Development of innovative systems for operation and control of electric power distribution networks: management and optimal use of distributed generation and of renewable energy resources

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Abstract - *The integration of distributed energy resources for the production of electrical energy is related to the evolution of future power distribution networks in order to achieve: flexibility (meeting final user's requirements); accessibility (allowing access to local generation and particularly to renewables); reliability (ensuring the highest possible security and power quality levels); economy (allowing an adequate management of energy in an efficient and competitive way).In this framework, the paper presents some results of a joint research project involving five Italian universities. The focus is on the proposition and development of the main functionalities implemented into a centralized Distribution Management System (DMS) for the operation and control of the energy resources connected to distribution networks (generation, storage and loads) and of the network itself (automation systems, protection, etc.). Architecture, hierarchical structure and relevant functions for the control, operation and management of the active distribution network, are illustrated.*

Keywords: *Distributed Generation, active distribution networks, renewable energy sources.*

1 Introduction

The integration of distributed energy resources for the production of electrical energy is related to the evolution of future power distribution networks in order to achieve: flexibility (meeting final user's requirements); accessibility (allowing access to local generation and particularly to renewables); reliability (ensuring the highest possible security and power quality levels); economy (allowing an adequate management of energy in an efficient and competitive way) [1].

These requirements can be satisfied through the attainment of the following two main tasks:

- the development of innovative methodologies and technologies for the operation and control of the energy resources connected to distribution networks (generation, storage and loads) and of the network itself (automation systems, protection, etc.);
- the definition of standards, protocols and adequate market regulatory structures that would make it possible the evolution from the old to the new network asset.

The automation of the electrical system is integrated in a structured control hierarchy in order to satisfy various necessities relevant to the delivery of electrical energy [2]. For the management of electric distribution networks a structure similar to well known EMSs (Energy Management Systems) adopted for the transmission network, may be suitably adapted. In analogy to EMSs, electric distribution networks will use similar distributed structures suitably coordinated at different levels. In this respect, the term DMS (Distribution Management System) is generally used to identify such a specific structured control hierarchy for electric distribution networks [3].

In this framework, this paper describes the proposition and development of a DMS of which control, operation and management functions have been developed at the Authors' laboratories. Its interface with remote monitoring systems (of both network and dispersed resources) suitably developed by means of innovative technologies represents a key feature. In this respect the use of advanced Phasor Measurement Unit devices, developed at one of the laboratories involved in the research project, is discussed in the paper. Finally, as the development of the DMS functions is related to the regulatory scenarios and, at the same time, the evolution of the future distribution networks is influenced, for a fixed scenario, by the DMS itself, the paper addresses also the issue of the definition of a framework of regulatory scenarios in which the DMS and its control and operation functions are expected to be tested and assessed.

The paper is structured in the following way: in the second section, the architecture, control hierarchy, and functions of the DMS are presented along with its control and operation functions. In the third section the main functionalities of the DMS for what concerns the state estimation and the optimization of the distribution network are illustrated. In this section the use of advanced Phasor Measurement Unit devices, developed at one of the laboratories involved in the research project will be illustrated too. A further subsection is devoted to the discussion on power quality issues while the fifth section is devoted to the Conclusions.

2 DMS Architecture

It is widely recognized that local controls are no longer suited to mitigate voltage regulation issues caused by bidirectional power flows or to manage faults in distribution systems with high shares of DER (Distributed Energy Resources) [4]. The debate on decentralized or centralized control systems for Smartgrid and active distribution system is still open. There is a general consensus on the need of hierarchical control, but the techniques for the system optimization span from central control systems to autonomous agents [5]. Autonomous agents have the great benefit to reduce the need of broadband communication systems, but in many cases there is the need of a central coordination that reduces the value of agents. The centralized control systems with hierarchical structure are quite easy to implement, provided that a clear regulation framework is established in order to allow the DSO (Distribution System Operators) to make transparent and market based decisions. Anyway, in order to improve the reliability local resources have to be equipped with local intelligence capable to make decisions when the communication flow from the control center is interrupted. A centralized active management scheme generally consists of:

- 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 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), and also can take a decision if the signal from the control center is interrupted;
- a measurement system, consisting of a 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 and the exchange of measurement data and control signals between control center and LCs.

Ad hoc DSE algorithms that provide the real-time status of the network, by gathering data from the distributed measurement system (insufficient at distribution level) and other available information retrieved from historical data (pseudo-measurements) have to be used in the DSE frame of the control center [6], [7]. The DMS, supervises the operation of the electric distribution network and, if necessary, modifies the set points of DERs (e.g., generators, storage devices), and responsive loads according with the results of the optimization. DERs (DG owners and Responsive Loads-RL) send day by day to the control center bids for the one day-ahead active and/or reactive power generation or load demand. Furthermore, they also offer their support to the active distribution networks (ADNs) operation for the next time interval in the intra-day market, by offering changes to production schedule and/or load demand. 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 an intra-day optimization. Finally, if the active management reaches an advanced level of implementation, also the network reconfiguration can be profitably exploited.

The DMS solves the optimization problem running in real-time on a dedicated DSP or on industrial computers that can be sited in the primary substation. Once the time horizon (typically one day) and the time interval (e.g. 1 hour, but even shorter) are defined, at the beginning of the time interval the DMS receives the status of the network, the technical constraints, as well as the market prices and information on energy trades. Furthermore, the DMS collects bids from DERs for the next time interval. The new set points and the current network topology are hold until the end of the time interval, when new data are gathered from the network and used for a new optimization.

In order to describe more in details the typical structure of DMS, it is worth noting that electric distribution network can be managed from a single control center and/or from distributed control centers on the territory [3], [8]. As known, control centers use a so-called SCADA (Supervisory Control and Data Acquisition) - and are based on the communication between the control center itself and the primary equipment that can be controlled (generation, breakers, on load tap changers, etc). These devices must necessarily be equipped with actuators that allow carrying out the operation demanded from the control center. The communication between the control center and the actuators is possible by use of secondary devices called Intelligent Electronic Devices (IED).

Two are the typical approaches in the development of DMS applications: (a) “GIS-centric” solution; (b) “SCADA oriented” solution.

The first solution makes reference to the term GIS - Geographical Information System and is more oriented to the off-line management of the distribution systems. The more typical functions of the distribution systems, like fault detection and network restoration have been implemented in the past thinking more to the territory and therefore with requirements of having a clear picture of the distribution network using software solutions more oriented to off-line control and management.

Figure 1 illustrates the general structure of a possible advanced DMS.

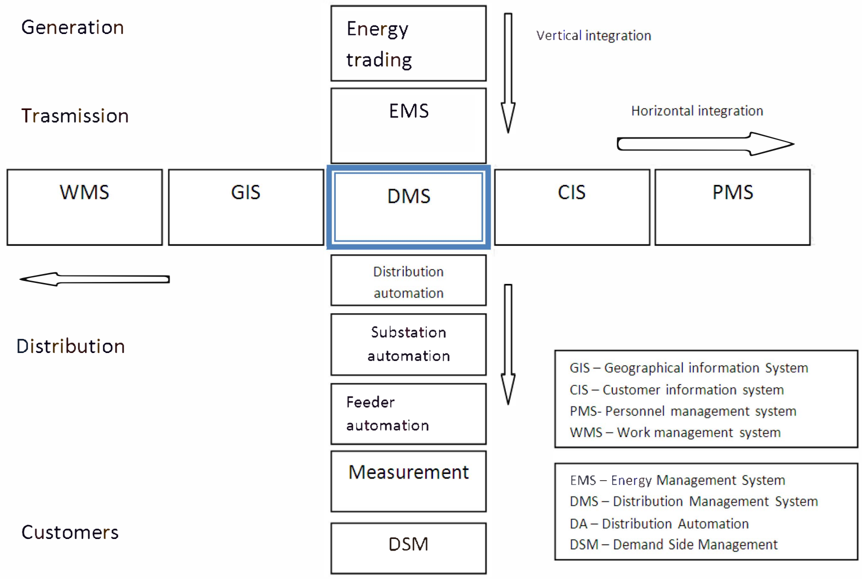

Fig. 1 - Vertical and horizontal integration in distribution networks (adapted from [8]).

3 State Estimation and Optimization in DMS

3.1 State Estimation of Active Distribution Networks

Innovative management strategies in active distribution networks require a reliable State Estimation (SE) of the system in terms of line flows and bus bar voltages. Traditional SE algorithms, adopted in transmission systems, appear hardly applicable in distribution networks because of the lack of available real-time measurements, with a consequent high level of uncertainty resulting in the estimations [10].

At present, in the distribution networks, the availability of real-time measurements is often limited to the Primary Substation (PS) (MV bus-bar voltage and P-Q flows on the outgoing feeders). In this case a large number of so-called pseudo-measurements has to be used to guarantee the network observability [11]. Pseudo-measures may represent estimates relevant to load consumptions or to DG injections and are usually afflicted by a high uncertainty, due to the impracticability of a widespread measurement system. High levels of uncertainty negatively affect the accuracy of voltage estimates, preventing an effective control of network voltages. Two different strategies may be adopted to ensure a suitable reduction of the estimated voltages uncertainties:

– reduction of pseudo-measurements uncertainty by using load modelling techniques [12].
– introduction of further remote on-line measurements. In particular, further voltage measurements in critical nodes produces the best results in reducing the degree of uncertainty [13]; to this aim a suitable algorithm has been developed to provide the optimized measurements location [14],[15].

The method evaluates the network operational state by computing a suitable parameter, denoted as “variance moment”, in accordance with the time-variable probabilistic value of loads demand and generators production respectively. The uncertainties of the active and reactive injections in each node and its distance from the Primary Substation define the “variance moment” parameter.

The calculation of the variance moment is based on a matrix computation able to handle both network data (topology, composition, status of switches) and load and DG characteristics. The load uncertainty is considered equal to three times the standard deviation of the probabilistic distribution representing such load (and similarly for the generating plants). Active and reactive consumptions are separately modelled. The uncertainties on power injections are represented node by node in the diagonal matrix U_L (1), where N is the number of nodes while σ_{Pi2} and σ_{Qi2} are the variances of the overall active and reactive injected power at the ith node. The additional measurement points have been optimally allocated adopting the following procedure.

$$\mathbf{U_L} = \begin{bmatrix} \frac{\left(\sigma_{P1}^2 - j\sigma_{Q1}^2\right)}{V_1} & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & \frac{\left(\sigma_{PN}^2 - j\sigma_{QN}^2\right)}{V_N} \end{bmatrix} \begin{array}{l} 1^{st}\ node \\ \\ N^{th}\ node \end{array} \quad (1)$$

The method requires that one measurement is available at least in the power system (in case of complete absence of remote voltage measurement). If other bus-bars are already equipped with on-line voltage measurements, so this nodes are introduced in the process as forcing parameters equal to one in the N_Vx1 matrix V, naming as N_V the number of on-line voltage measurements. The value of N_V determines the size of the four sub-matrixes in which the admittance matrix Y is split, as in (2).

$$\begin{array}{cc} \mathbf{Y} = \begin{bmatrix} \mathbf{Y_1} & \mathbf{Y_2} \\ \mathbf{Y_3} & \mathbf{Y_4} \end{bmatrix} & \begin{array}{l} 1:\mathrm{N_V} \\ (\mathrm{N_V}+1):\mathrm{N} \end{array} \\ \quad 1:\mathrm{N_V} \quad (\mathrm{N_V}+1):\mathrm{N} & \end{array} \qquad (2)$$

The value of N_V defines also the matrix U_L* which is extracted from UL as in (3) (distribution of power injections uncertainty), while matrix V* is consequentially, determined as in (4), is a (N-NV)x1 vector and represents a sort of "performance drop" in the estimated voltage accuracy.

$$\begin{array}{cc} \mathbf{U_L} = \begin{bmatrix} \left(\sigma_{P1}^2 - j\sigma_{Q1}^2\right) & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & \mathbf{U_L^*} \end{bmatrix} & (N_V+1):N \\ \qquad\qquad (N_V+1):N & \end{array} \qquad (3)$$

$$\overline{\mathbf{V}}^* = -\left(\mathbf{U_L^*} + \mathbf{Y_4}\right)^{-1} \cdot \mathbf{Y_3} \cdot \overline{\mathbf{V}} \qquad (4)$$

Finally the variance moment M is obtained as in (5) for each node where a voltage measurement is not performed (by definition, nodes 1...N_V, where a voltage measurements is performed, have variance moment equal to one). M is a (N-N_V)x1 matrix containing in the tth row the value of the performance parameter of the (N_V+t)th node. In case of radial networks, with on-line measurements available only at the primary substation, the variance moment represents the products of variances of the active and reactive power injections and their relevant electrical distance from the power system.

$$\overline{\mathbf{M}} = \begin{bmatrix} 1 - \left|\mathbf{V}^*(1)\right| \\ \vdots \\ 1 - \left|\mathbf{V}^*(N - N_V)\right| \end{bmatrix} \quad [MVA^2 \cdot \Omega] \qquad (5)$$

Once the matrix M has been obtained, the algorithm calculates which node of the grid is characterized by the maximum variance moment. If the voltage estimation uncertainty exceeds the imposed limits, the algorithm allocates an additional measurement point in correspondence to the generator nearest to the node with the highest variance moment; the matrix M is re-calculated and the procedure continues until the voltage estimation uncertainty returns within the limits in every node of the monitored network.

3.2 DMS Operation

The DMS makes the system complying with the technical constraints at the minimum cost by resorting to:

- DG Generation Curtailment (GC),
- Reactive power exchange from DG (Ancillary Service-AS),
- Storage devices control,
- Demand Side Integration (DSI),
- OLTC control in the primary substation
- Network reconfiguration.

The DMS may be tripped only by constraint violations like voltage regulation problems (typically over-voltage caused by DG and voltage drops caused by high load) and thermal overload. DMS can also continuously strive to cut costs or reduce the exploitation of the existing assets (e.g. the network may be reconfigured to reduce the energy losses or to minimize the DG curtailed power).

In each time interval, the DMS finds the optimal combination of the available operation options and outputs the optimal set points to be sent to the local controllers of DERs and the open/closed status of the branches available for the network topology. Given one network topology, the problem to find the optimal combination is an OPF (Optimal Power Flow) problem. In the proposed DMS, load flow equations have been linearized to use linear programming in order to reduce the computing burden so that the algorithm can be applied to real time calculation. The DMS is also able to find the optimal network configuration within a range of optimal topologies to reduce the energy losses and to limit or avoid overloads in branches. In this case, the DMS also outputs the open/closed status of remote controlled breakers in the weakly meshed distribution network (Fig. 2). The external loop assesses all N_{config} feasible configurations and chooses the topology with the smallest calculated value of the Objective Function (O.F.). The proposed DMS architecture has been tested on real size networks and proved to be effective in allowing high shares of RES to be integrated in the system. The resort to flexible topologies allows reducing both energy losses and the variations to the production of RES. The research is now focused on the optimal control of storage devices.

Active networks require 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 system. Therefore, suitable techniques of DSE are necessary. The DSE provides a complete and consistent model of the operating conditions and it is essential for the DMS operation. The optimal placement of measurement devices is also covered.

Currently, the research is focused on the impact of uncertainties in state estimation on DMS.

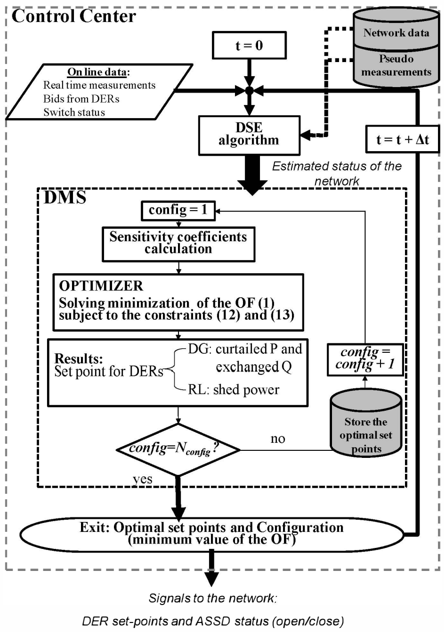

Fig. 2 - Flowchart of the proposed procedure.

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).

3.3 Optimal scheduling of Distributed Energy Resources

A possible solution for the optimal control of DER has been proposed in [16] where a two-stage scheduler has been proposed. It is composed by a day-ahead economic scheduler, that calculates the active power set points during the following day in order to minimize the overall costs, and an intra-day scheduler that, on the basis of measurements and short-term load and renewable production forecasts, updates the DERs and control set points every 15 minutes. The need for 24-hour horizon function is justified by the requirement for an optimal use of the available energy storage facilities and by inter-temporal operation constraints. The optimal intra-day scheduling of DERs is based on the use of a detailed three-phase load flow calculation and a MILP (mixed-integer linear programming) optimization algorithm. Fig. 3 shows the main concepts of the procedure in which the multi-objective function of the scheduling problem consists in the minimization of the voltage deviations with respect the rated value of the DERs production deviation with respect the maximum efficiency point calculated by the day-ahead scheduler. Also network losses are part of the objective function. The solution is based on the three-phase power flow calculation in which, in normal operating condition, the connection to the primary system is the slack bus. At each iteration, the initial values of the DERs control variables are modified by $\xi\Delta x$, where coefficient ξ is calculated so to minimize the value of objective function by means golden section method.

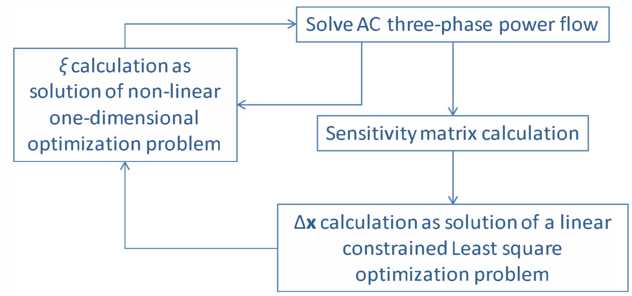

Fig. 3 - Scheme of the intra-day scheduling procedure.

3.4 Dynamic phasor monitoring of distribution systems

The evolution of power distribution networks from passive to active is determining major changes in their operational procedures: one of the main involved aspects is indeed the real-time monitoring of these networks. The above issue calls for a massive use of advanced and smarter monitoring tools that result into faster and reliable real-time state estimation of these networks. One of the most promising technologies in this field is certainly represented by the distributed monitoring based on the use of PMUs [17].
Synchrophasor estimation algorithms proposed in the literature are essentially based on the Discrete Fourier Transform (DFT) applied to quasi-steady state signals representing network node voltages and/or branch current waveforms. These DFT-based algorithms can be grouped into one-cycle DFT estimators, and fractional-cycle DFT estimators performing recursive and non-recursive updates [18]. Within this context, the algorithm presented by the Authors in [19], [20] belongs to the DFT algorithms; it has been conceived in order to: (i) allow the use of PMU in active distribution networks and (ii) keep the synchrophasor measurement accuracy within specific limits even in presence of distorted signal waveforms and electromechanical transients (namely, with frequency-varying signals). Concerning point (i), it is worth noting that, compared to transmission networks, active distribution networks are characterized by reduced line lengths and limited power flows. With reference to the use of bus voltage synchrophasors for the network state estimation, these characteristics result, in general, into very small phase differences between bus voltage phasors (generally in the order of tens of mrad or less). These characteristics calls for PMU devices characterized by synchrophasor phase uncertainty well below the limits provided by the IEEE Std. C37.118 [17]. Concerning point (ii), it is worth noting that distribution networks are characterized by much higher distortion levels than those of transmission networks.

Additionally, as active distribution networks are expected to operate even when islanded from the main transmission networks, PMUs appear a useful tool to support distribution system operators during the islanding and reconnection manoeuvres. In this respect, the application of PMU to monitor electromechanical transients, generally characterized by non-negligible deviations from the rated network frequency, could involve important bad estimation of the synchrophasors phases and frequencies.

3.5 Power Quality Issues in Active Distribution Networks

Regulatory scenarios give the framework to develop the DMS functions. For a fixed scenario, the evolution of the future distribution networks is influenced by the DMS itself. It is then important to define regulatory scenarios in which the DMS, its control and operation functions are expected to be tested and assessed. Among the various aspects regulated by National Authorities, like in Italy the Authority of Electric Energy and Gas (AEEG), the Power Quality (PQ) issues represent the constraints to be matched by the distributors in a liberalised market. In fact, regulators are increasingly utilizing performance based ratemaking (PBR) as a tool to promote efficiency in the provision of distribution services. Because of the cost pressures of deregulation and PBR regulation, most PBR schemes include minimum service quality requirements to ensure that utility service quality performance does not fall below desired levels. Most PBR regulatory schemes enforce the minimum standards for service quality performance through economic incentives for exceeding service quality targets or penalties for failing to meet those targets.

The presence of the DG globally influences the service quality that can be guaranteed to the final users, and, however, can be used also to compensate PQ disturbances exchanging with the network additional services, namely auxiliary services for PQ, besides the energy. This possibility requires: the presence of converters operating as distributed generation interface with the network and the measurability of the auxiliary services for PQ.

The measurability of the auxiliary services for PQ allows the centralised management verifies that the functions assigned to the active nodes have been performed, and then can be remunerated. In particular, it is worthwhile to evidence that the economical evaluation of PQ is one of the emerging issues in the National and International community of the research also for the push impressed by liberalised markets [21].

To develop a DMS able to implement functions for the management and the control of the network taking into account the PQ constraints, it is needed to ascertain and implement adequate methods and indices to estimate the PQ performance of the active networks.

First steps of the research have considered two main phenomena: the unbalances and the voltage dips.

Regarding the unbalances, the general problem of facing also the uncertainties that affect the evaluation of steady state operating conditions has been taken into account using the point estimate method. [22]. Moreover, since the point estimate method requires that the input random variables are uncorrelated, a suitable adjustment to take into account the correlation is applied. Different point estimate schemes (2m, 2m+ 1 and 4m+ 1 schemes) are presented and tested. The accuracy of the proposed techniques is tested on a three-phase unbalanced IEEE 34-bus test system; the results obtained applying the Monte Carlo simulation are assumed as reference. Both correlated and uncorrelated input random variables are considered, and multimodal probability density functions are tested. The final results evidenced that the 2m+1 scheme gives the best solution in terms of accuracy and computational efforts; in the case of correlated input random variables, an adequate procedure to take into account the correlation must be applied.

4 Conclusions

Major research activity is on-going on the subject of active distribution networks. The management and optimal use of distributed generation in distribution electrical networks is attracting several efforts and research funding.

In this context, the paper has presented the on mid-term results of a research national project that is involving five Italian Universities.

The architecture of a Distribution Management System (DMS) for active distribution network control has been presented focusing on its interface with remote monitoring and control systems of distribute resources including storage and loads.

Details and methodological insights on the DMS functions and operation such as state estimation, local controllers, communication systems and optimal scheduling strategies are provided.

The crucial importance of adopting new concepts for distribution network planning and operation, of using appropriate ICT technologies and equipment has been stressed. The necessity of identifying regulatory scenarios capable of permitting the full exploitation of distributed resources – generation, load and storage systems - has been put into evidence.

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