

Voltage Control on LV Distribution Network: Local Regulation Strategies for DG Exploitation

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Abstract: The presence of Dispersed Generation (DG) in LV distribution networks affects voltage profiles along distribution feeders, specifically over-voltages may occur at the DG Point of Common Coupling. This study focuses on a voltage control system that exploits DG units in order to mitigate overvoltage violations. The proposed approach is based on a local-corrective control strategy that modulates the reactive power injected/absorbed by the DG power plants. A chronological analysis is carried out on an annual basis to assess the performance of the control laws proposed and the sensitivity of the LV network characteristics on voltage regulation, i.e., the effectiveness of the LV reactive injections regulation model. From the results obtained by extensive numerical simulations it can be pointed out that the local-corrective regulation approach is a viable solution useful to increase the Hosting Capacity (HC) of existing networks, without the need for complex new infrastructures that entail huge investments. Finally, a novel DG coordination procedure is proposed, this approach has been designed in order to minimize the communication channel requirements, i.e., to allow coordinated voltage control without requiring complex real time apparatus and calculations (measurements, state estimation, Optimal Power Flow, etc.), considered to be impractical for LV grid applications.

Keywords: Chronological analysis, coordinated voltage control strategy, hosting capacity, local voltage control, optimal reactive power flow

INTRODUCTION

In the past, distribution networks were designed to be passive systems, i.e., without Dispersed Generation (DG) connected. Power injections at medium and low voltage level introduce new issues for network management to address: the fast expansion of DG can affect the quality of supply as well as the users safety. DG plants impact on power flows along distribution feeders: in particular the voltage profile along the feeder is no longer monotonous and over-voltages at the DG Point of Common Coupling (PCC) may occur (i.e., violations of the voltage upper limits).

In the past DG units were managed according to the fit and forget approach: in compliance with the standard of European countries, they have no voltage regulation. For instance, looking at the Italian standard CEI 11-20 (CEI, 2004), generators supply energy at unit power factor; similarly, in Spain a power factor scheme is implemented whereby DG has three different power factor settings determined by the system load level (REE, 2009). In Germany, according to the technical guideline (BDEW, 2008), it must be possible to operate the generating plant at any operating point with a reactive power output at least corresponding to a power factor at the network connection point in a range between 0.95 leading and 0.95 lagging. Nevertheless,

no details are reported with regard to regulation of the reactive generation according to the grid conditions.

With respect to the voltage control, currently the regulation is usually localized just at the Primary Substation (PS) and Secondary Substation (SS). The On-Load Tap Changer (OLTC) operates locally, reading the voltage on the MV busbar of the PS; moreover, by means of load drop compensator, the voltage set-point can be modified to compensate the effect of load (Hazel *et al.*, 2008).

As stated before, DG injections at distribution level alter the voltage profile along the feeder and decrease the power flow in the HV/MV transformer (decreasing the load compensation): in fact, networks with high penetration of active users (DG) require new voltage regulation approaches (Bonhomme *et al.*, 2001; Pecas Lopes *et al.*, 2006). Several proposals have been envisaged in the literature: Hazel *et al.* (2008), Bignucolo *et al.* (2007) and Choi and Kim (2000) focus on performing regulation structure, but real time measures about load consumptions and generation injections are necessary and state estimation techniques are required. Furthermore, the number of OLTC operations increases significantly.

To have a more effective voltage regulation it is necessary to exploit DG units as voltage control resources (or, practically, as reactive power resources).

In this way the voltage regulation is decentralized in the distribution network. In addition DG plants can perform voltage control with a fast dynamic response, thereby improving the actual operation speed (related to OLTC).

Two possible regulation strategies can be adopted. In the Local Control Strategy, each generator operates without coordination to other devices; this one is a simple, easy to implement, regulation structure, as no communication network is required (no investment in network assets) according to Vovos *et al.* (2007).

However, in an electrical network each regulation affects the voltage of all the system buses, for this reason voltage profiles and reactive power flows could be in a non-optimum working point. In a Global control strategy all regulation resources are coordinated and each item of equipment is adjusted remotely in order to obtain an optimum voltage profile; this approach is quite similar to the one usually adopted for the transmission network (Viawan and Karlsson, 2008a; Mohamad and Seyed, 2007). In Keane *et al.* (2011) a linear programming formulation is exploited to determine power factors of generators and tap settings; the solutions aim to reduce the impact on the transmission system and to overcome distribution network barriers to DG connections. Wanik *et al.* (2010) and Senjyu *et al.* (2008) present an intelligent management that finds the optimal reactive power of distributed resources; the objective is to minimize active power losses and to keep the voltage profiles within specified limits. In Viawan and Karlsson (2008b) and Carvalho *et al.* (2008) a different approach is proposed, injection regulation mechanisms for DG are managed by the Distribution System Operator (DSO) as power supplier agents which do not perturb the network voltage profile; the control strategy is put into practice by exploiting DSO assets, simple DG local reactive power control and communication with the DSO.

Generally, the global approach assures a better working point for the distribution network but it requires an integration between the power network, telecommunication network, state estimation procedure and optimal power flow (i.e., huge capital investment); moreover, the whole regulation structure (to be effective) has to be executed in a short time frame (tens of seconds).

Recently, voltage issues have emerged in Low Voltage (LV) networks because of the large expansion of distributed photovoltaic generations Braun and Ma (2011). Generally, because of the existing regulations on distribution networks (in Italy, Aeg (Italian Regulatory Authority for Electricity and Gas) (2008)), however, DSO is compelled to accept all DG connection requests.

The Hosting Capacity (HC) of distribution grids is the maximum level of DG which can be connected to each bus considered singly, taking into account

technical requirements, in order to guarantee a reliable and secure operation of the system, in compliance with the power quality prescriptions. HC was proposed in Bollen and Häger (2005) and Etherden and Bollen (2011) in order to define indicators useful to quantify the admissible quantity of DG penetration in a power grid with respect to either reliability standards or quality of electricity supply prescriptions (in Italy ruled by Aeg (Italian Regulatory Authority for Electricity and Gas, 2008). In this study, the HC computation has been extended to more than one DG injection considered at the same time; in particular it gives the maximum level of generation which can be connected simultaneously in two or more busses.

The approaches proposed in the literature were typically based on an iterative DG penetration increase in a given bus, until operating limits were violated. Thermal limits of transformers and lines, steady-state voltage limits and rapid voltage changes among various technical operating constraints were taken into account (Bollen and Häger, 2005; Deuse *et al.*, 2006). Voltage profile violation is one of the performance indices that mostly limits the HC of the network. In this study a method is proposed to determine the enhanced utilization of voltage control resources for DG, in order to meet the requirements and objectives of DSO. Indeed, the capability of the actual distribution network to accommodate new DG plants (HC) considerably increases by means of this new decentralized voltage control.

The study aims to define quantitative procedures useful to evaluate the performances of local voltage control strategies and their impact on grid losses. Moreover, a quantitative analysis is introduced in the study in order to compare local control with more complex options based on Information and Communication Technology (ICT); the results are useful to identify the most suitable solution with respect to a cost (complexity)-performance ratio.

IMPACT OF DG ON LV DISTRIBUTION NETWORK

Referring to the EU standard, the voltage limits in the LV distribution system are $\pm 10\%$ of the rated voltage U_n for 95% of the time and $+10/-15\%$ always (EN 50160, CENELEC TC 8X, 2008); the voltage has to be intended as the mean r.m.s. value computed in a 10 min period). In a passive network (no DG connected) the voltage profile decreases monotonously along the feeder. In the primary substation the OLTC acts with the goal of maintaining the voltage within the previously defined limit for all the busses of each feeder. On the other hand the voltage value at LV busbar of SS is not controlled and the tap of MV/LV transformer is fixed at a given value (which is based on the historical trend in passive network configurations) in order to avoid under-voltage violations. However,

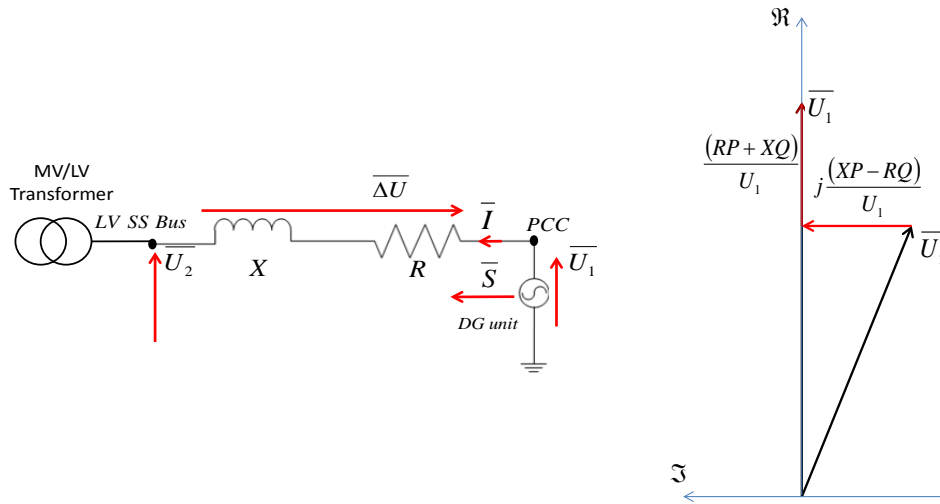


Fig. 1: Single line model of DG connection to an LV distribution feeder and phasor diagram of the DG connection model

today, with DG connected, the voltage profile is no longer monotonous. According to the power mismatch between load and generation, DG can lead to serious over-voltages to other connected customers or contribute to sustaining the feeder voltage profile. Indeed, the coordination of transformer tap in PS and SS becomes difficult to achieve. If the voltage set-point of the transformer is set to the upper level, in order to avoid under-voltages in the case of peak load, DG can create over-voltages during minimum load conditions. On the contrary, if the transformer voltage level is decreased, in order to improve the hosting capacity of the network, it may introduce under-voltages violation during peak load condition, especially if DG injections are low or absent (i.e., passive feeder). Voltage drops on both the MV and LV network affect the voltage at LV busses. Furthermore, the LV network usually has cable lines with a lower cross-section than MV conductors (i.e., higher resistance), thereby, in the case of power flow changes, the voltage profile on the LV network may have excessive voltage fluctuations.

Generally speaking, the DG impact on the voltage profile is determined directly by the entity of active and reactive power injections. Now, a simple scheme of the distribution network is considered (Fig. 1). This model, well known in the literature (Kundur *et al.*, 1994; Wallace and Kiprakis, 2002), is appropriated to examine the matter of supply voltage variations. Looking at the scheme, the right terminal represents the PCC of the DG unit, the left terminal is the equivalent of the LV busbar of the SS; load absorptions and shunt parameters of the line can be considered negligible:

- \bar{U}_1 = The phasor of the voltage at DG's PCC, at the end of the LV feeder
- \bar{U}_2 = The phasor of the voltage at SS LV busbar, upstream of the LV feeder

- R = The line resistance of the LV feeder (i.e., the resistance parameter between the generator and the SS LV busbar)
- X = The line reactance of the LV feeder (i.e., the reactance parameter between the generator and the SS LV busbar)
- $\bar{Z} = R + jX$ = The line impedance of the LV feeder (i.e., the impedance parameter between the generator and the SS LV busbar)
- $\bar{\Delta U}$ = The phasor of the line voltage drop
- \bar{I} = The phasor of the current injected by the generator (i.e., the current that flows along the feeder),
- \bar{S} = The apparent power injected by the generator and calculated as:

$$\bar{S} = P + jQ$$

where,

- P = The real power injected by the generator
- Q = The reactive power injected by the generator

Usually DG is controlled in a PQ mode, injecting constant power, whereas voltage \bar{U}_1 is not directly regulated. The voltage at LV busbar \bar{U}_2 can be assumed constant, even if this is not really true because of the voltage variations along MV distribution feeders and along the MV/LV transformer.

A relation between the voltage \bar{U}_1 and the real and reactive power injected by the DG unit (P and Q respectively) is exploited in order to evaluate, in principle, the network behavior in terms of voltage variations. This relation depends on both network parameters and voltage profile upstream of the SS LV busbar.

Let's consider the \bar{U}_1 voltage phasor on a real axis (i.e., null imaginary part):

$$\overline{U}_1 = U_1$$

The current phasor injected by DG can be written as:

$$\overline{I} = I_d + jI_q$$

where, I_d is the component in phase with the voltage phasor whereas I_q is the capacitive component (it is lagging the voltage phasor by 90°). The apparent power injected by DG is given by the following equation:

$$\overline{S} = U_1 \overline{I} = U_1 (I_d - jI_q) = U_1 I_d - jU_1 I_q$$

Considering the real and reactive power injected by DG in the grid (respectively $P = U_1 I_d$ and $Q = -U_1 I_q$) it is possible to express the voltage drop phasor as a function of these quantity. The voltage drop phasor is equal to (Fig. 1):

$$\overline{U}_1 - \overline{U}_2 = \Delta \overline{U} = \overline{ZI}$$

Considering phasor \overline{U}_1 on the real axis and remembering that $\overline{I} = \frac{S}{U_1}$, the voltage drop phasor can be written as:

$$\Delta \overline{U} = \overline{ZI} = \overline{Z} \frac{S}{U_1} = \frac{(R + jX)(P - jQ)}{U_1} = \frac{RP + XQ + j(XP - RQ)}{U_1}$$

This equation is useful in order to analyze voltage drop changes analytically according to the DG power injections.

The voltage at the DG's PCC can be written as:

$$U_1 = \overline{U}_2 + \frac{RP + XQ + j(XP - RQ)}{U_1}$$

By observing the equation it can be concluded that the effect of real power injections on PCC voltage depends on both R and X parameters; similarly the reactive power impact is also function of both parameters.

The phasor diagram of the U_1 equation is depicted in Fig. 1. In this case the generator injects real and reactive power and the phasor \overline{U}_2 lags with respect to \overline{U}_1 . It is usually acceptable to assume that real and reactive power are decoupled: real power effects on voltage mainly depend on R whereas reactive power effects depend on X (voltage drop component in phase with \overline{U}_1), but this assumption is not completely true, mainly in the case of reactive absorption, as gathered in the results of Braun and Ma (2011) (voltage drop component lagging with \overline{U}_1 becomes not negligible). For this reason it is not possible to use an approximated equivalent model to perform voltage analysis. Anyway, it is reasonable to claim that on the MV and, even more,

on the LV distribution network, a high R/X ratio results in a greater coupling between real power and voltage, which makes voltage increase a particular problem on such networks.

In order to manage the voltage profile of a distribution network, a viable solution could be based on DG reactive power injections modulation. This issue is under evaluation in several countries. Voltage control can be realized adopting a local-corrective control strategy, achievable with reduced investment. These solutions consist in changing the amount of reactive power of DG units; this can be regulated directly or in an indirect way by acting on the power factor $\cos\phi$ (or the tangent value $\tan\phi$). According to the recent Italian standard CEI 0-21 (CEI, 2012) DSO could impose regulation of voltage on active users. This standard suggests two control solutions in which the reactive power is modulated according to local measurements of either voltage or real power injected. Similarly, in the new evolution of the German technical guideline for LV networks rules for generators connection are provided and two reactive power provisions are given, which are the fixed power factor method and the power factor as a function of the real power generation method (E VDE-AR-N 4105, 2010). In France, ERDF investigates the reactive power management of DG following a dynamic regulation law; the regulation mode for reactive power management is discussed among three approaches: fixed reactive power, reactive power modulation as function of the real power or according to a Q/U characteristic (Braun and Ma, 2011).

In Smith *et al.* (2011), Stetz *et al.* (2010), Gallanti *et al.* (2011) and Monfredini *et al.* (2011) some local solutions are proposed and the reactive modulation on MV networks is tested; the simulation results show that according to this strategy it is possible to increase the HC of existing networks up to the structural limit (cable ampacity). All these approaches have some similarities that motivate a comparative analysis.

VOLTAGE CONTROL

This study aims to analyze the impact of a decentralized voltage control strategy on the voltage quality of LV distribution networks. Each DG power plant is exploited as a reactive resource in order to mitigate the overvoltage according to a local strategy.

In a first step, the simplified model of Fig. 1 is considered in order to estimate the effectiveness of the reactive modulation on a simple network model. A line impedance equal to $0.59 + j0.32 \Omega$ is adopted; it corresponds to the maximum of the reference impedance values for 95% of LV customers in Italy EURELECTRIC (2002). Table 1 and 2 show the DG reactive power injections that are needed to limit the over-voltage at PCC at $U_1 = 1.1$ p.u. (i.e., the

Table 1: Reactive power injected Q as function of the real power injected P at the U_1 upper-voltage limit 1.1 p.u., with $U_2 = 1.01$ p.u

	P (kW)					
	60	70	80	90	100	110
Q (k var)	-44.8	-54.3	-62.7	-70.3	-77	-83.1

Table 2: Reactive power injected Q as function of the voltage amplitude U_2 at the U_1 upper-voltage limit 1.1 p.u., with P = 100 kW

	U_2 (p.u.)					
	361	370.5	380	389.5	400.9	410.4
Q (k var)	-59.9	-67.1	-74.1	-81.2	-89.6	-96.5

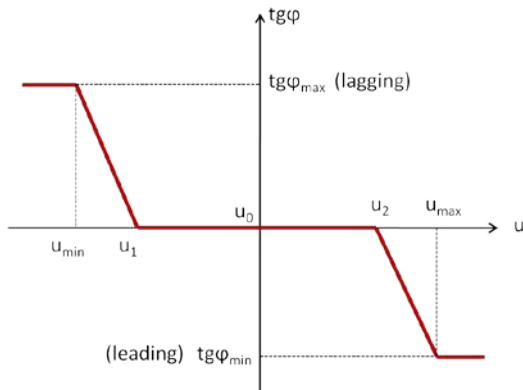


Fig. 2: Local voltage control strategy $tg\phi = f(u)$ (law A)

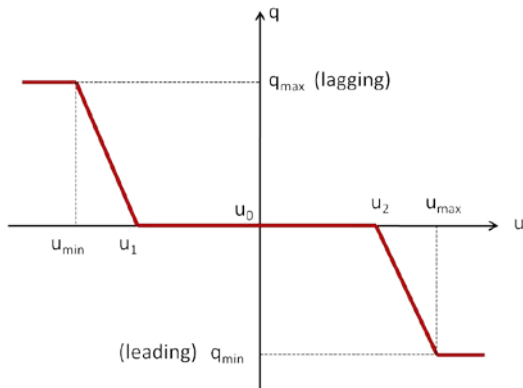


Fig. 3: Local voltage control strategy $q = f(u)$ (law B)

upper-voltage limit with respect to EN 50160 prescriptions). The results highlight the Italian LV network average behavior in response to the real and reactive power flows. In Table, the reactive power injection Q that is necessary to limit the voltage U_1 at the upper-voltage limit 1.1 p.u. is reported as a function of the real power injections P; e.g., for 110 kW injections, DG has to absorb 83.1 kvar (i.e., operating at 0.798 power factor) in order to keep the voltage within the limits. This low power factor operation motivates a more detailed analysis.

Furthermore, Table 2 reports the reactive power Q necessary to limit the voltage U_1 within the upper limit as a function of the upstream voltage U_2 : the higher the

voltage U_2 the higher the reactive power absorption to maintain the voltage quality.

These first examples demonstrate a partial effectiveness of the reactive injection for the LV distribution grid voltage control: R/X ratio of LV lines limits the effectiveness of this regulation, i.e., it is necessary to absorb a huge amount of reactive power in order to bring back voltage within the voltage limits.

Local voltage control: Voltage control structures could exploit several local control strategies. In this work several options have been investigated; they summarize the laws proposed in the European technical standards. The performances of the proposed local characteristics are compared among them in terms of voltage profile enhancement, hosting capacity and real power losses.

The local control strategies could be classified with respect to the variables monitored, as listed below:

- $tg\phi = f(u)$: Control of tangent of ϕ according to the PCC voltage
- $q = f(u)$: Control of reactive power according to the PCC voltage
- $tg\phi = f(p)$: Control of tangent of ϕ according to the real power injected
- $q = f(p)$: Control of reactive power according to the real power injected

Generally, the reactive modulation is based on local measurements available at PCC (voltage or real power injections).

The first possible solution (Law A) is depicted in Fig. 2. This method involves two conditions: a normal operating situation, where no control action is required and a situation where first voltage thresholds (u_1 and u_2) are violated. In the latter case the generator operates at $tg\phi$ different from zero according to the local voltage i.e., avoiding double repletion of $tg\phi$. The reactive power injected/absorbed from the network is given by $q = p.tg\phi$, therefore it is determined both by voltage and by real power injections. By this strategy it is possible to have a meaningful impact on voltage profile only if the DG unit injects a real power value close to the nominal one.

The working point of the system is the intersection between the voltage control curve and the reactive characteristic of the network, therefore the reactive power absorption is determined also by the network behavior.

The second solution proposed Law B (as depicted in Fig. 3) is similar to the previous one but the reactive power is directly modulated according to the voltage measured at PCC. By this strategy the DG unit can operate, in case of low power injections, at a power factor lower than the one imposed by Law A. This strategy causes a greater stress on generators in order to provide a better overvoltage mitigation in the network.

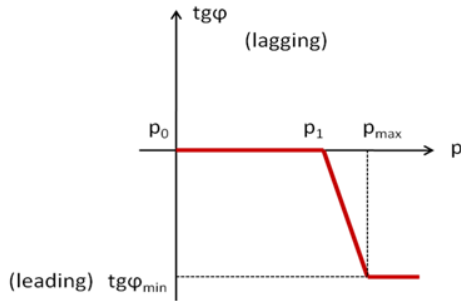


Fig. 4: Local voltage control strategy $tg\phi = f(p)$ (law C)

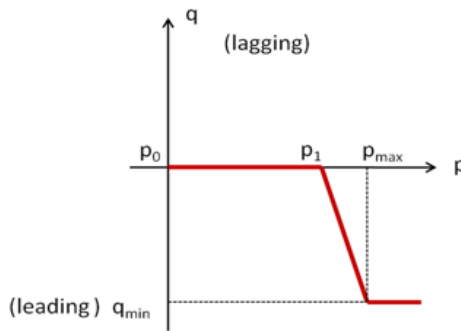


Fig. 5: Local voltage control strategy $q = f(p)$ (law D)

The two characteristics described above operate according to the local voltage measurements; the voltage feedback allows to involve the requested amount of reactive power for voltage mitigations until the power plant reaches its reactive power limits.

Furthermore, the proposed voltage control limits the actions of generators to the voltage control only when the nodal voltage exceeds a pre-defined range. In this way, the reactive power generated by the DG is null when the network voltage is within acceptable levels, limiting the current flow and avoiding real power losses increase.

The local control strategies Law C and D act directly according to the real power injected. The effectiveness of these characteristics is based on the fact that power flows from the DG plants to the secondary substation are directly responsible for voltage increase at the PCC point. Therefore, in the case of large amounts of DG connection it is appropriate to involve reactive power in order to correct voltage at a local level.

Law C is shown in Fig. 4. The value of tangent of ϕ is modulated according to the real power injected by the generator. Especially, in the case of higher injections than a predefined threshold p_1 the control tries to reduce voltage rise lagging reactive power from the grid (i.e., working at negative $tg\phi$). This strategy can be realized as follows:

- Without taking into account the voltage at the PCC (as proposed by VDE in E VDE-AR-N 4105 (2010)

Table 3: Control law parameters_law A and B

	Law A	Law B
u_0 (p.u.)	1	1
u_1 (p.u.)	0.9500	0.9500
u_2 (p.u.)	1.0500	1.0500
u_{max} (p.u.)	1.1000	1.1000
u_{min} (p.u.)	0.9000	0.9000
$tg\phi_{max}$	0.4843	/
$tg\phi_{min}$	-0.4843	/
q_{max} (p.u.)	/	0.4359
q_{min} (p.u.)	/	-0.4359

Table 4: Control law parameters_law C and D

	Law C	Law D
p_0 (p.u.)	0	0
p_1 (p.u.)	0.5000	0.5000
p_{max} (p.u.)	0.9000	0.9000
$tg\phi_{min}$	-0.4843	/
q_{min} (p.u.)	/	-0.4359
Lock-in (p.u.)	1.0500	1.0500
Lock-out (p.u.)	0.9800	0.9800

- With a voltage lock-in that triggers the regulation and, in the same manner, with a voltage lock-out that allows the control deactivation in case of low voltages (as proposed by the Italian regulation CEI, 2012)

Finally, the last solution proposed Law D is similar to the previous one, but the only difference is that the control is achieved by directly modulating the reactive power, in compliance with the regulation curve $q = f(p)$ reported in Fig. 5.

Each of the local strategies proposed can impact differently on the voltage quality and network efficiency; furthermore, different curve parameters lead to different performances.

This study aims to compare the performances of different curves in a generation scenario in which critical voltage conditions may occur. The results obtained will also be exploited to test/validate the voltage control solutions suggested by the different standards mentioned above.

The parameters of the local voltage control laws are reported in Table 3 and 4. The parameters are chosen in order to operate in all network conditions within the rectangular capability of the generator with reactive limits equal to $\pm 43.59\%$ of the rated power, i.e., a $\cos\phi = 0.9$ operation at the rated power (according to the Italian grid code (CEI, 2012)). Concerning the voltage characteristics based on voltage (Law A and B), the voltage dead band is in the range between $\pm 5\%$ of the rated voltage, whereas the maximum reactive power modulation is delivered at the voltage limits ($\pm 10\%$ of the rated voltage).

The two characteristic Law A and B have the same voltage setting, that being so, it is possible to evaluate the performance of the strategies by directly comparing the analysis results.

According to these settings, the analysis results of Law C and D can be compared as well.

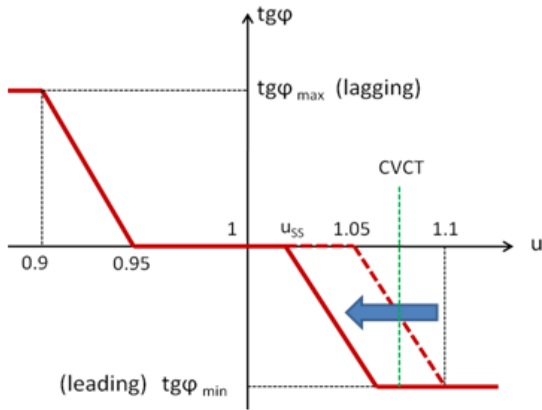


Fig. 6: Local control changing of law A according to the coordination between several DG units

Coordinated voltage control strategy: The local voltage control modulates the reactive power of each generator considering only the local measurements available at the PCC. In order to improve the voltage profile along the radial feeders, a coordination among all the DG units connected to the same feeder has been proposed.

Considering the LV grid scenario, the proposed approach is based on a weak communication channel, i.e., a slow ICT apparatus able to exchange only few bits between each DG unit and the SS. In particular the coordination action is triggered by a DG unit that reaches a predefined voltage threshold (Coordinated Voltage Control Threshold, CVCT) and, consequently, sends a warning message to the SS. After this triggering event, all DG units connected upstream in the same feeder will be activated by the SS voltage coordination strategy to change their local control law, in order to support the voltage profile. The local control changing of Law A is depicted in Fig. 6.

The part of the curve that comprises a reactive absorption (i.e., voltages higher than 1 p.u.) is shifted in order to increase the amount of reactive power involved; in particular the reactive modulation has been set at a voltage value equal to the SS LV busbar set-point (u_{ss}).

Considering the network scheme of Fig. 7 with three generators connected, let's suppose that the voltage at the terminal of *GEN_02* reaches the CVCT (i.e., *GEN_02* is the Critical Generator, CG) because of high real power injections.

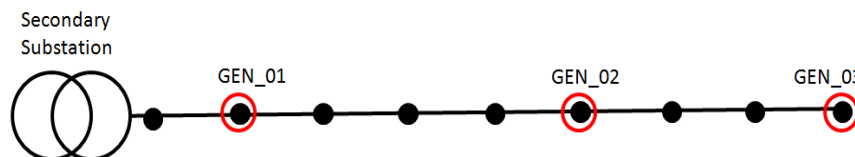


Fig. 7: Radial structure feeder with three DG units connected

The coordinated voltage control will reschedule the local voltage law of the other Generators connected upstream (*GEN_01*) while, in order to avoid critical reactive power flows (e.g., with a significant impact on real losses), no regulation actions will be activated downstream (*GEN_03* in the example reported in Fig. 7). It consists in a mutual aid in which this control law is shifted in order to absorb more reactive power and support *GEN_02* to the voltage mitigation; in general, all the generators connected upstream of the CG are regulated in order to keep the voltage profile as close as possible to the SS busbar set-point. As stated before, communication channel is exploited only to share triggering signal and activation/deactivation signals, whereas the reactive power control is still set according to a local characteristic, but it is now modified on the base of a coordination between different generators connected to the same feeder.

In this study, with respect to the parameters reported in Table 3 and 4, the CVCT parameter adopted for the coordinated voltage control strategy is equal 1.075 p.u., whereas the lock-out voltage value to end the control coordination is set to 1.05 p.u.

METHODOLOGY

The approach proposed: Actually, in the literature the HC calculation is based on load flow analysis applied to a single reference scenario. This approach is not suitable to evaluate correctly the interaction between distribution grid and DGs in all possible working conditions. In this study, a different approach is proposed, specifically designed for the evaluation of the local voltage control effectiveness in LV grid application, it is based on a parametric load flow procedure defined in order to include a representative variety of generation scenarios.

In detail, an LV network with DG units connected is modelled and analyzed exploiting the DIgSILENT Power Factory package capability; for each DG scenario a chronological analysis of a whole year was performed; the network response is evaluated for each of the 8760 h of the year (time samples). The power absorbed by each load is modulated according to the chronological curve of the LV user's consumption, which is estimated starting from data published in AeeG (Italian Regulatory Authority for Electricity and Gas)

(2009) and related to the average consumption of SS in the Italian distribution system. A typical chronological photovoltaic curve is considered in order to model power injections of DG plants (Capone *et al.*, 2011); the curves are derived from meteorological data in an area of the north of Italy.

Different operating conditions are considered for each study case in a multi-generators scenario: first a unit power factor DG operation is considered, successively the voltage control strategies are implemented. The results are compared in order to evaluate the improvement introduced by the reactive modulation.

The proposed procedure considers the voltage limits of $\pm 10\%$ of the rated voltage, whereas values out of this range are considered as voltage violations. According to these voltage constraints a Hosting Capacity (HC) analysis is carried out for the multi-generator scenario; if the power injections are higher than the HC, the existing network is not able to accommodate such an high amount of DG and a strategy to reduce the voltage profile has to be adopted. The reactive power modulation allows an improvement of the voltage profile and an increase in the network capability to host new generation.

The impact of the voltage control strategies is studied considering a parametric approach applied to three connection cases: Base case, Variation I (Var I) and Variation II (Var II), as described in the following section. These new assumptions allow the evaluation of the impact of the reactive power injections at several points along the feeders (i.e., changing the electrical distance and the R/X ratio of the DG location from the SS), in this way a wider generation scenario is taken into account.

The purpose of this analysis is to determine the best voltage control strategy by observing the improvements in the LV distribution grid capability to host dispersed generation (i.e., the HC).

Test network and DG distributions: A realistic distribution network with radial structure (based on real network data) has been adopted in order to model the Italian Low Voltage (LV) distribution system.

In Aeg (Italian Regulatory Authority for Electricity and Gas) (2010a, b) a sample of 500 Italian realistic networks (about 0.1% of the LV national context) was studied; these networks are classified according to the population density (low, medium and high) and the MV/LV transformer size installed at the secondary substations (50, 100, 160, 250, 400 and 630 kVA, respectively).

On the basis of this information, a model network that reflects common features of the Italian distribution system was built. In particular, one of the most common configurations of the Italian system is a 250 kVA rated power MV/LV transformer (i.e., medium rated value), located in an area with medium population density (i.e., medium load consumptions). The model introduced is detailed in 61 buses and 4 feeders. In the model, the slack bus represents the MV side of the MV/LV transformer, which is fixed at the rated voltage of 15 kV. The tap changer operates at fixed value set in order to obtain a voltage at about 1.04 p.u. at the LV side of the SS in the maximum load condition. The cable lines have realistic cross-sections of the Italian distribution system (e.g., 70, 50, 25, 10 and 6 mm², respectively).

In order to evaluate the local voltage control strategies, a multi-generator model was developed; actually the longest feeder in terms of electrical distance of the selected test grid (named the main feeder) was considered. In this feeder three generators are connected, performing a parametric study with respect to their rated power. In particular, generators were located in the first bus, in the last bus and in the bus in the middle of the feeder in terms of electrical distance from the SS, as depicted in Fig. 8. For the generator connected to the last bus three connection

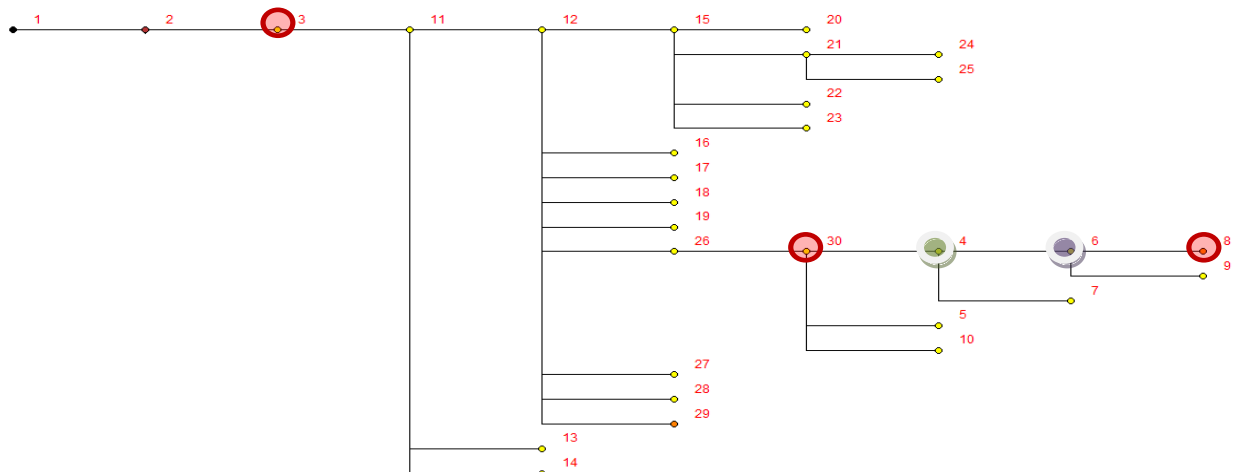


Fig. 8: Main feeder and DG unit locations

Table 5: Electrical characteristics of the generation locations

Generator name	Bus	Rtot (Ω)	Xtot (Ω)	Ztot (Ω)	Rtot/Xtot
GEN_01	3	0	0	0	1
GEN_02	30	0.1045	0.01723	0.1059	6.063
GEN_03_base case	8	0.4495	0.04509	0.4517	9.969
GEN_03_Var I	6	0.1987	0.03189	0.2012	6.230
GEN_03_Var II	4	0.1771	0.02871	0.1794	6.170

cases are considered: Base Case (bus8-red in Fig. 8), variation Var I (bus 6-violet in Fig. 8) and variation Var II (bus 4-green in Fig. 8).

The characteristics of the generator connections are reported in Table 5. The table reports data relevant to the characteristic of the network upstream each of the DG units i.e., the equivalent electrical distance from SS LV busbar. In particular, in the Base case generator GEN_03 is connected through a 10 mm² cable to the rest of the feeder, therefore it presents an R/X ratio of 9.969 (last column of Table 5), whereas GEN_02 is connected in the middle of the feeder by an electrical connection with R/X ratio of 6.063. Because of the higher R/X ratio, the reactive power modulation of GEN_02 has an higher impact on the voltage profile compared with the real power impact at the same bus.

SIMULATION RESULTS

In the multi-generator configuration, the standard HC according to the over-voltage limit (+10% of the rated voltage) is calculated. Two DG units operating conditions are considered: a unitary power factor operating condition and a 0.9 reactive absorption operating condition. The results of Table 6 are the network capability to host new dispersed power plants according to the standard approach usually reported in the literature (Bollen and Häger, 2005; Etherden and Bollen, 2011; Gallanti *et al.*, 2011; Aeg (Italian Regulatory Authority for Electricity and Gas), 2009). Adopting this approach, HC is the maximum power that is injected simultaneously by each of the three DG units up to activating the voltage constraints. The minimum load condition is considered, which is the worst case for over-voltages. In particular, for the sake of simplicity, Table 6 reports the HC values for a homogenous power subdivision among the three DG units modelled.

The HC grows owing to the lower electrical distance from the SS (i.e., observing from the Base case to Var I and to Var II); moreover, by a reactive power absorption at 0.9 power factor (row 2) the HC increases, when compared with the unitary power factor operation condition (row 1); it reflects the benefit of the reactive absorption to the voltage profile. Furthermore, the HC improvement introduced by modulating reactive power (row 3) is higher moving from the end of the feeder (Base Case) toward the SS (Var I and Var II); this is due to the lower R/X ratio, which reflects the better effectiveness of reactive power absorption on voltage profiles.

Table 6: Hosting capacity in kW according to voltage constraints (standard approach)

	Base case	Var I	Var II
cosφ = 1	20	36	39
cosφ = 0.9	24	43	47
Delta (%)	+8	+19.4	+20.5

Table 7: One year Hosting Capacity (HC1) in kW according to voltage constraints

	Base case	Var I	Var II
cosφ = 1	24	42	45
Law A	26 (+8%)	48 (+14%)	52 (+16%)
Law B	27 (+13%)	51 (+21%)	55 (+22%)
Law C	25 (+4%)	45 (+7%)	48 (+7%)
Law D	25 (+4%)	45 (+7%)	49 (+9%)

Table 8: Network losses in kWh with no voltage violations

	Base case P _{DG} = 25 kW	Var I P _{DG} = 45 kW	Var II P _{DG} = 48 kW
cosφ = 1	11595	12557	12669
Law A	11759 (+1%)	12954 (+3%)	13219 (+4%)
Law B	11979 (+3%)	13456 (+7%)	13784 (+9%)
Law C	11619 (0%)	12602 (+0.5%)	12823 (+1%)
Law D	11636 (+0.5%)	12636 (+1%)	12859 (+2%)

Compared with MV networks, the R/X ratio of the LV distribution system is quite higher (Monfredini *et al.*, 2011), as a consequence of this the HC improvement from unitary power factor to 0.9 power factor is limited. The HC analysis introduces a quantitative metric useful to appreciate the effectiveness of the proposed local voltage control strategy; in particular, the HC enhancement ranges between 8 to 20.5% with respect to the R/X ratio of the node under analysis.

As introduced in chapter IV, this study proposes a different, more realistic, HC computation approach, based on a 1-year chronological analysis of both loads and generators: 8760 time samples are taken into account. Each scenario is analyzed at unit power factor and considering the four control strategies: $tg\phi = f(u)$ (Law A), $q = f(u)$ (Law B), $tg\phi = f(p)$ (Law C) and $q = f(p)$ (Law D); this second approach allows a direct comparison among the voltage control laws proposed in order to quantify their performances on the distribution system. Owing to these assumptions, this new HC (here named HC1) is a little bit different from the standard HC of Table 4. Two main factors play an important role; first, using a 1-year chronological curve for load absorptions and generator injections the minimum load condition does not occur at the same time sample of the maximum generator injection: the critical load condition for over-voltages is not reached, i.e., HC1 will be higher than the standard one; second, the reactive power modulated by each generator is determined by the network operation at the PCC (according to the local control strategy), which varies according to the generator location, whereas the

standard HC assumes an equal power factor operation of power plants.

As expected, $HC1$ computed in a 1-year period (reported in Table 7) is higher than the standard HC (Table 6). The $HC1$ improvement for reactive power modulation with respect to the unit power factory operation (values in brackets) is different according to the local voltage control adopted. At buses far from the SS (Base Case) the benefit is low (from 4% of Law C and D to 13% of Law B) and only small power plants can be safely integrated into the grid (up to 27 kW if Law B is adopted). On the contrary, the lower the distance from the SS the higher the $HC1$ improvement introduced by local control laws, (up to 51 kW for Var I and up to 55 kW for Var II, both achieved by using Law B).

In order to complete the analysis of the four voltage control laws, a further analysis was carried out by exploiting the network losses index; it is one of the suitable indicators to summarize the impact of these strategies on the electrical system.

In Table 8 the 1-year network losses are reported. For each case under analysis (Base Case, Var I and Var II), losses are computed considering a real power injection of generators higher than the $HC1$ at unitary power factor and equal to the minimum $HC1$ in case of regulation, in order to analyze the behavior of all the local control strategies in the same network condition (i.e., with no over-voltage violations).

Results reported in Table 8 depicts that the higher the $HC1$ the higher the losses on the grid, while, considering one single case, the losses increase for reactive power modulation with respect to the unit

power factory operation (values in brackets) is different according to the local voltage control adopted.

Summarizing the analysis performed, for each topological case, the voltage control Law B has the highest impact on the network losses (+3% for the Base Case, +7% for Var I and +9% for Var II) and at the same time it presents the highest $HC1$ (27 kW for the Base Case, 51 kW for Var I and 55 kW for Var II, Table 7); it is due to the highest amount of reactive power involved by this strategy (as better described in the following). On the contrary, Law C seems to have the best impact on the losses but the lowest $HC1$ improvements.

The local voltage control proposed introduces a small $HC1$ improvement to the existing LV network (up to +22% for Var II with Law B).

From this first analysis the choice of the best strategy is a challenging task: A trade-off between $HC1$ improvement and losses increase seems to be an inescapable fact.

In order to better assess the reactive power flow driven by each local voltage control law, a statistical approach summary was evaluated considering the power factor value of generator GEN_03 (connected at the last bus of the feeder) in the base case generation scenario with $P_{DG} = 25\text{kW}$ (Fig. 9). The aim of this analysis is to evaluate statistically the operation point of the plants during the 1-year period for each of the four voltage control strategies.

A box of data is produced: the red central mark is the median value, the edges of the box are the 25th and 75th percentiles, the whiskers extend to the most extreme data points without considering outliers and the outliers are plotted individually.

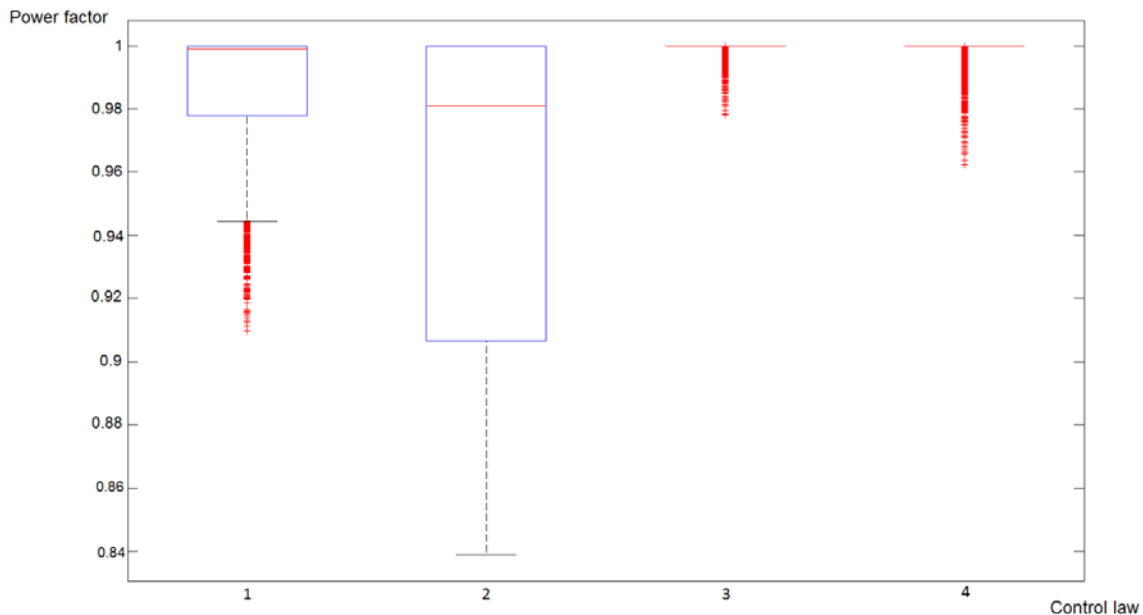


Fig. 9: Power factor for $P_{DG} = 25\text{ kW}$ base case for the voltage control strategies law A (1), law B (2), law C (3) and law D (4)

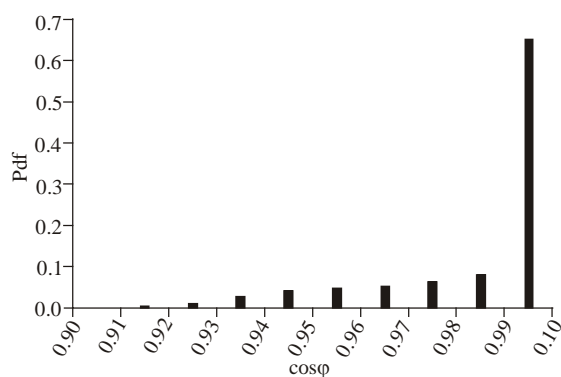


Fig. 10: PDF of $\cos \phi$ for voltage control strategy law A

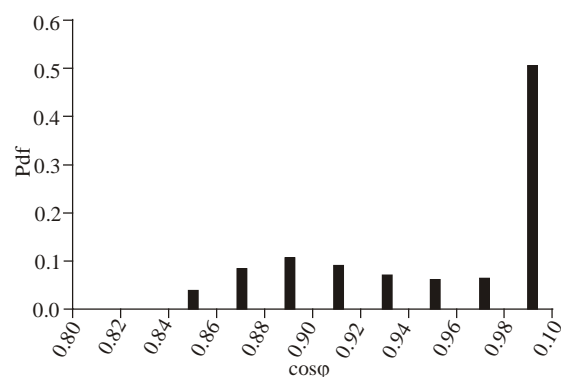


Fig. 11: PDF of $\cos \phi$ for voltage control strategy law B

The power factor values achieved by using Law A are, as expected, in a range between 1 and 0.9 and the average value is 0.987. With voltage control strategy B the power factor is in a range between 1 and 0.839 and the average value is 0.954. These results point out what is shown by the previous analysis: Law B involves a higher amount of reactive power than Law A. On the contrary, the control strategies based on the real power measurements (Law C and D) impose a DG operation at a power factor close to 1 for most of the time: it further demonstrates that these laws involve a lower amount of reactive power than the curves based on the voltage measurements.

The Probability Density Function (PDF) is calculated for data related to Law A and B in order to give further details on the matter. For Law A (Fig. 10) the power factor is for 64.14% of the time steps in the range between 0.99 and 1 and for 0.212% of the time

between 0.9 and 0.91, i.e., the case in which the voltage is close to the upper-voltage limit of 1.1 p.u. (saturation zone of the curve). For Law B (Fig. 11) the power factor is in the range between 0.98 and 1 for the 50.41% of the time and in the range between 0.84 and 0.9 for the 22.01% of the time. If an higher real power value of P_{DG} is considered, the amount of reactive power involved by the local control will be higher and the power factor distribution of both the curves will be lower.

Finally, a new DG coordination scheme is applied to voltage control Law A and B (i.e., the more effective voltage control laws on the grid *HC1*) and its performances are evaluated in the 1 year chronological scenario.

Compared with the local approach, the coordinated strategy involves an amount of reactive power that is higher owing to the shifting of the reactive modulation curve, as described in the section III-B. This coordination introduces a further improvement of the voltage profile, thanks to the cooperation between several generators; as a consequence of this, the capability of the existing network to host generation increases, as shown in Table 9.

The local voltage control and the coordinated control scheme can increase the *HC1* of the existing system. Because of the higher resistance values of the LV distribution system, it is not possible to reach a considerable *HC1* improvement just by a reactive power modulation: in the Base case, the maximum *HC1* improvement is equal to 12% by adopting Law A in coordination with other generators and 17% by adopting Law B, whereas for the Var II case DG units can inject up to 29% of extra power if Law B is applied.

It is important to point out that such performance improvements can be obtained without significant investment over the grid: only an update of the voltage rules of the grid code is necessary, i.e., the proposed approach is effective in a short term scenario, driving to a real improvement of the distribution system capability to host more dispersed generation.

Finally, the results of an Optimal Reactive Power Flow (ORPF) are reported in column ORPF of Table 9. They represent the maximum theoretical hosting capacity that can be achieved by dispatching each DG unit in order to minimize the energy losses of the network and at the same time to maintain the voltage within the limits.

Table 9: One year analysis-local control vs. coordinated control vs. ORPF

Generation connection	HC1 $\cos \phi = 1$ (kW)	Control law	HC1 (kW)		
			Local control	Coordinated control	ORPF
Base case	24	Law A	26 (+8%)	27 (+12%)	29 (+21%)
		Law B	27 (+13%)	28 (+17%)	
Var I	42	Law A	48 (+14%)	50 (+19%)	57 (+36%)
		Law B	51 (+21%)	53 (+26%)	
Var II	45	Law A	52 (+16%)	54 (+20%)	62 (+38%)
		Law B	55 (+22%)	58 (+29%)	

The ORPF is based on an AC Optimization (Internal Point Method) and the objective function is the minimization of the network losses. The constraints of the ORPF calculation are: the reactive power capability limits of the DG units $Q_{min} = -0.436$ p.u. and $Q_{max} = 0.436$ p.u. (with respect to the generator rated power) and the minimum and maximum voltage limits $U_{min} = 0.9$ p.u. and $U_{max} = 1.1$ p.u., respectively. The control variables of the ORPF are the reactive injections of each DG unit.

Looking at Table 9 it can be noticed that the local control has a quite good impact on the *HC1* improvement (with respect to the case without voltage regulation); in particular the local control achieves, case by case, an *HC1* improvement ranging from 13 to 22%; exploiting a low performance communication channel a coordinated control logic could be adopted, increasing the *HC1* from 17 to 29%. Finally, a more complex architecture based on powerful ICT, real time state estimation and optimization of the grid, will correspond to an *HC1* improvement ranging from 21 to 38%.

CONCLUSION

Different local voltage control strategies obtained by adjusting the reactive power output have been studied and discussed through a 1-year chronological analysis. A real LV distribution network has been modelled in detail; a multi-generator scenario is analyzed and the impact of a wide range of real power injections has been tested.

The adopted strategy has to be considered as a local corrective voltage control and the results demonstrate that the reactive regulation is helpful to manage the voltage profile (at least partially).

The hosting capacity was selected as the most relevant index in order to compare the effectiveness of the four voltage control strategies proposed, in particular a chronological approach (evaluating a 1-year time period) is proposed in order to study in detail the interactions between DGs and the distribution grid.

The analysis performed points out that a local voltage control based on Law B is the most incisive on the voltage profile, but at the same time it involves an higher amount of reactive power flow along the distribution feeder; whereas the curves based on real power measurements (Law C and D) are less effective on the voltage quality (but they present a negligible impact on losses).

Moreover, reactive power flows have an high impact on voltage violations in the case of proper *R/X* ratio. High *R/X* ratios are critical for the voltage control, whereas a lower *R/X* ratio results in an effective voltage regulation: this was tested moving the last generator upstream of the feeder (variation cases Var I and Var II).

The results of the chronological analysis show that the *HC1* for the LV distribution system is limited by the resistive nature of the lines, furthermore, the regulation is not able to solve all the over-voltage violations; it can be concluded that the local-corrective voltage control strategy is not completely resolving.

Actually, considering a typical configuration structure of the Italian LV distribution system, the results show an *HC1* improvement in a range between 4 and 22% according to the control law applied. The effectiveness of the local voltage control strongly depends on which law is adopted and on the bus under analysis.

Finally, a simple coordination between DG units was tested: the mutual aid between several generators introduces a further improvement to the voltage profile along the feeders, paying with higher reactive power flow and an increase in losses. As demonstrated by the analysis reported in this study, it is not possible to eliminate over-voltages totally, just locally modulating the reactive power of the DG units, i.e., *HC1* limits could be violated in the case of significant DG grid penetration.

Adopting an ORPF based control means the *HC1* improvement rises from 21 to 38%, nevertheless this solution requires relevant investment in the communication infrastructure whereas the local and the coordinated control are cheaper solutions which do not lead to serious implications (neither technical nor economic) for the equipment currently used.

The work proposed demonstrates that the infrastructure investment necessary to implement an ORPF-based voltage control in the existing LV grids has to be carefully examined since the extra costs can be much higher than the overall operation improvement.

Finally, it is important to point out that the local control applied to the LV system gives a relevant responsibility to the DSO for the selection of the proper regulation curve: a trade-off between the hosting capacity improvement and the negative effects in terms of energy losses due to an increased reactive power flow has to be considered.

LIST OF THE SYMBOLS

U_n	= Rated voltage (V)
U_1	= Voltage at the generator PCC (V)
U_2	= Voltage at the secondary substation LV busbar (V)
$\overline{\Delta U}$	= Phasor of the line voltage drop (V)
\overline{U}_1	= Phasor of the voltage at the generator PCC (V)
\overline{U}_2	= Phasor of the voltage at the secondary substation LV busbar (V)

\bar{I}	= Phasor of the current injected by the generator (A)	Z_{tot}	= Total feeder impedance from the secondary substation to the generator PCC (Ω)
\underline{I}	= Conjugate phasor of the current injected by the generator (A)	R_{tot}/X_{tot}	= Total feeder resistance-reactance ratio from the secondary substation to the generator PCC
I_d	= Current phasor component in phase with the voltage phasor (A)	P_{DG}	= Rated power injected by the generator (kW)
I_q	= Current phasor capacitive component (A)	Q_{min}	= Minimum reactive power capability limit of the generator for the ORPF calculation (p.u.)
\bar{S}	= Apparent power injected by the generator (VA)	Q_{max}	= Maximum reactive power capability limit of the generator for the ORPF calculation (p.u.)
\underline{S}	= Conjugate apparent power injected by the generator (VA)	U_{min}	= Minimum voltage limit for the ORPF calculation (p.u.)
X	= Line reactance of the LV feeder (Ω)	U_{max}	= Maximum voltage limit for the ORPF calculation (p.u.)
R	= Line resistance of the LV feeder (Ω)		
\bar{Z}	= Line impedance of the LV feeder (Ω)		
P	= Real power injected by the generator (W)		
Q	= Reactive power injected by the generator (var)		
u	= Voltage at the PCC of the generator (p.u.)		
u_{min}	= Under-voltage limit of Law A and B (p.u.)		
u_{max}	= Over-voltage limit of Law A and B (p.u.)		
u_1	= Voltage threshold for lagging reactive power modulation of Law A and B (p.u.)		
u_2	= Voltage threshold for leading reactive power modulation of Law A and B (p.u.)		
u_0	= Voltage reference of Law A and B (p.u.)		
$tg\phi$	= Tangent of angle ϕ of the generator		
$tg\phi_{min}$	= Minimum tangent of angle ϕ for Law A and C		
$tg\phi_{max}$	= Maximum tangent of angle ϕ for Law A and C		
q	= Reactive power injected by the generator (p.u.)		
q_{min}	= Minimum reactive power of Law B and D (p.u.)		
q_{max}	= Maximum reactive power of Law B and D (p.u.)		
p	= Real power injected by the generator (p.u.)		
p_0	= Real power reference of Law C and D (p.u.)		
p_1	= Real power threshold for leading reactive power modulation (p.u.)		
p_{max}	= Maximum real power of the generator (p.u.)		
u_{ss}	= Secondary substation LV busbar setpoint (p.u.)		
$CVCT$	= Coordinated Voltage Control Threshold (p.u.)		
$cos\phi$	= Cosine of angle ϕ of the generator		
$Lock-in$	= Voltage lock-in of <u>Law C</u> and <u>Law D</u> (p.u.)		
$Lock-out$	= Voltage lock-out of <u>Law C</u> and <u>Law D</u> (p.u.)		
R_{tot}	= Total feeder resistance from the secondary substation to the generator PCC (Ω)		
X_{tot}	= Total feeder reactance from the secondary substation to the generator PCC (Ω)		

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