A decentralized voltage controller involving PV generators based on Lyapunov theory

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ARTICLE INFO

Article history:
Received 8 February 2015
Received in revised form
18 July 2015
Accepted 29 August 2015
Available online 9 September 2015

Keywords:
Photovoltaic generator
Decentralized voltage control
Distribution networks
Reactive power control

ABSTRACT

This paper proposes a decentralized controller to coordinate the reactive power injections of PV generators in order to contribute to the voltage regulation in distribution networks. The control actions are evaluated in the real time by adopting an optimization methodology involving the sensitivity applied to the Lyapunov function. By this approach it is possible to derive an auto-adaptive algorithm that can be implemented on actual distribution network without implying additional costs for infrastructures. Computer simulations have been performed on a MV distribution system to demonstrate the effectiveness of the proposed control scheme at different operating conditions and to confirm its ability to work in the real time.

1. Introduction

Voltage regulation in distribution networks is becoming more and more difficult due to the increasing penetration of Distributed Generators (DGs) and, more specifically, of non-programmable Renewable Energy Sources (RESs). In fact, the already off-line implemented voltage control strategies adopt on-load tap changers (OLTCs) and reactive power compensators that cannot comply with rapid voltage fluctuations following generation's variability due to their rather slow response [1,2]. It has therefore grown the need of an automatic controller, operating in real-time, capable of dealing with steady-state as well as transient voltage variations. As consequence, several researches have been conducted on this topic giving rise to widely different voltage control solutions. The emphasis is often on those control strategies exploiting generating sources distributed on the network as reactive service providers. The main reason which lead to engage such sources in the voltage regulation service is that a significant part of them is connected to the grid through inverters that, thanks to their fast response time to control signals are capable to provide high performance voltage control techniques compared with traditional OLTCs [3]. In this sense, among others, Photovoltaic (PV) generators seem to be particularly. For this reason, the new grid codes adopted by many countries [4–7], dictate that new PV inverters must be equipped with a local controller for regulating P and Q as well, but limiting inverter power factor to be greater than 0.85 (leading or lagging). Therefore, PV systems are specifically designed to work within this limited practical range, even if, from a technical point of view they may operate with lower power factors. For this reason, the new Italian technical rules for grid connection [8,9] require that new PV inverters with a rating power greater than 400 kW must be able to provide reactive voltage regulation within their capability curve. In doing this, the reactive power level is compatible with the active power one imposed by PV modules. Thus, the maximum reactive power that can be exchange with the network is equal to its rating when the active power production is equal to zero. However, the issue on how to control in the real time such devices is still pending. For this reason, a lot of approaches have been developed during the last decade or are already at the test stage [10–16]. In these works centralized controllers have been implemented. Control actions have been developed by adopting algorithms based on artificial intelligence techniques [9–15] as well as on the sensitivity theory [16].

Although these control strategies can achieve good performances, their practical implementation needs a quite complex communication infrastructure able to monitor in the real-time a huge amount of electrical variables (i.e. powers and voltages at generators and load nodes). Depending on the network complexity, the number of electrical variables that must be monitored in the real time could be impracticable. The need of a coordination design

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deriving from the adoption of the primary and secondary voltage control can be overcome by a decentralized non-hierarchical voltage control structure as in papers [17–21]. However, it must be considered that with these approaches a cooperative control in the system is not guaranteed.

To overcome this problem, we propose a controller inspired to the secondary voltage control traditionally implemented in transmission systems [22–28]. The basic idea of this controller is to optimize the overall voltage profile by controlling the voltage of particular nodes called control buses. In doing this, the distribution network must be a-priori partitioned into one or more control areas each of them containing one control bus. A voltage controller is implemented for each control bus and it acts separately from each other. Each controller aims to keep voltage at its control bus as close as possible to an assumed reference value. Control actions are send to nodes where are connected PV generators able to provide the required reactive power following a control signal coming from the Control Centre. Moreover, in order to further simplify the communication burden, the derived controller adopts a reduced equivalent model of the distributed area associated to the control bus. In particular, the network model is reduced to the transformer substation, the control bus and the PV generators.

Several computer simulations have been performed on a typical MV distribution network in order to test the performances of the developed controller. The obtained results demonstrate that the controller is able to promptly respond to any change in the system operating point, confirming its ability to control the voltage profile in the real-time.

2. Decentralized voltage control scheme

In this Section the decentralized control architecture has been described.

The developed methodology focuses only on PV inverters, even if OLTCs still remain in the voltage regulation problem. In fact, due to the fast dynamic of PV inverters, compared to the slow dynamic of OLTCs, the two control loops can be considered as decoupled and, consequently they can be separately designed [29–31]. This is still valid if the PV variability on a regional level is considered. In fact, as experimentally demonstrated in Refs. [32–37], the PV variability on a regional level would take place on a time scale ranging from few seconds up to 2 min.

The starting point of the procedure consists in separating the network into smaller areas. For this purpose, several techniques originally developed for transmission networks, like those proposed in Refs. [38–41] or, more properly, the one developed in Refs. [42], can be adopted. The partitioning method [42] is a mathematical procedure based on the electrical distance concept evaluated by a sensitivity analysis of distribution network. This method is preferred to the others reported in the technical literature, because the derived sensitivities can be fruitfully adopted to identify also control nodes of each area. Once areas have been defined, a controller is separately designed for each of them. The proposed control architecture for a generic *i-th* area can be schematized as in Fig. 1.

We assumed that this area consists of a single transformer substation (TS) feeding n_{pv} PV plants and a single control bus (CB). Furthermore, it is assumed that electronic metering devices, such as those largely adopted in the Italian system [43], are installed on PV nodes, on the control bus and on the transformer substation. Such smart metering devices can transmit the data to the Area Controller (AC) in the continuous time domain [44–49]. Note that, differently from a centralized control architecture, where all nodal measurements are required, this structure is based on a limited amount of information. These data (i.e. voltage magnitudes as well as active and reactive powers) are processed into the Reduced Equivalent Model (REM) block, giving rise to an equivalent network seem at the above mentioned measurement nodes. Note that, the equivalent network is dynamically updated at every changes in the system operating conditions [50]. Its output feed the Optimal Reactive Power Controller (ORPC) that gives rise to optimal control actions to be sent to local controllers of PV-inverters. Note that, if a change in the network topology occurs, a new partition of the network and new control busses needs to be identified.

2.1. The Reduced Equivalent Model (REM) of an area

The aim of this block, is to design a suitable reduced equivalent model which, when subjected to the same input as the area, produces an output approximating the one exhibited by the physical system. In doing this, the following fitting error is defined:

$$\mathbf{e}_{red}(t, \mathbf{Y}_{red}(t)) = \bar{\mathbf{f}}(\bar{\mathbf{x}}^m(t), \mathbf{Y}_{red}(t)) - \mathbf{S}^m \tag{1}$$

where:

- $\mathbf{S}^m$ is the vector of active and reactive powers measured from the physical system at PV generator nodes, at the transformer substation and at the control bus;
- $\bar{\mathbf{f}}(\bar{\mathbf{x}}^m(t), \mathbf{Y}_{red}(t))$ represents the model outputs;
- $\bar{\mathbf{x}}^m(t)$ is the state vector in terms of nodal voltage magnitudes measured at PV generator nodes, at the transformer substation and at the control bus.

In order to obtain an accurate equivalent model for the given area, we adopt the online parameter identification process reported in Ref. [50]. This methodology is based on the sensitivity theory involving the Lyapunov function. This mathematical procedure basically consists in developing an appropriate mathematical model that does not requires any a priori knowledge of the grid. The identification method applied to this case, uses only measurements at nodes of interest (i.e. PV generator nodes, at the substation transformer and at the control node). As result, an equivalent admittance matrix ($\mathbf{Y}_{red}$) with no physical meaningful can be obtained. In fact, due to the mathematical equivalencing process, negative resistances could be derived.

2.2. The optimal reactive power controller

The control laws are evaluated by solving, in the real time, an optimization problem aimed at minimizing the voltage deviation of the control bus with regard to an assumed reference value. The following function, $\mathscr{V}$, is assumed:

$$\mathscr{V}(\mathbf{Q}_{PV}(t)) = \frac{1}{2}\left(V_{CB}(\mathbf{Q}_{PV}(t)) - V_{CB}^{ref}(t)\right)^2 = \frac{1}{2}e_V^2 \tag{2}$$

where:

- $\mathbf{Q}_{PV}(t)$ represents the vector of control variables, i.e. reactive powers injected by photovoltaic plants;
- $V_{CB}(\mathbf{Q}_{PV}(t))$ is the measured voltage magnitude at the control bus;
- $V_{CB}^{ref}(t)$ represents the desired voltage magnitude at the control bus.
- e_V is the voltage error defined as the difference between $V_{CB}(\mathbf{Q}_{PV}(t))$ and $V_{CB}^{ref}(t)$.

In order to comply with Standards EN 50160 [51], the acceptable range of the Performance Index $\mathscr{V}$ should be [0, 2] kV^2.

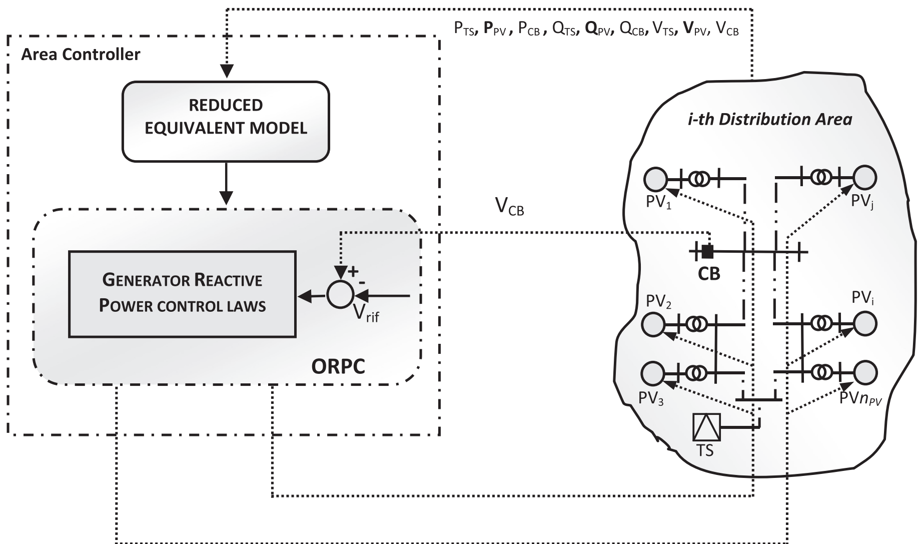

Fig. 1. The area controller architecture.

Note that $\mathscr{V}$ is a positive definite scalar function which we assume as the cost function to be minimized. The optimization problem to be solved can be stated as:

$$\min_{\mathbf{Q}_{PV}} \quad \mathscr{V}(\mathbf{Q}_{PV}(t)) \tag{3}$$

subject to

$$-\sqrt{\left(S^i_{\max}\right)^2-\left(P^i_{PV}(t)\right)^2} \le Q^i_{PV}(t) \le \sqrt{\left(S^i_{\max}\right)^2-\left(P^i_{PV}(t)\right)^2} \quad i = 1,\ldots,n_{PV} \tag{4}$$

where:

- $S^i_{\max}$ represents the maximum allowable apparent power of the *i-th* PV system;
- $P^i_{PV}(t)$ represents the active power produced in the real time by the *i-th* PV generator;
- n_{PV} represents the total number of PV generator engaged into regulation service.

Note that, constraints appearing in the Eqn. (4), refers to a dynamic set of constraints guaranteeing that actual active powers are always preserved and the reactive powers are compatible with the capability curves of PV generators.

To solve in the real-time the given optimization problem, we recall the online Optimal Reactive Power methodology developed in Ref. [16]. This is a mathematical procedure based on a fictitious dynamic system, whose state variables are represented by control variables $\mathbf{Q}_{PV}$. The solution of the optimization problem can be obtained finding the equilibrium point (if any) of such dynamic system.

To set up the dynamic model, we assume that the always positive definite cost function to be minimized, $\mathscr{V}$, is a Lyapunov function, whose time derivative is expressed as:

$$\dot{\mathscr{V}} = (e_V(t,\mathbf{Q}_{PV}))\dot{e}_V = (e_V(t,\mathbf{Q}_{PV}))\left(\frac{\partial e_V(t,\mathbf{Q}_{PV})}{\partial \mathbf{Q}_{PV}(t)}\right)\dot{\mathbf{Q}}_{PV}(t) \tag{5}$$

where $\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right)$ is the sensitivity vector whose elements represent the sensitivity of the voltage error with respect to the control actions:

$$\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right) = \left(\frac{\partial e_V}{\partial \mathbf{x}}\right)\left(\frac{\partial \mathbf{x}}{\partial \mathbf{Q}_{PV}}\right) \tag{6}$$

where $\left(\frac{\partial \mathbf{x}}{\partial \mathbf{Q}_{PV}}\right)$ is:

$$\left(\frac{\partial \mathbf{x}}{\partial \mathbf{Q}_{PV}}\right) = \mathbf{J}(\mathbf{x})^{-1}\left(\frac{\partial \mathbf{S}^m}{\partial \mathbf{Q}_{PV}}\right) \tag{7}$$

Therefore, substituting (7) into (6) we obtain:

$$\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right) = \left(\frac{\partial e_V}{\partial \mathbf{x}}\right)\mathbf{J}(\mathbf{x})^{-1}\left(\frac{\partial \mathbf{S}^m}{\partial \mathbf{Q}_{PV}}\right) \tag{8}$$

To apply the Lyapunov theory we have to force the function $\dot{\mathscr{V}}$ to be an always negative definite function. This condition can be achieved considering the following artificial dynamic system:

$$\dot{\mathbf{Q}}_{PV} = -k\left(\frac{\partial \mathscr{V}}{\partial \mathbf{Q}_{PV}}\right)^T = -k\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right)^T e_V \quad k\in\Re^+ \tag{9}$$

In fact, substituting (9) into (5), the desired negative definite function, $\dot{\mathscr{V}}$, can be obtained:

$$\dot{\mathscr{V}}(\ell) = -ke_V\dot{e}_V = -k\, e_V\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right)\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right)^T e_V \tag{10}$$

The adoption of the Lyapunov method ensures that an equilibrium point will be reached, and this will constitute the minimum of the given Lyapunov function. Thus, integrating the Eqn. (9) in the time domain, control laws, $\mathbf{Q}_{PV}(t)$, can be obtained:

$$\mathbf{Q}_{PV}(t) = -k\int\left(\frac{\partial e_V}{\partial \mathbf{Q}_{PV}}\right)^T e_V dt \tag{11}$$

Note that, with the above assumptions, Eqn. (11) gives rise to a stable solution of the optimization problem. Following a contingency occurrence on the system, the autonomous dynamic system (9) produces control laws moving the operating point to another equilibrium point where the Lyapunov function $\mathscr{V}$ is minimal.

3. The implementation of the optimal reactive power control laws

The overall optimization method can be implemented on the basis of the flow-chart shown in Fig. 2.

The voltage of the control bus (V_{CB}) is continuously measured and passed to the OPRC where it is compared with the reference value. The resulting voltage error is then processed providing required control laws. These control laws are compared with their limits just before to be send to local controllers of generators engaged in the regulation service. If some constraints are violated, the algorithm fix to the corresponding limit the value of the reactive power to be produced by the PV plants violating the reactive constraints, and the control burden is automatically shared among the remaining PV plants giving rise to a suboptimal condition.

Note that, differently from other methods where the total amount of the required reactive power is shared among the area generators on the basis of fixed participation factors, with this method each generator is called to provide its contribution on the base of its sensitivity with regard to the objective function.

The proposed algorithm runs permanently without stopping criterion producing control laws in the continuous time domain. If nothing happens on the system, the same solution recurs. Following the occurrence of a change in system operating condition, the proposed procedure renews control laws moving the system operating point to another optimal or to suboptimal solution if some constraints are violated. The algorithm can comply with load and generation variation. Moreover, if the system control architecture accounts an upper control level (called "the tertiary controller") aimed to manage the voltage profile in a multi-area sense by controlling the set point at control buses, the algorithm will react also to such control references.

4. Test results

Simulations have been performed in Matlab/Simulink environment [52]. In order to investigate the effectiveness of the proposed decentralized control scheme, we simulated the MV distribution network shown in Fig. 3. Its line and load data are reported in the Appendix A.

The test system is a typical 20 kV distribution network composed by n = 22 nodes, having a single transformer substation located at bus 1, and feeding five PV plants with a maximum allowable apparent power equal to 2 MVA.

All simulations were carried out considering the whole network as one area and taking bus #11 as the control bus. All per unit data are referred to a base of 20 kV and 40 MVA.

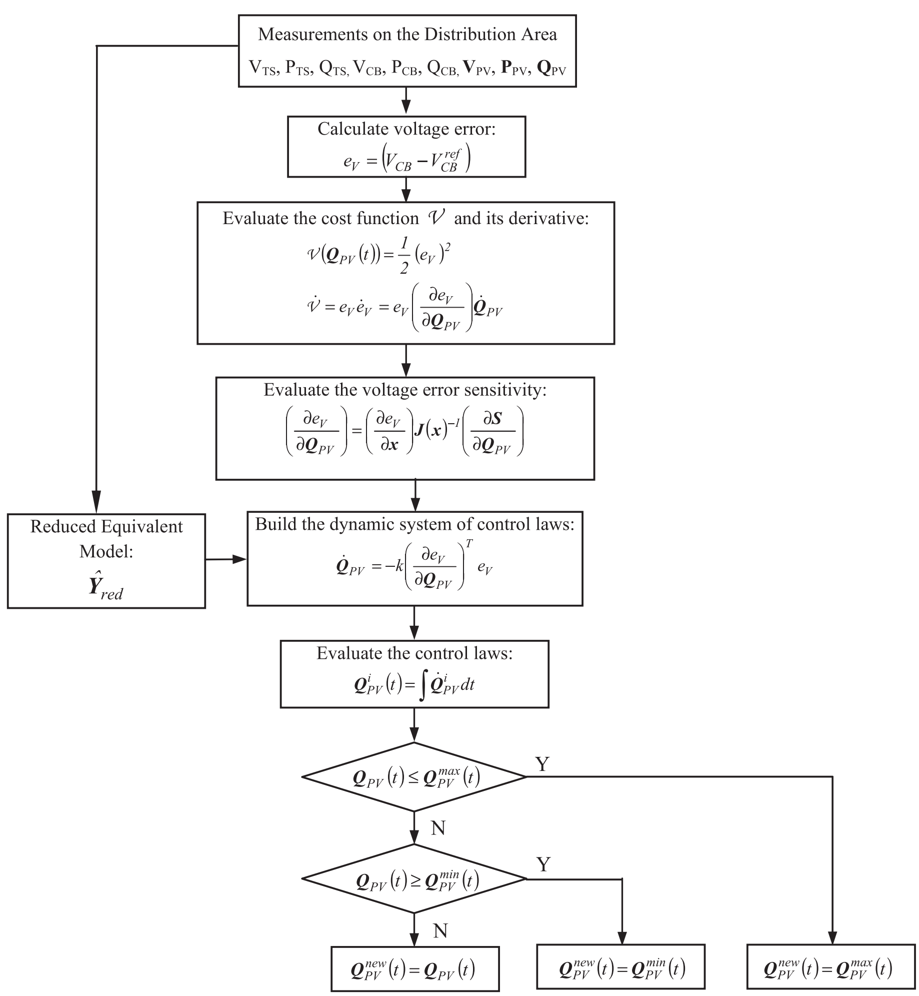

Fig. 2. Flow-chart of the proposed algorithm.

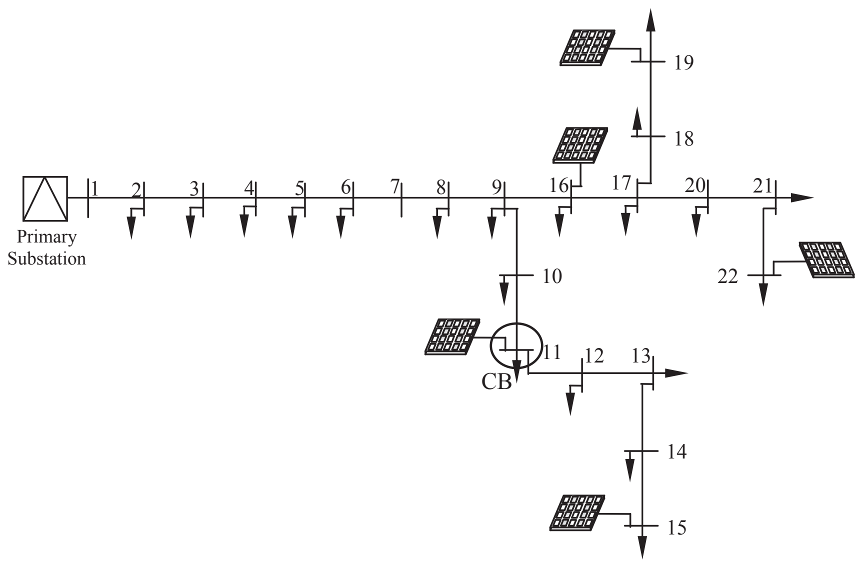

Fig. 3. Single-line diagram of the test system.

In order to define the base case operating condition we assumed a snapshot of the system having a pre-defined total load and generation. In particular, we forced each PV plant to inject an active power equal to 1 MW and to open the reactive power control loop. In this condition a load flow analysis was performed in order to evaluate the required system variables, i.e. power as well as voltage magnitudes at the primary substation, at nodes where PV systems are connected and at the control bus. These data were fed into the REM code to identify the reduced equivalent model of the network. The identified reduced equivalent admittance matrix, $\mathbf{Y}_{red}$, is equal to:

$$Y_{red} = \begin{bmatrix} 1.70 - j1.87 & -0.39 + j0.30 & 0 & -1.23 + j1.54 & 0 & 0 \\ -0.39 + j0.30 & 10.16 - j5.35 & -3.93 + j1.93 & -5.76 + j3.09 & 0 & 0 \\ 0 & -3.93 + j1.93 & 3.98 - j1.95 & 0 & 0 & 0 \\ -1.23 + j1.54 & -5.76 + j3.09 & 0 & 14.65 - j8.95 & -4.52 + j2.55 & -3.06 + j1.74 \\ 0 & 0 & 0 & -4.52 + j2.55 & 5.17 - j2.74 & -0.64 + j0.18 \\ 0 & 0 & 0 & -3.06 + j1.74 & -0.64 + j0.18 & 3.72 - j1.92 \end{bmatrix}$$

Starting from this non-optimized condition, it was assumed that at time t = 1s the control loop was turned on and the reactive power control laws, Q_{PV}, have been generated. Since the derived control laws exhibited substantially the same behavior, in Fig. 4 we reported only the one related to the PV generator connected at bus #11.

The steady state results of the simulation are schematically reported in Table 1.

As can be noted, depending on the individual contribution to the objective function, each generator is "*called*" to furnish a different amount of reactive power.

Fig. 5 reports the time domain behavior of the voltage at the control bus. Note that with these control actions, the target is achieved.

In order to evaluate the indirect improvement of the entire nodal voltage profile, an *a posteriori* load-flow analysis was performed on the original unreduced network. The resulting voltage profile is shown Fig. 6. In the same figure we reported the voltage profile evaluated when no control actions are applied on the system. Comparison between the two operation modes reveals the substantial improvement obtained by the proposed controller.

Starting from this optimized condition a sudden increase of the active power generation of all PV systems (+60%), occurring at time t = 1s, has been simulated. This event was chosen in order to obtain a considerably reduction of the reactive power reserve of the system investigating thus, on the controller's ability to comply with the reactive power limits violation. In Figs. 7 and 8 the time domain behaviours of the control laws and the nodal voltage at the control bus are shown.

As can be noted, at the first stage of the transient, the rapid rising of the voltage at the control bus forces all PV plants to absorb a large amount of reactive power. As the system approaches its

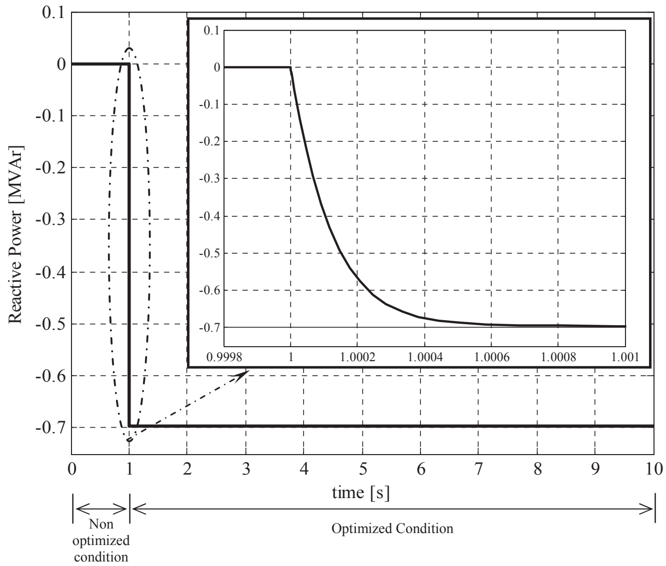

Fig. 4. Reactive power control law of PV inverter connected at bus #11.

Table 1
The set points of the reactive power output of all PV inverters.

Controlled buses	Reactive power provided [MVAr]
11	−0.696
15	−0.681
16	−0.595
19	−0.583
22	−0.583

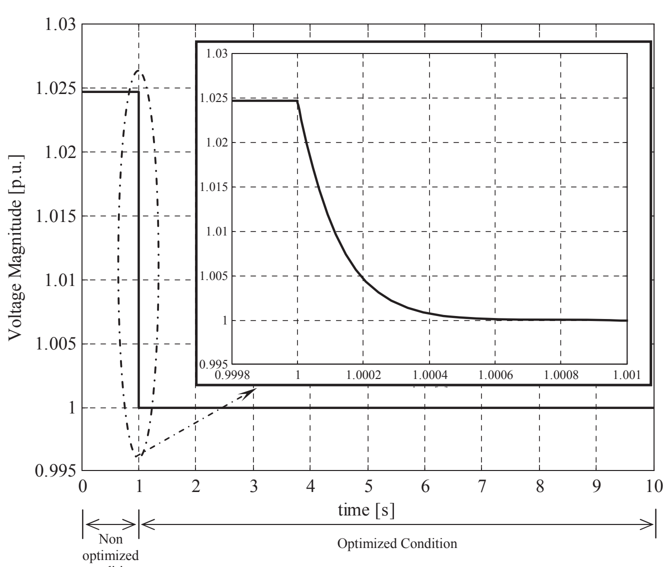

Fig. 5. Time domain behavior of the voltage at the control bus (bus no. #11).

steady-state condition, the plants at buses 11 and 15 reduce their reactive power until reach their lower limits. As consequence, the algorithm fixed the reactive power at these nodes and automatically shares the control burden among the remaining PV plants. In particular, for the test under investigation, inverters at buses 16, 19 and 22 reduce their reactive power injection at the value of −1.064 MVAr, −1.038 MVAr and −1.04 MVAr, respectively.

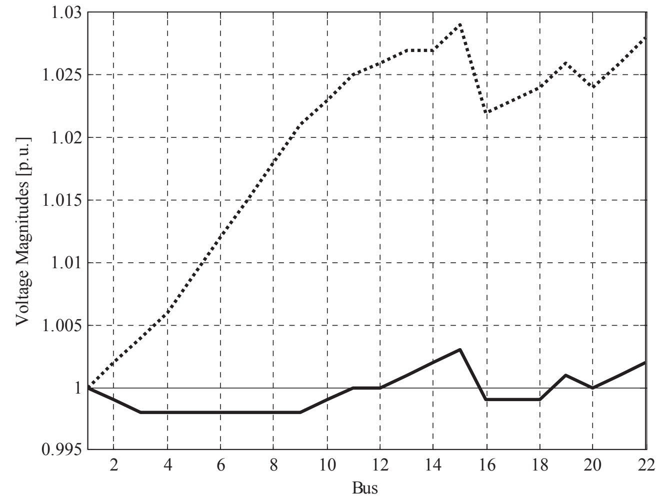

Fig. 6. Network voltage profile with (solid line) and without (dotted line) the secondary voltage control.

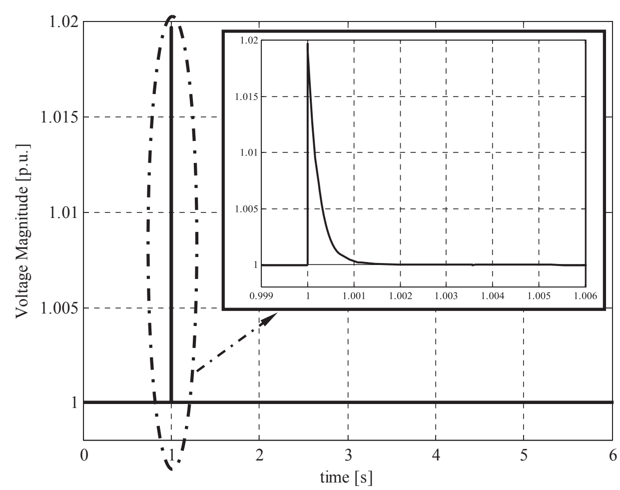

Fig. 7. Time domain behavior of the voltage at the control bus (bus no. #11).

The performance of the proposed controller is better understood considering daily load and generation variations. For this purpose, we used recorded data for the daily load profile of an existing MV feeder (Fig. 9) and for the active power produced by an existing PV plant (Fig. 10). In particular, we adopted the given generation profile for the generator connected at the control bus (#11), and we replicated it for all other generators engaged in our network by adding a white noise having variance equal to 0.1 to the magnitude of the active power production.

Note that, in this case, the need to develop a controller able to act in the real-time requires to continuously update the equivalent model parameters.

With these daily profiles, the PV generators were forced to provide the reactive powers shown in Fig. 11. For clarity purposes, we zoomed the control law at bus #22 from 01:00 p.m. to 01:30 p.m. In this period of time, since the generated active powers were at their maximum, the algorithm constrained the reactive power to comply the PV generation capabilities and thus to be equal to zero.

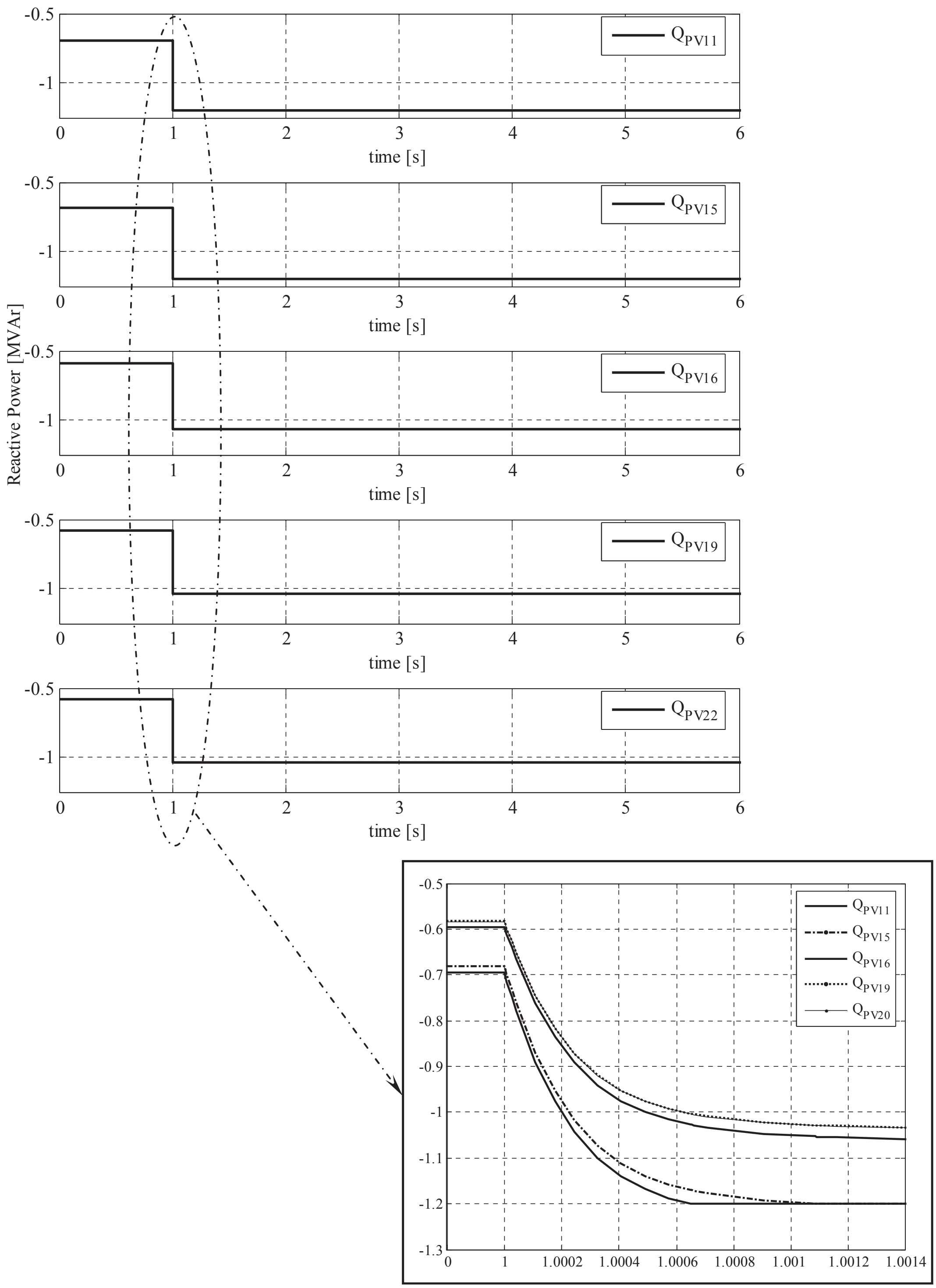

Fig. 8. The reactive power control laws of PV inverters.

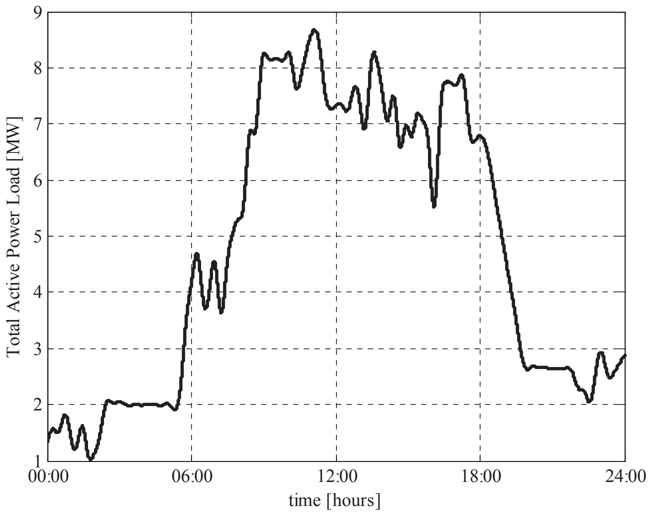

Fig. 9. Daily load profile of the system under investigation.

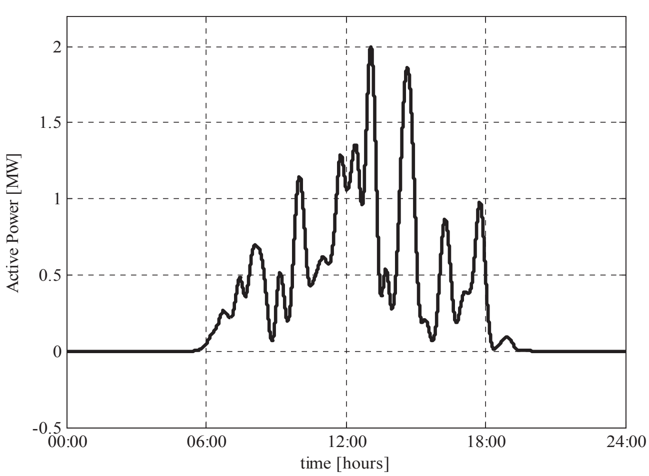

Fig. 10. Daily generation profile at the inverter of the PV plant connected at bus #11.

The effect of the given control actions in terms of daily behavior of voltage at the control bus, are shown in Fig. 12. In the same figure, we also report the voltage behavior at the same bus when no control actions were applied on the system.

As can be noted, the 20 kV target is always maintained except for the time period from 01:00 p.m. to 01:30 p.m., when the reactive powers were zero due to the constraints intervention. In this period the voltage at the control bus reached the non-optimized value equal to 20.4 kV.

The voltage optimization of the control bus inevitably affects the overall voltage profile of the original unreduced network. In order to evaluate this indirect effect, an a posteriori dynamic load-flow analysis was performed over the given day. The load flow results were adopted to evaluate the following performance index measuring how much far is the nodal voltage profile from a reference value:

$$J(t) = \frac{1}{2}\ \left(\boldsymbol{V}(t) - \boldsymbol{V}^*\right)^T \left(\boldsymbol{V}(t) - \boldsymbol{V}^*\right) \tag{12}$$

where $\boldsymbol{V}(t)$ represents the (nx1)-dimensional vector of nodal voltages and $\boldsymbol{V}^*$ is the (nx1)-dimensional vector of nodal voltage references. In our simulation we supposed that all buses were compared to the voltage $V_i^* = 20kV$. For this case, in order to comply with Standards EN 50160 [51], the Performance Index evaluated for 22 buses must be in the range [0, 44] kV^2.

The daily behavior of the performance index is shown in Fig. 13 and it is compared with the one evaluated when no control action is applied on the system. As can be noted, even if the controller drives the voltage magnitude at just one control bus, it is able to improve the overall voltage profile. Also from this figure it is clear that the lack of available reactive power in the period from 01:00 p.m. to 01:30 p.m. vanished the control action.

In order to give an aggregate performance index on the entire day, we integrate the performance index from 00:00 to 24:00:

$$\mathscr{J}_{daily} = \int_{t=00:00}^{t=24:00} \mathscr{J}(\ell)dt \tag{13}$$

Note that, in this case the Performance Index evaluated on the entire network for 24 h, should ranges in the interval [0, 1056] kV^2.

The controller was able to reduce the daily performance index from the value $\mathscr{V}_{daily}^{non-opt} = 273.56kV^2h$ in the non-optimized condition to the value of $\mathscr{V}_{daily}^{opt} = 0.09\ \ kV^2h$.

In order to understand how much the decentralized procedure influences the controller performance, we replicated the same test by applying the centralized methodology developed in Ref. [16]. In this case, the methodology tried to drive all nodal voltages to be close as much as possible to 20 kV. In this centralized optimization test results revealed the daily performance index equal to $0.078\ \ kV^2h$, confirming the effectiveness of the proposed method.

5. Conclusions and future works

In this paper, a decentralized controller has been proposed to reduce the computational burden of centralized voltage controller in large-scale distribution networks and to facilitate its practical implementation.

The design of the proposed controller requires the partition of the distribution network into smaller areas and the selection of the best possible control buses for each of one. To comply with this exigency, an analysis based on sensitivity theory has been performed in advance. Once the areas and their own control buses are identified, a self-adaptive controller is separately designed for each of them. Design of each area controller is based on a reduced equivalent model of its own network area. This model is characterized by an equivalent network connecting PV units, the primary substation and the control bus. This simplification can be applied for all operating conditions and for all network topologies with no isolated nodes.

It was shown that, once the reduced equivalent model of the area network was set, the voltage control can be formulated as an optimization problem. The solution of such problem was obtained by adopting a real-time algorithm based on a fast artificial dynamic system involving the sensitivity theory. Different computer simulations were performed on the MV distribution network. Test results showed that the area controller regulates the sharing of the reactive power among the area generators on the base of their sensitivities with regard to the control bus voltage. With this characteristic, the automatic controller is able to avoid unnecessary reactive power absorption or generation.

The controller complies also with the violations of the reactive power limits of one or more PV generators. In fact, in this case, the

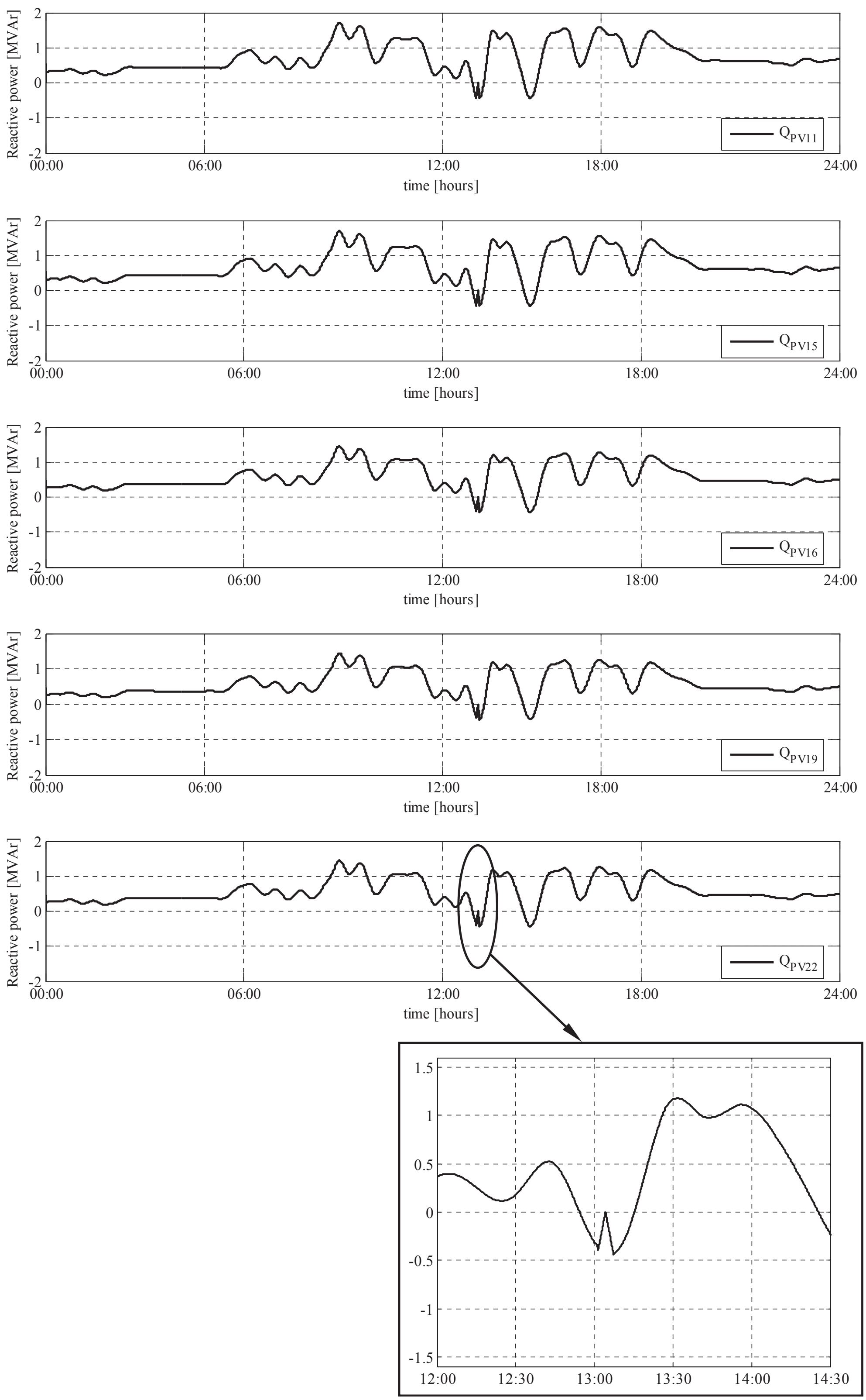

Fig. 11. Time domain behavior of the reactive power control law of PV inverters located at buses #11, 15, 16, 19 and 22.

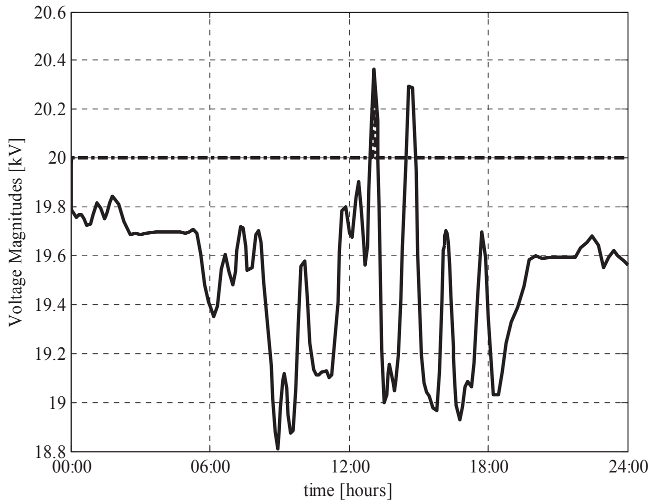

Fig. 12. Daily voltage profile at the control bus (#11): with (dotted line) and without (solid line) the control action.

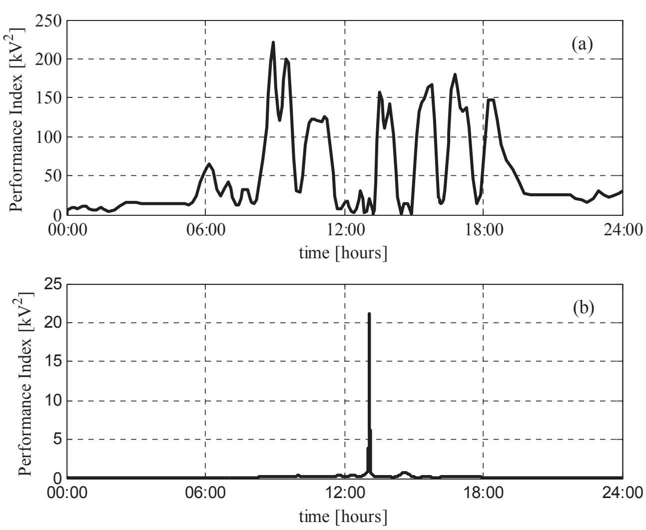

Fig. 13. Daily fluctuations of Performance Index evaluated on the reduced network: with (b) and without (a) the control action.

method fixed the reactive power at nodes violating to the constraints and, the control burden is automatically shared among the remaining PV plants.

A further simulation was carried out with daily variations of loads and generations to prove the ability of the proposed controller to operate in an on-line environment. It was observed a drastic improvement of the voltage profile over a day time.

Moreover, a comparison between centralized vs. decentralized methods showed minor differences in terms of voltage profiles. This result justifies the adoption of the proposed decentralized method in actual distribution networks where, otherwise, the implementation of centralized controllers would imply greater infrastructure costs. Furthermore, the results can be further improved by adopting a control scheme which is able to take into account the Performance Index for splitting the network into smaller areas. And this will be our focus in future research.

Appendix A. Data for the test system

Table A1
Load data.

Bus [#]	Active power [MW]	Reactive power [MVAr]	Bus [#]	Active power [MW]	Reactive power [MVAr]
1	Slack Bus	Slack Bus	12	0.101	0.029
2	0.101	0.029	13	0.101	0.029
3	0.000	0.000	14	0.101	0.029
4	0.101	0.029	15	0.080	0.023
5	0.101	0.029	16	0.101	0.029
6	0.030	0.009	17	0.000	0.000
7	0.000	0.000	18	0.101	0.029
8	0.101	0.029	19	0.080	0.023
9	0.000	0.000	20	0.000	0.000
10	0.101	0.029	21	0.050	0.015
11	0.101	0.029	22	0.030	0.009

Table A2
Line data.

Form	To	R [Ω]	X [Ω]
1	2	0.281	0.382
2	3	0.211	0.287
3	4	0.318	0.349
4	5	0.400	0.439
5	6	0.335	0.367
6	7	0.339	0.372
7	8	0.291	0.320
8	9	0.322	0.353
9	10	0.486	0.238
10	11	0.552	0.271
11	12	0.486	0.238
12	13	0.540	0.265
13	14	0.425	0.209
14	15	0.589	0.289
9	16	0.224	0.187
16	17	0.213	0.179
17	18	0.394	0.193
18	19	0.924	0.452
17	20	0.579	0.285
20	21	0.743	0.365
21	22	0.620	0.304

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