HiPerDNO

High Performance Computing Technologies for Smart Distribution Network Operation

FP7 - 248135

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Report on Use of Distribution State Estimation Results for Distribution Network Automation Functions, D2.2.1

Executive Summary

The introduction of near to real time state estimation in electricity distribution networks will enable new monitoring and control functionality, providing increased distribution network automation. This will be inherent in the development of smart grids and will rely on the application of high performance computing and advanced communication infrastructures to meet the challenges of scalability for large-scale practical implementation.

This report will discuss how the output results of the Distribution State Estimation will be used to drive various network automation functions, including: network restoration (post-fault), real-time system monitoring, energy loss minimisation, outage management via 'what-if' network analysis, security assessment, voltage / reactive power optimisation, generator and load control and intelligent energy storage management. Some of the issues considered in the report are: effect of the level of precision in state estimates, topology determination (the mapping between a 'bus-breaker model' and a 'node-branch model'), effects of dynamic changes in topology, data volumes and flows, task execution frequencies and timing. The report also describes the functionality of the automation tasks.

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Abstract	Real-time state estimation in electricity distribution networks will enable new monitoring and control functionality, providing increased distribution network automation. This will rely on the application of high performance computing and advanced communication infrastructures to meet the challenges of scalability for large-scale practical implementation. This report discusses how the output results of the Distribution System State Estimation will be used to drive various network automation functions and will also briefly describe the functionality of the various automation tasks.			

Keywords	Distribution Network Automation Functions, DMS, Distribution State Estimation

Contents

Introduction

Although distribution state estimation (DSE) provides a very useful role in itself by providing network operators with improved, consistent and complete information about the present operating state of their network, many of the benefits from DSE will arise from its ability to drive additional network automation functions [1]. This report will consider the functional interface between DSE and distribution network automation functions (DNAF). Network automation functions to be considered include: network restoration (post-fault), real-time system monitoring, energy loss minimisation, outage management via 'what-if' network analysis, security assessment, voltage / reactive power optimisation, generator control and intelligent load management. The technical issues considered in the report are: topology determination (the mapping between a 'bus-breaker model' and a 'node-branch model'), effects of dynamic changes in topology, data volumes and flows (and their impact on the requirements of the communications infrastructure), task execution frequencies and timing, the availability of suitable algorithms and methods [2], the benefits of high performance computing (HPC) and advanced communications. The report will also briefly describe the functionality of the network automation tasks. A detailed analysis of the effects of state estimation errors propagating into the (loadflow) models used by DNAF is presented. Case studies on the impact of state estimation on voltage control and the benefits of near-to-real-time state estimation for intelligent control of energy storage are also presented.

Overall Structure

An outline overall structure for the interfaces between DSE and DNAF is shown in Figure 1.

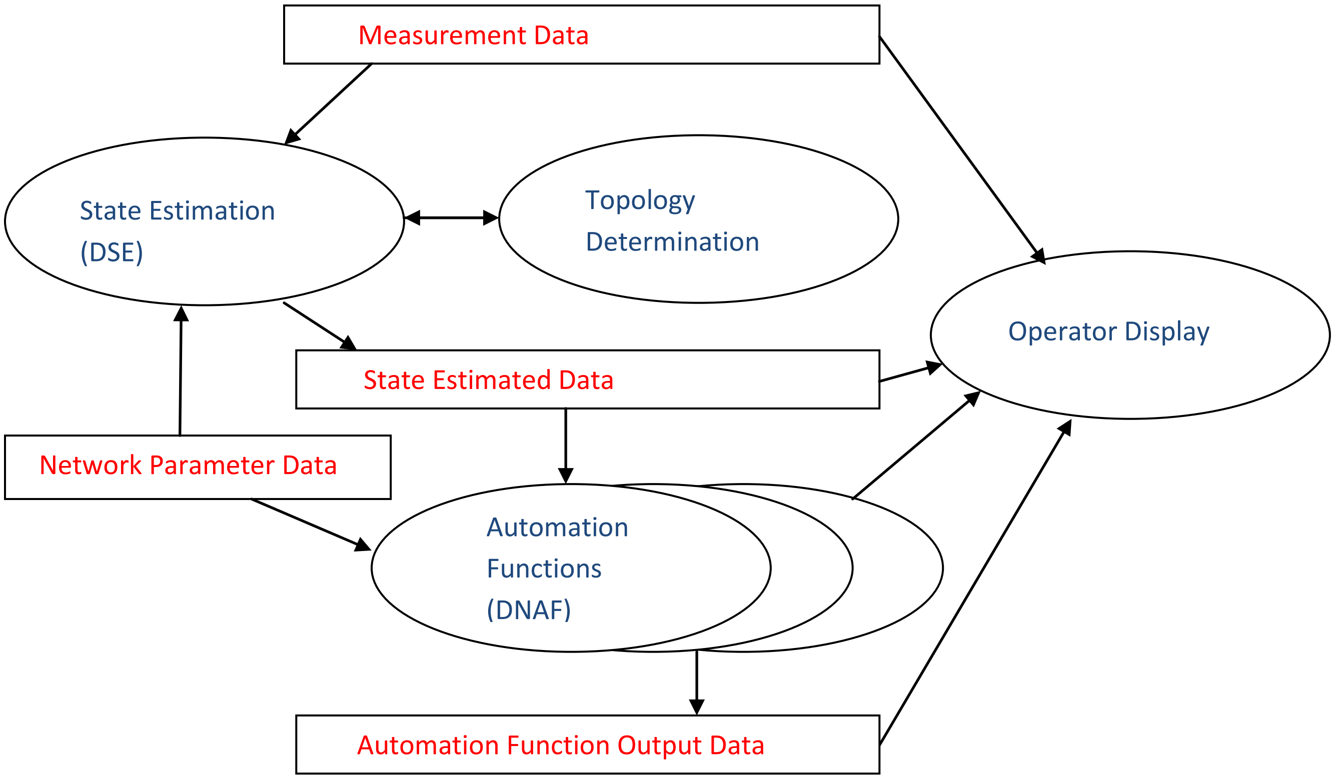

Figure 1: Outline Structure of DSE and DNAF Interfaces (red text indicates databases, blue text indicates functions)

The automation functions can be divided into three priority classes. Following a protection operation and switching event in the network, the highest priority task (after state estimation is completed) is the Network Restoration function (when and if required). This may require further restorative switching operations to be executed. Once this has been concluded a series of 'foreground functions' (real-time system monitoring, outage management, voltage/reactive power optimization, generator and intelligent load control) can be executed, followed by lower priority background functions (energy loss minimization, security assessment). Figures 2 and 3 show example time sequences of task execution; when additional switching is not required (Figure 2) and when a restoration sequence has been invoked (Figure 3). It should be noted that the results of any of the tasks are invalidated by the occurrence of a further significant switching event. Enough computational power must therefore be available so that all the relevant tasks can be completed in the 'typical minimum' time available between switching events. Under severe conditions (e.g. during a storm) the time elapsed between successive events could be of the order of minutes. If no events occur within a defined period (e.g. half an hour) all the tasks would be automatically re-run to allow for gradual changes in the network state.

The output results of the State Estimator provide a complete and consistent loadflow model for use by all the automation functions. The effect of imprecision in this model is therefore paramount. An extensive study, undertaken by EDF, which analyses the uncertainty produced in the resulting loadflow model as a consequence of various levels of measurement accuracy provided to the estimator is presented in a later chapter.

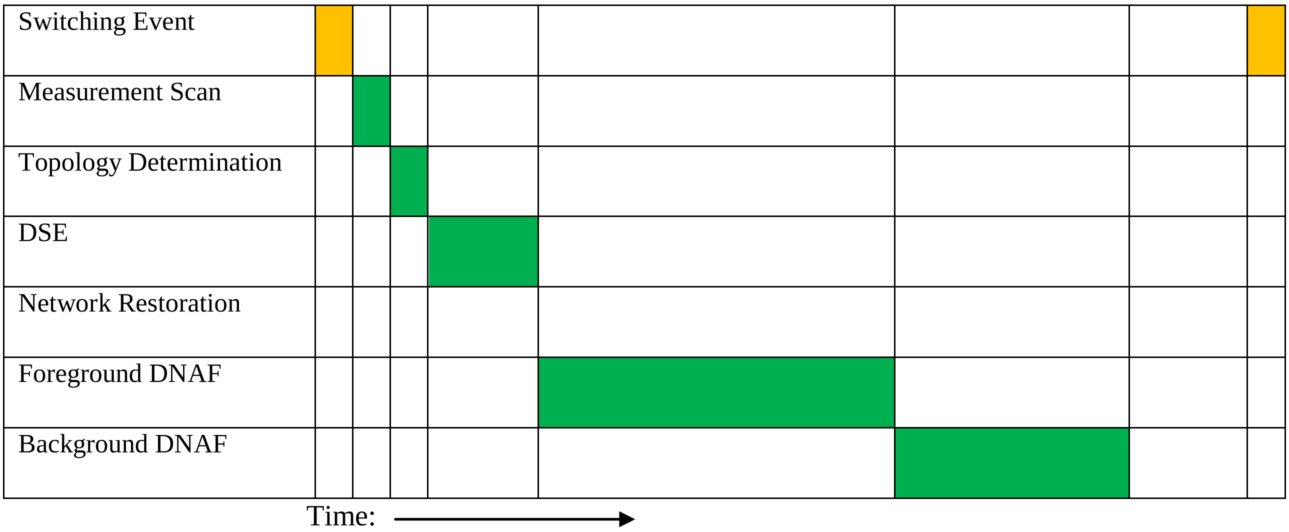

Figure 2: Example Time Sequence of Tasks (No Restoration Switching Required)

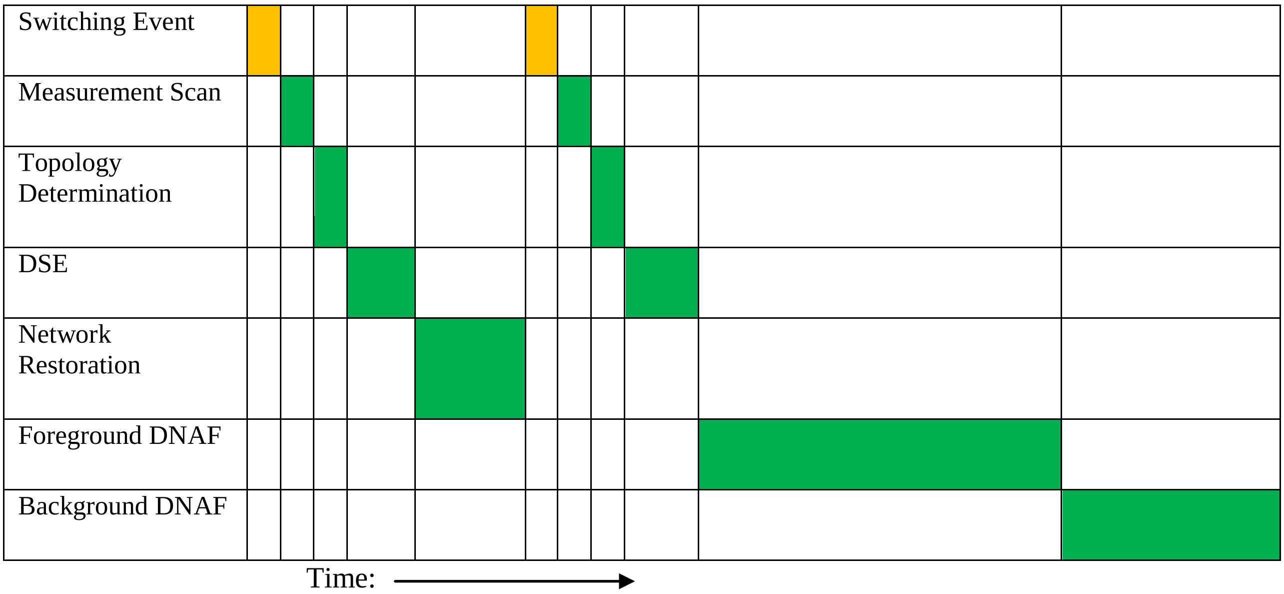

Figure 3: Example Time Sequence of Tasks (Restoration Switching Invoked)

Network Restoration

Functionality

Following a network fault and subsequent equipment outages, the network restoration function assists the operator by proposing switching sequence(s) to restore as much load as possible, consistent with a safe and secure new running arrangement.

Interface to DSE

The network restoration function must perform a sequence of loadflow analyses to examine the feasibility and optimality of each step within a possible switching sequence. Hence, the basic data for the initial loadflow analysis must be provided by DSE. Since the DSE is itself based on an AC loadflow model, the initial data provided is guaranteed to be consistent and complete. Consistent means that all the state variables and network parameters conform exactly to Ohm's Law and Kirchhoff's Laws, and complete means that data is available for every state variable and parameter in the AC network model.

It is expected that a real-time data base will store the latest state estimation results and this will be available for read-only access by applications such as the network restoration function. The switching analysis within this function will necessarily be based on a detailed model of busbar and switch arrangements and it is therefore necessary for a topology analysis function to be performed in conjunction with the state estimation model (which operates internally using a node-branch model).

The results produced by the restoration function are only valid if no further changes in network topology have occurred since the state estimation 'snap-shot' was obtained. If a further switching event has occurred the current solution should be aborted and a new run executed after an updated state estimation snap-shot becomes available. Significant time-stamping (or some other form of synchronisation) of internally generated data is therefore required. (Analogue data usually changes relatively slowly and the availability of new measurement scans or state estimation results would not necessarily invalidate the outputs of the application.)

The data requirements from DMS of Network Restoration Algorithm are shown in the following table (from Indra):

Data	**Description**	**Origin**
Failure location: substation/Transformer/feeder	The failures that the algorithm must solve are characterized by loss of any substation, any HV/MV transformer or any feeder	User (in case of simulation) or DMS Event Module (in case of real time)
Network Data (Static)	Node-Branch model of the network possible connected with the failures specified.	DMS Facilities Database and network model generator module
Switching Elements Data (Static)	Switching capabilities, Type of control and position (related with network node-branch model) of each switching element in the previous network	DMS Facilities Database
Network Data (Dynamic)	Better estimation of: - PQ load on each MV/LV transformer - PQ Injection on each distributed generator. All of them must be the latest known <u>before the failure for the faulted section</u>.	DMS State Estimation Module
Switching Elements Data (Dynamic)	State (opened/closed) of each switching element <u>before the failure.</u>	DMS SCADA connection

Table 1: Data Requirements of Network Restoration Algorithm

The following diagram (from Indra) shows how the Service Restoration algorithm should integrate into a DMS, and the interactions with other processes to receive all necessary input data.

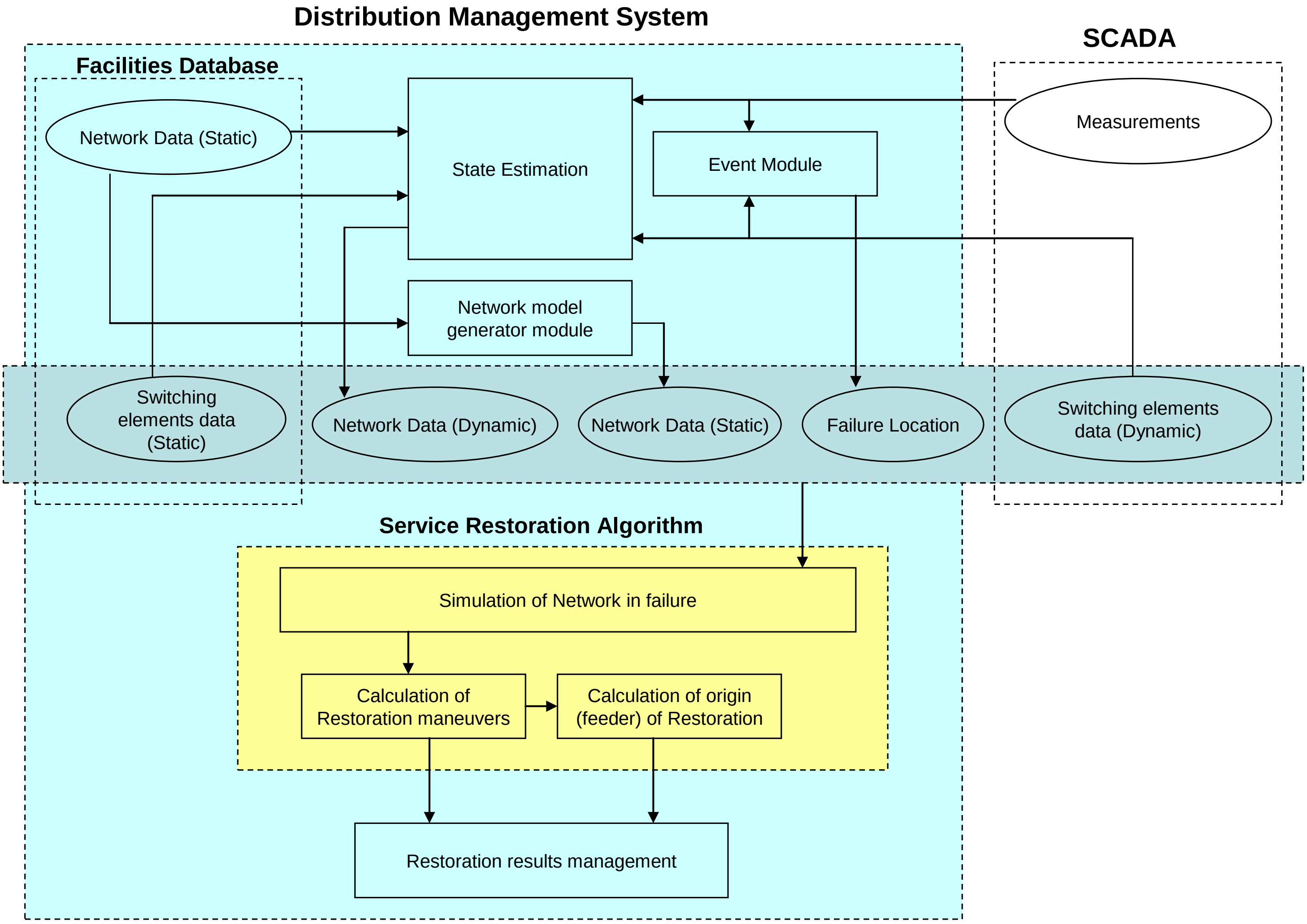

Figure 4: Service Restoration Algorithm Integration

The accuracy of dynamic data inputs to Service Restoration Algorithm can determine the quality of its results. In general terms, the following sensitivity effects are present:

1) Errors on Switching elements state

These are the worst possible errors in input data for Service Restoration, because only one incorrect state can change the entire solution.

In this sense, it is highly recommendable that DMS has some checking algorithms over the states, against the normal state defined in facilities database. Prior to a failure event, it is foreseeable that the state of each element is equal to its normal state. If this condition is not fulfilled by any switch (inside the network considered in the restoration problem), this should be warned to the user in order to evaluate the solution of restoration algorithm

2) Errors on loads and injections estimations (DSE results)

The effect of these errors depends strongly on load level related to rated values in the different network elements.

In any restoration problem there is a reference solution, which is that computed with no voltage/overload constraints and guarantees a total restoration. If this solution is discarded by the algorithm due to violations of the constraints, this leads to another solution worse in terms of number of manoeuvres, time of restoration, less balance between feeders, or even, the impossibility to achieve total restoration. Therefore, an incorrect evaluation of the fulfilment of constraints due to incorrect load values, can change the solution to a worse option.

To minimize this problem, in case of rejection of reference solution, Service Restoration Algorithm will provide the user not only the estimated better alternative solution, but also the reference solution, with the constraints violations detected, and the estimated amount of under-voltage or overload.

Algorithms

In general a range of algorithms are available for this function, usually based on modern heuristic methods (such as Genetic Algorithms, Particle Swarm Optimisation, etc.) and suitable algorithm(s) are being researched within HiPerDNO (see WP2.3).

Automation Level

Network switching is safety-critical and mission-critical for any Distribution Network Operator. Consequently, it is presently required to incorporate a human expert 'in the loop' to validate the computer generated switching sequence before it is implemented via SCADA. In this context it can be useful if the automation function is able to produce more than one possible 'solution', so that the operator is given a range of options to choose from.

Limited fully automatic switching is already present in networks (in the form of auto-reclose and inter-tripping schemes). It seems likely that more extensive automations of this type will gradually be introduced as a component of smart grids in the future.

High Performance Computing and Communications Infrastructure

Operators want to receive suggested switching options with a few seconds of fault occurrence. This represents a severe challenge to currently available algorithms, which typically require at least a few minutes of computing time for larger network problems. The use of HPC will be very beneficial in this application, once suitable parallel processing algorithms are developed. If the DSE and DNAF are implemented in a distributed format, significant communications between processing nodes would be required. Therefore we would need to make use of well known programming paradigms within the HPC community of either MPI or Shared memory. These allow for high bandwidth - low latency connections between processing units to be used, thereby allowing for the necessary inter-node communication to occur with minimal impact on the speed of operation of the DSE and DNAF. The communications infrastructure would need to maintain the consistency and availability of the various near to real time databases among the distributed application processes.

Real-time System Monitoring

Functionality

SCADA systems are conventionally used for real-time monitoring of distribution networks. Typically various quantities are not measured (particularly at lower voltage levels). The availability of DSE derived data will give the operator an enhanced image of the conditions in the network. Limit checks and alarm settings may also be attached to state-estimated outputs to warn the operator of previously unobserved overloads, under-voltages, etc.

Interface to DSE

The shared storage area for SCADA data would be extended to include state estimated output data.

Algorithms

No substantial algorithms are required for this function.

Energy Loss Minimization

Functionality

During normal running of the network it is desirable to keep energy losses in the network to a minimum, subject to other operational and technical requirements. The selection of transformer tap positions and the operational status of any capacitors or reactors will be considered as part of a voltage and reactive power optimisation function (see later section of this report). However, there is often some degree of freedom in the selection of normally-open-points to minimise losses, provided that operational flexibility and security are not compromised.

Interface to DSE

This function is very similar to the network restoration function with respect to interfaces.

Algorithms

Similar (or even identical) algorithms to the network restoration function can be applied.

Automation Level

It is unlikely that this function would ever be fully automatic, but an advisory function would be very useful. It is expected that energy loss minimisation could be a 'background task' to be applied when there are no faults or scheduled switching operations requiring attention.

High Performance Computing and Communications Infrastructure

The same comments apply as for network restoration, except that this is a lower priority task. Slightly longer computing times would therefore be acceptable.

Outage Management

Functionality

An important on-going task in distribution network operation is the planning and implementation of network outages for maintenance purposes. Prior to implementing the deliberate outage of any item of equipment, the operator would wish to simulate the post-outage state of the network (i.e. using a 'what-if' loadflow analysis). This would quantify the level of risk involved in taking the outage (e.g. how close does the network come to an overloaded or some other 'out-of-limits' condition) during the period of the outage.

Interface to DSE

The requirement here is for a real-time loadflow based on state estimated data. Topology assessment is again needed to analyse the effect of operations at switch-busbar level on the AC network model (at node-branch level). Additionally, an operator interface is required (possibly via SCADA) to introduce these hypothetical switching operations into the simulated 'what-if' model. Ergonomically, it would be important to distinguish clearly between actual switching instructions and hypothetical simulated operations. This could be done for example by a significant change in screen background colour.

Algorithms

The basic tool here is essentially a real-time AC loadflow. For AC loadflow applications, it is conventional to consider a balanced three-phase model. However, for low voltage networks and other networks with significant unbalanced loads (e.g. electrical traction supplies) it would be beneficial to apply an unbalanced three phase loadflow. The very limited availability of phase-related data in practice reduces the scope for unbalanced analysis at present.

More advanced options, which aim to quantify the risk to network security and to suggest optimised plans for a sequence of outages could also be considered.

Automation Level

This would be used in advisory mode initially, but particularly the more advanced tools could eventually be introduced within the autonomous operation of a smart grid.

High Performance Computing and Communications Infrastructure

The basic loadflow-based tool envisaged would not impose any severe computational issues, but the more advanced tools (which consider uncertainty/risk and which may optimise a complete maintenance plan) would be very large complex optimisation problems (e.g. stochastic mathematical programs or large-scale constraint satisfaction problems) and would require HPC to meet realistic performance targets.

Security Assessment

Functionality

In a power network, at any time, an outage may occur in which one (or more) items of plant become disconnected as a result of a protection operation. Security assessment is an algorithmic function, widely applied at transmission network level, which analyses the consequences of every hypothetical outage. This is usually referred to as N-1 security analysis. Since most distribution networks are mainly radial, almost all outages will result in a loss of supply to customers. However, application of a security assessment function may still be worthwhile, for the following reasons: to assess the impact of the forced outage of one of a set of parallel transformers, to analyse the effect of any outage on voltage levels in the remaining network. This limited range of security analysis studies could be provided by an automatically generated sequence of 'what-if' loadflow studies.

More ambitiously, the results of each N-1 outage study could be further considered (hypothetically) by the network restoration module, to assess the overall impact of any outage and to examine whether subsequent restoration could be achieved without long-term loss of consumer load.

Interface to DSE

This aspect is similar to outage management.

Algorithms

Specialised loadflow techniques are available which can screen outages in order of highest to lowest impact on loading and voltages, and which can perform a full AC analysis of an outage case from a warm-start provided by the 'base case' (intact network) loadflow.

Automation Level

Where security assessment is provided, it usually runs on a timer cycle, with a cycle period of about 30 minutes. It is also possible to schedule a security assessment run automatically following any major switching event in the network (synchronised to wait for updated state estimates). The results are prioritised and displayed to the operator for information about the level of risk implied by the current network loading and configuration.

High Performance Computing and Communications Infrastructure

A very large number of security cases may need to be studied. In principle, a network with N plant items implies that N separate loadflow analysis studies need to be performed for each security assessment run. The use of HPC would be very effective here since each N-1 loadflow analysis is independent of the others (although each can benefit in convergence speed by using the results obtained for the base case as a starting point).

Voltage / Reactive Power Optimization

Functionality

The controllable variables in a distribution network include: transformer tap position, on/off status of any capacitor or reactor banks, voltage target settings of any generators in voltage control mode. In the future it is likely that more controls will be introduced within smart grid initiatives (e.g. mini-FACTS devices, power quality conditioners, etc.). This automation function will apply a constrained numerical optimisation technique to select the best settings of all controllable variables to minimise energy losses (or some other target objective such as maximising voltage security).

Interface to DSE

Again the requirement is for a near to real time loadflow model. The voltage / reactive optimisation function would typically run as a background task on a timer cycle (say every 30 minutes). Since the results may be effectively invalidated by a topology change, a new run would be required after a switching event. However, this would be at a relatively low priority and could wait until high priority tasks such as network restoration have completed.

Algorithms

This function is similar to optimal power flow functions which are widely used at transmission level. There is a choice between mathematical programming based approaches (such as nonlinear interior point methods) and heuristic methods (such as Genetic Algorithms, Differential Evolution, etc.)

Automation Level

This function would be entirely automated, as the operator would not be interested or have time to validate the large number of output decision variables. Some additional operator control functions, to fix some variables manually, and to (temporarily) remove them from the optimisation process, would be needed to allow for special circumstances.

High Performance Computing and Communications Infrastructure

Even at transmission level, where the number of circuits and nodes are many fewer than at distribution level, this type of optimisation problem is currently regarded as a major computational challenge, in terms of both speed of solution and robustness of convergence. The use of HPC would probably be essential to allow this type of function to be applied extensively at distribution level.

Generator and Intelligent Load Control

Functionality

Distribution networks are seeing a rapid penetration of embedded generators and more intelligent controllable loads. Up to a certain penetration level, embedded generators and controlled loads can be regarded as ‘fit and forget’ and allowed to determine their own independent schedules and control actions. Once the penetration level reaches a significant proportion of the total load it becomes essential for the distribution network operator to exert more control on the output and on/off scheduling of such devices. This automation function, which is similar to constrained economic dispatch and generator scheduling at transmission level, will optimise the controllable variables to achieve secure and economic network operation.

Interface to DSE

A full AC loadflow model is required, and for this application the estimated active and reactive power injection at each node with an embedded generator or intelligent load is particularly significant. It is expected that this function will operate on the usual cycle time (of say 30 mins) but may also be triggered to run by a topology change or by any significant change in nodal injection, as detected by the estimator. The task runs at a lower priority than network restoration, but at a higher priority than loss minimisation since load / generation imbalance requires timely correction to avoid overloads and voltage excursions in the network.

Algorithms

Existing algorithms which are well known at transmission level (optimal power flows) are generally efficient up to the order of 1000 nodes and 200 controlled injections. This would be adequate for individual zones in a distribution network. It would be necessary to avoid the active /reactive decoupling assumed in many transmission-level packages, as this assumption is defeated by the high R/X ratios present in distribution feeders.

Automation Level

In this respect, this function would be similar to the voltage / reactive optimisation, in the sense that too many control variables need to be adjusted to allow convenient intervention by the human operator (except for temporary over-ride conditions).

High Performance Computing and Communications Infrastructure

This type of function is already regarded as very challenging at transmission level, where the inclusion of outage case constraints (to guarantee network security) is still a research topic rather than an everyday application. HPC will have a very significant role to play in computing solutions within a minute or so every half hour. The associated advanced communication infrastructure will clearly be essential to provide the necessary bandwidth and low latency links between the parallel computational algorithms.

Analysis of the Effects of State Estimation Precision

The connection between DSE results and other automation functions has been studied in WP2.2. As DSE results will be used as input of automation functions, it is very important to know the sensitivity of this automation functions to erroneous data. This sensitivity will determine the precision requested by DSE results.

This chapter, prepared by EDF, presents the approach that must be applied to each automation function to determine their sensitivity to erroneous data. As most automation functions are based on OPF calculations, it has been decided to apply the proposed approach to a load flow analysis. Case studies consider different assumptions regarding PQ errors (PQ is the active and reactive power consumed at each MV/LV substation).

This section presents the network used to run load flow analysis and the results obtained with different error hypothesis.

Network Description

The network used for tests is a rural network with four primary substations connected to a common 63 kV transmission system:

- In substation n °1,
  - There are two power transformers, 20 MVA each,
  - Power flow inside those transformers is 13.8 and 14.6 MVA,
  - Short circuit power of the upstream network is 446 MVA
  - The feeders of this substation is secured by three others (2, 3 and 4),

- In substation n °2,
  - There are two power transformers, 20 MVA each,
  - Power flow inside those transformers is 4.44 and 3.95 MVA,
  - Short circuit power of the upstream network is 403 MVA.

- In substation n °3,
  - There are two power transformers, 20 MVA each,
  - Power flow inside those transformers is 11.5 and 14.2 MVA,
  - Short circuit power of the upstream network is 398 MVA.

- In substation n °4,
  - There are two power transformers, 36 MVA each,
  - Power flow inside those transformers is 28.8 and 12.1 MVA,
  - Short circuit power of the upstream network is 897 MVA.

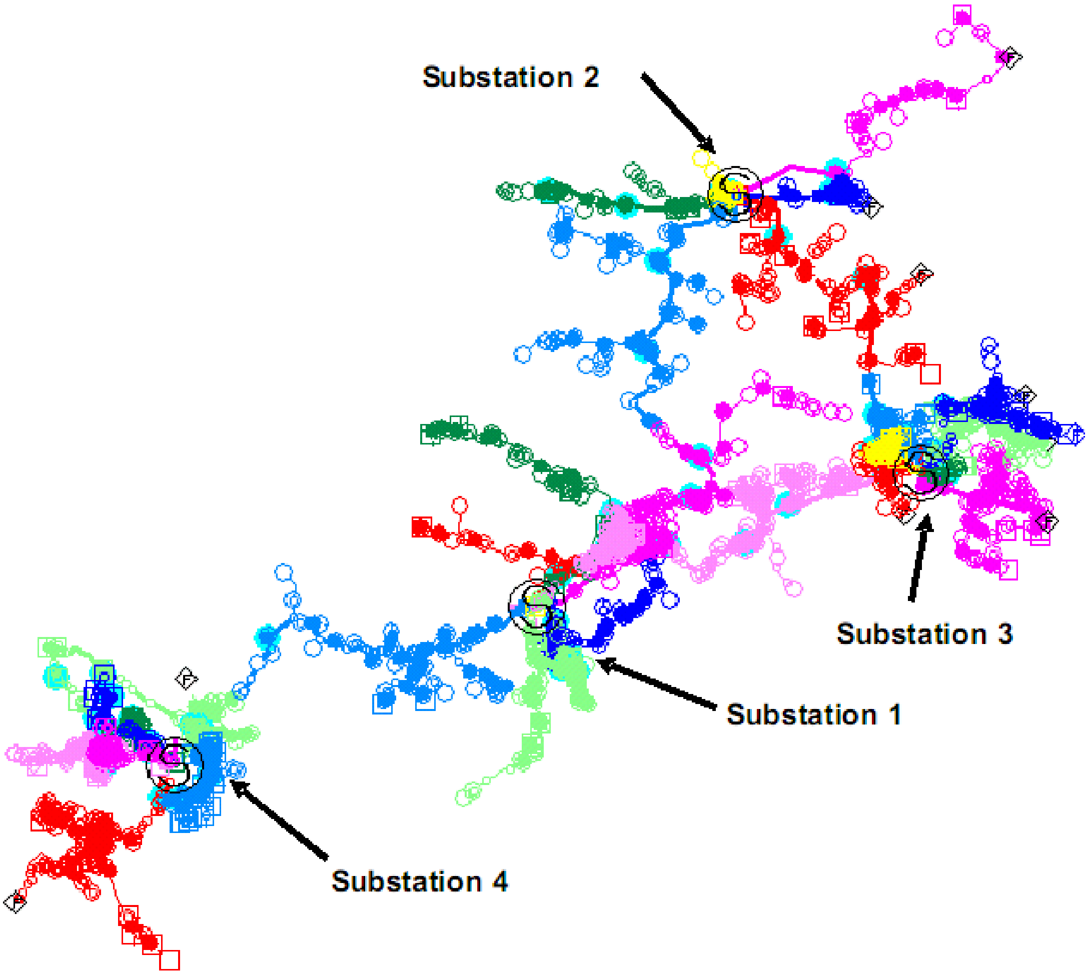

Figure 5: Geographical distribution for rural area

Appendix 1 provides general information for each MV feeder.

PQ Errors Normally Distributed

This chapter presents results obtained when the errors of the PQ loads are considered as a normal distribution centred on the real value. Three different standard deviations have been chosen (the errors correspond to 10%, 30% and 50% of the mean).

For each MV feeder three different network operating points have been chosen to define real values[1] (this defines the base case). For the same network, errors are modelled for each active and reactive power consumed at each secondary substation. 100 load flow are run with different errors. Detailed results are available in Appendix 2. The results of these tests are illustrated in Figure 6 for mean errors[2] and in

[1] These three network operating points have different load consumptions and different power flows.

[2] The mean error is the mean value of errors of all nodes of all load flows analysis

Figure 7 for maximum errors[3] of voltage amplitude. For most part of the feeders, voltage errors are not very important as errors of different loads compensate between them. Feeder F_1_7 has an important error due to a large DER connected to the feeder and considered as not measured (its production is also erroneous). It is also possible to see how the error (mean and maximum) of voltage amplitude increases when errors of PQ loads increase.

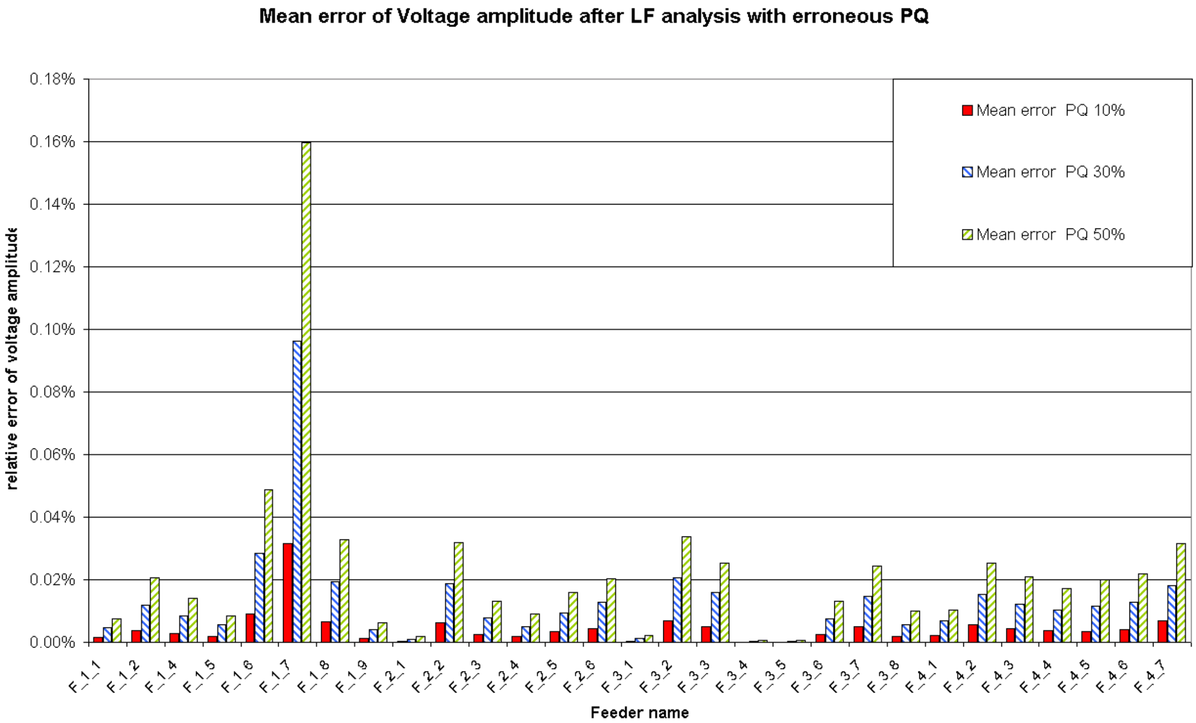

Figure 6: Mean error of voltage amplitude after a LF analysis with erroneous PQ (10%, 30% and 50%)

[3] The maximum error is the maximum value of errors of all nodes and all load flows

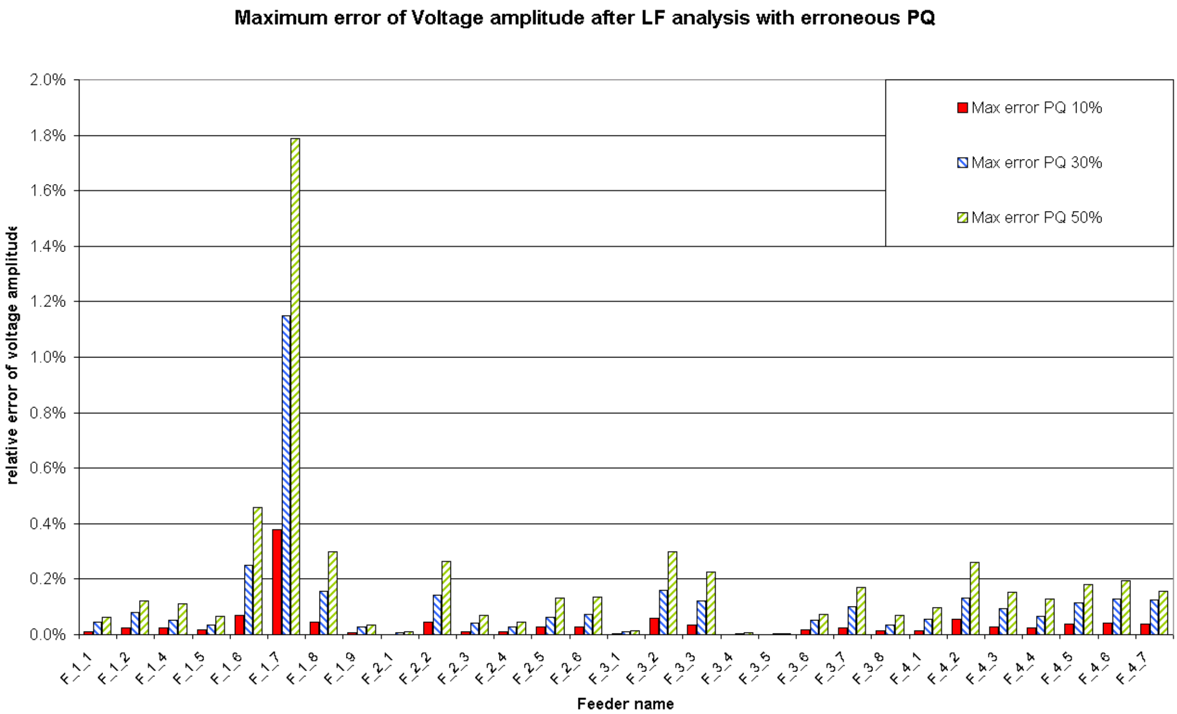

Figure 7: Maximum error of voltage amplitude after a LF analysis with erroneous PQ (10%, 30% and 50%)

Regarding flows in each section of the feeder, a similar analysis has been performed. For each one of these sections, the difference between the real flow and the result of the load flow with erroneous PQ has been calculated. The mean error[4] of power flow is illustrated in Figure 8 and in Figure 9 for the maximum error[5]. Both graphs show the same general behaviour, most part of feeders have accurate power flows results. As previously illustrated, feeder F_1_7 has an important DER connected so the important errors are due to this production not compensated with other loads. Regarding feeder F_4_2, large means errors are associated to large loads connected to this feeder.

[4] The mean error is considered as the mean value of errors in kVA of all sections of MV feeder and all load flow analysis.

[5] The maximum error is the maximum value of the errors in kVA for all sections of MV feeder and all load flow analysis.

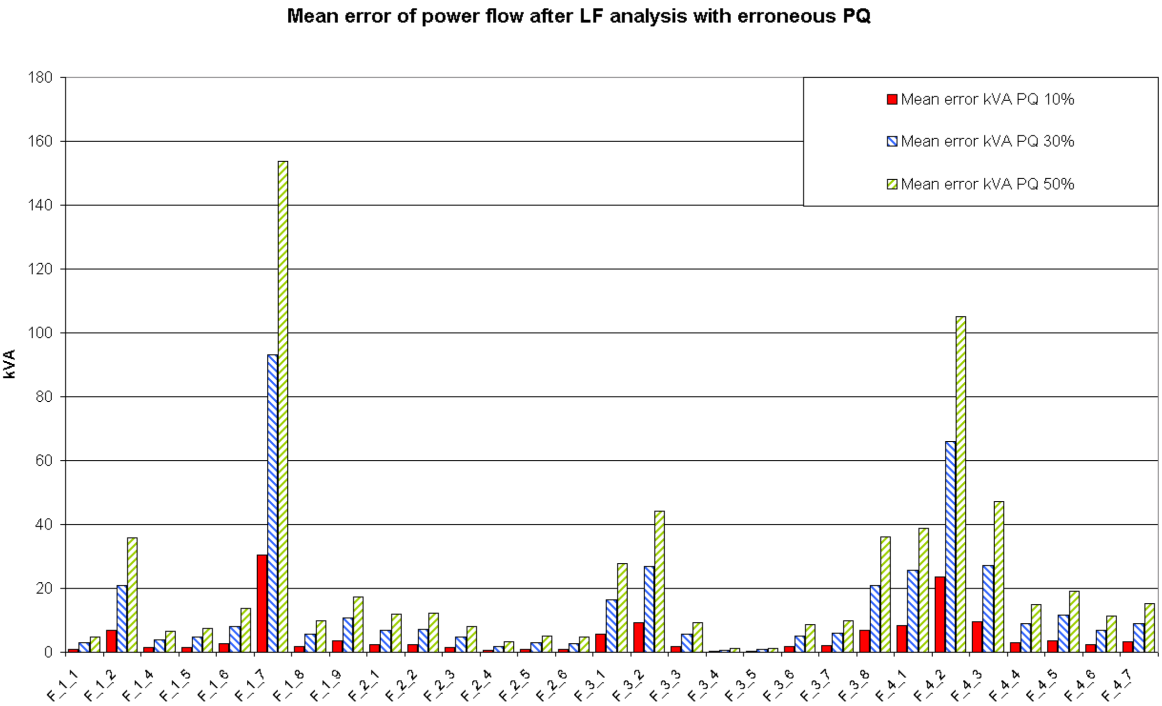

Figure 8: Mean error of power flow after a LF analysis with erroneous PQ (10%, 30% and 50%)

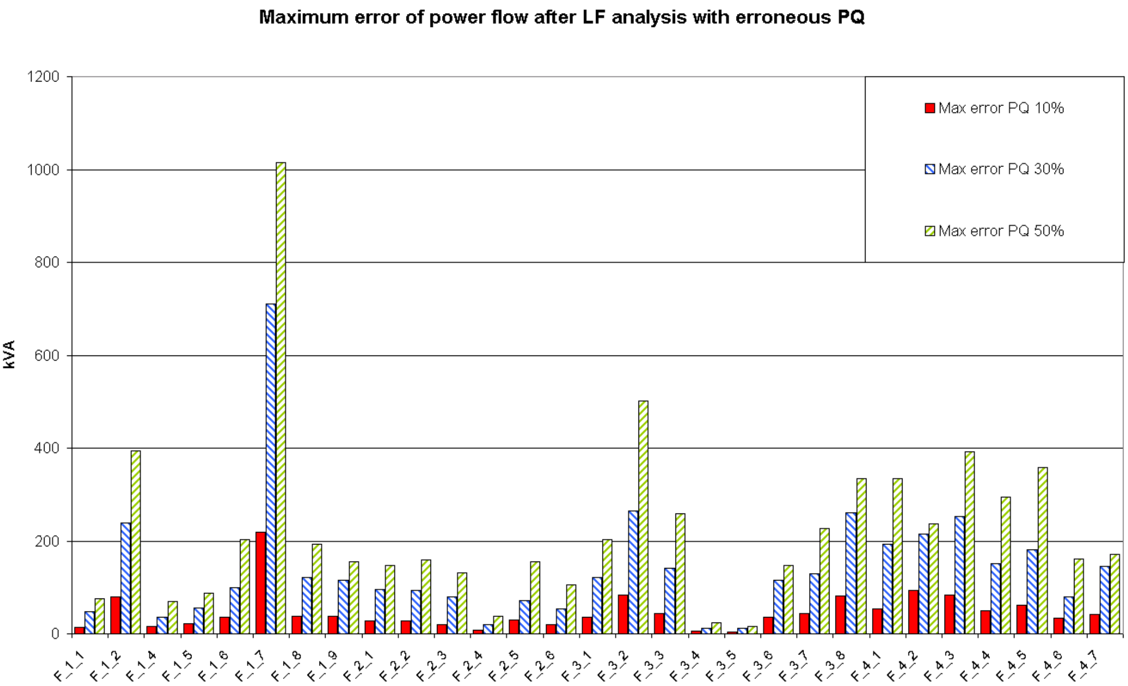

Figure 9: Maximum error of power flow after a LF analysis with erroneous PQ (10%, 30% and 50%)

Figure 10 and Figure 11 illustrate the mean and the maximum error of Copper losses in MV feeders. As seen for voltages, results are accurate for most part of feeders even when an important error is considered for PQ loads as errors of different loads compensate between them. For feeder F_1_7, an important error appears as the error of the DER has a huge impact on results.

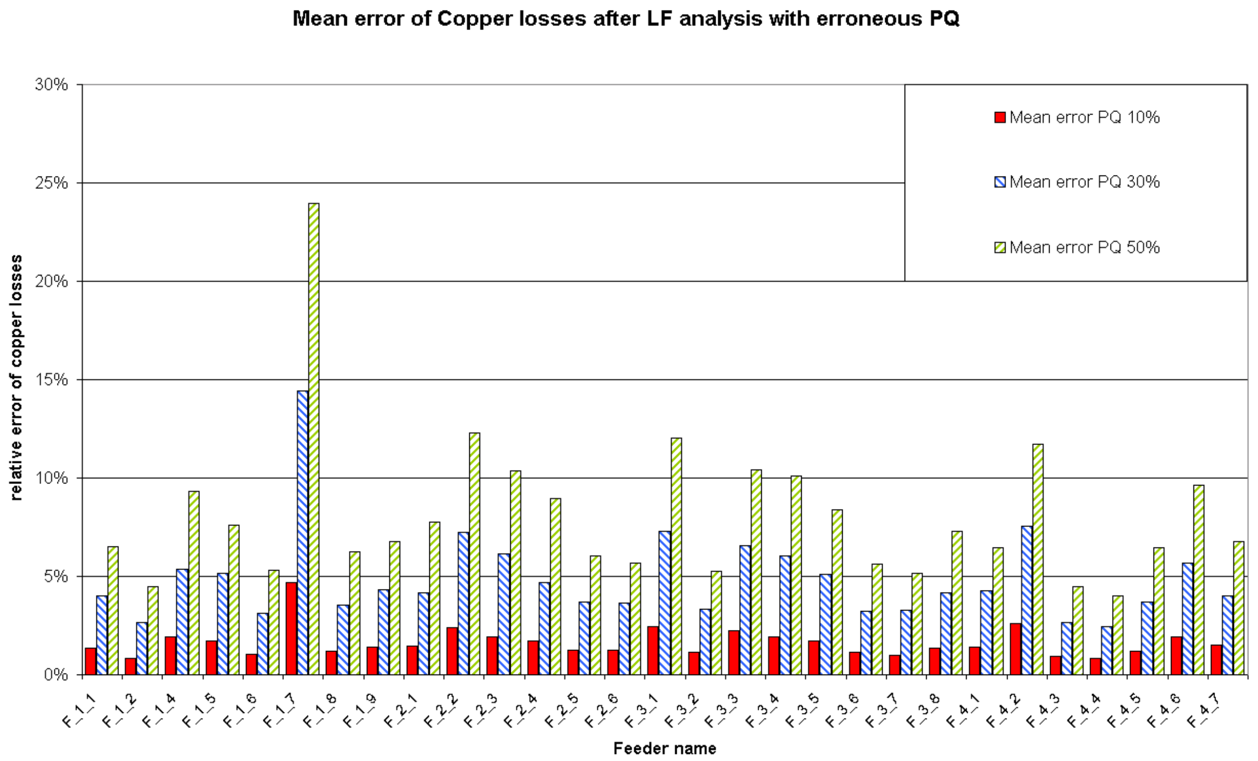

Figure 10: Mean error of Copper losses in MV feeders after a LF analysis with erroneous PQ (10%, 30% and 50%)

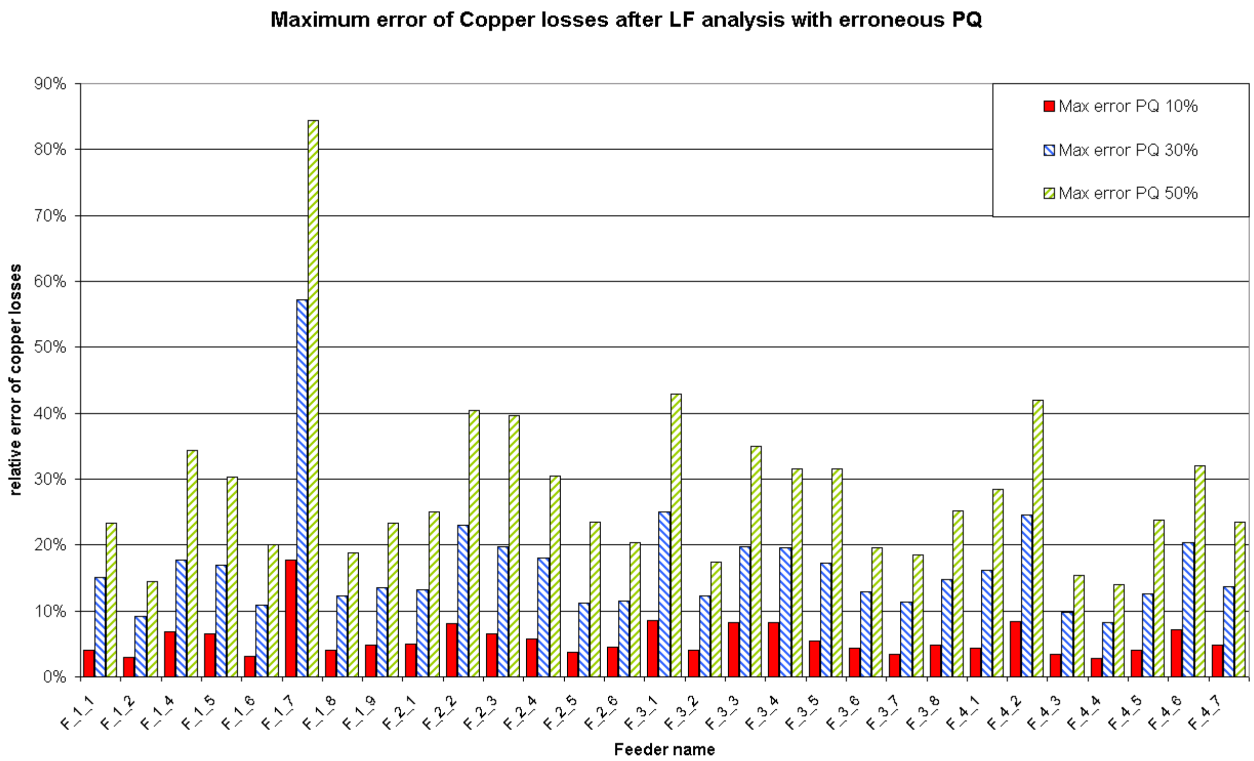

Figure 11: Maximum error of Copper losses in MV feeders after a LF analysis with erroneous PQ (10%, 30% and 50%)

Same PQ Error for all Loads

In paragraph §1, results with a normally distributed error have been analysed. It has been observed that in most cases, errors in different loads compensate between them, so it has been decided to test for one feeder, results where all the loads have the same error (10%, 30% and 50%). Tests have been run for feeder F_4_4 and for the same operating point as in paragraph §1.

A comparison between mean errors and maximum errors obtained for this configuration and the previous one has been performed and is summarized in Table 2, Table 3 and Table 4.

	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
10 %				
Normally distributed errors	0.004%	0.741	0.025%	5.094
Maximum errors for PQ loads	0.101%	20.396	0.184%	36.877
30 %				
Normally distributed errors	0.010%	2.091	0.065%	13.161
Maximum errors for PQ loads	0.303%	61.340	0.552%	111.002
50 %				
Normally distributed errors	0.017%	3.453	0.127%	25.599
Maximum errors for PQ loads	0.507%	102.491	0.924%	185.632

Table 2: Accuracy of voltage amplitudes with PQ loads normally distributed or with the maximum error

In Figure 12 and Figure 13, it is possible to see how the mean and the maximum error of voltage amplitude are highly increased when the same error is considered for all PQ loads. This can be explained because, in this case, no compensation between different errors is done.

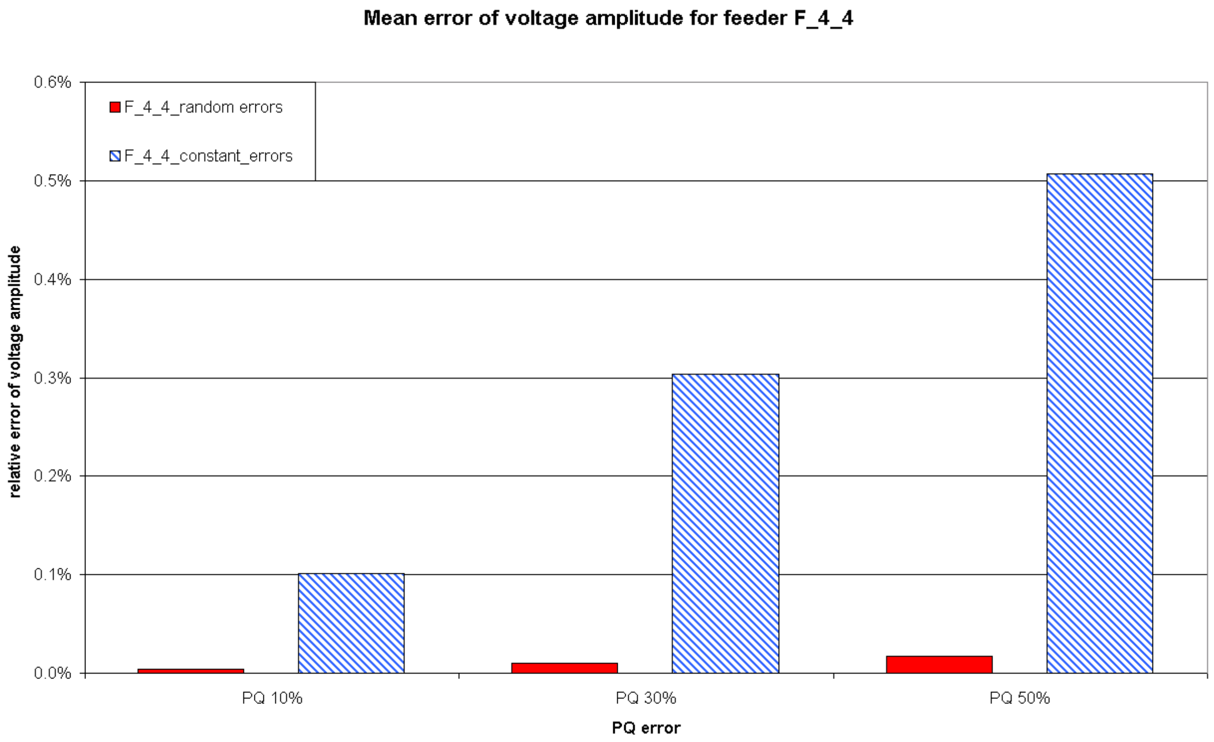

Figure 12: Mean error of voltage amplitude after LF analysis with different PQ errors

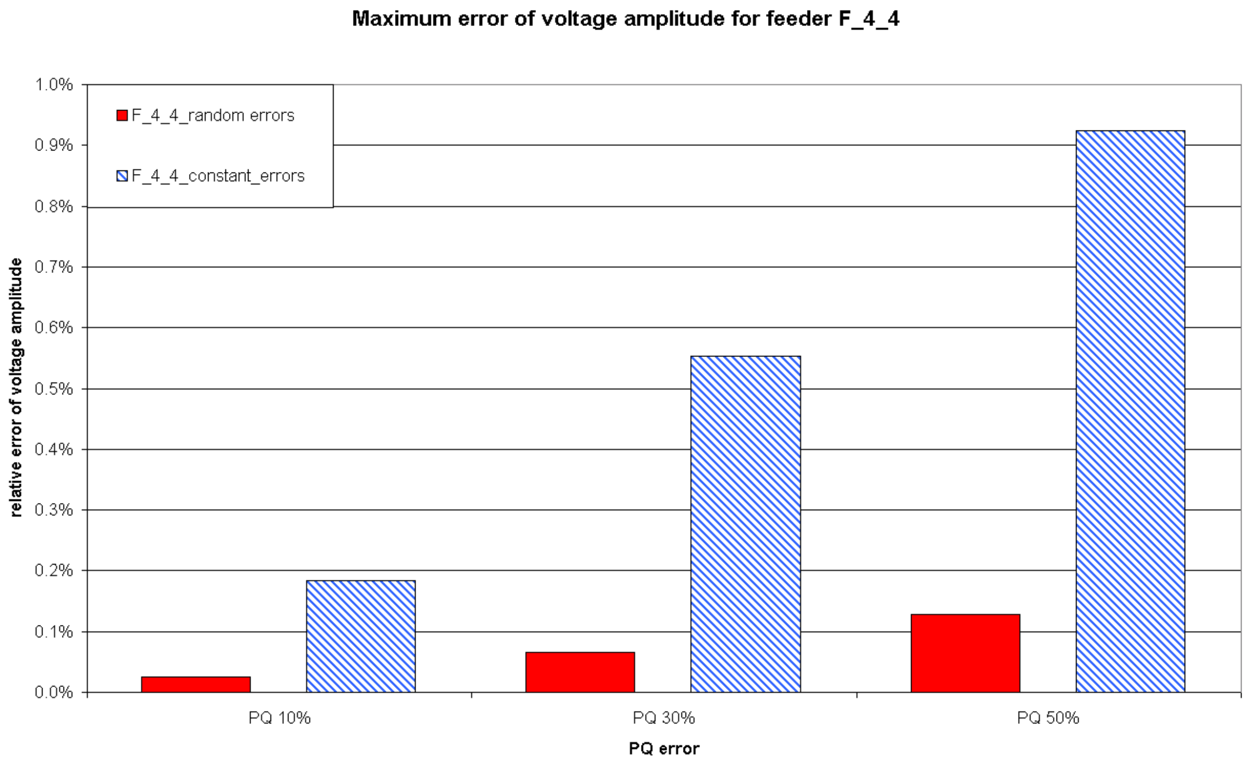

Figure 13: Maximum error of voltage amplitude after LF analysis with different PQ errors

Regarding power flows errors (Figure 14 and Figure 15), it is possible to see that the mean and the maximum error are importantly increased when the same error is applied to all PQ loads as no compensation between different errors is done.

	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
10 %				
Normally distributed errors	1.235%	3.066	30.430%	49.909
Maximum errors for PQ loads	7.522%	47.795	14.496%	344.819
30 %				
Normally distributed errors	3.614%	8.991	45.736%	150.429
Maximum errors for PQ loads	22.923%	146.313	31.452%	1046.139
50 %				
Normally distributed errors	5.975%	14.907	67.630%	295.318
Maximum errors for PQ loads	38.807%	247.675	52.830%	1759.378

Table 3: Accuracy of voltages amplitudes with PQ loads normally distributed or with the maximum error

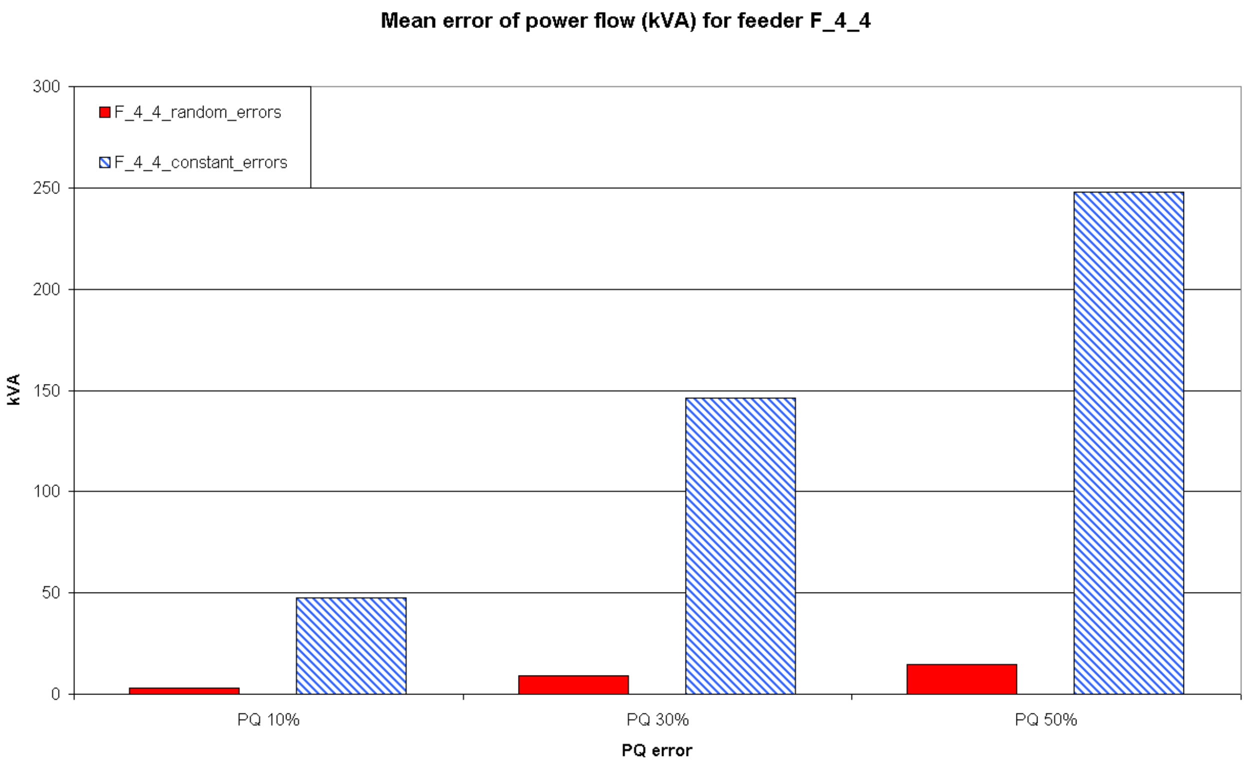

Figure 14: Mean error of voltage amplitude after LF analysis with different PQ errors

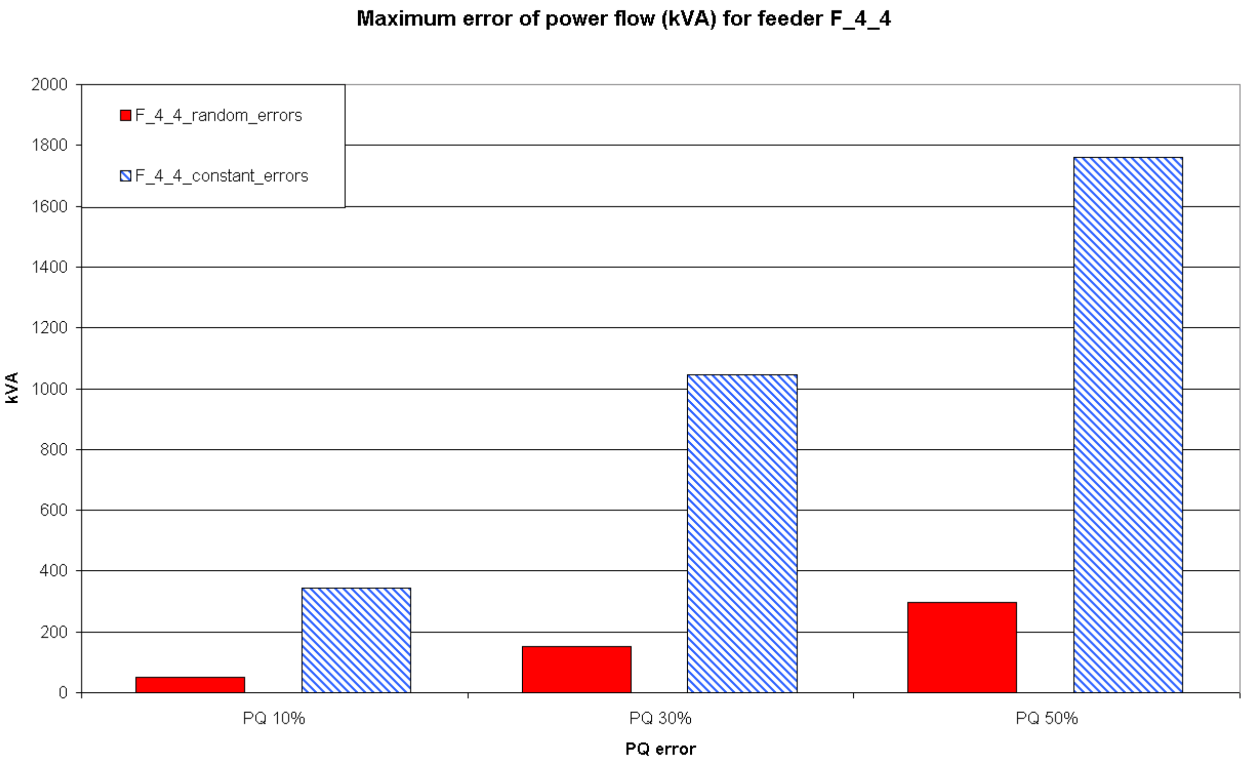

Figure 15: Maximum error of voltage amplitude after LF analysis with different PQ errors

Regarding Copper losses, the same behaviour as previously is observed. The errors are highly increased when the same error is applied to all PQ loads.

	Mean error in Copper losses (%)	Maximum error in Copper losses (%)[6]
10 %		
Normally distributed errors	0.835%	2.733%
Maximum errors for PQ loads	19.561%	19.561%
30 %		
Normally distributed errors	2.424%	8.284%
Maximum errors for PQ loads	65.630%	65.630%
50 %		
Normally distributed errors	4.006%	13.961%
Maximum errors for PQ loads	121.063%	121.063%

Table 4: Accuracy of voltages amplitudes with PQ loads normally distributed or with the maximum error

[6] When the maximum error is applied, the maximum copper losses error is the same as the mean, as no random value is taken into account.

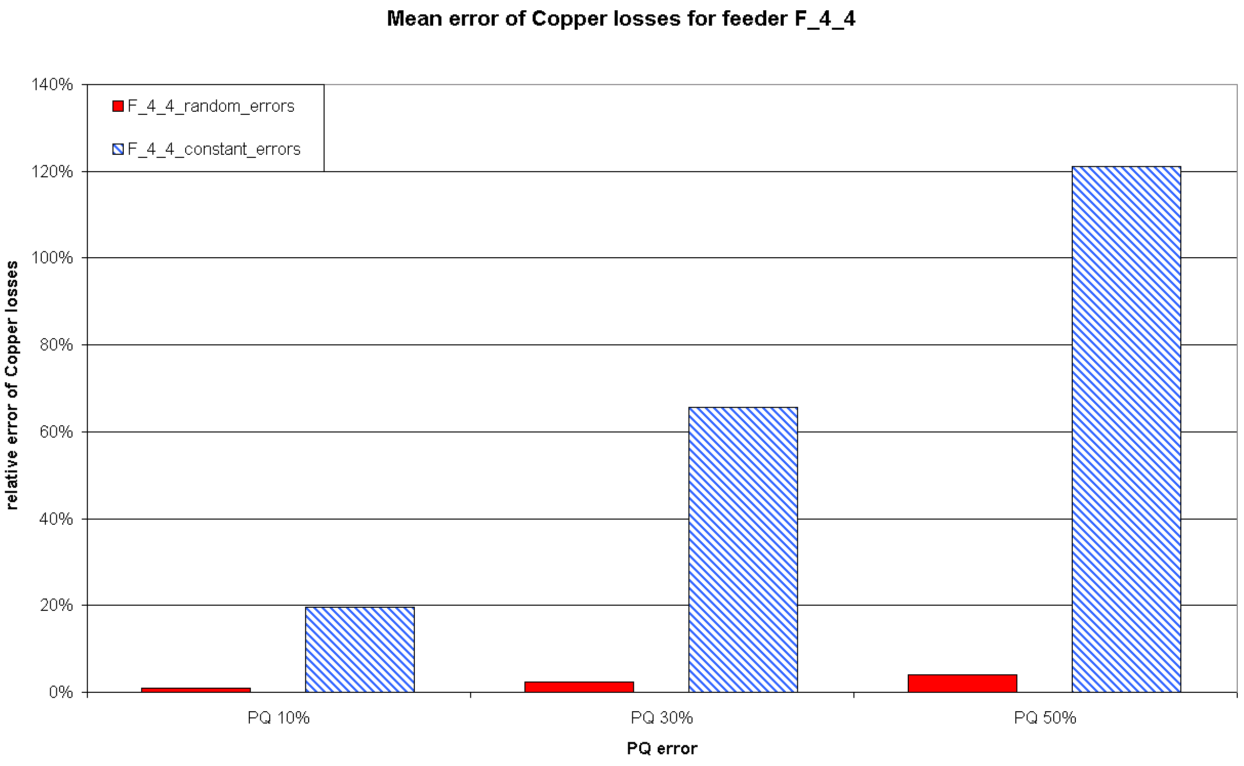

Figure 16: Mean error of voltage amplitude after LF analysis with different PQ errors

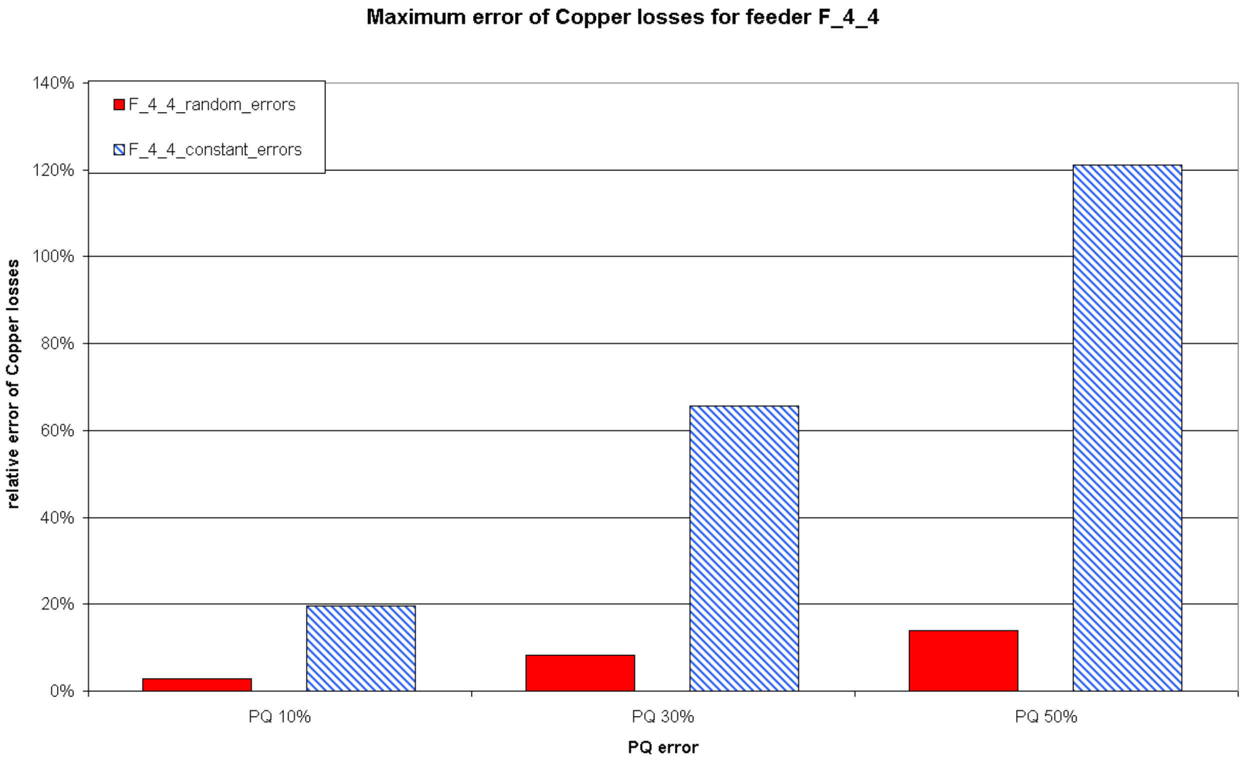

Figure 17: Maximum error of voltage amplitude after LF analysis with different PQ errors

In the above chapter the approach to determining the sensitivity of automation function to errors in the loadflow model has been explained. The examples tested have shown that assumed PQ error levels can significantly impact the sensitivity. For testing automation functions, several assumptions regarding PQ errors must be taken into account.

Case Study on Improved Voltage Control

This chapter, prepared by Fraunhofer IWES, describes the utilization of state estimation results for the improved voltage control approaches. The required information for the improved voltage control approaches is proposed, while the required time resolution and accuracy of DSE results need to be researched through case studies. Compared with the conventional approach, the improved approaches using estimated results provide several advantages, which enhance the network voltage stability not only at the time of heavy load, but also for network with high penetration of Distribution Generation (DG).

Conventional voltage control based on transformers equipped with On-Load Tap Changer (OLTC) plays a fundamental role nowadays. Without the actual network information, the control of OLTC is designed to hold only the substation voltage at reference level. Due to high penetration of Distributed Generation (DG) this conventional control is considered not to be adequate.

Both the network operators and the end users are expected to play a more dynamic role in dealing with the voltage problem, so improved coordinated voltage control approach by using the state estimation results is proposed. The state estimation provides not only a better overview of the entire network, but also detailed information at several strategic connection points, which is essential for the dynamic performance of the improved control approach. With the help of state estimation results, improved approaches are able to maintain the voltage at all nodes in the network within a required band rather than just the transformer terminal. Furthermore, the network connection capacity of DG can be maximized with the possibly least capital expenditure.

Firstly, this chapter describes the principle of voltage control with OLTC without using state estimation result and the possibility disadvantages of this conventional approach. Then, the data flow for the utilization of state estimation results, principle and requirement for improved voltage control approaches will be represented. Finally, the advantages of improved voltage control approaches will be discussed.

Conventional Voltage Control (without DSE results)

Voltage quality is one of the most important aspects of power system. Without the additional information at distribution network level the standard method that can be used to maintain the voltage within stable band is the tap changing under load. Power transformers at different voltage levels equipped with On-Load Tap-Changer (OLTC) are nowadays widely used by varying the transformer ratio to provide the voltage adjustment between the supply system and the consumer network [3]. This section describes the principle of voltage control with OLTC without using state estimation result and the possible disadvantages of this conventional approach.

Conventional voltage control

The simple control algorithm of OLTC is so called constant voltage control, which holds the substation bus voltage at reference level. The Voltage Transformer (VT) measures the secondary busbar voltage and sends it to the Automatic Voltage Regulator (AVR), as shown in Figure 18 (left). A bandwidth is centred on the reference voltage and describes the acceptable voltage range and remains constant by the means of constant voltage control. When the deviation between measured voltage and reference voltage exceeds the bandwidth limit, appropriate decision is made to increase or decrease the tap position. An intentional time delay is introduced to avoid operation for temporary voltage sags and swells outside of the defined bandwidth, which may cause many unnecessary operations of the tap changer 4. When the measured voltage is outside the preset limit during an adjustable time delay T_1, a command is activated and the motor on the OLTC is able to be driven in either raise or lower direction, as shown in Figure 18 (right). Otherwise, the delay counter is reset and no operation of tap changer is happened. Tap changer with motor-drive mechanism can be switched step-by-step to physically alter the transformer ratio and therefore affect the output voltage of the transformer to maintain a preset voltage limitation. The adjustable voltage for each tap step lies between 0.5% and 1.7% of the rated voltage. Standard tap changers offer between ±7 to ±17 steps [4].

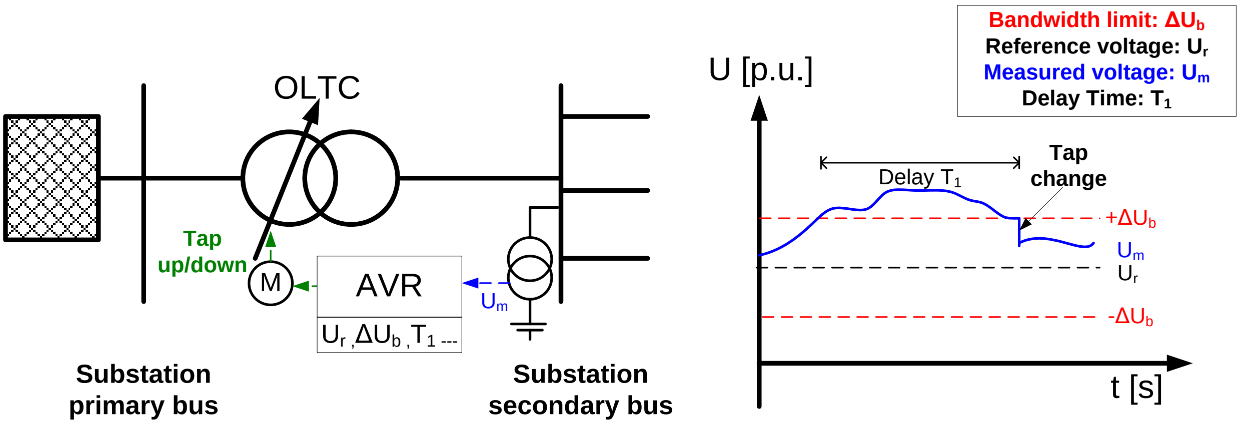

Figure 18 Constant voltage control of OLTC

The advantage of this simple conventional approach is no need of additional network information and communication channel. The only required information is the substation secondary voltage, which can be easily measured using voltage transformer.

Disadvantages of conventional voltage control

However, the high penetration of DG in Europe results in more complex network behaviour and the conventional control approach without using estimated network information is sometimes considered to be inadequate. In the following, disadvantages of the approach will be discussed.

a) Possibility to speed up a power system voltage collapse

Since the conventional approach just measures the substation secondary bus voltage and is blind to the primary bus voltage or the power flow in network, it is hard to find the actual reason for the voltage disturbances. At the maximum load condition, the tap position is increased in order to maintain the second bus voltage within the preset limit. Therefore the primary bus voltage starts to decrease because more power is taken by the loads from the already weakened network, which results in a loss of network balance and speed up voltage collapse [4].

b) Inefficient use of the voltage tolerance

According to European Standard EN50160, the average value of voltage must not exceed ±10% of the nominal voltage. In spite of that, the conventional approach uses only part of the tolerance due to the lack of near to real-time network status. The bandwidth in the constant voltage control is defined with experience value, for instance, EG sets a bandwidth of ±1% centred on the reference voltage for HV/MV transformers in RTP Primskovo. Figure 19 (left) illustrates the possible voltage curves along the radial network. Since the blue dashed line at substation secondary bus lies outside the bandwidth, the tap changer is decided to increase, while actually there is still available voltage tolerance ΔU at the end of the feeder. This operation increases the number of tap changer operations and lead to additional wear of the tap changer.

c) **Unsuitable with the increase of distributed generators**

The number of distributed generators connected to the distribution network has increased rapidly in recent years, due to the national economic incentives for renewable energy. That means in time of high generation a reverse power flow might be formed, which results in voltage increase at the connection point. Figure 19 (right) shows a maximum generation with minimum load condition, the maximum voltage at end of the feeder exceeds already the tolerance. Since the secondary bus voltage remains within preset limit, the tap change won't be operated according to the conventional control approach.

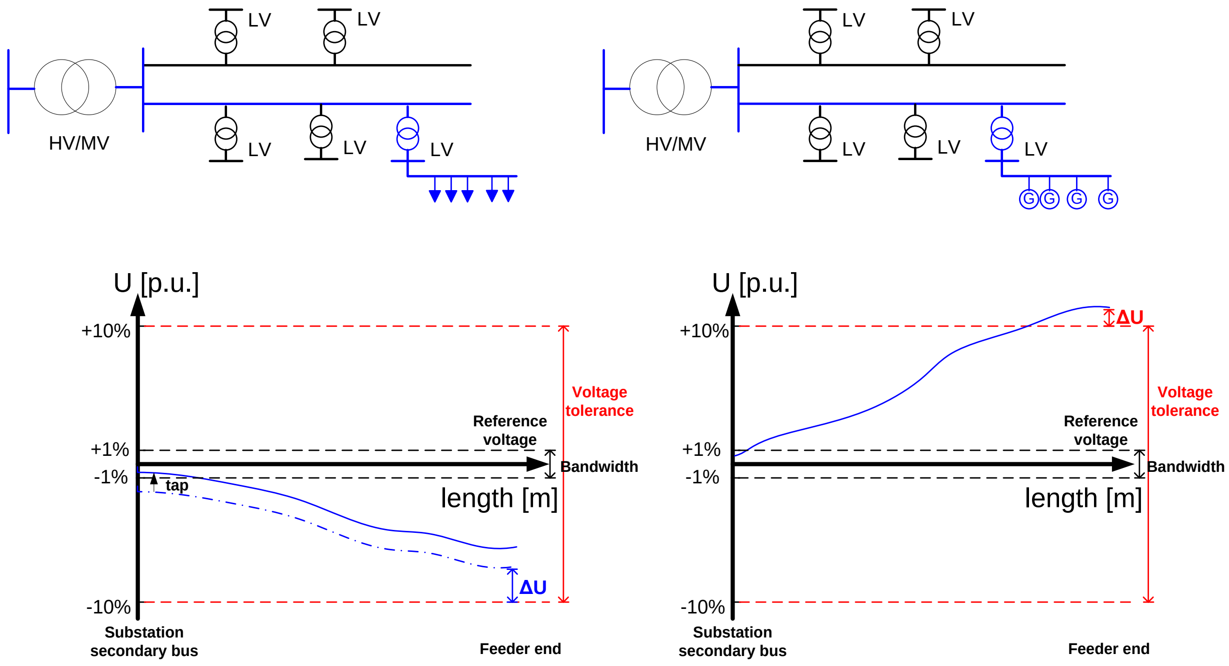

Figure 19: Disadvantage of conventional voltage control

d) **Hunting between the up-stream and down-steam control, when OLTC are operating in series.**

Transformers equipped with OLTC are more and more used at different voltage levels in power system. Due to the conventional control approach, OLTC at different levels may have mutual impacts on each other. An additional time delay called grading time (GT) has to be used to avoid it, which leads to a longer voltage correction time [8].

Improved Voltage Control Approaches (using DSE results)

Due to the strongly fluctuating and often reverse power flows caused by the integration of distributed generation, the distribution system operators are facing new challenges for maintaining the voltage quality. Thanks to the deployment of network measurement sensors, smart meters and so called cloud and grid computing, a near real-time overview of the network is enabled through state estimation. Beside previously mentioned OLTC, different possibilities based on a better network observability can be used to effectively deal with the voltage problem, for instance, active and reactive power of DG, controllable loads, in-line transformer [5], Static Var Compensator (SVC) and Static Synchronous Compensator (STATCOM) [6]. This section describes the principles of improved approaches with active control schemes, advantages of these approaches as well as the requirements and the data flow of the DSE results.

Improved voltage control approaches

Based on a near real-time overview of network information using state estimation, improved approaches with active control scheme are proposed below. The first approach is carried out by controlling substation voltage with OLTC according to the estimated maximum and minimum voltages in the network. The second approach combines active and reactive output power control of distributed generators with centralized OLTC control to maintain the voltage requirement.

a) Advanced Control of OLTC based on Estimation Results

In contrast to conventional control approach of OLTC, the reference voltage at secondary busbar can be adjusted by advanced AVC relay depending on estimated maximum and minimum voltages in order to maintain voltage at all nodes within the acceptable range, as shown in Figure 20. Actual Information about network topology, various loads and generators goes through the state estimator and line voltage drops as well as estimated voltage magnitudes at all nodes are represented at the output. The network model used for state estimation should be regularly updated based on static and dynamic data. According to the estimated maximum and minimum voltages, new reference voltage could be adjusted by AVC relay after a certain delay based on the algorithm mentioned in [7]. Another algorithm that helps to modify the reference voltage is described in [8] using the estimated generator current and the derived E_{ST} ratio that represents the load share between feeders with DGs to those without DGs. The operation of the tap changer is then carried out under the new reference voltage and effective solve the voltage problem caused by distributed generators.

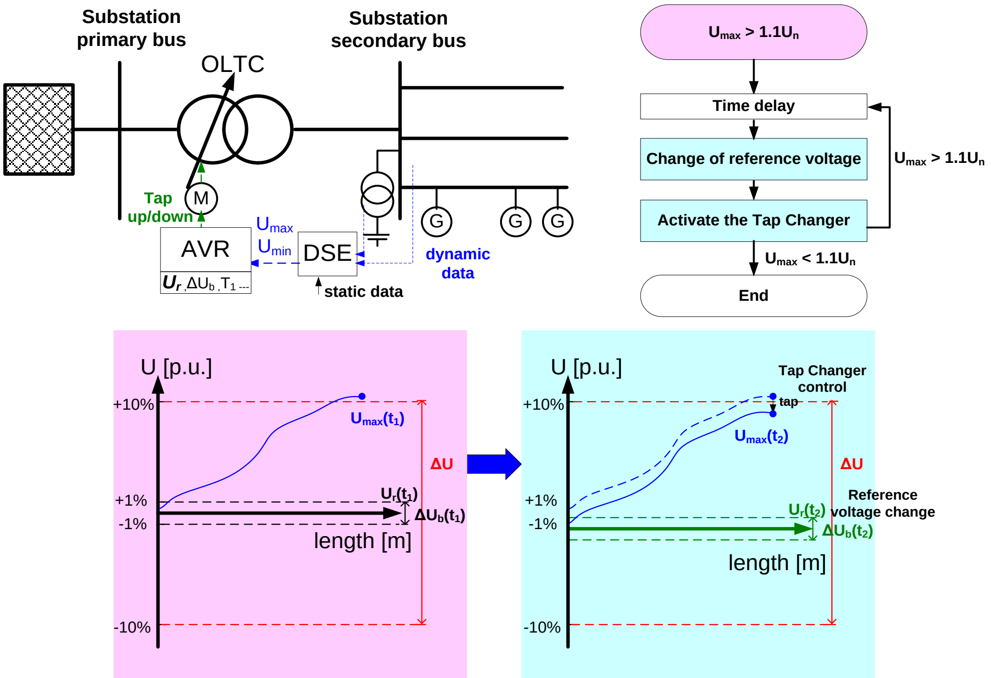

Figure 20: Advanced control of OLTC based on estimated results

b) Coordinated Control of Local DG Output Power and Centralized OLTC

Although, advanced control of OLTC performs well facing the various loads and generators, it may sometimes not be sufficient to cope with the voltage problem associated with heavy load in one feeder while high penetration of DG in another feeder. When both of the maximum and minimum voltages in the network feeder exceed the voltage limit, coordinated approach using control capabilities of both distributed generators and transformers equipped with OLTC appears to be the most efficient solution. According to variety of guidelines, more and more distributed generators are required to provide ancillary services to minimize their influence on the network. Referring to the R/X ratio in distribution network, the voltage control at distributed generation side is based on active and reactive output power of DG. Different types of distributed generation units including wind turbine generator systems, photovoltaic systems, hydroelectric systems, combined cooling, heating and power (CCHP) system and storage systems can be involved in the coordinated voltage control. The technological control capabilities of these systems are dependent on the energy availability and the type of converter, which is used to connect the generation system to the network [9]. Three types of grid-coupling converter, Doubly-Fed Induction Generator (DFIG), Synchronous Generator (SG) and inverter have voltage control capabilities.

The two most important tasks, which directly influence the performance of a coordinated voltage control, are the determination of the operating sequence and the determination the set point for the distributed generators output power. In order to avoid the control effect to work against each other in the coordinated voltage control one control scheme should be blocked, when the other is carried out. Since DG output power control and centralized OLTC control include different time horizons (speed of reaction) and different spatial perspectives (local or remote), the optimal operating sequence can be determined according to the characteristics of different voltage problems and network topology. It is important to notice that the near to real time state estimation results can play a major role in arranging the appropriate operating sequence. According to the estimated voltage values, load currents and power flows in different feeders and the available historic data, the responsibility for the voltage problem could be analysed. For example, in case of critical voltage fluctuations in most feeders in the same direction, the centralized control of OLTC could be carried out first to solve global voltage changing. By contrast, when only a few feeders suffer the voltage problem or the critical voltages in different feeders change in the opposite direction, the control of local generator output power should be performed first. The goal of the optimal operating sequence is to minimize unnecessary control activities whilst maintaining the network voltage within the preset limit.

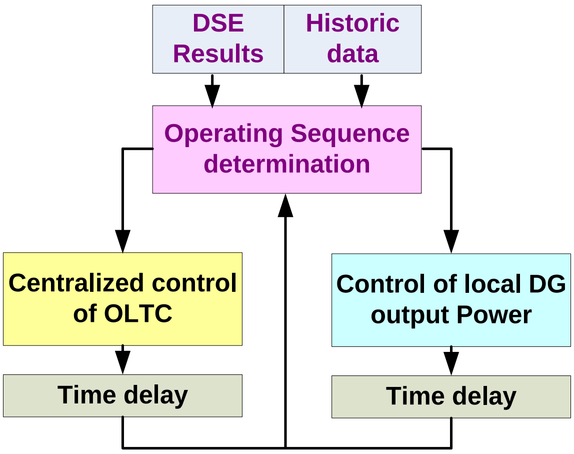

Figure 21: Determination of operating sequence using DSE results

Secondly, the set point of DG output power can be determined either dynamically at remote substation level or statically at local distribution generation level with preset value, as shown in Figure 22. By the remote determination of set point, appropriate algorithms based on actual network information given by estimated results can be used. Furthermore, the results of the other DNAFs (e.g. optimal power flow) can also be integrated in order to provide the optimal set point. The disadvantage of this method is the need of a long calculation time and the requirement of additional reliable, high speed communication channel for the transmission of activation signal and dynamic set point values. In contrast, the operating point of DG can be changed into preset point locally in the latter way. Only the activation signal regard to the operating sequence based on DSE results is needed, which results in a quick response time with less calculation and a low requirement of the communication channel. When the preset operating point is about output power or power factor [10], it is designed to relieve certain voltage problems and may not guarantee the voltage quality in all cases. When the preset operating point is about the voltage magnitude, it is able to avoid unnecessary reactive power provision and guarantee the voltage quality. But it is a heavy burden for DGs at relative weak connection points, since adjacent DGs wouldn't provide any support according to their connection voltages [11]. Compared to the first way, the preset operating point is not optimal operating point and may cause additional network losses.

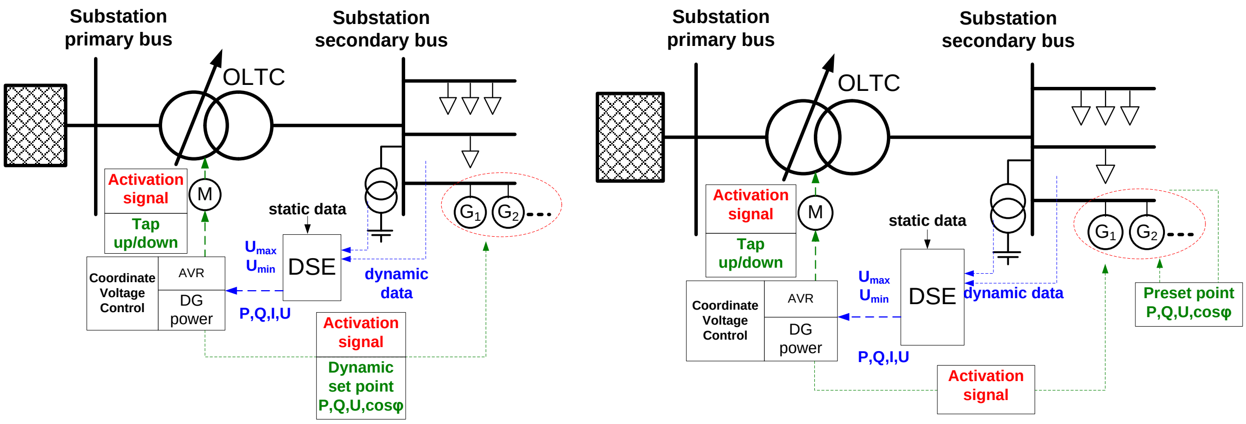

Figure 22: Determinate the set point of DG output power remotely (left) or locally (right)

The flow chart of an example of coordinated voltage control is shown in Figure 23. Actual Information about network topology, various loads and generators goes through the state estimator and estimated current, power flow as well as voltage magnitudes at all nodes are represented at the output. Since the maximum voltage in the network exceeds the upper limit and at the same time the minimum voltage lies near the lower limit, the short-term control of generator output power is carried out first. When the control of local generator output power is considered not to be adequate, medium-term control of centralized OLTC would be activated after a certain delay and the operation of tap change is then carried out under a new reference voltage. Further, because of the cost assessment by providing active power, reactive power would be restricted at first [9].

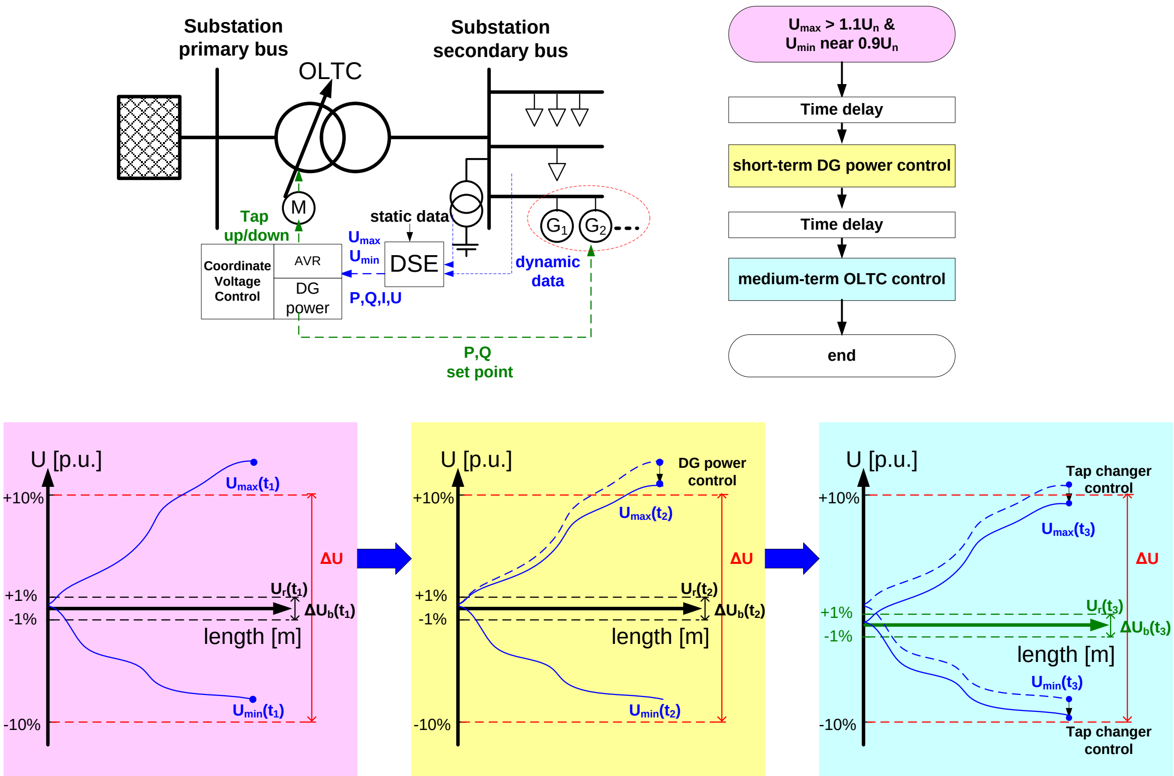

Figure 23: Coordinated control of local DG output power and centralized OLTC

Advantages of the improved voltage control approaches

With the help of numerous, accurate, near to real time information about the network status, the improved approaches are able to effectively regulate the voltage within required limits and maintain the power system stability. The improvements in performance of improved voltage control approaches using state estimation results are discussed in the following.

Avoidance of voltage collapse and better series OLTC operation

The state estimation results enable a better view of substation primary and secondary busbar voltage as well as the actual power flow (load demand / generator production). Under estimated extreme heavy load condition, OLTC rise operation can be blocked in order to prevent the load from taking more power from already weakened network and rescue a would-be voltage collapse. The high speed exchange of operating Information about OLTC at different levels enhances the cooperative work of transformer in series.

Efficient utilization of the voltage tolerance and reduce the unnecessary OLTC operations

Based on the better overview of actual network status, the improved voltage control approach is designed to choose optimal reference voltage, instead of constant reference voltage as in the conventional approach. This enhancement enables the control strategy to maintain the voltage at all nodes in the network within a tolerance band rather than just the transformer terminal. Number of unnecessary OLTC operations as in Figure (left) represented can be effectively reduced.

Use of control capabilities of DGs to maximize the DG connection capacity

Both the global view of network status and the detail information at several strategic connection points facilitate the improved approach to determine the responsibility for voltage disturbance in order to optimise the sequence of coordinated voltage control. Due to the coordinated control of local DG output power and centralized OLTC, the number of disconnected DGs during stressed situation can be reduced and the network connection capacity of DG can be increased.

Integration forecast information to facilitate the state estimation and improve load management

The technique of forecast for DG production has been recently developed based on the weather condition and historic data. Enhanced forecast information can be integrated to facilitate the state estimation and further improve the performance of load management. The goal of load management is to keep the load demand in balance with the DG production in order to fundamentally reduce voltage fluctuations.

Requirements and data flow of the DSE results

The voltage control function must determinate the appropriate OLTC position and optimize the operating sequence as well as set points for the distribution generator units based on the near to real time network information. Hence, the consistent and complete DSE is essential for the performance of the voltage control function. It is expected that the DSE will provide not only a better overview of the entire network, but also detailed information at several strategic connection points, even by limited measurement sensors or a single point failure of measurement sensor.

The Data flow of the utilization of state estimation for voltage control function is shown in Figure . Remote Terminal Units (RTUs) collect actual information from measurement sensors or smart meters in distribution networks and send this to the SCADA system as dynamic data. The state estimation algorithm uses the dynamic data together with the set of available static data such as network topology and conductor impedances, which is integrated by network operator in SCADA system, in order to evaluate the voltage values as well as the power flows, currents and tap changer positions. A real-time data base will store the latest state estimation results and this will be available for read-only access by the voltage control function. Detailed information at several strategic nodes, where large voltage variations are expected is especially important. Based on all estimated information and static data, the voltage control algorithm determines the optimal actions and sends the control command to adjust the voltage targets of AVC relays, output power of DGs or network configuration.

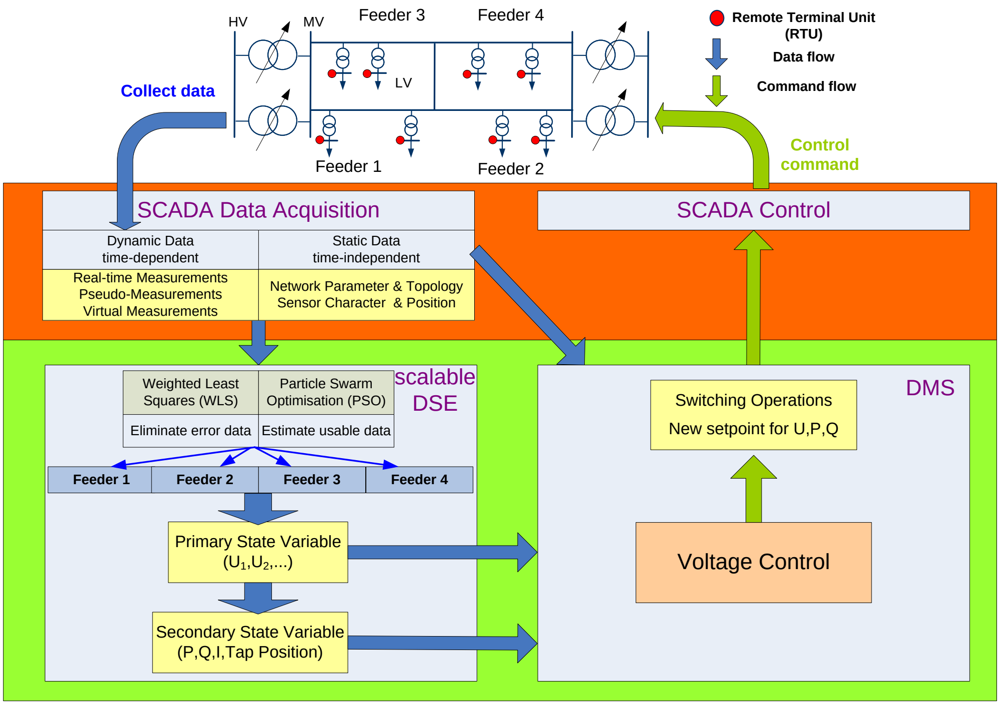

Figure 24: Data flow for the utilization of DSE results for voltage control function

The requirements of DSE results vary in content, time resolution and accuracy depending on the different voltage control functions. For the conventional OLTC control function no DSE results are needed, while for the advanced OLTC control the estimated maximum and minimum voltage in the network and the current tap changer position are necessary. Accuracy of voltage magnitudes at remote sites of network or nodes where large voltage variations are expected is significant for the performance of the advanced control function. This function would typically run continuously and the switch operation is connected with a trigger event. The remote measurements should continuously communicate with DSE. As the operation time of tap changing lies in seconds and the typically action delay for the AVC relay takes thirty seconds up to a few minutes [4], the proposed time resolution of DSE results for the advanced control approach lies between 10 and 15 seconds. Since the voltage tolerance is ±6% for MV network and ±10% for entire MV/LV network, the accuracy of DSE results about voltage amplitude should be higher than that.

The required DSE results for coordinated voltage control include not only the maximum and minimum voltage magnitudes in the network, but also the power flows at connection points of distributed generators and load currents. Numerous network information provided by DSE is used to trigger the control event on the one hand according to the voltage limit; on the other hand it would help to find out the responsibility for the voltage problem in order to determine the optimal operating sequence and even the optimal operating point. The total operation time of centralized OLTC including delay time lies in minute range, while the control of distributed generators power performs in seconds. As numerous network information need to be estimated, the proposed time resolution of DSE results for the coordinated control approach lies in minute range. Similar accuracy of estimated voltage amplitude is needed as previously mentioned. The requirement for accuracy of power flow and current differ in the way, how the set point of DG output power should be determined. High accuracy is required when set points are dynamically determined, otherwise medium accuracy is sufficient.

Other DNAFs (e.g. optimal power flow) would also be considered by coordinated voltage control in order to provide the optimal solution for the entire network. As long as no trigger event is active, optimisation function would typically run as a background task on a timer cycle (e.g. every 30 minutes).

Improved voltage control approaches based on the estimated actual network information have been presented. Compared with the conventional approach, the improved approaches using DSE results provide several advantages, which enhance the network voltage stability not only at the time of heavy load, but also for the network with high penetration of Distribution Generation.

Both the time resolution and the accuracy of DSE results are essential for the performance of the voltage control function. The detailed requirements and corresponding impact of them should be researched further using case-study simulation.

Case Study on Intelligent Control of Energy Storage

The modern energy sector is increasingly dealing with the integration of distributed renewable energy sources in distribution networks. Significant overall part of DG in distribution network can cause changed power flow direction, which is reflected as voltage regulation problems, increase in short circuit power, compromised protection selectivity, etc. In addition to these problems, network management is further complicated by unreliability and uncertainty of supplied energy from the renewable energy sources. Deficit and surplus of renewable energy in each feeder can therefore occur because of primary energy (sun, wind) inconsistency. Those fluctuations of electrical power are causing a difficult system management in terms of assuring the balance between production and consumption, as well as difficulty of ensuring sufficient power quality in the system.

This chapter (prepared by Korona) describes the operation of small power system (one feeder of HV/MV Primskovo substation) in which there are several loads, small hydro and solar power plant present. Variation in production from both DG sources is so big that the load flow is changing direction from and into the feeder of substation Primskovo. In this document there is a description of an example for how can the power flow be more constant and restricted in one way, by using energy storage system and controllable loads.

State estimator can in future provide us with metering information about load flow in distribution network and based on that, the operator or automated load control can decide on optimizing the power flow in specific feeder. Instead of energy storage system, the generator control can also be introduced.

DSE Interface

Load and generator (energy storage) control must manipulate with load flow in such way, that the load/generation balance is at optimum point, network maximum load is not exceeded and that the power flow at main nodes can be scheduled to some degree.

The state estimator uses the measurement data from sensors positioned in the network and static data such as topology to evaluate power flow – Figure 25. Estimated load flow data are then used for automated functions of load and storage/generator control based on objective function, which defines the output data. Objective function defines the desired state of the network which load/generator controllers are trying to achieve.

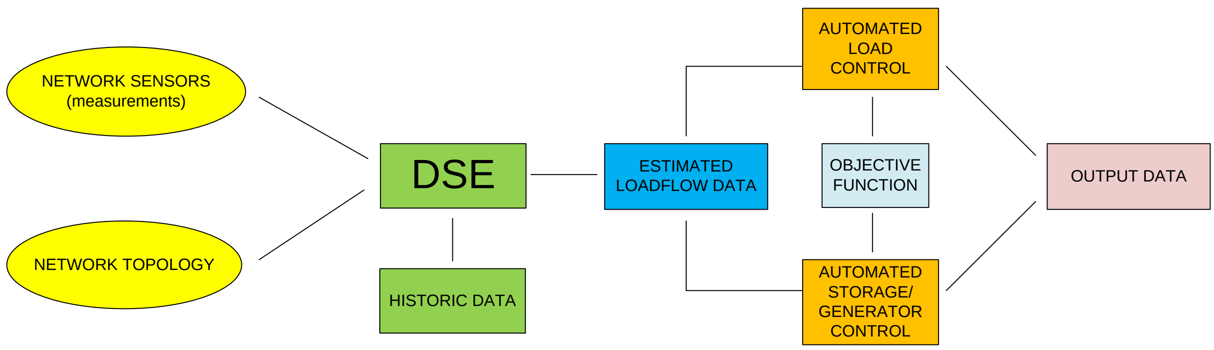

Figure 25: Operating sequence for using DSE results for automation functions.

State estimator will be able to provide us with detailed overview of the network in near to real time from combination of measurements, network topology as well as historic data in cases, where real time measurements will not be available. Load and generator automated control functions will then help us to maintain desirable state of the network by actively controlling load consumption and generator production (or in the case presented – energy storage system operation).

Network Model

Simulation of energy storage system was carried out on a part of Elektro Gorenjska distribution network. A small part of network was used (feeder Interspar – Figure 26) which is supplied by a 110/20 kV Primskovo substation. It consists of three transformer substations (TP Interspar 1, TP Planina Jug 1, TP Interspar 2 - all are 20/0,4 kV). Each substation has a load attached with a real weekly load diagram. The network is powered via cable K1441 from the busbar in 110/20 kV Primskovo substation. K1439 cable connection in Figure 26 is used for backup power so it is disconnected from the TP Interspar 2 in its normal state.

Fictional DG sources are presented as a grid connected solar power plant in TP Interspar 2 substation and a small hydropower plant connected to the TP Planina Jug 1 substation and both operate according to predefined production diagram. The diagrams are selected so that the power flow fluctuates into and out of the feeder which is shown in Figure 27. Positive power means that the energy flows out of the feeder (consumption of energy is higher than DG production), negative power means that energy flows into the feeder/MV network (consumption is lower than DG production). The objective was to restrict the power flow in one direction and make it more constant with help from an energy storage system and load control.

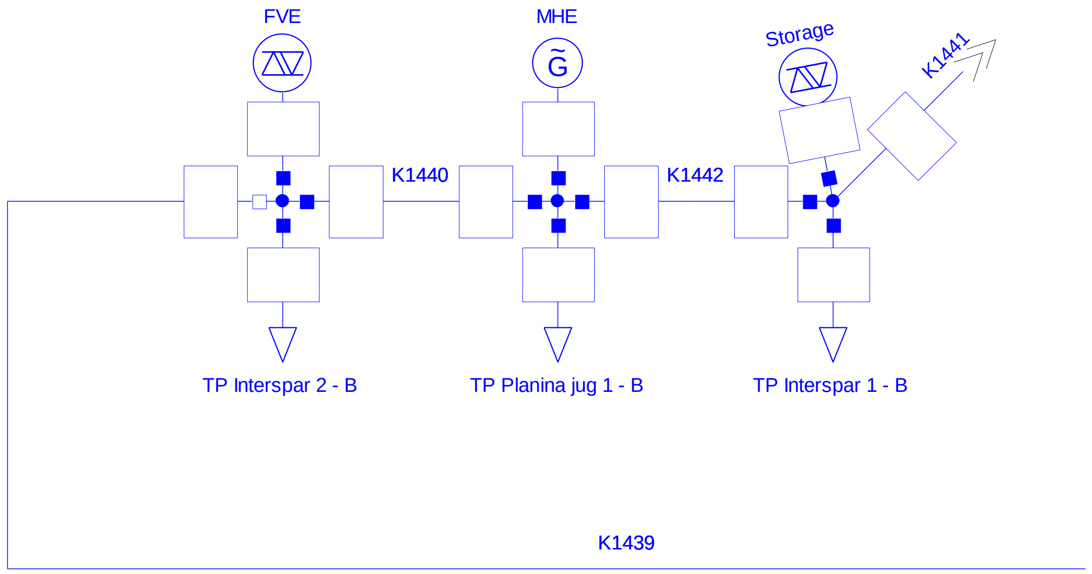

Figure 26: Interspar feeder from HV/MV Primskovo substation.

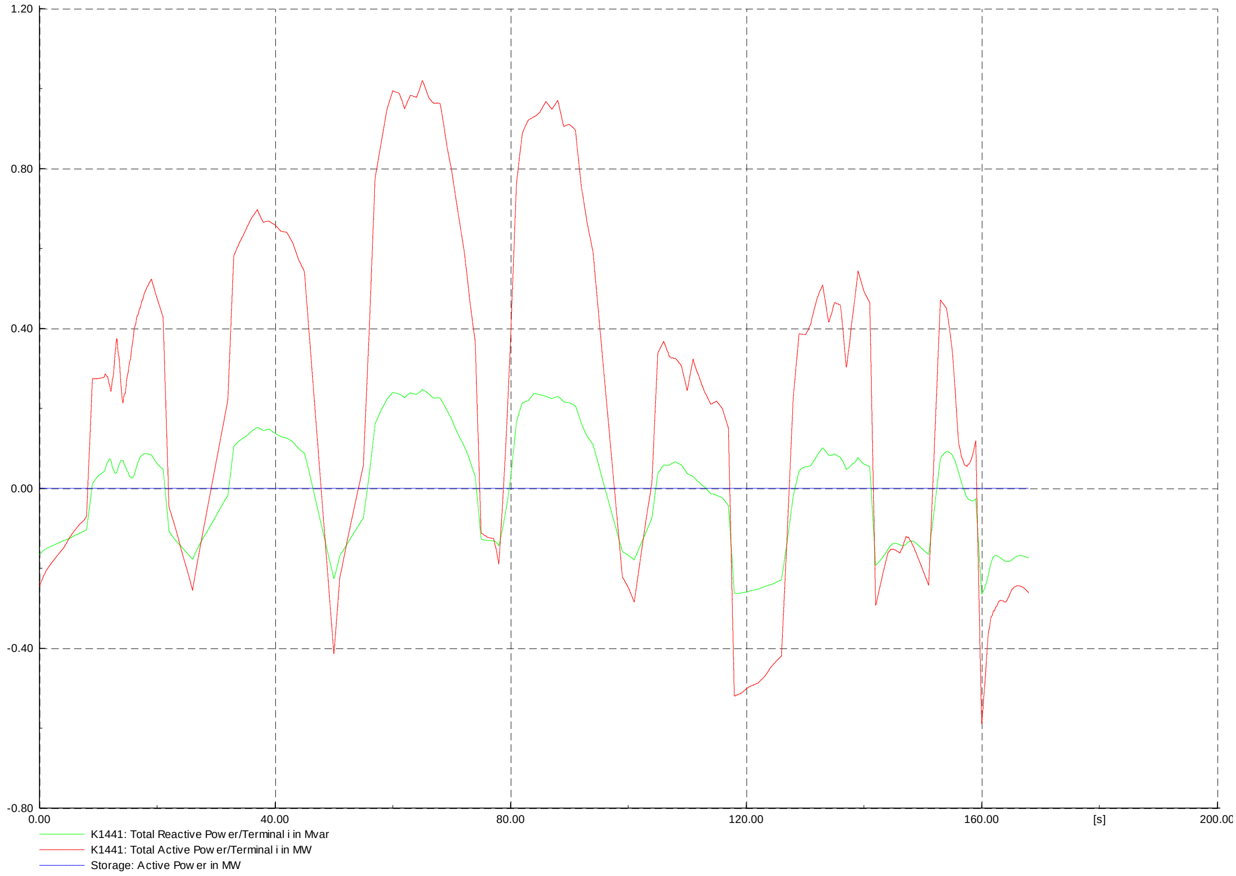

Figure 27: Power flow on K1441 without active energy storage and load control.

Energy Storage System

Energy storage system was modeled in Power Factory DigSilent and was represented as simplified static generator with the appropriate regulator. Figure 28 shows the model and control algorithm. For the operation of energy storage system, we need two measurements. The first is the measurement “P-storage”, which feeds the regulator with data about the output power of energy storage system. This information is needed to monitor the current capacity of the storage system, which is represented by integrating the output power in block “Capacity” and contains the information about the stored energy in MWh.

Second measuring element “P-ref” measures the power flow in regulation point, in our case that is the power on K1441 line. The measured value is compared with the desired power “Pdes” in the block “Preg” from which the PI regulator is controlling the power output. The power is limited in block “Reference” by the PI regulator, regarding to the storage capacity. The output signal of block “Reference” is controlling the actual power of storage system.

Controllable load

Model of the system also includes block "Load disconnect", which disconnects small part of the load from the grid, based on state of the energy storage current capacity and only in case where storage system can not provide the necessary power which is defined by PI regulator. Load on feeder Interspar (K1441) is reduced by 10 % in worst case scenario.

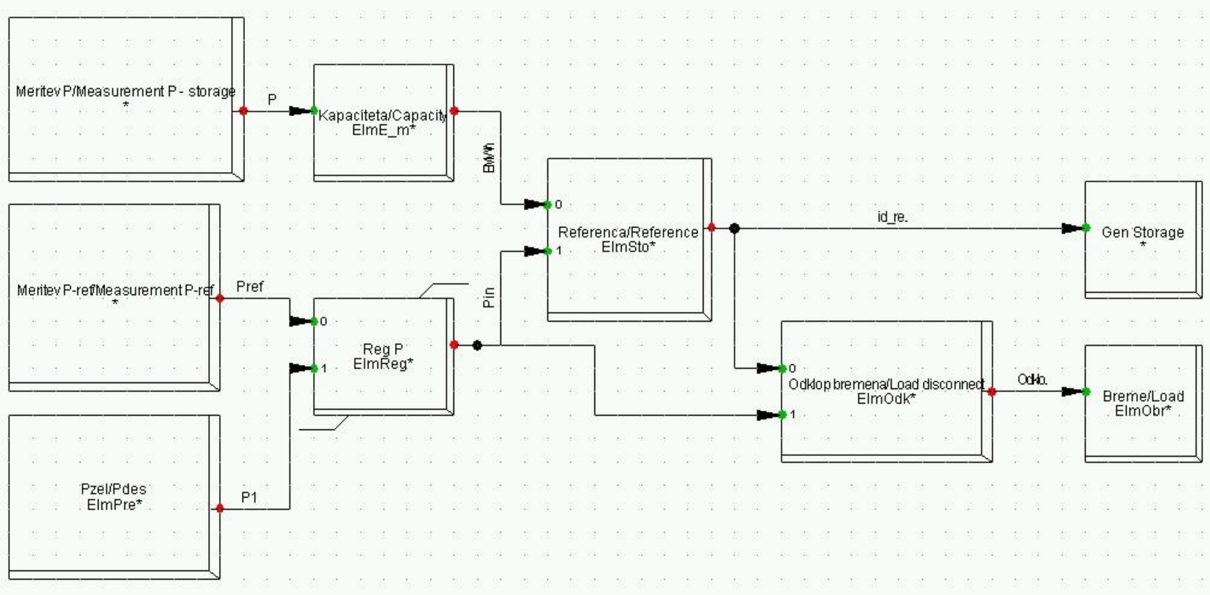

Figure 28: Energy storage and regulator model.

In the simulations carried out, the storage capacity was set to 20 MWh, while maximum output and input power were limited to 1 MW. The storage capacity is quite large (hydro based for example), so that the effect of it can be seen more clearly and to ensure suitable overall maximum capability planning. Network system simulation time is set to one week (from Monday to Sunday) and the desired power on K1441 is set to 0,4 MW during the week and 0,2 MW during the weekend.

Simulations and Results

Comparison of network system operating with energy storage turned on and off is shown in Figures 29 – 33. The load control was blocked at all times during this phase. We see that by using the energy storage system, we can restrict the power flow from the feeder and reduce the peak load by more than half. Using the energy storage system also facilitates better voltage conditions in feeder Interspar, as voltage fluctuation is slightly reduced.

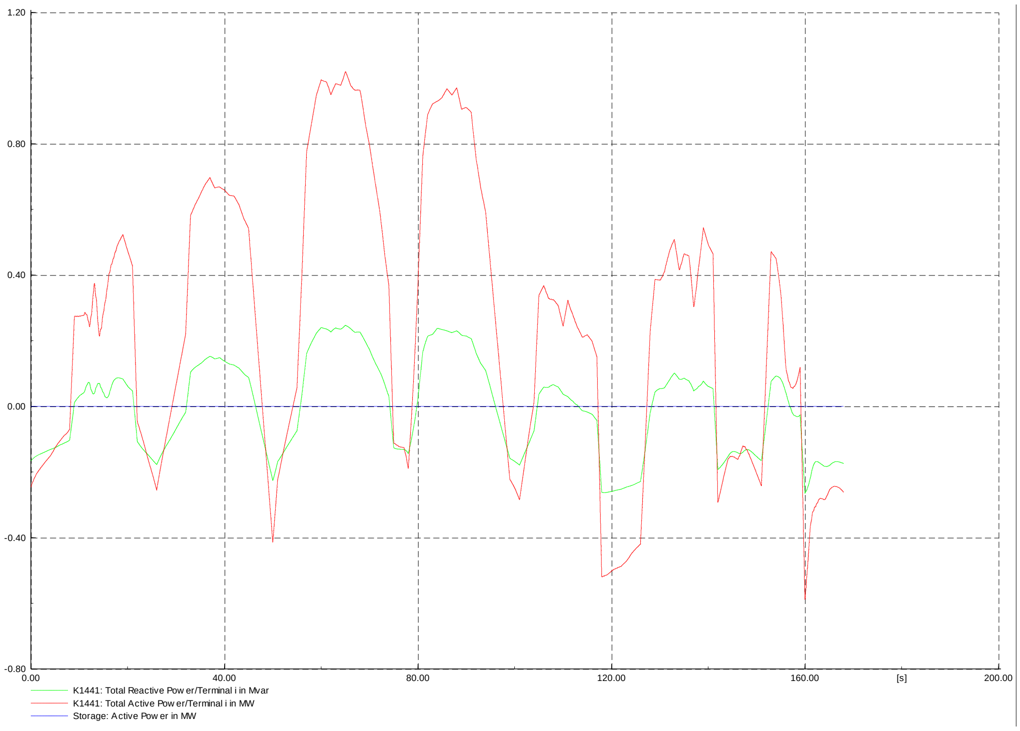

Figure 29: Power on line K1441 with energy storage system turned OFF.

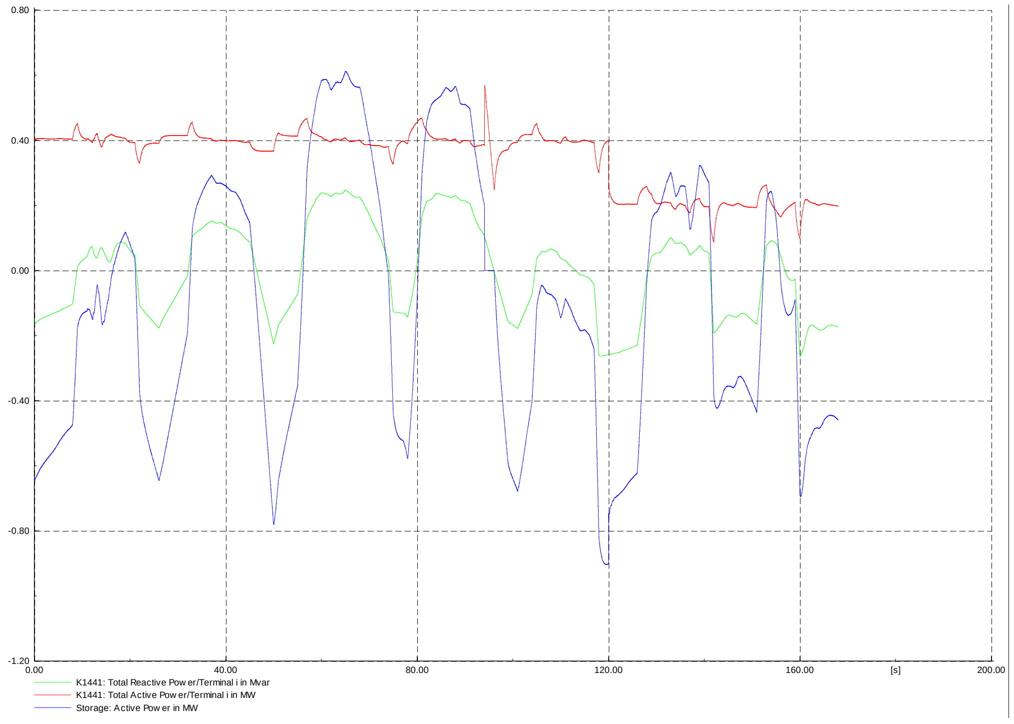

Figure 30: Power on line K1441 with energy storage system turned ON.

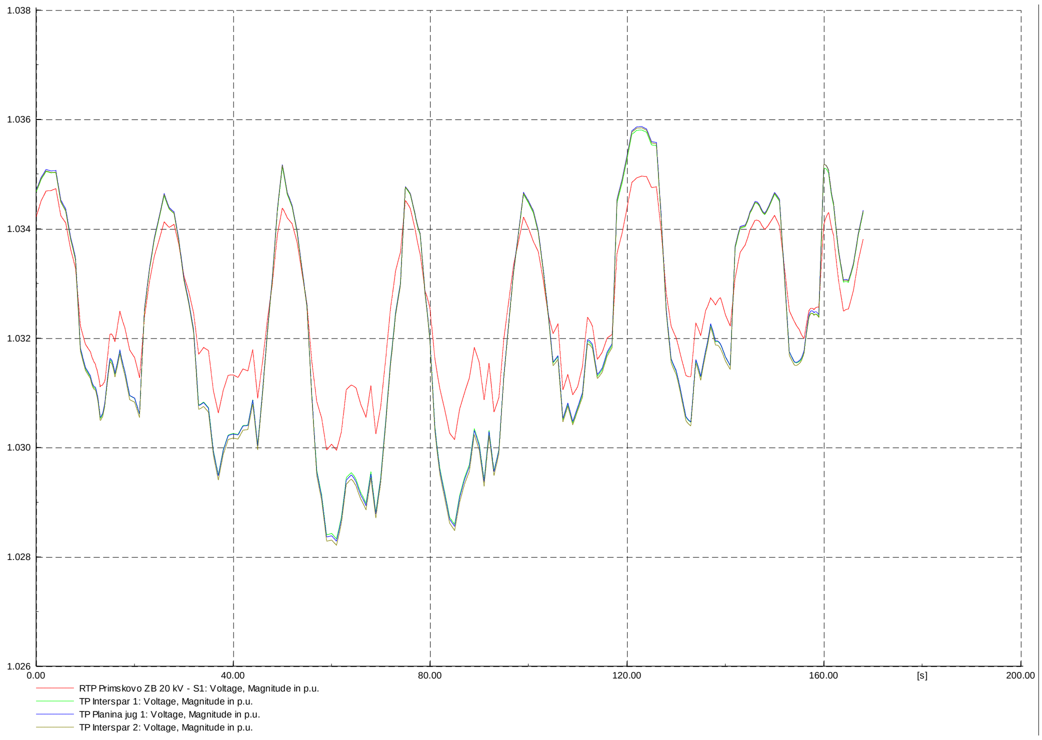

Figure 31: Interspar feeder Voltage at energy storage system turned OFF.

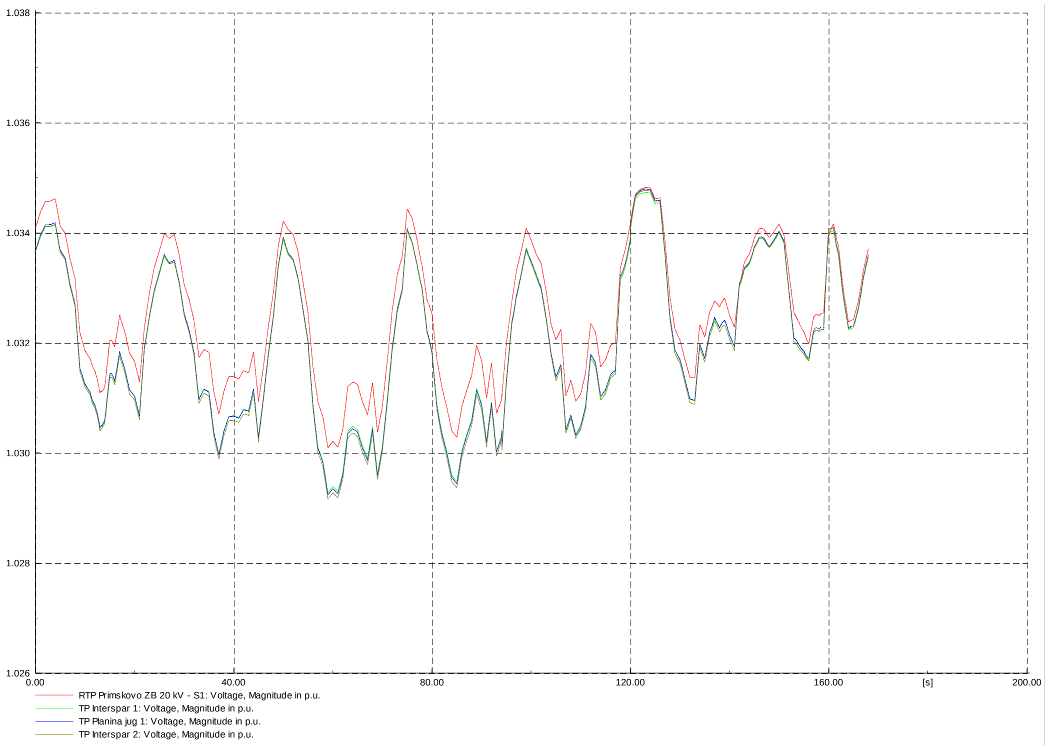

Figure 32: Interspar feeder Voltage at energy storage system turned ON.

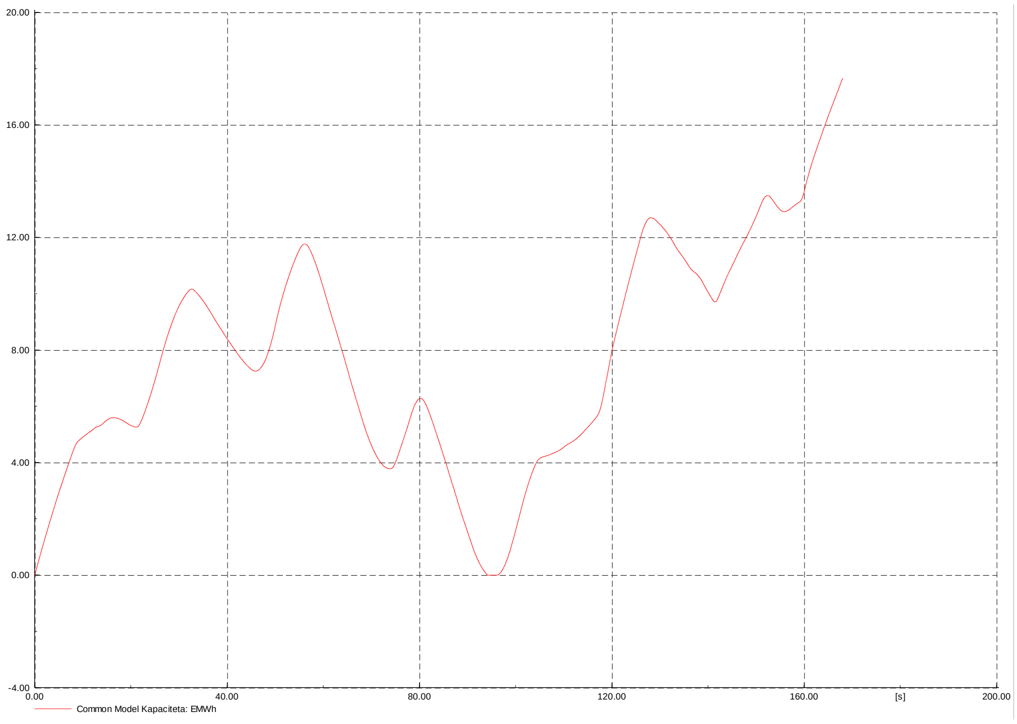

Figure 33: Current capacity of the energy storage system.

Below is a comparison of simulations with the load control turned OFF and ON. Note that there is a red marked area at the moment when energy storage system is unable to provide regulation requirements and load control is activated. We can see that after the partial load disconnection, peak power on K1441 is reduced.

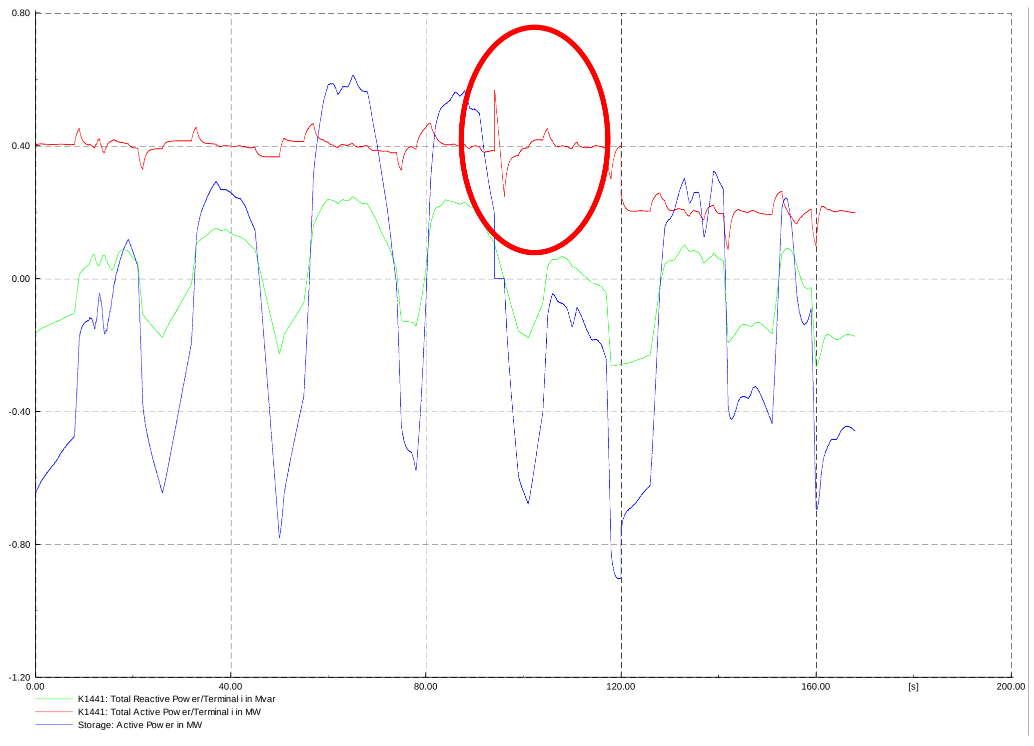

Figure 34: Power on K1441 with storage system activated and load control deactivated.

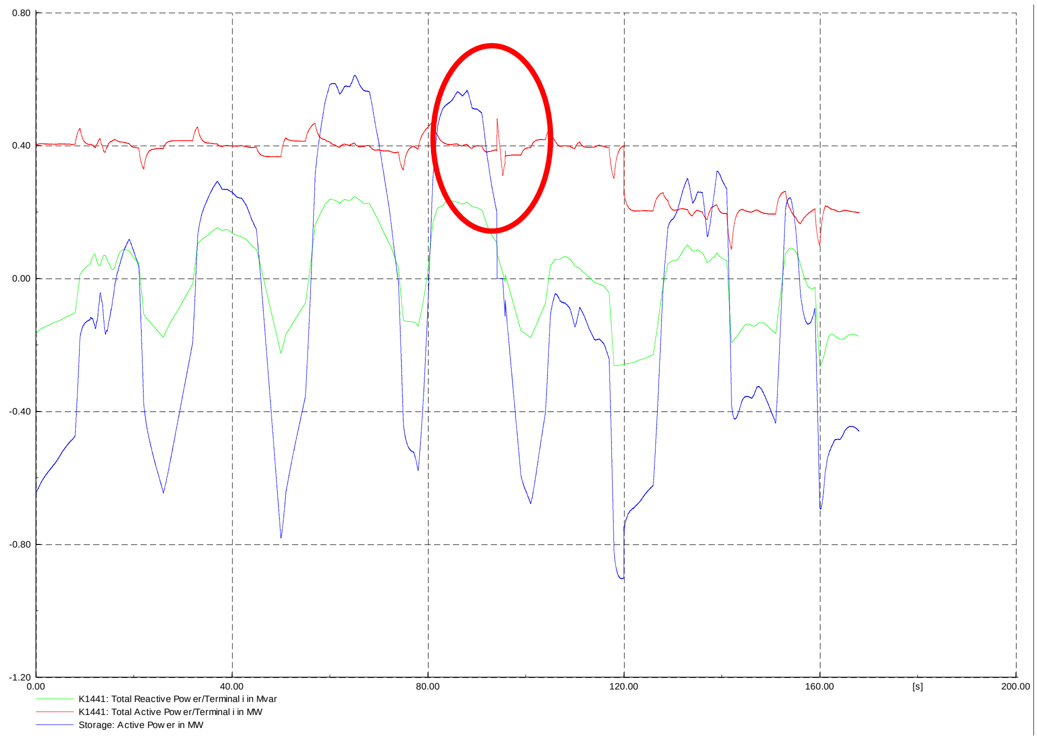

Figure 35: Power on K1441 with activated storage system and load control.

Intelligent load and distributed generation control with energy storage systems will be a new way to actively manage the distribution network power flows. An accurate input data for the controllers as well as the high resolution time of the data which DSE can provide is essential for optimal operation of such system.

In this chapter it was shown that load control and energy storage system management can have a significant influence on power flow in the network, which can be controlled in such way that big power fluctuations are eliminated. More constant power flow also eliminates some voltage regulation problems.

Conclusion

The availability of distribution state estimation, operating at near to real time, will provide the necessary accurate, complete and consistent real time database which is a prerequisite for the operation of a raft of distribution network automation functions. The use of such functions will be an essential component of future smart distribution networks.

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Appendices

Appendix 1. Network description

Substation 1

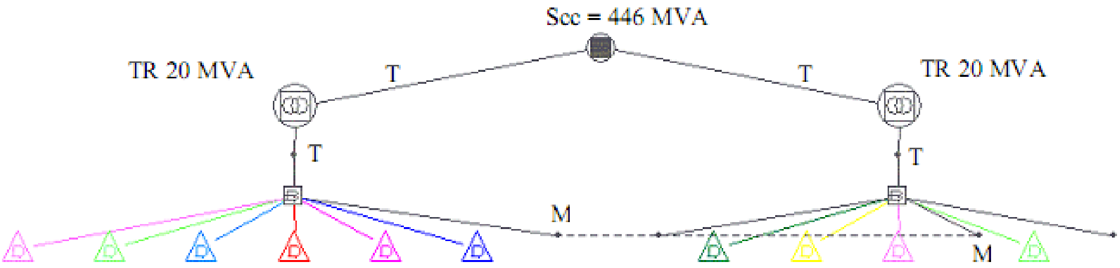

Figure 36: Structure of the primary substation 1

MV feeder	Number of remote control switches	Power Flow (kVA)	Length (km)	Overhead length (km)	Number of LV clients	Number of MV clients	Ps MV (kW)	Max. voltage drop (%)
F_1_1	2	1301.3	25.992	23.407	963	3	193	1.02
F_1_2	15	12879.8	26.743	0.049	5121	11	1532	4.18
F_1_3	0	38.7	0.076	0	74	3	402.2	0.01
F_1_4	1	1085.1	30.071	26.072	889	2	145	1.68
F_1_5	2	1624.0	22.816	17.653	915	1	48	1.15
F_1_6	2	5161.3	56.806	52.144	1692	3	242	9.97
F_1_7	1	1707.3	20.074	17.019	317	1	30	1.50
F_1_8	8	4068.8	51.042	47.913	1397	2	122	6.03
F_1_9	4	3659.9	11.807	0	2015	4	570	0.90
F_1_10	0	0	0.012	0	0	0	0	0.01

Table 5: Characteristics of MV feeders of substation 1

Substation 2

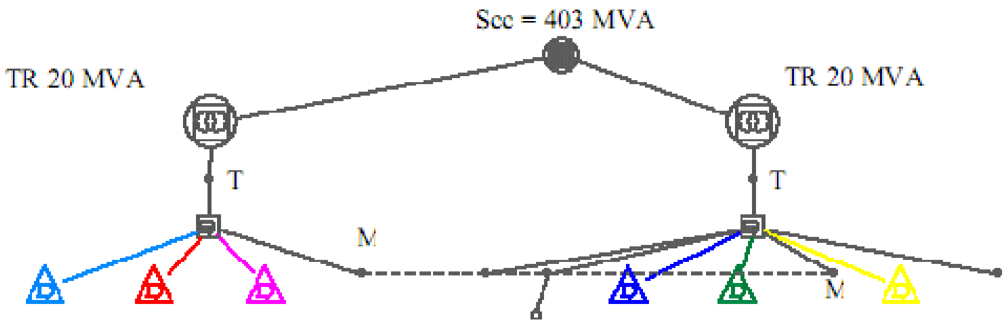

Figure 37: Structure of the primary substation 2

MV feeder	Number of remote control switches	Power Flow (kVA)	Length (km)	Overhead length (km)	Number of LV clients	Number of MV clients	Ps MV (kW)	Max. voltage drop (%)
F_2_1	3	2125.8	7.822	3.397	1279	3	155	0.18
F_2_2	2	1750.4	23.936	21.839	629	5	526	2.88
F_2_3	1	1249.9	15.789	12.935	705	2	84	0.89
F_2_4	4	374	33.446	30.33	339	2	66	0.66
F_2_5	3	2482.3	53.787	46	1369	8	880	2.82
F_2_6	4	1537.8	55.798	53.828	1176	1	52	2.35

Table 6: Characteristics of MV feeders of substation 2

Substation 3

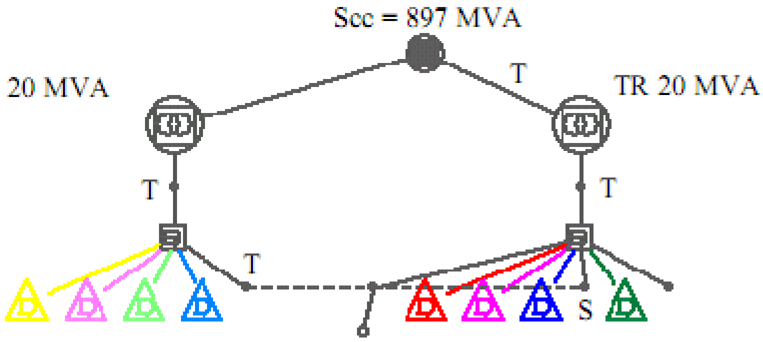

Figure 38: Structure of the primary substation 3

MV feeder	Number of remote control switches	Power Flow (kVA)	Length (km)	Overhead length (km)	Number of LV clients	Number of MV clients	Ps MV (kW)	Max. voltage drop (%)
F_3_1	0	1693.4	3.858	0	754	0	0	0.17
F_3_2	3	9235.6	33.090	6.847	3565	8	1020	6.46
F_3_3	4	2606.7	40.213	38.436	569	7	1162	2.04
F_3_4	1	259.5	14.810	14.102	239	2	90	0.08
F_3_5	2	260.9	16.009	15.217	175	4	128	0.09
F_3_6	1	3259	20.896	28.406	432	8	772	1.84
F_3_7	9	5742.2	57.533	34.754	2950	9	665	4.56
F_3_8	6	6512.5	10.717	0	2934	7	898	1.14

Table 7: Characteristics of MV feeders of substation 3

Substation 4

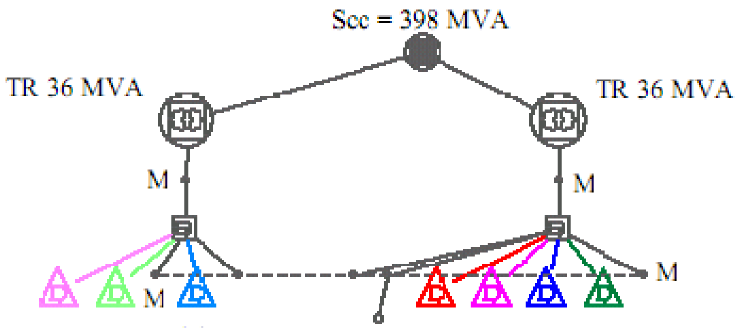

Figure 39: Structure of the primary substation 4

MV feeder	Number of remote control switches	Power Flow (kVA)	Length (km)	Overhead length (km)	Number of LV clients	Number of MV clients	Ps MV (kW)	Max. voltage drop (%)
F_4_1	3	6848.0	13.568	0	2411	10	720	1.98
F_4_2	6	6851.0	15.056	0.263	475	8	4886	2.94
F_4_3	11	11590.0	21.344	0	4484	39	2977	4.49
F_4_4	8	7822.5	54.032	20.021	2776	13	954	3.99
F_4_5	2	7135.4	21.702	16.714	1044	23	4440	4.11
F_4_6	5	1995.2	38.112	26.212	588	9	1409	2.35
F_4_7	1	4284.0	23.620	15.042	1160	9	982	4.40

Table 8: Characteristics of MV feeders of substation 4

Appendix 2. Results of Load Flow analysis with normal PQ errors

To have an idea of the precision of DSE results required to run automation functions, Load Flow analysis have been run on different MV feeders and with different errors in PQ loads. Errors of PQ load are considered as gaussian errors centred on the real value (each load has an independent error).

Three magnitude accuracies have been analysed: voltage amplitude, power flow in lines and Copper losses in the MV feeder. For each one of these magnitudes, the mean error and the maximum error are calculated[7]. The results for each magnitude and for each percent of PQ load error (10%, 30% and 50%) are summarized in the following tables.

Error of PQ loads : 10%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_1_1	0.0015%	0.305	0.0116%	2.357
F_1_2	0.0038%	0.757	0.0229%	4.582
F_1_3	-	-	-	-
F_1_4	0.0030%	0.599	0.0251%	5.096
F_1_5	0.0019%	0.380	0.0165%	3.348
F_1_6	0.0092%	1.827	0.0681%	13.255
F_1_7	0.0317%	6.650	0.3776%	80.439
F_1_8	0.0066%	1.328	0.0467%	9.274
F_1_9	0.0013%	0.268	0.0086%	1.745
F_1_10	-	-	-	-
F_2_1	0.0004%	0.072	0.0017%	0.349
F_2_2	0.0062%	1.251	0.0447%	8.981
F_2_3	0.0025%	0.500	0.0116%	2.360
F_2_4	0.0017%	0.356	0.0092%	1.873
F_2_5	0.0033%	0.665	0.0276%	5.562
F_2_6	0.0044%	0.890	0.0273%	5.492
F_3_1	0.0004%	0.084	0.0027%	0.545
F_3_2	0.0070%	1.407	0.0607%	12.027
F_3_3	0.0050%	1.014	0.0363%	7.326
F_3_4	0.0001%	0.030	0.0014%	0.279
F_3_5	0.0002%	0.031	0.0009%	0.190
F_3_6	0.0027%	0.538	0.0175%	3.540
F_3_7	0.0049%	0.985	0.0259%	5.190
F_3_8	0.0018%	0.370	0.0143%	2.897
F_4_1	0.0022%	0.454	0.0127%	2.576
F_4_2	0.0055%	1.124	0.0547%	7.704
F_4_3	0.0043%	0.872	0.0283%	5.669
F_4_4	0.0037%	0.741	0.0253%	5.094
F_4_5	0.0035%	0.716	0.0367%	7.361

[7] Mean error is considered as the mean value of all errors of different nodes/lines of all LF analysis. Maximum error is the most important error of all nodes/lines of all LF analysis.

F_4_6	0.0042%	0.844	0.0427%	8.641
F_4_7	0.0069%	1.389	0.0381%	7.626

Table 9: Accuracy of voltages amplitudes with erroneous PQ (Gaussian error of 10%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_1_1	1.7689%	0.963	11.1160%	13.747
F_1_2	1.3999%	6.785	14.0213%	80.483
F_1_3	-	-	-	-
F_1_4	1.5435%	1.351	21.2203%	15.175
F_1_5	1.6515%	1.596	11.3214%	21.945
F_1_6	1.5316%	2.705	12.1537%	35.017
F_1_7	2.2536%	30.398	11.7789%	219.225
F_1_8	1.7464%	1.940	14.9044%	37.305
F_1_9	1.4364%	3.511	9.5722%	37.517
F_1_10	-	-	-	-
F_2_1	1.5554%	2.293	11.5217%	27.892
F_2_2	1.8377%	2.358	32.1471%	27.924
F_2_3	1.9864%	1.544	34.9565%	20.553
F_2_4	1.4642%	0.635	12.4309%	7.123
F_2_5	1.6237%	1.011	13.5725%	28.891
F_2_6	1.7565%	0.961	12.9521%	20.420
F_3_1	1.7021%	5.610	12.0637%	35.166
F_3_2	1.0706%	9.261	21.4537%	84.395
F_3_3	1.8555%	1.875	12.3490%	43.853
F_3_4	2.0194%	0.236	32.4146%	5.052
F_3_5	1.8537%	0.255	11.4802%	3.377
F_3_6	2.0497%	1.785	127.9419%	36.342
F_3_7	1.5553%	1.953	12.7164%	43.819
F_3_8	1.3388%	6.821	10.4016%	81.790
F_4_1	0.9000%	8.341	11.0817%	52.849
F_4_2	1.5596%	23.433	32.9411%	92.927
F_4_3	1.0055%	9.578	21.2011%	84.020
F_4_4	1.2345%	3.066	30.4304%	49.909
F_4_5	1.5493%	3.654	11.4503%	62.457
F_4_6	1.6463%	2.277	10.9516%	34.366
F_4_7	1.5878%	3.180	12.5192%	42.493

Table 10: Accuracy of power flows with erroneous PQ (Gaussian error of 10%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_1_1	1.3387%	4.094%

F_1_2	0.8354%	2.945%
F_1_3	-	-
F_1_4	1.9072%	6.785%
F_1_5	1.6984%	6.585%
F_1_6	1.0385%	3.050%
F_1_7	4.6686%	17.699%
F_1_8	1.2208%	3.992%
F_1_9	1.3949%	4.753%
F_1_10	-	-
F_2_1	1.4725%	5.002%
F_2_2	2.3719%	8.099%
F_2_3	1.9226%	6.573%
F_2_4	1.7268%	5.743%
F_2_5	1.2439%	3.662%
F_2_6	1.2632%	4.558%
F_3_1	2.4719%	8.615%
F_3_2	1.1476%	4.108%
F_3_3	2.2255%	8.194%
F_3_4	1.9071%	8.189%
F_3_5	1.7065%	5.451%
F_3_6	1.1581%	4.349%
F_3_7	0.9895%	3.422%
F_3_8	1.3452%	4.853%
F_4_1	1.4047%	4.295%
F_4_2	2.6257%	8.318%
F_4_3	0.9569%	3.427%
F_4_4	0.8347%	2.733%
F_4_5	1.1734%	3.999%
F_4_6	1.9157%	7.099%
F_4_7	1.4850%	4.744%

Table 11: Accuracy of Copper losses in MV feeders with erroneous PQ (Gaussian error of 10%)

Error of PQ loads : 30%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_1_1	1.7689%	0.963	11.1160%	13.747
F_1_2	1.3999%	6.785	14.0213%	80.483
F_1_3	-	-	-	-
F_1_4	1.5435%	1.351	21.2203%	15.175
F_1_5	1.6515%	1.596	11.3214%	21.945
F_1_6	1.5316%	2.705	12.1537%	35.017
F_1_7	2.2536%	30.398	11.7789%	219.225
F_1_8	1.7464%	1.940	14.9044%	37.305
F_1_9	1.4364%	3.511	9.5722%	37.517
F_1_10	-	-	-	-
F_2_1	1.5554%	2.293	11.5217%	27.892
F_2_2	1.8377%	2.358	32.1471%	27.924
F_2_3	1.9864%	1.544	34.9565%	20.553
F_2_4	1.4642%	0.635	12.4309%	7.123
F_2_5	1.6237%	1.011	13.5725%	28.891
F_2_6	1.7565%	0.961	12.9521%	20.420
F_3_1	1.7021%	5.610	12.0637%	35.166
F_3_2	1.0706%	9.261	21.4537%	84.395
F_3_3	1.8555%	1.875	12.3490%	43.853
F_3_4	2.0194%	0.236	32.4146%	5.052
F_3_5	1.8537%	0.255	11.4802%	3.377
F_3_6	2.0497%	1.785	127.9419%	36.342
F_3_7	1.5553%	1.953	12.7164%	43.819
F_3_8	1.3388%	6.821	10.4016%	81.790
F_4_1	0.9000%	8.341	11.0817%	52.849
F_4_2	1.5596%	23.433	32.9411%	92.927
F_4_3	1.0055%	9.578	21.2011%	84.020
F_4_4	1.2345%	3.066	30.4304%	49.909
F_4_5	1.5493%	3.654	11.4503%	62.457
F_4_6	1.6463%	2.277	10.9516%	34.366
F_4_7	1.5878%	3.180	12.5192%	42.493

Table 12: Accuracy of voltages amplitudes with erroneous PQ (Gaussian error of 30%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_1_1	5.3668%	2.953	34.5163%	47.115
F_1_2	4.1770%	21.016	36.3927%	238.888
F_1_3	-	-	-	-
F_1_4	4.4818%	3.808	35.7328%	35.304
F_1_5	5.0029%	4.797	31.4529%	56.019
F_1_6	4.6132%	8.044	34.4393%	100.459
F_1_7	6.9024%	93.109	39.4329%	709.546
F_1_8	5.2152%	5.802	35.2608%	121.579

F_1_9	4.3133%	10.810	29.7129%	115.702
F_1_10	-	-	-	-
F_2_1	4.8080%	6.933	31.7993%	94.601
F_2_2	5.3351%	7.243	34.1546%	93.434
F_2_3	5.6750%	4.885	36.9586%	78.826
F_2_4	4.3514%	1.785	33.5731%	20.840
F_2_5	4.8481%	3.008	34.6282%	71.086
F_2_6	5.2815%	2.814	34.9294%	53.559
F_3_1	4.9487%	16.415	31.7079%	121.597
F_3_2	3.1006%	26.782	31.0091%	264.319
F_3_3	5.5776%	5.605	33.5937%	140.920
F_3_4	5.6171%	0.721	37.5554%	11.510
F_3_5	5.4926%	0.764	35.6872%	11.970
F_3_6	5.6170%	5.155	108.0117%	116.047
F_3_7	4.7138%	5.984	38.3248%	129.545
F_3_8	3.9989%	20.913	31.2923%	260.961
F_4_1	2.7223%	25.566	30.9188%	192.677
F_4_2	4.2943%	65.974	31.6894%	215.093
F_4_3	2.8358%	27.175	29.3682%	253.179
F_4_4	3.6139%	8.991	45.7355%	150.429
F_4_5	4.6771%	11.502	35.0229%	180.476
F_4_6	4.8212%	6.747	33.6117%	80.242
F_4_7	4.6631%	9.008	34.4793%	145.004

Table 13: Accuracy of power flows with erroneous PQ (Gaussian error of 30%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_1_1	4.0226%	15.041%
F_1_2	2.6589%	9.103%
F_1_3	-	-
F_1_4	5.3672%	17.704%
F_1_5	5.1360%	16.900%
F_1_6	3.1365%	10.859%
F_1_7	14.4302%	57.148%
F_1_8	3.5439%	12.293%
F_1_9	4.3150%	13.515%
F_1_10	-	-
F_2_1	4.1874%	13.158%
F_2_2	7.2513%	23.017%
F_2_3	6.1467%	19.691%
F_2_4	4.6903%	18.062%
F_2_5	3.7080%	11.264%
F_2_6	3.6380%	11.436%
F_3_1	7.2999%	25.021%
F_3_2	3.3146%	12.247%
F_3_3	6.5486%	19.681%

F_3_4	6.0655%	19.526%
F_3_5	5.0849%	17.182%
F_3_6	3.2139%	12.898%
F_3_7	3.2867%	11.293%
F_3_8	4.1460%	14.703%
F_4_1	4.2686%	16.237%
F_4_2	7.5283%	24.560%
F_4_3	2.6690%	9.771%
F_4_4	2.4237%	8.284%
F_4_5	3.7041%	12.626%
F_4_6	5.6538%	20.337%
F_4_7	4.0064%	13.691%

Table 14: Accuracy of Copper losses in MV feeders with erroneous PQ (Gaussian error of 30%)

Error of PQ loads : 50%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_1_1	1.3387%	4.094%	0.019%	0.058%
F_1_2	0.8354%	2.945%	0.068%	0.223%
F_1_3	-	-	-	-
F_1_4	1.9072%	6.785%	0.026%	0.082%
F_1_5	1.6984%	6.585%	0.014%	0.058%
F_1_6	1.0385%	3.050%	0.600%	1.618%
F_1_7	4.6686%	17.699%	2.755%	11.754%
F_1_8	1.2208%	3.992%	0.279%	0.961%
F_1_9	1.3949%	4.753%	0.012%	0.043%
F_1_10	-	-	-	-
F_2_1	1.4725%	5.002%	0.003%	0.010%
F_2_2	2.3719%	8.099%	0.227%	0.724%
F_2_3	1.9226%	6.573%	0.054%	0.174%
F_2_4	1.7268%	5.743%	0.010%	0.033%
F_2_5	1.2439%	3.662%	0.046%	0.155%
F_2_6	1.2632%	4.558%	0.115%	0.391%

F_3_1	2.4719%	8.615%	0.006%	0.023%
F_3_2	1.1476%	4.108%	0.083%	0.334%
F_3_3	2.2255%	8.194%	0.366%	1.191%
F_3_4	1.9071%	8.189%	0.003%	0.013%
F_3_5	1.7065%	5.451%	0.002%	0.007%
F_3_6	1.1581%	4.349%	0.306%	1.007%
F_3_7	0.9895%	3.422%	0.058%	0.182%
F_3_8	1.3452%	4.853%	0.029%	0.130%
F_4_1	1.4047%	4.295%	0.034%	0.084%
F_4_2	2.6257%	8.318%	0.113%	0.416%
F_4_3	0.9569%	3.427%	0.083%	0.296%
F_4_4	0.8347%	2.733%	0.029%	0.100%
F_4_5	1.1734%	3.999%	0.154%	0.606%
F_4_6	1.9157%	7.099%	0.031%	0.130%
F_4_7	1.4850%	4.744%	0.116%	0.375%

Table 15: Accuracy of voltages amplitudes with erroneous PQ (Gaussian error of 50%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_1_1	8.8902%	4.738	57.9568%	75.461
F_1_2	6.8477%	35.828	56.3732%	393.672
F_1_3	-	-	-	-
F_1_4	7.4266%	6.497	55.7505%	68.761
F_1_5	8.2085%	7.390	58.5919%	87.940
F_1_6	7.7069%	13.869	61.3993%	203.768
F_1_7	11.2211%	153.812	59.1263%	1015.443
F_1_8	8.6982%	9.714	60.0770%	192.374
F_1_9	7.2525%	17.314	56.3957%	155.647
F_1_10	-	-	-	-
F_2_1	7.9894%	11.921	57.3435%	147.807
F_2_2	8.9320%	12.255	65.0615%	158.587
F_2_3	9.2917%	8.066	51.2656%	131.006
F_2_4	7.4038%	3.274	62.4836%	38.143
F_2_5	8.1276%	4.936	63.2925%	154.286
F_2_6	8.7737%	4.650	61.3750%	104.663
F_3_1	8.2936%	27.715	55.3770%	202.046
F_3_2	4.9427%	44.122	52.1453%	502.221
F_3_3	9.1849%	9.272	67.1337%	258.306
F_3_4	9.3648%	1.202	61.4378%	24.498
F_3_5	9.3345%	1.276	59.2580%	15.633
F_3_6	9.0482%	8.591	105.9131%	148.179
F_3_7	7.6902%	9.945	59.6350%	227.318
F_3_8	6.9005%	36.237	46.0632%	333.464
F_4_1	4.3126%	38.915	51.4159%	333.669
F_4_2	6.7817%	105.161	45.7309%	236.269

F_4_3	4.8612%	47.101	59.5614%	391.213
F_4_4	5.9754%	14.907	67.6299%	295.318
F_4_5	7.9061%	19.147	57.8734%	358.271
F_4_6	8.0521%	11.484	58.9646%	161.995
F_4_7	7.8980%	15.084	57.9913%	172.101

Table 16: Accuracy of power flows with erroneous PQ (Gaussian error of 50%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_1_1	6.4951%	23.295%
F_1_2	4.4643%	14.462%
F_1_3	-	-
F_1_4	9.3218%	34.360%
F_1_5	7.6009%	30.373%
F_1_6	5.3241%	20.067%
F_1_7	23.9576%	84.362%
F_1_8	6.2539%	18.872%
F_1_9	6.7531%	23.286%
F_1_10	-	-
F_2_1	7.7555%	24.994%
F_2_2	12.2959%	40.444%
F_2_3	10.3641%	39.623%
F_2_4	8.9502%	30.481%
F_2_5	6.0512%	23.467%
F_2_6	5.6968%	20.417%
F_3_1	12.0280%	42.927%
F_3_2	5.2553%	17.477%
F_3_3	10.4235%	34.989%
F_3_4	10.1030%	31.480%
F_3_5	8.3612%	31.624%
F_3_6	5.6065%	19.636%
F_3_7	5.1776%	18.439%
F_3_8	7.2807%	25.179%
F_4_1	6.4651%	28.371%
F_4_2	11.7045%	42.003%
F_4_3	4.4748%	15.352%
F_4_4	4.0061%	13.961%
F_4_5	6.4647%	23.833%
F_4_6	9.6562%	31.984%
F_4_7	6.7961%	23.496%

Table 17: Accuracy of Copper losses in MV feeders with erroneous PQ (Gaussian error of 50%)

Appendix 3. Results of Load Flow analysis with normal PQ errors

Error of PQ loads : 10%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_4_4	0.1008%	20.39590701	0.1835%	36.87682369

Table 18: Accuracy of voltages amplitudes with erroneous PQ (error of 10%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_4_4	7.5215%	47.79516921	14.4962%	344.8194288

Table 19: Accuracy of power flows with erroneous PQ (error of 10%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_4_4	19.5613%	19.5613%

Table 20: Accuracy of Copper losses in MV feeders with erroneous PQ (error of 10%)

Error of PQ loads : 30%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_4_4	0.3032%	61.34037225	0.5524%	111.0015207

Table 21: Accuracy of voltages amplitudes with erroneous PQ (error of 30%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_4_4	22.9232%	146.3132943	31.4520%	1046.139082

Table 22: Accuracy of power flows with erroneous PQ (error of 30%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_4_4	65.6296%	65.6296%

Table 23: Accuracy of Copper losses in MV feeders with erroneous PQ (error of 30%)

Error of PQ loads : 50%

MV feeder	Mean error for Voltage amplitude (%)	Mean error for Voltage amplitude (V)	Max. error for Voltage amplitude (%)	Max. error for Voltage amplitude (V)
F_4_4	0.5067%	102.4912843	0.9238%	185.631503

Table 24: Accuracy of voltages amplitudes with erroneous PQ (error of 50%)

MV feeder	Mean error of power flows (%)	Mean error of power flows (kVA)	Max error of power flows (%)	Max error of power flows (kVA)
F_4_4	38.8070%	247.6750213	52.8304%	1759.3781

Table 25: Accuracy of power flows with erroneous PQ (error of 50%)

MV feeder	Mean error in Copper losses (%)	Maximum error in Copper losses (%)
F_4_4	121.0629%	121.0629%

Table 26: Accuracy of Copper losses in MV feeders with erroneous PQ (error of 50%)