ACTIVE DISTRIBUTION NETWORK COST/BENEFIT ANALYSIS WITH MULTI-OBJECTIVE PROGRAMMING

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ABSTRACT
The most innovative concept in the nowadays distribution system is that Distributed Energy Resources (DERs) are active subjects of the system with new business opportunities from the active management but with the responsibility to assure a proper work of the system working in coordination with DSOs. The Civil Society, the DSO and DER owner are clearly the stakeholders of the systems, that have contrasting and opposite goals; in the paper, the points of view and the needs of system stakeholders has been simulated. For this reason, Multi-Objective approach are used to capture the relationship among players in order to constitute an objective basis to define a regulatory environment with fair incentives for those distribution operators who invest in innovative distribution operation.

INTRODUCTION
Active Distribution Networks (ADNs) are based on controllable loads, generators and storage devices to reduce the Distributed Energy Resources (DER) impact on the distribution systems avoiding or deferring major system investments. In ADNs, DER are integrated and not simply connected to the system and responsibilities for the system operation are shared between Distribution System Operators (DSO) and customers according to the regulatory environment. The planning of the distribution system is strongly influenced by the introduced level of active management and by the reliability of DER and active network itself. A proper analysis should be performed to be sure that active management does not reduce system reliability, but ADNs constitute a significant opportunity for regulators, system operators, customers, and producers to achieve an open, fair and integrated distribution system. In the paper, a software tool developed by the authors is used to perform the costs/benefits analysis of ADNs. The main purpose of the paper is to quantify the costs of active network management and the economic benefits to DSOs and customers. Those data may constitute an objective basis to define a regulatory environment with fair incentives for those distribution operators who invest in innovative distribution operation. However, these three players (regulators, DSOs and customers) have often opposite goals and the use of a Multi-Objective (MO) approach becomes necessary to capture the contrasting driving forces and find a reasonable compromise. In fact, for regulators the main target is to evaluate system costs keeping high reliability levels without limiting the integration of DER and, in particular, of renewables. Instead, the main purpose of DSOs is the Capex and Opex reduction without reducing the prescribed reliability level and increasing the incomes from DER integration (e.g. connection costs and use of system tariffs). Finally, customers would like to have access to the network without economic and technical barriers; they may be committed or remunerated to share with DSO the responsibility for a reliable system. All these scenarios are analyzed on a comprehensive case study that can represent a typical distribution system. The results will give information to evaluate costs and benefits of ADNs.

MULTIOBJECTIVE APPROACH
Innovation in distribution systems is caused by environmental concerns and market. The need of a sustainable development is increasing the attention on CO2 emissions and energy efficiency. Energy market requires open access to customers and producers no matter at which level of the power systems they are. For those reasons, there are different goals that the actors of the systems would like to achieve with ADNs. In the paper the Civil Society (CS), the DSO and the DG owner (investors) have been regarded as the actors of the system that strive to achieve different goals. The Civil Society is mainly interested to preserve the environment, favorites the distributed generation and the integration of renewable energy sources at reasonable costs. The DSO is interested in Capex and Opex related to the distribution services. Furthermore, in order to increase revenues it is also interested to improve reliability and efficiency. ADNs are a new opportunity to consider but their value is strictly dependent on the regulatory environment. Anyway, ADN Capex and Opex as well as DG connection costs and use of system charges are able to influence the distribution planner choice. Finally, DER investors also make decision considering DER Capex and Opex, the connection costs, and use of systems charges. Moreover, it takes into consideration incomes from energy selling and incentives for renewables and the maximization of efficiency. It is clear that the stakeholders have conflicting goals and a compromise solution should be looked for. In order to do that a very simple procedure is proposed in the paper:
1. Choice of a representative distribution system,
2. Definition of scenarios and regulatory environments,
3. Generation of random solutions, and
4. Extraction of Pareto curves to identify the most convenient non dominated solutions.

**Choice of a representative distribution system**
The network adopted has been formed by merging portions of different existing Italian distribution networks (fig. 1), with the intention of creating a quite simple case study that includes the typical distribution system architectures. In order to limit the computational effort without losing the general validity of the example, the existing MV/LV nodes has been clustered and reduced to 16 trunk nodes and 13 lateral nodes, equivalent to an average active power demand of 10.5 MW. Two areas can be identified in the picture. The upper loop is a typical rural distribution network, characterized by long overhead lines with relatively small cross section due to the low load density; as a consequence of the load growth, voltage drop problems have to be expected. Distributed Generation (DG) in this area may severely affect voltage regulation causing overvoltages. Instead, the lower loop refers to an usual urban/industrial district arrangement, characterized by a pure open loop network: buried cables with bigger cross section are used due to the high load density. The increasing of the energy demand in this area may easily lead to overloads. Typically, DG in such networks determines an increasing of the short circuit level and can contribute to sharpen voltage regulation problems in the rural area. In both areas DG may or may not contribute to loss reduction depending on its position and production curve, and on the load profile. From the DSO point of view it can also be an opportunity to postpone investment in the system.

**Definition of scenarios**
In the initial phase of this research, the attention of the authors has been focused only on the presence of DG in the distribution network, and how its integration can be influenced by the regulator resolutions. Thus, at present the other DER (controllable loads and storage devices) have been disregarded, and the scenarios have been defined considering only DG connection and operation rules. In the paper, 3 possible different scenarios have been assumed (table I). Scenario A is the reference one and it is based on the present Italian regulation: passive management of the network, shallow connection costs based on voltage level, power rate, and the distance from the substation, and no use of system charges. The other 2 scenarios envisage different ADN implementation and revenue mechanism. Scenario B is based on the generation curtailment (GC) to eliminate system contingencies. Each DG unit has to accept a maximum amount of energy curtailment/year as a sort of use of system charge. Scenarios C is also based on GC but investors may decide to help the DSO to manage the network, sharing responsibilities and being paid for the services offered.

**Generation of random solutions**
The planning solution considered in this paper is represented by a random allocation of DG into a distribution network with fixed topology during the planning period. The random allocation is important to take into account that utilities cannot install own generators, whereas they have to guarantee the network accessibility to any investor. Thus, the solution is generated by randomly choosing number, technology, size and connection point of the generators. By so doing, a set of 5000 solutions has been created and assessed in all the scenarios considered.

**Table I – Definition of the 3 different regulatory scenarios**

<table>
<thead>
<tr>
<th>Scn</th>
<th>ADN</th>
<th>Investor responsibility</th>
<th>Connection Cost</th>
<th>Use of system charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>no</td>
<td>no</td>
<td>Based on distance from substation and power rate of generator</td>
<td>no</td>
</tr>
<tr>
<td>B</td>
<td>GC</td>
<td>committed</td>
<td>Based on distance from substation</td>
<td>energy curtailed</td>
</tr>
<tr>
<td>C</td>
<td>GC</td>
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**Fig. 1. The test MV distribution network.**

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are calculated for the three aforementioned players by using the Objective Functions (OF) reported in Tab. II.

| TABLE II – Objective Functions relevant to each system player. |
|---------------------------------|----------------|----------------|
| Civil Society                   | Distributors  | Investors      |
| renewable and high efficiency   | Cost of network | Cost of DG building and operation | Cost for ADN realization |
| DG %                            | upgrading (C_U) | (C_{DG_bu}) | (C_{DG_op}) |
| distribution system efficiency  | Cost of network | Losses (C_L) | Income from production and green certificate |
|                                 | losses (C_L)   | (C_{loss})  | (I_{}$\text{pro}$.c) |
|                                 | Cost for ADN  | Income from ancillary services (I_{}$\text{anc}$) |
|                                 | realization (I_{cons}) | (I_{cons}) |

**Distribution system efficiency**

It has been assessed using the Joule energy losses. In the paper, the customer’s demand variation has been modeled as a piecewise linear curve, with the load growth rate that may be different in each sub-periods into which the whole planning period has been divided. Due to this statement, it is acceptable for planning studies to assume that also the branch current grows linearly, making easy the assessment of the Joule energy losses for the $j^{th}$ branch in the $k^{th}$ sub-period through the following expression (in kWh) [1]:

$$E_{\alpha} = \frac{3.8760}{1000} R_{\alpha} \cdot \int_0^\alpha I_{\alpha}^2 dy = 26.28 \cdot R_{\alpha} \cdot \alpha \cdot \left( I_{\alpha}^2 + I_{i_{\alpha j}}^2 + I_{i_{\alpha k}}^2 \right)$$ (1)

where $I_{\alpha j}$ and $I_{\alpha k}$ are respectively the branch current at the beginning and at the end of the sub-period, $N_j$ is the sub-period duration in years, and $R_{\alpha}$ is the branch resistance. The total energy losses, $E_{\alpha}$, is then obtained as the sum of the contributions for each branch in each sub-period.

**Network upgrading cost**

The $C_U$ is assessed as:

$$C_U = \sum_{j=1}^{N_{\text{branches}}} C_{O_j} = \sum_{j=1}^{N_{\text{branches}}} \left( R_{O_j} + M_{O_j} - R_{B_j} \right)$$ (2)

where $N_{\text{branches}}$ is the number of network branches, $C_{O_j}$ is the present cost of the $j^{th}$ branch, and $B_{O_j}$, $M_{O_j}$, and $R_{B_j}$ are respectively its building, management and residual costs transferred to the cash value at the beginning of the planning period by using economical expressions based on the inflation and the interest rates. It is important to notice that the need to upgrade the network is based on the maximum value of the branch current, while the Joule losses are estimated by using its average value.

**Network losses cost**

The Net Present Value (NPV) of the network losses cost for the $j^{th}$ branch in the $k^{th}$ sub-period can be calculated as:

$$C_{L_{ijk}} = C_{L_{ijk}} \cdot \alpha^{N_j} \cdot \frac{1}{N_k} \cdot \sum_{i=1}^{N_k} \alpha^{N_j} \cdot \left( I_{i_{jk}} \cdot \left( N_k - i \right) + i \right)$$ (3)

where $C_{L_{ijk}}$ is the energy losses cash value at the beginning of the planning period, $C_{L_{ijk}}$ is the losses cost referred to last year of the sub-period, $N_k$ is the beginning year of the sub-period and $\alpha$ is the actualization rate. The total energy losses cost $C_L$ is then obtained as the sum of the $C_{L_{ijk}}$ for each branch and each sub-period [2].

**ADN implementation cost**

The implementation of an ADN implies fix ($C_{ADN_{fix}}$) and variable ($C_{ADN_{var}}$) costs: investments for the infrastructures installation necessary for an active management of the network (replacement of the obsolete control devices with modern SCADA systems, building of high speed or of point-to-point communication systems specially in rural area, realization of a state estimation system), and operational expenses in case the contribution of the DG to the network regulation has to be remunerated. In the paper, it has been decided to estimate the variable ADN cost by compensating the active energy not produced due to the ADN control action; thus, the NPV of this cost is:

$$E_{\sigma}^{ADN} = \frac{1}{\alpha} \cdot \sum_{i=1}^{N_j} \left( p_{\sigma} \cdot E_{\sigma}^{ADN} \right)$$ (4)

where $N$ is the number of years of the whole planning period, $N_{DG}$ is the number of DG connected to the network, $E_{\sigma}^{ADN}$ is the annual active energy not produced due to the GC operation, and $p_{\sigma}$ is the active energy price in a hypothetical local Ancillary Service market. Equation (4) can be used also to assess the income $I_{\sigma}$.

**DG building and operation costs**

These costs depend on the size of the generators installed. Usually, building costs are given differentiated in range of power, whereas maintenance and operation costs are estimated in percentage of building costs.

**System charges for the DG connection**

A recent the Italian Authority for Energy and Gas (AEEG) resolution [3] has formalized the procedure to assess the connection cost that an investor has to pay to the local DSO in case of connection to the MV distribution network. Typically, for renewable sources it is more convenient the direct connection of the DG to the HV/MV substation; however, in the paper it has been assumed always a connection to the distribution network in order to point out the positive and negative effects of DG to this system.

**Income from energy production and Green Certificate**

The NPV of the total revenue of the $g^{th}$ generator obtained from the production of active electrical energy in the whole planning period has been calculated as in (6):

$$I_{E_g}^{\text{ENP}} = \frac{1}{\alpha} \cdot \left( E_{\sigma}^{\text{ENP}} - E_{\sigma}^{\text{ADN}} \right) \cdot \left( p_{\sigma} + p_{\text{GC}} \right)$$ (6)

where $E_{\sigma}^{\text{ENP}}$ is the annual active energy produced by the $g^{th}$ generator, $p_{\sigma}$ is the hourly energy price sold to the electricity market, and $p_{\text{GC}}$ is the Green Certificate price fixed by the regulator. $I_{E_g}$ is then obtained as the average value of the all generators incomes assessed by (6).
Extraction of Pareto curves
For each scenario, a Pareto curve may be extracted to identify the family of non dominated solutions included into the random configurations set. According to the MO paradigm each point of the curve represents a compromise solution to the players. In fact, the Pareto optimal front of individuals in a given population is represented by those solutions that are non-dominated by any other solution in the same population or, in different words, that cannot be improved in any OF without deteriorating some of the other OFs considered. Referring to table II, the point of view of the three players can be represented with the following OFs:

\[ OF_{CS} = \left(1 - \frac{DG\%}{100}\right) + \left(\frac{E_L}{E_{\text{Lmax}}} - 1\right) \]
\[ OF_{DG} = C_{\text{Cu}} + C_L + C_{\text{ADN}} - I_{\text{Conn}} \]
\[ OF_{inv} = C_{DG} + C_{\text{Conn}} - I_{\text{Env}} - I_{\text{AS}} \]  

(7)

The idea is to show how much the regulatory environment on ADNs can influence the final solution and if the goals of the Civil Society may be achieved in terms of energy efficiency and DG penetration.

Planning tool
The planning calculation for each random configuration of DG has been performed with a planning tool developed by the authors in the past years. This tool allows considering active network management at the planning stage. In particular, it takes into account the effects of network reconfiguration, generation curtailment, reactive power control, and demand response. All these control options are modelled and solved by applying the linear programming. Details on how the planning tool works can be found in [4]. In the paper, only the GC has been considered. This control technique calculates the DG power output cuts necessary when a technical constraint (excessive overvoltage and/or overcurrent) has been violated due to loads or generators. This control action can be applied both in presence of a particular contingency (outage of a branch) and/or during normal operation of the network.

DESCRIPTION OF SIMULATIONS
The set of 5000 DG allocations, randomly generated, has been created considering the following power rates of the three aforementioned renewable generators: 1000 kW, 3000 kW and 6000 kW wind turbines, 500 kW photovoltaic generator, 1000 kW and 5000 kW biomass units. Not only generators but also customers have been represented through suitable daily load curves, assumed valid for all the days of the year. This model adopted for DG and loads is important to correctly assess the impact of the active network on the distribution network operation. In fact, the maximum continuous line current at the time of peak load can be calculated, and also the advantage introduced by DG to reduce this current can be taken into account. Moreover, the possible overload current and/or overvoltage that could appear at the time of minimum load due to the simultaneous high generation may be estimated. To perform these evaluations, the daily load (generation) curves have been discretized into 24 intervals. For each interval, the uncertainties on the loads (generators) power have been considered by using suitable normal pdf. Then, a probabilistic load flow has been applied repeatedly for all the discretization intervals in order to properly design the network, verifying technical constraints both in normal and in emergency conditions. In the paper, it has been assumed a maximum overvoltage of 5% and 10% of the nominal voltage respectively in normal ad emergency condition, whereas the maximum allowable overcurrent is 10% of the conductor ampacity. When a technical constraint is violated, first of all the planning tool tries to solve the problem by resorting to the ADN management, if available. Specifically, the generation curtailment has been limited utmost to 50% of the generator power rates. If GC fails, a network upgrading strategy is applied. Regarding the cost for the ADN realization, in the paper the fix component linked to the investments for the ADN infrastructures has not been estimated, assuming that this cost is typically refunded by the Regulator. Instead, the variable cost has been assessed by using the lowest hourly energy price assumed in the paper.

RESULTS AND DISCUSSION
It is well known that, if optimally located in the network, DG can reduce energy losses and postpone investment for network upgrading. However, the current DG connection rules do not allow DSO to control the generators placement, and consequently the presence of DG may cause detrimental effects on the distribution networks, specially for bigger generator. Figures 2 and 3 confirm this consideration, showing the best, the average, and the worst value for \( C_{\text{Cu}} \) and \( E_L \) calculated for the 5000 configurations examined, grouped into intervals of DG penetration levels. As mentioned before, the presence of GC allows reducing investment for network upgrading, but the preservation of the existing cross-sections provokes a higher value of \( E_L \).

By applying the MO approach to all the 5000 configurations, it has been possible to identify 18 solutions that constitute the Pareto set. This set remains the same in all the scenario examined, and for almost all of them there have been no GC interventions, with the exception of two configurations characterized by a little cut of power output during a specific emergency condition. Many of these solutions present a high penetration of DG (from 80% to 100%), i.e. the distribution network can accept a lot of generators without any specific control strategy only if they are optimally placed. Therefore, Regulators may try to develop suitable connection rules that help DSO to guide the connection of new generators, in order to limit their possible negative effects.
Another strategy that regulators can apply to help the DG integration is to promote the development of ADN. This consideration is confirmed by examining the average values of the three players OFs, in each DG penetration interval. By temporarily disregarding the regulator point of view, it is possible to draw the Pareto curves for Scenarios A and B (fig. 4). By comparing these two graphs, it is evident that the most robust solutions (typically located in the knee of the Pareto curve) for Scenario A occur in the range from 40% to 60% of DG penetration level, with the range up to 70% close to them, even if it is dominated. On the contrary, the presence of ADN allows expanding this range of robust solutions from 40% to 90%. Therefore, the ADN permits finding solutions with a good compromise among the goals of the different players for higher DG penetration levels. Continuing the analysis of the results, the ADN implementation allows limiting the DSO costs, specially thanks to the reduction of the network upgrading. On the same time, investors have a decrease of the average incomes, but not so high (about 10% – 15%). Moreover, investors have larger convenience on installing generators with high power rates, even in presence of Generation Curtailment. Finally, the results of the Scenario C have been analyzed (fig. 5). With the hypothesis assumed, the average income of investors are obviously higher than those of Scenario B, but not so high to reach the level of Scenario A. On the other hand, the costs paid by DSO (that cumulates all the compensations for the investors) significantly increase for high DG penetration levels. Therefore, for regulators (and the Civil Society that has to refund the DSO for the higher expenses due to the ADN) could be preferable to provide incentives to the development of ADN with the obligation of investors to share with DSO the network responsibilities (at least in the case of Generation Curtailment).

REFERENCES


[3] AEEG Resolutions ARG/elt 99/08 (code for active connections), and ARG/elt 179/08 (amendments and additions to Resolution 99/08).