ASSESSMENT OF PRICE AND QUANTITY OF ANCILLARY SERVICES PROVIDED BY ACTIVE DISTRIBUTION SYSTEMS AT THE TSO/DSO INTERFACE

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ABSTRACT

This paper concerns the quantification of the costs that a distributor must support to enable the new market scheme and the participation of new potential competitors to the ancillary service market. Starting by available open data and GIS the value of distributed resources and active demand in the market for system services has been assessed. Representative models of the network beyond the TSO/DSO interface have been developed in order to evaluate the operation extra-costs for solving contingencies. The impact on the flexibility (quantity) potentially offered by a distribution network and on the price of the bids in the ancillary service market has been calculated by applying the proposed methodology to real world cases.

INTRODUCTION

The provision of system services from the distribution system is an opportunity and a necessity for the whole power system. The share of not programmable energy sources that are making the balance between load and generation more expensive and risky causes the necessity. The opportunity is represented by the availability of more flexible resources scattered in the system that increase the number of players in the market and make it possible a wider participation of customers. In this context, the assessment of the impact of novel distribution systems is a complex task for the dimension and the number of players, for the inherent complexity of distribution systems and for the lack of open information about networks, consumption and production. This paper proposes an original procedure that starting by available open data and GIS allow assessing the value of DER and active demand in the market for system services. Different market models have been simulated to evaluate, for instance, at what extent the distribution system can impact the volumes of energy offered by traditional power plants in ancillary service market. In particular, the expected costs/prices/quantities for the services offered by the distribution system are calculated for each point of common coupling with the transmission system (namely, the primary substation, PS) to be compared with the offers from traditional services providers. The network beyond each PS is represented by a proper combination of representative distribution feeders (e.g. rural, urban and industrial). Finally, the impact of any PS in the bulk market for energy services can be assessed taking into account the impact of active controls for all distributed resources. A flow chart of the proposal is pictorially depicted in Figure 1, with the aim of better clarifying the rationale of the approach that has been applied to provide a suitable solution to the problem. The key innovations in the paper are the clustering procedure related to GIS regional systems, the application of representative models to assess the impact of new actors in ancillary services market and the integration of distribution systems in the simulation of bulk ancillary service markets. The paper is mainly devoted to explain the application of the process to real world cases with the aid of suitable test cases that will show the impact of possible scenarios for the development of renewable energy sources and the participation of active demand on the value of services that smartgrid can offer to the power system.

PROPOSED APPROACH

This paper aims at quantifying the volumes and the prices that can be offered by new potential actors of the Distribution in the ancillary service market. The new actors that may provide ancillary service will be:

- DG connected to the distribution grid (MV or LV), including both programmable and non programmable power plants;
- Loads (e.g., end users which agree to participate in Active Demand (AD) programs);
- Combinations of loads and DG;
- Distributed Energy Storage (DES) systems;
- DSOs in the role of aggregators or managers of the flexibility of those of the above actors that are connected to their grid.

Two recent papers, [1] and [2], described and clarified some aspects of the proposed approach. The main steps of the methodology can be summarized as follows:

1. **Estimation of load and generation profiles** of each PS in a given year, by using only available open data and GIS software. The considered year can be the starting year of the study (2014) or a future year obtained by applying an evolutionary scenario for load demand and DG production.
2. **Representation of the network** downstream each PS by composing elementary portion of representative networks. The elementary network portions are feeders typical of a certain ambit (i.e., rural, industrial and urban) that are characterized in terms of topology, conductors and loads as well as in terms of potential participation to the market for system services depending on the DER and active demand scenario.

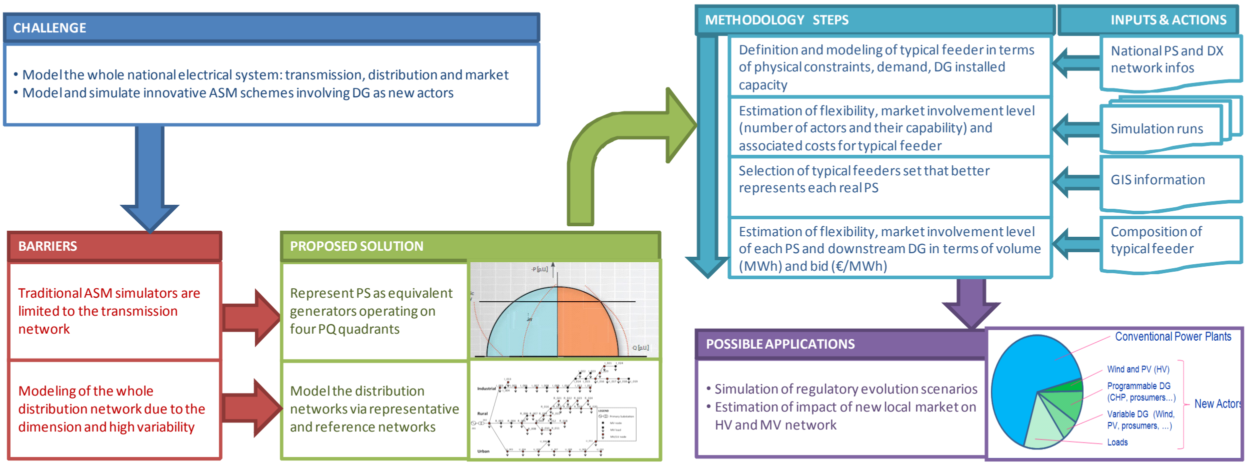

Figure 1. Flow chart of the proposal

3. **Assessment of flexibility capabilities and offers towards the global market of ancillary services,** for each PS network model, in terms of quantity and price pairs during the hours of the considered twelve typical days (working, semi-holiday and holiday for the four seasons respectively). The flexibility and the bids can be derived as combination of those of each typical feeder composing the PS network model.

This paper focuses mainly on the third step of the methodology.

Depending on the installed DERs (PV, WIND, CHP, AD, Energy Storage, etc.) and on the regulatory framework considered, a given Distribution Network could offer more or less flexibility in the market. Moreover, DERs can offer services at different prices depending on their hypothesized participation level. DER participation level has been assumed as reported in [2] but any other hypothesis of participation can be formalized, thanks to the flexibility of the procedure. In TABLE I the level of participation (i.e., how many DERs of those connected to the distribution network agree to provide ancillary services) and the relevant quantity/price pairs, for downward and upward reserve bids, are reported. More in details, all RES, only a small percent of CHP (i.e., 5%), and a quarter (i.e., 25%) of the installed power of industrial customers connected to the distribution network are assumed to participate directly or via aggregator to the global system service market. The quantities offered are reported as percentage of the instantaneous power produced by the RES and of the installed power for CHP and AD. For the sake of the present study it has been assumed that RES might limit power production to 90% of the instantaneous capability so that 10% is left for upward reserve. The bid prices refer to the Italian energy market data [3]. In particular, the selling energy prices P_s for the RES bids and the purchasing energy prices P_p for the AD have been used. For CHP the avoided cost for fuel saving (F) has been considered to formulate the upward offer price.

In addition, besides these assumptions for the prices of the energy offered by the distribution network, in this paper it is supposed that DER owners should be compensated for the reactive production they are called to exchange for solving local contingencies. Depending on the regulatory framework, DERs are enabled to sell ancillary services to the TSO directly or via Aggregators (including DSO). In any case the DSOs have to check the local technical constraints and, possibly, in case of contingencies, directly call the DER owners for their reactive power support. In the Italian Regulator proposal the compensation of the DER owners for the reactive power exchange should be based on an administrated-price until the creation of new local service market for reactive power [4]. In this paper the administrated-price is hypothesized equal to 5% $\cdot P_p$ [€/MVARh] (where P_p is the current energy price).

TABLE I DER participation and quantity/price pairs offered in ancillary service market

DER	**Parti-cipation level**	**Downward reserve**		**Upward reserve**	
		quantity [%]	**price [€/MWh]**	**quantity [%]**	**price [€/MWh]**
RES	all	-100%	0	+10%	$2 \cdot P_s$
CHP	5%	-20%	$0.9 \cdot P_p$	+20%	$1.1 \cdot 0.5 \cdot F$
AD	25% of industrial custo-mers	-5%	$0.9 \cdot P_p$	+5%	$1.1 \cdot P_p$

PS technical and economic model

In order to generalize the procedure and make it applicable to any distribution network beyond the interface TSO/DSO, simulations of each typical feeder are performed separately, with different DER scenarios, to create a database of their behavior in the ancillary service market. More in details, once the bid price is defined for each kind of DER according with TABLE I, by running load flow (LF) and optimal power flow (OPF) calculations for each typical feeder with different DER scenarios, is possible to assess (i) the participation, in terms of quantity/price pairs, of new potential competitors to the market, and (ii) the extra-cost to solve local contingencies

that a distributor must support to enable the new market schemes.
Therefore, the total potentially offered volume and bid cost of a given PS can be easily assessed through the definition of the network model as composition of typical feeders (step 2 of the proposed approach). More in details, once the number and the type of feeders that compose the PS network model are defined, the passive feeders of the model are completed by a certain DER's penetration level, according with the current installed power or with a hypothesized evolutionary scenario. Thus, the behavior of the PS can be completely assessed both in terms of compliance with the technical constraints and in terms of potential volume that can be offered in ancillary service market. It is worth noting that a certain penetration level of DER can be modeled in different ways: the same DG installed power can be considered spread in the network model or concentrated in a relatively small number of feeders. Depending of this choice the network can be considered respectively far to its hosting capacity (i.e., no contingencies due to DG) or characterized by critical issues relevant, for instance, to the voltage regulation or overload conditions which can be solved with the reactive power support or even with active power curtailment.
If the network model of a given PS is constituted only by feeders without expected contingencies the final cost of its bids is simply calculated by multiplying the offered volumes with the prices according with TABLE I. Otherwise, by using critical feeders for the network model composition, an extra-cost for the reactive power support has to be taken into account.

CASE STUDY

In order to clarify the proposed procedure, firstly a single distribution network downstream a HV/MV transformer (i.e., a single PS) is considered. A comparison between the cases of the feeder composition without and with critical contingencies has been made. Then, the results relevant to one of the six Italian market zones are used to discuss the entity of the potential extra-costs that could be derived by varying the network models.

Single primary substation results

The load demand of the considered PS is about 163 GWh/year and the installed PV power is about 18.4 MW. The passive model of the network, defined by the proposed procedure (step 2), is constituted by 12 typical feeders (1 industrial, 1 rural, and 10 urbans). The most critical feeders are the rural and the industrial ones. The *industrial* typical feeder supplies various different load types and is characterized by high rate of MV loads, relatively short line extension, and quite high total power demand. The *rural* typical feeder is constituted by long overhead lines with many branches, has reduced load energy demand, supplies spread LV customers (low power density), mostly with agricultural or residential profiles. Both of these two feeder categories may suffer for overvoltages or line overloads during non-coincidence conditions between production and load demand. Conversely, the relatively short *urban* typical feeder, characterized by underground cable lines, well tolerates such contingencies. In order to emphasize these critical issues, two scenarios have been hypothesized for representing the real installed PV, by forcing the tool to use only critical or not critical DG allocation:

1. *Non critical* DG scenario, that consider all the installed PVs along the urban feeders;
2. *Critical* DG scenario, in which the PV is concentrated mainly in the industrial and rural feeders.

TABLE II reports the typical feeders with DG that compose the network model in the two considered scenarios and the difference between the installed PV power in the real PS and in the models. The DG penetration level is defined as percentage of the total load demand; the remaining feeders do not have significant DG installed. Both the models well represent the real PV scenario (differences lower than 0.2%). However, the tool, without any specific force, by optimizing the DG allocation, is able to minimize the difference between the real installed DG and that is considered in the model.

TABLE II PS network model in the two considered scenarios

PS model scenario	*Urban typ. feeders*	*Industrial typ. feeders*	*Rural typ. feeders*	*Diff. with installed DG [%]*
***Non critical* DG scenario**	3 x 50% 3 x 120% 1 x 200%	---	---	+0.19%
***Critical* DG scenario**	4 x 20%	1 x 200%	1 x 200%	-0.14%

In TABLE III the results about the simulated upward and downward bids are shown for the considered PS.
In the *non critical* DG scenario the PS can offer in the system service market higher volumes at a lower price than those resulting in the *critical* DG scenario. In the first scenario, no extra-cost have to be taken into account for solving local contingencies, and the total cost of the bids, potentially awardable by the distribution network in the market, depends only on the selling prices in the market (according with TABLE I).
Otherwise, if the majority of the installed DG is concentrated in the most critical feeders (rural and industrial), contingencies may occur in several hours of the year (mainly in the central hours of the summer days). Such contingencies can be solved relying on the reactive power support from DG or by curtailing the active power of PVs. Only an advanced level of smart grid enables the DSO to curtail the active power from DG during severe contingencies. In this paper the volt/var regulation is considered for complying with the voltage constraints, while the necessity of active power curtailment for solving line congestions may result in a reduction of the width of the bids, due to the unfeasibility of the expected state of the network. This explains the reduced volumes in the case of *critical* DG scenario (2.157 GWh/year vs. 2.232

GWh/year): the maximum potential upward reserve cannot be offered because of intolerable line overloads. Instead, the increase of average offered price (from 91.78 €/MWh to 95.32 €/MWh) is due to the extra-cost paid for the reactive power support. It is worth noting that without the reactive power support the PS modeled with the critical DG scenario could offer only 1.379 GWh/year. While by considering the volt/VAR regulation the volume potentially offered by the PS increases of 56% (2.157 GWh vs. 1.379 GWh/year). The extra-charge for allowing this increase is equal to 6.4 k€/year. This result is the most important of the proposed procedure that is able to assess the extra-volume that would be offered and the relevant extra-cost, if at least a basic level of smart grid is implemented (i.e., the reactive power contribution to the voltage regulation). It is worth noting that the difference between the two average prices strictly depends on the assumption for the administrated-price for the reactive power, and could be higher or lower in a future local market for reactive power.

TABLE III Upward and downward bids in the simulated scenarios for the single PS in the year 2014

Scenario: PV participation		**Upward**	**Downward**
***Non critical* DG scenario**	Offered Volume [GWh/year]	2.232	22.323
	Average offered price [€/MWh]	91.78	0
***Critical* DG scenario**	Offered Volume [GWh/year]	2.157	22.176
	Average offered price [€/MWh]	95.32	0

Entire market zone results

The methodology has been applied to the Sardinia's power distribution system that constitutes one of the six market zones of the Italian national grid. In [2] the results of the whole procedure to this zone are reported for the case in which the model of each PS has been obtained with typical feeders without expected contingencies. In the Sardinian PS the PV is predominant and the total installed PV power at the starting year has been evaluated about 620 MW. The total year energy consumption by the PS loads is about 6.76 TWh/year.

In TABLE IV are reported the bids for the scenario in which the all PVs participate to the ancillary service market (ASM) for both representations with and without expected contingencies. The comparison between the awarded volume in the real ASM during the year 2014 has been investigated. In the scenario characterized by PS network models that include feeders with concentrated DG (*Critical* DG scenario) the potential upward volumes awarded in the ASM would be reduced from about 3.5% to 3.2 %. Nevertheless, the average offered price for the upward reserve that includes also the extra-cost for solving local contingencies is lower than the average awarded one in the real ASM (i.e., 92.40 €/MWh vs. 128,40 €/MWh).

Regarding the downward bids, both in the non critical and in the critical DG scenario, despite the significant volume offered by PV plants, the corresponding yearly volumes would be not awarded. This is because PV plants offers should be placed at a negative price (not admitted in the current regulatory framework) or at zero price. Such offers are no competitive for downwards reserves if compared with conventional power plants.

By considering the participation of the active consumers, according with the hypothesis considered in TABLE I, the cumulated AD volumes offered by all the Sardinian PSs is equal to 0.007 TWh/year that represents a significant share of the awarded downward volume in the real ASM. In any case, both for upward and downward the AD bids might be competitive with average offered prices lower than the average awarded price in the real ASM.

Furthermore, the exploitation of the active demand can be particularly convenient for a DSO because it could help solving some contingencies relative to the non-coincident profiles of DG and loads, possibly reducing the consequent extra-cost.

TABLE IV Upward and downward bids in the simulated scenarios for Sardinia's power system and accepted in the real ASM in the year 2014

Scenario: PV participation		**Upward**	**Downward**
Real ASM (2014)	Volume [TWh/year]	2.123	0.012
	Average awarded price [€/MWh]	128.40	32.40
***Non critical* DG scenario**	Offered Volume [TWh/year]	0.074	0.741
	Average offered price [€/MWh]	91.78	0
	Potential awarded market [%]	3.49%	0%
***Critical* DG scenario**	Offered Volume [TWh/year]	0.068	0.679
	Average offered price [€/MWh]	92.40	0
	Potential awarded market [%]	3.19%	0%

CONCLUSION

This paper concerns the quantification of the costs that a distributor must support to enable the new market scheme and the participation of new potential competitors to the ancillary service market, taking into account the extra cost derived to the compliance with the technical constraints.

The main strength of this work is that the proposed procedure is able not only to define the volumes and the cost of the bids potentially offered in the market by the new actors connected to the distribution system, but also to model the distribution network downstream each PS and, thus, to evaluate the issues relevant to the real operation of the network. An advanced level of smart grid allows to comply with the technical constraints even in case of severe contingencies by exploiting, for instance, the reactive power support for volt/var regulation. The cost of this local service has been taken into account starting from defined assumptions. The impact of this cost in the system service market can be significant for those networks in which the DG hosting capacity is close to being reached.

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