

Real Time Monitoring of distribution System based on State Estimation

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Abstract— The development of the smart grid requires new monitoring systems able to support automation functionalities to control Distributed Energy Resources (DERs). A real time Distribution System State Estimator (DSSE) integrated with bad data processor is presented in this work as a key element of the monitoring system. The developed DSSE is optimized for real time applications, particularly for computational efficiency, numerical stability and robustness against measurements with large error. The DSSE is localized within an automation platform, that performs monitoring and control at substation level, from which the requirements for monitoring are derived. DSSEs located in different automation platform may be coordinated through Multi Area algorithms, improving solution's time efficiency and robustness, but maintaining acceptable accuracy levels. The performance of real time DSSE, both for single and multi-area is analyzed and discussed by means of real time simulations performed in distribution Medium Voltage (MV) and Low Voltage (LV) networks.

Keywords— *state estimation, distribution system, real time operation, monitoring, automation architecture*

I. INTRODUCTION

Nowadays, variable renewable energy generation and storage sources are being introduced into the traditional electric power grid beside the typical passive loads. More specifically, renewable generation such as wind turbines and photovoltaic panels are more and more connected at distribution level rather than at transmission level, as well as private electrical storage systems and electrical vehicles. Such variable power injection and consumption, may lead to stresses in the distribution networks: namely, over- and undervoltages, overload of lines and transformers, issues in protection schemes and automatic voltage controllers of on-load tap changers, due to the inversion of power flow direction [1]. In the meantime, both customers and network operators expect a very high reliability of power supply, defined by a set of power quality requirements [2]. Consequently, in order to allow a large penetration of renewables in distribution systems and maintaining strict power quality requirements, the aforementioned power injections and consumptions should be controllable. The DERs are loads, generators and storage units whose output may be regulated and coordinated by an automation system. The ongoing research on automation systems in distribution

networks is focused on methods and components to coordinate efficiently the DERs in order to limit the number and the total duration of the disturbances, minimize the grid losses and maximize the active power production of the renewable energy resources [3]. A key component of the future automation architectures in distribution is the monitoring system. In fact, it should provide an accurate state of the network, in real time, to feed automatic and supervisory control of the network components. Real time monitoring systems are complex systems that involve several elements [4]. The general architecture includes sensors, merging units and measurement devices, which provide, continuously, information of the system to data concentrators. Here, data interfaces should provide the measurement quantities to state estimators and databases. State estimators exploit heterogeneous measurement quantities, such as powers, currents and voltages to obtain the status of the system, which is usually the voltage phasor at all the nodes. In the recent years many research works have been dedicated to the improvement of monitoring systems based on state estimation (SE) for distribution. The SE algorithms based on Weighted Least Square (WLS) shown in [5], [7] are based, respectively, on rectangular and polar node voltages; whereas [7] and [8] are implementations based on polar and rectangular branch currents. In [9] a detailed comparison of several types of estimators has been conducted, showing that they provide similar accuracies and slightly shorter computation time for rectangular voltage and current state estimators. Besides the improvement of the algorithm per se, it is important to integrate efficiently the SE in the monitoring chain; for instance in [10] the effects of measurement devices and instrument transformer on the weights of WLS is analyzed. In [11] synchronized measurements are harmonized with traditional SCADA measurements. In [12] the impact of different uncertainty sources in the monitoring chain, as the type of real time measurements, pseudo measurements and amount of injected load is investigated. In [12] the mathematical relation between the level of uncertainty of the measurements and the one of the estimation is demonstrated. Therefore, given the good level of knowledge regarding the type of SE for distribution grid monitoring and their accuracy, more focus is required on the development of a monitoring architecture that estimates the

state in real time while satisfying the requirements for a field implementation. The testing of such architecture requires a platform for simulating the power system and testing the SE in real time, as proposed in [4]. Some real time laboratory testing setups have been already exploited in [13] for measurement devices such as SCADA measurements and PMUs for Wide Area Monitoring applications and in [14] for exploitation of smart meters in low voltage monitoring systems. This paper, aims at proposing an effective architecture for real time monitoring, based on the collection of measurement and estimation of the state at substation level on the so-called Substation Automation Units (SAUs) in MV and LV systems. The Distribution System State Estimation (DSSE) algorithm in was designed based on the requirements of accuracy, real time computation and robustness against bad or missing data. This paper, that is the technical extension of [15], aims at further defining the architecture, both on hardware and software sides, and the data exchanges needed to support state estimation functionalities and testing the former in real time environment to prove its feasibility for field applications. Furthermore, a multi area type of state estimator is proposed based on local estimates as in [15] and a following step of optimization as described in [16] in order to obtain the estimation of the whole grid; results are thus compared with the single area DSSE. The multi area DSSE (MADSSE) is based on the hierarchical division between automation in MV and LV. Therefore, in this paper two DSSEs will perform separate estimations for the LV and MV parts, respectively in the Primary and Secondary Substation Automation Units (PSAUs and SSAUs) and the final step of optimization will be performed at the PSAU. In the text below, chapter II explains the main features of DSSE and introduces the automation architecture where the monitoring systems, and consequently the local DSSEs and in general the MADSSE should take place. Chapter III presents the main DSSE and MADSSE algorithms' features. Chapter IV shows the lab physical implementation of the real time monitoring system. Chapters V and VI presents some real time tests results, respectively for DSSE and MADSSE on MV and LV grids, using the testing platform developed in [4].

II. THE DSSE IN AUTOMATION ARCHITECTURE

The design process requires presenting the general state estimation algorithm and the particular features of its implementation in distribution grids. Then, more detailed specifications may be obtained from mapping the monitoring system, and in particular the DSSE, on distribution automation systems. The SE exploits a set of measurements z as input and produces the state of the system x [5]. The methods available in literature aim at filtering the error in the input and are optimized for the type of power system where the SE operates. The status x , is normally estimated through the weighted least square (WLS) method [5], minimizing the residual between the difference between the actual measurements z and the

measurement function vector $h(x)$, derived from the estimated state. The objective of the state estimation is to reduce, as much as possible, the sum of the squares of the N elements of the residual vector; each one weighted by a factor w_{ii} , equal to the inverse of the variance of the i^{th} measurement.

A. SE applied in distribution networks

Even though SE has been successfully deployed in transmission networks (TNs) [5], it is hardly exportable to Distribution Networks (DNs). There are several differences in the feature of the power system per-se [17]: the topologies in DNs are radial or weakly meshed, whereas in TNs are meshed. In DNs the power consumption may be unbalanced, and in some cases the lines are single phases, consequently in DNs the SE output should be three phase. Moreover, there are differences in the measurement infrastructure [18]: in DNs the number of measurement devices is relatively low compared to the number of buses, then it is necessary to exploit the so called "pseudo-measurements" obtained from historical data of power consumption and generation [19]. However, the absolute number of measurements in DNs is large, and the collection of data and their storage in time series database is a critical issue for real time implementation. In DNs the type of measurement devices are very heterogeneous in terms of type of physical quantity provided, communication protocols and data models used. Substation measurements use IEC 61850 or DNP3 (Distributed Network Protocol) data models and protocols and have high reporting rates; smart energy measurement system use DLMS/COSEM data models and protocols and provide energy measurements with low reporting rates. Furthermore, the phasor measurement units, lately proposed also in DNs, provide synchronized phasors with very high reporting rates [20]. In TNs the SE, is updated every 15 minutes and the measurement devices use the same standardized protocols, data models and type of physical quantities; consequently the real time implementation has been already optimized in the last decades [5]. In general the SE computation time is connected to the total number of nodes to be estimated and given that DNs may have thousands of nodes, it is suggested to divide the problem in local SEs and then perform an aggregation of the results in a following step [16]. The MADSSE permits to reduce the number of data to be computed and stored, reducing hardware and software requirements and total computation time. Furthermore the overall robustness of the monitoring system is improved as in case of loss of observability of one of the areas, due to measurement devices' or communication's failures, other areas estimations can still be calculated.

B. DNs automation architecture and monitoring systems

The monitoring system is a key component of the automation systems. It supports the automation functionalities with accurate and reliable information. The IDE4L project [3], proposes to divide the points of information aggregation and control in 3 levels, secondary

substation, primary substation and control center, as shown in Fig. 1. In this way the big load of data, both measurements and control set point can be better managed. The proposed automation architecture clusters the measurement devices in four groups: smart meters, placed at the connection of prosumers to the low voltage grid, secondary substation and primary substation intelligent electronic devices (IEDs), that utilize the substation local area network to retrieve the sampled values from the merging units, and distributed IEDs that are directly wired to the sensors and placed in MV or LV lines, outside of the substation. The data concentration units are clustered in three groups, secondary substation automation unit (SSAU), primary substation automation unit (PSAU) and control center. The DSSE is performed for LV grids in SSAU; for MV grids in PSAU, exploiting MV measurement devices and the results of LV SE. SEs are then merged and further optimized through MADSSE at PSAUs and exported to the control center exploiting a wide area network (WAN).

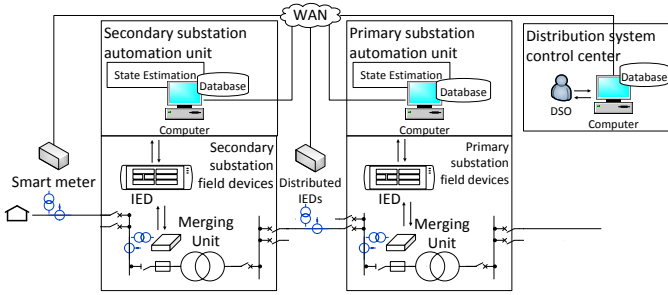


Fig. 1 Distribution automation architecture as proposed in IDE4L fp7 project

The substation automation unit is a computer that includes three important functionalities: 1. Interfaces to devices, the control center and other SAUs; 2. Database; 3. Automation algorithms (included the SE). An example is proposed in Fig. 2A, where the SAU has interfaces to DNP3 and IEC 61850 MMS (Manufacturing Message Specification) protocols; the application state estimation, reads and writes data into the database. In Fig. 2B, an alternative approach is proposed, based on a direct access of the SE application to the quantities retrieved by the DNP3, then it stores the SE results in database, in order to be used by other SAUs through IEC 61850 MMS interface.

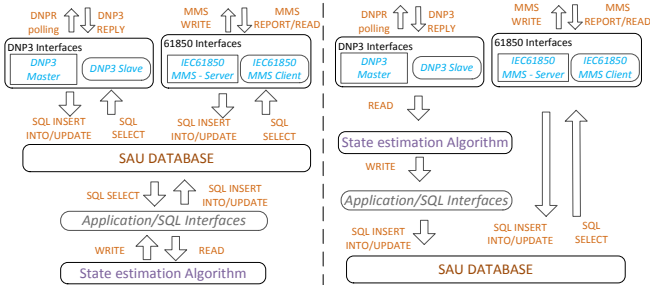


Fig. 2 A, example of substation automation unit (SAU) structure, with database as interface to application. Fig. 2 B, the real time data are passed directly to the monitoring application and then stored into database

The elements presented in Fig. 1 and Fig. 2 are supposed to operate in the following order: 1. Measurements from smart meters and IEDs are requested by SAUs or directly reported by devices to SAUs on regular rates, both at MV and LV level. State estimation is performed synchronously at both SSAUs, for the LV portion of grid, and PSAUs for the MV portion of the grid. The results of LV state estimation are reported from SSAUs to PSAUs, where the second step optimization of MADSSE algorithm is performed. The results are then reported again to SSAU and to control centers.

C. Real time state estimation Requirements

In order to design a state estimation algorithm, it is necessary to define the main requirements of monitoring applications in distribution automation systems. The DSSE requirements can be clustered in accuracy of the estimated with regards to the true state, real time computation and robustness with regards to degradation of quality the available measurements. The accuracy requirement correspond to bound that the maximum estimation error below a certain threshold. The definition of maximum state error may be based on the settings of the controllers that will act on top of the output of the state estimation. The requirement on the real time computation is, like for the accuracy, connected to the specification of the automation system. The maximum DSSE reporting rate is limited by the highest measurement reporting rate: $f_{DSSE} \leq f_{meas}$. The minimum is specified by the quickest action that can be taken by the controllers, consequently $f_{DSSE} \geq f_{controller}$. The automation functionalities, such as forecast algorithms, coordinated control of DERs and on load tap changers and SCADA systems, from literature [17] are never updated with frequencies greater than 1 Hz. Therefore, in this paper, the reporting rate of DSSE is set to 1 Hz. Eventually, given the adverse conditions in which the DSSE may operate. for instance: measurements may be delayed or not received because of problems in the communication systems; or similarly, degradation in the performance of transducers, merging units or measurement device may yield unexpected measurement errors, some measures to increase the robustness of DSSE should be taken, as provision of redundant measurements, the use of bad data processing and the division in local DSSEs (MADSSE).

III. DSSE AND MADSSE ALGORITHM DESIGN

Given the requirements for accuracy, real time operation and robustness, previously described, the major design choices are described below.

A. Definition of local DSSE

In this paper a rectangular branch current DSSE (BC-DSSE) in the model of [8], is selected, as it guarantees accurate results and shorter execution times than voltage rectangular estimator and polar current and voltage estimators [9]. However such a SE, does not handle voltage phasor measurements. The equations needed to include voltage phasor measurements come from [11]. Beside the

decision of the state variable, it is important to specify the method to reduce the numerical instability in DSSEs. In the nodes where nor loads neither generators are connected, a very accurate constant measurement of zero power injection is considered. Zero injection measurements maximum error is null; but, nevertheless, a non-zero variance should be associated, as the weight in the DSSE-WLS based method is considered as the inverse of the variance. Having very high weights associated to zero injection measurements, yields to ill-conditioned G matrix bringing errors in the solution of the SE or even cases of no-convergence to solution. In order to improve the robustness of the state estimation by reducing the ill-conditioning problem, it is possible to assign the zero injection measurement as constraints and not as measurement inputs [5]. A further step can be applied considering the residual equations in equation (1), as an additional constraint, building the so called “Augmented Matrix (AM) Approach”[5]. The same BC-DSSE algorithm is tested for the case with 1. the standard approach, with 2. the constraints for the zero injection points and with 3. the AM approach. The tests performed on an IEEE standard 13 buses network [21], are shown in Fig. 3. Phasor Measurement Unit (PMU) voltage measurements are considered at bus 650 and 671 and current PMU measurements at the branches between buses 650-632, 671-692, 671-684 and 671-680. Buses 632, 633, 84 and 680 are considered as zero injection buses. State estimation methods 1,2 and 3 are compared in terms of conditioning number and average execution time (over 100 thousands Monte Carlo simulations) as shown in TABLE I. and memory expense as shown in TABLE II.

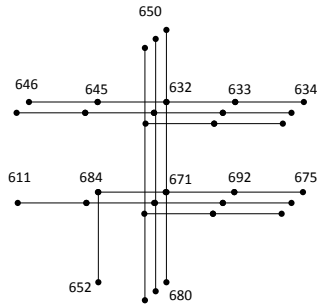


Fig. 3 IEEE Standard 13 buses distribution network

TABLE I. COMPARISON OF NUMERICAL STABILITY AND COMPUTATIONAL EFFICIENCY

Method	Weighting factor of zero injection measurements	Conditioning number[-]	Average execution time [ms]
Standard approach	$9 \cdot 10^8$	$3.50 \cdot 10^{12}$	18
	$9 \cdot 10^{10}$	$3.50 \cdot 10^{14}$	17
	$9 \cdot 10^{12}$	$3.50 \cdot 10^{16}$	14
	$9 \cdot 10^{14}$	$3.50 \cdot 10^{18}$	Diverges
Standard approach with constraints		$1.92 \cdot 10^7$	15
Augmented matrix		$5.76 \cdot 10^3$	14

The three methods have comparable execution time and number of iterations, hence similar real time performances. The non-zero elements, that represent the true information to

be stored, are similar throughout the three methods. Therefore, in this paper the AM Approach is deployed, given the big advantage for the numerical stability that is critical in DNs.

TABLE II. COMPARISON OF MEMORY USAGE

Method	Number of elements [-]	Number of non-zero elements [-]
Standard approach	$58 \cdot 58 = 3364$	410
Standard approach with constraints	$80 \cdot 80 = 6400$	492
Augmented matrix	$150 \cdot 150 = 22500$	424

B. Bad data processor and heterogeneous measurements

A key function to improve robustness in SE is the bad data processor (BDP), which includes bad data detection and identification. The Chi-squares test, is a quick method for bad data detection; whereas the largest normalized residual test, which may perform both bad data detection and identification, is more accurate but requires more computational effort than the former [5]. In this work, the Chi-squares test is exploited at first. If any bad data is suspected, the largest normalized residuals method will be applied to find the exact location of the bad data in the measurement set. In this way, the computational effort will be saved when not needed, maintaining acceptable levels of robustness but reducing the average computation time.

Accurate pseudo measurements, based on the type of loads, e.g. residential, industrial users and DGs in the network [19], together with the knowledge of the nodes where such types of customers are placed, are exploited. Furthermore, it should be considered that the reporting rate of real time measurement devices may be asynchronous and with different sampling rates [22]. The approach in this work is to use the last measurement available in time for every device. Another key step is the substitution of measurements that are recognized to be bad data or not updated by the measurement devices. In this work it will be checked if the observability of the system is still valid; if not, a new pseudo-measurement will be added.

C. Multi area DSSE

The MADSSSE is implemented by distributing the computation of the state estimation into several local DSSEs, in order to achieve a more computational efficient method without significantly degrading the accuracy of the estimation. Since the local DSSEs run in parallel, the processing time in Multi Area DSSE is much shorter than the one with a single area DSSE. MADSSSE also improves the robustness of the system, as in case of non-observability or non-convergence of a single area DSSE, the others DSSEs can still provide a solution. The network is divided into areas; thus considering the radial nature of distribution grids, the areas can be defined as LV areas starting from the secondary substation and including the LV networks, and MV areas starting from the primary substation and covering the MV grid up to the secondary substation. Thus, the

boundary buses, estimated by both MV and LV DSSEs, are the MV side of secondary transformers, as shown in Fig. 4.

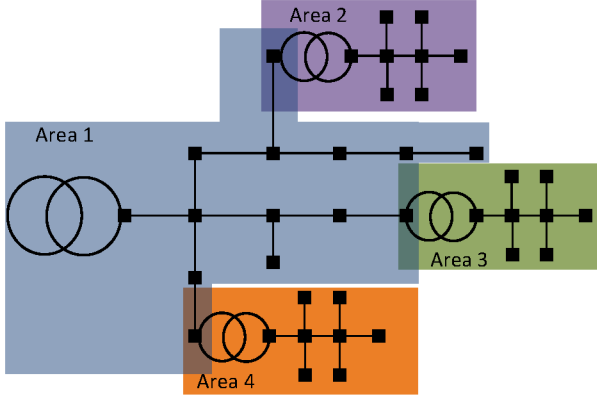


Fig. 4 Instance of MV and LV grids and division in areas

The two level MADSEE implemented in the paper, exploits the method in [16], based on two steps state estimation. In the first step, the local areas DSSEs are executed in parallel. Each state estimator is the same as the one explained in section III.A and works independently and synchronously. At the second step: The PSAU, in the role of coordinator, improves the accuracy of the estimation for the entire network by analyzing and opportunely merging the local states. The objective function J of every local area state estimation ($J_1; J_2; \dots; J_n$) is exploited, as information of the quality of the local estimations. The coordinator chooses the state estimator DSSE $_i$, which has the smallest J . Therefore, the selected DSSE $_i$ can be considered as the most accurate local area DSSE among the N local area DSSEs. The better quality of estimation depends on the number and type of devices present in the area. The coordinator corrects the results of the DSSE results exploiting the estimated state of the selected area DSSE $_i$. If, the area to be corrected DSSE $_j$ is adjacent to area DSSE $_i$ and therefore share a boundary bus, the correction factor $V_{p,ij}$ for magnitudes and correction angle $\Delta\theta_{p,ij}$ for phase angle are presented in eq (1) and (2).

$$V_{p,ij} = \frac{|\dot{V}_{bi}|}{|\dot{V}_{bj}|} \quad (1)$$

$$\Delta\theta_{p,ij} = \theta_{bi} - \theta_{bj} \quad (2)$$

where $|\dot{V}_{bi}|$ and $|\dot{V}_{bj}|$ are the magnitude of voltage at the boundary bus, estimated by DSSE $_i$ and DSSE $_j$, respectively; and where θ_{bi} and θ_{bj} are the phase angles of voltage at the boundary bus, estimated by DSSE $_i$ and DSSE $_j$, respectively. Then the states of DSSE $_j$ are corrected, following equations (3) and (4).

$$|\dot{V}_{kj}|_2 = |\dot{V}_{kj}|_1 \cdot V_{p,ij} \quad \text{for } k = 1, \dots, N_j \quad (3)$$

$$\theta_{kj_2} = \theta_{kj_1} + \Delta\theta_{p,ij} \quad \text{for } k = 1, \dots, N_j \quad (4)$$

where the subscript 1, indicate the results of the first step estimation, and 2 the results of the second step estimation; and N_j is the number of buses in the area DSSE $_j$. In case the areas DSSE $_i$ and DSSE $_j$ are not adjacent an alternative

method based on tie lines and boundary measurements can be applied [16]. The advantage in terms of computation time has been tested on a distribution grid, with a MV network of 16 three phase buses and a LV network with 6 buses, and shown in TABLE III.

TABLE III. EXECUTION TIME MADSEE AND DSSE

Method	Average execution Time [ms]	
MADSSE	DSSE-MV	512
	DSSE-LV	45
	Coordinator	14
DSSE		852

It is possible to verify how, even for relatively small network, the MADSEE yields significant saving in the total computation time. The time intervals required for DSSEs, in TABLE III include the operation of measurement collection, bad data processing, calculation of SE and storing of results (all the operations included in “loop state estimation” and shown in Fig. 5). The time interval required for the “coordinator”, in TABLE III, includes reading of MV and LV DSSE results, the algorithm of coordination, storing of updated results and sending of final results to SSAU. TABLE III does not include the time required for the data exchange among measurement units and SAU and between SAUs, as for the laboratory tests done, they were negligible (always <1ms), whereas in field implementation they will depend on the type of communication infrastructure exploited.

D. Fundamental steps in local and multi area DSSE

Each local state estimator acquires the measurements (or reads their periodic reports) and on fixed cycle (in Fig. 5 called “loop state estimation”) perform a series of steps, namely reading measured values and applying Chi-squares test to verify the presence of bad data. In the case of any bad data detected the proposed technique permits to recognize which data are incorrect and substitute them with pseudo-measurements extracted from the SAU database; eventually, the set of measurements is provided to the SE algorithm that calculates the state and stores the results in the database.

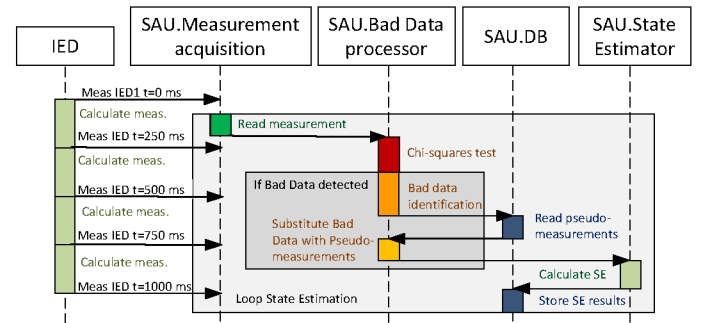


Fig. 5 Diagram of local DSSE

A diagram, representing the steps of the MADSEE, is presented in Fig. 6. Each SAU performs a series of operations indicated in Fig. 5, starting at the same time, thanks to a time synchronization signal provided to the

SAUs. In this work a flag through DNP3 protocol is exchanged to trigger the start of each operation. The results of MV and LV state estimations are provided to the PSAU, where the coordination of the results of MV and LV SE is executed as presented in section III.C; eventually the new results are stored at PSAU database and sent to SSAU.

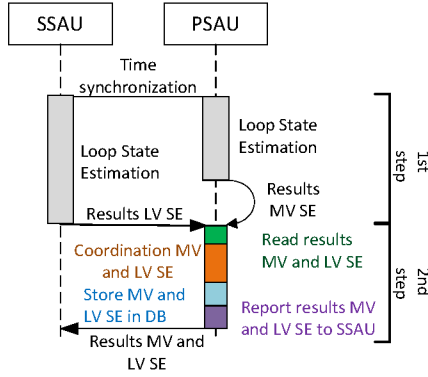


Fig. 6 Diagram of MADSSE

IV. LAB IMPLEMENTATION OF DSSE AND MADSSE

The monitoring system, Fig. 7, has been divided in SAUs, measurement devices and interfaces. The choice of software for interfaces and algorithms together with interfaces and data objects and protocol, represent a contribution to the design. The power system simulation has been realized in order to provide realistic network behaviors as input to the tested monitoring system.

A. Substation automation unit

The substation automation unit (both PSAU and SSAU), is implemented in a lab computer. The software exploited are Labview and KEPServerEX. The only condition to export such SAU to other environments is to have a sufficient computational capability to run the state estimation and Ethernet access to read the measurements. The data provided by the measurement devices in the power grid can be gathered by the OPC (Open Process Control) server (KEPServerEX). LabVIEW is chosen to realize the real time DSSE because it performs stable execution and precise timing thanks to its real time features. The LabVIEW provides various possibilities to manage and store the big data in an efficient way, such as cloud storage, OPC server or SQL databases.

B. Measurement devices and transducers

Measurement devices are connected through an Ethernet local area network to the SAU. In Fig. 1, the IEDs, that in the current lab implementation are software entities programmed in the Real Time Digital Simulator (RTDS), access the mathematical quantities provided by the transducers, and calculate RMSs, phase angles and other physical quantities. The Gigabit Transceiver Network (GTNET) Interface card of RTDS encapsulates in DNP3 messages and delivers to the SAU the mathematical output of the IEDs. The scan rate is 4 Hz. In other words, the

measurements data are updated from RTDS to the OPC server every 250ms. Therefore, the measurements acquisition meets the real time requirements given that the DSSE is realized every 1 second.

In order to reproduce realistic power system conditions the error of transducers and measurement devices has been artificially added in RTDS, assigning them to a certain accuracy class. The error of current and voltage transducers is added to the real value, after being extracted from a Gaussian distribution multiplied by a standard deviation obtained from the maximum error as defined in the standards IEC 60044-1 and IEC 60044-2 respectively. Similarly the error of the measurement of voltage and current phasors, from where other measurements as power are calculated, is obtained assuming a certain total vector error (TVE) as defined in IEEE C37.118.1 standard. In order to verify, in real time, the error of the state estimation, together with the erroneous measurements, also the errorless measurements and the true status of the grid are sent to the SAU.

C. Power system

The power system equations are solved in real time by the RTDS. The model has been implemented in the Graphical User Interface (GUI) of RTDS, including topology, transformer and lines parameters. The active and reactive power injection at the buses varies in real time following realistic profiles of residential and industrial customers created by statistical tools [19].

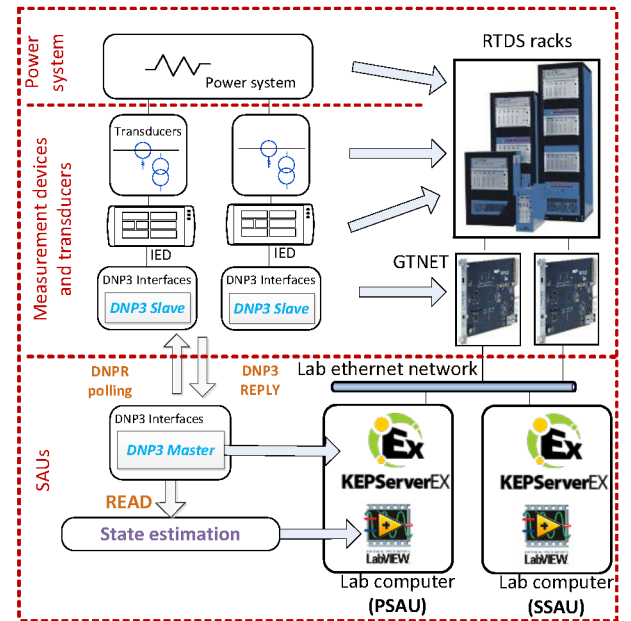


Fig. 7 Lab implementation of real time monitoring system

D. The multi area lab implementation

The two state estimators are performed in two separate computers, respectively for PSAU and SSAU. The two computers are connected to the same LAN, where also the GTNETs cards are connected, as shown in Fig. 7. In real field applications PSAU and SSAU may be connected with

other communication technologies that may bring communication degradation as delays and packet loss. The MV and LV state estimators run separately on Labview environment. The SAU computers are connected to the same local area network and are synchronized with a time resolution of 1 millisecond, using the nanosecond engine (software component to keep track of time within a program) provided by Labview, that is based on IEEE 1588 standard [23]. The event that yields the starting of 1 second MAD SSE loop is the beginning of the RTDS simulation, communicated to the SAUs with a DNP3 message. This step is necessary only in simulations; the state estimation would run every 1 second on the field, regardless of from the events in the grid. When the estimation at the SSAU is completed, the LV SE results are sent, with DNP3 protocol, to PSAU computer, that realizes the second step estimation and sends the results back to SSAU.

E. Data exchange to support DSSE and MAD SSE

There are two sets of data exchanges; one between measurement devices and generic substation automation units, and one between SSAUs and PSAUs for the second optimization step of MAD SSE. The first set of information exchanges contains the grid measurements. Thus, for a grid with N buses, the total number of data exchanges in the first set, would be $m \geq 2 \cdot N$. The second set of data exchange contains the state results and the objective function. Therefore, a total of $2 \cdot N + 1$ pieces of information is to be sent from each area. The IEC 61850 standard include in the logical node MMXU, the data object and attributed to exchange measurements and state results, included the data attribute for the time reference and the objective function; they could be associated to time stamp and quality data attributes respectively.

V. TESTS ON DSSE

The real time DSSE is tested in the previously described lab set up, using the testing platform developed in [4]. A 16 bus medium voltage UK standard radial distribution network [24], shown in Fig. 8, is simulated in RTDS.

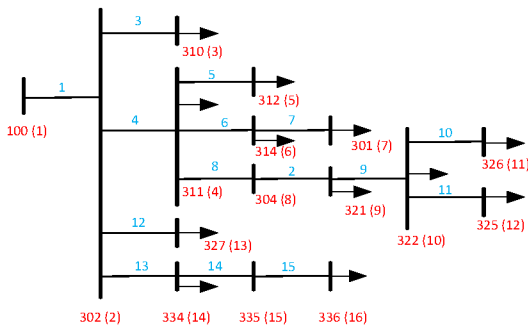


Fig. 8 16 bus UK standard radial distribution network

The following tests present the error of the state estimation in time for all the buses in the grid. Indeed, given that the system is tested in real time, the power loading conditions, as well as the working condition of the

components forming the measurement chain, are different, and consequently the state estimation errors are not suitable to be used for uncertainty evaluation. Consequently, the tests results provide only an understanding of the accuracy of the real time monitoring system based on DSSE. However, real time testing permits to verify if the monitoring system works properly; in other words, if the errors stay under a certain threshold for the time window analyzed and if the real time objective is met [4]. Through the "Scheduler" blocks, the power profiles can be imported to the grid. In this test cases, 13 loading schedules are considered, which are changed automatically every second. Industrial customers are connected at buses 2, 3, 5, 6, 7, 10, 11; whereas residential customers are considered at buses 4, 9, 12, 13, 14 and 16. The power injection, in the buses where residential customers are installed, is obtained by aggregating a number of individual LV power profiles proportional to the total nominal installed power indicated in [24]. All the following test cases are performed over one day of a typical spring working day, where 6 minutes of the 24 hours are simulated in 1 second in RTDS. In order to check the network operating conditions, it is possible to see the active and reactive power flow at the power transformer connected at bus 1 in Fig. 9.

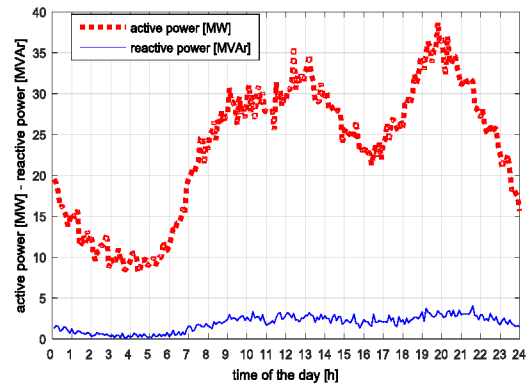


Fig. 9 Active and reactive power flow at the HV/MV power transformer during one day

In all the test cases the measurement provided are three phase voltage magnitudes and voltage phase angles at buses 2, 6, 10 and branch current magnitudes and phase angles at the branches between buses 1-2, 2-3, 2-4, 2-13, 2-14, 4-6, 4-7, 9-10, 10-11 and 10-12. The measurements are received every 250 ms; the DSSE is performed every second and exploits the last available measurement. The reporting rate of 4 frames per second is not usual for PMUs, but is the largest reporting rate available for the GTNET interface card of RTDS. Nevertheless, the standard IEEE C37.118.1 states that the actual PMU rate may be user selectable. Considering that the state estimation processes the last available measurements from each device in the given time window, higher reporting rates from PMUs may yield to better results (particularly in case of fast changes of network state) than the ones presented in the following sections. The transducers simulated in RTDS have accuracy class 0.2 both for current

and voltage, whereas the measurement is provided with TVE = 1%. An error, extracted from a Gaussian probability curve with standard deviation equal to one third of the aforementioned declared maximum errors, is added in the simulation environment [4] to the actual voltages and currents in order to emulate the accuracy behavior of transducers and measurement devices. The pseudo measurements are present in all the buses, except for the slack bus. Pseudo-measurements are obtained by the standard load profiles for residential and industrial customers in UK [24]; their time resolution is half an hour. The DSSE expects maximum error 1% for voltage and current magnitude and 1crad for voltage and current phase angle measurements [12]; active and reactive power injection pseudo measurements are expected to have maximum error below 100% [19]. The expected maximum errors are converted to standard deviation information, assuming a Gaussian distribution of the error and coverage factor equal to three. The standard deviations are squared in order to obtain variances and then inverted in order to populate the covariance matrix for the WLS method. The tests presented will be: A. reference case; B. Presence of Bad Data and use of bad data processor.

A. Test A

The test A represents the reference case. In Fig. 10, the results in terms of relative error of bus voltage magnitude and absolute error of bus voltage phase angle at phase A for every bus in the grid is presented for 4 representative times of the day (0h, 6h, 12h and 18h). It is possible to see how different times of the day exhibit different quality of the estimation, due to better or worse pseudo measurements and different actual loading condition of the grid. Observing Fig. 10, it is possible to notice that the error for the whole duration of the test is included in the uncertainty interval determined in [12] as a function of the uncertainty of the input measurements, as no other degradation phenomena (e.g. large error of measurement devices, communication delays or failure of measurement devices) are present.

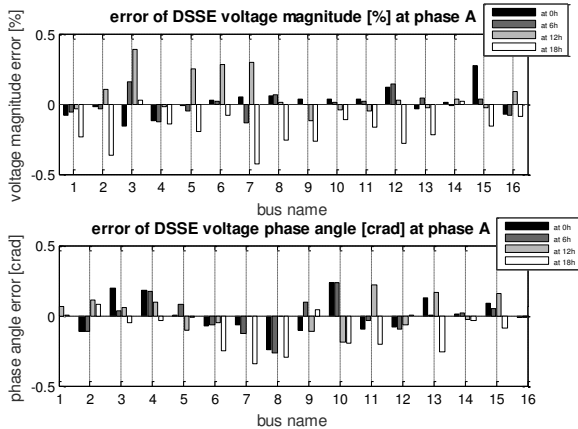


Fig. 10 Relative error of bus voltage magnitude estimation and absolute error of bus voltage phase angle estimation during one day in all the A phases of the grid buses

B. Test B

In test B, the effect of bad data is evaluated, with and without the usage of bad data processor. For this test, the degradation that is provided to the monitoring system is an error in some of the input measurement larger than the one expected by the DSSE. The actual maximum error for the PMU installed at bus 6 is, for bus voltages and branch currents, 10% for magnitudes and 10 crad for phase angles, whereas the DSSE expect a maximum error of respectively 1% and 1crad. In Fig. 11, the results of the state estimation, in terms of relative error of voltage magnitude estimation are compared for the case with and without BDP. It can be observed that the error, for the case with BDP, is maintained within the range $\pm 0.5\%$, whereas without BDP it increases up to $\pm 0.8\%$. Therefore, the use of the proposed bad data processor shows to guarantee high reliability and robustness against large error in measurements to the real time DSSE. It is worth considering that degradation in the input measurements in the range of the ones used for this tests, may be due to delay in communication (if the measurement does not have a time tag) or to slow reporting rates, in case of dynamic evolving voltages and currents. Also in this case the BDP, may help reducing the overall error of the state estimation.

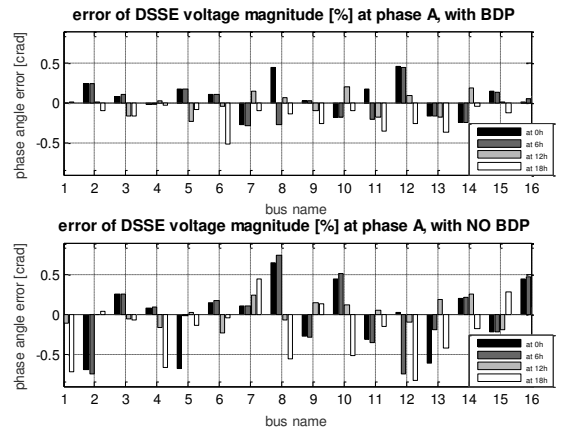


Fig. 11 Relative error of bus voltage magnitude estimation during one day in all the A phases of the grid buses, in presence of bad data, using and not using bad data processor

VI. TESTS ON MADSSE

The modular approach considering MV and LV grid and therefore separate estimations with multi area case is here considered. The single area DSSE previously tested, is compared with the MADSSE, in particular, with regards of error in real time. The test case with a distribution grid, composed by MV and LV part is considered. For the MADSSE case the DSSEs are performed separately in two local estimators respectively at PSAU and SSAU computers; consequently the second step optimization is performed at PSAU computer. The MV grid considered is the one presented in section V. A portion of LV grid is considered to be connected to MV bus 9, as shown in Fig.

12. The LV grid is obtained from the data of a real LV grid from “A2A Reti Elettriche SpA” DSO in Italy.

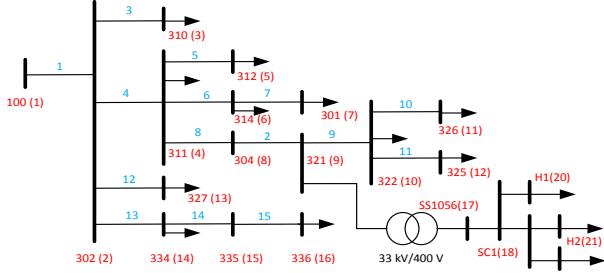


Fig. 12 MV and LV distribution grids

The measurement configuration of the MV grid is kept as in section V, whereas in LV A PMU is placed at bus 17, which is the secondary side of the MV/LV power transformer. Actual errors of PMU measurement device and transducers, as well as expected error are the same as the one described in section V. The measurements are received every 250 ms; the DSSE is performed every second and exploits the last available measurement. For the MADSSE case, as soon as the LV estimation is performed, the results are sent to PSAU computer for the second step. Both for single DSSE and MADSSE the real time objective of 1 second is met. The results are shown in Fig. 13 and Fig. 14 for what concerns the error during time at phase A of bus 1, in MV, and phase A of bus 17, in LV grid. Fig. 15 instead shows the Root Mean Square (RMS) errors over time at all the buses, both from MV and LV grid.

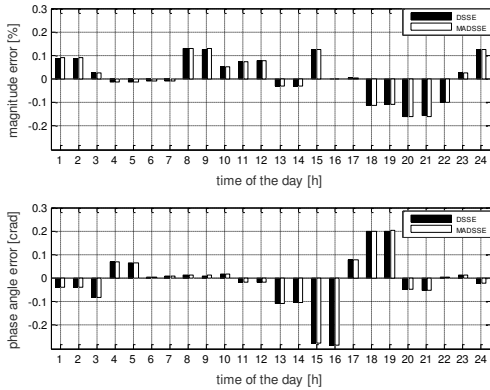


Fig. 13 Bus voltage magnitude and phase angle error at bus 1, phase A

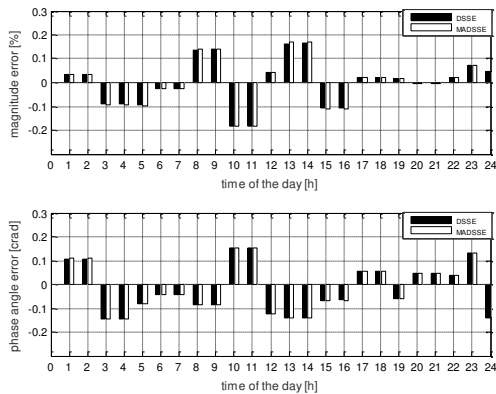


Fig. 14 Bus voltage magnitude and phase angle error at bus 17, phase A

The real time estimation error in buses 1 and 17, is heavily influenced by the PMU transducer and measurement error, which has been emulated in simulation in the RTDS environment. In the other buses, as shown in Fig. 15, a further contribution to the estimation error is due to the pseudo measurement error. This is due to the difference between the standard load profile available at the DSSEs and the real active and reactive power consumption implemented in RTDS, which simulates realistic MV and LV power consumption; hence causing over- or under-estimations of the real RMS voltage.

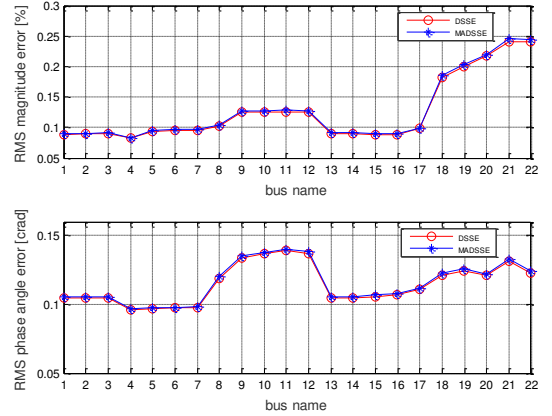


Fig. 15 Averages of absolute values of bus voltage magnitude and phase angle errors in time for phases A of MV and LV grid buses

It is possible to see that the results in terms of accuracy are slightly better for DSSE case, but the difference is generally negligible. Instead, the computation time, as presented in TABLE III is significantly improved. The better performance, in terms of execution time, is going to be more important with a larger size of the networks as in typical distribution networks, with hundreds of LV buses connected to each MV bus, the real time objective of 1 second, required to automatically control DERs, will not be satisfied.

CONCLUSION

In this paper a process design of a real time DSSE is proposed based on the requirements of accuracy, real time operation and robustness. The design choices connected to the optimization of the aforementioned three parameters are shown, namely the type of DSSE, the bad data processor, and the multi area implementation. For what concerns, implementation details, the substation automation unit has been presented, in terms of software for interfaces, database, state estimation and bad data processing algorithms. A further step towards optimization of time efficiency and robustness is done with the proposition of multi area DSSE in two separate lab computers, with real time data exchange of state estimation results and flags for synchronization of operation. The multi area partition of the network is based on the voltage level, having therefore the low voltage

estimation results, periodically reported to primary SAUs where the second optimization step is performed. The monitoring system as a whole is tested in the real time lab environment, simulating realistic power system conditions and is proved to furnish reliable results during the time window of the test in stress conditions as presence of bad data. The exploitation of the BDP shows to improve the accuracy of the state estimation in presence of non-expected large errors up to 30% in many of the network nodes. The tests show that dividing the DSSE in smaller SE areas does bring only negligible degradations in the quality of the results, also when considering real time implementation. On the other hand, the MADSSSE shows to spend in average 581 ms, versus the 852 ms of the DSSE, to perform the estimation of a 22 buses distribution network; presenting, therefore, promising time saving margins for larger size grids. Furthermore, with the MADSSSE, in case of missing measurements, and consequently lack of observability, only the area affected by such issues is no longer observable, whereas the others may continue to be monitored. When the MADSSSE approach is linked with the automation approach of dividing the control measures in voltage levels, exploiting the local DERs and On Load Tap Changers [3], a large increase in the overall robustness of the automation system is expected.

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