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MORE MICROGRIDS

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Foreword

Coordination of frequency control in MV distribution networks is addressed here with the purpose of improving system operation conditions (such as minimizing frequency deviations and allowing islanded operation of MV networks) by exploiting, in a combined way, the control capabilities of DG units, microgrids (that can be regarded as active cells, including several different microgeneration units) and controllable loads. Specific physical and technical limitations of all these controllable devices are taken into account and this fact lead to the implementation and use of adequately detailed models of several of these devices.

It was also assessed whether the provision (selling) to the Transmission System Operator (TSO) of different frequency control reserves by the operator of Microgrid(s) and/or micro-sources is economically attractive.

INESC Porto developed a multi-microgrids simulation platform to be used as a tool to evaluate the need for specific generation abilities (e.g., provided through storage) or alternative control strategies (e.g., load curtailment). ABB developed studies required to identify benefits from selling reserves to the host grid operator.

The contributions given by the partners INESC Porto and ABB, regarding the topics presented in Task TD3.3 – Coordinated Frequency Support, are presented in the next two parts of this document.

INESC PORTO CONTRIBUTION

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Acronyms and Abbreviations

CAMC – Central Autonomous Management Controller
CHP – Combined Heat and Power
DFIM – Doubly-Fed Induction Machine
DG – Distributed Generation
DMS – Distribution Management System
DSM – Demand Side Management
DSO – Distribution System Operator
EMS – Energy Management System
HV – High Voltage
LC – Load Controller
LV – Low Voltage
MC – Microsource Controller
MGCC – MicroGrid Central Controller
MV – Medium Voltage
OF – Objective Function
PF – Power Factor
PI – Proportional-Integral
RTU – Remote Terminal Unit

1. General Introduction

A microgrid as defined so far comprises a Low Voltage (LV) feeder with several microsources, storage devices and controllable loads connected on that same feeder. A scheme of such a system can be seen in Figure 1.

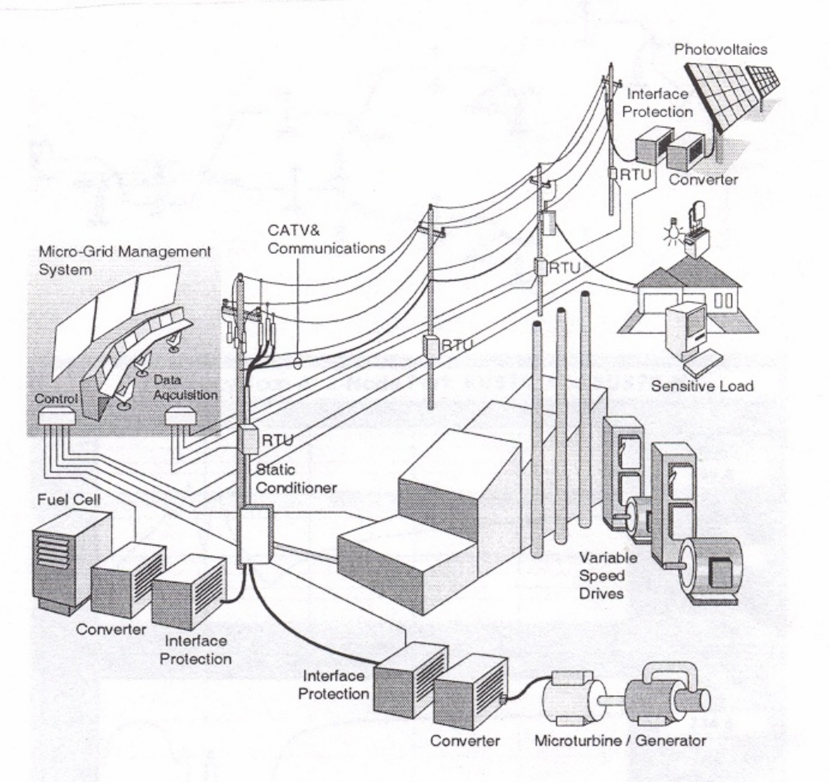

Figure 1: Typical MicroGrid System

A control scheme for microgrid operation requires three different control levels that can be seen in Figure 2:

- Local Microsource Controllers (MC) and Load Controllers (LC)
- MicroGrid Central Controller (MGCC)
- Distribution Management System (DMS)

The new concept of multi-microgrids is related to a higher level structure, formed at the Medium Voltage (MV) level, consisting of several LV microgrids and Distributed Generation (DG) units connected on adjacent MV feeders. Microgrids, DG units and MV loads under Demand Side Management (DSM) control can be considered in this network as active cells for control and management purposes.

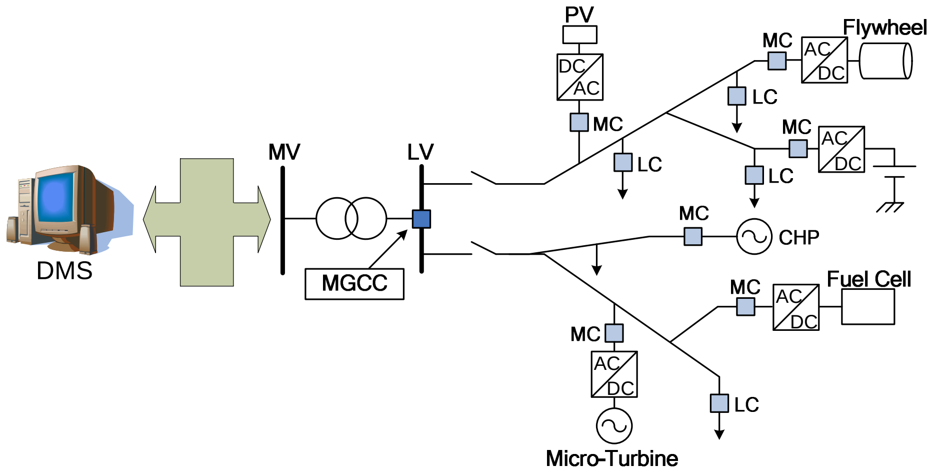

Figure 2: Microgrid Control Architecture

The technical operation of such a system requires transposing the microgrid concept to the MV level where all these active cells, as well as MV/LV passive substations, shall be controlled by a Central Autonomous Management Controller (CAMC) to be installed at the MV bus level of a HV/MV substation, serving as an interface to the Distribution Management System (DMS), under the responsibility of the Distribution System Operator (DSO). In fact, the CAMC may be seen as one DMS application that is in charge of one part of the network.

The main issue when dealing with control strategies for multi-microgrids is the use of individual controllers acting as agents with the ability of communicating with each other in order to make decisions [1]. The controllers should aggregate several devices of the same type in order to obtain a more "operational" system – Load Controllers (LC) controlling groups of loads or Microsource Controllers (MC) controlling groups of microgenerators. A decentralized scheme is justified by the tremendous increase in dimension and complexity of the system so that the management of multi-microgrids requires the use of a more flexible control and management architecture [2].

Nevertheless, decision making using decentralized control strategies must still hold a hierarchical structure [1]. A central controller should collect data from multiple agents and establish rules for low-rank individual agents. These rules for each controller must be set by the high level central controller (DMS) which may delegate some tasks in other lower level controllers (CAMC or MGCC). In this case, a purely central management would not be effective enough because of the large amount of data to be processed and treated, and therefore would not ensure an autonomous management namely during islanded mode of operation. The CAMC must then communicate with other “local” controllers such as MGCCs or with DG sources or loads connected to the MV network, serving as an interface for the DMS.

Therefore, the CAMC will be playing a key role in a multi-microgrid system: it will be responsible for the data acquisition process, for enabling the dialogue with the DMS upstream, for running specific network functionalities and for scheduling the different agents in the downstream network [2]. In general terms, this new management and control architecture is described in Figure 3.

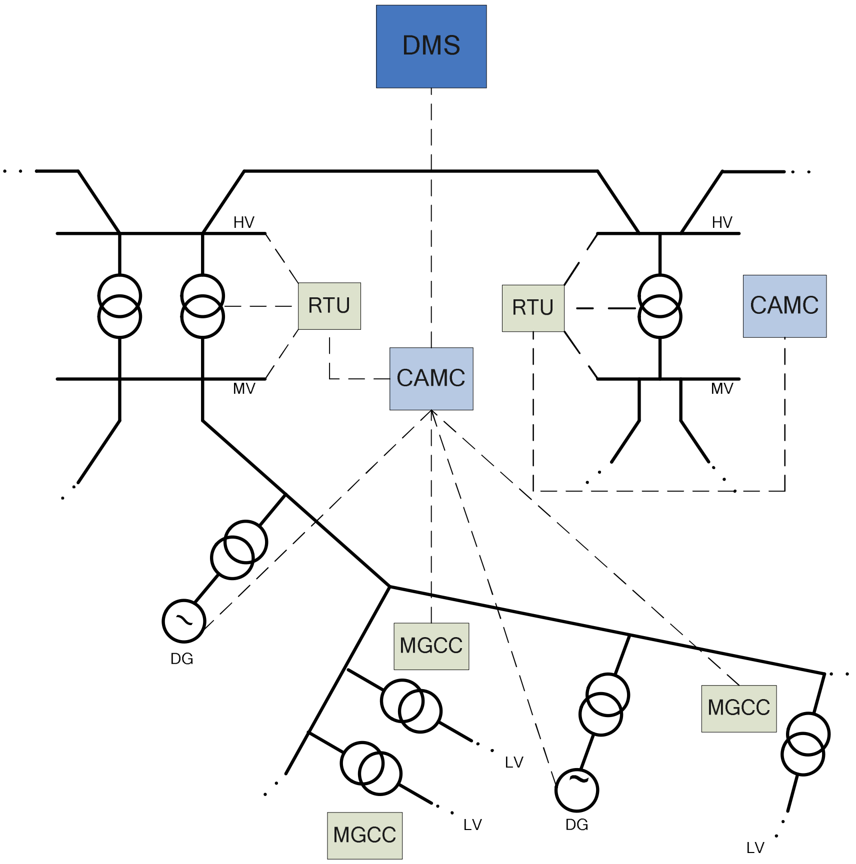

Figure 3: Control and Management Architecture of a Multi-MicroGrid System

Existing DMS functionalities need to be adapted due to the operational and technical changes that result from multi-microgrid operation and the introduction of the CAMC concept and corresponding hierarchical control architecture.

The management of the multi-microgrid (MV network included) will be performed through the CAMC. This controller will be responsible for acting as an intermediate to the DMS, receiving information from the upstream DMS, measurements from RTUs located in the MV network and existing MGCCs. It will also have to deal with constraints and contracts to manage the multi-microgrid in both HV grid-connected operating mode and emergency operating mode. A first set of functionalities to integrate the CAMC can be seen in Figure 4.

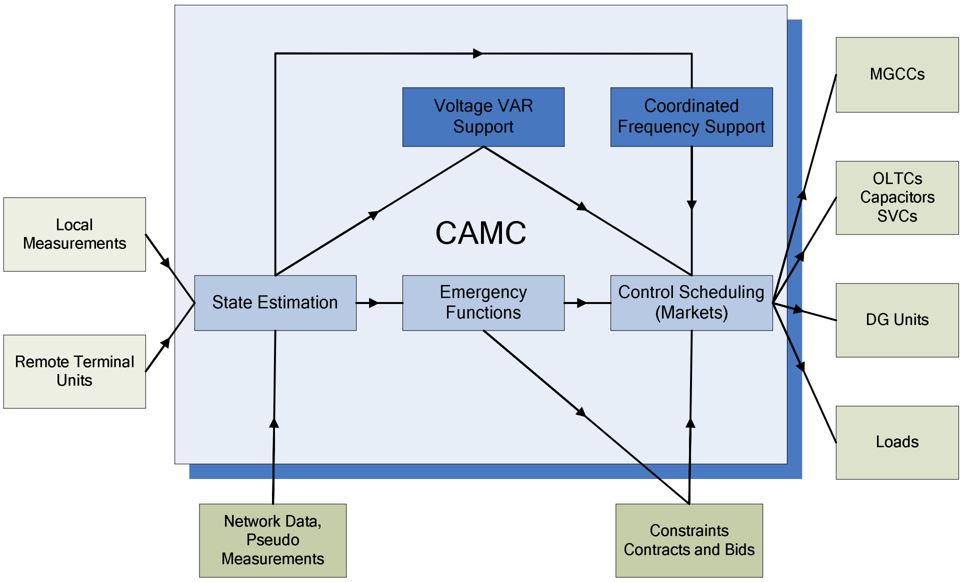

Figure 4: CAMC Functionalities

However, not all these functionalities will be available in any multi-microgrid system. Their availability will depend on the characteristics of the MV network and on the local DG units present.

The Coordinated Frequency Support functionalities presented in Figure 4 will be described in detail in the two following sections.

2. Introduction to Coordinated Frequency Support

As previously mentioned, reliability and security has become a primary concern for power systems since network conditions are becoming more and more stressed. In order to maintain a good quality of supply, distributed generation can be used to partially fulfil the role of traditional active power reserve services. This is particularly true since the moment DG is showing up as a leading player in distribution system reorganization.

However, a problem remains: how to coordinate the efforts of multiple generation units, along with controllable loads, so that frequency control can be effectively achieved in multiple network operating points? The solution is based on the hierarchical system already described by Figure 3 and Figure 4, which depends heavily on the CAMC (at the MV network level) and on the various MGCCs (at the LV microgrid level).

Activation of reserve services for frequency control can be performed in either grid connected or emergency modes of operation. Islanded operation is considered to be possible, so load-following performance is important. Another important subject to tackle is the transition to islanded operation while the Multi-MicroGrid is importing substantial power from the upstream HV network. In this case the power imbalance that may take place inside the island must be eliminated in the least amount of time possible, with the contribution of all the available elements.

The implementation of controlled Load Curtailment programs (also known as Load-Shedding, Demand Response, Dispatchable DSM, etc.) was always thought as useful in this kind of scenarios. Loads that can be managed at the microgrid level are, for instance, normal customers that can be rewarded with special tariffs for allowing having their consumption partially curtailed if needed.

In order to study these control strategies, it was necessary to implement a simulation platform capable of reproducing the way in which an intermediate managing control structure – the CAMC, capable of controlling the downstream agents depending from a MV bus of a HV/MV distribution substation – can be used to accomplish some management and control tasks in this kind of multi-microgrid system Such tool is particularly important to address frequency control in case of MV network islanding and also load-following in islanded operation. This dynamic simulation platform was built around Eurostag and MATLAB software packages. This combination was chosen due to the flexibility that their simultaneous use brings to the simulation. In fact, Eurostag 4.2 is very strong in dynamic simulation but is left behind because of its lack of capabilities for algorithm implementation. MATLAB, on the other hand, is completely at ease regarding the implementation of complex algorithms and control procedures, just like most other programming languages.

This simulation approach requires having a procedure, under MATLAB environment, starting multiple Eurostag simulation runs that last for a predefined period of time. This MATLAB routine is used to emulate both CAMC and MGCC behaviours. Such behaviour requires the monitoring of system frequency variations and involves sending setpoints or load change commands to the Eurostag environment where the system dynamic simulation runs. The MATLAB routine will also acquire several measurements from Eurostag's data files, corresponding to the real system, and use them in this process.

The implemented simulation platform enables the testing of the coordination of contributions from generators together with those from load curtailment. If necessary, dynamic equivalents of microgrids (derived in TD2) can be used to improve simulation times for large-scale Multi-MicroGrid systems.

3. Hierarchical Control Overview

The hierarchical control system can be represented by the block diagram in Figure 5. Only Control Levels 2 and 3 are implemented, as the simulation platform deals only with a single autonomous multi-microgrid (a single MV network) and does not perform any function related to the DMS that is dealing with several MV networks.

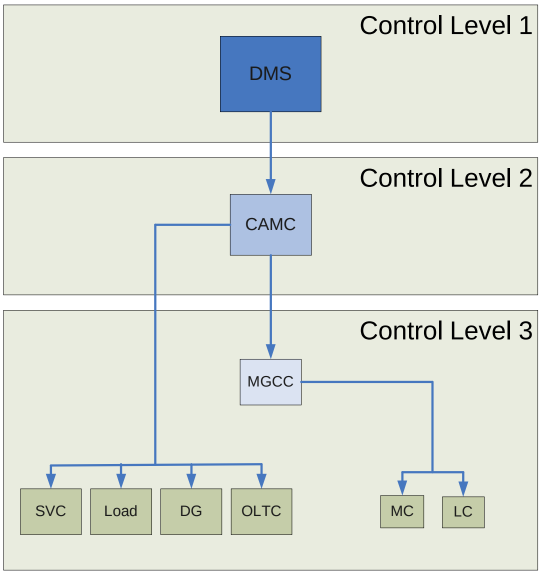

Figure 5: Hierarchical Control Scheme

The commands needed to modify generation and load are originated in the CAMC. These commands are sent to MGCCs, to independent DG units and also to controllable MV loads. MGCCs act as an interface between the CAMC and the internal active components of the microgrids, so that the CAMC doesn't need to have the details of each microgrid's constitution.

While connected to the upstream HV network, the MV CAMC limits its autonomous intervention to a minimum. However, in islanded operation, the CAMC will respond to power system frequency changes in a way similar to the one implemented in regular Automatic Generation Control (AGC) functionalities [3]. A PI controller is used to derive the requested global power change needed to restore system frequency. Then, an economical allocation algorithm will allocate contributions for this power change among all the power generation units, controllable MV loads and MGCCs under CAMC control but only if they are willing, at that point in time, to participate in frequency regulation.

Each of the MGCCs will also allocate the necessary power changes among its subordinate controllable loads and micro-generation units, through the Load Controllers (LC) and Microsource Controllers (MC). Some of these microsources do not usually have regulation capabilities (e.g., PV or wind generation, due to limitations in primary resource availability) and will not normally be asked to change power generation.

It should be noted that the CAMC will only act if strictly needed and will not try to globally change set-points in order to achieve a near optimum point of operation of the system. This justifies the choice of using power setpoint variations and not absolute power set-points in order to make it possible to have a higher order control system, either automatic or manual, that would independently adjust microsource or DG output to set-points other than the system optimal ones. One example of this “control system” could be the microsource individual owners who would adjust microturbines, for instance, according to their heating needs.

The approach adopted for load-shedding, in the context of this hierarchical control system, is fairly different from the one used in conventional systems, as the hierarchical control system which supervises the controllable loads isn’t capable (mainly due to communication system limitations) to act in near instantaneous time-frames. Therefore, in these circumstances, load-shedding is not expected to reduce the amplitude of frequency excursions in the few seconds following a disturbance. It should be seen more as a kind of secondary reserve – rather than an emergency resource – helping the frequency return to the rated value faster or without depending so much on the availability of renewable resources or other generation systems.

In order to make the control algorithm as generic as possible so that its future evolution and software maintenance is not impaired, loads are regarded simply as negative generation, with few exceptions. In this way, a seamless integration of all kinds of controllable elements is achieved, as they share a substantial part of the properties relevant to the control (e.g., associated costs, limits on power variations, etc.).

The main difference that distinguishes between microsources and controllable loads resides on the fact that it is not feasible to keep loads disconnected indefinitely, so it is mandatory to reconnect them after the system frequency recovers. This is accomplished through the use of a control loop that runs on a larger time-scale, reconnecting loads after the system is running on a near steady-state condition for a predefined period of time.

Starting from the assumption that the system, after some time running stable and near the rated frequency, is capable of supporting the connection of some more loads, the control systems starts to reconnect the most expensive/important ones first. This is done step by step, always ensuring that there is enough available reserve on the multi-microgrid in order not to unnecessarily compromise the system's stability. Before each new reconnection, the control system waits for the frequency to stabilize.

A cluster of several storage devices (e.g., flywheels and batteries) could, if integrated in the hierarchical control system, efficiently establish a storage reserve that would be of great help to the islanded operation of the network at the microgrid and multi-microgrid levels. On the other hand, these storage devices, assumed to have interface inverters of the Voltage Source Inverter (VSI) type, can also have their output power controlled on the basis of frequency droop.

Therefore, these storage devices can help in two possible ways: a) they can act autonomously, with their output power PVSI responding to system frequency changes providing energy used to balance initially the system using a proportional control element as described by (1) or b) they can receive setpoints controlled from a central location, in a hierarchical way.

$$P_{VSI} = K_P \times \left(f_{rated} - f \right) \tag{1}$$

These two control methods are not mutually exclusive: while an autonomous response will undoubtedly improve the system's response to the initial frequency deviations following a disturbance, the hierarchical system can take over after that initial response and real-locate each source and storage element contributions according to some predefined criteria. This two-step approach can be justified by the intrinsically slow nature of the hierarchical control scheme, which suggests that grid connected storage devices under hierarchical control should be regarded as secondary reserve while, in order to be able to limit initial frequency excursions, storage devices must be capable of acting autonomously if necessary. However, these actions are only possible while enough energy is stored in the storage devices. From the simulation point of view, the implementation of such control capability required a step by step evaluation of the energy injected into the grid and a comparison with the available nominal storage values in each existing storage or cluster of storage devices.

4. Hierarchical Control Details

In the proposed approach system's frequency is continuously monitored by the CAMC (Figure 6). Every time interval T_S (sample time), if triggered by significant changes in frequency, the CAMC will send control setpoints to every MGCC, other DGs and controllable loads. This sample time T_S cannot be very small, mainly because of the constraints imposed by the communication system on which this control system depends.

Therefore, the frequency error and the frequency error integral will be used to determine the additional power *ΔP* (2) to be requested to the available contributors under CAMC control: MGCCs, DGs and controllable loads.

$$\Delta P = \left(K_P + K_I \frac{1}{s} \right) \times \left(f_{rated} - f \right) \tag{2}$$

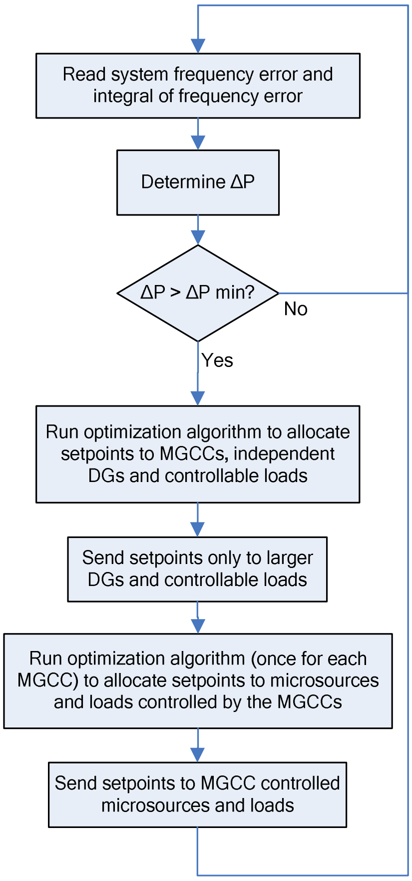

Figure 6: Implementation flowchart – this procedure runs once each period T_S

It should be noted that this additional power can have negative values if the frequency rises over its rated value. In this way the CAMC can also respond to other disturbances, such as load loss while in islanded mode, commanding the distributed generation to reduce power output (including micro-generation curtailment, if necessary), eventually reconnecting some loads still disconnected at the moment.

If the required power variation ΔP is larger than a predefine threshold (related to a deadband), the control system will proceed to determine how to optimally distribute the power requests through the available sources. Unitary generation costs for each of the sources (MGCCs and other DGs) are used for this purpose.

The optimization is based on standard linear optimization techniques:

$$\begin{aligned} &\min_x z = c^T x \\ \text{subject to} \quad &\sum x = \Delta P \\ &x \geq b_1 \\ &x \leq b_2 \end{aligned} \tag{3}$$

Where the vectors represent:

c	generation cost and load curtailment prices;
x	generation or load setpoint variations;
b_1	smallest variations allowed (lower bounds);
b_2	largest variations allowed (upper bounds);

The set of restrictions (3) can also define which generators/loads participate in frequency regulation. This can be done by setting to zero the i^{th} elements of both b_1 and b_2 corresponding to units that cannot be adjusted.

Because loads are considered as negative generation, the corresponding coefficients (elements in vector c of prices) are negative.

In order to avoid globally changing setpoints (e.g., decreasing production from expensive microsources and replacing them with less expensive ones), it is necessary to adjust the lower and upper bounds in (3) according to the ΔP value:

$$\begin{cases} \Delta P > 0 \Rightarrow b_1 = 0 \\ \Delta P < 0 \Rightarrow b_2 = 0 \end{cases} \tag{4}$$

The enforcement of these conditions (4) assures that no microsource will decrease its production so that another can increase it (i.e., there will not be any unsolicited power transfers between microsources).

This optimization is performed each sample period T_s and will originate a vector representing the power generation changes to be requested to microgrids (MGCCs), independent DG units (e.g., CHP) and loads (MV load-shedding operations).

Each MGCC will now use the power change requested by the CAMC to establish the main restriction of a new optimization procedure (identical to the one used before by the CAMC) which will determine the power changes to be requested to microsources and controllable loads under MGCC control.

5. Power System Modelling

As already mentioned, Eurostag 4.2 was chosen as the main power system multi-microgrid simulation platform. However, Eurostag is unable, on its own, to provide enough flexibility to allow for the implementation of complex control algorithms. Because of this limitation, the hierarchical control algorithm was implemented in MATLAB which calls Eurostag for simulation runs which last for the time defined as the CAMC sample time. At the end of each run, the frequency value and the integral of the frequency error are extracted from Eurostag data files and used to determine the new setpoint values. Additionally, the estimated communication system delay times are also calculated and the Eurostag data files are then modified, in order to enable setpoint modification and load variations on the next dynamic simulation run.

Some of the dynamic models of the power system components came directly from Eurostag's library but most of the models for microgeneration devices and some DG technologies were not available in the version of Eurostag used and had therefore to be implemented in this platform. This was the case, for example, of the Double Fed Induction Machine Wind Generator (DFIM), the storage elements with VSI, the GAST Microturbine and the SOFC Fuel Cell (the last two microgenerators are used in every microgrid).

An additional effort was needed in order to implement models in such way that their initialization and simulation performance is robust enough to allow their use in a large variety of scenarios.

In this environment, modelling of the microgeneration devices is performed using specific block diagrams. This has several advantages, namely regarding the implementation of linear control systems or the transposition of other models, from similar programming environments such as Simulink/MATLAB.

Although the programming blocks in use, shown in several of the following pictures, are easily identifiable and usually self-explanatory, the understanding of all the underlying details requires the study of some of the Eurostag documentation [4]. Such details fall outside the scope of this document.

5.1 Voltage Source Inverter Model

As already mentioned, the VSI model assumes the presence of some type of storage element coupled to it.

As most of the user models in Eurostag, the VSI is modelled as a power injector and is programmed to emulate the behaviour of a synchronous machine (e.g., injecting active power when system frequency transitorily drops [15]). The VSIs can also be controlled by two different and complementary systems, as mentioned before, so they are equipped with a standard proportional controller and also respond to setpoints received from the control system.

As the storage element is limited in capacity, the VSI can only inject power for a certain period of time before its reserves are depleted.

The initial modelling approach was based on the direct control of the amplitude and phase of the sine wave of a voltage source relative to the amplitude and phase of the voltage at the VSI connection point. However, this kind of simulation approach is very slow when implemented in Eurostag due to the rapidly changing values of the instantaneous values of voltages, which prevent Eurostag from incrementing the simulation step. Another added problem was the fact that Eurostag requires the use of power injectors as the interface to the grid, so the sinusoidal voltage waveforms weren’t practical. These limitations conducted to the use of the following expressions:

$$
\begin{aligned}
P &= \frac{V_t E_f}{X_s}\sin\delta \\
Q &= \frac{V_t E_f}{X_s}\cos\delta - \frac{V_t^2}{X_s}
\end{aligned}
\tag{5}
$$

Although these expressions (5) are commonly used only for the steady state analysis of the synchronous machine, the validity of their use in this context is expected because there is no need, for the moment, to do any analysis of fast electrical transients.

This control system is implemented in such a way that the output power of the VSI is zero as long as the system frequency remains constant at the rated value. In case this frequency suddenly changes, the abrupt modification of the voltage phase at the connection point will trigger the temporary injection of a positive or negative power, depending if the frequency lowers or increases. A similar approach is used for the reactive power injections, but in this case the trigger is the terminal voltage amplitude and not the frequency.

If the proportional control (droop) is not enabled, the active power injection will last only until the VSI adjusts its own operation point. In other words, without the proportional controller the VSI will behave just like a synchronous machine with no mechanical power and with constant excitation.

The proportional control enables the VSI to inject power through periods in which the frequency deviates from the rated value. This kind of behaviour is, however, limited by the capacity of the storage elements coupled to the VSIs.

The modelling approach used in this case was subject to validation through the comparison of simulation results with those of a more complex model, implemented in MATLAB/Simulink, which employed sinusoidal voltage synthesis initially thought of. It was found that, after some controller parameter adjustment, it was possible to obtain similar behaviours from both implementations.

In order to exemplify how the implementation of these models was done in Eurostag, the block diagram for the VSI, as implemented in Eurostag, is show in the following picture (Figure 7).

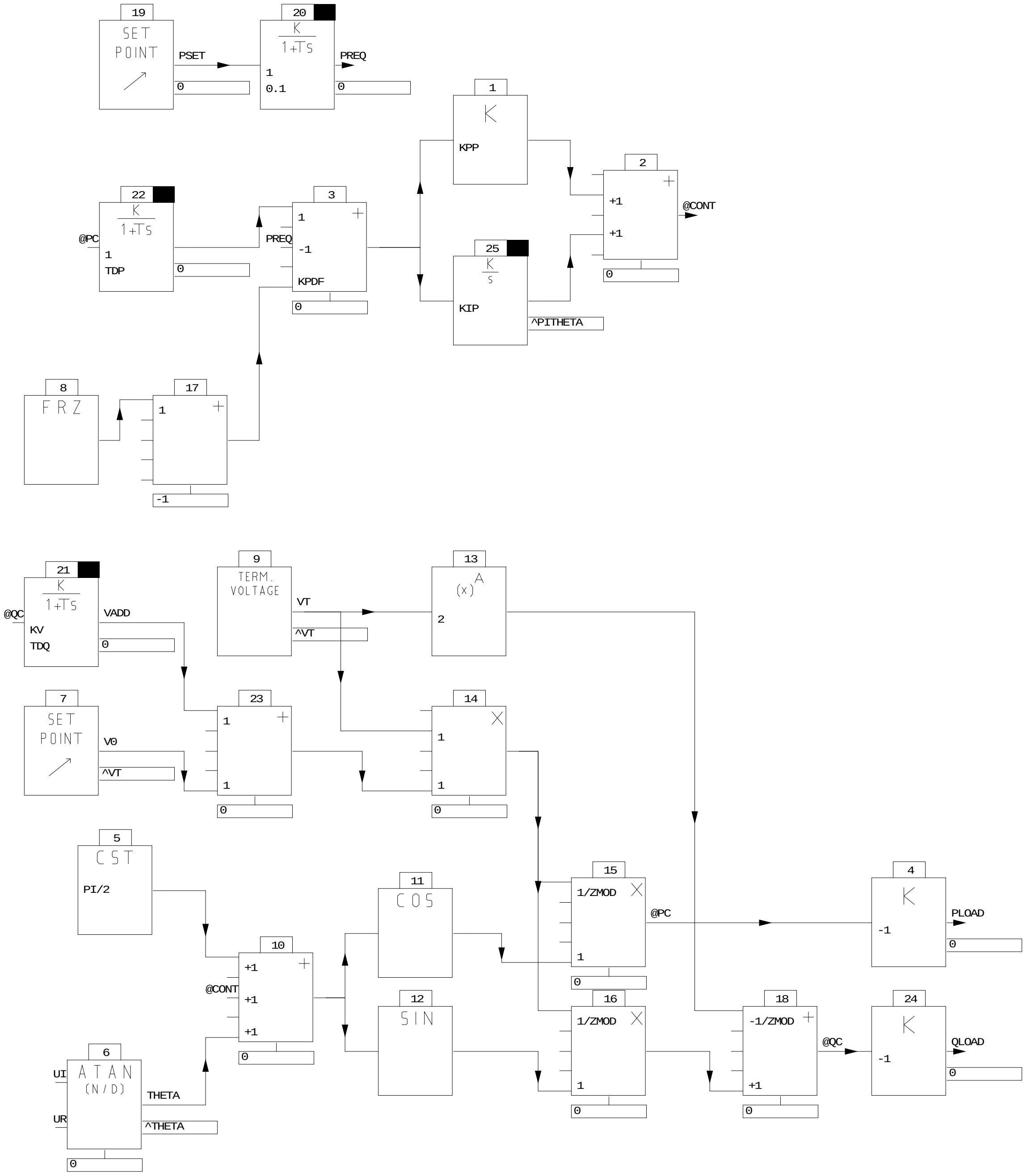

Figure 7: Voltage Source Inverter block diagram

5.2 DFIM Wind Generator Model

The DFIM model is based on the approach described in [6,5,7] but includes additional modules for pitch and de-load control which could enable it to participate in primary frequency regulation [8].

This model is one of the most elaborated. This is, in part, due to the fact that the available Eurostag version doesn’t have an asynchronous machine model that enables the modification of rotor voltages (only short-circuited rotors are considered in this Eurostag version). Therefore, a complete model, capable of dealing also with generator deloading, had to be built from scratch integrating the following components:

- Asynchronous machine (ASM – wound rotor);
- Power converters and associated controllers;
- Wind turbine model;
- Pitch control.

The classic ASM model has no particular features except for the access to the rotor terminals. The expressions involved are show below.

The first equation set (6) defines the voltages behind the transient reactances in the d and q axis.

$$\begin{cases} \dfrac{\partial \bar{e}_d}{\partial t} = -\dfrac{1}{T_0}\left[\bar{e}_d - \left(\overline{X} - \overline{X'}\right)\times \bar{i}_{qs}\right] + s\times 2\pi f_s \times \bar{e}_q - 2\pi f_s \times \dfrac{\overline{L}_m}{\overline{L}_{rr}}\times \bar{v}_{qr} \\ \dfrac{\partial \bar{e}_q}{\partial t} = -\dfrac{1}{T_0}\left[\bar{e}_q - \left(\overline{X} - \overline{X'}\right)\times \bar{i}_{ds}\right] + s\times 2\pi f_s \times \bar{e}_d - 2\pi f_s \times \dfrac{\overline{L}_m}{\overline{L}_{rr}}\times \bar{v}_{dr} \end{cases} \qquad (6)$$

The following equation set (7) allows the calculation of the stator currents, again in both the d and q axis.

$$\begin{cases} \bar{i}_{ds} = \dfrac{1}{\left(\overline{R}_s^2 + \overline{X'}^2\right)}\times\left[\left(\bar{e}_d - \bar{v}_{ds}\right)\times \overline{R}_s + \left(\bar{e}_q - \bar{v}_{qs}\right)\times \overline{X'}\right] \\ \bar{i}_{qs} = \dfrac{1}{\left(\overline{R}_s^2 + \overline{X'}^2\right)}\times\left[\left(\bar{e}_q - \bar{v}_{qs}\right)\times \overline{R}_s + \left(\bar{e}_d - \bar{v}_{ds}\right)\times \overline{X'}\right] \end{cases} \qquad (7)$$

Another equation set (8) defines the values of the rotor currents.

$$\begin{cases} \frac{\partial}{\partial t}\bar{i}_{dr} = \left(2\pi f_{base}\right) \times \left\{ \frac{1}{\left(\bar{L}_{rr} \times \sigma\right)} \times \left[\bar{v}_{dr} - \bar{R}_r \times \bar{i}_{dr} + \bar{s} \times \bar{\omega}_s \times \left(\bar{L}_{rr} \times \bar{i}_{qr} - \bar{L}_m \times \bar{i}_{qs} \right) \right] \right\} \\ \frac{\partial}{\partial t}\bar{i}_{qr} = \left(2\pi f_{base}\right) \times \left\{ \frac{1}{\left(\bar{L}_{rr} \times \sigma\right)} \times \left[\bar{v}_{qr} - \bar{R}_r \times \bar{i}_{qr} + \bar{s} \times \bar{\omega}_s \times \left(\bar{L}_{rr} \times \bar{i}_{dr} - \bar{L}_m \times \bar{i}_{ds} \right) \right] \right\} \end{cases} \quad (8)$$

The last set of equations (9) describes the electro-mechanical interaction in the machine model.

$$\begin{cases} T_e = e_d \times i_{ds} + e_q \times i_{qs} \\ \frac{\partial \omega_r}{\partial t} = \frac{1}{J} \times \left[T_m - T_e - \left(D \times \omega_r \right) \right] \end{cases} \quad (9)$$

The implementation is quite straightforward but the implementation in Eurostag, using block diagrams, is very extensive and will, therefore, be omitted. Additional model information can be found in [3,5,9].

This DFIM has the advantage of allowing this type of wind generator to have control systems enabling the adjustment of turbine speed and output power factor. These two variables aren’t easily controllable in standard induction machines with short-circuited rotors (SFIM).

Rotor voltage control is done, in this model, by acting on the voltages along the d and q axis. The speed and PF control that arise from here may enable the machine to operate at an optimum point and could, if properly controlled, allow for the provision of ancillary services (e.g., frequency and voltage control). Another advantage of having access to the rotor terminals is the recovery of energy from the rotor circuit that would normally be wasted. Injecting this power back into the grid can help improve the overall system efficiency.

The next picture (Figure 8) shows both the voltage and speed control loops. The speed control loop changes the rotor q voltage, while the voltage control loop acts upon the rotor d voltage.

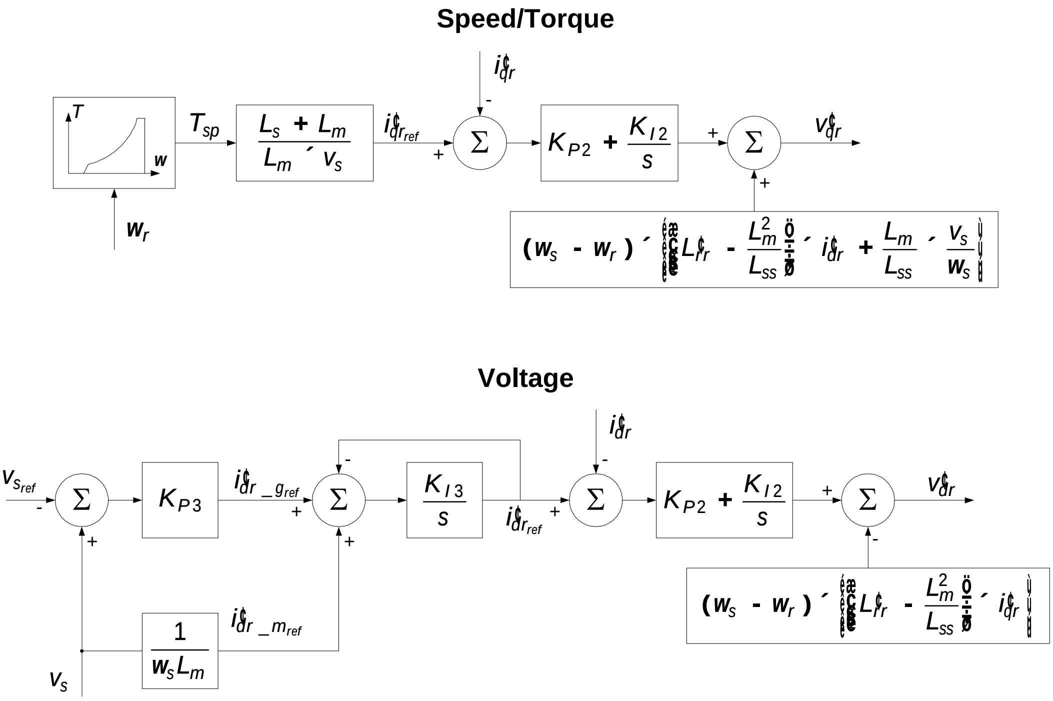

Figure 8: Speed/torque and voltage control loops

The speed control is done supplying the controller with the ideal power output for the current turbine speed (calculated separately). The speed controller will then try to adjust the DFIM torque so that the machine rotates at the ideal speed in order to obtain the maximum power output. This ideal speed will change according to turbine characteristics and wind speed, so it must be correctly determined for each case.

The recovery of the power from the rotor circuit is simulated through the injection of a current to the grid, determined from the rotor circuit power and the voltage at the machine terminals. In a similar way, it is also possible to determine the additional current needed to inject some predefined added reactive power. Through the sum of these currents to those of the machine stator, the total DFIM current is determined and this is then used to calculate the total active and reactive power output of the machine. This is needed because Eurostag models generally behave as power injectors on the point (bus) where they are connected.

The electronic speed control is usually adequate for most of the operating conditions. However, when the wind speed is too strong or when the electrical output power is suddenly reduced, it is necessary to adjust the blade angle (pitch) to a value different than the default (usually zero) so that the turbine speed doesn't increase to dangerous levels. This is accomplished through the use of the pitch control.

The implemented pitch controller, as presented in [7] and in slightly different versions in [6,11,10], has a zero output (ideal pitch) every time the turbine speed is under the reference speed. When the turbine speed increases above this value a PI controller will become active and adjust the blade angle accordingly. The speed and range of the blades rotation is limited by the control blocks following the PI controller: a minimum and maximum value limiter, a 1st order filter (delay) and a rate limiter.

The pitch angle so determined will be fed to the mechanical wind turbine model, together with the turbine and wind speeds. This model [6,12] will determine the power that can be extracted from the wind speed in that particular moment.

This model incorporates functions that are responsible for the calculation of the power that needs to be injected into the grid in order to balance the input and output powers for the required turbine speed, as previously mentioned.

5.3 Fuel Cell Model

The fuel cell model in use was chosen due to the extensive literature available about it [13] and the experience that was previously gathered in its simulation. As this kind of technology is still under heavy study in order to attain ever better processes enabling the widespread commercial usage, it is difficult to say which fuel cell technology (or technologies) will become prevalent in the future. However, it is expected that the chosen Solid Oxide Fuel Cell (SOFC) model will be somewhat representative of this kind of power generator.

5.4 Microturbine Model

The block diagram of the mechanical part of the implemented GAST microturbine model [13,14] can be seen in the following picture (Figure 9). This was the model chosen because it was well documented and there were coherent parameter sets available. This model is expected to be reasonably representative of the microturbine technologies available for use in these systems.

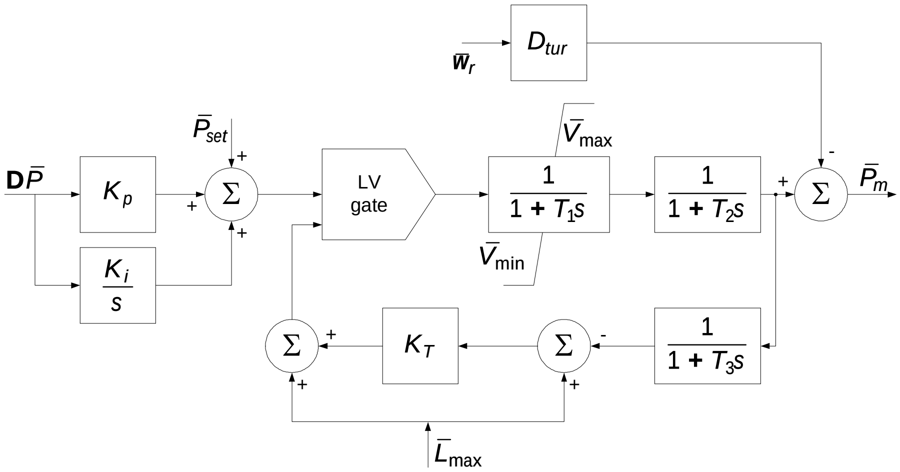

Figure 9: Microturbine mechanical model block diagram

T_1 & T_2: fuel system time constants

T_3: load limiter time constant

L_{MAX}: load limit

K_T: temperature controller gain

V_{MAX} e V_{MIN}: valve position limits

D_{tur}: turbine damping

This block diagram has the corresponding Eurostag implementation shown in Figure 10.

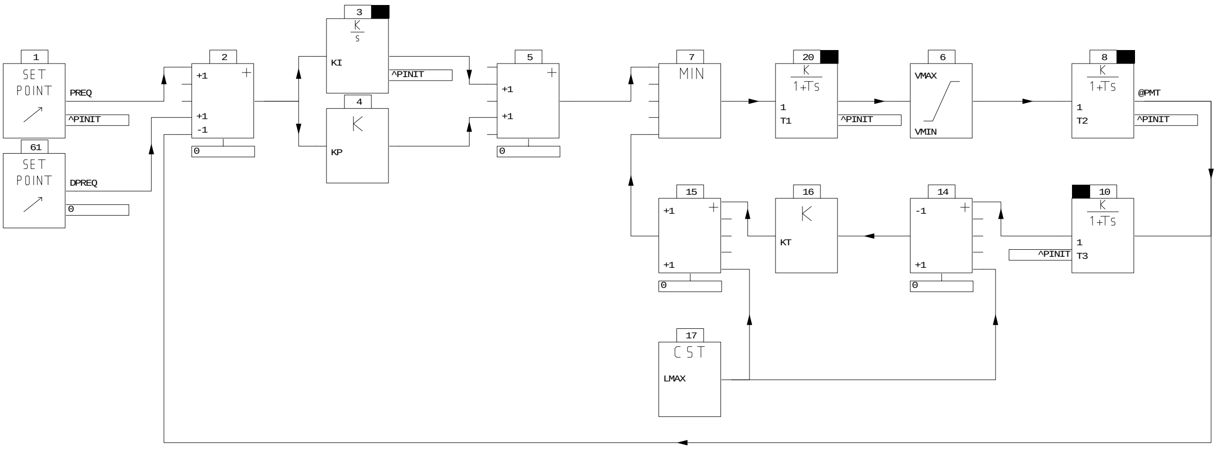

Figure 10: Microturbine mechanical model block diagram (Eurostag)

On the top left corner, a block with an output labelled “PREQ” can be seen. This block was included in this simulation environment in almost every used generator models and is exploited to allow the coordinated use of Eurostag and MATLAB. Its purpose is to adjust the model output to values different than those specified by the initial load-flow solution in order to simulate the behaviour of the model when receiving commands for setpoint modifications from the hierarchical control system (from the MGCC or directly from the CAMC).

The microturbine model also includes the Permanent Magnet Synchronous Machine (PMSM) model coupled to the strictly mechanical components. The model is similar to that of a standard synchronous machine but somewhat simpler due to the use of a fixed value for the rotor’s magnetic field and also due to the assumption of no magnetic coupling between rotor and stator electric circuits.

The model’s output is, once more, the active power. The reactive power is considered to be zero because it is expected to have the control system trying to minimize the output current.

The microturbine control system works in a way somewhat similar to that of the DFIM controllers. In fact, the power interface controllers force the stator voltage (or voltages, in the dq frame of reference) in order to establish rotation speeds corresponding to operating points near those specified as optimum by the machine operating curve.

6. Test System

The adopted test network represents what could possibly be the typical structure of a MV grid containing multiple microgrids and several kinds of larger DG systems (Figure 11).

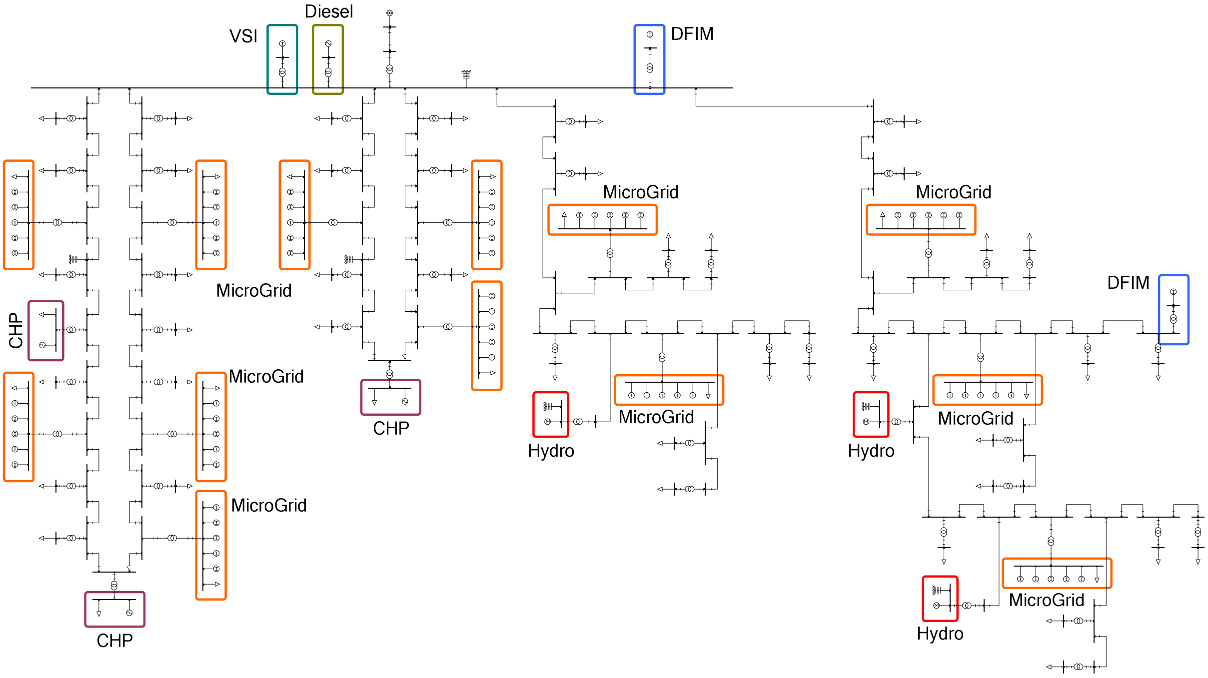

Figure 11: The complete test network

In this network one has assumed four zones, two rural and two urban (the loops in Figure 11, on the left), connected to a HV/MV substation. We can find in this system a relatively large number of microgrids, all connected to MV buses, and also some other typically DG oriented generation systems: a small diesel group, several CHP and hydro units, two doubly-fed induction machines (DFIM) corresponding to wind-generator systems and a storage element interfaced with the MV grid via a voltage source inverter (VSI). The approximate active power initially generated by each of these units, in the considered scenario, can be found in Table 1, along with the rated power of each of the units.

All the micrograms have a 150 kW / 50 kVAr equivalent controllable load and also the same mix of micro-sources: a small wind-generator, a fuel cell, a microturbine, a photo-voltaic generator and a storage element connected to the grid via a VSI (representing storage elements).

Table 1: Test network initial active power generation

Source	Output Power (MW)	Rated Power (MW)
Diesel	1	1.1
VSI	0	1
DFIM 1 & 2	4 / 2	9
Hydro 1, 2 & 3	1.5 / 1.5 / 0.8	2.2 / 2.2 / 1.1
CHP 1, 2 & 4	1 / 1 / 0.5	2.1 / 2.1 / 1.1
Microgrids (13)	0.1	0.25 (+0.15 VSI)

There are also some capacitor banks that are used for two purposes: to guarantee a better voltage profile throughout the network and, additionally, to provide sufficient reactive power to balance reactive generation and reactive load under islanded operation.

7. Test Case Results

7.1 Test Case Setup

The test case analyzed shows a situation where the MV network containing the microgrids is importing approximately 5.3 MW of active power from the upstream HV network, in order to be able to supply a total load of 19.9 MW.

Starting from this point, in steady-state, the HV/MV branch is disconnected at t = 10 s and the multi-microgrid system will become islanded. In order to evaluate the load following capabilities of this control approach, it was assumed that at t = 110 s the load at several nodes[1] begins to change at a rate of 4% per second for 10 s (for total increase of nearly 0.9 MW). These disturbances are picture in Figure 12.

The sample time in use is T_s = 5 s. Lower values can accelerate the system's response but, even if technically possible to attain, they could also create some stresses on the control system. The most adequate value will ultimately depend on the communication system in use and on the mix of microsources and other DGs on the system.

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[1] Nodes NLV1A, NLV6A, NLV11A and NLV18A.

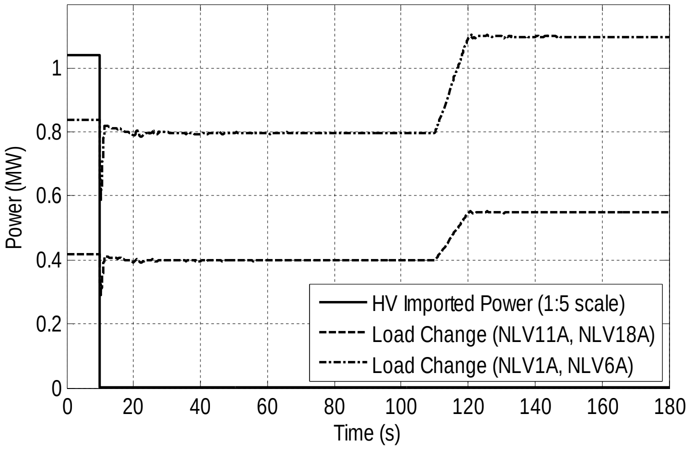

Figure 12: System disturbances

7.2 Results

The first results, in Figure 13, show how the hierarchical control adopted in this multi-microgrid manages to recover the frequency to the rated value after islanding. Although the minimum frequency value after the disturbance remains practically unaltered, in the moments that follow the system's behaviour is much better.

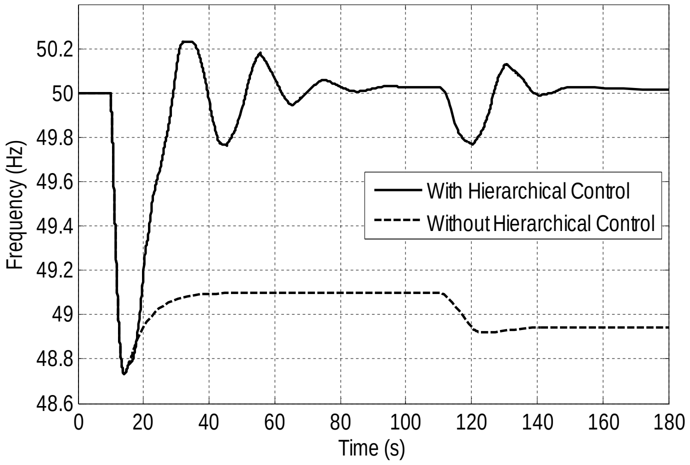

Figure 13: Frequency with and without hierarchical control

The success of the frequency recovery is in part due to the fact that the CAMC is sending setpoints do the microgrids and other DG units dispersed on the MV network. The Diesel group also plays a part but, as it is working near its maximum limit, the contribution is very modest (Figure 13).

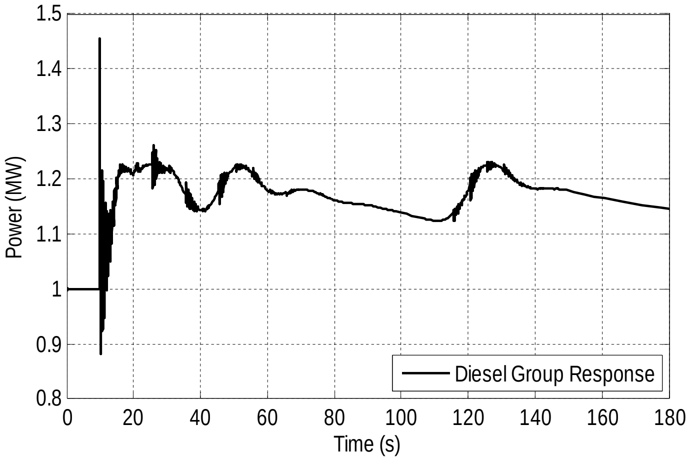

Figure 14: Diesel group behaviour

In Figure 15 and Figure 16 the setpoints sent to one of the microgrids and to one of the DGs (a CHP unit) are shown, together with the corresponding output powers. The order by which the microgrids or the DG units start to contribute is based on their cost as a direct consequence of the optimization method adopted. Therefore, in this case, it becomes clear that the microgrids are considered to be less "expensive" than the CHP unit. Figure 15 also shows how the algorithm is ready to cut generation in case the frequency rises above the rated value (generation curtailment).

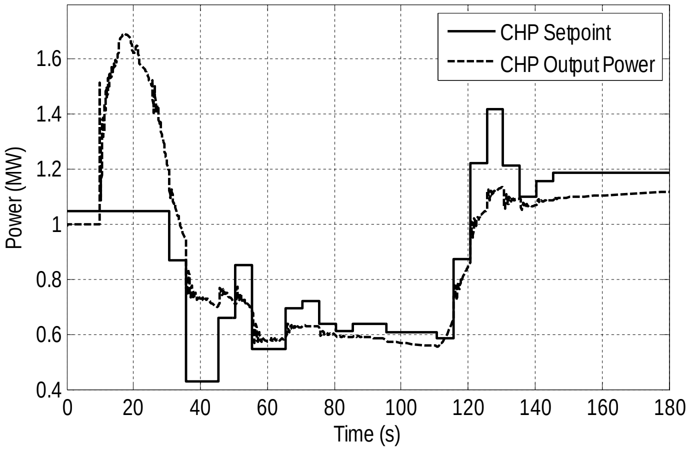

Figure 15: CHP setpoint commands and output power

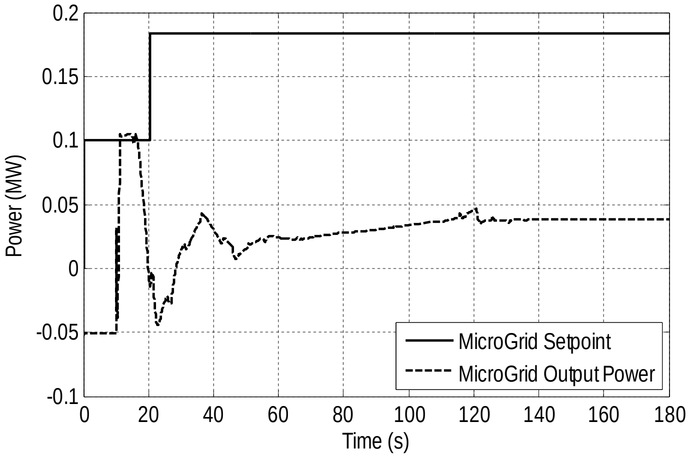

Figure 16: Example MicroGrid setpoint commands and output power

The microsources inside the microgrids are also subject to setpoint attribution according to a similar price dependent optimization algorithm. Figure 17 shows how the microgrid setpoint of Figure 16 translates into individual setpoints for each of the microsources inside that same microgrid.

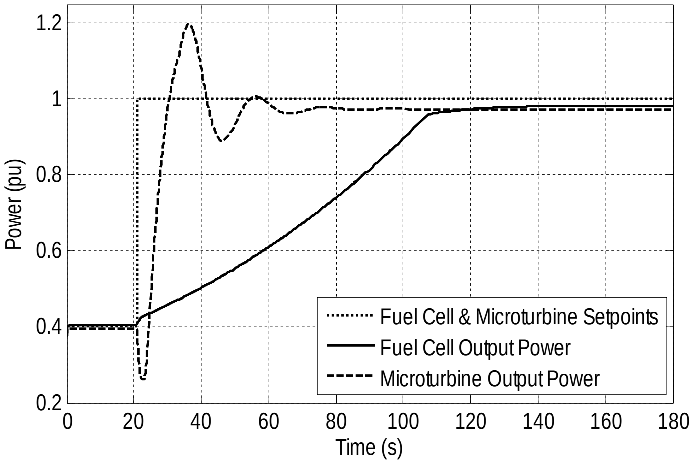

Figure 17: Setpoint commands and output powers inside one of the microgrids

As mentioned before, the test network contains several VSI devices coupled to storage elements. The VSI devices' output is based on the frequency error through the use of a proportional controller. Figure 18 show an example of the power output of a large VSI (connected to the MV level) and one of the MicroGrids' VSIs. For the case of the large VSI, it can be clearly seen that it transitorily reaches its maximum power output. Also, it should be noted that the fact that the VSIs emulate the behaviour of synchronous machine may mask the influence of the proportional controller during heavier transients.

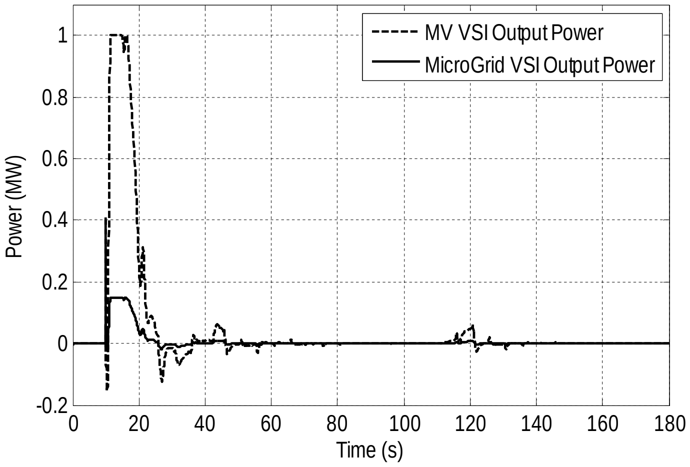

Figure 18: VSI (storage elements) power injections sample

As previously mentioned, the hierarchical control algorithm is capable of acting on controllable loads, integrating them in the optimization process. The expected benefits include the increase in system response speed (Figure 19), while still complying with the optimization rules (in this case, economically sensible) adopted by the algorithm.

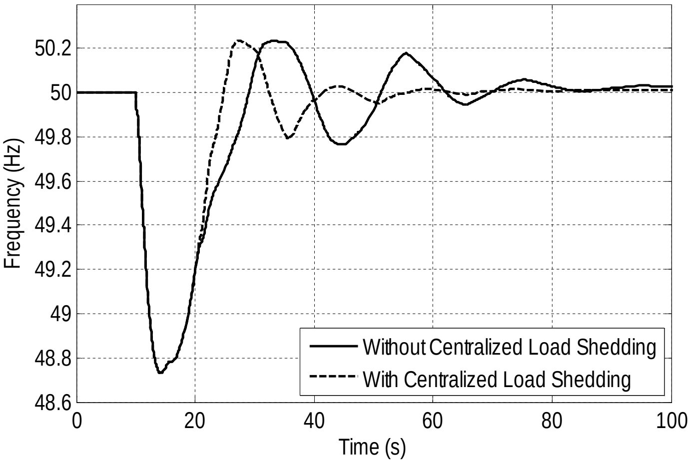

Figure 19: Influence of centralized load-shedding in system response

Loads are disconnected according to their “cost” or importance. The next two pictures illustrate how load-curtailment occurs. Figure 22 shows two of the larger loads, but considered less important. These loads begin to be curtailed soon after the main disturbance (islanding). On the other hand, Figure 23 shows the response of two smaller, but more expensive/important loads. It rapidly becomes apparent that these two loads begin to be disconnected only later, after all the less expensive ones have attained their minimum values.

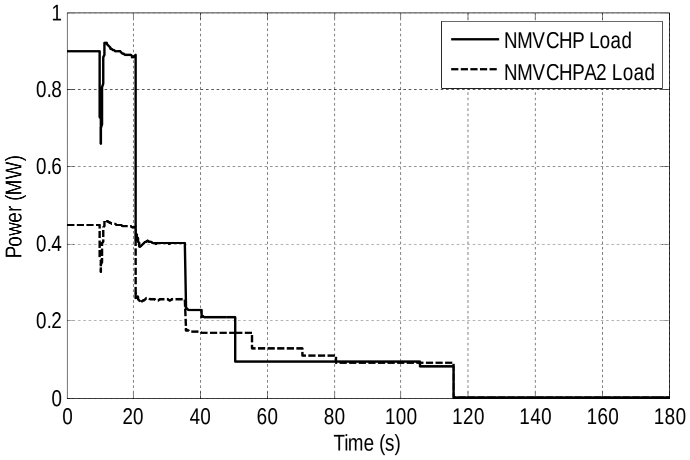

Figure 20: Load-shedding in larger loads near CHP units

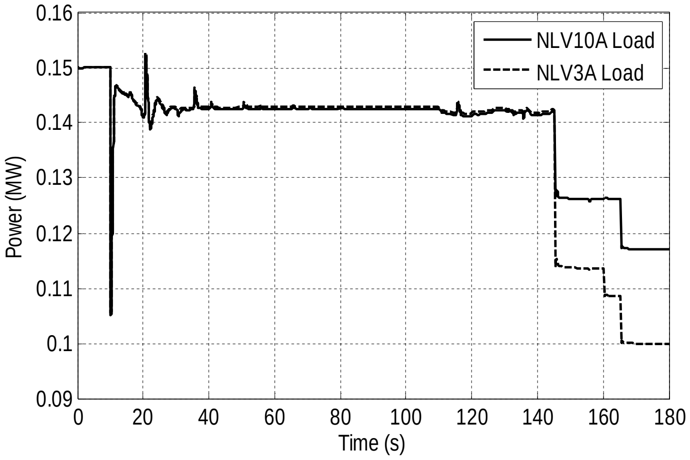

Figure 21: Load-shedding in smaller loads inside MicroGrids

All the previous simulation results benefit from the usage of the storage elements as active and autonomous participants on frequency regulation. As mentioned before, this was accomplished through the use of proportional controllers and is considered essential to limit the initial frequency deviation following any disturbance, due to the very fast response of this kind of autonomous control. Next picture (Figure 22) clearly illustrates the importance that this kind of fast control has when acting together with the proposed hierarchical control scheme. The autonomous proportional control on the storage elements significantly improves the minimum value of frequency after the main disturbance from 47.60 Hz to 48.75 Hz.

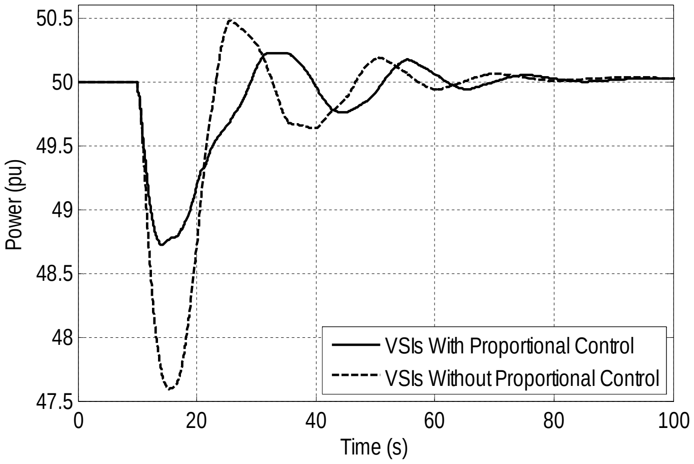

Figure 22: System response with and without autonomous proportional control in storage devices inside microgrids

As mentioned before, storage elements can also be centrally managed by being included in this global optimization approach. This control scheme is used in addition to the proportional control previously mentioned and is exploited only if the storage elements have enough energy reserves available. As these storage elements have a very fast response, it is expected that the possibility of increasing their output power will reduce the need to perform load-shedding actions. The results obtained corroborate this assertion showing that, when the storage elements inside the microgrids are centrally managed, no load-shedding occurs inside these microgrids. In fact, without centralized management, all the thirteen MGCCs requested load-shedding operations for several times after $t = 145$ s (totalling nearly 660 kW after $t = 180$ s), while with centralized management no load-shedding occurred.

8. Conclusions

A new integrated approach designed for the activation of reserve services for frequency control, to be used in distribution grids with large scale integration of DG and microgeneration devices, was successfully developed in this research. This control approach is equivalent to a secondary frequency concept and was developed to be housed at the CAMC level. This approach is capable of exploiting and mobilizing, generation resources, responsive loads and storage devices to provide reserve and contribute to balance locally the system.

Tasks related with coordinated frequency control were successfully fulfilled, either after islanding or for load-following purposes. The setpoint modification commands sent to DG units, microgrids and controllable loads, enable the frequency to return to the rated value in a reasonable amount of time.

Centralized load-shedding, albeit not as fast as the conventional, independent approach, has shown to be of some help in this frequency recovery, while keeping the compliance to the economically sensible optimization rules used in this approach.

The presence of storage devices in the network proves essential to manage the initial frequency excursion following large disturbances. Also, the inclusion, in the hierarchical control system, of the storage devices power output setpoints, has also shown to be able to alleviate the burden on load-shedding.

The implemented simulation platform and control algorithm are flexible and fast, being capable of dealing with relatively large networks and numbers of distributed devices with simulation times approaching real-time, in this case, even on a modest laptop.

Hierarchical control is expected to provide a flexible, easier to implement and potentially cost effective way to efficiently control networks with multiple microgrids and high penetration levels of DG. However, this new control paradigm will require substantial changes to the standard practice for distribution networks management, namely regarding protection and automation systems which will need to be adjusted or developed to allow MV islanded operation.

The feasibility of the use of this kind of control system approach when used in large size distribution systems was also successfully demonstrated.

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Annex I – Test Network Description

This annex aims to describe in some detail the test network currently in use for the dynamic simulation tests of the coordinated frequency support algorithm. Each new developed or translated model is integrated and tested within this network. For that reason, this test network had a very “dynamic” nature, and was constantly evolving and being subject to revisions in order to accommodate other models or different versions of the ones that already existed.

The test network was initially envisioned by NTUA and that primordial version can be seen on the next figure (Figure 23). The network actually in use is a natural evolution of this one in order to accommodate a larger proportion of MicroGrid-based generation. The initial network has two clearly different areas: one with a typically urban topology (the loop) and a rural one (radial).

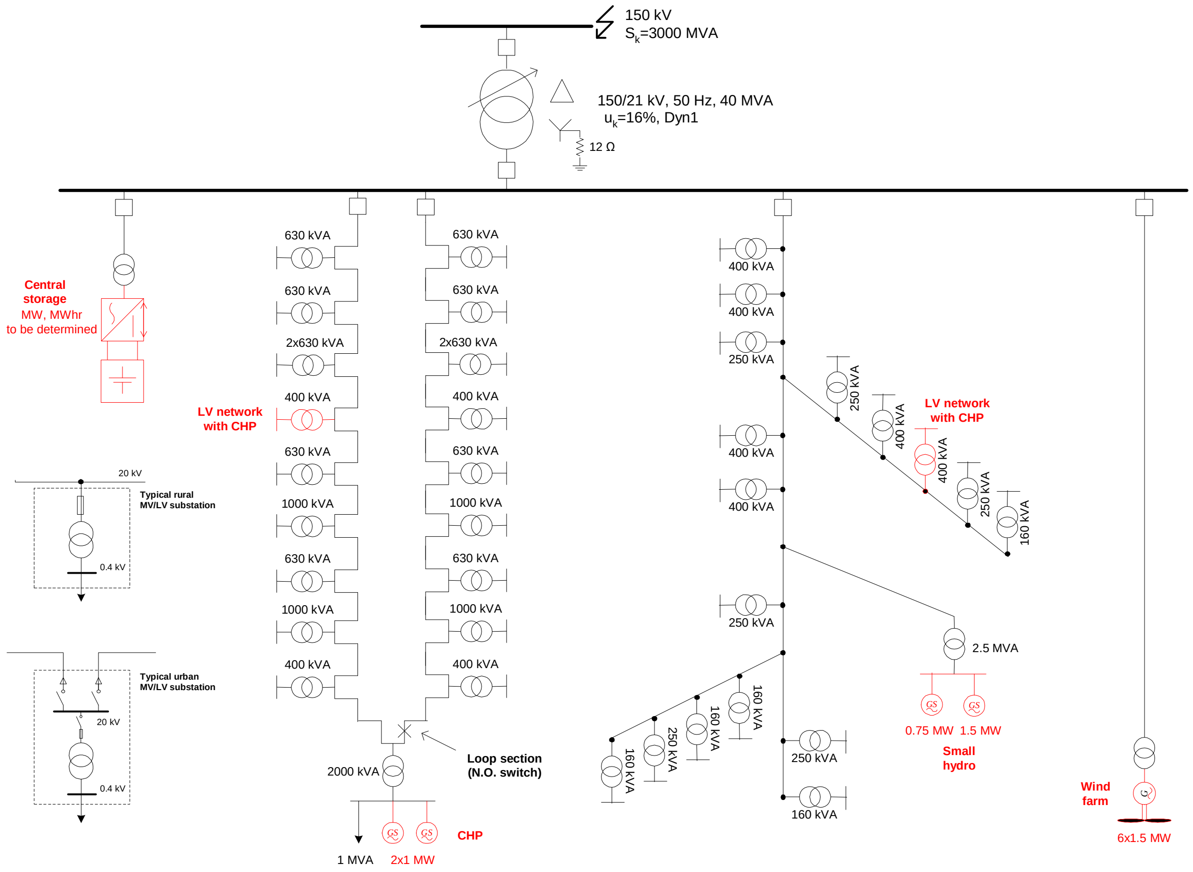

Figure 23: Initial proposal for the test network structure

It was decided to keep the basic initial structure but reduce slightly the number of transformers in each zone and assume that some more MicroGrids would be connected in the MV network. This way the influence of the MicroGrids would be more noticeable which makes it possible to better evaluate the contributions of this type of generation to the coordinated voltage and frequency support.

The resultant network, here shown in the way Eurostag presents it, can be seen on the next figure (Figure 24).

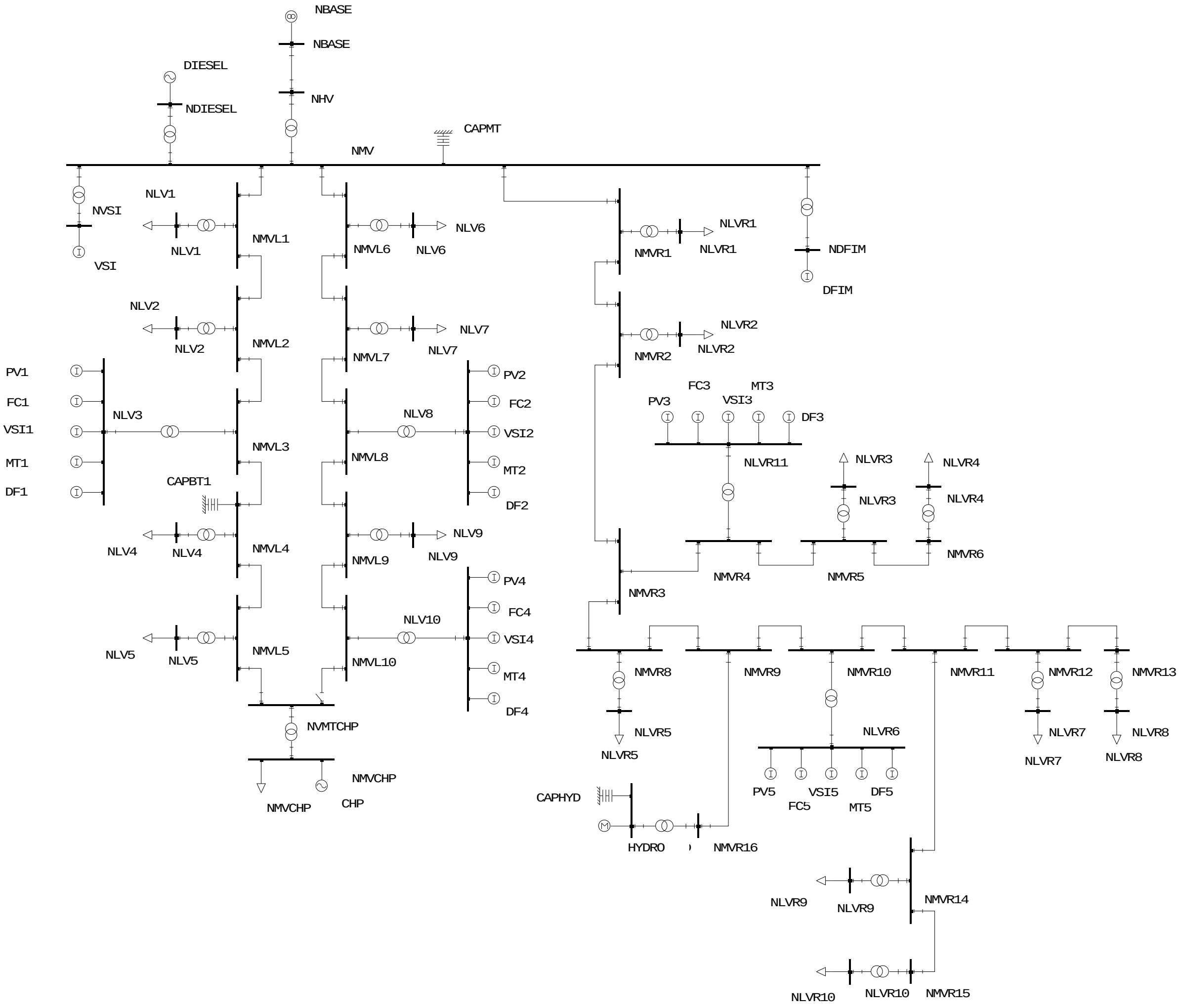

Figure 24: Second approach to the test network structure

Comparing with the initial proposal, this network diagram has some more differences. Firstly, it was decided to add some capacitor banks in order to improve the voltage profile across the network. In a second step, it was decided to include a diesel generator with a PI controller. This generator was needed because initially there was no way to regulate frequency when in islanded mode (the other synchronous generators only have a droop controller). Also, Eurostag has a limitation on the use of its power injector elements that makes them turn off whenever the network zone they belong to doesn’t have a frequency reference (synchronous machine). This could pose some problems because power injectors are used extensively in DG modelling, which means a synchronous machine will be always needed, but can be set to have a very small nominal power so that its influence will be much reduced, thus there is no risk of masking the effect of MicroGrids’ contribution.

Finally, one should also mention that the MV voltage value was adjusted down from 21 kV to 15 kV, the value currently in use in distribution networks in Portugal.

In a final step, it was decided to further increase the size of the test network. This would enable the testing of larger MV networks with large proportions of distributed generation and MicroGrids and also make any possible limitations of the algorithm stand out. The overall structure of this final test network can be seen in the next picture (Figure 25).

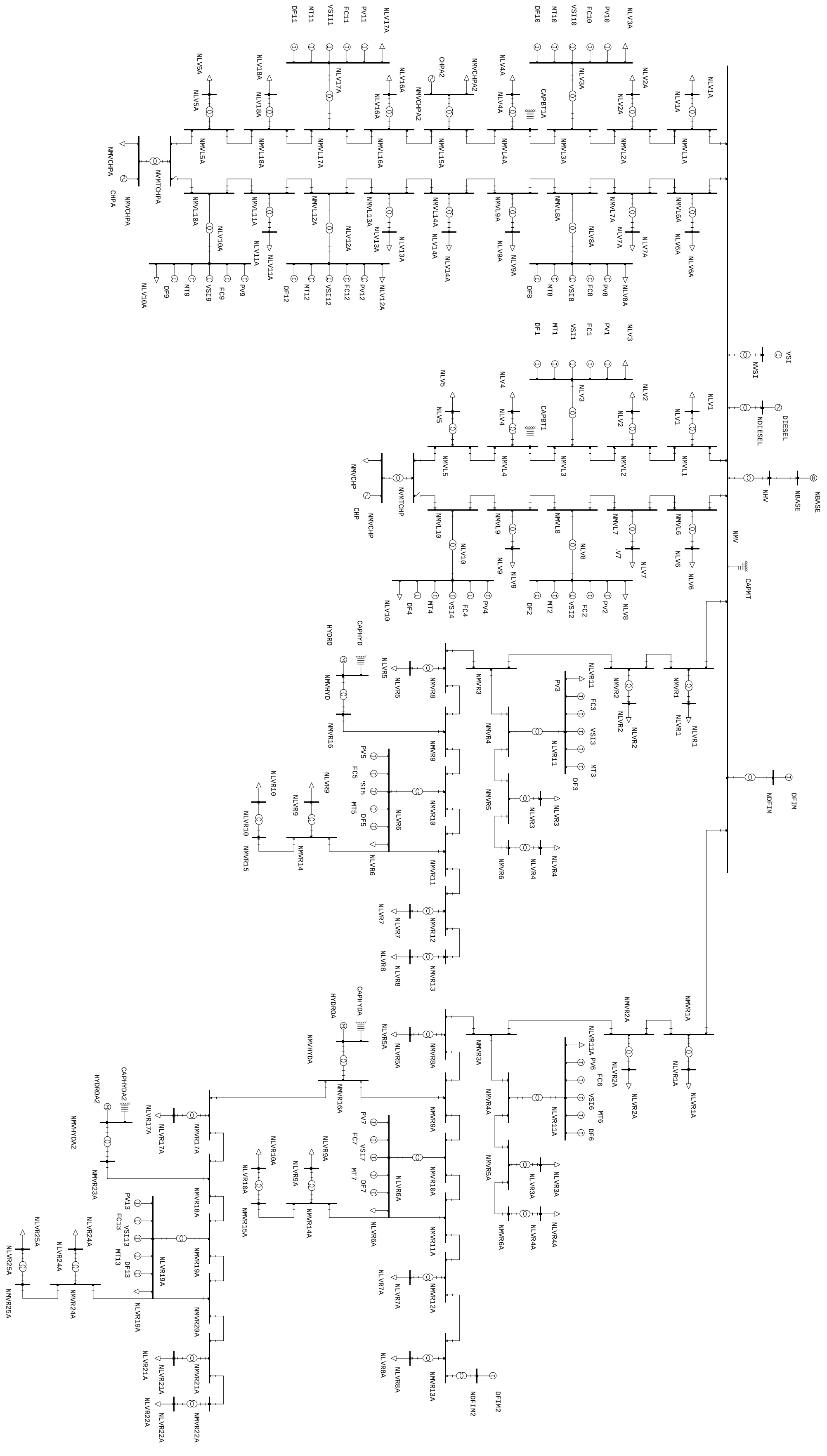

Figure 25: Final test network

The HV network to which this MV distribution network is connected is represented by an infinite bus (at the top of the diagram). The islanding operations are to be simulated by disconnecting one end of the branch connecting the HV and MV networks together.

A total of 13 MicroGrids can be seen in the diagram of Figure 25. They can be easily identified by the relatively large buses, each with 5 identical power injectors and a single load. The MicroGrids in use are almost identical. There aren't, however, any strict limits to its configuration, which is described in its present form later in this annex.

In the next table (Table 2) we can see the parameters in use for the lines in this network. For the loop zones (assuming an urban area) the parameters were taken from a catalogue of underground cables. The rural areas' parameters take into account the probable use of overhead lines.

In order to try to keep the system's complexity low (and because the network that is being simulated does not correspond to an existing one) the line segments length was kept the same in each of the main zones (300 meters for the urban area and 900 m for the rural area).

Table 2: Line parameters

Node 1	Node 2	R total (pu)	X total (pu)	Semi-shunt susceptance (pu)
NMVL6	NMVL7	0.0204	0.01508	0.0000276
NMVL7	NMVL8	0.0204	0.01508	0.0000276
NMVL8	NMVL9	0.0204	0.01508	0.0000276
NMVL9	NMVL10	0.0204	0.01508	0.0000276
NMVL5	NMVL4	0.0204	0.01508	0.0000276
NMVL4	NMVL3	0.0204	0.01508	0.0000276
NMVL3	NMVL2	0.0204	0.01508	0.0000276
NMVL2	NMVL1	0.0204	0.01508	0.0000276
NMVL6	NMV	0.0204	0.01508	0.0000276
NMVL1	NMV	0.0204	0.01508	0.0000276
NMVL10	NVMTCHP*	0.0204	0.01508	0.0000276
NMVL5	NVMTCHP	0.0204	0.01508	0.0000276
NMVR1	NMVR2	0.29236	0.1576	0.0000029
NMVR2	NMVR3	0.29236	0.1576	0.0000029
NMVR3	NMVR4	0.29236	0.1576	0.0000029
NMVR4	NMVR5	0.29236	0.1576	0.0000029
NMVR5	NMVR6	0.29236	0.1576	0.0000029
NMVR3	NMVR8	0.29236	0.1576	0.0000029
NMVR8	NMVR9	0.29236	0.1576	0.0000029
NMVR9	NMVR10	0.29236	0.1576	0.0000029
NMVR10	NMVR11	0.29236	0.1576	0.0000029
NMVR11	NMVR12	0.29236	0.1576	0.0000029

Node 1	Node 2	R total (pu)	X total (pu)	Semi-shunt susceptance (pu)
NMVR12	NMVR13	0.29236	0.1576	0.0000029
NMVR9	NMVR16	0.29236	0.1576	0.0000029
NMVR11	NMVR14	0.29236	0.1576	0.0000029
NMVR14	NMVR15	0.29236	0.1576	0.0000029
NMVR1	NMV	0.29236	0.1576	0.0000029
NBASE	NHV	0.0017	0.0058	0.00095
NMVR11A	NMVR14A	0.29236	0.1576	0.0000029
NMVR9A	NMVR16A	0.29236	0.1576	0.0000029
NMVR12A	NMVR13A	0.29236	0.1576	0.0000029
NMVR2A	NMVR3A	0.29236	0.1576	0.0000029
NMVR3A	NMVR4A	0.29236	0.1576	0.0000029
NMVR8A	NMVR9A	0.29236	0.1576	0.0000029
NMVR1A	NMVR2A	0.29236	0.1576	0.0000029
NMVR3A	NMVR8A	0.29236	0.1576	0.0000029
NMVR4A	NMVR5A	0.29236	0.1576	0.0000029
NMVR5A	NMVR6A	0.29236	0.1576	0.0000029
NMVR10A	NMVR11A	0.29236	0.1576	0.0000029
NMVR9A	NMVR10A	0.29236	0.1576	0.0000029
NMVR11A	NMVR12A	0.29236	0.1576	0.0000029
NMVR14A	NMVR15A	0.29236	0.1576	0.0000029
NMV	NMVR1A	0.29236	0.1576	0.0000029
NMVL2A	NMVL1A	0.0204	0.01508	0.0000276
NMVL6A	NMVL7A	0.0204	0.01508	0.0000276
NMVL3A	NMVL2A	0.0204	0.01508	0.0000276
NMVL7A	NMVL8A	0.0204	0.01508	0.0000276
NMVL4A	NMVL3A	0.0204	0.01508	0.0000276
NMVL8A	NMVL9A	0.0204	0.01508	0.0000276
NMVL5A	NVMTCHPA	0.0204	0.01508	0.0000276
NMVL10A	NVMTCHPA*	0.0204	0.01508	0.0000276
NMVL6A	NMV	0.0204	0.01508	0.0000276
NMVL1A	NMV	0.0204	0.01508	0.0000276
NMVL16A	NMVL15A	0.0204	0.01508	0.0000276
NMVL14A	NMVL13A	0.0204	0.01508	0.0000276
NMVL17A	NMVL16A	0.0204	0.01508	0.0000276
NMVL13A	NMVL12A	0.0204	0.01508	0.0000276
NMVL18A	NMVL17A	0.0204	0.01508	0.0000276
NMVL12A	NMVL11A	0.0204	0.01508	0.0000276
NMVL11A	NMVL10A	0.0204	0.01508	0.0000276
NMVL18A	NMVL5A	0.0204	0.01508	0.0000276
NMVL4A	NMVL15A	0.0204	0.01508	0.0000276
NMVL9A	NMVL14A	0.0204	0.01508	0.0000276
NMVR18A	NMVR23A	0.29236	0.1576	0.0000029
NMVR20A	NMVR24A	0.29236	0.1576	0.0000029
NMVR18A	NMVR19A	0.29236	0.1576	0.0000029
NMVR17A	NMVR18A	0.29236	0.1576	0.0000029
NMVR19A	NMVR20A	0.29236	0.1576	0.0000029
NMVR21A	NMVR22A	0.29236	0.1576	0.0000029
NMVR20A	NMVR21A	0.29236	0.1576	0.0000029
NMVR24A	NMVR25A	0.29236	0.1576	0.0000029
NMVR16A	NMVR17A	0.29236	0.1576	0.0000029

* These lines are left open at this end.

The next table (Table 3) shows the transformer parameters in use. All of the MV-LV transformers have a 5% reactance (p.u.). All active transformer losses were ignored.

Table 3: Transformer parameters

Node 1	Node 2	Sn (MVA)	X (pu)
NMVL1	NLV1	1.26	3.968254
NMVL6	NLV6	1.26	3.968254
NMVL2	NLV2	1.26	3.968254
NMVL7	NLV7	1.26	3.968254
NMVL4	NLV4	0.63	7.936508
NMVL5	NLV5	0.63	7.936508
NMVL9	NLV9	0.63	7.936508
NMVL8	NLV8	0.4	12.5
NMV	NVSI	2	2.5
NVMTCHP	NMVCHP	2	2.5
NMVHYD	NMVR16	2.5	2
NMVR1	NLVR1	0.4	12.5
NMVR8	NLVR5	0.4	12.5
NMVR2	NLVR2	0.25	20
NMVR5	NLVR3	0.25	20
NMVR12	NLVR7	0.25	20
NLVR9	NMVR14	0.25	20
NMVR6	NLVR4	0.16	31.25
NMVR13	NLVR8	0.16	31.25
NLVR10	NMVR15	0.16	31.25
NMVR4	NLVR11	0.4	12.5
NDIESEL	NMV	4	1.25
NLV3	NMVL3	0.4	12.5
NMV	NDFIM	10	0.5
NMVL10	NLV10	0.4	12.5
NMVR10	NLVR6	0.4	12.5
NMVR13A	NLVR8A	0.16	31.25
NMVR1A	NLVR1A	0.4	12.5
NMVR2A	NLVR2A	0.25	20
NMVR8A	NLVR5A	0.4	12.5
NMVR4A	NLVR11A	0.4	12.5
NMVR5A	NLVR3A	0.25	20
NMVR6A	NLVR4A	0.16	31.25
NMVR10A	NLVR6A	0.4	12.5
NMVR12A	NLVR7A	0.25	20
NMVHYDA	NMVR16A	2.5	2
NLVR10A	NMVR15A	0.16	31.25
NLVR9A	NMVR14A	0.25	20
NMVL1A	NLV1A	1.26	3.968254
NMVL2A	NLV2A	1.26	3.968254
NLV3A	NMVL3A	0.4	12.5
NMVL4A	NLV4A	0.63	7.936508
NMVL5A	NLV5A	0.63	7.936508
NMVL6A	NLV6A	1.26	3.968254
NMVL7A	NLV7A	1.26	3.968254
NMVL8A	NLV8A	0.4	12.5
NMVL9A	NLV9A	0.63	7.936508
NMVL10A	NLV10A	0.4	12.5

Node 1	Node 2	Sn (MVA)	X (pu)
NVMTCHPA	NMVCHPA	2	2.5
NMVL15A	NMVCHPA2	1.26	3.968254
NMVL16A	NLV16A	1.26	3.968254
NMVL14A	NLV14A	1.26	3.968254
NMVL13A	NLV13A	1.26	3.968254
NLV17A	NMVL17A	0.4	12.5
NMVL18A	NLV18A	0.63	7.936508
NMVL11A	NLV11A	0.63	7.936508
NMVL12A	NLV12A	0.4	12.5
NMVR17A	NLVR17A	0.4	12.5
NMVR19A	NLVR19A	0.4	12.5
NMVR21A	NLVR21A	0.25	20
NMVR22A	NLVR22A	0.16	31.25
NMVHYDA2	NMVR23A	1.26	3.968254
NLVR24A	NMVR24A	0.25	20
NLVR25A	NMVR25A	0.16	31.25
NDFIM2	NMVR13A	4	1.25

The loads at each node were considered to be associated to the rated power of the transformer supplying that node. The load power factor (PF) also changes, depending if the associated zone is a rural or urban one. The values in use are shown on the next table (Table 4).

Table 4: Node load values

Node	Transformer MVA	MW	MVAr
NLV6	1.26	0.838	0.275
NLV7	1.26	0.838	0.275
NMVCHP	2	0.9	0.436
NLV1	1.26	0.838	0.275
NLV5	0.63	0.419	0.138
NLV9	0.63	0.419	0.138
NLV4	0.63	0.419	0.138
NLV2	1.26	0.838	0.275
NLVR1	0.4	0.216	0.105
NLVR2	0.25	0.135	0.065
NLVR3	0.25	0.135	0.065
NLVR4	0.16	0.086	0.042
NLVR5	0.4	0.216	0.105
NLVR7	0.25	0.135	0.065
NLVR9	0.25	0.135	0.065
NLVR8	0.16	0.086	0.042
NLVR10	0.16	0.086	0.042
NLV3	0.4	0.15	0.05
NLVR11	0.4	0.15	0.05
NLVR6	0.4	0.15	0.05
NLV10	0.4	0.15	0.05
NLV8	0.4	0.15	0.05
NLVR1A	0.4	0.216	0.105

NLVR2A	0.25	0.135	0.065
NLVR11A	0.4	0.15	0.05
NLVR3A	0.25	0.135	0.065
NLVR4A	0.16	0.086	0.042
NLVR5A	0.4	0.216	0.105
NLVR6A	0.4	0.15	0.05
NLVR7A	0.25	0.135	0.065
NLVR10A	0.16	0.086	0.042
NLVR9A	0.25	0.135	0.065
NLVR8A	0.16	0.086	0.042
NLV1A	1.26	0.838	0.275
NLV2A	1.26	0.838	0.275
NLV3A	0.4	0.15	0.05
NLV4A	0.63	0.419	0.138
NLV5A	0.63	0.419	0.138
NLV6A	1.26	0.838	0.275
NLV7A	1.26	0.838	0.275
NLV8A	0.4	0.15	0.05
NLV9A	0.63	0.419	0.138
NLV10A	0.4	0.15	0.05
NMVCHPA	2	0.9	0.436
NMVCHPA2	1.26	0.45	0.218
NLV17A	0.4	0.15	0.05
NLV16A	1.26	0.838	0.275
NLV14A	1.26	0.838	0.275
NLV12A	0.4	0.15	0.05
NLV13A	1.26	0.838	0.275
NLV18A	0.63	0.419	0.138
NLV11A	0.63	0.419	0.138
NLVR17A	0.4	0.216	0.105
NLVR19A	0.4	0.15	0.05
NLVR24A	0.25	0.135	0.065
NLVR25A	0.16	0.086	0.042
NLVR22A	0.16	0.086	0.042
NLVR21A	0.25	0.135	0.065

In order to keep adequate voltage profiles across the network in the simplest of ways, several capacitor banks were added in some locations that looked suitable, namely near the hydro generator (which is an induction machine) and at the MV bus.

The next table shows the MVAr ratings that were necessary. Actually, the bank placed at the MV bus is only needed when the system is isolated from the HV network.

Table 5: Capacitor banks

Capacitor Bank	Node	MVAr
CAPMT	NMV	4
CAPHYD	NMVHYD	0.5
CAPBT1	NMVL4	0.5
CAPHYDA	NMVHYDA	0.5
CAPBT1A	NMVL4A	0.5
CAPHYDA2	NMVHYDA2	0.25

The next table (Table 6) shows the generated power at the nodes, as well as the nominal node voltages. Most of the nodes have no generation. The MVAr of the NMVHYD node are negative and were determined interactively as the machine at this node is a standard induction generator. Also, some machines (the DFIM and the CHP) are much below their rated power because we are, in this case, testing an import scenario with a significant power production from the 13 MicroGrids in this test network.

Table 6: Node voltages and generated powers

Node	Generated MW	Generated MVAr	kV
NBASE	0	0	150
NDFIM	4	0	15
NDFIM2	2	0	15
NDIESEL	1	0	15
NHV	0	0	150
NLV1	0	0	0.4
NLV10	0.1	0	0.4
NLV10A	0.1	0	0.4
NLV11A	0	0	0.4
NLV12A	0.1	0	0.4
NLV13A	0	0	0.4
NLV14A	0	0	0.4
NLV16A	0	0	0.4
NLV17A	0.1	0	0.4
NLV18A	0	0	0.4
NLV1A	0	0	0.4
NLV2	0	0	0.4
NLV2A	0	0	0.4
NLV3	0.1	0	0.4
NLV3A	0.1	0	0.4
NLV4	0	0	0.4
NLV4A	0	0	0.4
NLV5	0	0	0.4
NLV5A	0	0	0.4
NLV6	0	0	0.4
NLV6A	0	0	0.4
NLV7	0	0	0.4
NLV7A	0	0	0.4
NLV8	0.1	0	0.4
NLV8A	0.1	0	0.4
NLV9	0	0	0.4
NLV9A	0	0	0.4
NLVR1	0	0	0.4
NLVR10	0	0	0.4
NLVR10A	0	0	0.4
NLVR11	0.1	0	0.4
NLVR11A	0.1	0	0.4
NLVR17A	0	0	0.4
NLVR19A	0.1	0	0.4
NLVR1A	0	0	0.4
NMVL1	0	0	15
NMVL10	0	0	15
NMVL10A	0	0	15
NMVL11A	0	0	15
NMVL12A	0	0	15
NMVL13A	0	0	15
NMVL14A	0	0	15
NMVL15A	0	0	15
NMVL16A	0	0	15
NMVL17A	0	0	15
NMVL18A	0	0	15
NMVL1A	0	0	15
NMVL2	0	0	15
NMVL2A	0	0	15
NMVL3	0	0	15
NMVL3A	0	0	15
NMVL4	0	0	15
NMVL4A	0	0	15
NMVL5	0	0	15
NMVL5A	0	0	15
NMVL6	0	0	15
NMVL6A	0	0	15
NMVL7	0	0	15
NMVL7A	0	0	15
NMVL8	0	0	15
NMVL8A	0	0	15
NMVL9	0	0	15
NMVL9A	0	0	15
NMVR1	0	0	15
NMVR10	0	0	15
NMVR10A	0	0	15
NMVR11	0	0	15
NMVR11A	0	0	15
NMVR12	0	0	15
NMVR12A	0	0	15
NMVR13	0	0	15
NMVR13A	0	0	15
NMVR14	0	0	15
NMVR14A	0	0	15
NMVR15	0	0	15

Node	Generated MW	Generated MVAr	kV
NLVR2	0	0	0.4
NLVR21A	0	0	0.4
NLVR22A	0	0	0.4
NLVR24A	0	0	0.4
NLVR25A	0	0	0.4
NLVR2A	0	0	0.4
NLVR3	0	0	0.4
NLVR3A	0	0	0.4
NLVR4	0	0	0.4
NLVR4A	0	0	0.4
NLVR5	0	0	0.4
NLVR5A	0	0	0.4
NLVR6	0.1	0	0.4
NLVR6A	0.1	0	0.4
NLVR7	0	0	0.4
NLVR7A	0	0	0.4
NLVR8	0	0	0.4
NLVR8A	0	0	0.4
NLVR9	0	0	0.4
NLVR9A	0	0	0.4
NMV	0	0	15
NMVCHP	1	0.6	15
NMVCHPA	1	0.6	15
NMVCHPA2	0.5	0.2	15
NMVHYD	1.5	-0.887	15
NMVHYDA	1.5	-0.887	15
NMVHYDA2	0.8	-0.4	15
NMVR15A	0	0	15
NMVR16	0	0	15
NMVR16A	0	0	15
NMVR17A	0	0	15
NMVR18A	0	0	15
NMVR19A	0	0	15
NMVR1A	0	0	15
NMVR2	0	0	15
NMVR20A	0	0	15
NMVR21A	0	0	15
NMVR22A	0	0	15
NMVR23A	0	0	15
NMVR24A	0	0	15
NMVR25A	0	0	15
NMVR2A	0	0	15
NMVR3	0	0	15
NMVR3A	0	0	15
NMVR4	0	0	15
NMVR4A	0	0	15
NMVR5	0	0	15
NMVR5A	0	0	15
NMVR6	0	0	15
NMVR6A	0	0	15
NMVR8	0	0	15
NMVR8A	0	0	15
NMVR9	0	0	15
NMVR9A	0	0	15
NVMTCHP	0	0	15
NVMTCHPA	0	0	15
NVSI	0	0	15

A MicroGrid usually comprises a Low Voltage (LV) feeder with several microsources, storage devices and controllable loads connected on that same feeder.

All of the 13 MicroGrids are connected to 0.4 MVA transformers. Each one of them has, for the moment, five different microsources:

- Voltage Source Inverter (VSI)
- Photovoltaic (PV) module
- Doubly-Fed Induction Generator (DFIM)
- Fuel Cell
- Microturbine

For all the MicroGrids, both the DFIM and the microturbine have a 100 kW nominal output power. The PV module is very small, at 10 kW output power. The fuel cell is somewhere in between with a nominal 40 kW output. The VSI accounts for the rest (150 kW) and, because it is assumed that it is coupled to some sort of storage device, it only injects power to the bus when some sort of disturbance is perceptible (e.g. frequency variations). This also justifies the fact that the initial generated power of the nodes where MicroGrids are connected is only 100 kW even if the associated power transformers are rated at 400 kVA.

ABB CONTRIBUTION

1. Executive Summary

The main objective of this study is to answer a question, whether a provision (selling) of different frequency control reserves by the operator of the Microgrid(s) and/or micro-sources to the Transmission System Operator (TSO) is economically attractive.

TSOs use the frequency control to provide a secure and high-quality power supply for the consumers. Frequency control requires that a certain amount of active power is kept in reserve (that has not yet been committed to the production of energy) to be able to re-establish a balance between load and generation at any instant. The frequency regulation usually contains three layers. Using UCTE terminology [1], these layers are called Primary, Secondary and Tertiary frequency control.

Due to a limited power output of a single micro-source and relatively high minimum traded volume of frequency control reserves (ex. ±2 MW primary reserve and ±20 MW secondary and tertiary reserves) we assume an aggregated reserve supply from micro-sources located in multi-Microgrids. This approach is known as Virtual unit and requires a presence of a centralized EMS and communication links as well as mutual agreements between owners of micro sources and multi-Microgrids operator.

Taking into account frequency control reserve prices, technical requirements and maintenance expenses long term supply of fast (primary) frequency control reserve is the most profitable option for the Microgrids with all time adjustable micro sources (CHP, biomass, etc.). In the case of prevailing intermittent micro sources (wind, solar, etc.) without energy storage a participation in short term reserve market (usually tertiary reserves) is more suitable.

This has been concluded from (1) an analysis of the existing markets for ancillary services in Europe, in particularly in Germany, (2) a specification for typical micro sources and (3) an application of the multi-Microgrids (virtual unit) concept.

A rise of reserve volumes and prices is generally expected due to the planned increase of renewable generation, especially wind power [2]. This can make the Microgrids a big business opportunity. A potential market capacity for Microgrids application only for primary frequency regulation in the UCTE zone (only countries with existing ancillary service markets) is currently estimated at the level of 100-150 MW. We also expect that a development of ancillary service markets in most of the UCTE member states will take place in 3-5 years. Therefore, a potential market capacity will be extended up to 200-300 MW.

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2. Introduction

2.1. Power Equilibrium

The electric power system is unique in that aggregate production and consumption must be matched instantaneously and continuously (Figure 1). Disturbances in this balance cause a deviation of the system frequency from its set-point value which thus decrease the quality of power supply which becomes noticeable to network users. By an increase in the total demand the system frequency will decrease, and by a decrease in the demand the system frequency will increase. Therefore, the production system must have sufficient flexibility in changing its generation level in real-time. It must be able to instantly to handle both changes in demand and outages in generation and transmission.

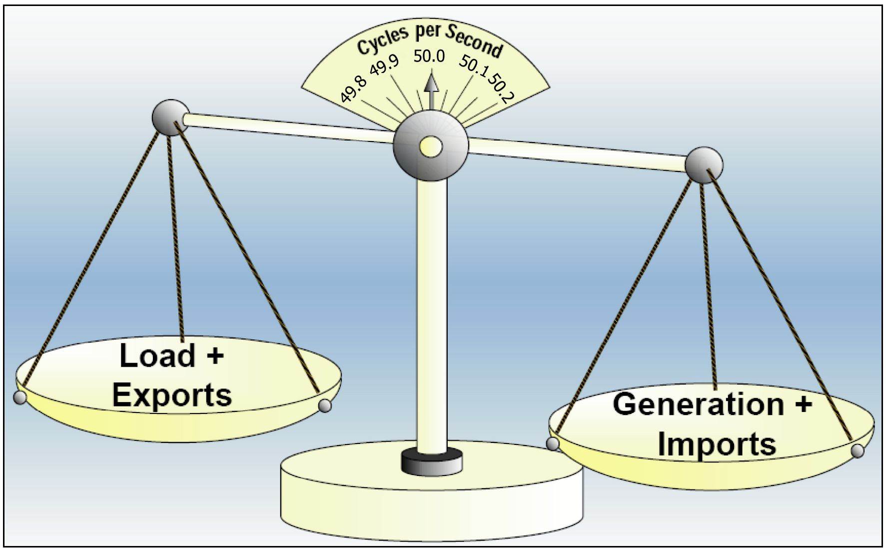

Figure 1: Power equilibrium

2.2. Frequency control reserves

Frequency control reserves moderate the dynamic phenomena that follow sudden unexpected loss of generating units or transmission lines, as well as the daily peak load forecast errors and hourly schedule changes. Each Transmission System Operator (TSO) is obliged to maintain a sufficient volume of frequency control reserve and to ensure a secure transmission of that reserve power within his area of responsibility. Since it is technically impossible to guard against all random variables affecting production, consumption or transmission, the volume of reserve capacity will depend upon the level of risk which is deemed acceptable. TSOs typically keep enough reserves available to compensate for the worst credible contingency. This is typically either the loss of the largest generation or transmission facility, or a certain percentage of the peak load.

Several types (in terms of deployment time, size and duration) of controllable reserves are maintained to help the TSO to achieve the required generation/load balance. The time required to reach a full utilization of different reserves depends upon many factors, such as inertia of the turbine-generator, governor characteristics, type of consumer-load mix, boiler control, etc.

Different TSOs use different definitions of reserves which are tightly defined within the legal and contractual regimes, making a “like for like” comparison difficult. However it has been found that the purpose behind the varying services is generally common. We called frequency control reserves according to the order of deployment (Figure 2). The standard timing of reserve deployment indicated in Figure 2 is typical for most European countries.

Power system frequency drops suddenly when generation trips (Figure 2). In this instance, there is no time for the grid operator to react. Therefore, frequency-sensitive generator governors respond automatically and immediately stop the frequency drop. This fast response is accomplished by primary reserve. Then, secondary automatic/manual reserve successfully returns both the frequency and inter-area power exchanges to the reference values. Afterwards, the secondary reserve is replaced by a manually instructed long term tertiary reserve.

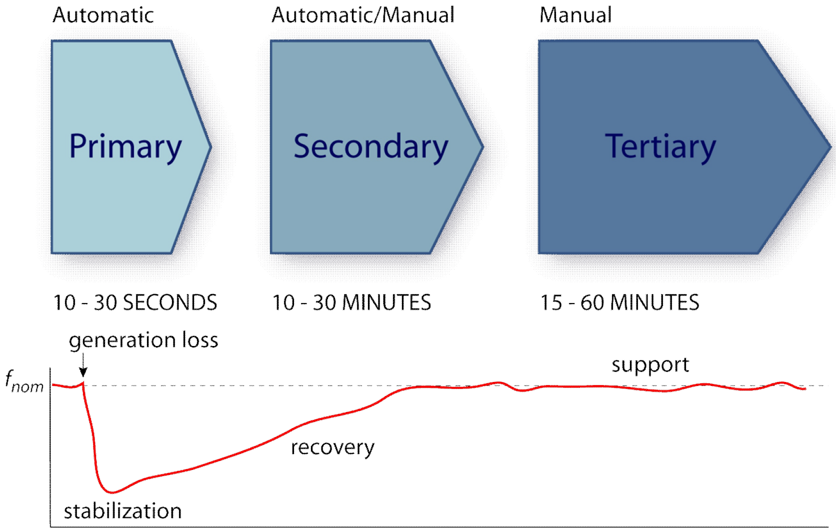

Figure 2: Typical frequency control reserves

2.2.1. Primary frequency control reserve

This deviation in the system frequency will cause the primary controllers of all generators subject to primary control to respond within a few seconds. The controllers alter the power delivered by the generators until a balance between power output and consumption is re-established. As soon as the balance is re-established, the system frequency stabilises and remains at a quasi steady-state value, but differs from the frequency set-point because of the droop of the generators which provide proportional type of action (Figure 3).

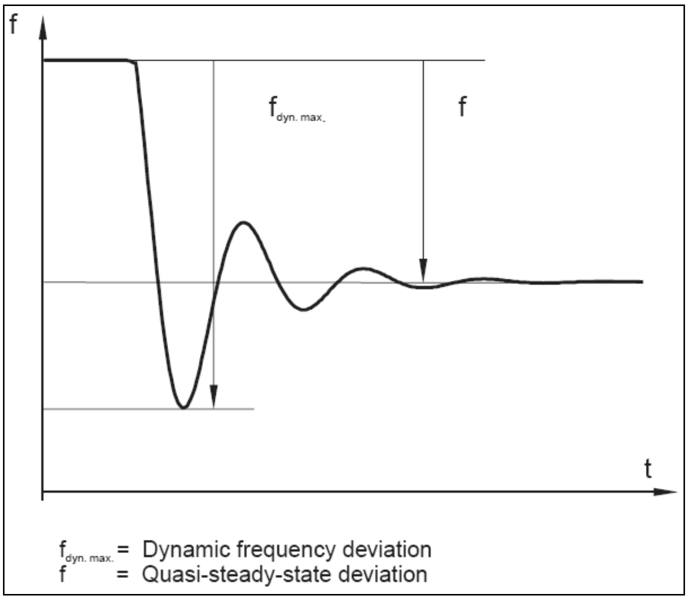

Figure 3: Principle of primary frequency control

The magnitude $\Delta f_{dyn.max}$ of the dynamic frequency deviation is governed mainly by the following:

- amplitude and development over time of the disturbance affecting the balance between power output and consumption.
- kinetic energy of rotating machines in the system.
- number of generators subject to primary control, the primary control reserve and its distribution between these generators.
- dynamic characteristics of the machines (including controllers).
- dynamic characteristics of loads, particularly the self-regulating effect of loads.

The quasi-steady-state frequency deviation f is governed by the amplitude of the disturbance and the network power frequency characteristic, which is influenced mainly by the following:

- droop of all generators subject to primary control in the synchronous area.
- sensitivity of consumption to variations in system frequency.

In case that the frequency exceeds the permissible limits, additional measures out of the scope of primary control, such as (automatic) load-shedding, are required and carried out in order to maintain interconnected operation.

Each interconnected TSO must contribute to the correction of a disturbance in accordance with its respective contribution coefficient to primary frequency control. These coefficients are calculated on a regular basis for each TSO as a relationship between the electricity generated in its control area (including electricity production for export and scheduled electricity production from jointly operated units) and the total electricity production in all control areas of the synchronous area. In order to ensure that the principle of joint action is observed, the network power frequency characteristics of the various control areas should remain as constant as possible. This applies particularly to small frequency deviations, where the "dead bands" of generators may have an unacceptable influence upon the supply of primary control energy in the control areas concerned. The deployment time of the primary control reserves of the various control areas should be as similar as possible, in order to minimise dynamic interaction between control areas. The primary control reserve of each control area must be fully activated as soon as possible (typically within a linear time limit of 15-60 seconds) in response to a disturbance.

Presently, primary reserves are provided by combustion turbines or hydroelectric generators that are synchronized and can be ramped up quickly. In some cases reserve power can be additionally supplied by responsive loads.

2.2.2. Secondary frequency control reserve

Since all control areas contribute to the control process in the interconnected system, with associated changes in the balance of generation and consumption in these control areas, an imbalance between power generation and consumption in any control area will cause power interchanges between individual control areas to deviate from the agreed/scheduled values (power interchange deviations). The function of secondary control (also known as load-frequency control or automatic generation control - AGC) is to keep or to restore the power balance in each control area and, consequently, to keep or to restore the system frequency to its set-point value of 50 Hz and the power interchanges with adjacent control areas to their programmed scheduled values, thus ensuring that the full reserve of primary control power activated will be made available again. Whereas all control areas provide mutual support by the supply of primary control power during the primary control process, only the control area affected by a power unbalance is required to undertake secondary control action for the correction. Consequently, only the controller of the control area, in which the imbalance between generation and consumption has occurred, will activate the corresponding secondary control power within its control area. Parameters for the secondary controllers of all control areas need to be set such that, ideally, only the controller in the zone affected by the disturbance concerned will respond and initiate the deployment of the requisite secondary control power.

The rate of change in the power output of generators used for secondary control is defined as a percentage of the rated output of the control generator per unit of time, and strongly depends upon the type of generator. Typically, for oil or gas fired power stations, this rate is of the order of 8% per minute. In the case of hydro power stations, the rate ranges from 1.5 to 2.5% of the rated plant output per second. In hard coal and lignite fired plants, this rate ranges from 2 to 4% per minute and 1 to 2% per minute respectively. The maximum rate of change in output of nuclear power plants is approximately 1 to 5% per minute.

The secondary control may not impair the action of the primary control. Their actions will take place simultaneously and continually, both in response to minor deviations (which will inevitably occur in the course of normal operation) and in response to a major discrepancy between production and consumption (associated e.g. with the tripping of a generating unit or network disconnection) (Figure 4).

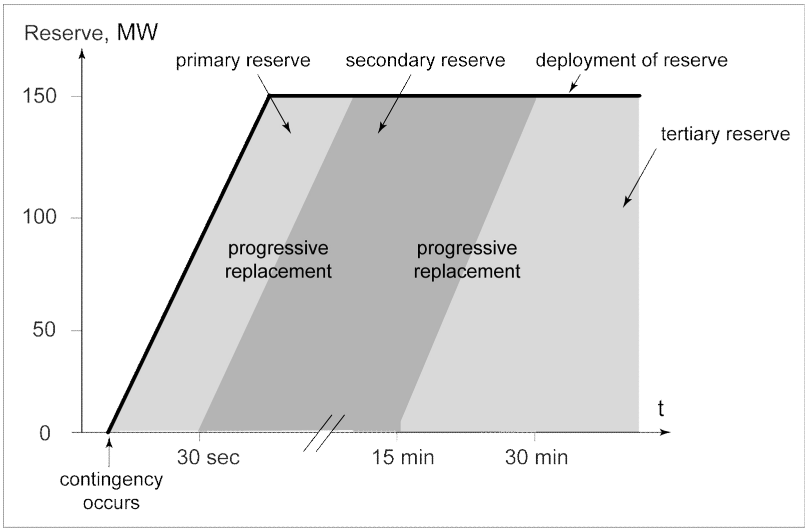

Figure 4: Deployment of reserves after a contingency

2.2.3. Tertiary frequency control reserve

Tertiary reserves are those that are not automatically delivered when required, but are instead instructed by the TSO. They used in such a way that it will contribute to the restoration of the secondary reserve. Reserves that fall into this category vary widely by country. There are some interesting features regarding when the TSO can issue an instruction and expect tertiary reserve delivery (an example of the differences that exist is given below):

UK	Dispatch any time (1 minute resolution) for current settlement period, delivery starts 2 minutes after instruction.
Germany	Dispatch in 15 minute blocks. The TSO must normally issue an instruction in the first half of the current 15 minute settlement period to get delivery in the next 15 minute settlement period.

The main factors determining these timescales are transmission system requirements, the mechanism by which TSOs call off services and the physical capability of plant connected. It is interesting to note that the majority of countries do not have fast acting tertiary reserves (less than 5 min). They rely on reserves to act in timescales approaching 15 min, which generally cater for structural demand forecast errors, plant loss, and the restoration of primary control holding. Tertiary reserve is provided by combustion turbines, diesels, or hydroelectric generators, but often can be additionally purchased from a neighbouring utility.

2.3. Procurement of frequency control reserves

The TSOs can procure balancing power reserves in two different ways – either by commercial means (there is no obligation on generators to provide reserves) or mandatory obligations (all large generators >100 MW are obliged to provide frequency control reserves). When there is a mandatory provision of reserves, the expenses of generators can be either remunerated or not by the TSO.

During the last five years markets for frequency control reserves (ancillary service markets) have been appearing in several European countries. Usually, the TSOs use hourly, daily, monthly or annual markets, or bilateral contracts to procure different types of reserves on a commercial basis.

TSOs of different European countries have been interviewed about a procurement mechanism of reserves. The results are shown in Table 1. We can see that the primary reserve is still a mandatory service in most of the countries. However, secondary and tertiary reserves are in general commercial services with some exceptions where they are still mandatory for generators exceeding a certain size.

Table 1: Procurement of frequency control reserves in Europe (2006)

Country	TSO	Primary	Secondary	Tertiary
Germany	E.ON	C	C	C
Germany	VE	C	C	C
Germany	RWE	C	C	C
Germany	EnBW	C	C	C
Denmark-West	Energinet	C	C	C
Czech Rep.	CEPS	C	C	C
Hungary	MAVIR	C	C	C
UK	National Grid	C+M	C	C
Ireland	Eirgrid	C	C	C
Sweden	Svenska Kraftnat	C	NA	C
Norway	Statnett	C	NA	C
Finland	Fingrid	C	NA	C
Denmark-East	Energinet	C	NA	C
France	RTE	M	C	C
Netherlands	TenneT	M	C	C
Belgium	Elia	M	C	C
Spain	REE	M	C	C
Slovenia	ELES	M	C	C
Romania	TRANSELECTRICA	M	C	C
Poland	PSE-Operator	M	M	C
Greece	HTSO	M	M	M
Croatia	HEP	M	M	M
Albania	KESH	M	M	M
Switzerland	ETRANS	M	M	M
Luxemburg	Cegedel	-	-	-
Portugal	REN	-	-	-
Italy	GRTN	-	-	-
Austria	TIRAG	-	-	-
Slovakia	SEPS	-	-	-
Serbia	EPS	-	-	-
Bosnia	JPCC	-	-	-
Macedonia	EMS	-	-	-
Bulgaria	NEK	-	-	-

C - commercial **M** – mandatory **NA** – not applicable **-** – no data

2.4. Payment of frequency control reserves

There are two common ways for a procurement of frequency control reserves: either by commercial means or mandatory obligations.

2.4.1. Payment of commercial frequency control reserves

In countries where all reserves are procured on a commercial basis (Germany, Denmark, etc., (Table 1) there is no obligation on generators to provide these reserves. In the framework of the provision of reserves, the TSO shall pay adequate remuneration for the delivery of the necessary reserves to the providers in accordance with contractual agreements. The payment mechanism is generally based upon a reserve availability payment (power) and a reserve utilisation payment (energy).

The reserve availability payment is based on a reserve capacity provided/contracted. All successful suppliers are paid the fixed capacity price for the whole tendering period (1 hour – 1 year) per MW for standing ready to supply reserves if they are needed. Figure 9 and Figure 13 illustrate availability prices of primary reserves for TSOs in Germany and Denmark in the period 2001-2005. The reserve availability payment can be calculated as a product of reserve capacity and market clearing price which is based on the final accepted bid submitted to the TSO over the period for which the quantity used is measured and reconciled (ex. €/MW/period) (1).

$$\mathbf{Payment_{Availability} = Reserve\ Capacity\ [MW] \cdot Market\ Clearing\ Price\ [€/MW/period]} \quad (1)$$

i.e., the annual cost of a primary reserve of ±2 MW with a price 65 €/kW/½ year is 260 k€.

The reserve utilization payment is applied only if reserves are actually supplied. In that case, reserves are selected for deployment based on their energy bids, with the cheapest reserves being deployed more frequently. The reserve utilization payment is based upon a delivered energy metered per period of time for which the reserve is made available multiplied either by an energy bid price or by a market marginal price (2).

$$\mathbf{Payment_{Utilization} = Metered\ Energy\ [MWh] \cdot Energy\ Bid\ Price\ [€/MWh]} \quad (2)$$

Assume that the tertiary reserve of ±20 MW is deployed 4x15 minutes during a day (positive reserve) and 2x15 minutes at night (negative reserve). The market marginal prices are 200 €/MWh and 2 €/MWh correspondingly. Thus, the utilization payment is ≈4000 €/day. With the same daily deployment the annual reserve utilization cost will climb to 1.46 M€. Only secondary and tertiary reserves have the reserve utilization payment. The primary reserve usually has only the availability payment.

Consequently, the total frequency control reserve payment ($\mathrm{Payment_{Utilization}} = 0$ for primary control reserve) can be found as (3).

$$\textbf{Total Payment} = \textbf{Payment}_{\textbf{Availability}} + \textbf{Payment}_{\textbf{Utilization}} \quad (3)$$

The equations (1-3) provide a simple methodology for a calculation of frequency control reserve cost.

2.4.2. Payment of mandatory frequency control reserves

In some countries (Greece, Switzerland, etc., (Table 1) no payment is made by a TSO to mandatory reserve suppliers (all large generators, for example P_{gen} >100 MW, are obliged to provide reserves permanently or on rotational schemes). In other countries mandatory reserves are remunerated on a cost reflective basis.

3. Procurement of frequency control reserves in Europe

3.1. UCTE

The "**U**nion for the **C**o-ordination of **T**ransmission of **E**lectricity" (UCTE) is the association of TSOs from 23 continental Europe countries (Figure 5). Through the networks of the UCTE, about 500 million people are supplied with electric energy; annual electricity consumption totals approximately 2300 TWh and total installed capacity is about 520 GW. 50 years of joint activities laid the basis for a leading position in the world which the UCTE holds in terms of the operating security and quality.

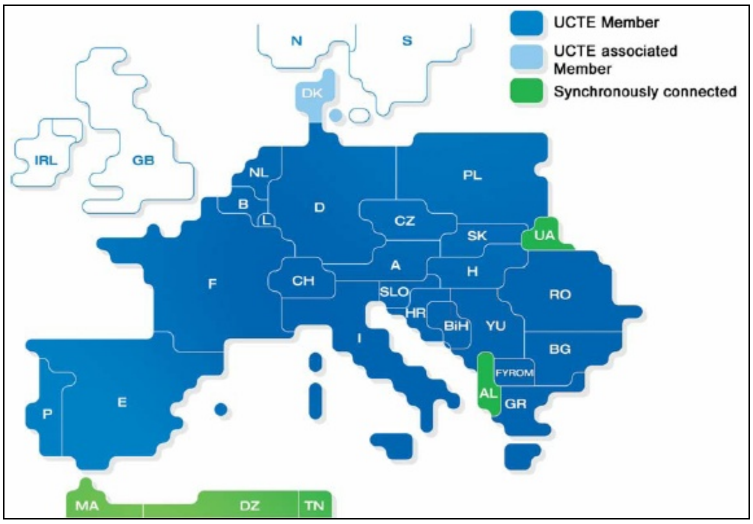

Figure 5: Map of UCTE

The system is very heavily meshed providing a large inertia and a very stable frequency response. The frequency deviation in UCTE is less than ±20 mHz (frequency regulation deadband) for 70% of the time (Figure 6) and never over ±50 mHz over a sustained period of 15 minutes. The average period where the frequency deviation has been more than ±50 mHz is less than 10 hours per month.

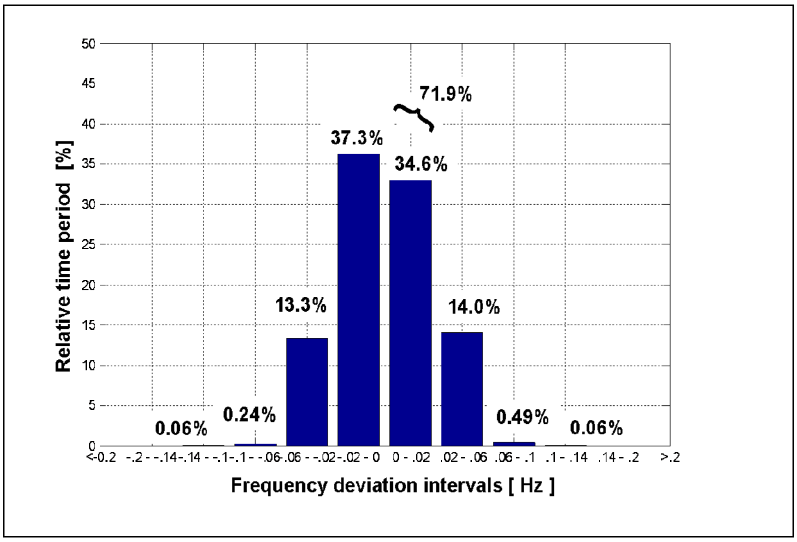

Figure 6: Frequency statistic in UCTE, September 2005

Each TSO is responsible for taking care of frequency control reserves, and managing inadvertent energy exchange with the neighbouring TSOs (Figure 7). Since the early days of UCTE, each block organised these reserves through the vertically integrated electrical utilities, making all power plants available for a provision of reserves. In the free market conditions, this control philosophy is still respected, but the system operators now do not exercise direct authority over the power plants. They acquire or organise these reserves under national energy market rules and countries' grid codes.

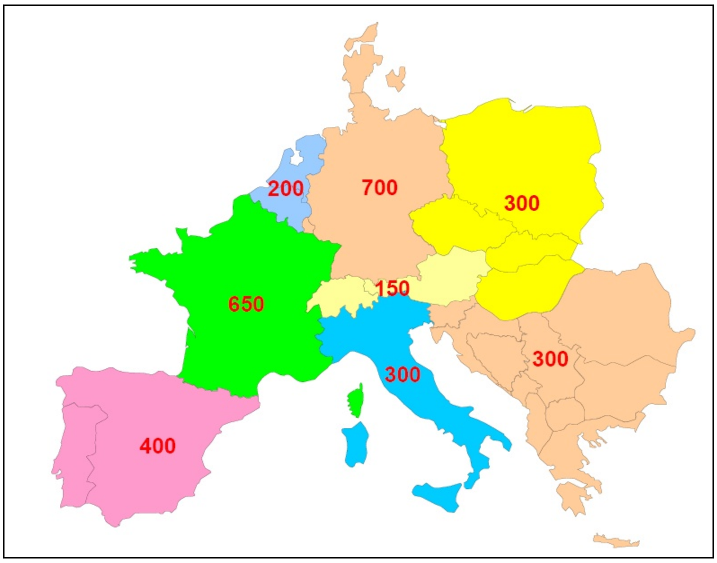

Figure 7: Primary frequency control reserve responsibility of different UCTE members (MW)

Nowadays, reserves markets are in different stages of development in different countries. There is no difference in the quality of frequency control visible over the last three years while market opening has been gradually increasing. Most of reserves are organised through long-term contracts but short-term markets have also started to operate. Cross border reserve markets are being discussed and may be established in near future.

3.1.1. UCTE operating rules

The "UCTE Operation Handbook" is a comprehensive collection of all relevant technical standards and recommendations, including operation policies for frequency control reserves [1]. Standards for accounting, the commercial part of unintentional deviations, billing procedures and market rules are usually set by national grid codes, laws and contracts.

Three groups of frequency control reserves exist in UCTE (Figure 2). They performed in different successive steps, each with different characteristics and qualities (Table 2).

Table 2: Classification of frequency control reserves in UCTE

Type	Primary	Secondary	Tertiary
Volume (MW)	3000	Defined by each TSO	Defined by each TSO
Purpose	Stops the frequency drop	Brings frequency and power exchanges to the set value	Frees secondary control
Activation	Automatic joint action of all European TSOs, when frequency deviates ±20 mHz from a set frequency	Automatic action of responsible TSO, when frequency and power exchanges deviate from schedule	Manual action of responsible TSO, when secondary reserve has to be replaced
Start Fully activated End	3-5 sec ≤15-30 sec ≥15 min	≤30 sec ≤10-15 min As long as required	when called by TSO ≤15 min As agreed
Minimum single bid (MW)	1-2	1-30	10-30
Maximum single bid (MW)	10-15	50	50-100
Payment	Availability	Availability, utilization	Availability, utilization

Complete information on technical requirements and operational rules for supplying frequency control reserves in the UCTE area is given in [1].

3.1.2. Germany

In Germany, the common ancillary service market rules are created by VDN (an independent association representing the interests of German TSOs - E.ON, RWE, EnBW and Vattenfall) in order to ensure a fair competition and maintenance of the security of electricity supply.

3.1.2.1. Tendering procedure for frequency control reserves

Frequency control reserves whose procurement falls within the responsibility of the TSOs are subject to public invitation for tenders. The TSOs shall invite tenders for these reserves in the liberalised electricity market, and shall procure reserves on competitive terms and conditions. The requirements (technical and organisational) imposed on the suppliers of frequency control reserves in Germany are described in the following sections.

3.1.2.2. Steps and deadlines of the tendering procedure

The common obligatory steps of the tendering procedure in Germany are shown in Figure 8. It consists of a prequalification procedure, signing of a framework agreement and participation at tenders.

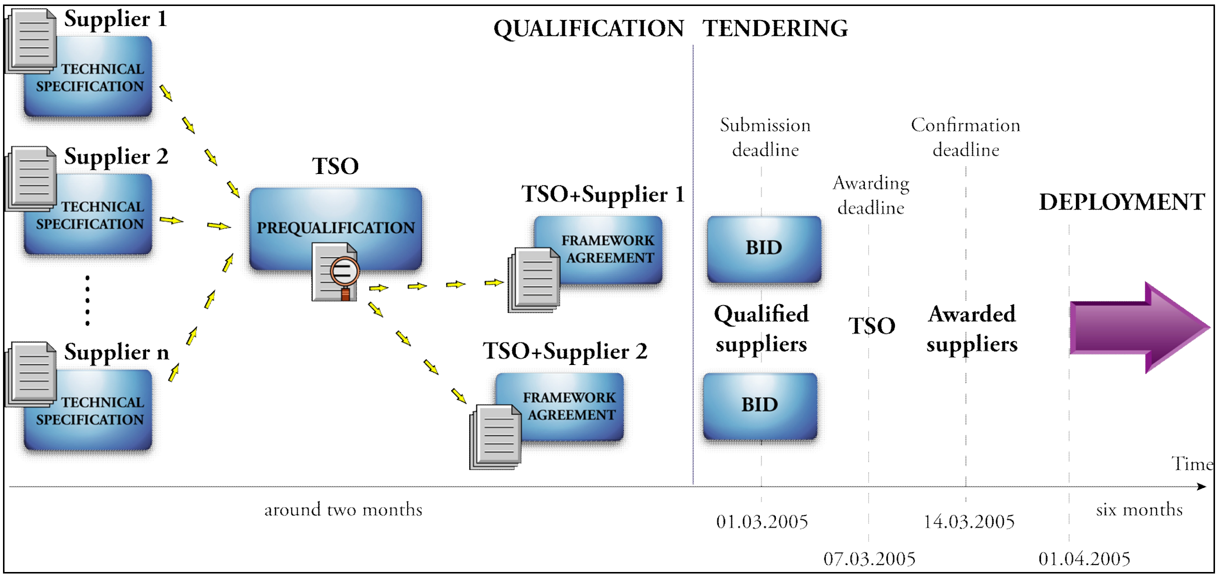

Figure 8: Tendering procedure for a supply of frequency control reserves in Germany

3.1.2.3. Prequalification procedure

Through the prequalification procedure, potential suppliers of reserves provide evidence that they fulfil the requirements for guaranteeing a reliable supply in order to furnish the various reserve types necessary for the maintenance of the security of supply. Technical requirements for supplying frequency control reserves in Germany are described in the Grid Code [3] and correspond to the UCTE technical requirements [1].

However, there are some following peculiarities:

- Primary control range offered per technical unit totals at least ±2 % of the rated output of the generating unit, but at least ±2 MW (*E.ON comment: minimum unit size is limited by an ability of TSO to check a delivery of reserve.* ***It can be decreased if several small units have a common central controller****. In general, rules for primary control are dominated by existing technology of power plants using inlet valves flux reduction*).

- Asymmetrical primary control ranges can be offered.
- Secondary and tertiary (minutes) control ranges offered per technical unit totals at least ±30 MW (±20 MW in Vattenfall).
- Rate of power change for hydroelectric units must be at least 2 %/sec of the rated unit output; for other units the rate of power change must be 2 %/min.
- Pump-hydro storage plants must be available for at least 4 hours at the full contracted control power. Other units must be capable of being operated without any limits within the different time periods.
- Units must have an availability time ratio of 100% for primary and at least 95 % for secondary reserve. Partly lost secondary control power can be replaced by minutes (tertiary) reserve after consultation with the TSO.

Apart from the technical expertise, the proper provision of the frequency control reserves under operating conditions must be guaranteed. This requires that the suppliers give details in the questionnaires [4] of the prequalification and send them to the TSO concerned. The TSO reserves the right to obtain further evidence from the suppliers. The implementation of a corresponding prequalification procedure requires a period of about two months.

A bidder may pre-qualify for all, several or individual reserves. Prequalification is possible at any time. Secondary control may necessitate a longer period of time, depending on the complexity of the schemes regarding the integration of generators into network control.

3.1.2.4. Framework agreement

The bidders having pre-qualified will be offered framework agreements on the maintenance and provision of the different types of reserves by the TSO awarding the contract. In the framework agreement the bidder shall undertake to adhere to all attributes assured in the prequalification and to comply with all framework conditions specified by the contracting TSO in the prequalification documents. In addition, all technical, administrative, operative, and commercial frame conditions are stipulated in the framework agreement. The conclusion of the framework agreement is a prerequisite for participation in the tendering procedure.

3.1.2.5. Contracts awarding

After concluding a framework agreement with a TSO a qualified supplier can participate in the relevant invitations to tender. Tendering for primary and secondary balancing power reserve takes place every six months, tendering for minute reserve is carried out every day. Tendering for minute reserve is Internet-based. All communications with respective bidders, such as submission of bids and information about the award decision, take place in a secure portal. Tendering for primary and secondary balancing power is not conducted across the Internet, but in a conventional manner because these contracts are awarded for longer periods of time.

Awarding of contracts for the provision of reserve is realised in a non-discriminatory manner on the basis of the quoted price performance ratio, separately for each type of frequency control reserve. When awarding contracts, TSOs see to it that network stability and operational security concerns are sufficiently taken into consideration (a selection of the bids providing balancing power is made with the help of MILP algorithm = "Mixed Integer Linear Programming", while minimizing costs and respecting all system requirements) . Subsequently, all partaking bidders are notified of their respective results of contract awarding. General market information, including an anonymous presentation of the bids and award decision, is available in a public area.

3.1.2.6. Results of previous tenders in Germany

The results of all previous tenders are publicly available at Internet [5-8]. They were analyzed and represented here in the form of tables and diagrams. Table 3 summarizes the latest results (Q3, 2006) of the tendering procedures in four German TSOs for different types of reserves. Contracts for secondary and minute reserves are awarded separately according to whether the control direction is positive or negative.

Table 3: Results of tenders for frequency control reserves in Germany (Q3 2006)

Type of reserve	**TSO**	**Tender period**	**Tendered power (MW)**	**Power rates (€/kW)**	**Energy rates (€Ct/kWh)**	**Number of qualified suppliers**
Primary Reserve	E.ON	6 months	±164	60.62	-	4
	RWE	6 months	±285	62.51	-	4
	EnBW	6 months	±71	60.59	-	?
	VE	6 months	±137	59.13	-	3-5
Secondary Reserve	E.ON	6 months	+800 -400	38.29 12.84	6.2 to 10.9 0 to 0.9	4
	RWE	6 months	+1230 -1230	49.56 17.94	7.2 to 11.8 0 to 0.6	4-5
	EnBW	6 months	+720 -390	43.84 28.12	6.75 to 9.85 0.4 to 1.1	?
	VE	6 months	+580 -580	44.47 19.93	8.9 to 11 0.3 to 1.4	Less than 10
Minutes Reserve	E.ON	daily	+1100 -400	≈0.5 ≈0.1	12 to 110 0 to 0.2	11
	RWE	daily	+930 -760	≈0.5 ≈0.1	12 to 190 0 to 0.8	More than 20
	EnBW	daily	+390 -330	≈0.10 ≈0.06	18 to 190 -0.2 to 0	?
	VE	daily	+730 -530	≈0.5 ≈0.1	12 to 190 0 to 0.2	More than 10

Note: The power rates refer to the period of the stated day for minute reserve. Energy rates with a minus sign for negative minutes reserve are paid to TSO by the supplier of reserve.

Figure 9 illustrates the results of the tenders in four German TSOs for primary frequency control reserve starting from 2001. The price for primary reserve varied from 55 to 87€/kW/6 month (tendering period) at the moment the market was established. Since the beginning of 2003, when EnBW and VE also joined the reserve market, the price range became narrow (60-70€/kW/ 6 months).

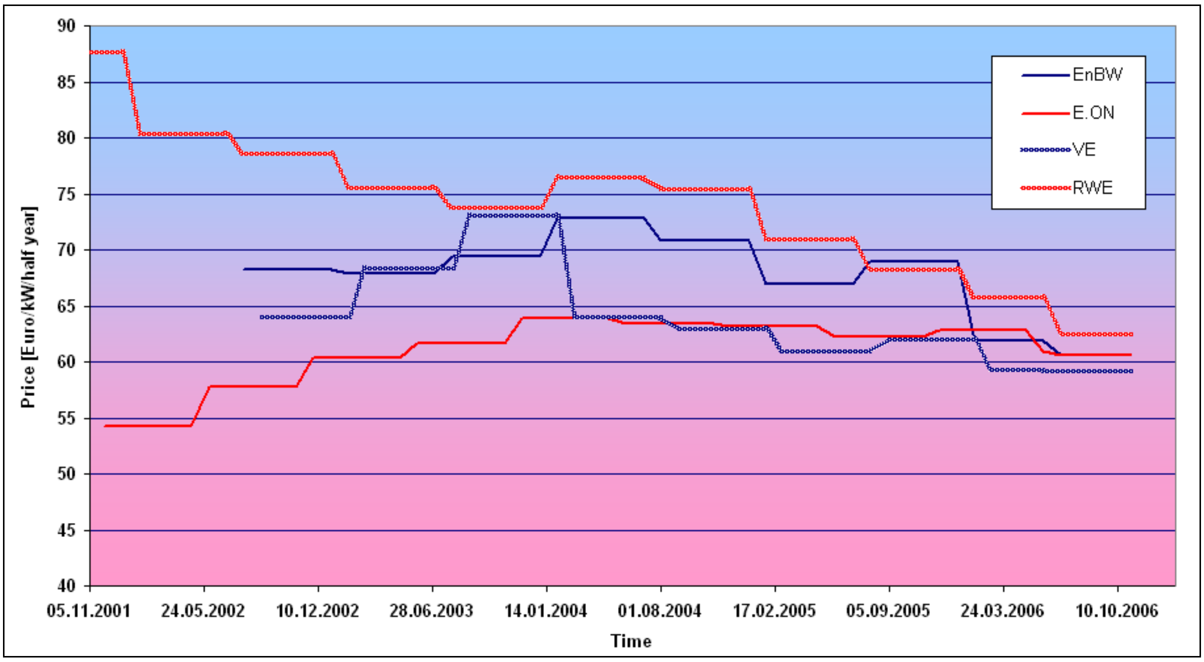

Figure 9: Prices for primary frequency control reserve in Germany in 2001-2006

Figure 10 represents the results of the tenders in four German TSOs for secondary reserve starting from 2001. There are two separate prices according to the control direction (positive or negative) for each TSO.

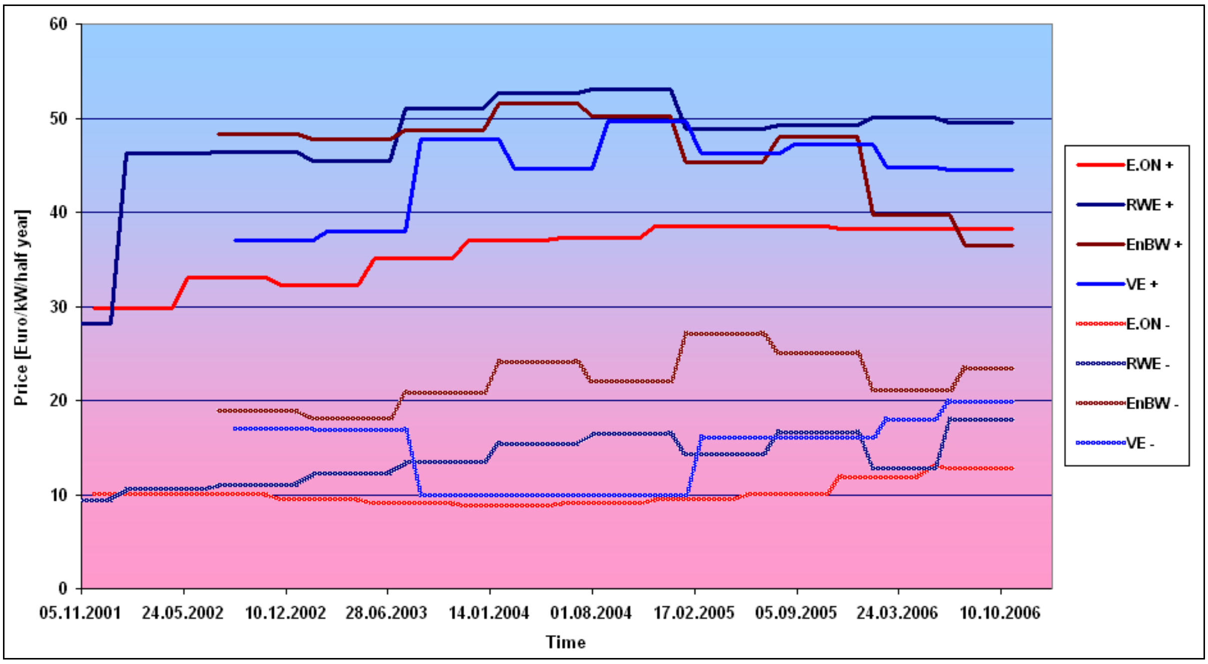

Figure 10: Prices for secondary frequency control reserve in Germany in 2001-2006

Prices for minutes reserve may vary from one day to another and between working days and weekends. Figure 11 represents the results of the tenders in E.ON Netz control zone for minutes reserve starting from 2002. Only monthly average price is represented, therefore, this diagram gives only a rough picture of the price variation of minutes reserve. There are two separate prices according to the control direction (positive or negative).

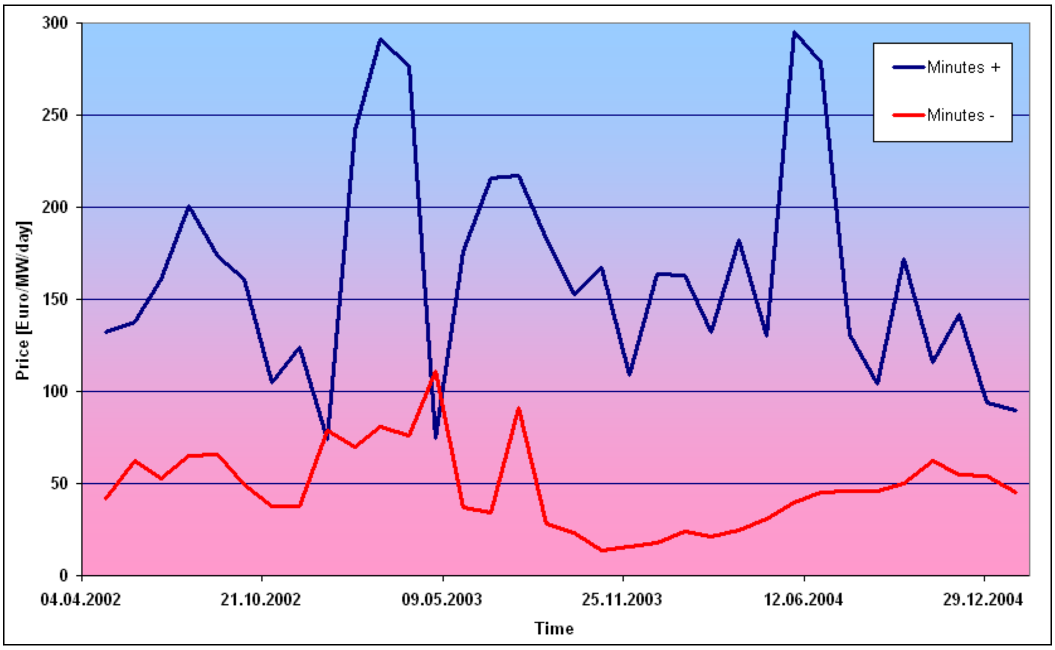

Figure 11: Prices for minutes (tertiary) reserve in E.ON Netz in 2002-2005

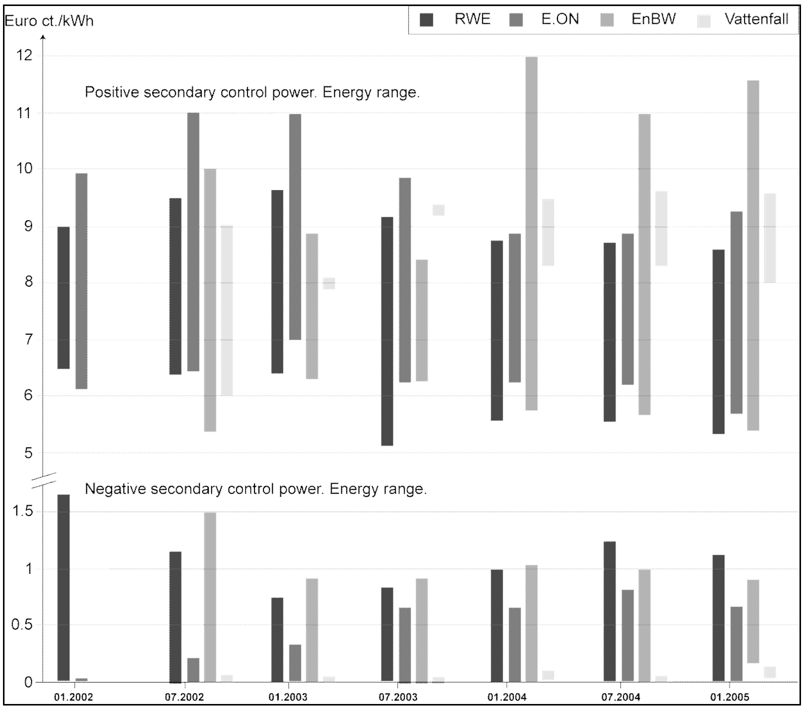

Figure 12: Energy rates for a deployment of secondary reserve in Germany in 2002-2005.

Figure 12 shows the results of tenders in four German TSOs for energy rates to deliver and to absorb a secondary reserve power starting from the end of 2001.

3.1.3. Denmark-West

Denmark has two parts connected to different systems (due to geographical conditions). The western part is synchronized with the UCTE, while the eastern part has an AC connection with Nordel via Sweden. The western part has HVDC connections with Norway and Sweden. These circumstances exert influence on the standards for a procurement of frequency control reserves. Below, the operational principles of the reserve market in Denmark-west control area are described.

3.1.3.1. Tendering procedure for balancing power

Energinet (Danish TSO) invites tenders for public contracts for frequency control reserves and uses the same market mechanism for as TSOs in Germany. For this purpose, a qualification system has been established for companies that wish to be considered as balancing reserve suppliers. The first round of the tender procedure has been initiated in the second half of 2004.

3.1.3.2. Prequalification procedure

Technical requirements for supplying reserves correspond to the UCTE technical requirements. The most important specific features are listed below:

- Primary control range offered per technical unit totals at least ±1 MW. With a view to ensuring that the reserve is distributed on more units, a single unit can only be included in a tender for a maximum volume of 15MW.
- The automatic secondary reserve is an upward and downward regulation reserve activated by way of a network controller function. The volumes tendered must be at least ±1 MW. With a view to ensuring that the regulating reserve is distributed on more units, a single unit can only be included in a tender for a maximum volume of 50MW.
- The manual tertiary reserve is an upward and downward regulation reserve activated manually by the TSO. The volumes tendered must be between 10 MW and 50 MW.

After the qualification procedure, Energinet will consider whether the applicants are qualified, and qualified applicants will receive the tender documents. Tendering for primary reserve takes place every 6 months, for secondary reserve every 3 month, and for tertiary reserve every month. Balancing power in Denmark is 100% from heat generated power. An interesting view is that Energinet is looking at wind power to be used for frequency control purposes in some way.

3.1.3.3. Results of previous tenders

The results of all previous tenders for different reserves are publicly available at Internet [9]. They were analyzed and represented in the form of table and diagram. After the call for tenders in January 2005, TSO has concluded contracts with several balancing reserve suppliers for 2005 (Table 4). Contracts for secondary and tertiary reserves are awarded separately for positive and negative directions.

Table 4: Results of tenders for frequency control reserves in Denmark West in 2005.

Type	Amount [MW]	Total price
Primary regulating reserve H1,2005	±32.1	The total fixed payment for primary regulating reserves in the contact period amounts to DKK 15.2 million or ≈63 €/kW/6 months
Automatic upward regulating reserve Q1, 2005	+100	Is calculated according to the prices of the average power rate for the positive secondary controlling power range as determined at E.ON Netz' auction for the delivery period 01.12.2005 – 31.05.2005 (38.54 €/kW). The energy payment is calculated at the spot price plus 100 DKK/MWh at upward regulation.
Automatic downward regulating reserve Q1, 2005	-100	Is calculated according to the prices of the average power rate for the negative secondary controlling power range as determined at E.ON Netz' auction for the delivery period 01.12.2005 – 31.05.2005 (9.90 €/kW). The energy payment is calculated at the spot price plus 100 DKK/MWh at downward regulation.
Manual upward regulating reserve	+442.5	Is calculated at the expiry of the contract period on the basis of the period's price of positive minute reserves at E.ON Netz' daily auctions less 5%. Total payment is calculated at the expiry of the delivery period as the sum of the period's 24-hour payments converted to DKK. 4350 €/MW/month in September 2005
Manual downward regulating reserve	-160	Is calculated at the expiry of the contract period on the basis of the period's price of negative minute reserves at E.ON Netz' daily auctions, provided that the monthly average price of manual downward regulating reserves amounts to 19.00 DKK/MWh as a minimum. Total payment is calculated at the expiry of the delivery period as the sum of the period's 24-hour payments converted to DKK. 1750 €/MW/month in September 2005

Figure 13 illustrates the results of the tenders in the control area of Energinet (former Eltra) for all types of balancing reserves starting from 2004. There are two separate prices according to the control direction (positive or negative) for secondary and tertiary reserves.

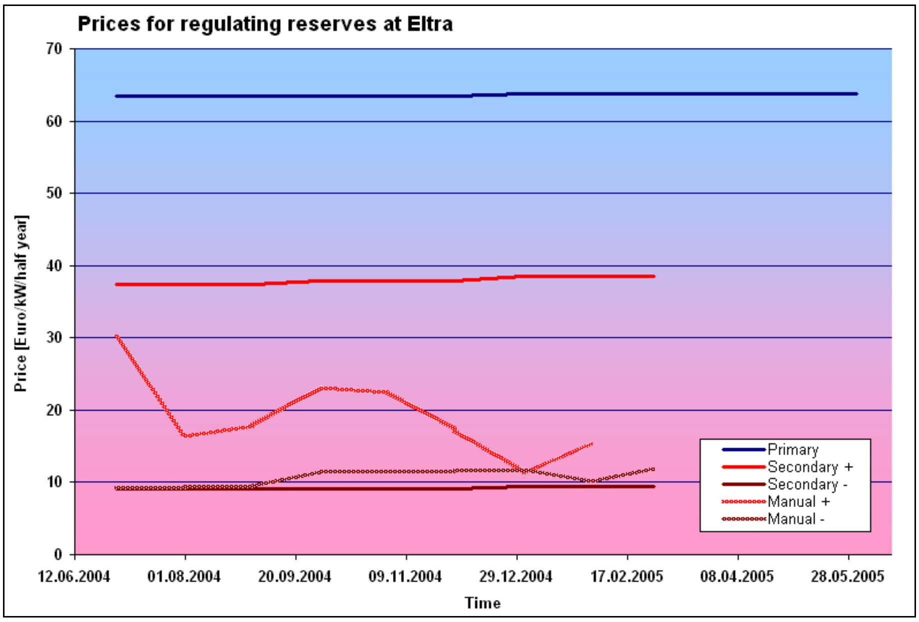

Figure 13: Prices for balancing reserves in Energinet (former Eltra) in 2004-2005

3.1.4. Czech Republic

3.1.4.1. Tendering procedure for balancing power

The TSO of Czech Republic (CEPS) provides technical management of system services such as power-frequency control and is responsible for the availability and efficient use of power reserves. Entities connected to power system have got the right, not an obligation, to offer frequency control reserves on condition that they fulfil technical and commercial conditions set by TSO, and reserves prices are being created on a market principle. Selection for reserves providing is being carried out on the basis of open and non-discriminatory approach to all users. Since 1 October 2001 day-ahead market with ancillary services has been in operation. Providers of individual categories of reserves are selected on the basis of submitted certification or on the basis of a temporary eligibility recognition resulting from providing the services prior to 1 January 2001. CEPS purchases primary reserve from its business partners mainly through long-term contracts. Power purchased in this manner represents roughly 90% of the required reserve. The remaining part of balancing power, approximately 10%, is being purchased through internet - Damas ePortal.

Reserves are being purchased by CEPS by the means of two commercial instruments: long-term and mid-term contracts are being concluded from tenders that

CEPS opens for individual reserve categories. The bid prices are being used for long-term (yearly), cogently mid-term (quarterly or monthly) contracts. There is the so-called marginal price being created for each trading hour on Day-ahead balancing power market by the market, i.e. the price of the most expensive accepted offer. This price is, then, paid to all accepted providers that fulfilled their obligation. Meeting technical requirements defined for the equipment is a necessary condition for participation in frequency control reserve supply.

3.1.4.2. Prequalification procedure

Provider will submit an application in which it informs CEPS on its intention to become a reserve provider. On the basis of this application CEPS will set the date for the meeting together with a list of technical data of the equipment of the applicant. Applicant will submit to CEPS a certificate of a generating unit that has to be issued by a certification authority in accordance with the valid wording of the grid code [10]. Technical requirements for supplying balancing reserves in Czech Republic are described in the grid code and correspond to the UCTE technical requirements [1]. However, there are some following peculiarities:

- The maximum value of primary control reserve purchased from one unit is set at 10 MW in order to limit the failure influence of the unit providing reserve. The minimum value is limited by 3 MW.
- The secondary reserve provider must provide the unit regulation reserve with the minimum rate of change 2 MW/min. The minimum value of secondary reserve provided by one unit 10 MW.
- The tertiary reserve provider must provide the unit regulation reserve with the minimum rate of change 2 MW/min. The minimum value of tertiary reserve provided by one unit 10 MW. The maximum value of tertiary reserve provided by one unit must not exceed 100 MW.

On the basis of the submitted certification CEPS will perform point-to-point check and functional tests of controlling the generation plant. CEPS together with the applicant will verify viability of communication routes between control dispatch system and equipment of the applicant.

Price index (average weekly [Kč/MWh] of primary reserve in 2005 is shown in Figure 14. The legend (in the order show): daytime of working day, night-time of working day, daytime of non-working day, night-time of non-working day.

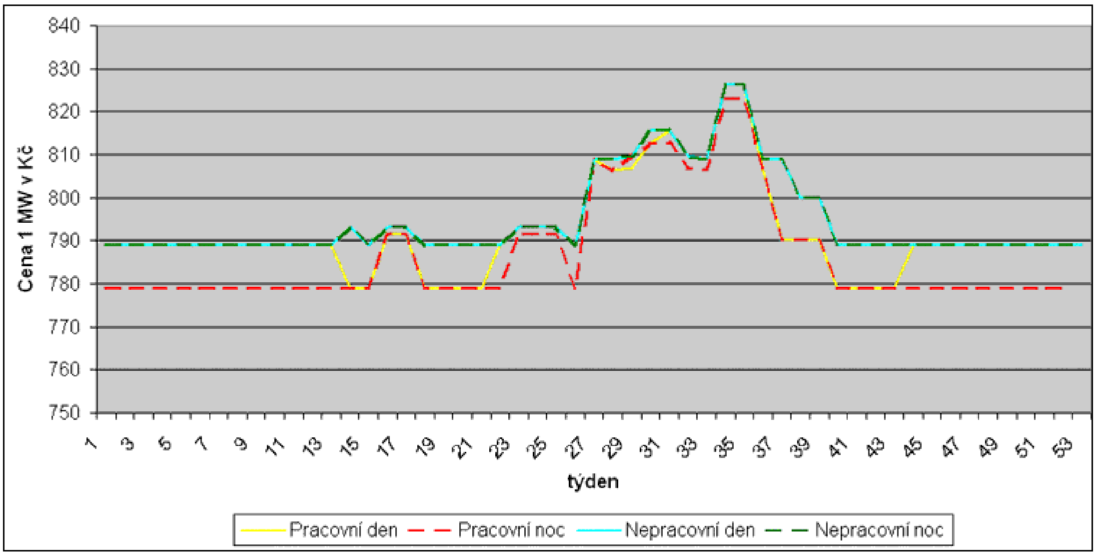

Figure 14: The average weekly price of primary reserve in Czech Republic in 2005

The average price of primary reserve in Czech Republic during 2005 was 790 Kč/MWh = 27.8 €/MWh.

3.1.5. Spain

The ancillary service market is managed by an independent entity called OMEL. The TSO – Red Electrica (REE) only asks for a certain amount of reserves, but OMEL is the responsible for procurement. A provision of primary frequency control reserve is currently mandatory for all large generators. However, secondary and tertiary reserves are commercial services. The historic hourly prices for secondary frequency control reserve are available in Internet [11]. Figure 15 shows a variation of traded reserve volumes and prices during two different days in May 2005. The price varies from 5 to 45 €/MWh.

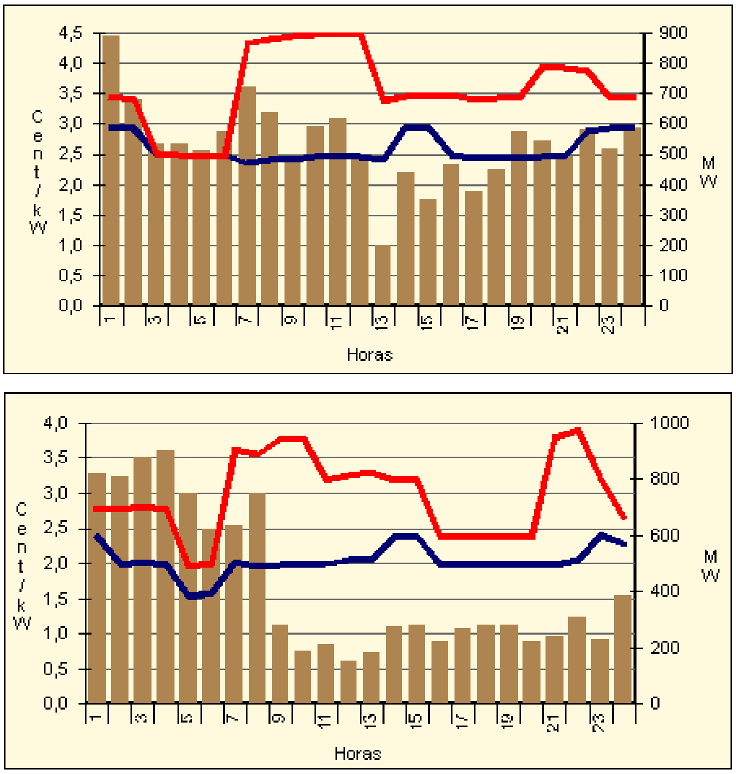

Figure 15: The hourly prices of secondary reserve in Spain in May 2006 (red line is band assigned to rise, blue line is band assigned to low, bars are hourly reserve prices)

3.1.6. Poland

Both primary and secondary reserves are mandatory services in Poland. However, all suppliers are remunerated based on the negotiated price. Tertiary reserve is a commercial service. Average remuneration cost to generators in 2005 was 24,66 PLN/MWh availability payment for primary reserve and 28,39 PLN/MWh availability and 8,46 PLN/MWh utilization payment for secondary reserve. The currency exchange rate is 1 € = 4.06319 Polish Zloty. The price in Euro is 6.08 €/MWh for primary reserve and 7 €/MWh availability and 2.1 €/MWh utilization payment for secondary reserve. However, there is a clear trend to a commercialization of ancillary services in Poland. This topic can be readdressed again after establishing of frequency control reserve market and required modifications of the national grid code in 2006-2007.

3.1.7. Romania

Until recently, the reserves were acquired at regulated prices, through annual contracts. The primary reserve is still mandatory non-remunerated service, although there are active discussions about a creation of the market. The availability prices depend on the type of reserve and the costs the providers had to cover (approx. 1.2€/MWh for fast tertiary units with fast start capability; 12€/MWh for spinning tertiary reserve; 15€/MWh for secondary reserve).

3.1.8. Hungary

There are more than 20 primary reserve suppliers qualified yearly. The reserve is procured on the day-ahead market. Typically, 5 units each with 10 MW of reserve are selected to provide a Hungarian 50 MW portion from the total 3000 MW UCTE primary reserve. Daily prices vary from 5 to 20 €/MWh depending on the time and available units. Secondary and tertiary reserves are as well commercial services. However, prices are not available.

3.2. NORDEL

Nordel is a body for co-operation between the TSOs in the Nordic countries Denmark (eastern part), Finland, Iceland, Norway and Sweden (Figure 16). Through the networks of Nordel, about 25 million people are supplied with electric energy; annual electricity consumption totals approximately 400 TWh with a peak demand of 70 GW. The power systems in the Nordic countries are very different. Norway has only hydro-electric power, Denmark only conventional thermal power and significant wind power, whilst Sweden, Finland and Iceland have mixed systems. This affects the frequency control reserves and directs the use of reserve sources to some extent. Liberal frequency control practices have always been applied in Nordel. Strict set-point control was not required except under certain stressed conditions. The deviations from pre determined power interchanges were settled after the fact following certain rules. In practice no automatic generation control was needed.

Figure 16: Map of Nordel

After deregulation, these same control practices are applied with the difference that market based solutions have been developed over the last five to ten years to acquire the needed ancillary services. The reserve management, exchange and trade of reserves between countries must be in accordance with respective national legislation and other governmental and legal documents. In the legislation there are statements about what kind and amount of reserves that have to be made available, and how the reserves should be made available. Each country is in principle free to decide, but in practice they are all following the recommendations formed by Nordel [12].

3.2.1. Nordel operational rules

The “Nordel operational standard” is a comprehensive collection of all relevant technical standards and recommendations, including operation policies for a supply of frequency control **reserves**. In the Nordic grid, the frequency is allowed to vary between 49.9 and 50.1 Hz, i.e ±100 mHz. The Nordel Operations Committee reports regularly on a monthly basis the quality of frequency as the number of minutes during which frequency exceeding the limits of the normal range (high or low). From 1994 until 2002 the number of minutes has increased: from 500 to 2010 for frequency below 49.9 Hz and from 170 to 2400 for frequency above 50.1 Hz. These deviations are more remarkable in summer time at low load periods with less generation connected to the power system. Another observation is that the deviations seem to occur around the change of the hour. These variations in frequency are not yet seen as critical because the quality of the frequency is still far below the limits of concern but the trend gives some reasons of concern for the TSOs.

Control actions are performed in the presence of frequency deviation in different successive steps, each with different characteristics and qualities, and all depending on each other:

- Automatic normal operating reserve (600 MW in a normal state) starts within seconds as a joint action of all undertakings involved. At current time Sweden is responsible for 40%, Norway for 34%, Eastern Denmark for 4% and Finland for 22%. The amount of activated reserve increases with frequency deviation, from 0.1Hz to 0.5Hz when the entire reserve is fully activated.
- Automatic disturbance reserve (approx. 1,000 MW in a normal state) is shared between the TSOs based on the biggest unit. It has the same activation policy as a normal operating reserve. The volume of the frequency controlled disturbance reserve maintained in the Nordic grid is such that the power system can withstand for instance the disconnection of a large production unit from the grid without it causing a permanent frequency deviation greater than 0.5 Hz. The reserve required by the entire system is defined weekly to correspond to the volume of production disconnected in conjunction with the largest individual fault in the system, deducted by the natural regulation capacity of the system. A TSO can take over responsibility for frequency response from another TSO or interruptible loads.
- Tertiary manual upward or downward regulation reserve frees automatic reserves by re-scheduling generation and is achieved through power deals with the balance administrators who have entered into agreements with TSOs with regard to participating in balance regulation. The TSO also ensures that sufficient disruption reserves are available in the power system. These reserves can consist of, for instance, quick-start gas turbines

Payments for generators which participate in automatic frequency control vary between the different areas. Generators have two types of costs related to primary control: fixed costs for equipment which makes a generating unit available for primary control, and variable costs which result from increased wear and limitations on generation levels. Below, we present practices for a procurement of frequency control reserves in Nordic countries.

3.2.2. Finland

Fingrid maintains a regulating power market because it does not have regulation capacity of its own to maintain the power balance. Through the regulating power market, Fingrid can adjust production or loads whenever necessary on the basis of the prevailing operational situation. Holders of production or loads can submit regulation bids to the regulating power market concerning their capacity which can be regulated. The balance service agreement gives balance providers a right to participate in the regulating power market. Other holders of capacity can participate in the regulating market through their balance provider or by signing a separate regulating power market agreement with Fingrid. The regulating power market maintained by Fingrid is part of the Nordic regulating power market. Of the Nordel countries maintained total frequency controlled normal operation reserve of 600 MW, Finland's share is 141 MW (Table 5).

Table 5: Different types of balancing (frequency control) reserve in Fingrid

Type of reserve	Contractual capacity	Obligation
Frequency controlled normal operation reserve	- Power plants - Vyborg DC link, 10% of transmission power	141 MW*)
Frequency controlled disturbance reserve	- Power plants - Disconnectable loads	220-240 MW **)
Fast disturbance reserve	- Gas turbines - Disconnectable loads	850 MW ***)

*) The obligation is divided between the subsystems annually in proportion to the annual energies used by them.
**) The obligation is divided between the subsystems weekly in proportion to the dimensioning faults.
***) Volume corresponding to a dimensioning fault.

The participation of electricity producers in the maintenance of the reserve is fully voluntary. Fingrid has established a so-called reserve bank where companies owning capacity which can be regulated can register their resources. The resource owners maintain the measured regulation properties at their power plants in the agreed manner and receive a compensation for this from TSO. The parties sign a balance service agreement which specifies rights and obligations relating to power deliveries and for agreeing on the terms and conditions under which balance provider can participate in the regulation power market. Balancing power reserves in Finland is to about 90% from hydro and 10% from heat generated power. In Finland there are between 5-10 companies supplying balancing power, of which the three largest are: Fortum, Helsinki Energy and TVO.

3.2.3. Sweden

SvK (Swedish TSO) procures the following reserves in the market:

- Primary reserve automatically connected within 30 seconds, controlled by regulators, ramped up for a maximum of 15 minutes.

- Secondary; manual (similar to tertiary within UCTE), ramped in after 15 minutes, controlled by an operator.

The acquisition of regulating power is a continuous process that is manned around the clock. Bids are received from the companies that are responsible for the balancing power. In Sweden there are four companies providing balancing power: Fortum, Skellefteå Kraft, Sydkraft and Vattenfall. Balancing power in Sweden is to 100% hydro power using generators and regulators to connect the power. Initially there is an agreement procedure where an agreement is signed between SvK and a provider of reserve for one year. Normally an agreement is signed for both primary and secondary reserves simultaneously. However, it is possible to have an agreement only for one type of reserve.

The purchase of primary balancing/regulating power is a procedure which is done in two steps: about 2/3 of the regulating power is purchased through a weekly routine. Bids are given every Thursday. The rest is purchased with an hourly rate from the Spot market. The price for primary balancing power per hour is not available for the 2/3 that is bought through bids but for the rest that is bought on the Spot market the price is available on the web. The bids for primary are given for periods, where one day is divided into three periods. The hourly price for one period is the same. New bids are placed every week on primary balancing power; the amount of MW supplied can be changed from week to week. The supplier is obliged to supply the amount that was bided. If the supplier is not able to do this the supplier has to buy the remaining MW on the Spot market.

The bidding for secondary reserve is separated from the primary and it is bought on the Spot-market through bids given on an hourly basis. Bids can be given until ½ hour before they become active and bids can be removed a half hour before bid becomes active. The Spot price for primary and secondary regulating power is the same. A minimum reserve power of 10 MW is required. **It can be several plants (aggregated power)**.

The tendering procedure can be summarized according to the following (Figure 17):

1. Supplier requests for balance power responsibility to SvK, minimum 10 MW required being qualified.
2. An agreement is signed for 1 year, starting date Nov. 1, ("balance power responsibility agreement"), which includes the amount of balancing power reserved and a fixed price for the balancing power.
3. When an agreement has been signed the supplier can give bids for balancing power, (lowest price wins).
4. Bid procedure:
   - on Thursday every week a purchase is made for the next week (Sat-Fri). About 2/3 of the balancing power is purchased in this way.
   - the rest is bought in the Nordic spot market (hourly price).

The bids are then evaluated according to certain criteria e.g: activation time, sustainability, cost, availability, etc. A ranking is then made and the reserves are then purchased.

The primary regulating power is always connected and responds on deviations in the frequency. If the frequency is outside the range 49.9-50.1 Hz, regulating power is connected.

The providers of the balancing power get paid for two services:

- maintaining/providing a primary regulating reserve, a set price for 1 year, which is inofficial. However, the total paid to the suppliers is approximately 150 MSEK/year = 16.3 M€.
- supplied amount of primary regulating power based on the spot price.

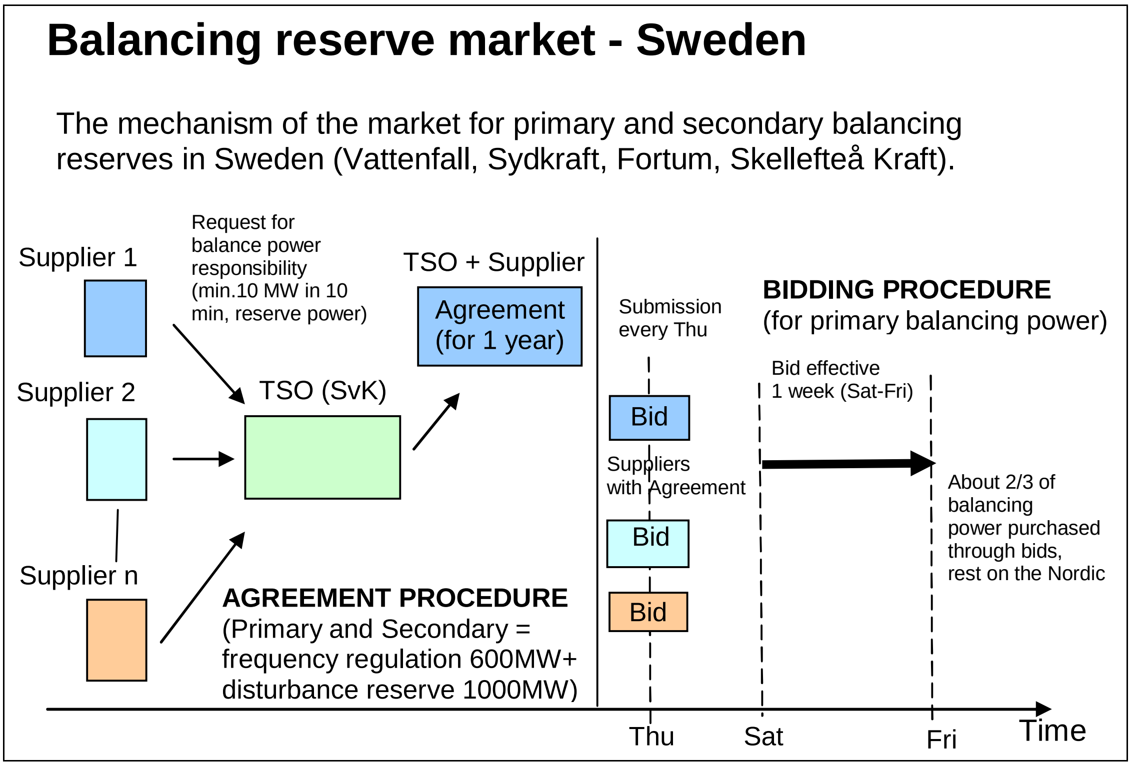

Figure 17: Tendering procedure for frequency control reserves in Sweden

Table 6: Price of frequency control reserves in Sweden (2005)

Paid to suppliers:	Maintaining/providing a momentary reserve, a set price for 1 year, which is inofficial. (SvK yearly budget is about 16.3 M€ / 4 suppliers), this is both for primary and secondary balancing power. The figure of how much of this that is for primary is unofficial.
Bids and amount of power supplied:	Hourly rates, price range see figures below.
SvK buys:	- about 2/3 of the regulating power through bids (within Sweden) - and the rest from the hourly sPOT price market (Nordic market)

The 150 MSEK/year (16.3 M€ in the calculation in Table 6) can end at 90-200 MSEK/year depending on the weather conditions and the amount of hydro power that can be produced, more rain gives lower price. The 150 MSEK is paid so that the supplier shall have a reserve/an amount of MW available, so that it is not sold to the spot market. The reserve is about 640 MW in Sweden for regulating power, of which about 240 MW is for primary. Secondary is used to support primary (within 15 minutes) or “pure” secondary after 15 minutes.

Regarding the prices for primary balancing power, called automatic regulating power, there are no official data published but through the person handling the statistics, some data was received in an excel sheet. The data received covered every single hour from January 1 to August 31, 2005 (Figure 18).

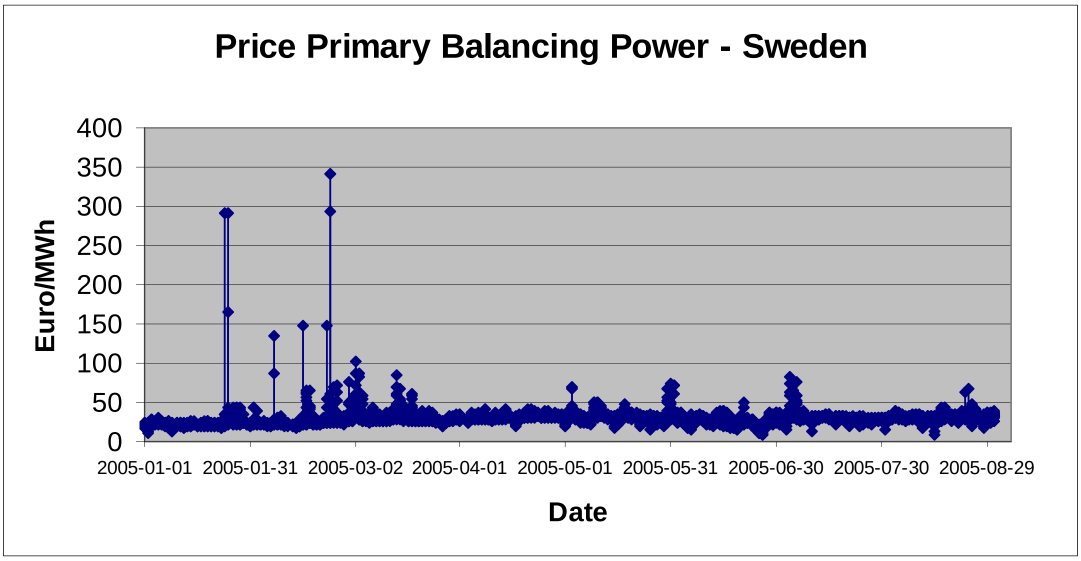

Figure 18: Price for primary balancing reserve in Sweden (January-August 2005)

The prices are generally in the range 20-30 €/MWh, sometimes above 50 €/MWh and rarely above 100 €/MWh. The highest prices occur most frequently during the winter season. The volumes of Upward and Downward regulation, per hour, are usually below 100 MWh, but can in some cases exceed 150 MWh. The volumes for Upward and Downward regulation are somewhat higher during the winter season.Figure 19 illustrates hourly prices for secondary reserve (similar to tertiary within UCTE) on the spot market.

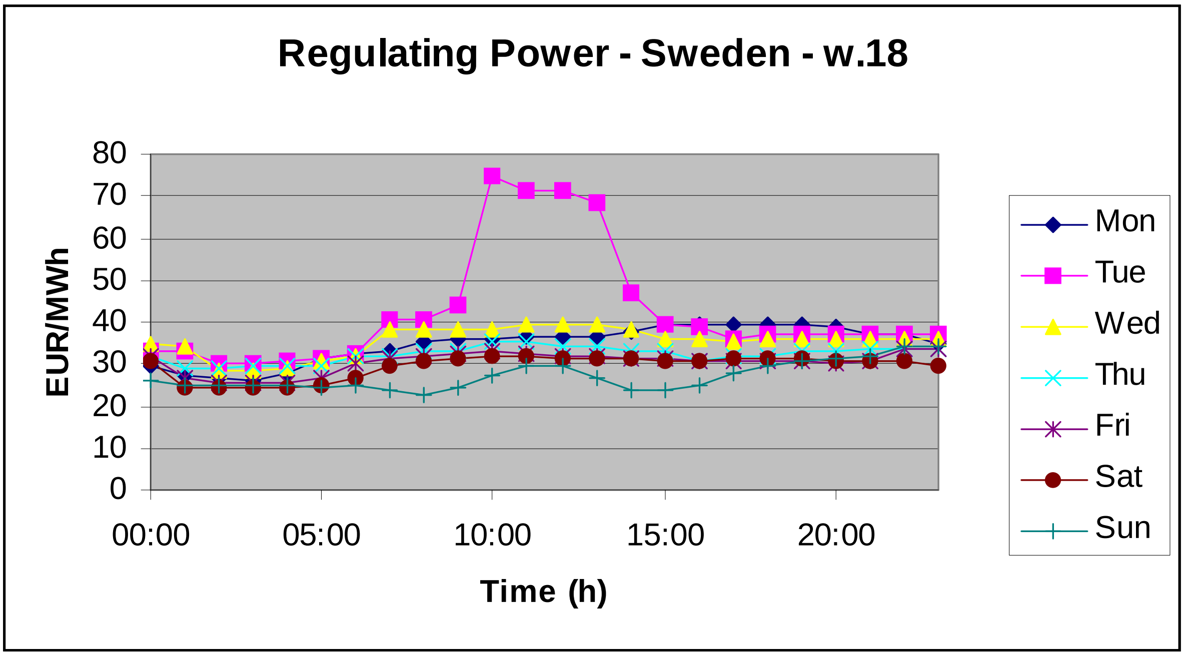

Figure 19: Spot price for secondary reserve in Sweden (week 18, 2005)

3.2.4. Norway

Balancing power (frequency control) reserves in Norway is to 100% hydro power using generators. The definition regulating power is used for all kind of “balancing power” in Norway. There is primary and secondary regulating power.

3.2.4.1. Tendering procedure for balancing power

There is no minimum amount of power that has to be provided and tendered for primary balancing power. For the secondary (similar to the tertiary within UCTE) 50 MW is set as a minimum amount. However, Statnett are not that strict on this and often 20-30 MW is supplied. There are separate conditions for supplying primary and secondary power.

The tendering and bid procedure is operated on a weekly basis. A marginal price is set on the balancing power for a selected time interval of a week. Directions from Statnett are that 6% of the base delivery of hydro power shall be reserved for balancing power.

3.2.4.2. Prequalification procedure

Before providing the balancing power and agreement is signed between Statnett and the provider of balancing power. This agreement is valid as long as the prerequisites for the agreement stay the same. If there are some changes that need to be made, then a new agreement is written. In Norway there are many companies providing balancing power, in total 60-70. There are 8-10 of these that are the most active and largest providers. If it is a rainy season there is plenty balancing power in Norway, however, during dry years or seasons, there may sometimes be a need to import balancing power.

3.2.4.3. Results of previous tenders in Statnett

Prices are sometimes given in NOK/MW/Hz on the web which makes it difficult to compare with other countries. However, according to Stattnet the price for balancing power in Norway is at least a factor of two less than in Sweden, which would mean a price for primary balancing power between 10-15 €/MWh, when compared with Figure 18 (price for primary balancing power in Sweden). An unconfirmed figure is that Norway pays 10.9 M€/year to the suppliers for maintaining/providing a primary regulating reserve of 544 MW.

According to Stattnet the trend is that the market is going to more market driven mechanisms. But within the Scandinavian countries there are still some physical restrictions that need to be solved before a common Scandinavian market could be established. The Swedish and Danish balancing power markets are seen as less commercial than the Norwegian as there are few power companies that are supplying balancing power today. These markets as well as the German market are more politically driven with agreements between the TSOs and the providers of reserves. With the increase of wind power there will be a need for more reserves which would come from hydro power as well.

3.2.5. Denmark-East

3.2.5.1. Tendering procedure, prequalification and framework agreement

Energinet (former Elkraft) invites tenders for reserves from 2004. A potential supplier can apply for admission to the list by filling in and submitting the application form. Having received the applications, the TSO will assess whether the applicant is qualified within one calendar month. Energinet will select the applicants from the qualification list that will be asked to submit tenders. They will subsequently receive the tender documents and have to send tenders within the next month. Having received the first tenders, the TSO will assess whether the tenders are in conformity with the tender conditions. All tenderers that have submitted tenders in conformity with the tender conditions will subsequently be invited to negotiations, which are expected to be carried out during the following two months. After the negotiations, tenderers will be requested to submit a revised tender not later than four days after the negotiations. At the end of the current month, a contract is expected to be awarded to the tenderers that have submitted the most economically advantageous tenders.

3.2.5.2. Contracts awarding

In practice there is **no lower limit** of how many MW that has to be supplied to become a supplier. It is possible to sign an agreement to only supply primary balancing power but it is not common. The agreement is signed for one year and renegotiated every year. When the agreement is written an amount of supplied balancing power is agreed and a price is set for the supply contract for one year. This price is unofficial. Hence, there are no hourly prices for the balancing power in eastern Denmark. Energi2 is the largest supplier but there are also several smaller suppliers, about ten in total. Obviously there is a market but the competition is limited. No balancing power is bought from Nord Pool. Balancing power in Denmark is to 100% from heat generated power.

3.3. UK and Ireland

3.3.1. England, Scotland and Wales

The UK market is divided into the arrangements for England and Wales and those for Scotland (Scotland holds 21 % of primary frequency response). The market from 1990 operated on a pool basis but has now moved to a power exchange system with a **short-term mechanism for balancing, operating 1 hour ahead of real time**. The TSO National Grid - NG is responsible for the management of the frequency for the UK (including Scotland).

The generators have a **mandatory requirement** to provide primary frequency response which is charged at a “cost reflective” price. Mandatory primary control services are complimented by additional ‘commercial’ services. These are either enhanced services beyond a generator’s mandatory requirement (which are based upon a 4% droop characteristic), or commercial demand reduction (the demand is on low frequency relays, which are activated for deviations of around 0.3 Hz).

The System security and quality of supply standard define the limits to which the frequency has to be controlled. The standard currently states that unacceptable conditions are where: the steady state frequency falls outside the statutory limits of 49.5 Hz to 50.5 Hz; or a transient frequency deviation persists outside the statutory limits and does not recover to 49.5 - 50.5 Hz within 60 seconds. These deviations should only occur at intervals, which ought reasonably to be considered as infrequent.

Since NG does not use LFC, it controls the frequency using only governor response (divided into three subsets: primary, secondary and high frequency responses), and by changing the dispatching and unit commitment (by activating respectively regulating and standing reserve) through the balancing mechanism (BM) and bilateral contracts.

The services used to control frequency are:

- Primary response, which is defined as the response provided within 10 seconds and maintained for a further 20 seconds.
- Secondary response, which is defined as the response provided within 30 seconds and maintained for 30 minutes.

- High frequency response, which is defined as the response to high frequency provided within 10 seconds and maintained thereafter.

Typically, these services are provided by heat generated power which is the largest source for frequency control reserves, but also by hydro generation, and large demand providers. Reserves of hydro power are connected within 2 minutes (not automatic).

The amount of primary control held is optimised on an hourly resolution and is dependant on total system demand, and the largest single infeed to the system. For the instantaneous loss of 1320MW generation this results in a requirement for a primary frequency response reserve range of 400-500MW and a secondary frequency response reserve range of 900-1300MW. Further developments are being concentrated on the increased optimisation of the frequency dispatch process. This is including the possible increased usage of demand options, thus reducing the overall requirement for balancing plant. Figure 20 shows prices and volumes for primary, secondary and high frequency response reserves for the period April - June 2005 [13].

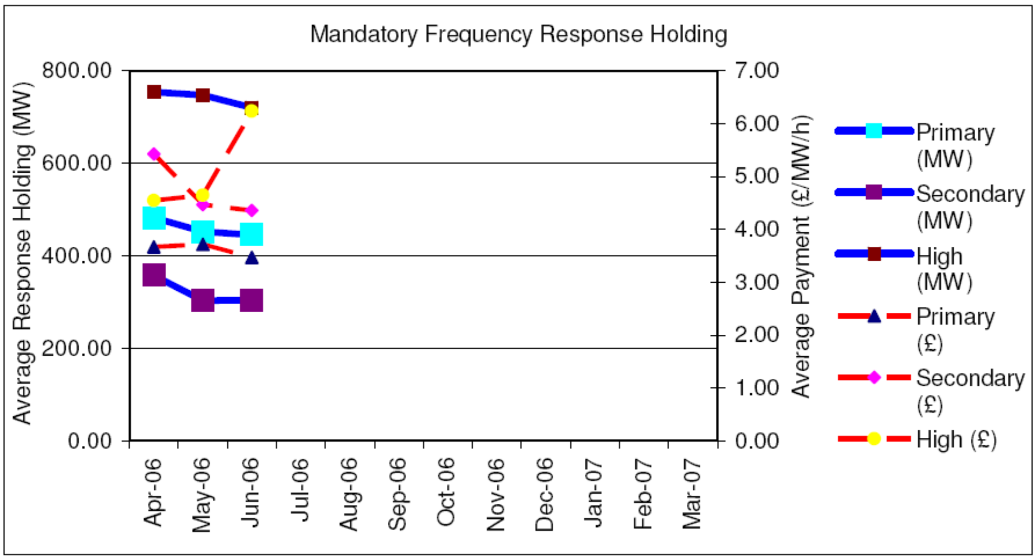

Figure 20: Price and holding volume for frequency control reserves in UK (April-June 2006)

3.3.2. North Ireland and Republic of Ireland

There is a reserve sharing agreement in place on the island. In Ireland, the grid codes for the two systems, both of which are under the control of their respective regulators, define the outline frequency standards for the two systems:

- Maintain the frequency at between 49.8 and 50.2 Hz in normal conditions.
- Maintain the frequency at between 48.0 and 52.0 Hz during transmission disturbances.
- Maintain the frequency at between 47.0 and 52.0 Hz during exceptional transmission disturbances.
- Keep the frequency above 49.5 Hz for the largest single generator contingency. The largest single contingency is a loss of 400 MW of generation.

There are four types of operating reserve in two systems [14]:

- Primary operating reserve (POR) must be available between 5 and 15 seconds after an event. This is provided by governor response, interruptible loads or via pump-hydro storage. Typically, there is in excess of 300 MW of POR with the official rate of 1.84 €/MWh for 2006.
- Secondary operating reserve (SOR) must be available between 15 and 90 seconds after the event to replace the tripped unit and to allow maintenance of POR. This is usually provided by pumped-hydro storage units. Typically, there is 400 MW of SOR with the official rate of 1.67 €/MWh for 2006.
- Tertiary operating reserve 1 (TOR1) must be available between 90 seconds and 5 minutes after an event. This is provided by hydro units, in the Republic, and gas turbines in Northern Ireland. TOR1 official rate is 1.53 €/MWh for 2006.
- Tertiary operating reserve 2 must be available between 5 and 20 minutes after an event. TOR2 has the same rate as TOR1.

4. Provision of frequency control reserves by Microgrids

4.1. Virtual unit concept

The change in frequency control reserve procurement practices from mandatory to commercial opens numerous opportunities for Microgrids made up of small micro sources, responsive loads and energy storage devices linked together using secure, cost-effective communication network technology and controlled by a central EMS. In general, there is more financial reward for supplying fast (primary) frequency control reserve than for supplying slower (secondary and tertiary) reserves as a result of the higher prices (ex. Table 3).

However, due to the fact that typical micro sources have a power output 10-100 kW; it is hard to believe that a single Microgrid (with a total install capacity of 1 MW) will be qualified as a supplier of frequency control reserve alone. The reason is that the minimum required control range offered per technical unit totals at least ±2-3 MW for primary and 20-30 MW for secondary and tertiary reserves (Table 2). Therefore, an aggregation of multiple Microgrids is required. It will be seen by a TSO from outside as a ***virtual controllable unit*** which provides a contracted reserve volume at the point of connection to transmission network.

For example a virtual unit with ±2 MW primary reserve needs 40 micro sources of 100 kW or 400 micro sources of 10kW in the case if a full micro source capacity is contracted for a provision of reserve. These numbers should be multiplied by a factor of 10 for a provision of secondary and tertiary reserves. In the case if only a small fraction (5-10%) of micro source capacity is used for a provision of reserves further increase in the number of aggregated micro sources is required. It is possible that frequency control using multiple aggregated micro sources would not require continuously variable feedback systems as used in central generation and could be implemented by coordinated switching of micro sources.

Multi-Microgrids should be a more reliable supplier of reserves than large conventional generators. Because each micro source will be supplying a smaller fraction of reserve, the failure of a single resource is less important. There can still be failures in the facilities of the aggregator, but it is easier and cheaper to install redundancy in this portion of the system than with an entire hundreds megawatt conventional generating unit. Principally every micro source can be a part of the virtual unit. With a lot of different types of micro sources it is possible to compensate the different disadvantages of the units. One way to aggregate energy resources into the virtual unit is to create sub-groups by the type of fuel used to generate power. With the cost of different fuel types constantly fluctuating, EMS can choose to dispatch only cheapest micro sources.

In multi-Microgrids with prevailing intermittent energy resources (wind, solar, etc.) which are used for long term provision of frequency control reserves (ex. yearly or monthly contracts for primary reserves), there is a risk that reserve capacity would not be available at certain periods. Thus, a contracted reserve is limited by a minimum guaranteed production during the contracted period. Therefore, it is more effective to use intermittent micro sources for a provision of tertiary reserve where the bidding appears on the hourly (sometimes 15 minutes) basis (Table 7). It may be noted that the power output of these micro sources can be predicted in the short term with reasonable confidence. The better the prediction of available output, the higher is the profit.

Table 7: Applicability of Multi-Microgrids with prevailing of different types of micro sources for a provision of frequency control reserves

	Fast reserve (seconds)	Slow reserve (15-30 min)
Volume	minimum 2-3 MW	minimum 20-30 MW
Contract time frame	year, months	Hour
MG with CHP	Yes	Yes (large amount of micro units)
MG with PV, wind	Yes (only in combination with energy storage)	Yes (large amount of micro units)

4.2. Main technical and administration issues

4.2.1. Central EMS

A centralized EMS for multi-Microgrids is needed to control distributed micro sources for a provision of reserves. In the case of participation on hourly reserve market, the first step normally involves analyzing the weather forecast (whether more sunshine or weaker winds are to be expected) over the next day. The forecast is also important for predicting local consumer behaviour.

Based on this information the EMS would make a decision whether it would be profitable to supply the reserve, and at what price. The EMS would then bid in to the market, and shortly would find out if the bid were successful. If successful, the EMS would plan to supply the reserve for the next day. The bidding and dispatching could be done fully automatically with only periodic operator oversight.

4.2.2. Communication

What's absolutely essential for the provision of ancillary services is high-performance communications links connecting the central EMS to the various generation and storage units. Should frequency control reserve is needed in the network (called by TSO), the EMS will instruct the many decentralized micro-sources to step up/down production.

4.2.3. Agreement

A virtual unit needs a lot of micro sources for a provision of reserves. A large number of micro sources make the realisation complicated, because it is difficult to get so many interests together. So it is necessary to have good agreements and financial impulsion for the owners of the micro sources because the owners do not give willingly the control of their units to another organisation. The conditions for and methods of possible operating variants must be specified in bilateral agreements between the multi-Microgrids operator and the owners of micro sources.

5. Conclusions

Transmission System Operators (TSOs) use the frequency regulation to provide a secure and high-quality power supply for the consumers. The frequency regulation usually contains three layers. Using UCTE terminology [1], these layers are called Primary, Secondary and Tertiary frequency control (see table below).

In total, more than 30 TSOs (from UCTE, Nordel and UK) have been contacted via email and around 15 were interviewed on the phone. Details of procurement mechanisms and technical requirements for frequency regulation reserves at each TSO are presented in Sections 2 and 3. The availability prices and volumes of reserves (2005-2006) in different countries are shown in the following table.

Country	TSO	Primary Reserve	Secondary reserve	Tertiary reserve
Germany	E.ON	14.21 €/MWh ±163 MW	8.87 €/MWh +800 MW 2.30 €/MWh -400 MW	4.58 €/MWh +1100 MW 2.50 €/MWh -400 MW
	VE	13.90 €/MWh ±140 MW	10.55 €/MWh +580 MW 3.65 €/MWh -580 MW	4.60 €/MWh +730 MW 2.40 €/MWh -530 MW
	RWE	15.58 €/MWh ±285 MW	11.24 €/MWh +1230 MW 3.80 €/MWh -1230 MW	4.65 €/MWh +1030 MW 2.40 €/MWh -760 MW
	EnBW	15.73 €/MWh ±73 MW	10.96 €/MWh +720 MW 5.71 €/MWh -390 MW	4.55 €/MWh +510 MW 2.50 €/MWh -330 MW
Denmark-W	Eltra	14.50 €/MWh ±32 MW	8.80 €/MWh +100 MW 2.26 €/MWh -100 MW	6.00 €/MWh +442 MW 2.40 €/MWh -160 MW
Czech	CEPS	23.60 €/MWh ±80 MW	C	C
Hungary	MAVIR	5-20 €/MWh ±50 MW	C	C
UK	National Grid	3.90 €/MWh +540 MW 1.07 €/MWh -835 MW	4.08 €/MWh 387 MW	6.85 €/MWh 450 MW plus 2250 MW standby
Ireland	Eirgrid	1.84 €/MWh 300 MW	1.67 €/MWh 400 MW	1.53 €/MWh
Sweden	SvK	25 €/MWh 640 MW	**NA**	1000 MW
Norway	Statnett	15 €/MWh 545 MW	**NA**	C
Finland	Fingrid	350 MW	**NA**	850 MW
Denmark-East	Energinet	65 MW	**NA**	C
France	RTE	650 MW	at least 500 MW	1500 MW
Netherlands	TenneT	120 MW	C	600 MW
Belgium	Elia	100 MW	C	660 MW
Spain	REE	1.5% of all generators	35 €/MWh +690 MW 20 €/MWh -490 MW	45 €/MWh + 15 €/MWh -
Slovenia	ELES	M	C	C
Romania	Transelectrica	M	15 €/MWh	12 €/MWh
Poland	PSE-Operator	6.10 €/MWh ±160 MW	7.00 €/MWh	C
Switzerland	ETRANS	no payment	no payment	M

C - commercial **M** – mandatory **NA** – not applicable

In this table, reserve prices are normalized to €/MWh unity for adequate comparison. However, in a reality different contracting periods (year, month and hour) are used in different countries.

It has been also seen that using a concept of the virtual unit (aggregated micro sources) the multi-Microgrids satisfy typical technical requirements for a provision of frequency control reserves. Thus, there are no technical barriers for a qualification to participate in the tendering procedure on the market. It is recommended that requirements for frequency response are defined in such a way as to accommodate either continuous control or coordinated modular switching approaches to providing frequency response. Separating the OF from UF response is useful, as micro sources without energy storage can make a useful contribution to OF response, but are more costly to use for UF response.

To determine the economic viability of the multi-Microgrids application for frequency control reserve a detailed economic valuation has to be carried out where the total net present value (NPV) of the revenue from an availability and utilization payment for reserve must be compared with the NPV of the cost overhead of including a control capability with micro sources plus the running cost involved in participating in frequency control over a certain period. Economic success is achieved if the NPV of the revenues is greater.

The price of frequency control reserves is the most important parameter, which influence the estimated profit. Unfortunately, sufficient historical data are not yet available, and where it is, it may not be very meaningful since it is a subject to a considerable amount of uncertainty. However, we assume that there will be an increase of the reserve prices due to the limited available resources.

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