IMPACT OF DISTRIBUTION STATE ESTIMATION IN DMS OPERATION

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ABSTRACT

Active networks are distribution networks with generators and storage devices and flexible loads subject to control. Distribution Management System (DMS) is necessary to manage and control the system economically and safely, by interacting and coordinating distributed energy resources. The main goal of the DMS is finding the optimal operation point of the network, minimizing the overall costs and keeping the system within the technical constraints. Since measurement system in distribution is constituted by a limited number of measurement devices, the DMS operating has to be based on the estimated status of the network provided by an ad hoc distribution state estimator. The state estimation algorithm, starting from real measurements and historical data, e.g. pseudo-measurements, is able to find the value of the status variables with a prefixed level of quality. The quality of the estimates can seriously affect the system management. This paper presents the evaluation of the uncertainty level introduced by the distribution state estimation in the DMS operating. Examples derived by a representative distribution network are presented.

INTRODUCTION

Nowadays distribution networks are approaching a critical point whereby the connection of Distributed Energy Resources (DER) will require an active approach [1]-[2]. The active management of distribution systems reduces the impact of DERs with a coordinated use of demand side integration (DSI), storage devices and distributed generation (DG). With an active approach the system hosting capacity may increase, and fewer limitations to the maximum rated capacity of generators are imposed. The DSOs (Distribution System Operators) coordinate DERs, and DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreements. The main goals of the active management are to minimize the system operation costs and to comply with technical and contractual constraints by exploiting the DG Generation Curtailment (GC), Ancillary Services (AS) from DG, storage devices and DSI.
In an more advanced level of implementation of active management, the DSOs also may have the possibility to manage electricity flows using a flexible network topology (network reconfiguration) [3].
A practical implementation of active management (Fig. 1) may be constituted by:

- a control center sited in a relevant PCC (Point of Common Coupling), e.g. in the primary substation; in this control center there are at least a Distribution Management System (DMS) and a Distribution System Estimator (DSE);
- the DER local controllers (LC) that send/receive communication signals to/from the control center (i.e. place bids for the next time interval and receive the control actions for DERs);
- a measurement system, constituted by few measurement devices in the field; it is able to send measurement signal to the DSE;
- a communication system synchronized with a GPS system for time reference, for the exchange of measurement and control signals between control center and LCs.

According to this implementation, daily DG owners and Responsive Loads (RL) send bids for the one day-ahead active and/or reactive power generation or load demand. Furthermore, in an intra-day market they also offer their support to the ADNs operation for the next time interval, in terms of active power that may be curtailed, DG power factor that may be modified, or load demand that may be deferred.
DSOs may adjust the day-ahead scheduling paying producers and RLs when their set points are to be changed, according to the regulatory environment. Moreover, during the day DSO provides to the DERs the control actions for the active management of the network, based on the results of the intra-day optimization.
Finally, if the active management reaches an advanced level of implementation, also the network reconfiguration can be profitably exploited.
At least, two ad hoc algorithms run into the control center: the optimization algorithm into the DMS that performs the intra-day optimization, and a state estimation algorithm that runs within the DSE. During the day, in a given time, the DMS, by evaluating the system status, aims at finding the optimal operation point for the next time interval, avoiding critical contingencies and minimizing the operation cost. The system status, since in distribution systems the number of available measurements is significantly small, can be obtained by means of the DSE. The estimated state of the system, together with the real time measurements, becomes the input of the DMS.
The DSE represents a source of uncertainty in the operation of the DMS and the more accurate the quality of the estimates the more suitable the decisions made by the DMS can be.

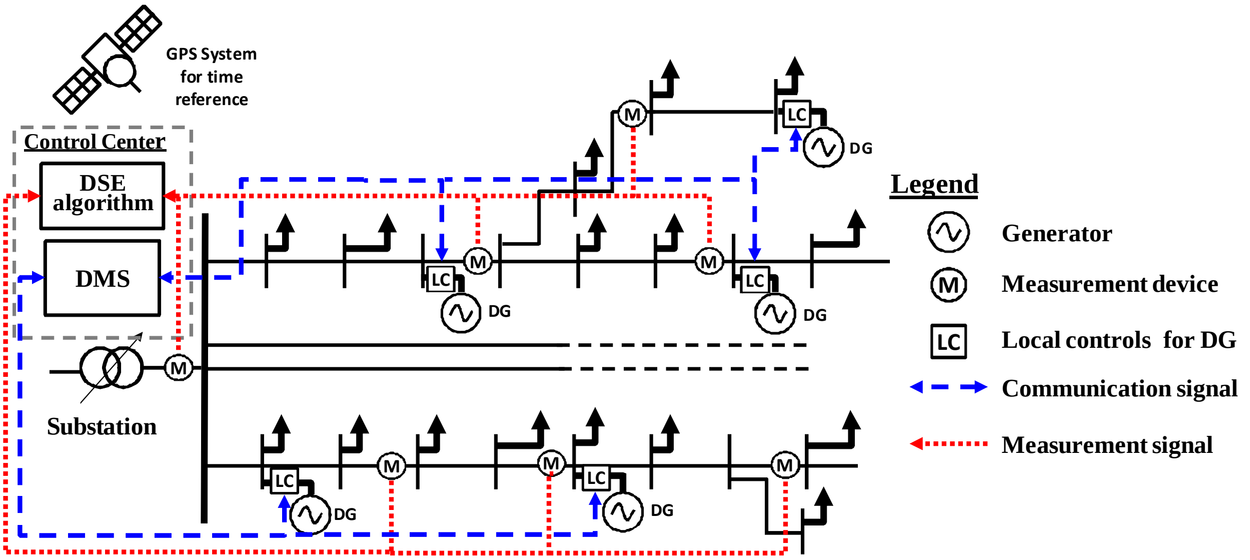

Fig. 1. Practical implementation of the active management

This paper presents the evaluation of the uncertainty level introduced by the DSE in the DMS operation. In the paper, the DMS presented by the authors in previous works has been improved and equipped with a DSE algorithm suitable to deal with DERs in real size applications [4].

DISTRIBUTION MANAGEMENT SYSTEM

In previous papers the authors proposed an optimal power flow (OPF) algorithm suitable for on line applications in DMS (intra-day optimization) [3], [5]. The OPF finds the optimal set points of DERs by minimizing the overall system operation cost, and by keeping the system within the technical boundaries. The cost of system operation is the sum of the cost of energy losses, the cost of curtailed energy, the cost of reactive support. Demand Side Integration (DSI) costs are taken into account with the price of the power shed to responsive loads.

The general form of the objective function is reported in (1).

$$J = \min\left\{C^{GC} + C^{AS} + C^{RL} + C^{loss}\right\} \qquad (1)$$

where the C^{GC} is the cost of the generation curtailment, C^{AS} the cost of the ancillary service related to the reactive power exchange, C^{RL} the cost of the exploitation of the responsive loads that participate to DSI programs, and, finally, C^{loss} is the cost of the energy losses. Such minimization is subject to technical and commercial constraints. The technical constraints concern the boundaries in node voltages and branch power flows during normal and emergency conditions, the maximum and minimum active and reactive power from generators, the charge/discharge cycles of the storage devices, etc..

Both the objective function and the constraints are

Table I. Cost coefficients used in the paper

Cost of generation curtailment (β)	0.100	€/kWh
Cost of line losses (δ)	0.100	€/kWh
Cost of DSI (ψ)	0.025	€/kWh
Cost of ancillary service (γ)	0.090	€/kWh

linearized to reduce the computing burden so that the algorithm can be used in real time applications [3], [5]- [7]. The unknown variables of the problem in each time interval are the set points for each generator (i.e., active and reactive power), and the power demand for the RL.

Equation (1) can be formulated as a linear combination of power losses (P^{loss}) [8] and of the unknown variables: the curtailed active and exchanged reactive power from DG (P^{GC} and Q^{AS}), and the shed power from RLs (P^{RL}), as in (2) [3].

$$\min \sum_{j=1}^{N_{DG\_GC}} \beta_j P_j^{GC} + \sum_{k=1}^{N_{DG\_AS}} \psi_k Q_k^{AS} + \sum_{l=1}^{N_{RL}} \gamma_l P_l^{RL} + \sum_{i=1}^{N_{br}} \alpha_i P_i^{loss} \qquad (2)$$

Since it is hypothesized that DG owners and RLs are get paid for their support to the operation of the network, tariffs for each kWh curtailed and for each kVARh exchanged are taken into account with suitable coefficients α, β, ψ, and, γ, which represent the unitary costs in the time interval considered. Table 1 reports the cost coefficients used in the paper.

In addition, the linear form of the OF is obtained using only non-negative variables, thus in the operative formulation both the reactive power flow Q^{AS} and the power flow F_i, used to approximate the P^{loss}, can be expressed by means of two non-negative quantities, X and Y, that cannot be both nonzero at the same time. This is to take into account that generators cannot simultaneously be inductive and capacitive, and the powers may flow in the positive or in the negative direction of the oriented graph.

More details regarding the optimization can be found in [3], [5].

DISTRIBUTION STATE ESTIMATION

The implementation of the active network paradigm requires that accurate data about the network conditions are continuously available from the field. Large scale distributed measurement systems are necessary to carry out

simultaneous measurements of electrical quantities in several monitored points on the tested systems.
The status of a system with a measurement device on each node would be totally known, but, owing to the extension of electric distribution networks, this approach is economically unacceptable. Therefore, suitable techniques of Distribution State Estimation (DSE) are needed to evaluate the status of the system on the basis of few measurements. The DSE provides a complete and consistent model of the operating conditions and it is essential for the DMS operation.
The main goal of DSE is the achievement of a good state estimation, also with very few real time data. The state variables can be voltages, branch and nodal currents, active and reactive powers, phase angles, etc.. They are related to the electrical quantities that are directly measured in the field.
A heuristic optimization algorithm based on the Dynamic Programming theory is proposed by the authors in [4] to find the optimal placement of measurement devices, i.e. to determine their number and position.
Since most of the SE techniques are designed for transmission systems, where many real time measurements are available, in [4] an ad hoc DSE algorithm was designed to exploit the special characteristics of distribution systems, also suitable to deal with DG. In particular, to reduce the computational complexity and memory requirement, the radial nature of the majority of distribution networks was exploited, and information achieved from a priori knowledge, namely pseudo-measurements, was used to obtain the observability of the system.
The proposed DSE algorithm is able to find the value of the status variables with a prefixed level of quality that depends on the accuracy and the number of the measurement devices. The branch currents are taken as state variables for improving the quality of the DSE; field measurements (i.e. powers from DG) and load pseudo-measurements are used as input data to estimate such state variables.
In particular, the input data of the DSE algorithm are the measured branch currents and the powers in each node, pseudo-measured or measured, if related to loads or generators respectively. Starting from these input data, the nodal currents can be calculated by using the nominal voltage. In this sense, loads and generators are modeled as constant current nodes. Then, the voltage in every node can be directly determined by using the constant nodal currents, solving the following equation:

$$[\boldsymbol{V}] = [\boldsymbol{Z}] \cdot [\boldsymbol{I}] \qquad (3)$$

where Z denotes the network impedance matrix.
It is worth noticing that with this simple approach also the significant impact of DG on the network voltage profiles has been properly taken into account. Thanks to the radial nature of distribution networks, the algorithm does not require the solution of the complete load flow equations.
Once the voltages in the nodes are known, the vector of the branch currents, I_{branch}, is calculated by simply dividing the corresponding branch voltage drop by the branch impedance. The DSE algorithm iteratively adjusts the nodal loads (pseudo-measured at the starting point) by using the difference between the measured and calculated data until the estimates of the measured branch currents become sufficiently accurate. More in details, the iterative procedure can be summarized as follows:

1. starting from measurements and pseudo-measurements, solve (3) and evaluate the state variables vector I_{branch};
2. for each *i-th* branch equipped with a measurement device calculate the difference between the calculated current (I_{branch}) and the measured one (I_{meas});
3. sum these differences to assess a quantity Δ that represents a global measure of the difference between the estimated and the real situation, with the following equation (4).

   $$\Delta = \sum_{i=1}^{N_{meas}} \left[I_{branch}(i) - I_{meas}(i) \right] \qquad (4)$$

   where I_{meas} is the vector of the N_{meas} measured branch currents;
4. adjust the node pseudo-measured powers on the basis of the quantity Δ;
5. use the new pseudo-measurements to repeat the procedure (return to step 1).

The algorithm stops when the corrective quantity becomes smaller than a prefixed threshold or when the maximum number of iterations is reached.
The quality of DSE can be affected by different issues:

- the number and the position of the available measurement devices;
- the uncertainties introduced by the measurement devices;
- changes of the network topology (network reconfiguration) and deviations from their nominal value of the network parameters ;
- partial lack of communication (emergency mode).

Obviously the greater the number and the more suitable the position of the measurement devices in the network, the more accurate will be the estimates. It can be hypothesized that the network is equipped with at least a minimum number of measurement devices, positioned in optimal sites, that assures a prefixed level of accuracy of the estimates. In any case, the uncertainty introduced by the accuracy of the instruments cannot be removed and the minimum number of the needed devices to obtain a certain quality of the estimates in a given network strictly depends on the intrinsic accuracy of the used instruments. The lower the accuracy of the measurement devices, the greater is the number of the necessary devices. In addition, changes in the network topology or unavoidable differences between the current line impedances and their rated values affect the estimates.
The major concern is related to the partial lack of communication, especially in those networks where the measurement system is constituted only by the sufficient number of devices to assure a low level of accuracy. The lack of even only one measurement may lead in bad quality estimates.

Since the DMS operation is mainly based on the estimated status of the network the quality of the estimates can seriously affect the system management. For instance, in case of a real contingency, e.g. overvoltage in some nodes of the network, due to an excessive production from DG, the DMS tries to optimize the operation point, by minimizing the active power to be curtailed and modifying the power factor of the local generators. According with a fair regulatory environment, these control actions imply that the DG owners get paid for the requested change in active power production respect to the scheduling pattern and for their support to the network (exchange of reactive power). It is clear that if the DSE underestimates or overestimates the contingency condition the optimal operation point assessed by the DMS could not be adequate to solve the problem. It might happen, for example, that, even after the DMS control actions, the voltage at the connection node of the involved generator is kept out of the technical constraints. In this case the DG local controller orders the instantaneous disconnection of the generator, causing problems to both DG owner and DSO. Indeed, the new, not foreseen, network operation point may cause new contingency conditions that can be more difficult to solve.

CASE STUDY

The described procedure has been implemented in a composite digital tool to test the validity of the proposed approach. The simulation has been performed with a commercial software package for power system simulation. The software is used only to model a representative portion of a real distribution network with the measurement system. Both DMS and DSE algorithms have been implemented in user defined functions that interact with the software package. It is hypothesized that the DSE gathered the measurement data from the field (in the simulated network) and then, once the DSE algorithm stopped, the estimated status of the network are passed to the DMS that perform the optimization and gives the results to the local controllers that act directly on the set point of the generators and RLs in the simulated network. A further subroutine verifies that the operation point defined by the DMS could be acceptable or not, in terms of related costs and comply with technical boundaries.

Test network

Figure 2 shows the case study: an MV distribution network model used in an Italian research project [9]. One primary substation feeds 118 MV substations (52 trunk nodes and 66 lateral nodes) that deliver about 26.3 MW to the MV and LV customers.

The network may be subdivided into two areas, the rural one (upper part of Fig. 2) where there are long overhead lines with small cross sections feeding small loads, and the urban one, (lower part of Fig. 2) where underground cables with bigger cross sections supply urban/industrial high loads. Two typologies of generators have been taken into account: wind turbine (WT) and gas turbine (GT). Five WTs installed in the rural part can generate about 3.6 MVA. Three 1.5 MVA GTs are installed in the urban area (only in the left feeder of Fig. 2, in the nodes 26, 34, and 35) and one 7 MVA GT is connected to the rural portion of the network. Five typologies of loads, with their own daily curves, have been considered: residential, industrial, commercial, agricultural, and public lighting.

In order to emphasize the role of the DMS control the rated power capacity and position of DG has been chosen to severely affect voltage regulation causing overvoltages and thermal overloads. In particular, during the night, when the demand is small, overvoltages in many may occur.

Results and discussion

Figure 3 reports the voltage profiles of the urban feeder with generation in a particularly critical hour of the night. The upper curve refers to a condition without uncertainties, except those due to the accuracy of the measurement devices. This is true only if the measurement system is constituted by a measurement device on each node: the system is totally known.

The voltage profile in the lower curve of Fig. 3 the DMS operates as in the reality, thus the state of the system, input of the optimization, is estimated by means the proposed DSE algorithm. In the considered case the DSE underestimates the severity of the contingency.

In any case, in the considered hour, due to the sustained overvoltage condition (Fig. 3), the DMS optimization has to curtail the production from the involved GTs (the three 1.5 MVA GTs) and to regulate the exchange of reactive power from DG, minimizing the operation cost.

In the first condition, to comply with the technical constraint, the power production of the generators connected in the nodes 34 and 35 is reduced and the reactive power from GTs is adapted according with the grid requirements. In particular, the production curtailment is 16.4% and 9.4% for the GT in the node 34 and in the node 35, respectively, and their reactive power production increases and changes from leading to lagging. The new voltage profile of the considered urban feeder is reported in the lower curve in Fig. 4; this curve complies with the constraints and the voltages of the buses are all under the maximum allowable deviation (1.05 p.u.).

In the second case, the DMS uses the estimated status of the network in the considered hour of the night (the voltage profile in the lower curve of Fig. 3). The result of the optimization imposes 3.4% of reduction of the active power production of the generators in the nodes 34 and 35 and their reactive power production small increases and changes from leading to lagging (less than the first case).

Figure 4 reports the new voltage profiles, the lower is the one resulting from the optimization starting with the system totally known, the upper is the one resulting from the same optimization but in this case it is assumed that the estimates are affected by uncertainties. This voltage profile is out of the imposed voltage boundary.

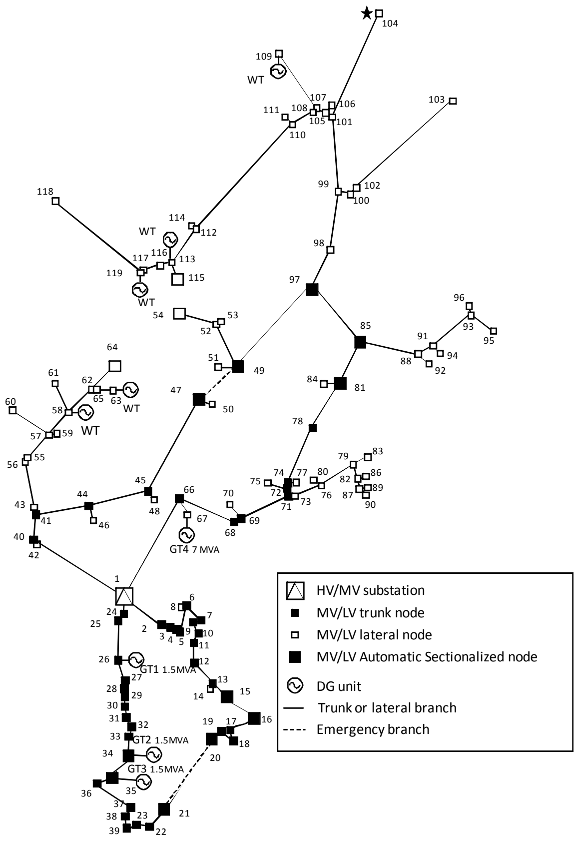

Fig. 2. Test network

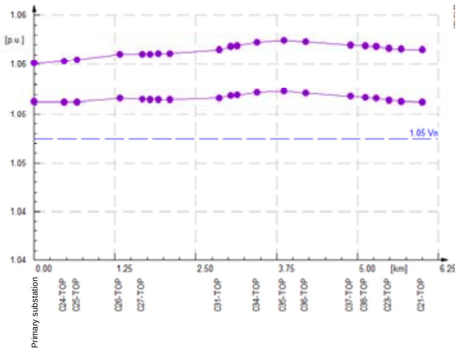

Fig. 3. Real and estimated voltage profile of the urban feeder with generation in a particularly critical hour of the night (before the optimization).

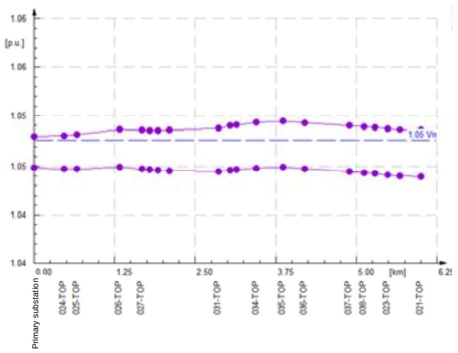

Fig. 4. Voltage profile of the urban feeder after the DMS control action.

CONCLUSION

Distribution State Estimation is fundamental for the active management of the distribution networks because it gives the Distribution Management System the essential information for the real time scheduling of generation and responsive loads and the network reconfiguration. The DSE represents a source of uncertainty in the operating of the DMS and the more accurate the quality of the estimates the more suitable the decisions made by the DMS can be.

This paper presents the evaluation of the uncertainty level introduced by the DSE in the DMS operating. The performed simulations using a representative distribution network model demonstrate that the quality of the estimates can seriously affect the system management.

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