSO blocks. The reductions are, respectively, 10% in upward and 12% in downward; similar values have been obtained for case B. Furthermore, extra costs have to be considered. The quantity is different for the upward and downward BIDS according to the different DER availability reported in Table 1. To sum up the different behaviour, a unitary price has been calculated, with and without the extra cost relevant to the reactive support needed in the orange points. The unitary price derives from the combinations of the different offers (DG and end-users). Regarding the results reported in Table 3, the end-users' participation allows a cost reduction in the upward part, until 17%, taking into account the additional cost for the Q control. On the contrary, in the downward part, the unitary cost increases, but these results depend on the downward bids adopted by the RES owners, who might bid at zero or even at a negative price, if allowable by the regulatory framework. A zero price bid means that the producer will receive the money corresponding to the energy curtailed at the market clearing price. In these conditions, starting from a zero price (Table 1), the increase is unavoidable. Further details about this topic can be found in [46]. Finally, it is important to remark that the flexibility analysis cannot be stopped at the "potential quantity" (first row of Table 4) but on the effective energy that can be used for the flexibility. Even though the fit and forget approach caused an extremely cautious development of distribution systems to host distributed generation, bottlenecks in distribution networks still impede the provision of flexibility or cause adjunctive costs.

7. Discussion and Conclusions

The growing penetration of RES at each voltage level and the progressive use of electricity for applications normally covered by other energy vectors, namely natural gas, are evident trends. Thus, more flexibility in services from distribution systems will be necessary to balance generation and consumption with adequate security margins. Markets for services should change to allow new resources to participate, and the interaction and the communication between the TSO and DSO at the TSO/DSO interface will have to be modified accordingly. The interaction between the DSO and TSO can imply blocks or augmented costs caused by the impact of increasing/decreasing power generation/consumption on distribution systems to allow DER to offer services for balancing and reserve. The paper proposes a quantitative analysis of such interactions with particular reference to the impact on the operation of distribution systems (i.e., voltage regulation and power flows) of TSO requests for services. The final goal is quantifying the flexibility that the TSO can procure from the distribution system without a harmful impact on the distribution network operation. The paper investigates the expected interactions between the use of flexibility for power system balancing and security and the operation of distribution systems. The result of this methodology is the price/quantity curves for upward and downward offers from a given (modelled or real) distribution network. The extra costs possibly sustained for the flexibility products or the blocks imposed by the DSO for avoiding harmful impacts on the distribution network operators are also outcomes of the methodology. The main result of the study is that although the distributed energy resources have been connected under the hypertrophic conditions generated by the fit and forget approach, distribution systems are not robust enough to accept changes in DER production/consumption without any operational action. In particular, voltage regulation is the most common cause of block that inhibits TSO from using flexibility or that requires DSO to change reactive power provision by DERs (that means extra costs). This is an interesting result that can be considered general validity because it is obtained by applying the proposed methodology to a test network composed of representative portions of the distribution system and reproduces a realistic or synthetic model of a real network (e.g., the DG penetration level is corresponding to the real scenario and the delivered energy to the loads is relevant to the share of the real demand of the province on which is located the primary substation). In addition, while the extra costs depend on the hypothesised regulatory and market frameworks, the possible harmful impacts on the distribution network operation rely only on the defined location of the DERs along the network lines. Thus, for obtaining general validity results, many and different scenarios of DER location should be simulated to assess the expected maximum and minimum feasible flexibility. However, if one possible scenario, such as the one presented in the paper, produces the reported impact on the network operation, it is reasonable to expect that a harmful impact caused by the uncontrolled use of flexibility may exist, and, with the proposed procedure, it would be predicted.

For answering the questions formulated at the beginning of this paper, we can observe:

- It is necessary to carefully assess to what extent can a TSO exploit flexibility without causing issues at the distribution level. Such extent depends firstly on the number of the DERs intentioned to participate in the market, and secondly on the specific position of the resources in the network. The more DERs participate in the market, more quantity can be managed, but the increasing potential does not necessarily increase the same quantity in the feasible flexibility that can be moved without harmful impact on the network operation. The reported assessment, together with resorting to the methodology used for representing the real network via a realistic model (i.e., the synthetic network), can be a valid option for estimating such extent by players different from the DSOs (i.e., TSO and aggregators).
- The main issues caused by flexibility are voltage regulation problems, as overvoltage conditions caused by upward bids (i.e., extra production or load shedding) or excessive voltage drops in case of uncontrolled downward bids (i.e., curtailment of production or increasing of consumption by the active customers). In some cases, such violations of the technical constraints can be solved, with extra costs, by resorting to the reactive power support from DG. In other cases, the potential bids might be definitely reduced. In any case, resorting to flexibility cannot disregard the distribution grid limitations.
- The operational actions that enable flexibility at the distribution level rely mainly on the interactions between system operators. In the case of uncontrolled participation of DERs in the whole ancillary service market, possible blocks to the bids by the DSO may occur. The assessment in advance of the possible violations of the network constraints may prevent such situations and simplify the use of the flexibility for global services achieving a reduction in the system operation costs.
- The expected costs to enable flexibility depends on the regulatory framework. In the proposed Case Study, a possible rational behaviour in the market of the DERs owner has been proposed. The final costs are quantified according to the hypothesis of remunerating the reactive power support.

The final remark of this study is that a sort of prequalification of the DER bids to the TSO should be assessed in advance for preventing distribution network operation problems. Such prequalification could facilitate the TSO to use flexibility coming from the distribution system and also reduce costs because the requested quantities do not receive any block by the DSO.

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