THEME [ENERGY.2012.7.1.1] Integration of Variable Distributed Resources in Distribution Networks

(Deliverable 2.3)

Definition of Overall System Architecture

Lead Beneficiary:

EFACEC

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List of Acronyms and Abbreviations

µG	Microgeneration
AM	Asset Management
AMI	Advanced Metering Infrastructure
AMM	Advanced Metering Management
CAP	Capacitor Banks
CHP	Combined Heat and Power
CC	Control Centre
CL	Controllable Load
DER	Distributed Energy Resources
DG	Distributed Generation
DoW	Description of Work
DSL	Digital Subscriber Line
DSM	Demand Side Management
DSO	Distribution System Operator
DT	Distribution Transformer
DTC	Distribution Transformer Controller
EB	Smart Meter
ERP	Enterprise Resource Planning
ESCO	Energy Service COmpanies
EV	Electric Vehicle
FACTS	Flexible AC Transmission Systems
GENCO	GENeration COmpanies
GIS	Geographic Information Systems
GPS	Global Positioning Systems
HMI	Human-Machine Interface
HV	High Voltage
IED	Intelligent Electronic Device
LV	Low Voltage

MV	Medium Voltage
NWP	Numerical Weather Predictions
OLTC	On-Load Tap Changing
OMS	Order Management System
OPF	Optimal Power Flow
PMU	Phasor Measurement Units
RES	Renewable Energy Sources
RTU	Remote Terminal Unit
SCADA/DMS	Supervisory Control and Data Acquisition / Distribution Management System
SAS	Substation Automation System
SSC	Smart Substation Controller
STOR	Storage Device
TSO	Transmission System Operator
TVPP	Technical Virtual Power Plant
VPP	Virtual Power Plant
WLS	Weighted Least Square

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Executive Summary

In order to fully realize the vision of the SuSTAINABLE concept, a reference architecture for management and control of the distribution system as a whole is described. This novel architecture is based on the hierarchical architecture already deployed in the InovGrid test site in Évora, Portugal – InovCity.

The main objective of the reference architecture proposed is to allow large scale integration of Distributed Energy Resources, namely Distributed Generation based on variable Renewable Energy Sources such as wind generators and photovoltaic panels, in a secure and efficient way.

This will require the development of specific algorithms and tools to support distribution system operation that are able to exploit distributed intelligence in several network components. These advanced control functionalities are summarily described and include: Load and Renewable Energy Sources Forecasting, State Estimation and Voltage Control.

Furthermore, the main information flows foreseen concerning data between the several control layers and control signals between the several network devices are identified. The functionalities residing at each control layer and equipment requirements are also detailed and specified.

Finally, the concept of Technical Virtual Power Plant is developed, applied to distribution networks, bearing in mind the reduction of the impact on the transmission network of variable generation in distribution systems under very high penetration of Renewable Energy Sources. The main components and architecture of this Technical Virtual Power Plant is detailed, particularly regarding the interaction with the Transmission System Operator and the integration in a market environment.

1. Architecture and Control Layers

Description of the **Task 2.2 "Definition of Overall System Architecture"** from the Description of Work (DoW) [1]:

"*In order to fully realize the vision of the SuSTAINABLE concept,* ***a novel control and management architecture must be developed*** *that addresses the distribution system as a whole. The main objective of this architecture will be to* ***allow large scale integration of DER*** *and improve the flexibility and reliability of the system. This will be done through the* ***implementation of specific advanced functionalities for planning and operation*** *that exploit distributed intelligence among the several network components. The reference architecture for the SuSTAINABLE project will be* ***based on the hierarchical architecture already implemented in the InovGrid test site*** *in Évora that will include several control layers*"

The main aim of the proposed control architecture for the SuSTAINABLE project is to enable a coordinated and efficient control of the whole electrical distribution system, taking advantage of its own resources in order to overcome technical problems that may arise in operation especially in scenarios with high integration of Renewable Energy Sources (RES). It must be stressed that these DER, located at the LV level or at the MV level, may be either the property of the Distribution System Operator (DSO) or be owned by individual customers/entities. Therefore, in the latter case, the use of these resources for supporting network operation has to be ensured through adequate means of remuneration for instance in the framework of a market structure, as described later in Chapter **Error! Reference source not found.**.

A general framework for the data flow model of the SuSTAINABLE concept is presented in Figure 1. This framework comprises two different types of information: commercial (related to billing information) and technical (related to operational information).

At the top level is the DSO Central Information System, which includes Advanced Metering Management (AMM), Enterprise Resource Planning (ERP) / Asset Management (AM), Order Management System (OMS) and Geographic Information Systems (GIS). All the billing information from the customers down to the LV level, transmitted by the Advance Metering Infrastructure (AMI), must be processed in an AMM module located at the central information system level. Also, since several control algorithms that may be envisaged (such as forecasting functions, load flow analysis, state estimation routines) require the knowledge of the exact position of the DER, it will be necessary to have GIS at the central information system level that should not be local but cover all the territories that the DSO is responsible for. Therefore, every SCADA/DMS should be able to communicate with this system. Moreover, a similar situation occurs for the technical characteristics of the lines, substations, transformers or smart meters. These characteristics are usually recorded in a central database (ERP / asset management) as

well all the subcomponents (e.g., current/voltage transformers, etc.). Their replacement or occurrence history is also logged (i.e., replace of a current transformer with a new one with a different transformation ratio). This central database also interacts with the OMS of the distribution network assets. A Communication and Event Management System module, at the SCADA/DMS level, is also considered for functions such as outage analysis and pattern detection, communication failures with pattern detection.

Finally, the DSO can be a market facilitator that collects all the commercial (e.g., billing measurements) and technical (e.g., consumption, generation, technical constraints) data and provides this information to the market agents (e.g., GENeration COmpanies – GENCO, Energy Service COmpanies – ESCO, retailers, etc.) via DSO Central Information System. The DSO also provides data to the TSO in order to support its operational management processes (e.g., detect reverse power flows from the distribution grid) and facilitate the DSO/TSO cooperation. Ancillary services activated bids are communicated by the TSO and must also be taken into account since it is not realistic that they will communicate directly with each SCADA/DMS.

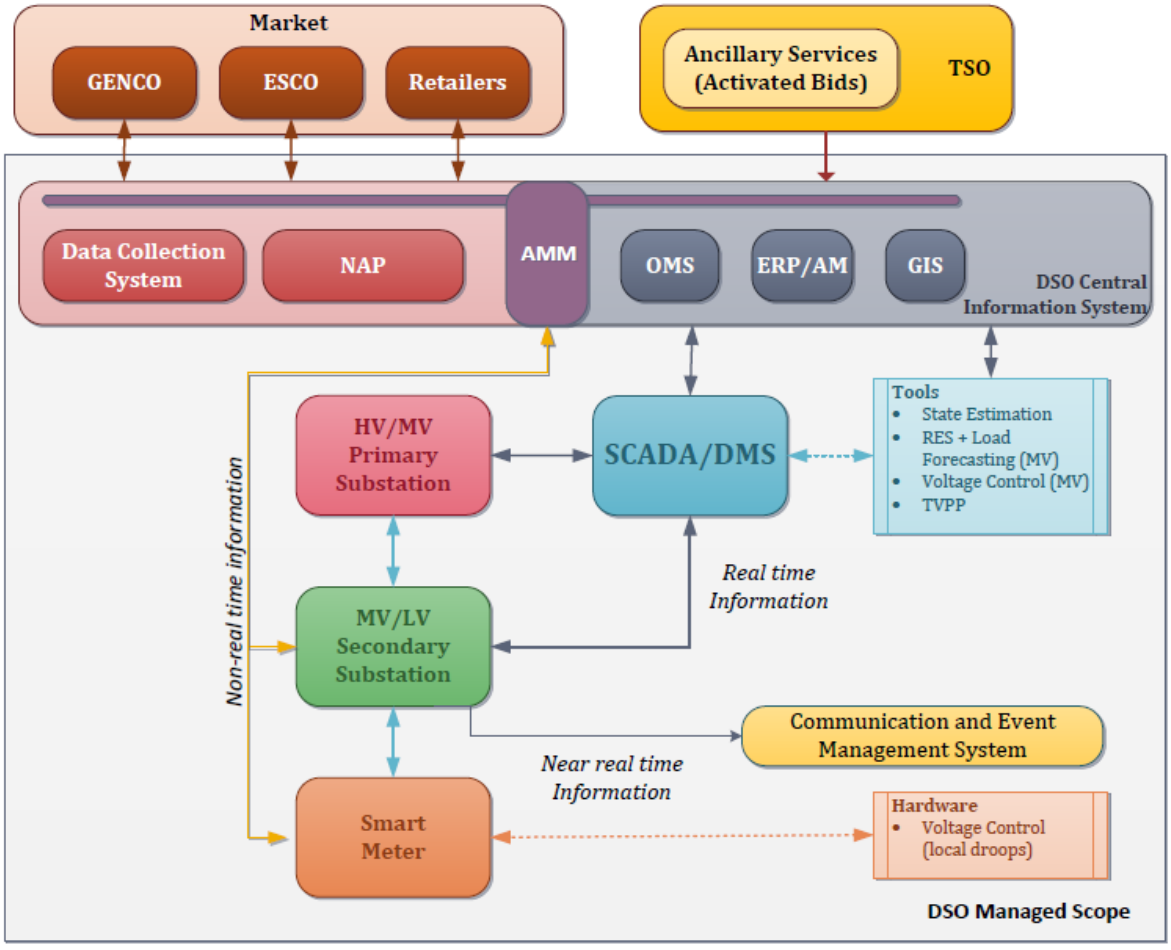


Figure 1 – Overall SuSTAINABLE Framework and Data Flow Model

The main objective of the architecture to be proposed according to the SuSTAINABLE concept concerns the operational part of distribution system. Therefore, a control and management architecture is proposed based on the hierarchical architecture already implemented in the InovGrid test site in Évora, Portugal (InovCity), illustrated in Figure 2, and is organized in three main layers as follows:

- The upper control level with the Supervisory Control and Data Acquisition / Distribution Management System (SCADA/DMS) located at the control centre of the distribution system (i.e., dispatch level). This layer is under the responsibility of the DSO for managing the whole distribution network and should ensure the interface with the upstream transmission network.
- An intermediate control level located at the HV/MV primary substation – the Smart Substation Controller (SSC) – which is in charge of each MV network and incorporates a set of advanced control and management functionalities that will allow a coordinated and efficient operation of the MV system exploiting the multiple resources that may be available at this level through set-points, namely storage systems (STOR MV in Figure 2), controllable loads under Demand Side Management (DSM) actions (CL MV in Figure 2), Distributed Generation units (DG in Figure 2), On-Load Tap Changing (OLTC) transformers (OLTC in Figure 2) and capacitor banks (CAP MV in Figure 2).
- A lower control level located at the MV/LV secondary substation – the Distribution Transformer Controller (DTC) – which is responsible for a single LV network. This control layer is used to serve as a gateway of data to the upstream systems but will also incorporate some basic control functionalities in order to efficiently respond to technical problems that may occur at the LV network level by communicating set-points to the several smart meters and corresponding DER under its control as well as for MV/LV On-Load Tap Changing (OLTC) transformers and storage devices (property of the DSO) that may be located at the secondary substation.
- A field control level located at the customer premises in which the smart meter will serve as a gateway to control its associated resources, namely micro-generation (µG in Figure 2), controllable loads under DSM actions (CL LV in Figure 2), storage devices (STOR LV in Figure 2), and Electric Vehicles (EV in Figure 2).

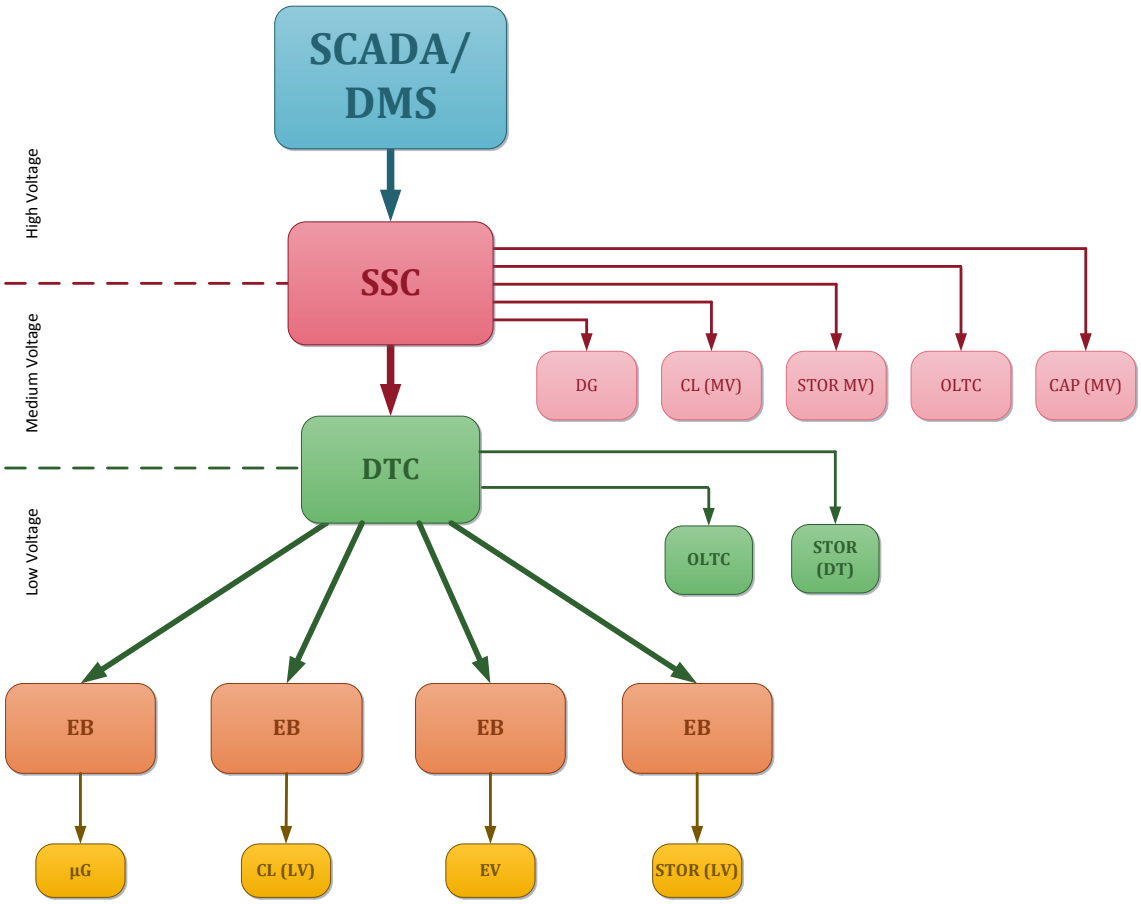


Figure 2 – Proposed SuSTAINABLE Architecture and Control Layers

This architecture is expected to evolve to a future version in the medium/long run where a Home Energy Manager (HEM) at the LV customer will be installed, which will be in charge of managing all the resources of domestic clients including controllable loads (appliances), microgeneration units, EV and storage devices (if they exist) following a request from the upstream control structure (i.e., the DSO). In this case, there will be a coordinated management of all resources regardless of their nature, requiring only a single smart meter that will serve as a gateway to communicate with the HEM. This architecture is presented in Figure 3.

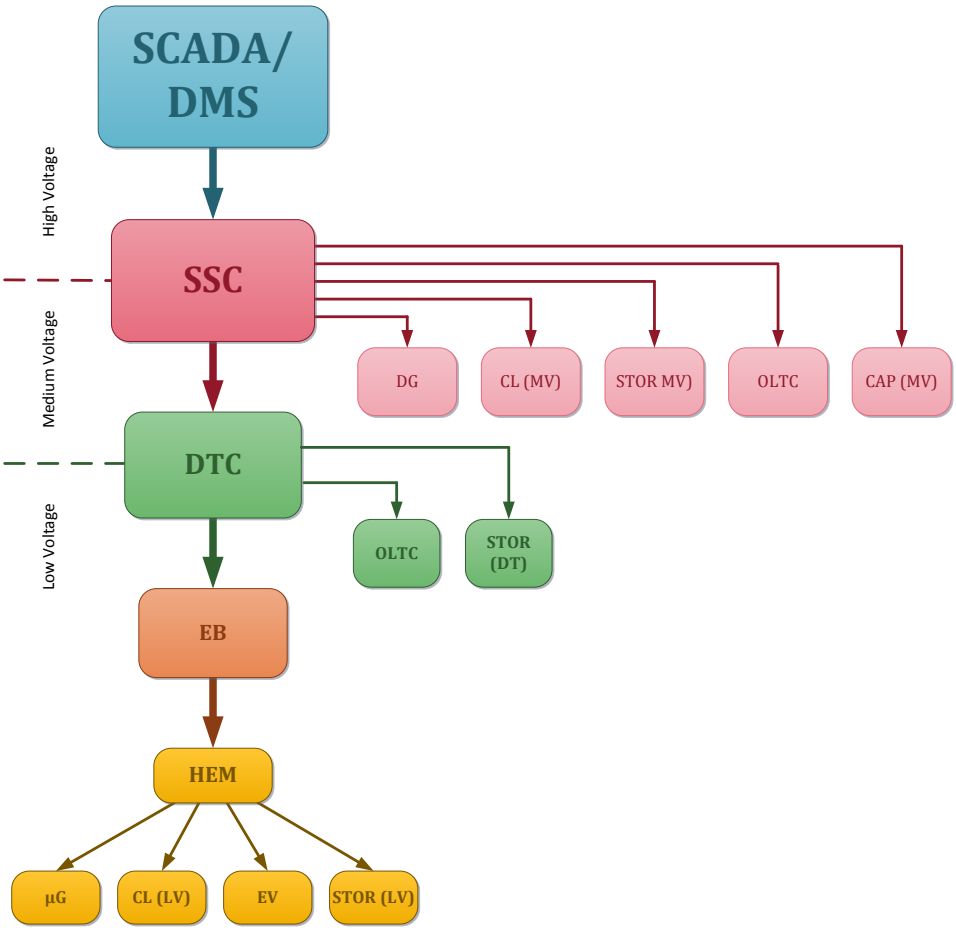


Figure 3 – Future SuSTAINABLE Architecture and Control Layers

2 Advanced Control Functionalities

Description of the **Work Package 3 "Design of new tools for smart distribution system operation"** from the DoW [1]:

"*The main objective of WP3 is to* ***develop a set of advanced functionalities to enable maximizing the integration of RES in distribution networks****, together with a methodology for optimal provision of differentiated QoS considering a spatial mapping of grid node requirements*"

Future distribution systems will be composed of active networks (at the HV, MV and even LV levels) with several controllable and non-controllable DER, which will result in large volumes of data to be exchanged. Consequently, the proposed control architecture incorporates several control layers previously identified and enables some form of automated local actions in order to overcome technical problems in network operation on the several voltage levels.

In order to achieve an efficient coordinated control of the distribution system, it is necessary to develop specific advanced control and management functionalities. These functionalities, under the control of the DSO, will aim at exploiting local resources whenever possible in order to overcome technical problems that may occur in the distribution network. This is particularly important as it is now essential that the problems that may arise at the distribution level are not passed to the upstream transmission level and translate into an uncertainty seen by the transmission system. In this regard, the distribution system should not be seen as a burden to the transmission system and use its own resources to manage the technical difficulties that may be encountered.

Consequently, a set of advanced control and management functionalities will be developed that will aim at: a) ensuring an increased knowledge of the distribution system and b) effectively acting on the available DER to solve technical problems.

The main functionalities identified are the following:

- State Estimation at the MV level;
- Load and RES Forecasting at the MV level;
- Network Planning at the MV level;
- Voltage Control at the MV, LV and field level.

Depending on whether these functionalities reside physically at the DMS or SSC level, two different architectures can be envisaged:

- Data processed at the SCADA/DMS level: parallel processing of each SSC data on separate CPUs of a computer cluster or a multi-core processor, which constitutes a **hierarchical** structure;

- Data processed at the SSC level: **decentralized** algorithm based on geographically distributed computers physically located at different SSC, provided an appropriate communication infrastructure is available.

At a first stage, it is assumed that these functionalities may reside physically at the central system's level – at the SCADA/DMS, since they will require data from different MV networks (i.e., different SSC), according to the hierarchical structure presented previously. Nevertheless, in the medium/long-term, it is expected that the architecture may evolve to a really distributed one provided that adequate communication solutions (such as GPRS – General Packet Radio Service, or Digital Subscriber Line – DSL, Radio Frequency, Fibber, etc.) are employed.

The different control layers, their physical levels as well as the main functionalities identified are presented in Figure 4.

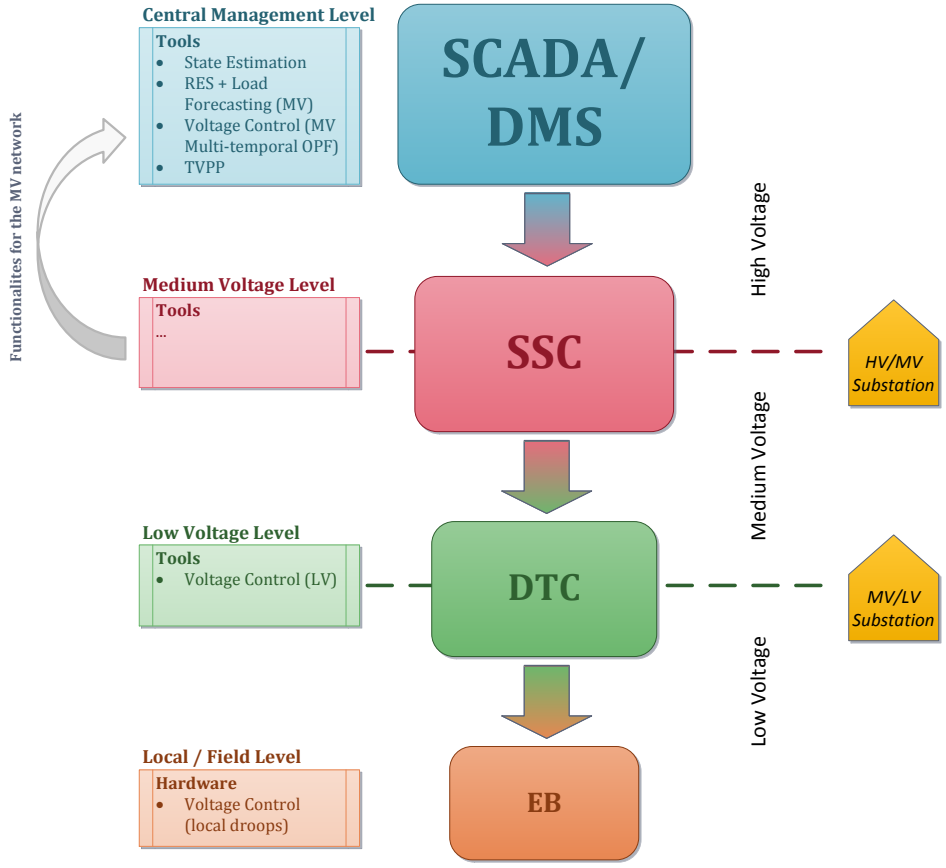


Figure 4 – Proposed Functionalities and Control Layers

2.1 Load and Renewable Energy Sources Forecasting

Description of the **Task 3.1 "Advanced Forecasting Tools for Reliable Prediction of Load at the MV Level"** from the DoW [1]:

"*Develop advanced forecasting tools to make reliable* ***predictions of load at the MV level, with a time horizon of 15 minutes to 3 hours****. It will not only target an accurate forecast of the amount of load demand, but* ***will also address the composition of the forecasted load and the expected evolution of its components, distinguishing particularly between controllable an non-controllable loads*** *(…)****.*** *The tools will be* ***developed based on the assumption that there is synchronized information in all MV buses*** *(DTC will provide aggregated LV network information and MV costumers will have smart meters)"*

Description of the **Task 3.2 "Advanced Local Forecasting Tools to Predict Renewable Generation"** from the DoW [1]:

"In this task advanced forecasting tools to make ***predictions of generation for the DG units (wind power and PV) connected at the MV level will be developed taking as time horizon 30 minutes to 3 hours****. The prediction tool for DG w****ill rely on a record of all the data that can be measured and it is available****, such as: recent states of the system,* ***forecasts for neighbouring DG units*** *(wind generation and PV), forecasts for regional solar PV and wind power production, and a record of recent measurements of weather variables. The prediction tool will extract, from this information,* ***point and probabilistic forecasts*** *for wind power generation and solar power generation"*

Figure 5 depicts the framework of the RES (wind and solar power) and load forecasting systems to be developed for the MV level. Both systems are installed at the central management level, in the DMS of the DSO. Although installed in the DMS, the forecasting systems can be virtually distributed by HV/MV substation, but using information from DTC connected to different HV/MV substations.

The load forecast takes as inputs the load time series of each DTC, which means that the forecasts are produced for the total load of each MV/LV substation. The load consumption of medium/large consumers directly connected to the MV network is individually forecasted.

Similarly to the load forecast system, the RES forecasts are also produced for each DTC and for DG units connected to the MV network. In order to capture the impact of clouds in solar power for the very short-term forecast horizon (i.e., up to six hours ahead) the measurements from the EB with solar power are included as explanatory variables in the model. Thus, the RES forecasting system can use two alternative sources of information:

a) RES generation time series aggregated by DTC and which decreases the volume of transmitted data from the DTC to the DMS;
b) Aggregated generation by DTC plus time series data from the EB; this solution increases the volume of transmitted data.

It must be stressed that although currently the communication between the DTC and the EB is in many cases based on PLC communication, other technologies are expected to become widely available in the future. For these technologies all the data will be collected in a central point and not in each substation separately.

Numerical Weather Predictions (NWP) for multiple coordinates in one region can be included in the RES forecasting system in order to produce forecasts for longer time horizons (e.g., up to 48 hours ahead) with lower forecast error compared to a model that only uses measured information.

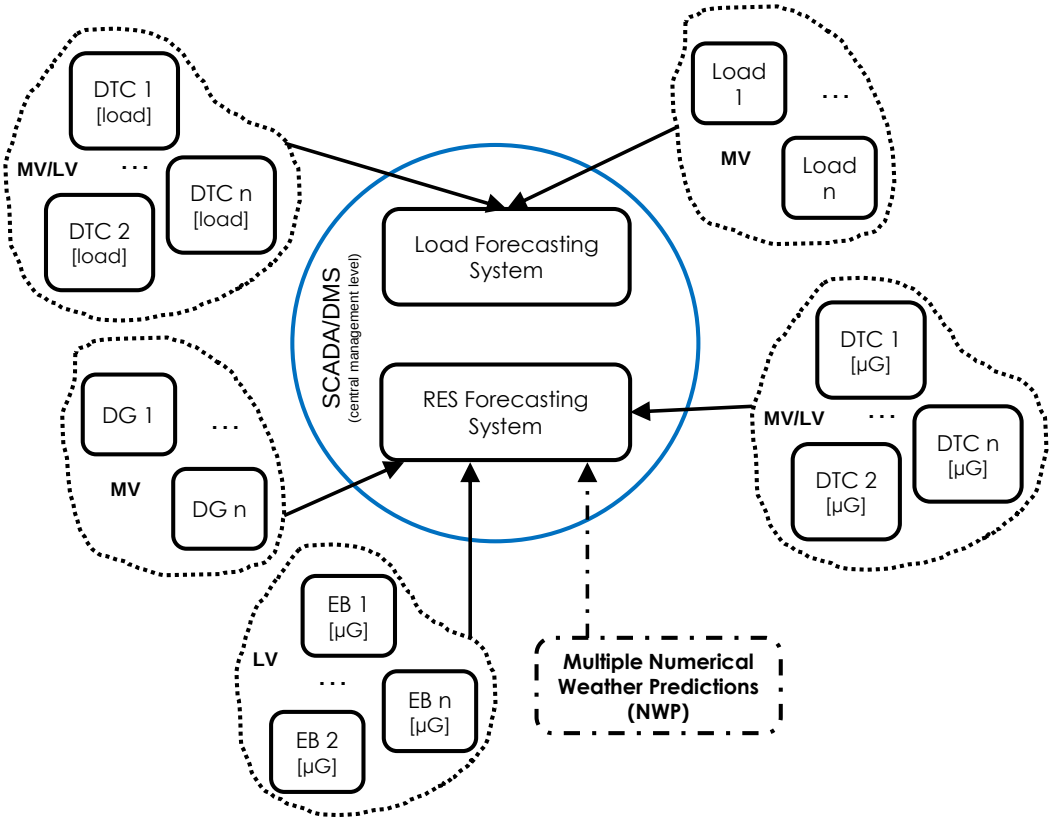


Figure 5 – Framework of the Load and RES Forecasting Systems at the MV Level

2.1.1 Forecast Update

The time instant t_0 (illustrated in Figure 6) is called launch time and corresponds to the time instant where a new forecast is generated by the system. This forecast is generated with all the data (e.g., historical records, NWP) available at t_0.

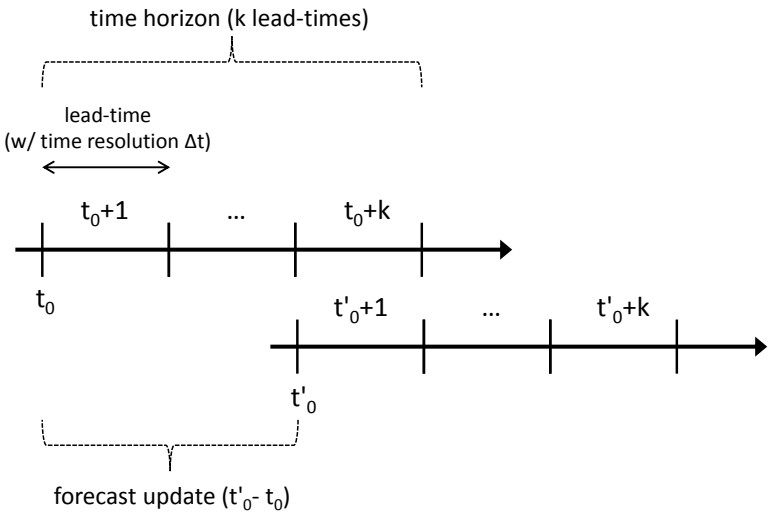


Figure 6 – Forecast Update, Lead-time and Time Horizon

The difference between t_0 and the time instant of the next forecast (t'_0) is called forecast update. It can range between 30 minutes and several hours (e.g., four hours) and is constrained by the communication requirements related with the transmission of time series data from all EB to the DMS. For example, sending information from all EB to the DMS every 30 minutes might be prohibitive in terms of cost of communications.

2.1.2 Lead-time

The lead-time is a time interval of the forecast horizon with time resolution Δt, i.e., forecast launched at time instant t_0 for lead-time t_{0+k}. Usually, for horizons on the order of 24-72 hours-ahead, the time resolution is hourly and, for shorter time horizons, it can be in the scale of minutes (e.g., 10 minutes, 30 minutes).

The time resolution varies with the decision-making problem that uses the forecasts. For steady-state analysis (e.g., voltage control) it is foreseen a time resolution of 30 or 60 minutes. The time resolution of the forecast also defines the time resolution of the historical time series data that is used to fit the statistical models and produce the forecasts.

2.1.3 Time Horizon

The time horizon indicates the total length of the forecasting period (i.e., set of k lead-times with a specified time resolution) in the future. If only historical records from the load and RES generation time series are available, the time horizon is up to 6 lead-times ahead (i.e., 3 hours for 30 minutes time resolution, 6 hours for hourly time resolution). If NWP are available, the time horizon can be extended to 48 hours-ahead, but it can go up to one week-ahead.

2.1.4 Forecasting Products

Three different forecasting products are envisioned:

- Point forecast by DTC: single value of the forecasted RES generation and load;
- Probabilistic forecast by DTC: can be expressed as a set of quantiles or interval forecasts (depicted in Figure 7a), or a probability density function (pdf), or moments from the distribution for each lead-time;
- Statistical scenarios (depicted in Figure 7b) by DTC: generally, the RES probabilistic forecasts do not include the temporal and spatial dependency of forecast errors. Although, not included in the DoW, the dependency of errors is valuable information for multi-temporal decision-making problems, such as voltage control. Each scenario is a time/spatial trajectory generated with a statistical method.

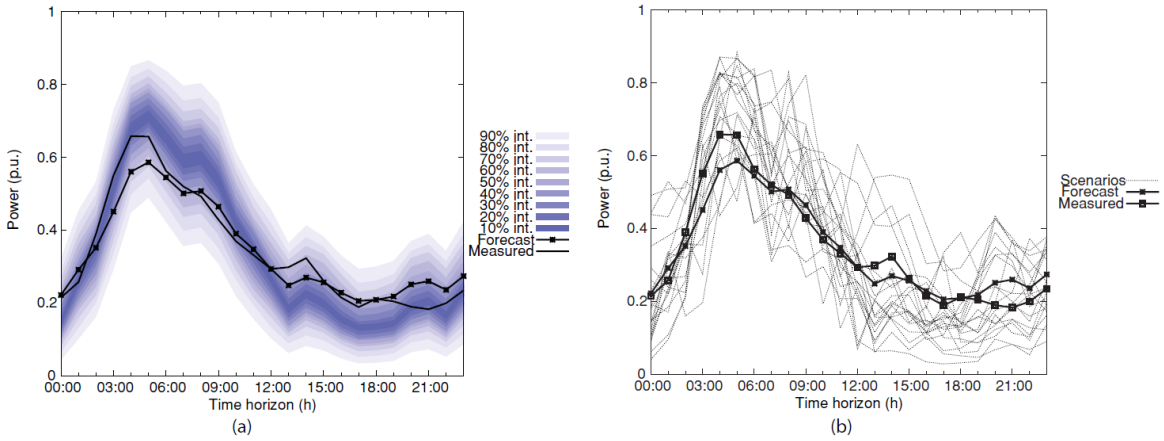
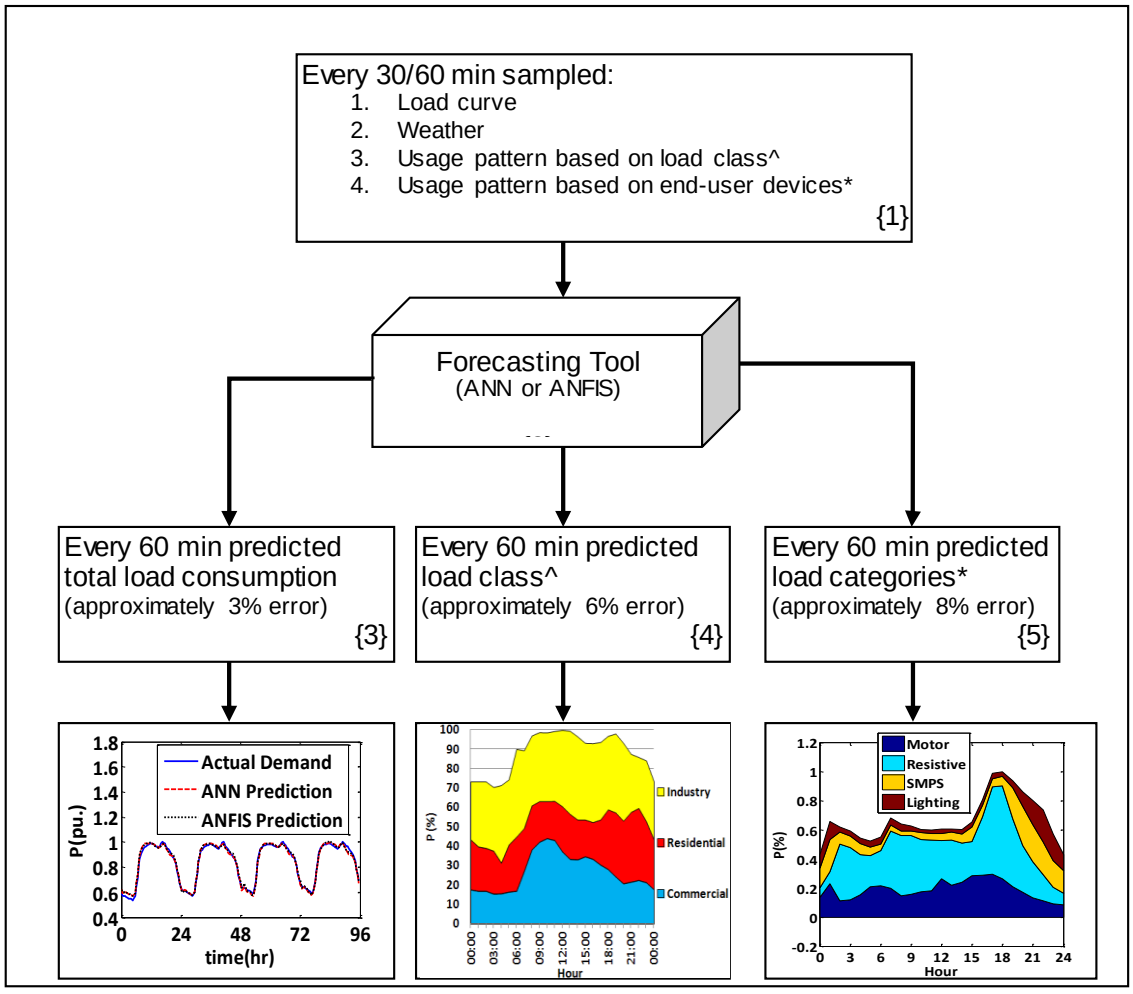


Figure 7 – (a) Forecast Intervals, centred in the median, and limited by its lower and upper bounds, which are forecasted quantiles; (b)Twenty Statistical-based Scenarios with temporal dependency of errors and that respect the marginal distribution of the probabilistic forecasts (i.e., plot in (a))

2.1.5 Advanced forecasting tools for reliable prediction of load at the MV level

The block diagram below presents methodology for load forecasting that has been developed and implemented. The methodology forecasts both, total demand and, for the first time, demand composition down to the level of load categories at any point in time using historic demand data together with measured voltage, real power, reactive power and weather data (or a subset of above). Based on forecasted load composition and generic dynamic responses of different load categories further forecast of dynamic load response can be made at given time based on readily available information without having to perform field tests or measurements.



Block {1}: This block collects input data every 30/60 min for prediction of total load as well as load subdivision. It includes:

- Load curve sampled every 30/60 min for real power consumption

- Weather data from, e.g., Weather History [26] (sampled every 30/60 min) including temperature, humidity and wind speed or any combination of these.
- Real time usage pattern based on load classes (i.e. residential, commercial, industrial) from, e.g., [27]
- Real time usage pattern based on load types, i.e., induction motors, resistive loads, Switch Mode Power Supply (SMPS), lighting etc., from, e.g., [27]

Block {2}: This block represents the load forecasting tools developed using Artificial Neural Network (ANN) or Adaptive Neuro-based Fuzzy Inference System (ANFIS)..

2.1.5.1 Artificial Neural Network

The structure of a two-layer feed-forward artificial neural network with a hidden layer and an output layer is shown in Fig. 8. Either layer contains an input vector, a weight matrix W, a bias vector b, a sum operator, a transfer function f and an output vector. The relationship of the input and the output in either layer can be represented by (1). The output of the hidden layer is the input of the output layer. The full description of this type of ANN is given in [28-30].

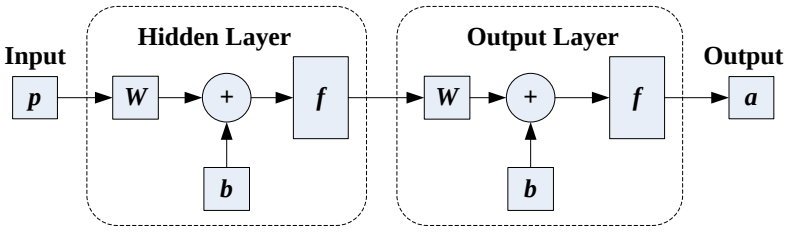


Figure 8 – Structure of a feed-forward ANN

$$\boldsymbol{a} = f(\boldsymbol{W}^{\boldsymbol{T}}\boldsymbol{p} + \boldsymbol{b}) \qquad (1)$$

2.1.5.2 Adaptive Neuro-based Fuzzy Inference System

The structure of an ANFIS with two inputs, two membership functions and one output is shown in Fig. 9. Layer 1 is the *fuzzification* layer, where the input data are fuzzfied. Layer 2 executes the fuzzy AND Function of the antecedent part of the fuzzy rules. The outputs from Layer 2 are named firing strengths [31]. In Layer 3, each of firing strengths is normalized and the normalized firing strengths are the weights assigned to corresponding rules. In Layer 4, the consequent part is executed by implication method. Layer 5 is a sum operator that superimposes all outputs of Layer 4 and produces the final output. ANFIS is a robust AI tool since its output is unique once the numbers and types of membership functions and the training algorithms are defined.

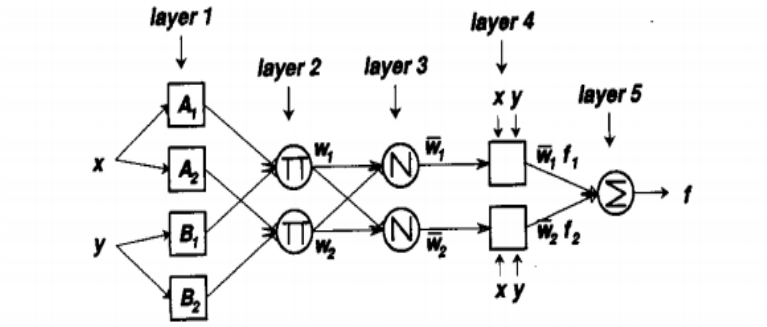


Figure 9 – Structure of an ANFIS [31]

Block 3~5: These blocks show the outputs and the examples.

2.2 State Estimation

Description of the **Task 3.3 "Advanced Local Distribution Grid Monitoring / State-Estimation"** from the DoW [1]:

"*In this task,* ***a robust approach to distribution state estimation will be developed*** *with enough robustness* ***to face lack of information collected from the smart meters or RTU located in the grid by using additional historical information*** *stored in the system data base"*

2.2.1 Introduction

The main objective of the state estimation functionality is to find the values for a set of variables (states) that adjust in a more adequate way to a set of network values (measurements) that is available in real-time [2]. The state variables are such that all the other network variables can be evaluated from them, and the operation state is obtained. The calculation of state variables considers the physical laws directing the operation of electrical networks and is typically done adopting some criteria. The Distribution State Estimation (DSE) is implemented at the functional level of the HV/MV primary substation, and only the MV level state variables are calculated [3]–[7]. It is assumed that the state estimation functionality will be installed at the central management level, i.e., at the SCADA/DMS.

Although distribution systems are unbalanced in nature, in order to avoid modelling complexities, the network is assumed to be balanced and the single phase equivalent network model is considered for state estimation analysis.

2.2.2 State Estimation Information

In order to derive consistent and qualified state estimates, it is necessary to use all the information available for the network and not only real-time measurements because their availability is very limited. Therefore, the DSE functionality includes information coming from different sources, namely: AMI, DTC acting as Remote Terminal Units (RTUs), and Phasor Measurement Units (PMUs) synchronized by the Global Position System (GPS) signal, if available [7]–[9]. Smart meters (EBs) connected to LV nodes can make time-synchronized measurements of active (*P*) and reactive (*Q*) loads, as well as voltage magnitudes, at predefined time intervals (usually every 15 minutes). These measurements are transmitted to a database server periodically (for instance, daily). This ensures that the DSE will have, at least, measurements from the previous day of all the loads [6].

Based on these measurements, a set of pseudo-measurements will be generated and used, together with near real-time information, for instance from distributed generators (DG) [6], to make the network fully observable and guarantee an adequate degree of redundancy for running the state estimator. This can be accomplished by an autoregressive load estimation model [7], which utilizes previous day metered LV consumption data as well as same day explanatory variables, such as temperature, day type (weekday or weekend) ,, humidity, etc. The upstream MV/LV substation load (P and Q) will be estimated by aggregating all the downstream LV loads. This will be done using an expert system trained specifically for this purpose [35]. This expert system will be located at the central management level, where historical information is available.

The MV/LV substations that require these pseudo-measurements generation are the ones without DTC or substations where the transmission of real time DTC measurements has failed. When the MV/LV substation has a DTC with measurements that are available in real-time, the generation of pseudo-measurements is not necessary.

2.2.3 State Estimation Algorithm

The weighted least-squares (WLS) method [5] will be used for DSE, considering the following nonlinear measurement model:

$$z = h(x) + e$$

The nodal states will be estimated by minimizing the quadratic objective function:

$$\min_{x} J(x) = \left(z - h(x)\right)^{T} R^{-1} \left(z - h(x)\right)$$

where z is the measurement vector, $h(x)$ is the vector of nonlinear functions relating measurements to states, x is the true state vector consisting of nodal voltages

(magnitudes and phase angles), e is the vector of normally distributed measurement errors, with $E(e) = 0$ and $E(ee^T) = R = diag(\sigma_i^2)$, and σ_i^2 is the variance of the ith measurement error. Measurement gross errors will be identified using the largest normalized residual test [2].

A general framework for the combined simulation of load and state estimation is presented in Figure 10. This framework assumes that previous day's customer load data are available with their corresponding normalized load curves, as well as near real-time data from DGs. The DSE is executed at predefined time periods, usually every 15 minutes.

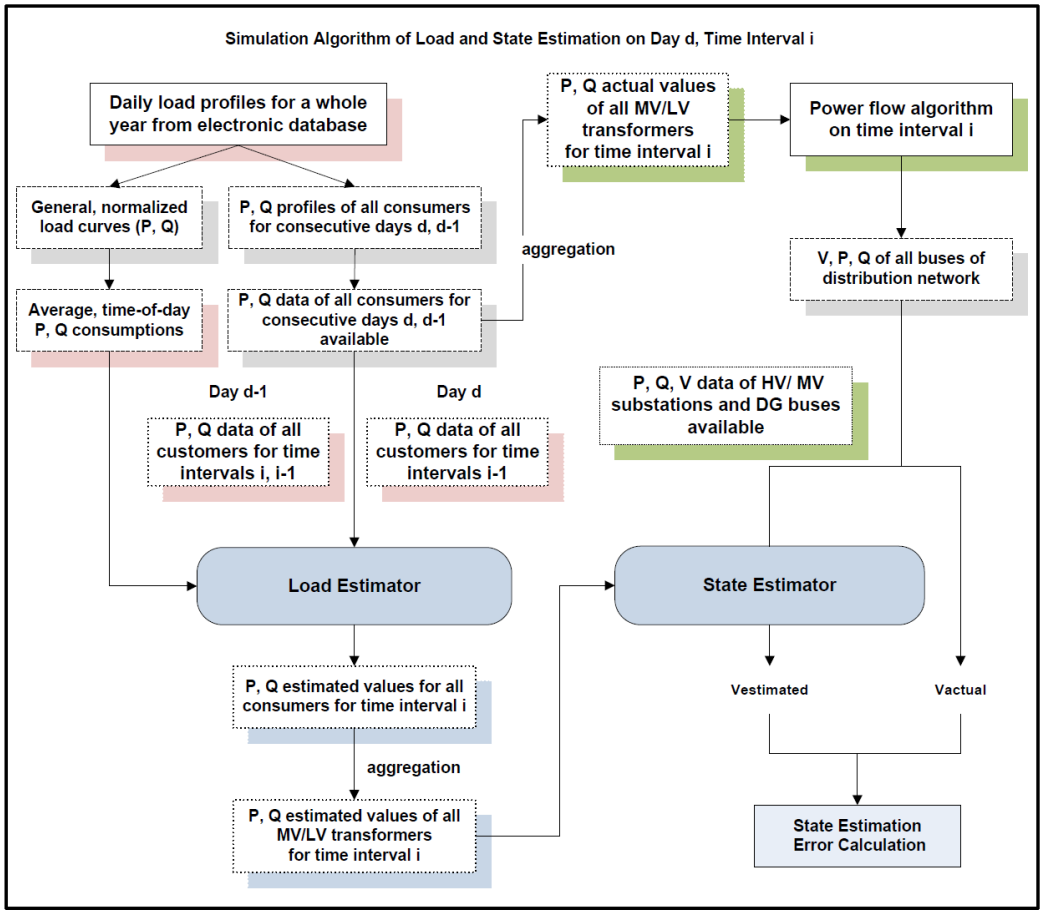


Figure 10 – Data flow chart of the load and state estimation

2.2.4 Parallel Processing

In order to reduce the computational burden of the enormous volumes of data produced by the smart meters and the load estimation algorithms that generate the pseudo measurements, parallel processing will be implemented by dividing the network into control areas (i.e. one zone for each HV/MV substation and its associated feeders

assigned to SSC). The zones will perform local data acquisition (near real-time measurements from DG and generation of pseudo-measurements). A hierarchical structure will be developed that will exploit parallel processing of the data gathered from each zone on multiple CPUs or multicore CPUs and coordinate the zone border information to compute the system-wide state [10]–[13]. Zones can communicate with each other and with the coordination level.

2.2.5 Topology Identification

Due to frequent reconfiguration actions and limited or missing switch status information, it is necessary to develop algorithms that can detect topology changes and identify the correct network topology. It must be considered one network configuration to initiate the state estimation process, but the formulation should be flexible enough to correctly identify any topology changes. In order to simulate an in service / out of service generator, load, or branch, the generalized state estimation model, reported in [14]–[17] will be used. The proposed approach will use any available status information from switching devices together with all pseudo-measurements and any available real-time information from smart metering equipment. A probabilistic procedure is proposed for the topology identification, by augmenting the state vector with the switch statuses and "soft" operating constraints with a degree of uncertainty (zero voltage drops across closed switching devices and zero flows through open switching devices). This means that topology will be estimated at the same time with analogue information.

When the network is split into two or more non-connected electrical islands, due to a set of switching devices reported as open, the system becomes unobservable and the state vector cannot be computed. Another problem appears as the number of islands is not known when starting the state estimation process as a consequence of some switching devices having an unknown or suspicious status. The network splitting problem can be formulated as the problem of finding the state variables in all network islands. By including appropriate soft constraints (pseudo measurements), involving the open breakers and the local reference buses of the islands, the network becomes observable and the state vector can be estimated [17].

2.2.6 Smart Meter Placement

In order to assure accurate distribution voltage estimates and minimize the estimated voltage uncertainties, identification of the minimum number and location of additional voltage, current and P/Q sensors in the network is included as a sub-function of the state estimation functionality [18]–[19]. A heuristic method will be applied using the state error covariance matrix as a metric to assess the accuracy of the DSE solution [5]:

$$C_x = \left(H^T R^{-1} H \right)^{-1}$$

where the ith diagonal entry $C_x(i,i)$ of C_x is the variance of the ith state.

2.3 Voltage Control

Description of the **Task 3.4 "Advanced Coordinated Voltage Control"** from the DoW [1]:

"*To maximize the integration of renewable energies in distribution networks,* ***advanced operation strategies need to be implemented at the level of the HV/MV substations to control voltage*** *magnitudes and real power injections*"

The objective of the coordinated voltage control functionality to be developed in the SuSTAINABLE project is a manifold one. The maximization of the integration of energy from variable RES is a first target. Other significant objectives include the optimization of voltage regulation, the reduction of energy losses and the minimization of the RES energy curtailments. In order to achieve this, it is necessary to develop a methodology that will control voltage throughout the network by coordinating all available regulation devices, DG active and reactive output power, storage and controllable loads. This strategy will be implemented at the level of the HV/MV primary substation (SSC), while a secondary controller will also exist at the level of the MV/LV substations (DTC).

Such a methodology will exploit two different levels of control, which will be detailed in the following subsections:

- **At the MV level** – using a multi-temporal Optimal Power Flow (OPF) at the functional level of the SSC to coordinate the several MV control means (DER, storage, loads, OLTC, capacitor banks, etc.) in order to avoid technical problems by satisfying the constraints and minimizing a single or a multi-objective function. Furthermore, in real time operation, the multi-temporal OPF may be augmented by practical rule-based control, which will address potential regulation issues (e.g. unforeseen load or DER power variations, voltage limit violations);
- **At the LV level** – centralized controller housed in the DTC, which will send set-points to DER located within the specific LV network (i.e., controllable loads, microgeneration, storage devices) in order to observe the requirements imposed by the SSC or by responding independently to a set of voltage alarms obtained from the EB; using local droop functionalities implemented in some inverters interfacing the DER available and a centralized voltage control algorithm housed in the DTC to remotely update the parameters of these droops based on a set of rules.

Figure 11 illustrates the developed approach for the voltage control system at the MV and LV levels.

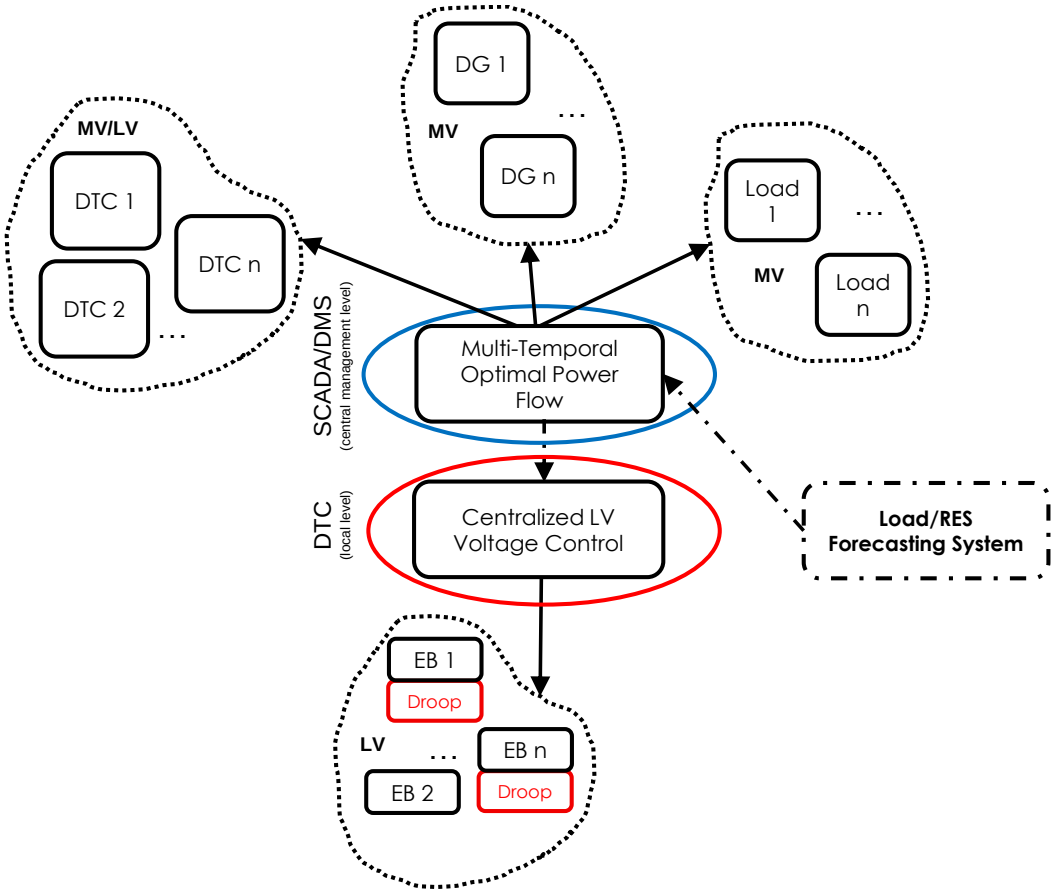


Figure 11 – Framework of the Voltage Control System

2.3.1 Multi-Temporal Optimal Power Flow at the MV Level

Description of the **Sub-Task 3.4.1 "Development of an Integrated Multi-Temporal Operational Management Tool for MV Grids"** from the DoW [1]:

*"This sub-task involves the development of the software optimization tool to obtain solutions for a **multi-temporal OPF that will use the information provided by the prediction tools mentioned and the state estimation results to define set-points** for OLTC, capacitor banks, batteries and storage devices, as well as controllable demand and controllable DG units"*

A multi-temporal OPF that will operate at the level of the HV/MV primary substation, i.e., at the functional level of the SSC, will be responsible for controlling MV network operation. Nevertheless, since the load/RES forecasting systems are located at the central systems' level (SCADA/DMS), the multi-temporal OPF will also be physically at the SCADA/DMS. An overview of the proposed approach is given in Figure 12.

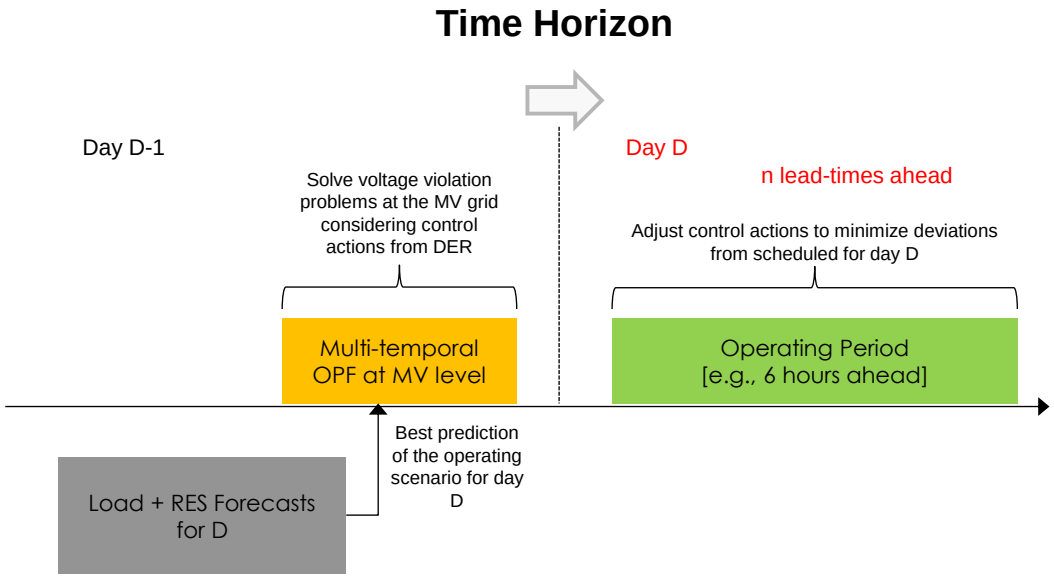


Figure 12 – Proposed Approach for the Voltage Control at the MV Level

As can be observed, the approach developed is expected to work in 2 time-frames:

- Day-ahead (D-1 Analysis) → Taking as inputs load and generation bids from the market agents as well as results from state estimation, the multi-temporal OPF will produce a set of control actions for the next day by MV network node (i.e., DTC). The main objective will be to maximize the integration of energy coming from variable RES subject to a set of technical and operational constraints, namely node voltage limits and branch thermal limits. In this algorithm, the available DER will be utilized, including not only the resources owned by the DSO but also resources from customers providing ancillary services to the system. The resulting actions will allow defining the operation plan for the next day and close both the energy and ancillary services market.
- N-hours ahead (6 Lead-times Ahead Analysis) → The same multi-temporal OPF developed for the day-ahead analysis will be used n-hours ahead in order to adjust the control actions previously identified feeding from more recent and accurate data regarding load and RES forecast (generated by the DSO forecasting system). The main objective will now be to minimize the deviations in a sliding window of 6 lead-times ahead (with hourly updates) regarding the scheduled scenario in D-1 analysis. This will enable correcting the deviations that occur and solve eventual technical problems that may arise close to real-time.

2.3.2 Voltage Control at the LV level

Description of the **Sub-Task 3.4.1 "Definition and Development of Local Voltage Control Schemes for LV Grids"** from the DoW [1]:

"Definition and development of local voltage control schemes for LV grids, ***working at two different levels****:*

- ***A centralized voltage control algorithm installed in the distribution transformer controller (MV level), using the aggregated information received through the smart meter infrastructure****. The outputs of the algorithm are reference set points to DG units, flexible loads and other controllable devices (…)*
- ***A local control, installed in DG units, based on a local droop that will use as reference the set point received from the DTC and operate around its value (…)"***

As previously described, a two-stage approach is foreseen as follows:

- **A "centralized" control scheme** based on a set of rules that will aim at sending set-points to DER located at the LV level, i.e., controllable loads, microgeneration and storage devices exploiting data collected from smart meters (for instance, sending a set-point to a storage unit that is geographically close and on the same phase as a client with a high voltage value);
- **A local control scheme** based on droops operating at the inverter level of some DER in order to quickly react to sudden voltage drop/rise phenomena (for instance, to locally act on a PV microgenerator that has high voltage values at its terminals due to a change in the primary resource – sun, in order to avoid technical violations).

The "centralized" control scheme will operate at the functional level of the MV/LV substation (i.e., at the DTC level) and is expected to be physically embedded at the DTC. This "centralized" control scheme will be triggered by alarms (due to voltage violations detected by the EB) to mobilize the most adequate resource at the LV to solve the problem.

On one hand, the articulation between the "centralized" control scheme and local control scheme is ensured by allowing remote adjustment of droop parameters.

On the other hand, the multi-temporal OPF will define the "desired" power injection at the MV/LV transformer level for 6 lead-times ahead that must be incorporated in the rules of the LV "centralized" control scheme in the corresponding DTC in order to ensure coordination between the two control levels (MV and LV). This means that the DTC can, considering this control scheme, operate in a virtual "slave" mode, fulfilling the results of the "master" multi-temporal OPF (dispatch scheduling) implemented by the SSC at MV level.

2.4 Differentiated Quality of Service (QoS)

2.4.1 Provision of Differentiated QoS

Description of the **Task 3.6 "Provision of Differentiated Quality of Supply"** from the DoW [1]:

*"This task aims at developing a methodology for **optimal, close-to real time provision of required Quality of Supply (QoS) to different parts**, i.e. different customers, of the network with DG (in particular intermittent and stochastic power electronic interfaced DG)"*

2.4.1.1 Introduction

The term power quality refers to a wide variety of electromagnetic phenomena that characterizes voltage and current at a given time and given location on the power system [20]. One of the main characterizations of the smart grids is that it should provide power quality for digital economy. This includes monitor, diagnose, and respond to power quality deficiencies, leading to a dramatic reduction in the business losses of customers. Power quality vision of SuSTAINABLE envisages varying grades of power quality at different pricing levels.

The overall aim of the report is to develop a methodology for optimal, close to real time provision of required Quality of Supply (QoS) to different parts of the power distribution network. The phenomena under consideration include harmonics, voltage imbalance and voltage sags. It is considered that the phenomena under consideration vary with time and location due to activities of industrial customers and because of the stochastic and intermittent distributed generation in the network. Since the quality requirements across the network are not uniform, grading the QoS for the network is required based on customer's willingness to pay. Most cost effective mitigation solutions need to be deployed considering grading of network and premium associated with grade based on type or class of customers.

2.4.1.2 Customer Classification

Concept of differentiated power quality originates from the existence of varied level of requirements among customers. Identifying reasons behind these distinct needs helps to find commonality in power quality requirements among a set of business activities. These reasons can be referred to as techno-economic in nature. This electro-economic nature is due to the fact that the level of power quality requirement depends on the sensitivity of customer process to inadequate quality as well as the financial vulnerability of it on customer profits. While classifying customers these two important aspects need to be taken care of, to ensure power quality differentiation is made in accordance with realistic requirements.

This section looks into both electrical and economic nature of power quality from the point of view of customer's business activity. A classification methodology is derived based on both these factors. Electrical aspects and economic aspect of power quality are separately analysed for different business types. A general categorization of electrical aspects can be performed based on level of customer process sensitivity. Financial losses of different industries from inadequate power quality help to demarcate economic sensitivity. Both of these can be combined together to perform classification of business types into power quality requirement classes by applying the classification methodology. Flow chart shown in Figure 13 provides an insight into the classification approach developed. Techno-economic characteristic of power quality can be differentiated into electrical sensitivity and economic sensitivity, identifying both separately. The results from each analysis can then be combined to identify a grouping by segregating them based on their demand levels. This segregation helps in identifying demand function for customers so that the supply of differentiated power quality can be positioned appropriately by DSO's.

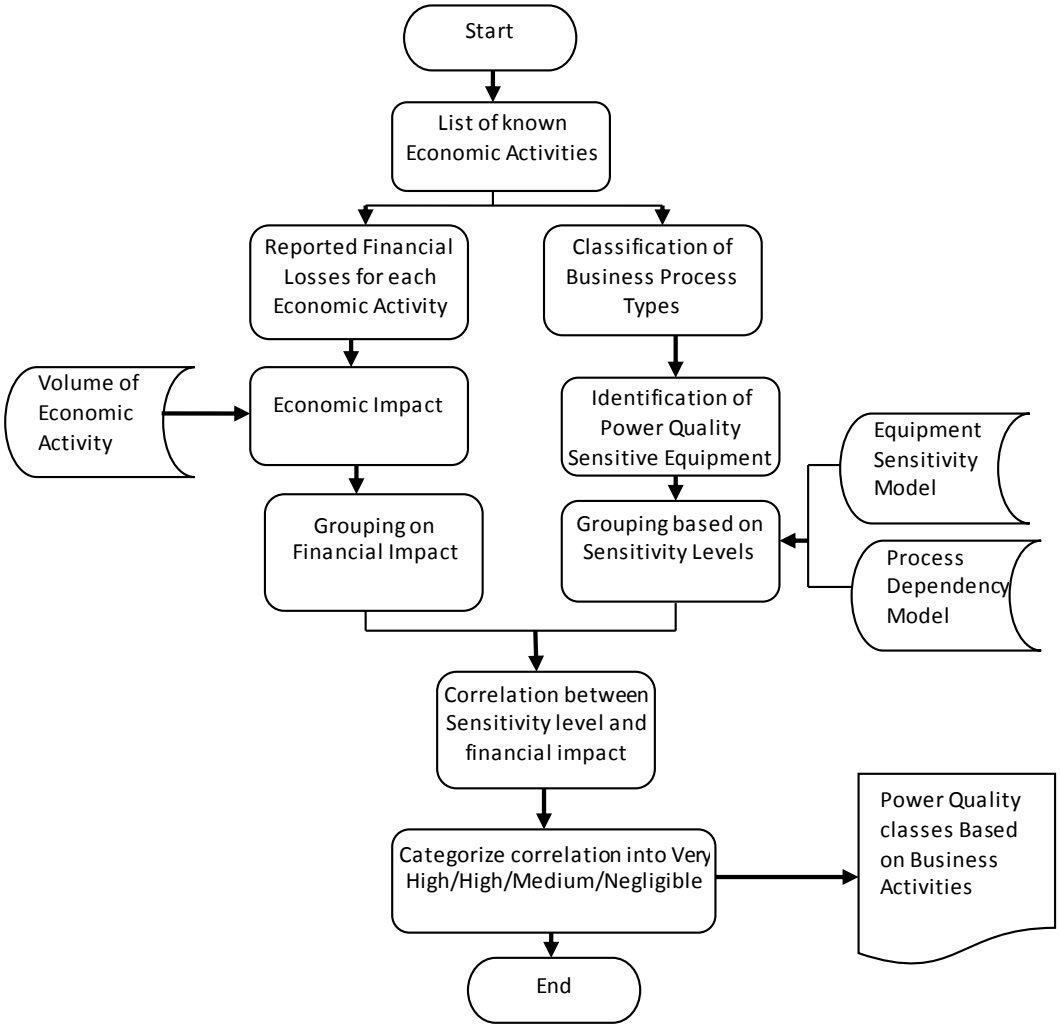


Figure 13 – Methodology for customer classification

2.4.1.3 Considered QoS phenomena

2.4.1.3.1 Voltage Sag - Customer Damage

Identification of voltage sag profile (number and characteristics of voltage sags) at Point of Common Coupling (PCC) of customer and network is the most important information required for the analysis of customer damage due to voltage sags. The power system faults are the major cause of voltage sags, so the statistical information about faults must be used to identify the sag profile at the customer connection point. Since not all sags lead to customer process interruption and consequent financial losses, it is essential to identify sags that lead to process interruption. This can be done using equivalent voltage tolerance curves for different customers derived based on generic ITIC curve (or SEMI F47 standard) with incorporated relevant uncertainties to account for different types of customers. Once the number of interruptions per year has been determined it should be multiplied by cost of individual interruption based on existing customer damage functions. Figure 14 illustrates the overall assessment methodology.

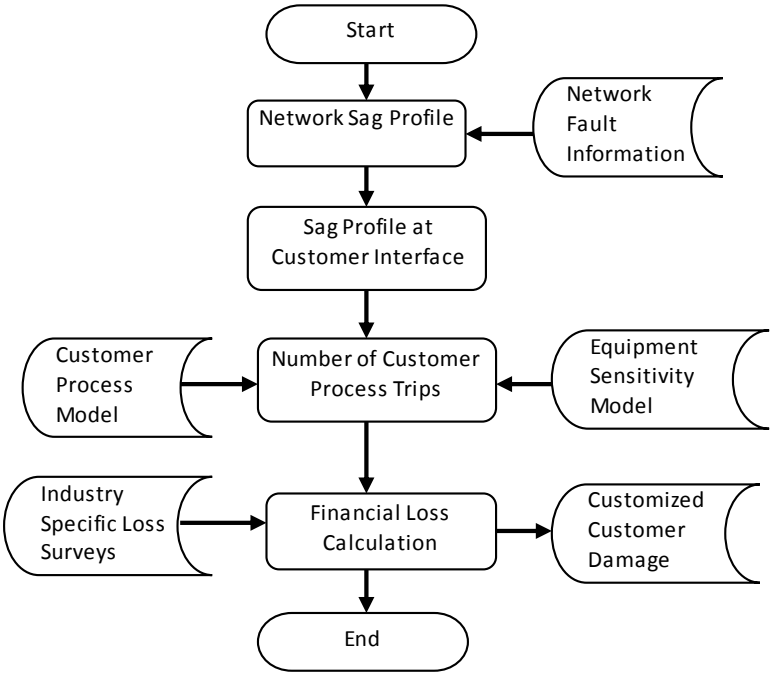


Figure 14 – Sag financial assessment methodology

2.4.1.3.2 Unbalance – Customer Damage

Voltage unbalance is the condition when the three phase voltages are of different magnitude and/or do not have a phase shift of 120° with respect to each other. The unbalance incurs overheating in both, power system equipment, such as transformers and motors, and end user device, contributing to the accelerated thermal ageing and therefore the reduction of equipment lifetime. With unexpected negative sequence power flowing in the same path with positive sequence power, the capacities of transformers, cables and lines are reduced, resulting in a reduction in efficiency. Generators and induction motors are additionally required to be derated due to safety consideration according to National Electricity Manufacturer's Association (NEMA) standard. The unbalance yields extra costs on operation, maintenance or replacement for both DSOs and end customers. Further impacts of unbalance include an increase in harmonic levels caused by power electronic devices, reduction in reactive power available and the reduction of luminous flux in discharge lamps. As far as end customers are concerned the major impact is on induction motors, and can be considered as one of the major source of economic losses for them. These losses happen both due to de-rating of induction motors and loss of useful life. Combining all the above individual costs, estimated based on generic data, and their future projection (e.g., using net present value calculation) provides the estimate of net financial loss due to unbalance.

2.4.1.3.3 Harmonics – Customer Damage

Financial losses from voltage and current harmonics can be classified into border category of energy losses, losses due to premature ageing and losses from equipment malfunction.

CIGRE/CIRED C4.107 report [21] presents methodologies for evaluating economic losses arising from waveform distortion due to harmonics. The report identifies two possible approaches for assessment of the financial losses due to harmonics, deterministic approach and probabilistic approach. Deterministic methods are adequate and yield good results only if the required input parameters influencing losses are known to good level of certainty, which is rarely the case. Probabilistic methods therefore are more suitable as they consider relevant uncertainties in estimation of potential economic losses. The impact on operational expenditure and capital expenditure with increased level of harmonics can be assessed using probabilistic approach as both overall distortions of the waveform as well as individual levels of harmonics can be taken into account.

2.4.1.4 Classification of Customers based on required Power Quality level

A classification methodology based on the two pronged approach of financial losses and customer Power Quality sensitivity helps to establish financial sensitivity due to inadequate Power Quality. This financial sensitivity level is the key parameter indicating level of premium customers would be willing to pay for meeting their inadequacy. Initial requirement for classification is to identify a list of possible business activities carried out

by DSO's customers. A clear and standard demarcation is required while defining these activities. International Standard Industrial Classification of All Economic Activities (ISIC) standard by United Nations statistical commission (UNSTAT) offers such a definition in international level, European Commission adopted this standard with further levels of classification under the acronym NACE [24]. NACE is used as the standard for referring to business activity; second level classification of codes identified by a two-digit numerical code representing division of activity is used.

First, business processes are classified using the nature of the process. As part of this Power Quality sensitive devices are identified. An equipment sensitivity model, along with business process model is used to group customers based on Power Quality sensitivity levels. Secondly, financial losses for each economic activity are identified using data available from a set of reference surveys. Volume of business activity is indicated by production rate or turn over and this can be used to quantify level of losses for size of activity. Since this information may not be publicly available the electricity consumption for the industrial customer can be used as first approximation [25]. This loss level classification of customers is then correlated with customer sensitivity level to Power Quality disturbances and the highest correlation indicates the most sensitive customers, i.e., the customers requiring the highest level of Power Quality. Classification of customers into different groups is performed using this correlation factor

A very strong correlation between "Very High" Power Quality sensitivity level and "Extreme" financial loss level suggests that the customers are in the "Sensitive" group that requires the highest level of quality of electricity supply. This may also indicate their greater willingness to pay for PQ improvement. A strong correlation of "High" Power Quality sensitivity and "Substantial" losses indicates set of economic activity where the financial losses are considerable in terms of the scale of activity. Even though these activities are viable with limited exposure to Power Quality levels, an improvement in Power Quality level has a noticeable improvement in net profits. These types of customers are classified as type "Essential". A third category of correlation exists where the Power Quality sensitivity and financial losses are a combination of medium and moderate. Customers of this category are named as "Important" and these customers may not be willing a to pay high levels of premium for an improved Power Quality but still appreciate better Power Quality with not considerable increase in existing energy cost. This category might pay minimal charges for improved quality but such customers will be large in number and hence account for considerable revenue from differentiated quality of supply. Final correlation is based on the low Power Quality sensitivity and Negligible Power Quality losses, which can neglected for a differentiated Power Quality because an improvement in Power Quality is difficult for such customer and it may not yield considerable savings for them. The categorization is performed making use of the available data for different economic activities as mentioned in earlier sections. In the case of economic activities where there is a lack of input data, a higher level abstraction is performed based up on information from similar category.

Within the above mentioned customer classification a further grouping like the one shown in Table 4.1 below can be performed based on similarity in characteristics of sensitive equipment they use and the nature of their business process. Such a grouping helps to easily model the financial damage using customer damage function with a limited number of sensitivity groups.

A differentiated quality of power supply has multitude of benefits. It makes power quality improvement driven by its own demand which is discriminated against nature of economic activity, location and time. In order to make this concept a value based proposition for real life implementation an appropriate economic framework is needed for DSO's to perceive it as a viable business. A cost benefit analysis therefore should be carried out as the most valuable decision tool while planning for a capital investment towards offering enhanced power quality through network based mitigation solutions.

Table 4.1 – Power Quality Grouping of Customers based on Power Quality Sensitivity

Category	Group Index	Division	NACE Code
Sensitive	Group1	Manufacture of computer, electronic and optical products	26
Essential	Group2	Manufacture of basic metals	24
		Manufacture of motor vehicles, trailers and semi-trailers	29
		Manufacture of other transport equipment	30
	Group3	Manufacture of textiles	13
		Manufacture of paper and paper products	17
		Manufacture of rubber and plastic products	22
		Manufacture of other non-metallic mineral products	23
	Group4	Manufacture of food products	10
		Manufacture of coke and refined petroleum products	19
		Manufacture of chemicals and chemical products	20
		Manufacture of basic pharmaceutical products and pharmaceutical preparations	21
Important	Group5	Manufacture of tobacco products	12
		Manufacture of wearing apparel	14
		Manufacture of wood and of products of wood and cork, except furniture; manufacture of articles of straw and plaiting materials	16
		Manufacture of fabricated metal products, except machinery and equipment	25
		Manufacture of electrical equipment	27
		Manufacture of machineryand equipment n.e.c.	28
		Manufacture of furniture	31
		Manufacture of other transport equipment	30
		Repair and installation of machinery and equipment	33
	Group6	Electricity, gas, steam and air conditioning supply	35
		Water collection, treatment and supply	36
		Residential care activities	87
	Group7	Printing and reproduction of recorded media	18
		Telecommunications	61
		Information service activities	63
		Computer programming, consultancy and related activities	62
		Insurance, reinsurance and pension funding, except compulsorysocial security	65
		Activities of head offices; management consultancy activities	70
		Architectural and engineering activities; technical testing and analysis	71
		Scientific research and development	72
		Office administrative, office support and other business support activities	82
	Group8	Financial service activities, except insurance and pension funding	64
		Activities auxiliary to financial services and insurance activities	66
		Public administration and defence; compulsory social security	84
		Human health activities	86
Desirable	Group9	Apartments and House Hold Consumers	

2.4.2 Differentiated QoS Planning

Description of the **Task 4.2 "Power Quality Planning for Flexible Distribution Systems"** from the DoW [1]:

"*This task will focus on* ***optimising the QoS mitigation infrastructure based on customer requirements and presence of stochastic and intermittent power electronics interfaced DG in the network***"

Power Quality mitigation can be handled at different levels of system hierarchy. Mitigation options and approaches vary at equipment level, process level, plant level and network level.

At equipment and process level, the equipment can be made more insensitive and immune to quality of power supply, and the process design can incorporate more redundancy and fail proof approach. In industries, the immunity capability of equipment needs to meet certain standards. For instance, the performance of most modern electronic equipment should follow ITIC/CBEMA curve. SEMI F47 defines standard requirements that semiconductor processing equipment needs to tolerate voltage sags connected to their AC power line. SEMI has one of the most stringent immunity requirements in place comparing to other sensitivity curves. Equipment and process level immunity enables only limited immunity from financial loss, and inadequate power quality and immunity outside their tolerance limits has to be dealt on a higher level.

Power quality mitigation can be handled at plant/customer level and network level. Offering power quality as an additional service by a distribution network operator has multiple benefits. Individual customers do not have to make huge upfront investments in capital costs for insulating themselves against power quality problems. DSO's gets additional revenue from offering a differentiated quality and guaranteed levels. The benefits in having network level solution is distributed through an overall improvement of quality levels in demarcated zones of the network, hence there exists opportunities for DSO's to ensure profits from this business. Solutions at plant level and network level can guarantee better immunities by two different approaches.

1. Prevention strategy: The first approach follows the general principle of prevention is better than cure. Preventive approaches are more relevant in the case of network wide solutions since they got a wide scope of application and overall benefit when performed at network level. Most of the preventive strategies at network level deal with designing, planning, operating, and maintaining aspects of networks. Power supply regulations also play important role as a preventive approach by limiting the amount of emissions allowed by individual customers. Even though these preventive strategies yields good result they are not enough to offer a guaranteed quality of supply at all time.
2. Compensation strategy: The second approach is to provide online real-time compensation detecting power quality events using custom power devices and harmonic filters. Custom power devices for voltage sag mitigation work on the basic principle of injecting power to compensate the lost voltage. These devices take the required power from less impacted phases or lines, or from energy storage. Most common type of custom power devices used for voltage sag mitigation are dynamic voltage restorers (DVR), static VAR compensator (SVC), distribution static compensator (DSTATCOM), uninterruptible power supplies (UPS). Static Transfer Switch is considered as good option to protect from sags originated on distribution networks. Voltage Source Converter (VSC) based shunt

active filters are most commonly used as mitigation devices for harmonic compensation of line current. Synchronous Static compensators can be used effectively in mitigating voltage unbalance.

With these mitigation devices, an optimal deployment methodology for mitigation solutions has to be applied to identify the most appropriate type of mitigation, rating of devices, location of their placement in network based on the objectives of maximizing DSO's profits and minimizing deviation from guaranteed quality levels for each category of customers. In our study, the mitigation problem is described as a minimization problem, which is to find the minimum of the objective function in the search space constrained by certain constraints. The objective function, F, is to evaluate the mitigation solutions, and it is defined as:

$$F(x) = \sum_i (UBPI_i(x))$$

$$UBPI_i(x) = AHP(S_i(x), U_i(x), H_i(x))$$

$$\text{subject to: } g(x) = 0,\ h(x) \geq 0$$

where index S_i denotes the voltage sag performance at bus i. In our study, the voltage sag index is assessed based on voltage tolerance characteristic of loads connected to the bus. Index U_i represents the system unbalance level, and it is defined as VUF at bus i. Index H_i denotes the system harmonic level, and it is defined as THD of bus i. For each bus, the three assessed indices S_i, U_i and H_i are combined into one unified index using Analytical Hierarchy Process (AHP) methodology. The sum of the unified indices of all buses is considered as objective function F. With the application of AHP approach, F can reflect the severity of three phenomena throughout the whole network. Parameter x denotes the variables to be optimized, i.e. the mitigation solutions, which consist of the location, type and size of various FACTS devices. Formula $g(x) = 0$ and $h(x) \geq 0$ denote the equality and inequality constraints respectively.

Before applying the optimization algorithm, a solution pool, which includes all possible mitigation solutions, is formed first. Four types of FACTS models (STATCOM, SVC, DVR and Passive Filter) are adopted in our study. Different placement and size of FACTS devices will result in different mitigation effects at the system level. To find the possible installation locations, severe areas which are highly affected by power quality phenomena is identified throughout the network. Then, the possible location of particular devices is selected based on the performance of power quality phenomena. Although the possible location of various FACTS devices is pre-set, the exact installation location will be selected during the optimization process. For each type of FACTS device, its rating (i.e. size) range is defined as $(\mathrm{R_{min}}, \mathrm{R_{max}})$. The range is divided into a certain number $(\mathrm{N_{rating}})$ of intervals. To present the possible rating of one interval, a value is randomly selected within the interval. The selected values, representing the possible rating, will be added in the solution pool to be tested.

After the solution pool and objective function are defined, a conventional methodology, Greedy Algorithm, which is widely applied to solve the travelling

salesman problem (TSP), is applied to optimize the mitigation variables of FACTS devices. The greedy algorithm solves the problem heuristically by making the local optimal choice 'greedily' at each stage, until the stop criteria is reached. The choice made by the algorithm depends on the choices so far instead of the future choices. In other words, it chooses the optimal solutions of sub-problems derived along the selection process. In our study, a certain number of stages are applied for the placement of FACTS devices. The Greedy Algorithm is applied at each stage where only one FACTS device which has the best mitigation effect is chosen. The choice is made after all unselected FACTS devices with various proposed ratings are tested individually. The reason for repeatedly testing all the unselected FACTS devices is that the change of load flow caused by the integration of selected devices will result in the change of mitigation effects, even the same device with the same rating is applied. The repeating device selection stops if the improvement to the objective function between two neighbouring stages is smaller than a pre-set value. The simulation is performed using DIgSILENT and Matlab.

2.5 Virtual Power Plant

Description of the **Task 3.5 "Assessment of TVPP Contribution to Distribution / Transmission Coordination"** from the DoW [1]:

"One of the cutting-edge concepts to be developed in the SuSTAINABLE project is the Technical Virtual Power Plant (TVPP). This concept ***enables a co-coordinative action between different distribution networks that can also influence power transfer over a part of the transmission system****.* ***Load forecasting*** *for distribution networks as developed in Task 3.1,* ***renewable power generation forecasting*** *as developed in Task 3.2* ***will aid in forecasting mismatches****.* ***The VPP Control Centre will process the forecasting information and send appropriate signals to the TVPP participating resources in order to compensate these mismatches****"*

The Virtual Power Plant (VPP) consists of the Commercial Virtual Power Plant (CVPP) and the Technical Virtual Power Plant (TVPP). The CVPP is responsible for the participation of the Virtual Power Plant in the energy and ancillary services market by optimizing the operation of its various aggregated units. The Technical Virtual Power Plant is responsible for the operation of the various VPP actors in order to provide system management and support its real time operation.

The TVPP consists of loads (interruptible and non-interruptible) and – mainly – DER units, regardless of their technology and whether or not they share a physical connection. That said, a VPP may consist of actors under different feeders or with a transmission system among them [36,37].

The Virtual Power Plant that is developed in the SuSTAINABLE project will consist of the Virtual Power Plant Control Centre and three agent levels. The Primary substation agents aggregate all the units up to the HV/MV primary substation or represent a DER that is connected directly to the HV/MV substation. These agents communicate with neighbouring agents of other distribution networks in order to coordinate the operation of the participating resources. The Secondary Substation Agents aggregate the low voltage level units up to the MV/LV secondary substation or represent a DER that is directly connected to the MV/LV substation. The structural architecture of the VPP is illustrated in Figure 15.

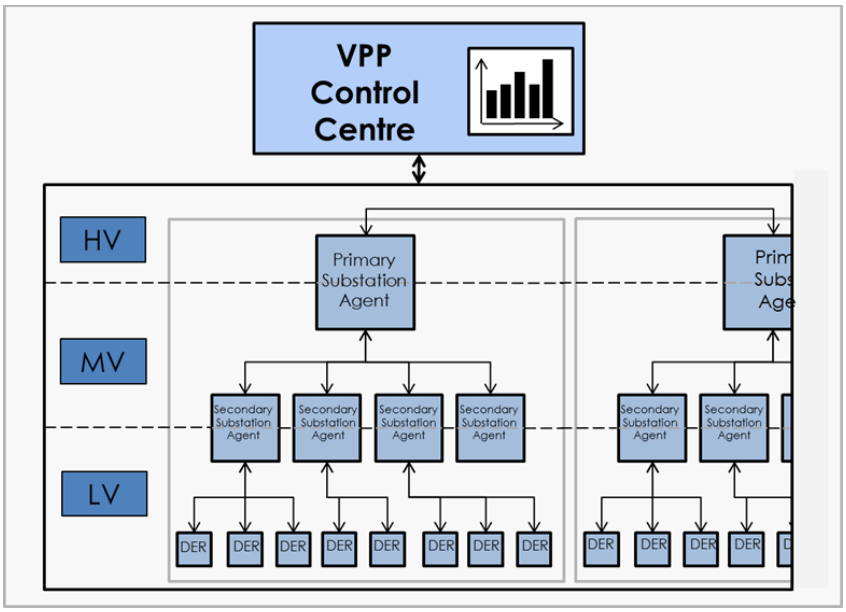


Figure 15 – Virtual Power Plant Architecture Layers

This architecture gives the opportunity to have a multi-agent control scheme using hierarchy in order to achieve fast reacting control solutions. In normal operation the VPP Control Centre communicates with the agents of the various levels in order to supervise the operation of the VPP. In critical or emergency operation the controls can either take place on each agent level independently or following the hierarchy of the aggregation units, depending on the type of the emergency and the service the VPP has to offer.

The VPP concept in the SuSTAINABLE project aims at developing a coordinative action between neighbouring distribution systems, in order to cover fluctuations that might happen due to the intermittent nature of renewable energy resources. Moreover, a main goal is to define an operating strategy of the VPP that will contribute to the provision of differentiated Quality of Supply (QoS) and will ensure the safe and reliable system operation.

The VPP can participate in the day-ahead energy market, the intra-day energy market and provide ancillary services. In particular, the VPP's operation is optimized for all the aggregation levels in order to minimize its operation costs subject to emission and reliability constraints. The available reserve capacity is also assessed and the optimized schedules are derived. Subsequently, the VPP requests the technical validation of both the DSO and the TSO, so that they will verify that the operation does not violate the network's constraints.

In critical circumstances, such as congestion, voltage variations, or in case the provision of other ancillary services, such as secondary reserve, is needed, the TVPP communicates with the DSO and the TSO and does the necessary adjustments to its operation, in order to fulfil the system's technical requirements. In order to achieve a secure and stable system operation in parallel with the VPP operation strategy, the close communication between the system operator and the VPP is a prerequisite.

2.5.1 The New Role of the DSO

The VPP concept opens new perspectives towards improving the coordination between the DSO and the TSO and the way how the distribution system is presented at the transmission network boundaries. This will enable defining a new role of the DSO which involves mitigating the impact on the transmission network of variable generation connected to the distribution grid under very high penetration of RES. In this context, the DSO is expected to operate its set of distribution networks (normally divided by HV/MV primary substation – SSC) based only on the direct-control over its own assets (such as On-Load Tap Changing (OLTC) transformers and other reactive power compensation devices), while the VPP presents its bids to the electricity market (pool) and the system is operated according to the results from the market-clearing.

In **Error! Reference source not found.** the framework that will allow integrating the VPP concept and the day-ahead/intraday sessions of the electricity market with this new role of the DSO is presented. The VPP, as well as other market agents, should submit their selling/buying bids in the electricity market. These bids represent the "best guess" " (i.e., based on load and/or RES forecasts generated by the forecasting system of each market agent) regarding the expected values of generation and load in the electric power system for a time horizon matching the market clearing period.

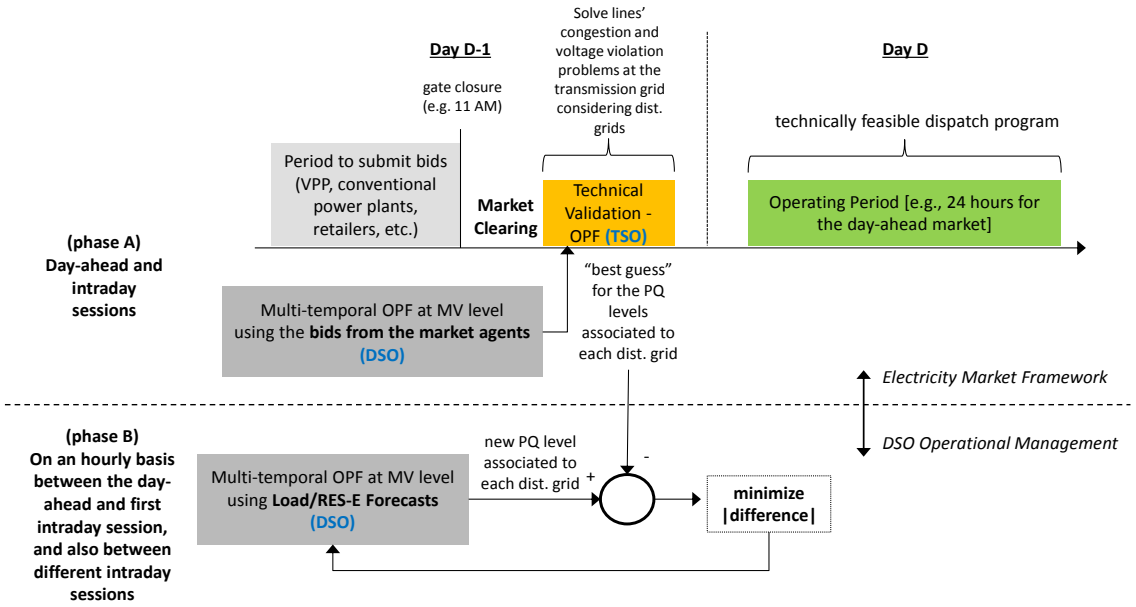


Figure 16 – Proposed Framework for TSO/DSO Coordination

The DSO will then use this information to run a multi-temporal OPF, similar to the one used for voltage control at the MV level but with different objectives, that will have as main output a "best guess" for the active and reactive power injection values at the node with the transmission network associated to each distribution grid. Therefore, the formulation of this multi-temporal OPF will aim at influencing the power transfer over a part of the transmission network, which will introduce a new objective function and new

constraints in the formulation of the multi-temporal OPF. It must be stressed that the TSO will see the distributions grid as PQ nodes of the transmission grid. As a result, the DSO will utilize the forecasting tools and the results of the multi-temporal OPF available in its tool portfolio for the management of the distribution system, which will allow maximizing the integration of energy from RES in the distribution grid. Under this framework, it is assumed that the bids, after the market-clearing phase, can be disaggregated by MV/LV secondary substation (i.e., by DTC). In case of distribution systems where this information cannot be disaggregated by the MV node level, the DSO should use its own forecasts.

In each day-ahead and intraday session, based on the information transmitted by the DSO, the TSO will run its own OPF at the transmission system level for technical validation (and identification of eventual corrective actions) with the power plants connected to the transmission grid (control variables) and the injections from the distribution system provided by the DSO representing each distribution grid (state variables). After exploiting all control possibilities at the transmission level, the TSO may send a control signal to the DSO in order to readjust its PQ levels particularly in cases of large power injections from the distribution side. In this case, the DSO, using the multi-temporal OPF, defines a set of adjustments to the solution found previously to be followed the VPP/aggregator and larger producers/consumers connected to the MV level. In this situation, the DSO will try to maximize RES integration and at the same time comply with the requests at the transmission level. The final result will be a technically feasible dispatch program that is obtained by a joint validation between the TSO and the DSO.

Between intraday and day-ahead sessions (e.g., with hourly updates) the DSO will run a multi-temporal OPF for each distribution grid that minimizes the differences between the information agreed in the technical validation in the day-ahead/intraday sessions (PQ values defined) and the current solution of the multi-temporal OPF with updated information (i.e., very short-term forecasts for the load and RES) as shown in Figure 16. This process consists on a technical validation and operation of distribution system conducted by the DSO on a regularly basis in order to enable maximizing the integration of energy from RES at all times. Ultimately, the operational management presented seeks a more stable operation of the electric power system as a whole, ensuring more reliable information at the distribution grid nodes and increasing the TSO/DSO interoperability.

2.6 Advanced Protection Schemes

Description of the **Task 4.3 "Planning of Advanced System Protections"** from the DoW [1]:

"Advanced protection system will be proposed by ***incorporating flexible schemes for distribution network protection and grid interconnection protection of DG units, in order to minimise/avoid protection misoperation and failure****"*

MV substation feeder protection relays are used in structured top-down radial topology networks with unidirectional power flows. Protection schemes have been successfully defined and deployed together with substation automation, coping efficiently with transient disturbances always on a top-down perspective. Traditionally, configuration settings are assigned to each protection device, considering the different types of faults, the protection zone each relay is responsible for and the expected directionality.

The penetration of renewables is introducing time dependent bidirectional power flows, sometimes with high variance due to its intermittent nature. Therefore, those configuration settings are no longer adequate for dynamic time dependant bidirectional power flows prone to faulty transient behaviour.

In [32], architecture concepts are presented, as well as coordination proposals for dealing with the DG dynamics, also dealing with topology changes arising from self-healing or operational switching schemes.

2.6.1 Protection Schemes

The design of distribution networks is commonly characterised by the extensive deployment of radial feeders. Simple protection schemes have been deployed successfully for these network topologies, both at substation and feeder side. However, this conventional approach did not consider challenges that DG introduce nowadays.

Protection relays deal with a multiple range of faults and disturbances. Each protection device observes and protects a specific zone of the grid, on a time-of-day basis, in coordination with other protective devices, namely reclosers installed along the feeder or fuses in MV/LV distribution substations. Its settings result from the predictability of top-down power flows, typically in feeders where loads are fed by the upstream substation feeder.

Over-current protections for phase-to-phase and phase-to-ground faults are available. Directionality is usually not necessary for phase-to-phase faults, the coordination being typically achieved by different operation thresholds and trip time delays. Phase-ground faults present a harder challenge, being usually complemented with directional options fitted to the specific neutral connection present in the substation.

These specific features guarantee protection scheme dependability and security, avoiding that a fault on a feeder affects its neighbouring feeders.

Other protection functions are also available for disturbances such as over-voltage, voltage sags, or frequency variations. Concerning DG, protection relays must also be in accordance with grid codes, for which special schemes are available such as rate of change of frequency (ROCOF) or vector shift protection.

2.6.2 DG Dynamics

Distribution networks were designed to be passive systems, not being able to receive high quantities of energy, namely generated from intermittent DG.

DG renewable sources bring intermittent behaviour to the network operation. To some extent, it is possible to predict with an uncertainty level, a daily DG profile, e.g. solar or wind source. Yet, its real time behaviour might not be exactly what the operator was expecting creating mismatch problems in the reactive and real power balance between load and generation, as its intermittence impacts on voltage and frequency.

From a substation perspective, feeder protections support the needed clearance of phase-to-phase and ground-faults, as well as under and overvoltage or under and over-frequency disturbances, considering that feeders are passive and there is no DG penetration, which is not the case on the SuSTAINABLE project.

Currently, the penetration level of DG is considerably high, influencing the power flows and their directionality across feeders and the substation, and, together with the dynamics of topological changes arising from operational decisions (improving network conditions, self-healing), impose a huge challenge for protection coordination and selectivity.

DG also contributes to short-circuit power variation, which subsequently affects fault current magnitude, and may shorten the reach of protection stages, increase fault clearance time (particularly for time inverse curves) or prevent protection trip at all.

On the other hand, protection relays play an important role dealing with voltage and frequency oscillation, thus preventing installations, including DG, to maintain their power injections under certain undesirable conditions.

DG imposes a new set of dynamic requirements for grid protection, as coordination of passive methods for dealing with nuisance or unwanted tripping require a trade-off between reliability and events selectivity.

Regarding DG, nuisance tripping can be described as the inability of the protection associated with the DG asset to distinguish voltage/frequency variations from other external faulty events, such as upstream disturbances at HV level, faults in adjacent feeders or sudden load changes. This unwanted tripping (Figure 17 - Nuisance tripping due to an adjacent fault) affects economically DG producers. As DG is supposed to

sustain the network under voltage or frequency disturbances, unwanted tripping may trigger a chain reaction with further loss of generation, with the possibility of a complete collapse, not to mention the reduction of the lifetime of synchronous machines and gas turbines, also typical network assets.

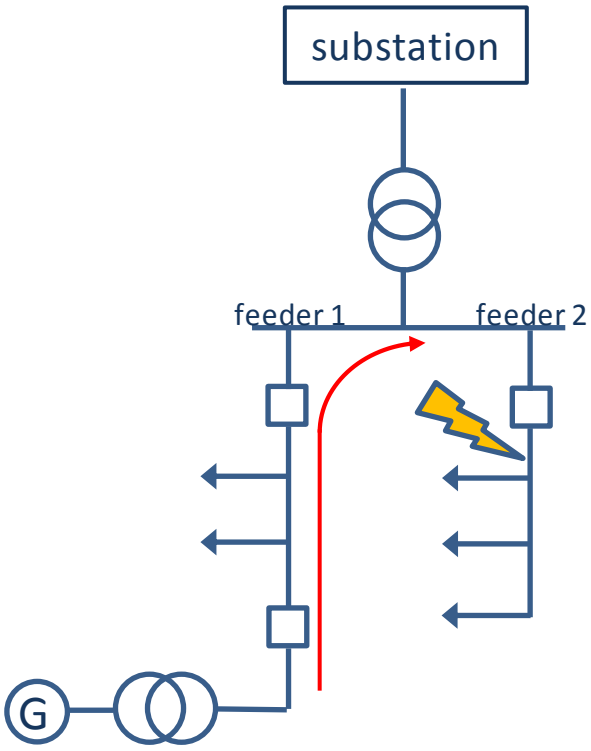


Figure 17 - Nuisance tripping due to an adjacent fault

2.6.3 Preventive assessment

The behaviour of protections for passive feeders is affected by the upstream short-circuit power, as well as by any downstream reconfiguration that may result from operational switching or self-healing schemes, as a consequence of network topology changes.

When feeders have DG assets connected, they also influence the dynamic of the short-circuit power, affecting the coordination of protection relays. In particular cases, the anti-islanding protection schemes may fail due to uncoordinated settings between the ROCOF protection at the DG and feeder protections. DG plays also a role on changing the directionality of power flows, even contributing to unbalance transformer N+1 redundancy at substations, as security is normally designed on a top-down perspective.

The distribution network, with this entire DG dynamic, may be assessed preventively, in terms of demand, network topology and power flows, stability, voltage profiles, as well as contingency risk, the latter including weather forecast conditions.

In SuSTAINABLE, it is proposed the application of the Distribution Grid Area (DGA) concept [33]. A DGA is a network area defined according to utility criteria where an intelligent system sited at the primary substation – the Smart Substation Controller, already described – plays the role of DGA master [34].

The SSC holds a data model of all downstream feeders, their tie points to other feeders, and their relation with adjacent substations, as well as of all DG assets present in the feeders. Also, a comprehensive and adequate communications infrastructure must be in place to ensure interfaces with the control centre, sensors, actuators, switches and protection devices deployed throughout the grid. Besides, SSC has local intelligence capable of executing self-healing algorithms after a network disturbance.

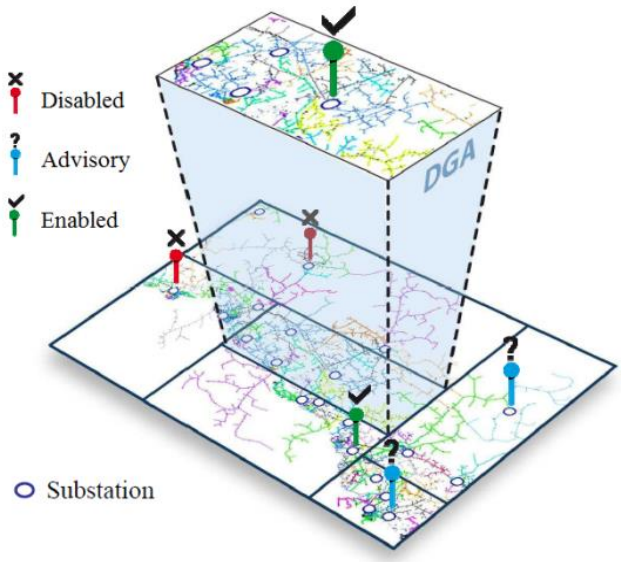


Figure 18- Representation of several DGA and their status

Each DGA is a zone for fast and accurate protection schemes coordination, a task to be performed in real time.

The centralized SCADA/DMS performs network assessment tasks over the whole network divided in several DGAs, sending pertinent short-circuit power data to each DGA's SSC, as well as assigning them with a tag for autonomous protection parameterization. The received data drives the overall dynamic adaptive protection setup coordination, which will be held at DGA level, carried out by its SSC. By receiving such tag, each DGA's SSC becomes aware about its role for protection coordination setup, according to the following working modes: disabled, enabled or advisory.

2.6.3.1 Disabled Mode

When disabled, the DGA's SSC is not authorized to perform any autonomous setting of adaptive protections, due to constraints imposed by the performed operational assessment carried out at SCADA/DMS level, e.g. a) entering into a high state alert for dealing with fault occurrences that may arise from weather conditions, b) maintenance

tasks being carried out or programmed for some portion of the DGA's network, c) non-normal network configuration (cut, jumper). In these circumstances, only the SCADA/DMS may instruct the DGA's SSC to carry out specific upgrades on protection settings, for instance, shortening the Non Detective Zone of voltage and frequency relays.

2.6.3.2 Enabled Mode

When enabled, the DGA's SSC is granted with the right to perform any autonomous setting of adaptive protections, as a result of the mentioned operational assessment, (e.g. normal operating conditions, no problems expected from outage management or SCADA/DMS systems). While enabled, each DGA's SSC will take into consideration any short circuit-power data sent by the SCADA/DMS, while using its awareness of the downstream feeders and their inter-connection to other feeders. The available data will drive the execution of any new setting for the feeder protections and RES DG units protections as well.

2.6.3.3 Advisory Mode

When in advisory mode, the DGA's SSC, upon detecting a situation candidate to carry out some new adaptive protection settings, will propose the corresponding actions, informing the control centre. Remotely, an authorized user will assess the group of protection setup proposed steps, by validating, contesting or changing them according to his/her own operational view and expertise.

The setting of protections, by the SSC at each DGA, can be performed by using pre-defined protection setting groups configured at the protection relay.

2.6.3.4 Pre-defined protection setting groups

This option is feasible, as manufacturers provide this kind of feature, available at protection relays. The typical range of setting groups may reach up to 8, depending on the manufacturers. The protection relay has no ability to detect the most convenient pre-defined setting group, as this decision carries the responsibility of knowing the neighbourhood segments or even farther network conditions. But the protection relay can switch between more convenient setting groups as a response to a remote control sent by the DGA's SSC.

As the SSC is a high processing power system and has a data model, its specific coordination application for protection setting determines which protection relays should change their setting groups. This task is performed by the SSC, by sending to each protection relay a remote control stating the new setting group number, which is a reliable approach to undertake dynamic configuration of protection settings. There is the limitation of the number of setting groups, available by manufacturers for their protection relays, but, at least for the most important cases, this flexibility may be enough as it is worthy.

2.6.4 Conclusions

The proposed model aims at improving the selectivity of protection relays, by performing dynamic tuning of their protection setting, enhancing the role and performance of DG. Nuisance tripping will be minimized, limiting the impact of adjacent feeder faults.

The role of the Smart Substation Controller (SSC) within the concept of the Distribution Grid Area (DGA) for managing the setting of protection relays considers different modes of autonomy assigned to the DGA, as a result of the preventive assessment performed by SCADA/DMS at control centre level.

3 Information Flows

The most relevant information flows foreseen in the SuSTAINABLE architecture proposed in Chapter 1 are presented in Figure 19.

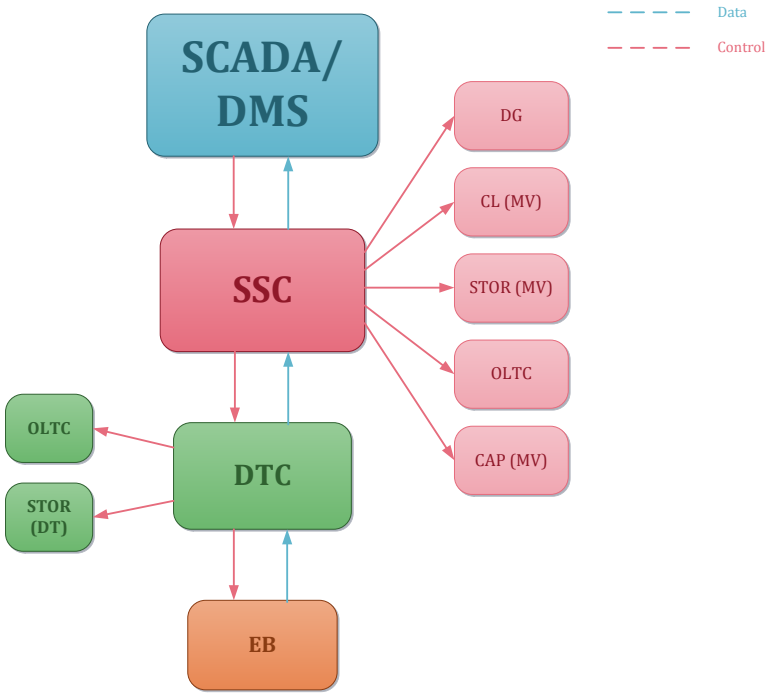


Figure 19 – Proposed Information Flows

The type of information flows that may be expected can be divided in two types: Data Flows and Control Signals.

3.1 Data Flows

The main data flows expected within the SuSTAINABLE concept involve mainly the values of the variables that will allow assessing the present operating condition of the network.

These data flows are of two different types: between controllers at different hierarchical levels (EB, DTC, SSC and SCADA/DMS) and between DER and the controllers at the corresponding control layer.

Between different controllers, real-time measurements will be obtained from devices such as EB, DTC, SSC as well as other Intelligent Electronic Devices (IED) and RTU. These include measurements of several electrical quantities such as voltage, active power and reactive power, as well as several alarms from operation.

Information from the several DER located at the MV and LV levels may be useful to support grid operation, namely the indication of current state of operation from nodes

where DER are connected, as well as data on the existing and available generation, controllable load and storage connected to the network that can be switched on/off.

3.2 Control Signals

The main control flows expected within the SuSTAINABLE concept involve the remote operation of resources and controllers at the several voltage levels.

These control signals are sent from a hierarchically superior controller to a lower rank controller (e.g., from the central SCADA/DMS to the SSC). These control signals can involve sending a set-point for a specific device such as an SSC, DTC or EB or a direct request to a specific distributed resource to change its operating point (e.g. request for reduction of active power injection by a microgeneration unit through its power electronic interface).

3.3 Communication requirements

The present section describes the communication requirements for the testing of SuSTAINABLE functionalities in optimal conditions. However, for the proof of concept and demo cases, some of the requirements may have to be adjusted to the existing infrastructure constraints.

Functionality	**Required (Dynamic) Data**	**Frequency of data transmission**
SF1-Load forecast	- Hourly active and reactive energy consumption for consumers directly connected to the MV network and corresponding voltage rms values - Hourly active and reactive energy consumption for each MV/LV substation DTC (collect the measure of the net energy delivered to the LV network) and corresponding voltage rms values - Hourly active and reactive energy inputted to the MV network (at HV/MV substation feeder)and corresponding voltage rms values	Time series data transmitted on an hourly basis, with a maximum delay of one hour (e.g., at 10h59 there should be available production data until 10h00).
SF2-Renewable energy forecast	- Hourly active energy production aggregated by DTC;	Time series data transmitted on an

	- Hourly active energy production discriminated by a subset (or reference) EB (e.g., around 20% of the EB associated to each DTC);	hourly basis, with a maximum delay of one hour (e.g., at 10h59 there should be available production data until 10h00).
SF3-State estimation	**LV network**: active and reactive power consumption and voltage magnitude at every LV consumption bus; active power production and voltage value (magnitude) at every LV production bus; **-MV/LV (secondary substation):** active and reactive power consumption, voltage magnitude and/or current (magnitude and power factor) in the primary or in the secondary of the transformer if available; -**MV network**: active and reactive power consumption at MV consumption bus if available; active and reactive power production and voltage value (magnitude and phase) at MV production bus if available; active and reactive power flow in the MV lines with RTU or PMU; -**HV/MV (primary substation)**: active and reactive power consumption, voltage (magnitude) and/or current (magnitude and power factor) in the primary or in the secondary of the transformer if available. These measurements could also be available for each MV feeder;	**Past data of the LV network:** The data should be available once a day with 24 hours of delay (i.e., from D-1). **Dynamic data of the LV network:** The data of some reference DG and load units (e.g., around 20% by DTC) should be available every 15 minutes with a maximum delay of 1-minute. **MV network:** the data should be available in real time (e.g., on a 1-minute time basis).
SF4-Voltage control	- **LV network (information for the voltage control at the DTC level)**: Active power consumption and voltage value (magnitude) at LV consumption and production points; **Information for the voltage control (multi-temporal OPF) at the MV level:** **-MV/LV (secondary substation):** tap	- **LV network**: Intra-hourly measurements from the EB associated to a specific DTC (15 or 30 minutes) with a 1-minute delay. - **MV/LV (secondary substation):** The data should be available on

	position of OLTC, capacitor banks and other voltage control devices; input from load and RES generation forecasting tools, storage state-of-charge, input from state estimation tool (e.g., node voltages, active/reactive power consumption and generation, etc.).	an hourly basis with a 1-minute delay.
SF5-Virtual Power Plant (CVPP and TVPP)	**Day ahead operation (D-1):** -Forecasted generation data of RES for the next day in 15 minute time steps -Forecasted load data for the next day in 15 minute time steps if available According to the German market regulations: -Hourly price data forecasts of the day ahead market (€/MWh) -Forecasted 4-hour time frames of capacity price (€/MW) for the next day for providing tertiary reserve **Intra-day operation (D):** -Forecasted generation data of RES for the next hours in 15 minute time steps -Forecasted load data for the next hours in 15 minute time steps if available -15 minute time step price data forecasts of the intra-day market (€/MWh) **Close to real time operation:** **Primary substation agent** (to simulate provision of primary control reserve by the TVPP): -Forecasted generation data of RES for the next 15 minutes -Forecasted generation data of other	**Day ahead operation (D-1):** -The RES, load and price for day ahead market data should be available once a day, 12 hours before day D with the time scope of 24 hours -The price data for the tertiary reserve market should be available once a day, 14 hours before day D with the time scope of 24 hours **Intra-day operation (D):** -The data should be available every 15 minutes and at least 45 minutes before the real time operation **Close to real time operation:** -The data should be available every 5 minutes if possible

	types of generators for the next 15 minutes -Forecasted load data for the next 15 minutes **LV level** (to simulate voltage unbalance)**:** -Active and reactive power generation data of RES -Active and reactive power generation data of other types of generators -Active and reactive load data -Voltage value (magnitude and angle)	
SF6 and SF8- Differentiated QoS and Power quality planning	For planning purposes we do not need any specific communication as everything is done in advance, i.e., placement of mitigation devices to ensure delivery of differentiated QoS. We do need information though as much as possible about types of customers and DGs in the network, their harmonic characteristics and patterns of operation in particular. Current and voltage waveforms measured in the system, for example at substations, if available.	NA

Communication between the primary substation (HV/MV) and the SCADA/DMS system, being essentially supported by an optical fibre infrastructure, has no particular limitations on what concerns data latency and amounts of data being transferred.

On what concerns the communication between the secondary substation (MV/LV) and either the SCADA/DMS or the SSC located at the primary substation, there are two different situations:

1. If an optical fibre connection exists, there are no particular limitations that have to be taken into consideration;

2. If no fibre connection exists, then the latencies and bandwidths associated with the available communication paths, either cellular, DSL or other have to be taken into consideration, namely the frequency of data retrieval, the amount of retrieved data, and the maximum delay that is acceptable depending on the functionality to be executed.

The communication with the smart meters (EB), regardless of the technology, is the one that introduces stricter constraints, both on volume of data to be transferred, available bandwidth and data latency. Current technologies, either cellular, PLC or RF-Mesh may impose limitations on the amount of data that can be retrieved or the frequency of data retrieval.

The limited data processing capabilities at the smart meters (EB) may also introduce further limitations that have to be taken into consideration. The use of the same communications infrastructure to convey different types of data, like metering and control, may introduce more constraints. This can have impact on the data traffic patterns with consequences in terms of quality of service. Segregation of data flows can be considered, especially when applications with different requirements need to be considered. This can be achieved combining different communications technologies or by combining private and operator based networks.

4 Equipment Specification

The goal of SuSTAINABLE is to draw accurately a reference architecture for management and control of the future smart grid as a whole, based on the hierarchical architecture already deployed in the InovGrid test side in Évora, Portugal, the InovCity.

The subsequent sections describe the main equipment supporting each of the 3 SuSTAINABLE architecture and control hierarchical layers already presented in Section 1, as depicted in Figure 2. For simplicity, the term grid monitoring is used to refer to power grid monitoring.

This hierarchical architecture provides the potential for decentralized fast-reacting control solutions, autonomous control domains as well as minimization of communication needs, aiming at balancing demand and generation, particularly in the presence of a large scale of DER, namely renewable assets (wind generation and PV panels). Independently of how all generation and demand assets interact, the architecture aims at covering all circumstances and levels of the grid, either as a whole (grid scale) or at smaller neighbourhood areas.

The functional architecture assumes that coordination between the several hierarchical levels must be assured at all times. Each control layer is able to collect and process data related to the operation of the grid.

At HV level, the top layer, central management systems provide overall interactions with DSO management systems and operational procedures (grid monitoring and control,

load and renewable energy sources forecasting, state estimation, virtual power plant awareness and control set-points calculation).

The central management systems include the Supervisory Control and Data Acquisition (SCADA) / Distribution Management System (DMS) among other corporate systems.

At MV level, the MV grid will be managed by the SSC housed at the HV/MV distribution substation level that will include local intelligence and several operational and voltage control functionalities, as well as monitoring responsibilities. SSC features also comprise monitoring and controlling of HV/MV transformer OLTC and of MV storage assets, as well as MV controllable loads (under DSM), MV dispersed generation assets and MV controllable CAP.

Also at this level, the SCC participates in the advanced protection schemes aiming at protecting the substation feeder infrastructure, while dynamically updating each protection device (e.g. protection relays, reclosers) settings according to the grid topology and operational conditions.

Regarding the LV grid, it will be controlled by the DTC located at the MV/LV substation level, responsible for managing the DER (via the EB) at LV level. DTC features also comprise monitoring and controlling of MV/LV transformer OLTC targeted for voltage control, as well as of LV grid storage assets.

At the LV level, the EB (smart meters) will be used as interfaces not only to monitor but also to manage domestic controllable loads (under DSM), micro-generators, EV charging assets, as well as LV storage assets.

4.1 SCADA/DMS

SCADA/DMS plays an important role within the Smart Grid model adopted by the SuSTAINABLE project. SCADA/DMS, by its own, is placed at the top of a system wide hierarchy which includes the SSC, the DTC and the EB, all these described in the next sections.

Moreover, SCADA/DMS also performs interfacing with other corporate DSO central information systems, such as AMM/AMI, ERP/AM (describing the electrical nature of the grid assets) and GIS (describing the grid assets positioning and the topological/connectivity nature of those grid assets and how they are related to each other). Combined with these, a holistic awareness of the distribution grid is capable of providing enough data and resources to accomplish the main target of SuSTAINABLE which is balancing demand and generation with high penetration of DG, namely RES.

Effectively SCADA/DMS will manage a collection of intelligent semi-autonomous sub-networks. All pertinent operational data is obtained from the downstream layers, which are described below in the next sections. Although some could be more useful to be used

only locally, especially for implementing local proactive and autonomous control and set-points actions towards fulfilling the aim of SuSTAINABLE, as said, a holistic awareness of the wide distribution grid is deemed necessary, as local actions rely on the overall global state of the grid, where every contingency or faulty event may lead to unprecedented cascading grid disturbances or unbalances between demand and generation (centralised or distributed), which, ultimately can lead to blackout.

Conventional features such as topology processing are available at SCADA/DMS level, relying on grid state data and measurements (e.g. voltages, currents, power and frequency), digital data (switching or protective devices state, e.g. open or close) and metering data (indices, energy). Not only state data is available, but also alarm indications associated to the SCADA events also draw the attention of the SCADA/DMS operators, for quick decision making and reaction.

The role of those operators is improved by advanced mimic one-line displays with friendly navigation tools, magnifying lenses, panning and zooming with decluttering features to hide any graphical representation that may not be needed at certain zoom levels. Besides, data filtering associated to the overall Human-Machine Interface (HMI) and cross navigation between any types of graphical application are also common features.

The collection of real-time and historical data drives graphical tools such as trend displays and lists of pertinent data with filtering options.

HMI operators may use SCADA/DMS to perform grid control or set-point orders towards the downstream grid equipment.

Finally, SCADA/DMS offers a comprehensive user-friendly engineering tool enabling all system data configuration and mimic display design.

So far, this specification has been mainly being focused on SCADA features. Now it is time to step forward DMS features.

Within SuSTAINABLE, the main DMS functions are:

- State Estimation
    - This feature enhances the observability of the state of certain zones of the grid, mainly those where traditionally there are no sensing devices for monitoring purposes, despite the grid effect on those zones of the DG assets, namely those intermittent as RES;
    - All available grid data will be used to characterize the distribution grid model at DMS level, and, wherever there is a lack of real-time data, near real-time or deferred data obtained from AMM/AMI will also be used;
    - It also uses predicted data resulting from the Forecasting features.
- Renewable generation forecasting

- This feature, although performing at DMS level, can also be virtually distributed along other players such as SSC placed at HV/MV primary substations;
- It uses recent states of the grid, forecasts for neighbouring DG units (wind generation and PV), forecasts for regional solar PV and wind power production. Furthermore, it uses a record of recent measurements of weather variables. The prediction tool will extract, from this information, point and probabilistic forecasts for wind power generation and solar power generation.

- Load forecasting
  - This feature uses available load curves and load historical data, as well as a record of recent measurements of weather variables. Besides, it also includes usage patterns based on load classes and on end-user devices;
  - The forecasting method will be Artificial Neural Network (ANN) or Adaptive Neuro-based Fuzzy Inference System (ANFIS).
- Voltage Control
  - This feature uses the output of State Estimation and of the Forecasting features (generation and demand) to drive set-point orders needed at SSC level, which will then be performed locally over OLTC, capacitor banks, grid storage devices, as well as controllable demand and DG inverter units.
- Interface with the Virtual Power Plant Control Centre
  - This feature provides the output of the Forecasting features (generation and demand) to the VPP/CC, enabling it to drive set-point orders needed at the lower layers of the SuSTAINABLE system model, namely at SSC and DTC levels, the latter also playing a role on forwarding subsequent set-point orders to the EB;
  - At those lower layers, all TVPP participating resources (DG inverters and storage assets) will perform accordingly, contributing for the mitigation of the fluctuations arising from the intermittent nature of RES. This way, an improved QoS will ensure a safer and more reliable grid operation, particularly, improving the interaction between the DSO's and TSO's grids, assuring that no grid constraints are violated.

SCADA/DMS interacts downstream with the primary and secondary substations, respectively with the SAS/SSC and with the DTC. It also interacts with the corporate systems, each one using the most appropriate protocol. This interaction is supported by communication architectures, from conventional serial and hardwired to WAN platforms, using standard protocols such as IEC 60870-5-104.

4.2 SSC

At this level, a Smart Substation Controller (SSC) manages the MV grid through a set of monitoring and control functionalities, including several DER that are directly connected at the MV level.

The SSC includes functionalities to manage MV level demand flexibility (provided through MV controllable loads and storage assets) in conjunction with an overall grid demand control strategy.

At the HV/MV substation, the SSC collects input information from the MV level and from the lower LV level of the architecture. Hence, equipment deployed at these levels must not only have a great deal of processing capability but also be able to collect data from local sensors, both at MV and LV level.

Several data acquisition points are required so that enough local sensors can be interfaced with. Advanced coordinated voltage control exploiting controllable dispersed generation, controllable loads, storage devices, On-Load Tap Changers (OLTC) and capacitor banks is another goal which requires a local interface to the Substation Automation System.

Acting in coordination with central systems (SCADA/DMS), the SSC will be responsible to calculate and send set-points to controllable devices such as controllable loads and storage assets, according to any DSM criteria, or such as DG units and again storage devices depending on the local monitoring of voltage profiles.

Also, depending on data collected at each individual feeder (from remote sensors and concentrators at MV/LV substations) and also data from the LV network (such as voltage alarms from smart meters), control orders will be sent to the lower architecture level. Therefore, the monitoring of operational parameters with local sensors in real-time is crucial.

Besides, the SSC also supervises locally the MV power quality, performing control actions over the grid for QoS improvement (compensation), in conjunction with a given HV grid level QoS preventive control strategy, arising from the upper level, namely from the CC.

The monitoring variables collected and recorded locally are:

- MV 3-phase Bus Voltage
- MV 3-phase Line Current
- MV 3-phase Active Power (value and direction)
- MV 3-phase Reactive Power (4 quadrants)
- MV 3-phase Power (S)
- Frequency
- MV feeder 3-phase Line Current

- MV feeder 3-phase Active Power (value and direction)
- MV feeder 3-phase Reactive Power (4 quadrants)
- Active Energy
- Reactive Energy
- HV 3-phase Line Current

The protection functions can be enumerated as follows:

- Phase Over-voltage Protection
- Zero Sequence Over-voltage Protection
- Phase Under-voltage Protection
- Over and Under-frequency Protection
- HV grid 3-phase Bus Voltage

SSC interacts upstream with SCADA/DMS and downstream with DTC. It also interacts on a peer-to-peer basis with the SAS which performs all typical substation automation and protection functions. Besides, SSC also interacts with reclosers performing protection functions, placed along each distribution feeder. This interaction is supported by communication architectures, from conventional serial and hardwired to WAN platforms (more details on the interaction with the DTC are available on the following section), using standard protocols, such as IEC 60870-5-104 to IEC 61850.

Protection features assure grid stability during load and external faults while preserving resilient operation for internal faults. Adequate design options provide correct fault selectivity and adequate coordination among protection IED, either at substation (integrated automation and protection system) or along the feeders (reclosers).

Furthermore, adaptive protection via multiple setting groups selectable according to grid conditions (topology, contingencies, power flow directionality, demand, generation, injection points) are driven by the SSC, which ensure the adaptation of the overall system protection function behaviour in response to dynamically grid changing conditions.

From the functionalities residing on the SSC, it is possible to notice that the dynamicity of the grid topology results in the need for a constant and real-time update of the network model. This means that the local model of all the assets supplied and connected to that primary substation must be updated if any network reconfiguration occurs. This impacts not only the grid model itself (topology, characteristics, etc.) but also the communication model. For example, if, for some reason, there is a load transfer between neighbouring substations, the SSC must keep the grid and communication model updated in real-time.

4.3 DTC

The control and monitoring layer located at the MV/LV Secondary Substation level is where the Distribution Transformer Controller (DTC) will be deployed. The DTC is in charge of the management of the LV grid. It manages a set of LV grid consumer assets and micro-producers, as well as other LV grid assets, via local actuators and sensors.

Specifically, the DTC is also responsible for executing local demand flexibility control of EVs and controllable loads in households, as well as of storage assets placed at the LV grid level, combined with local set-point control of micro-generation assets, in conjunction with a given MV grid level demand control strategy, arising from the SSC.

Besides, the DTC also supervises locally the LV power quality, performing control actions over the grid for QoS improvement (compensation), in conjunction with a given HV or MV grid level QoS preventive control strategy, arising from the upper levels, namely from the CC or from the SSC. Among these, DTC is capable of actuating over MV/LV transformer OLTC, as well as over LV grid storage assets – whenever these are able to perform active filtering.

The monitoring variables collected and recorded locally are:

- LV grid 3-phase Bus Voltage
- LV 3-phase Line Current
- LV 3-phase Active Power (value and direction)
- LV 3-phase Reactive Power (4 quadrants)
- LV 3-phase Power (S)
- Power Factor
- Voltage interruptions (number and duration)
- Voltage Sags (number and duration)
- Over-voltages (number and duration)
- THD (total harmonic distortion)
- Voltage Unbalance
- Frequency
- Active Energy
- Reactive Energy

DTC interacts upstream with SSC and downstream with EB.

The interaction with SSC is supported by communication architectures, suitable for GPRS/UMTS modem or Ethernet ports which may be used to integrate the DTC in the system WAN. IEC 60870-5-104 or Web Services or others standard protocols assure all needed standard ways of bridging MV and LV levels.

The interaction with EB is supported by communication architectures, suitable for several communication technologies (e.g. narrowband and broadband PLC, wireless such as RF MESH), using standard protocols (such as DLMS).

Since the LV network is constantly changing its assets (smart meters replacements, new connections of microgenerator's or other DER), the DTC must have the capability of updating the assets connected to the secondary substation where the DTC is housed. This means that every time a new asset is connected, the database must be updated as a plug&play system.

4.4 EB

EB (smart meters) play an important role at LV grid level, as they enable the interface between this level's master controller, the DTC, with any domestic LV controllable loads, micro-generator inverters, EV charging assets, as well as LV storage assets.

Housed at the customers' premises, smart meters enable the accurate recording of load/generation profiles in real-time (e.g. micro generators, overall loads, controllable loads under DSM, EV charging and storage), detecting fraud, providing accurate and useful data for assuring energy balancing and allowing the customer to actively manage his own energy behaviour, while providing the DTC with all data needed for controlling micro-generation.

All these features are also suitable for allowing the implementation of third-party related services, provided by an ESCO.

It is through the smart meter (and via all the upstream infrastructure comprising the DTC, the SSC and the SCADA/DMS) that the DSO is able to collect detailed information regarding energy consumption and production as well as power quality data and events. Also, direct load management set-points (selective load shedding and restoration) and dynamic tariffs schemes can be sent to the final client from the DSO. Furthermore, and if applicable, these control options can also be implemented by a third party aggregator directly to the household controller, via the Internet, again third-party related services, provided by an ESCO.

The monitoring variables collected and recorded locally are:

- LV grid Bus Voltage
- LV Line Current
- LV Active Power (value and direction)
- LV Reactive Power (4 quadrants)
- LV Power (S)
- Power Factor
- Active Energy
- Reactive Energy

- Voltage interruptions (number and duration)
- Voltage Sags (number and duration)
- Over-voltages (number and duration)

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