Investigation of stability aspects in a Pan-European interconnected grid with different wind power penetration

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Abstract

Large-scale deployment of Renewable Energy Resources (RES) has led to significant generation shares of variable RES in power system worldwide. RES units, notably inverter connected wind turbines and photovoltaics, are effectively displacing conventional generators and their rotating machinery. This has implication for frequency dynamics and power system stability. In fact frequency dynamics are faster in power system with low rotational inertia, making more difficult the frequency control and system stability after fault.

This thesis presents studies about transient system stability in a Pan-European interconnected grid with particular focus on voltage, frequency and rotor angle stability after disturbances: i.e. 3-phase fault in a tie-line and a load step in one area.

The grid analyzed, a transmission power grid principally composed of HV lines with a meshed HV 725 kV DC grid, is the test grid used for the EU project ELECTRA Task 5.4. A set of scenarios has been defined with different levels of renewable wind generation penetration and gradual switching off of traditional rotating generation units.

Root-mean-square RMS simulation studies have been carried out in DIgSILENT PowerFactory software environment using a simulation time between 1 to 50 s following the fault. Simulation result has been analyzed referring on new EU grid codes and present standards. A first set of simulation is performed with a severe fault, i.e. 3-phase fault in a tie line. The second analysis considers grid’s behaviour after an imbalance between load and generation, i.e. a load step. The conducted simulations show that the increasing of wind power generation as replacement of conventional generation is not leading necessary to worst stability behaviour but has a positive contribution in term of the achievement of steady state equilibrium after the disturbance without oscillation.
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Chapter 1

Introduction

In this chapter an introduction concerning the thesis goals is reported as well as a description of new topology of power system in the future vision of an interconnected Pan-European grid. The project ELECTRA, which goes in this direction, is described.

The problem of system stability is figured out with a detailed description of voltage, frequency and rotor angle stability. Furthermore a description of the main indexes defined in literature to analyze the transient stability behaviour of a network has been reported.

The commercially available power system simulation tool DIgSILENT PowerFactory, used to perform the simulation, is briefly described in this section.

In the end of the chapter a description of new European network codes has been reported, principally focusing on requirements for grid connection of generators and regulations for voltage characteristic of electricity supplied by public distribution system

1.1. Project Goals

Aim of this thesis is the study of the stability issue after severe events, i.e. fault and power imbalance, in a future transmission grid with different penetration of wind generation. In the interest of the thesis is the analysis of new type of grid in the future vision of smart grids, for that reason it has been taken as test grid the Pan-European network of the EU project Electra Task 5.4. This grid derives from the European HV Benchmark network proposed by the Cigré with the integration of a high Voltage Direct Current HVDC part.
In order to develop the studies a set of scenarios has been defined with increasing of wind generation and gradual disconnection of conventional generators, i.e. synchronous generator.

For testing the transient behaviour of the grid simulation are carried out with the power system simulation tool DlgsILENT PowerFactory. A first set of simulation is carried out with a three-phase fault in a tie line for testing the stability behaviour of the grid after the most severe disturbance. Finally a second set of simulation is developing defining a load step in a part of the grid for simulate a power imbalance between generation and consumption.

### 1.2. Problem Statement

In new power system generation will shift from classical dispatchable units to more intermittent renewables. Related to penetration of renewable energy resources a significant part of the generation units will shift from big centralized power plants to many smaller units, like photovoltaic and small wind generation. The generation will move from central transmission system connected generation to decentralized distribution system connected generation. However, there will be equally some big and centralized power plants, mainly composed by RES (Renewable energy resources) generation and placed onshore and offshore locations.

To support and foster research in the European Research area in this vision the European union/European commission has created the funding program for Research and Technological Development, also called Framework Programmes or abbreviated FP1 through FP7 with “FP8” being named “Horizon 2020”. The targets of the Horizon 2020 are to reduce greenhouse gas emission by 20%, increase of 20% of energy efficiency and ensure 20% of renewable energy resources in the EU energy mix respect to 1990 within the 2020. The key EU technology challenges for meet the 2020 targets included also [1]:

- Double the power generation capacity of the largest wind turbines, with off-shore wind as the lead application;
- Demonstrate commercial readiness of large-scale photovoltaic and concentrated solar power;
- Enable a single, smart European electricity grid able to accommodate the massive integration of renewable and decentralized energy resources;

In fact the EU energy strategy sets ambitious goals for the energy systems of the future that foresees a substantial increase in the share of renewable electricity production. The whole-
sale deployment of Renewable Energy Resources connected to the network at all voltage levels will require a radically new approaches for real time control that can accommodate the coordinated operation of millions of devices, of various technologies, at many different scales and voltage levels, dispersed across EU grid. To address this challenge an European Liaison has been constituted named ELECTRA (European Liaison on Electricity Committed Towards long-term Research Activity).

ELECTRA Integrated Research Programme on Smart Grid (IRP) brings together the partners of the EERA (European Energy Research Alliance) Joint Programme on Smart Grid (JP SG) to reinforce and accelerate Europe’s medium to long term research cooperation in the area of smart grid. The goal is studying new power system in the view of smart grid, with high penetration of renewable resources and observability of the grid.

In the proposal of project Electra the EU grid is divided in web of cells structures. Each cell is a group of interconnected loads, concentrated plants and/or distributed energy resources and storage units. Each cell is managed by a single system operator, called cell system operator, that is responsible for establishing and maintaining automatic control mechanism as well as procuring sufficient reserves within is cell. For maintaining the balance he can procure reserves from within is cell but also “cross cell border” reserves from neighboring cells. In this way no global system state information is required and a “divide and conquer” way of tackling voltage and balancing issues is implemented. Thus, local problems are resolved in the cell in a fast and secure manner, limiting complexity and communication overhead. However inter-cell coordination is possible to support global optimization if needed. In order to regain reliable control over the power grid, also distributed generators and loads should be controlled in a way that increases the predictability of the maximum power imbalance as perceived system-wide by the TSO’s.

A new control concept [2] in the future power system is shown in Figure 1-1.
A vertical integration control schemes reinforced by a horizontally-distributed control schemes are expected to provide for a dynamic power balance that is closer to its equilibrium value than a conventional center control scheme. This enables grids operators to regain control in a future power system with a high share of decentralized generators.

1.3. Background to power system stability

Power system stability is the ability of an electrical power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact [3].

This definition applies to an interconnected power system however the stability of a particular generator or a particular loads or loads area is also of interest. Could be that a generator may loss stability without cascading instability of the main system.

When subjected to a disturbance, the stability of the system depends on the initial operating conditions as well as the nature of the disturbance.

Power systems are subjected to a wide range of disturbances, small and large. Small disturbances in the form of load changes occur continually and the system must be able to adjust to the changing condition and operate satisfactorily. It must also be able to survive
numerous of large disturbances, such as short circuit on a transmission line or loss of a large generator.

Power system stability could be defined keep in consideration the following:

- The physical nature of the resulting mode of instability as indicated by the main system variable in which instability can be observed;
- The size of the disturbance considered, which influences the method of calculation and prediction of stability;
- The devices, processes, and the time span that must be taken into consideration in order to assess stability.

Based on the consideration explained above power system stability could be divided into the categories and subcategories reported in Figure 1-2. In any given situation, however, any one form of instability may not occur in its pure form; as system fails one form of instability may ultimately lead to another form.

![Figure 1-2: Classification of power system stability](image-url)
1.3.1  *Rotor angle stability*

Rotor angle stability refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. It depends on the ability to maintain/restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators. In fact if the system is perturbed, the equilibrium between the input mechanical torque and the output electromagnetic torque is upset, resulting in acceleration or deceleration of the rotors of the machines according to the laws of motion of rotating body.

It is useful to characterize rotor angle stability in terms of the following two subcategories:

- **Small-disturbance rotor angle stability** is concerned with the ability of the power system to maintain synchronism under smaller disturbances. Small-disturbance rotor angle stability problem is usually associated with insufficient dumping of oscillations. The time frame of interest in this case is on the order of 10 to 20 seconds following the disturbance.
- **Large-disturbance rotor angle stability** or transient stability, as it is commonly referred to, is concerned with the ability of power system to maintain synchronism when subjected to a severe disturbance, such as short circuit on a transmission line. The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance; it may be extend to 10-20 seconds for very large systems with dominant inter-area swing.

As identified in Figure 1-2, small-disturbance rotor angle stability as well as transient stability are categorized as short term phenomena.

1.3.2  *Voltage stability*

Voltage stability referred to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. It depends on the ability to maintain/restore equilibrium between load demand and load supply from the power system. The driving force of voltage instability is usually the loads. In response to a disturbance power consumed by the loads tends to be restored by the action of motor slips adjustment, distribution voltage regulators and tap-changing transformer. Restored loads increased the stress on the high voltage network by increasing
the reactive power consumption and causes further voltage reduction. If the restore power consumption is beyond the capability of the transmission network and the connected generation a run-down situation occurs causing voltage instability.

Problems of voltage stability could lead to loss of load in an area or tripping of transmission lines and other element by their protective system leading to cascading outages. Loss of synchronism of some generator may result from these outages and in other hand pole slips between groups of machines could lead to a rapid drop in bus voltages.

While the most common form of voltage instability is the progressive drop of bus voltages, the risk of overvoltage instability also exists. It is caused by a capacitive behaviour of the grid and the inability of the combined generation and transmission system to operate below some load level.

Voltage instability problems may also be experienced at the terminals of HVDC links associated by the unfavorable reactive power load characteristic of the converters. The HVDC link control strategies have a very significant influence on such problems, since the active and reactive power at the ac/dc junction are determined by the controls.

Another form of voltage stability problems that result in uncontrolled overvoltages is the self-excitation of synchronous machines. This can arise if the capacity load of the machines is too large, for example in the case of open ended high voltage lines and shunt capacitors and filter banks from HVDC station.

As in the case of rotor angle stability, it is useful to classify voltage stability into the following subcategories:

- Large-disturbance voltage stability refers to the system’s ability to maintain steady voltages following large disturbance such system fault, loss of generation or circuit contingencies.
- Small-disturbance voltage stability refers to the system’s ability to maintain steady voltages when subjected to small perturbation such as incremental changes in system load.

As the time frame of interest may extend from few second to tens of minutes voltage stability may be either a short-term or a long-term phenomenon as identified in Figure 1-2.
Short-term voltage stability study involves dynamic of fast acting load components such as induction motors, electronically controlled loads and HVDC converters. The study period in this case is in the order of several second.

Long-term voltage stability involves slower acting equipment such as tap-changing transformer, thermostatically controlled loads and generators current limiters. The study period of interest may extend to several or many minutes.

1.3.3 Frequency stability

Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load. Instability that may result occurs in the form of sustained frequency swings leading to tripping of generating units and/or loads. Generally frequency stability problems are associated with inadequacies in equipment response, poor coordination of control and protection equipment or insufficient generation reserve.

Frequency stability, as identified in Figure 1-2, may be a long-term or a short-term phenomenon. In fact during frequency excursion, the study period of interest will range from a fraction of second, corresponding to the response of device such as under frequency load shedding and generator control and protection, to several minutes, corresponding to the response of devices such prime mover energy supply system and load voltage regulators.

During frequency excursion, voltage magnitude may change significantly. Voltage magnitude changes affect the load generation imbalance and may cause undesirable generator tripping.

1.3.4 Index for transient stability evaluations

In the literature there are two main defined indexes for evaluating transient stability behaviour of power systems: TRASI, transient rotor angle severity index and CCT, critical clearing time. A briefly description of these indexes is reported below.

As said in 1.3.1 transient stability is defined as the ability of synchronous generator angles to regain their operating equilibrium following a transient fault in a network. When the maximum rotor angle difference between two generators or a group of generators exceed 180° there will be a high probability of losing stability. Therefore this measure can be used as an
indicator of transient stability following a transient grid disturbance. In fact an index could be defined, named TRASI, using the maximum rotor angle difference to analyze the severity of the angular separation between synchronous generators.

The transient rotor angle severity index (TRASI) is defined as follow:

\[
TRASI = \left( \frac{360^\circ - \max(\delta_{\text{max},d}^{\text{pst}})}{360^\circ - \delta_{\text{max},d}^{\text{pre}}} \right)
\]  

(1-1)

The coefficient \(\delta_{\text{max},d}^{\text{pst}}\) and \(\delta_{\text{max},d}^{\text{pre}}\) represent the post-disturbance and pre-disturbance maximum rotor angle difference in the network respectively [4]. The maximum rotor angle difference can be specified in equation (1-2 based on the rotor angles measured with reference to the reference machines angle.

\[
\delta_{\text{max},d}(t) = \max[\delta_{\text{ref},m1}(t), \delta_{\text{ref},m2}(t), \delta_{\text{ref},m3}(t), \ldots, \delta_{\text{ref},mn}(t)] - \min[\delta_{\text{ref},m1}(t), \delta_{\text{ref},m2}(t), \delta_{\text{ref},m3}(t), \ldots, \delta_{\text{ref},mn}(t)]
\]

(1-2)

The relative rotor angle \(\delta_{\text{ref},m}\) could be specified based on the rotor angle w.r.t. the local bus voltage \(\delta_{\text{local}}\), the generator bus voltage angle w.r.t. the reference machine voltage angle \(\alpha\) and the reference machines rotor angle \(\delta_{\text{ref}}\) as: \(\delta_{\text{ref},m} = \delta_{\text{local}} + \alpha - \delta_{\text{ref}}\). The graphical representation of the defined angles is reported in Figure 1-3.

![Figure 1-3: Relative rotor angle measurement](image-url)
The TRASI index varies from 0 to 1, with values closer to one considered to be more stable, since the angular separation between the synchronous machines in the system are less compared to the pre-fault values.[4]

Critical clearing time (CCT) is widely used as an important transient stability index which is defined as the maximum duration that a disturbance may sustain without losing the power system’s capability of recovering to a normal operating condition [5]. CCT is usually calculated by iterative time domain simulation, more specifically, adjusting the fault duration time in the time-domain simulation to find out the maximum duration of a short circuit to maintain the synchronization of central power plants in the whole power grid. For synchronous generator units thus means the maximum duration of a short circuit without any synchronous generator out of step.

The indexes defined above are significant for transient stability study but the definition implies the presence of synchronous generator. However, in power grid with a lot of RES generation units the conventional synchronous generation is replaced more and more by inverter connected generation. There is thus a lack of parameters for studying and compared the transient stability of a grid. One possible approach in a grid with inverter connected generation is to define the limit, out of which the system stability is lost, as the fault-ride-through capability of the connected generation.

1.3.5 System rotational inertia

In this chapter is reported a synthetic definition of system inertia. In fact the inertia of the system plays a key role in determining the initial frequency behaviour after a disturbance has occurred in the system. Inertia of a power system is a measure of the energy stored within the rotating masses connected to that system. Due to electro-mechanical coupling, a generator’s rotating mass (as synchronous generator) provides kinetic energy to the grid, or absorbs it from the grid, in case of a frequency deviation $\Delta f$.

Following a frequency deviation, kinetic energy stored in the rotating masses of the generator system is released, rendering power system frequency dynamics slower and, hence, easier to regulate. The rotational energy is given as
\[ E_{\text{kin}} = \frac{1}{2} J (2\pi f_m)^2 \]  

(1-3)

with \( J \) as the moment of inertia of the synchronous machines and \( f_m \) the rotating frequency of the machines. The inertia constant \( H \) for a synchronous machine is defined by

\[ H = \frac{E_{\text{kin}}}{S_B} = \frac{J (2\pi f_m)^2}{2 S_B} \]  

(1-4)

With \( S_B \) as the rated power of the generator. \( H \) denotes the time duration during which the machines can supply its rated power solely with its stored kinetic energy. Typical value of \( H \) are in the range of 2-10 s [6].

The classical swing equation describes the inertial response of the synchronous generator as the change in rotational frequency \( f_m \) (or rotational speed \( \omega_m = 2\pi f_m \)) of the synchronous generator following a power imbalance as

\[ \dot{E}_{\text{kin}} = J (2\pi)^2 f_m \hat{f}_m = \frac{2H S_B}{f_m} \hat{f}_m = (P_m - P_e) \]  

(1-5)

with \( P_m \) as the mechanical power supplied by the generator and \( P_e \) as the electric power demand.

Noting that the frequency excursion are usually small deviations around the reference value, \( f_m \) could be replaced by the reference frequency \( f_0 \). It is often desirable to include also a component of load-damping constant \( D_{\text{load}} \) that takes into account the self-stabilizing property of power system. Considering the system change (\( \Delta \)) before and after a disturbance the relative swing equation is

\[ \Delta \dot{f} = -\frac{f_0}{2 H S_B D_{\text{load}}} \Delta f + \frac{f_0}{2 H S_B} (\Delta P_m - \Delta P_e) \]  

(1-6)

The equation (1-6) describes the change that will occur in the frequency in response to an unbalance between \( P_m \) and \( P_e \). As could be seen in the equation the kinetic energy provided is proportional to the rate of change of frequency \( \Delta \dot{f} \), the higher inertia constant \( H \), the slower and more benign are frequency dynamics.
1.4. Power system simulation tool

The routine to perform the simulations is implemented in the commercially available power system simulation tool DIgSILENT PowerFactory [7].

The calculation program PowerFactory, as written by DIgSILENT, is a computer aided engineering tool for the analysis of transmission, distribution, and industrial electrical power systems. It has been designed as an advanced integrated and interactive software package dedicated to electrical power system and control analysis in order to achieve the main objectives of planning and operation optimization.

“DIgSILENT” is an acronym for “DIgital SImuLation of Electrical NeTworks”. This power system analysis software present an integrated graphical single-line interface that included drawing functions, editing capabilities and all relevant static and dynamic calculation features.

PowerFactory uses a hierarchical, object-oriented database. All the data, which represents power system Elements, Single Line Diagrams, Study Cases, system Operation Scenarios, calculation commands, program Settings etc., are stored as objects inside a hierarchical set of folders. The folders are arranged in order to facilitate the definition of the studies and optimize the use of the tools provided by the program.

The objects are grouped according to the kind of element that they represent. These groups are known as ‘Classes’ within the PowerFactory environment.

All data which defines a power system model is stored in “Project” folders within the database. Inside a “Project” folder, “Study Cases” are used to define different studies of the system considering the complete network, parts of the network, or variations on its current state. This ‘project and study case’ approach is used to define and manage power system studies in a unique application of the object-oriented software principle.
1.5. **Background to European network code about voltage and frequency variation range**

The European Commission, together with many stakeholders, have established that greater effort is needed to create a secure, competitive and low carbon European energy sector and a pan-European Internal Energy Market. To reach this objective ENTSO-E, with guidance from the Agency for the Cooperation of Energy Regulators (ACER), has drafted Network codes. They are a set of rules to facilitate the harmonization, integration and efficiency of the European electricity market. At present, ENTSO-E is working on 10 network codes, each code is submitted to the European Commission for approval through the Comitology process, to then be voted into EU law and implemented across Member State. These new network codes will work together with the European Standard EN norms and technical CENELEC specification.

In the interest of this thesis present the network code on requirements for grid connection of generators and the regulation about the main requirements for voltage characteristic of electricity supplied by public distribution system. In this view a description of these regulations has been reported in the following chapters.

### 1.5.1 Requirement for grid connection of generator

The Network Code on Requirements for Generators [8] lays down the requirements for grid connection of power generating facilities, synchronous power generating modules, power park modules and offshore power park modules, to the interconnected system.

On 26 June 2015, the network code on Requirements for Generators was adopted by European Union Member States in Comitology. The network code will now be reviewed by the European Parliament and Council who will check its compliance with the main principles of the European Union and the 3rd Energy Package (scrutiny). It is expected to become a binding regulation in Europe in early 2016, which will mark the start of a 3 years implementation period across Europe.

It is in the interest of the analysis to report the permitted variation range of the network code related to the synchronous area of the continental Europe.

The requirements for grid connection of generation state the limit of disconnection of the power generating modules after voltage and frequency variation. To ensure system security
in the grid it should be possible for the generators to remain connected to the system for specified frequency and voltage ranges. In the regulation the definition power generating module means either a synchronous power generating module or a park module.

In view of the different voltage level at which generators are connected and their maximum generating capacity, the regulation makes a distinction between different types of generators by establishing different levels of requirements. Power generating modules are divided into four categories in the basis of the voltage level of their connection point and their maximum capacity:

- **Type A**: connection point below 110 kV and maximum capacity of 0.8 kW or more;
- **Type B**: connection point below 110 kV and maximum capacity at or above 1 MW;
- **Type C**: connection point below 110 kV and maximum capacity at or above 50 MW;
- **Type D**: connection point at or above 110 kV and maximum capacity above 75 MW, a power generation module is also of type D if its connection point is below 110 kV and its maximum capacity is at or above 75 MW.

A power generating module, without difference regarding the type, shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Table 1-1.

<table>
<thead>
<tr>
<th>Synchronous area</th>
<th>Frequency range</th>
<th>Time period for operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continental Europe</td>
<td>47.5 Hz-48.5 Hz</td>
<td>To be specified by each TSO, but not less than 30 minutes</td>
</tr>
<tr>
<td></td>
<td>48.5 Hz-49.0 Hz</td>
<td>To be specified by each TSO, but not less than the period for 47.5 Hz - 48.5 Hz</td>
</tr>
<tr>
<td></td>
<td>49.0 Hz-51.0 Hz</td>
<td>Unlimited</td>
</tr>
<tr>
<td></td>
<td>51.0 Hz-51.5 Hz</td>
<td>30 minutes</td>
</tr>
</tbody>
</table>

Table 1-1: Minimum time periods for which a power generating module has to be capable of operating on different frequencies without disconnecting from the network.

In fact if the frequency range goes out of the values 47.5 Hz – 51.5 Hz, that means 0.95 – 1.03 in p.u. (with a base of 50 Hz), the interface protection trips and this could lead to a loss of generation and consequently to the system failure.

Regarding the fault-ride-through capability there are different requirements according to the different power generating modules’ type. The fault-ride-through curve is voltage-against-time profile which describes the conditions in which the power generating module is capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by faults on the transmission system.
Regarding power generating units belonging to type A there is no specific requirement respect the fault-ride-through profile.

With regards to fault-ride-through capability of type B and C power generating units each TSO shall specify a voltage-against-time profile in line with Figure 1-4. The profile express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault. Regarding the parameters set out in Figure 1-4 $U_{ret}$ is the retained voltage at the connection point during a fault and $t_{clear}$ is the instant when the fault has been cleared. The ranges of variation of the parameters are set out in Table 1-2, for synchronous power generating modules, and in Table 1-3, for power park modules.

![Figure 1-4: Fault-ride-through profile of a power generating module](image-url)
With regards to voltage stability, type C power generating modules shall be capable of automatic disconnection when voltage at the connection point reaches levels specified by the relevant system operator in coordination with the relevant TSO. In addition, with regards to loss of angular stability or loss of control, a power generating module shall be capable of disconnecting automatically from the network in order to help preserve system security or to prevent damage to the power generating module.

With regards to type D power generating modules specific voltage ranges and a fault-ride-through capability are defined. The power generating modules shall be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to the reference 1 p.u. voltage, and for the time periods specified in Table 1-4 and Table 1-5 for different voltage base values.

<table>
<thead>
<tr>
<th>Voltage parameters [pu]</th>
<th>Time parameters [seconds]</th>
</tr>
</thead>
<tbody>
<tr>
<td>U_{ret} : 0.05 - 0.3</td>
<td>t_{clear} : 0.14 - 0.15 (or 0.14 - 0.25 if system protection and secure operation so require)</td>
</tr>
<tr>
<td>U_{clear} : 0.7 - 0.9</td>
<td>t_{rec1} : t_{clear}</td>
</tr>
<tr>
<td>U_{rec1} : U_{clear}</td>
<td>t_{rec2} : t_{rec1} - 0.7</td>
</tr>
<tr>
<td>U_{rec2} : 0.85 - 0.9 and ≥ U_{clear}</td>
<td>t_{rec3} : t_{rec2} - 1.5</td>
</tr>
</tbody>
</table>

*Table 1-2: Parameters for fault-ride-through capability of synchronous power generating modules*

<table>
<thead>
<tr>
<th>Voltage parameters [pu]</th>
<th>Time parameters [seconds]</th>
</tr>
</thead>
<tbody>
<tr>
<td>U_{ret} : 0.05 - 0.15</td>
<td>t_{clear} : 0.14 - 0.15 (or 0.14 - 0.25 if system protection and secure operation so require)</td>
</tr>
<tr>
<td>U_{clear} : U_{ret} - 0.15</td>
<td>t_{rec1} : t_{clear}</td>
</tr>
<tr>
<td>U_{rec1} : U_{clear}</td>
<td>t_{rec2} : t_{rec1}</td>
</tr>
<tr>
<td>U_{rec2} : 0.85</td>
<td>t_{rec3} : 1.5 - 3.0</td>
</tr>
</tbody>
</table>

*Table 1-3: Parameters for fault-ride-through capability of power park modules*
Table 1-4: The table shows the minimum time periods during which a power generating module must be capable of operating for voltage deviation from the reference 1 pu at the connection point without disconnecting from the network. The voltage base for pu values is from 110 kV to 300 kV.

<table>
<thead>
<tr>
<th>Synchronous area</th>
<th>Voltage range</th>
<th>Time period for operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continental Europe</td>
<td>0.85 pu - 0.90 pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td></td>
<td>0.90 pu - 1.118 pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td></td>
<td>1.118 - 1.15 pu</td>
<td>To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes</td>
</tr>
</tbody>
</table>

Table 1-5: The table shows the minimum time periods during which a power generating module must be capable of operating for voltage deviation from the reference 1 pu at the connection point without disconnecting from the network. The voltage base for pu values is from 300 kV to 400 kV.

<table>
<thead>
<tr>
<th>Synchronous area</th>
<th>Voltage range</th>
<th>Time period for operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continental Europe</td>
<td>0.85 pu - 0.90 pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td></td>
<td>0.90 pu - 1.05 pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td></td>
<td>1.05 - 1.10 pu</td>
<td>To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes</td>
</tr>
</tbody>
</table>

Regarding the fault-ride-through capability power generating modules of type D shall be capable of staying connected to the grid and continuing to operate stably after the power system has been disturbed by a symmetrical fault. That capability shall be in accordance with a voltage-against-time profile defined by the relevant TSO in line with Figure 1-4.

The ranges for the parameters are set out in Table 1-6 and Table 1-7, for type D power generating modules connected at or above the 110 kV level, and in Table 1-2 and Table 1-3 for type D power generating modules connected below the 110 kV level.

Table 1-6: Parameters for fault-ride-through capability of synchronous power generating modules

<table>
<thead>
<tr>
<th>Voltage parameters [pu]</th>
<th>Time parameters [seconds]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uret:</td>
<td>0</td>
</tr>
<tr>
<td>tclear:</td>
<td>0.14 - 0.15 ( or 0.14 - 0.25 if system protection and secure operation so require)</td>
</tr>
<tr>
<td>Uclear:</td>
<td>0.25</td>
</tr>
<tr>
<td>trec1:</td>
<td>tclear - 0.45</td>
</tr>
<tr>
<td>Urec1:</td>
<td>0.5 - 0.7</td>
</tr>
<tr>
<td>trec2:</td>
<td>trec1 - 0.7</td>
</tr>
<tr>
<td>Urec2:</td>
<td>0.85 - 0.9</td>
</tr>
<tr>
<td>trec3:</td>
<td>trec2 - 1.5</td>
</tr>
</tbody>
</table>

Continental Europe
Offshore power generating modules connected to the interconnected system shall meet the same requirements for onshore power generating modules, unless the connection of power park modules is via a high voltage direct current connection.

To complete the regulation explanation on grid connection of generators also the Technical Specification of CENELEC, CLC/TS 50549 [9], has been reported. In fact Technical Specification is also intended to serve as a technical reference for the definition of national requirements where European Network Codes requirements allow flexible implementation.

Regarding the high-voltage-ride-through capability of a power generating modules the Network codes [8] does not defines any limits while the technical specification of CENELEC [9] sets also upper limits for the fault-ride-through capability of a power generating modules. Regarding this the regulation defined that a generating plant shall be capable to stay connected to the grid if the voltage at the terminals goes beyond the upper limit of the continuous operating voltage range:

- Up to 120% $U_c$ (1.2 p.u.) for a duration of 100 ms and;
- Up to 115% $U_c$ (1.15 p.u.) for a duration of 1 s.

Where $U_c$ is the declared supply voltage.

### 1.5.2 Voltage characteristic of public distribution system

The standard EN 50160 [10] defines and describes the main characteristic of the supply voltage concerning: frequency, magnitude, wave form and symmetry of the three phase voltages. These characteristics are subject to variations during the normal operation of a supply system due to changes of load, disturbances generated by certain equipment and the occurrence of faults which are mainly caused by external events.
Regarding the characteristic of medium-voltage supply, that means voltage range from 1 kV to 36 kV, the standard gives the ranges briefly described below.

With regards to power frequency range, under normal operating condition the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- 50 Hz ± 1% (i.e. 49.5 - 50.5 Hz) for 99.5% of a year;
- 50 Hz - 6%/+4% (i.e. 47.0 – 52.0 Hz) for 100% of a year.

The first range, valid for 95.5% of the year, has to be view as the range for events more probable like loss of load or increased load demand. While the second range takes into consideration also less frequent events like fault.

With regards to supply voltage variation under normal operating condition, excluding the periods with interruptions, voltage variations should not exceed ± 10% of the declared voltage $U_c$.

Regarding the characteristic of high-voltage supply, i.e. voltage range from 36 kV to 150 kV, the standard gives the ranges described below.

With regards to power frequency range, under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within the same range previously defined for the medium-voltage supply.

As the number of network users supplied directly from HV networks is limited and normally subject to individual contracts, no limits for supply voltage variations are given in this standard.
Chapter 2

Network Layout and Modeling

In this chapter a description of the network Pan-European grid, used for the simulation, is presented. Since the grid comprises RES wind generation a section has been introduced to reviews briefly the different available typology of wind turbines. The dynamics analysis, RMS simulation, available in DigSILENT Power Factory is presented as well as the basis of modelling approach used in this program, with particular detail in the modelling of synchronous generator, wind turbines, loads and converter.

2.1. Network layout

The European HV Benchmark network proposed in the Cigré report [11] laid the foundation for the derived Pan-European test grid for Electra Task 5.4. [12] A synthetic overview of the original Cigré network is reported below before describing the so called “Pan-European” network.

The original Cigré network is shown in Figure 2-1. The network transmission voltages are 220 kV and 380 kV, which are typical in European transmission systems. Generation bus voltages are 22 kV, and the system frequency is 50 Hz. The system is a balanced three-phase HV transmission network, and assumes ideal line transposition. The network consists of 13 buses and covers three geographical areas, referred to as Areas 1, 2, and 3, denoted by dashed lines. Area 1 is predominantly a generation center. Area 2, situated about 500 km from Area 1, is a load center with a small amount of generation available. Area 3 is situated between the main generation Area 1 and the main load center Area 2. Three voltage levels exist in the network: generation bus voltage of 22 kV, primary transmission high voltage of
220 kV, and a long line connecting Area 1 and 2 at the extra high voltage (EHV) level of 380 kV. Bus 6a in Area 3 is a suitable location for studying the incorporation of large-scale renewable energy sources such as wind energy conversion systems.

Since the Cigré grid only represents a pure AC grid and Electra focuses on the future power grid, the grid has been extended with a DC part. In fact High Voltage Direct Current (HVDC) technology will play an important role in the European energy grid system as it could be viable used to connect offshore wind farms to the grid and as interconnectors between countries. Moreover the Cigré grid has been subjected to a revision of the AC side in order to improve load flow convergence. Furthermore, the grid topology has been modified in order to create a more diverse and flexible model while trying to keep it as simple as possible. The network includes a 220 and 400 kV AC grid together with a meshed DC 725 kV grid. In fact the 380 kV AC level has been updated to 400 kV. The DC voltage level has been chosen so that it allows direct connection of HVDC VSC (voltage source converters) without need of internal transformers for stepping down the AC side. The generation units are connected to the 20 kV AC buses (it has been chosen to change the 22 kV level with the more common 20 kV level).

Most of the buses have both conventional and renewable units. The conventional units are either gas turbine or hydraulic power plants. Renewable units are mainly wind turbines type 3 and 4. A more detailed description of the types of wind turbines is reported in the following chapter.
In this grid no PV is included, however from stability point of view, the transient behaviour of a PV system can be compared to the one of type 4 wind turbine, being both units connected with PWM converter.

In the extended Electra grid, shown in Figure 2-2, four cells are identified and the main information for each cell are reported in the Table 2-1 below.

It has to be noted that the loads have been chosen so that it is not possible for the generation units to produce full power at the same time. In this way it is possible to investigate several renewable penetration scenarios, having conventional plant progressively displaced (i.e. physically disconnecting synchronous machines from the network) in order to make room for renewable resources.
Figure 2-2: Pan-European grid
<table>
<thead>
<tr>
<th></th>
<th>Cell 1</th>
<th>Cell 2</th>
<th>Cell 3</th>
<th>Cell 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voltage levels [kV]</strong></td>
<td>20; 220; 400; 725</td>
<td>20; 220; 400</td>
<td>20; 220</td>
<td>220; 400; 725</td>
</tr>
<tr>
<td><strong>AC/DC</strong></td>
<td>AC and DC</td>
<td>AC</td>
<td>AC</td>
<td>AC and DC</td>
</tr>
<tr>
<td><strong>Nominal generation power</strong></td>
<td>2x500 MVA Synchronous machines (gas turbine governor) 65x6 MW (type 3 wind turbines)</td>
<td>2x500 MVA Synchronous machines (hydraulic governor) 65x6MW (type 3 wind turbines)</td>
<td>2x500 MVA equivalent wind generation (type 4)</td>
<td></td>
</tr>
<tr>
<td><strong>Nominal consumption power</strong></td>
<td>2x500 MW+ j 2x165 MVar loads</td>
<td>3x400 MW+ j 3x130 MVar loads</td>
<td>1x400 MW+ j 1x130 MVar loads</td>
<td>no load</td>
</tr>
<tr>
<td><strong>Number of tie-lines</strong></td>
<td>Cell 1-2 : 2 AC 220 kV tie lines</td>
<td>Cell 2-1 : 2 AC 220 kV tie lines</td>
<td>Cell 3-1 : 2 AC 220 kV tie lines</td>
<td>Cell 4-1 : 1 AC 400 kV tie line</td>
</tr>
<tr>
<td></td>
<td>Cell 1-3 : 2 AC 220 kV tie lines</td>
<td>Cell 2-4 : 2 AC 400 kV tie lines</td>
<td>Cell 3-2 : 1 AC 220 kV tie line</td>
<td>Cell 4-1 : 1 DC 725 kV tie line</td>
</tr>
<tr>
<td></td>
<td>Cell 1-4 : 1 AC 400 kV tie line</td>
<td>Cell 2-3 : 1 AC 220 kV tie line</td>
<td>Cell 3-4 : 1 220/400 kV transformer</td>
<td>Cell 4-2 : 2 AC 400 kV tie lines</td>
</tr>
<tr>
<td></td>
<td>Cell 1-4 : 1 DC 725 kV tie line</td>
<td>Cell 2-3 : 1 AC 220 kV tie line</td>
<td>Cell 3-4 : 1 AC 220 kV tie line</td>
<td>Cell 4-3 : 1 220/400 kV transformer</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Cell 4-3 : 1 AC 220 kV tie line</td>
</tr>
<tr>
<td><strong>Number of internal lines</strong></td>
<td>2 x 220 kV lines</td>
<td>4 x 220 kV lines</td>
<td>3 x 220 kV lines</td>
<td>3 x 725 kV lines</td>
</tr>
<tr>
<td><strong>Nominal HVDC capacity</strong></td>
<td>2 x 500 MVA PWM converters</td>
<td>no PWM converters</td>
<td>no PWM converters</td>
<td>3 x 500 MVA PWM converters</td>
</tr>
</tbody>
</table>

*Table 2-1: Overview of cell generation and consumption level*
2.2. Wind turbine

Beyond mechanical power regulation, turbines are further divided into fixed speed (Type 1), limited variable speed (Type 2), or variable speed with either partial (Type 3) or full (Type 4) power electronic conversion [13].

Type 1 wind turbine generator (WTG) is implemented with a squirrel-cage induction generator and is connected to a step-up transformer directly. The turbine speed is fixed to the electrical grid’s frequency, and generates real power when the turbine shaft rotates faster than the electrical grid frequency.

Type 2 turbines, wound rotor induction generators are connected directly to the WTG step-up transformer in a fashion similar to Type 1, but also include a variable resistor in the rotor circuit. Adding resistance to the rotor circuit allows some ability to control the speed to achieve the best energy capture.

The Type 3 turbine, known commonly as the Doubly Fed Induction Generator (DFIG), consist of a wound rotor induction generators with the stator windings directly connected to the three-phase grid by a step-up transformer and with the rotor windings connected to a back-to-back partial scale power converter. The back-to-back converter is a bi-directional partial scale power converter. It consists of two independent controlled voltage source converters connected to a common DC-bus. These converters are illustrated in Figure 2-3 [14], as rotor-side converter and grid-side converter. The behaviour of the generator is governed by these converters and their controllers both in normal and fault conditions. The converters control the rotor voltage in magnitude and phase angle and are therefore used for active and reactive power control.
A small amount of power injected into the rotor circuit can affect a large control of power in the stator circuit. This is a major advantage of the DFIG — a great deal of control of the output is available with the presence of a set of converters that typically are only 30% of the rating of the machine. In addition to the real power that is delivered to the grid from the generator’s stator circuit, power is delivered to the grid through the grid-connected inverter when the generator is moving faster than synchronous speed (over-synchronous operating area, s<0) as could be seen in Figure 2-3. When the generator is moving slower than synchronous speed (sub-synchronous operating area, s>0), real power flows from the grid, through both converters, and from rotor to stator. This is the reason why a back-to-back PWM (bi-directional) converter configuration is used.

The greatest advantage of the DFIG, is that it offers the benefits of separate active and reactive power control by independent control of the rotor excitation current, much like a traditional synchronous generator, while being able to run asynchronously. DFIG is therefore capable of producing or absorbing reactive power to or from the grid, with the purpose of voltage control.

The control system of a variable speed wind turbine with DFIG has as goals to control the reactive power interchanged between the generator and the grid and the active power drawn from the wind turbine in order to track the wind turbine optimum operation point or to limit the power in the case of high wind speeds.
The overall control system, shown in Figure 2-4 [14], of a variable speed DFIG wind turbine is built up with a hierarchical structure. It consists of two control levels with different bandwidths, strongly connected to each other. A slow dynamic control level named wind turbine control and a faster control, DFIG control.

The fast dynamic control level, i.e. DFIG control, encompasses the electrical control of the power converters and of the doubly-fed induction generator. Since this controller is an electric one, it works very fast. The DFIG control level has as goal to control the active and reactive power of the wind turbine independently. The DFIG control contains two controllers:

- **Rotor-side converter controller**: that controls independently the active and reactive power on the grid point M. The active power set-point $p_{grid}^{ref}$ for the RSC is defined, in normal operating condition, by the maximum power tracking point (MPT) as a function of the optimal generator speed: for each wind speed there is only one generator speed resulting in maximum aerodynamics coefficient $C_p$. The reactive power set-point $Q_{grid}^{ref}$ for the RSC can be set to a certain value or to zero according whether or not the DFIG is required to contribute with reactive power.

- **Grid-side converter controller**: that controls the DC link voltage $U_{DC}$ and guarantees unity power factor in the rotor branch. The transmission of the reactive power from DFIG to the grid is thus only through the stator.

On the other hand, the wind turbine control is a control with slow dynamic responses. It contains two cross-coupled controllers: a speed controller and a power limitation controller. It supervises both the pitch angle actuator system of the wind turbine and the active power set-point of the DFIG control level. It thus provides both a reference pitch angle $\theta_{ref}$ directly to the pitch actuator and a converter reference power signal $p_{grid}^{conv}^{ref}$ to the DFIG control.
In case of grid fault, the generator speed variation is not due to the wind speed change but due to electrical torque reduction. This means that the active power set-point $p_{\text{grid}}^{\text{conv,ref}}$ for the RSC has to be defined differently in case of grid fault, i.e. as the output of a damping controller. This controller has the task of damping the torsional oscillations that are excited in the drive train owing to the grid fault. When a fault is detected, the definition of the active power set-point is switched between the normal operation definition (i.e. MPT) and the fault operation definition (damping controller) as could be seen in Figure 2-5.

In case of grid fault, the PI damping controller produces the active power reference signal for the RSC control based on the deviation between the actual generator speed and its reference. The speed reference is defined by the optimal speed curve at the incoming wind.
Type 3 wind turbine has been used in the Pan-European grid for the three wind turbine units connected in the AC grid part, instead for the wind turbine unit in Cell 4 has been used a wind turbine of type 4, which is briefly described above.

The Type 4 turbine offers a great deal of flexibility in design and operation as the output of the rotating machine is sent to the grid through a full-scale back-to-back frequency converter. The turbine is allowed to rotate at its optimal aerodynamic speed, resulting in a “wild” AC output from the machine. In addition, the gearbox may be eliminated, such that the machine spins at the slow turbine speed and generates an electrical frequency well below that of the grid. This is no problem for a Type 4 turbine, as the inverters convert the power, and offer the possibility of reactive power supply to the grid, much like a STATCOM. The rotating machines of this type have been constructed as wound rotor synchronous machines, similar to conventional generators found in hydroelectric plants with control of the field current and high pole numbers, as permanent magnet synchronous machines, or as squirrel cage induction machines. However, based upon the ability of the machine side inverter to control real and reactive power flow, any type of machine could be used. Advances in power electronic devices and controls in the last decade have made the converters both responsive and efficient. It does bear mentioning, however, that the power electronic converters have to be sized to pass the full rating of the rotating machine, plus any capacity to be used for reactive compensation.
2.3. **Dynamics analysis – RMS Simulation in DlgSILENT PowerFactory**

The dynamics simulation functions available in DlgSILENT PowerFactory are able to analyze the dynamic behaviour of small systems and large power systems in the time domain. These functions therefore make it possible to model complex systems such as industrial networks and large transmission grids in detail, taking into account electrical and mechanical parameters [7].

The study of power system stability involves the analysis of the behaviour of power systems under conditions before and after sudden changes in load or generation, during faults and outages. The robustness of a system is defined by the ability of the system to maintain stable operation under normal and perturbed conditions. It is therefore necessary to design and operate a power system so that transient events (i.e. probable contingencies), can be withstood without the loss of load or loss of synchronism in the power system. Transients in electrical power systems can be classified according to three possible timeframes:

- Short-term, or electromagnetic transients;
- Mid-term, or electromechanical transients;
- Long-term transients.

The multilevel modelling of power system elements and the use of advanced algorithms means that the functions in PowerFactory can analyze the complete range of transient phenomena in electrical power systems. Consequently, there are three different simulation functions available:

- A basic function which uses a symmetrical steady-state (RMS) network model for mid-term and long-term transients under balanced network conditions;
- A three-phase function which uses a steady-state (RMS) network model for mid-term and long-term transients under balanced and unbalanced network conditions, i.e. for analyzing dynamic behaviour after asymmetrical faults;
- An electromagnetic transient (EMT) simulation function using a dynamic network model for electromagnetic and electromechanical transients under balanced and unbalanced network conditions. This function is particularly suited to the analysis of short-term transients.
To carry out transient stability studies in this project the first type of simulation has been used (Balance RMS simulation) because only a symmetrical fault and balance events have to be analyzed. The balanced RMS simulation function considers dynamics in electromechanical, control and thermal devices. It uses a symmetrical, steady-state representation of the passive electrical network. Using this representation, only the fundamental components of voltages and currents are taken into account. Because of the symmetrical network representation, the basic simulation function allows the insertion of symmetrical faults only.

Time-domain simulations in PowerFactory are initialized by a valid load flow, and PowerFactory functions determine the initial conditions for all power system elements including all controller units and mechanical components. These initial conditions represent the steady-state operating point at the beginning of the simulation, fulfilling the requirements that the derivatives of all state variables of loads, machines, controllers, etc., are zero.

Before the start of the simulation process, it is also determined what type of network representation must be used for further analysis, what step sizes to use, which events to handle and where to store the results.

In the Initial Conditions command (ComInc) dialogue, see Figure 2-6, all simulation settings can be defined, such as the simulation type (i.e. RMS or EMT, balanced or unbalanced) and simulation step size settings.
The process of performing a transient simulation typically involves the following steps:

- Calculation of initial values, including a load flow calculation;
- Definition of result variables and/or simulation events;
- Optional definition of result graphs and/or other virtual instruments;
- Execution of simulation;
- Creating additional result graphs or virtual instruments, or editing existing ones;
- Changing settings, repeating calculations;
- Printing results.

During an EMT or RMS simulation, a large number of signal variables are changing over time. To reduce the available data and to narrow down the number of variables to those necessary for the analysis of each particular case, a selection of these signals for later use has to be defined. In this way it is necessary to define for each grid element which variables should be calculated, choosing from different category lists, such as Calculation Parameter, Element Parameter, Type Parameter, Reference Parameter, Bus Results, Signals and Currents, Voltages and Powers. As example in Figure 2-7 a variables selection window is shown. Therefore, one or more result objects containing the result variables can be configured. The simulation function needs the reference to a result object to store the results.
Stability analysis calculations are typically based on predefined system models. In the majority of cases the standard IEEE definitions for controllers, prime movers and other associated devices and functions are used. Anyway it is otherwise possible to improve the system model not using the IEEE standard models, but instead building a new block diagram of the individual controller/mechanical system to represent the device. This facilitates highly accurate system modelling.

The PowerFactory modelling philosophy is targeted towards a strictly hierarchical system modelling approach, which combines both graphical and script-based modelling methods. All the data, which represents power system Elements, Single Line Diagrams, Study Cases, system Operation Scenarios, calculation commands, program Settings etc., are stored as objects inside a hierarchical set of folders. The folders are arranged in order to facilitate the definition of the studies and optimize the use of the tools provided by the program. The objects are grouped according to the kind of element that they represent. These groups are known as ‘Classes’ within the PowerFactory environment.

The basis for the modelling approach is formed by the basic hierarchical levels of time-domain modelling:

- The **DSL block definitions**, based on the "DIgSILENT Simulation Language" (DSL), form the basic building blocks to represent transfer functions and differential equations for the more complex transient models.
• The **built-in models** and **common models**. The built-in models or elements are the transient PowerFactory models for standard power system equipment, i.e. for generators, motors, static VAR compensators, etc. The common models are based on the DSL block definitions and are the front-end of the user-defined transient models.

• The **composite models** are based on **composite frames** and are used to combine and interconnect several elements (built-in models) and/or common models. The composite frames enable the reuse of the basic structure of the composite model.

The following part explains the relationships between the Composite Model (which is using a Frame as type) and the Common Model (based on a block diagram as type) in detail.

The Composite Model (ElmComp) references the definition of a composite frame. This composite frame is basically a schematic diagram containing various empty slots, in which controller or elements can be assigned. These slots are then interconnected according to the diagram. The slots in the composite frame are pre-configured for specific transient models.

The Composite Frame (BlkDef) has different slots which are interconnected according to the diagram. The composite model, which uses this composite frame, shows a list of the available slots and the name of the slot, as can be seen in Figure 2-8.

The Built-In Models are pre-configured elements which do not need a specific model definition. Any kind of element which is able to provide input or output variables, e.g. converters, busbars, etc, can be inserted into the slots.

The Common Models (ElmDsl) combines a model definition with specific parameter settings. There are predefined definitions as well, so that the user can create his own model.
definitions. The common model has a reference to the Model Definition (BlkDef), which looks similar to the composite frame. Here different blocks are defined and connected together according to the diagram. The input and output variables have to fit with the slot definition of the slot that the model is defined for. Usually not all slots of the composite model must necessarily be used: there can also be empty slots. In such cases, the input of this slot is unused and the output is assumed to be constant over the entire simulation.

2.4. Grid elements modeling in PowerFactory

2.1.1. Synchronous Generator

As presented in paragraph 2.1 the grid is fed by 8 conventional units, i.e. synchronous generator power plants. It has been decided to equip them with either a gas turbine governor or a hydraulic governor; the excitation system is similar for all of them. Both of them have been represented in PowerFactory with the predefined standard models. A brief description of the used model is reported in the following section.

For the governor modeling of gas turbine power plants has been used the standard model GOV_GAST (Gas turbine governor). It represents the principal dynamic characteristics of industrial gas turbines driving generators connected to electric power system [7]. The model consists of a forward path with governor time constant and a combustion chamber time constant, together with a load-limiting feedback path. The load limit is sensitive to turbine exhaust temperature, and the time constant to represent the exhaust gas measuring system is considered. For the excitation system has been used the standard model avr_IEEET1, named 1968 IEEE type 1 excitation system. This model is widely used to represent systems with shunt dc exciters as well as systems with alternator exciters and uncontrolled shaft-mounted rectifier bridges.

For the governor modelling of hydraulic power plants has been used the standard model HYGOV (Hydraulic turbine governor). It represents a straightforward hydroelectric plant governor, with a simple hydraulic representation of the penstock with unrestricted head race and tail race, and no surge tank. For the excitation system has been used the same standard model used for the gas turbine power plants, i.e. avr_IEEET1 (1968 IEEE type 1 excitation system).
2.1.2.  Wind turbine (DFIG Generators)

For modelling the DFIG wind turbines have been used the predefined template “DFIG WTG xMW” for Wind turbine models in the Templates Library of PowerFactory. This template is a generic model of a wind turbine with a doubly fed induction generator. The model represents one wind turbine but the number of parallel machines can be also changed. The model accounts for the PQ characteristic and short-circuit contribution of the generator (steady-state analysis), the dynamic controllers of the DFIG and converters as well as the mechanical part of the rotor and the aerodynamics. The model from the template is equipped with the 20kV transformer.

The doubly fed induction generator (DFIG) is represented, in the single line diagram, by an asynchronous machine which is configured as a DFIG. The model of the controller and the dynamic parts are collected in the composite model DFIG Control. The composite model DFIG Control is created from the frame definition Generic DFIG-Turbine_resync. The graphical definition of this frame is shown in Figure 2-9.

![Figure 2-9: Frame definition generic DFIG-Turbine_resync(.*BlkDef)](image)
The single slots are briefly described in Table 2-2. Each slot could be filled with either a DSL model, a measurement device or a PowerFactory element, such as an asynchronous machine. All measurement devices are connected either to the terminal or to the cubicle, which connects the generator with the terminal.

<table>
<thead>
<tr>
<th>Slot name</th>
<th>Description</th>
<th>Needed type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compensation</td>
<td>This models calculates a coordinate transformation of the rotor voltage</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>Current Measurement</td>
<td>Calculates the rotor current from angle and id/iq of the DFIG</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>DFIG</td>
<td>Asynchronous machine, configured as DFIG</td>
<td>*.ElmAsm</td>
</tr>
<tr>
<td>Ir-ctrl</td>
<td>Calculates a rotor reference voltage for a given rotor current set point</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>MPT</td>
<td>Maximum power tracker, calculates optimal speed for max. power</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>OverFreq Pwr Reduction</td>
<td>Reduces the power in case of electrical over frequency</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>Pitch Control</td>
<td>Controls the pitch angle of the rotor</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>PQ Control</td>
<td>Controls active and reactive power through the rotor current</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>PQ_tot</td>
<td>Active and reactive power measurement device</td>
<td>*.StaPmea</td>
</tr>
<tr>
<td>Protection</td>
<td>Triggers bypass, in case of high rotor current, high speed or over voltage. Could also disconnect and resynchronize the DFIG</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>Shaft</td>
<td>Calculates from wind power and generator speed the mechanical power and the rotor speed</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>SlowFrequMeas</td>
<td>Slow frequency measurement device (PLL)</td>
<td>*.ElmPhi</td>
</tr>
<tr>
<td>Speed-Ctrl</td>
<td>Calculates a reference power from speed and reference speed</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>SpeedRef</td>
<td>Reference speed, needed only for initialisation of the mechanical generator speed</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>Theta meas.</td>
<td>Fast frequency and voltage angle measurement device (PLL)</td>
<td>*.ElmPhi</td>
</tr>
<tr>
<td>Turbine</td>
<td>Calculates from pitch angle, rotor speed and wind speed the wind power</td>
<td>DSL-Model</td>
</tr>
<tr>
<td>Vac_bus</td>
<td>AC-voltage measurement device on bus side</td>
<td>*.StaVmea</td>
</tr>
<tr>
<td>Vac_gen</td>
<td>AC-voltage measurement device on generator side</td>
<td>*.StaVmea</td>
</tr>
</tbody>
</table>

Table 2-2: Frame description of DFIG composite frame

Should be noted that the Speed-Ctrl block definition in the composite frame contains the block PI that has the task to damp the torsional oscillation excited at a grid fault in the drive train system as explained in Chapter 2.2. As could be seen in Figure 2-10 the controller give the reference power signal to the next controller through the PI controller from the difference between the speed and the reference speed coming from the MPT controller.
2.1.3. Load

Loads could be modeled according to the classic ZIP (impedance Z, current I and power P) theory [15]. The polynomial model, commonly referred as ZIP model, has been widely used to present the voltage dependency of loads.

\[ P = P_0[\eta_1 \bar{V}^2 + \eta_2 \bar{V} + \eta_3] \]  
\[ Q = Q_0[\zeta_1 \bar{V}^2 + \zeta_2 \bar{V} + \zeta_3] \]  

(2-1)  
(2-2)

In the equations (2-1) and (2-2) \( \bar{V} = \frac{V}{V_0} \) and \( V_0, P_0, Q_0 \) are rated values. The proportion of each component is defined by the coefficients \( \eta_1 \) to \( \eta_3 \) with the relation \( \eta_1 + \eta_2 + \eta_3 = 1 \), and \( \zeta_1 \) to \( \zeta_3 \), \( \zeta_1 + \zeta_2 + \zeta_3 = 1 \). Loads are also been modeled to have frequency dependency.

In PowerFactory the dynamic voltage and frequency dependency of loads is represented by the block diagrams shown in Figure 2-11.
Figure 2-11: Model used to approximate the behavior of the non-linear dynamic load

The values of the parameters, used for the frequency dependency of loads in the block diagrams, are usually $k_{pf} = \frac{\partial P}{\partial f} = 0 \sim 3.0$ and $k_{qf} = \frac{\partial Q}{\partial f} = -2.0 \sim 0$. [15]

As the block diagram shown in Figure 2-11 represents small signal models, it is only valid over a limited voltage range. This range is defined by the variables $u_{min}$ and $u_{max}$, defined respectively in the model 0.8 and 1.2. When the voltage is outside of this threshold the load is converted to constant impedance load to avoid computational problems.

For modelling the voltage dependency of load in PowerFactory are used three polynomial terms as shown in (2-3) and (2-4).

\[
P = P_0 \left( aP \cdot \left( \frac{V}{V_0} \right)^{e,aP} + bP \cdot \left( \frac{V}{V_0} \right)^{e,bP} + (1 - aP - bP) \cdot \left( \frac{V}{V_0} \right)^{e,cP} \right) \quad (2-3)
\]

\[
Q = Q_0 \left( aQ \cdot \left( \frac{V}{V_0} \right)^{e,aQ} + bQ \cdot \left( \frac{V}{V_0} \right)^{e,bQ} + (1 - aQ - bQ) \cdot \left( \frac{V}{V_0} \right)^{e,cQ} \right) \quad (2-4)
\]

In equation (2-3) and (2-4), the subscript “0” indicates the operating point values as defined on the Load Flow page of the load element dialog and $1 - aP - bP$ is equal to $cP$ and
$1 - aQ - bQ = cQ$. The exponents $e_{aP}, e_{bP}, e_{cP}$ and $e_{aQ}, e_{bQ}, e_{cQ}$ could be 0,1 and 2 respectively. The load behaviour can be modelled by specifying the values of the parameters $aP, bP$ and $aQ, bQ$, as shown in Table 2-3, on the Load Flow page in the dialog of the general load type.

<table>
<thead>
<tr>
<th>constant</th>
<th>power</th>
<th>current</th>
<th>impedance</th>
</tr>
</thead>
<tbody>
<tr>
<td>$aP, aQ$</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$bP, bQ$</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>$cP=1-aP-bP$</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>$CQ=1-aQ-bQ$</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 2-3: Selection of values for different load model behaviour

In the analysis it has been assumed that the loads have a frequency-dependent behaviour, in fact in the case of motor loads, such fans and pumps, the electrical power changes with frequency due to changes in motor speed. Moreover it has been assumed that the active power consumption is linearly dependent on voltage value (constant current behaviour $aP = 0, bP = 1$) and linearly dependent on frequency, i.e. $k_{pf} = \frac{\partial p}{\partial f} = 1.5$. The reactive power consumption is quadratically dependent on voltage (constant impedance behaviour $aQ = 0, bQ = 0$) and inversely dependent on frequency, i.e. $k_{qf} = \frac{\partial q}{\partial f} = -1$.

2.1.4. **HVDC capacitors**

In the HVDC grid has been inserted five DC capacitors in the buses where the converters are connected. The DC capacitors are the energy storage elements for VSC (voltage-source-converter) and they have several primary function:

- They provide a low-inductance path for switch turnoff current;
- They provide temporary energy storage between the switching instant, stabilizing high frequency dynamics;
- They reduce the DC voltage harmonic ripple;
- They decrease the harmonics coupling between different VSC substations connected to the same DC bus.

For estimate the capacitor size it is possible to use a practical formula [16].
\[ C_{dc} = \frac{2 S_{VSC} E_s}{V_{dc}^2} \]  

(2-5)

Where \( S_{VSC} \) is the converter MVA rating, \( V_{dc} \) is the rated DC voltage and \( E_s \) [J/VA] is the energy-to-power ratio, in practical converters is \( 10 \text{ (kJ/MVA)} < E_s < 50 \text{ (kJ/MVA)} \). In the analyzed case \( E_s \) has been considered as \( 20 \text{ kJ/MVA} \) and the resulting capacitor size is \( 38 \mu F \).

### 2.1.5. Converters

In the analyzed grid there are 5 converters, PWM 1.2, PWM 4.1, PWM 4.2, PWM 4.3 and PWM 4.8. The latter is the one of the offshore wind park instead others are part of the onshore grid. The converter PWM 4.3 is configured as a master controller for the DC voltage. Indeed has been used a master-slave control [17]. Only one converter in the DC grid is configured to constant DC mode while all the others are configured to constant power mode, as slave terminals. In the DC grid there is also a wind park so the controller in that terminal, PWM 4.8, must control the frequency, for give it a reference, and the AC voltage.

Basically in this grid have been used three different types of controller: Controller_Vac_Vdc, for the master converter, Controller_P_Vac, for the slave PWM, and Controller_Vac_freq for the converter of the offshore wind park. Consequently three types of frame have been used: Frame_Vac_Vdc, Frame_P_Vac and Frame_Vac_freq. A description of all the types of controllers and frames used in the grid is reported below.

- **Controller_P_Vac**

![Figure 2-12: Block definition of the Controller_P_Vac](image)
This type of controller is used as model definition for the main controller of the converters PWM 1.2, PWM 4.1 and PWM 4.2 named respectively Common Model_P_Vac_1.2, Common Model_P_Vac_4.1 and Common Model_P_Vac_4.2.

The controller, shown in Figure 2-12, has as an input the AC voltage $u_{ac}$ and the power $P_{in}$, coming from measurement in the related bus. The measurement delay is represented by a first order delay block $\frac{1}{1+sT}$ in the scheme. After this first block there is a comparison with the real reference magnitude: $p_{ref}$, for the power, and $u_{ac ref}$, for the voltage. The resulting errors are inserted into a PI block $kp + \frac{ki}{s}$ that gives as output the currents $id_{ref}$ and $iq_{ref}$. These two currents are used as an input for a limits block which is necessary for link the magnitude of the two currents. In fact the currents $id$ and $iq$ are linked by the relation $I = \sqrt{id^2 + iq^2}$ and the amplitude is been fixed at $I = 1.1 \, p.u$. This relation is also explained in Figure 2-13.

![Figure 2-13: Current limit characteristic of onshore controller](image)

The relationship between the two current has been inserted in the block definition of the Limits_id_iq block as could be seen in Figure 2-14.

![Figure 2-14: Additional equation added in the block definition of the limits block to link the magnitude of the id and iq current](image)
This controller finally has as outputs the reference current $id_{ref}$ and $iq_{ref}$.

After modelling the controller it is very important to set the correct initial condition. The initial conditions are calculated so that the first derivative of the equation is equal to zero (i.e. steady state condition). Initial condition should be calculated for all the state variables used in the blocks. For example for the measurement delay block the state variable is $x$ and the block definition equations are: $yo = x$ and $x = \frac{yi - x}{T}$. For the steady state condition $x = 0$ so $x = yi = yo$. Consequently the initial condition for the variable $x$ must be equal to the input variable that is $P_{in}$. Doing the same for the measurement delay of the voltage (state variables = $x2$), the initial condition obtained is $inc(x2) = uac$.

In the case of the PI blocks for the d axes the state variable is $x1$ and for the q axes the state variable is $x3$ and the block definition equations are: $yo = x$ and $x = ki * yi$. For steady state condition $x = 0$ so $x = yi = yo$ and the initial conditions of the state variables of these block are $inc(x1) = id_{ref}$ and $inc(x3) = iq_{ref}$.

It’s necessary to put also an initial value for the currents $id_{ref}$ and $iq_{ref}$, this value could be a random value. In steady state $id_{ref} = id_{ref}$ and $iq_{ref} = iq_{ref}$ so $inc(id_{ref}) = id_{ref}$ and $inc(iq_{ref}) = iq_{ref}$.

The reference values of power and voltage $pref$ and $uacref$ are been settled equal to the measured one: $inc(uacref) = uac$ and $inc(pref) = P_{in}$.

In Figure 2-15 are shown the initial condition of all the state variables in the controller.

![Block Definition - User Defined Model](image)

Figure 2-15: Additional equation added in the block definition of the controller to settle the initial condition
For all the three common model associated with this controller (Common Model_P_Vac_1.2, Common Model_P_Vac_4.1, Common Model_P_Vac_4.2) have been used same values for the parameters $Trudc$, $Truac$, $Kpd$, $Kid$, $Kpq$ and $Kiq$ of the blocks. The values assigned are reported in Table 2-4:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Trudc$</td>
<td>0.001</td>
</tr>
<tr>
<td>$Truac$</td>
<td>0.001</td>
</tr>
<tr>
<td>$Kpd$</td>
<td>10</td>
</tr>
<tr>
<td>$Kid$</td>
<td>10</td>
</tr>
<tr>
<td>$Kpq$</td>
<td>10</td>
</tr>
<tr>
<td>$Kiq$</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 2-4: Values for the parameters used in the Common Model_P_Vac

- **Frame_P_Vac**

In the frame shown in Figure 2-16 there are two main slots, Main Controller and Converter, and three measurement slots: AC-Voltage, for the AC voltage measurement, PQ_Measurement_onsh, for the power measurement, and PLL for the Phase measurement device. This device is used for the measurement of $\cos \phi$ and $\sin \phi$. The slot Main Controller is related to the Controller_P_Vac described before while the Converter slot has been linked
to the relative PWM converter. This frame has been associated with three composite models: Onshore Controller_P_1.2, Onshore Controller_P_4.1 and Onshore Controller_P_4.2.

- **Controller_Vac_Vdc**

This type of controller, shown in Figure 2-17, is used as model definition for the main controller of only the converters PWM 4.3 named Common Model_Vac_Vdc_4.3. In fact, as said before, the converter 4.3 is the master controller for the DC grid and has the task to control the DC voltage.

![Block definition of the controller of the converter 4.3](image)

*Figure 2-17: Block definition of the controller of the converter 4.3*

This type of controller is similar to Controller_P_Vac but it differs in the input; instead of the active power measurement the input is the DC voltage $u_{dc}$ coming from a real measurement in the relative bus. Initial condition of all the state variables in the controller has been calculated in the same way as explained for the slave controller. Their values are shown in Figure 2-18.
For the Common Model_Vac_Vdc_4.3, associated with this controller, have been utilized the same values used in the previous common model for the parameters $T_{r\Delta C}$, $T_{r\Delta C}$, $K_{p\Delta}$, $K_{i\Delta}$, $K_{p\Delta}$, and $K_{i\Delta}$ of the blocks. The values are reported in Table 2-4.

- **Frame_Vac_Vdc**

In the frame shown in Figure 2-19 there are two main slots, Main Controller and Converter, and three measurement slots: AC-Voltage, for the AC voltage measurement, DC-Voltage for the DC voltage measurement, and PLL for the Phase measurement device. This device is used for the measurement of $\cos \phi$ and $\sin \phi$. 
The slot Main Controller is related to the Controller_Vac_Vdc described before while the Converter slot has been linked to the relative PWM converter. This frame has been associated with the composite model Onshore Controller_4.3.

- **Controller_Vac_freq**

![Block definition of the controller of the converter 4.8](image)

Figure 2-20: Block definition of the controller of the converter 4.8

This type of controller, shown in Figure 2-20, is used as a model definition for the main controller of the offshore wind park PWM 4.8 named CommonModel_Vac_freq.

This controller has as an input the AC voltage, $u_{ac}$, coming from a measurement made in the relative bus. For keep in consideration the measurement delay a first order delay block has been inserted. After that has been made a comparison with the real reference magnitude, $u_{acref}$. The resulting error is inserted into a PI block with upper and lower limits. This mean that the output value must be 0 if the condition $(Kp \cdot y_i + x) \geq y_{max}$ or the condition $(Kp \cdot y_i + x) \leq y_{min}$ are met. Otherwise the value must be $\frac{y_i}{T_i}$. The upper and the lower limitation in this case are $i_{max}$ and $i_{min}$. The output of the PI block is the quadrature axis current $I_q\_ref$. This current has then been compared with the real $i_q$ current coming from a feedback loops. Like the other controllers the resulting error is inserted into a PI blocks with upper and lower limits, $Uac\_max$ and $\_min$. The resulting values, $uaci$, is
then inserted with the DC voltage, $u_{dc}$, coming from a measurement in the relative bus, in a block called Uac/Udc-Pm relation. This type of block explains the relation between the AC voltage/DC voltage and the pulse-width amplification factor Pm of the PWM. This relation is shown in Figure 2-21.

![Figure 2-21: PWM converters characteristic](image)

The nonlinear relation between Uac/Udc and Pm could be approximated with five linear relations as shown in Table 2-5.

<table>
<thead>
<tr>
<th>Pm&lt;1</th>
<th>Uac/Udc&lt;0.6</th>
<th>$pm1 = \frac{u_{aci}}{u_{dc1}} \cdot 0.6$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 &lt; Pm &gt; 1.25</td>
<td>0.6 &lt; Uac/Udc &gt; 0.69</td>
<td>$pm2 = \frac{u_{aci}}{u_{dc1}} - \frac{0.24}{0.36}$</td>
</tr>
<tr>
<td>1.25 &lt; Pm &gt; 1.5</td>
<td>0.69 &lt; Uac/Udc &gt; 0.72</td>
<td>$pm3 = \frac{u_{aci}}{u_{dc1}} - \frac{0.54}{0.12}$</td>
</tr>
<tr>
<td>1.5 &lt; Pm &gt; 2</td>
<td>0.72 &lt; Uac/Udc &gt; 0.75</td>
<td>$pm4 = \frac{u_{aci}}{u_{dc1}} - \frac{0.63}{0.06}$</td>
</tr>
<tr>
<td>2 &lt; Pm &gt; 3</td>
<td>0.75 &lt; Uac/Udc &gt; 0.76</td>
<td>$pm5 = \frac{u_{aci}}{u_{dc1}} - \frac{0.73}{0.01}$</td>
</tr>
</tbody>
</table>

*Table 2-5: Linear relation for approximate the PWM converter characteristic*
The output of the Controller_Vac_freq are the pulse-width amplification factor Pm and the constant reference frequency fo.

Initial conditions of all the state variables in the controller are calculated in the same way as before as could be seen in Figure 2-22. For the measurement delay block with the state variable xu the block definition equations are yo = x and \( x = \frac{yi-x}{T} \) and for steady state should be \( x = 0 \). For steady state condition \( x = yi = yo \) that implies that \( inc(xu) = uac \).

For the first PI controller with limits, state variable \( x1 \), the initial condition must be \( inc(x1) = 0 \). In fact

\[
x = select((Kp * yi + x) >= y_{max}), or. ((Kp * yi + x) <= y_{min}), 0, yi/Ti)
\]

\[
yo = lim(Kp * yi + x, y_{min}, y_{max})
\]

And for have \( x = 0 \) the variable \( yi \) must be equal to zero and from the second equation \( yi = 0 \) means \( x = yo \). In this case \( yo \) must be 0 in steady state. Doing the same for the second PI controller with limits, state variable \( x2 \), for having \( x = yo \) the variable \( x2 \) must be equal to \( uaci \) but from the relation \( Pm = \frac{uac}{udc} * 1/0.6 \) and \( uac = Pm * udc * 0.6 \) so \( inc(x2) = Pm * udc * 0.6 \).

![Block Definition - User Defined Model](PWM Converter Control\Controller_Vac_freq.BldDef)

*Figure 2-22: Additional equation added in the block definition of the controller to settle the initial condition*
This controller has been associated to a Common Model_Vac_freq. The values assigned to the parameters $K_{u_ac}$, $T_{u_ac}$, $K_{i_ac}$, $T_{i_ac}$, $F_{ref}$, $T_{filter_U}$, $i_{min}$, $U_{ac\_min}$, $I_{max}$ and $U_{ac\_max}$ of the blocks are reported in Table 2-6.

\[
\begin{array}{|c|c|}
\hline
\text{Parameter} & \text{Value} \\
\hline
K_{u_ac} & 2 \\
T_{u_ac} & 0.2 \\
K_{i_ac} & 2 \\
T_{i_ac} & 0.02 \\
F_{ref} & 1 \\
T_{filter_U} & 0.005 \\
i_{min} & -0.7 \\
U_{ac\_min} & -0.1 \\
I_{max} & 0.7 \\
U_{ac\_max} & 1.1 \\
\hline
\end{array}
\]

*Table 2-6: Values of the parameters used in Common Model_Vac_freq*

- **Frame_Vac_freq**

In the frame shown in Figure 2-23 there are two main slots, Controller and Offshore VSC, and two measurement slots: AC-Voltage, for the ac voltage measurement and DC-Voltage.
for the dc voltage measurement. The slot Controller is related to the Controller_Vac_freq described in the previous section while the Offshore VSC slot is been linked to the relative PWM converter. This Frame has been associated with the Composite Model Offshore Controller_4.8
Chapter 3

Scenarios Definition

To study the behavior of the Pan-European grid in the Task 5.4 of the project ELECTRA, have been decided to define eight scenarios with different cases of penetration of renewable energy sources (RES). In this chapter has been reported the description and the configuration of all eight scenarios. Since not all of them have been used for performing the simulation in this thesis a specific subparagraph has been inserted to motivate the choice. In the final part of this chapter it is reported a briefly review of regulation’s voltage and frequency limits that has to be taken into account in light of the grid characteristics.

3.1. Scenario definition

The behavior of the Pan-European grid is been analyzed by define eight different scenarios. These scenarios consider several levels of renewable sources penetration and different numbers of synchronous machines connected. The index \( \% \text{REN} = \frac{P_{\text{ren}}}{P_{\text{load}}} \) is been used to count the amount of renewable resources penetration in each scenarios. This is defined as the division between the total power generation, \( P_{\text{ren}} \), coming from renewable resources and the total amount of power requested by the loads \( P_{\text{load}} \).
As said in Chapter 2 the grid could be fed by conventional generation units, as synchronous generators, and as well as by renewable wind power generating units. The main characteristics of the conventional generation units are reported in Table 3-1.

<table>
<thead>
<tr>
<th></th>
<th>Snom [MVA]</th>
<th>Pnom [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of units per cell</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cell 1</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Cell 2</td>
<td>SL</td>
<td>2</td>
</tr>
<tr>
<td>Cell 3</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Cell 4</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Total conventional generation [MVA]</td>
<td>4000</td>
<td></td>
</tr>
<tr>
<td>cos ϕ</td>
<td>0,85</td>
<td></td>
</tr>
<tr>
<td>Total conventional generation [MW]</td>
<td>3400</td>
<td></td>
</tr>
</tbody>
</table>

*Table 3-1: Conventional synchronous generation characteristic*

The nominal consumption $P_{load}$, reported in Table 3-2, has been considered constant in all the cases.

<table>
<thead>
<tr>
<th>Load [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cell 1</td>
</tr>
<tr>
<td>Cell 2</td>
</tr>
<tr>
<td>Cell 3</td>
</tr>
<tr>
<td>Cell 4</td>
</tr>
<tr>
<td>Total load [MW]</td>
</tr>
</tbody>
</table>

*Table 3-2: Load consumption in each cell*

The main characteristics of all the defined scenarios are reported in Table 3-3.
Table 3-3: Definition of the scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>%REN</th>
<th>Pren (MW)</th>
<th>number of conventional generators enabled</th>
<th>Pgen (MW)</th>
<th>% Pgen</th>
<th>Total inertia 2H (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>0%</td>
<td>0</td>
<td>8</td>
<td>325</td>
<td>76</td>
<td>10</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>25%</td>
<td>650</td>
<td>8</td>
<td>244</td>
<td>57</td>
<td>10</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>25%</td>
<td>650</td>
<td>6</td>
<td>325</td>
<td>76</td>
<td>7.5</td>
</tr>
<tr>
<td>Scenario 4</td>
<td>50%</td>
<td>1300</td>
<td>6</td>
<td>217</td>
<td>51</td>
<td>7.5</td>
</tr>
<tr>
<td>Scenario 5</td>
<td>50%</td>
<td>1300</td>
<td>4</td>
<td>325</td>
<td>76</td>
<td>5</td>
</tr>
<tr>
<td>Scenario 6</td>
<td>75%</td>
<td>1950</td>
<td>3</td>
<td>217</td>
<td>51</td>
<td>3.75</td>
</tr>
<tr>
<td>Scenario 7</td>
<td>75%</td>
<td>1950</td>
<td>2</td>
<td>325</td>
<td>76</td>
<td>2.5</td>
</tr>
<tr>
<td>Scenario 8</td>
<td>90%</td>
<td>2340</td>
<td>2</td>
<td>130</td>
<td>31</td>
<td>2.5</td>
</tr>
</tbody>
</table>

The first scenario (Scenario 1) considers only conventional generation with all the renewable resources and the HVDC grid disabled. The other scenarios (Scenario from 2 to 7) consider an increasing penetration of unconventional generation units until the last one (Scenario 8) that considers a renewable penetration of 90% with only two conventional synchronous generator enabled. The last case could also be representative of the reality over the upcoming years. By 2025, 22 countries in the EU are reported to have a RES capacity penetration level higher than 50%. [18] Eight countries, such as Denmark, Germany, Great Britain, Greece, Ireland, Northern Ireland, Netherlands, and Portugal, will reach full hourly load penetration level (100%). However, it should be noted that this result does not mean 100% penetration occurs simultaneously for these eight countries on the same hour.

In Table 3-3, %\( P_{gen} \) is defined as %\( P_{gen} = \frac{P_{gen}}{P_{nom}} \times 100 \) and identifies how much power of the rated each conventional unit is providing to the grid. For each scenario also the total inertia, 2H, of the system has been calculated. This is calculated as:
\[2H = \frac{\sum_{i=1}^{n} 2H_i \cdot S_i}{\sum_{i=1}^{n} S_i}\]  \hspace{1cm} (3-1)

In equation (3-1) \(H_i\) and \(S_i\) are respectively the inertia constant and the nominal apparent power of the \(i^{th}\) generator, with \(n\) the number of total generators in the grid. The inertia constant \(H_i\) of all the synchronous generators in the grid has been considered equal to 5 s.

As could be seen in Table 3-3 with decreasing conventional generation the total inertia of the grid decreases. In fact in the grid only the conventional rotating generation is providing inertia to the system.

In each scenario the active power generation provided by unconventional generation is split in two parts. Half (50%) of this power is provided equally by the three wind parks with DFIG, the remaining 50% is given by the type 4 wind generator unit and then managed by the full converters in the HVDC grid.

It has to be noted that the number of DFIG wind turbines in each of the three wind parks is remained constant in all the scenarios and equal to 65. With the increase RES generation, from Scenario 2 to Scenario 8, is the set point of the wind turbines power production that changes.

3.1.1. Scenario 1

The first scenario could be seen as a reference for all the further analysis, in fact this case presents only conventional generation. Only the eight synchronous based generation units are feeding the grid and the HVDC grid is disabled. The load power request is given equally by the synchronous units and the system inertia is maxim.

3.1.2. Scenario 2 and Scenario 3 (25% of RES)

In Scenario 2 and 3 there is a 25% of renewable penetration in the grid, notably all the 3 DFIG wind turbines are feeding the system and also the wind park in the HVDC is enabled. Half of the RES power generation is given equally by the DFIG turbines and half is given by the full converter part of the grid. The difference between the two cases is given by the number of conventional generating units that are working. In Scenario 2 all the eight synchronous machines in the grid are enabled while in Scenario 3 only six of them are working. In particular in Cell 1 only one generator unit in bus 1.9 and in bus 1.10 is enabled.
3.1.3. **Scenario 4 and Scenario 5 (50% of RES)**

In these two cases has been considered the RES penetration of 50%. In Scenario 4 there are only six conventional generating units like in Scenario 3 while in Scenario 5 only four conventional synchronous machines are feeding the grid. In Cell 1 all the conventional generator in bus 1.9 are disabled and in bus 1.10 only one synchronous machine is working. In Cell 3, bus 3.12, only one of the hydraulic power units is enabled.

3.1.4. **Scenario 6 and Scenario 7 (75% of RES)**

The RES penetration in the Pan-European grid is increased and the overall renewable production covers 1950 MW of the 2600 MW requested by the grid. In Scenario 6 only three conventional units are feeding the grid while the rest is given by wind DFIG turbines and the full-scale converter wind generation in the HVDC grid. Only one generator in bus 1.10 in Cell 1 and the two generators in Cell 2 are enabled.

In Scenario 7 only the two conventional units are feeding the grid, one slack generator in Cell 2 and SG 1.10 (1) in Cell 1. The other 1950 MW are given by the RES wind generation.

3.1.5. **Scenario 8 (90% of RES)**

The last Scenario foresee a renewable penetration of 90%, almost all of the power request is given by the wind power generation units and the rest is fed by the only two conventional units enabled one in bus 2.11 in Cell 2 and SG 1.10 (1) in Cell 1.

3.2. **Testing scenarios**

In the conducted analyses only more significant comparison between scenarios has been reported case by case. It has been chosen to investigate principally scenarios with 0%, 25%, 50% and 75% of renewable wind production. These cases have been considered as more significant for doing the comparison because the set-point of synchronous generator is remaining the same while more and more conventional generators are disabling to make room at the increasing wind production. Moreover a comparison between cases with same number of synchronous generator enabled but lower set-point to make room at the increasing wind has been studied for analyze the contribution of the increasing wind with the inertia of the system constant. It has also been compared in one analysis the difference between
scenarios with the same renewable penetration but different number of conventional generating units enabled.

3.3. Voltage and frequency ranges

As explained Chapter 1.5, there are variating ranges in generation buses that should be respected by regulation otherwise the power units could be disconnected from the grid leading to aggravation of the system behaviour and cascading outages of the grid.

With reference to the first scenario where there is only conventional generation, the hydraulic and gas turbine generating units works with a set point of generating power of 325 MW. The connection generating point is 20 kV so the type required by the regulation to be considered for FRTC (fault-ride-through-capability) is type D. Since the capacity of all the synchronous units is above 75 MW and the connection point is at 20 kV also in all the further scenarios the type to be considered is type D. The FRT capability as well as the OVRT capability is reported in the plot in Figure 3-1.

![Figure 3-1: LVRT and OVRT of synchronous power plants of type](image-url)
Concerning the three renewable wind parks generators, i.e. DFIG, since they are composed of 65 wind turbines units in parallel and the rated power of each unit is 6 MW, the type required by regulation to be considered for FRTC is type D. The FRT capability in case of low voltage and over voltages of the DFIG units of type D is reported in Figure 3-2.

For all the generating buses the frequency ranges should stay between 47.5 and 51.5 Hz, so 0.95-1.03 p.u. with a base of 50 Hz. Regarding all the other buses the variations ranges stated by the regulation EN 50160, could be uses as limits even if suited for voltage up to 150 kV. It is in favor of security use those varying ranges also for higher voltage level, i.e. 220 kV and 400 kV as in the analyzed grid. Pointed out that, regards the power frequency range in the analyzed network, under normal operating condition, the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- 50 Hz ± 1% (i.e. 49.5 - 50.5 Hz) for 99.5% of a year;
- 50 Hz - 6%/+4% (i.e. 47.0 – 52.0 Hz) for 100% of a year.
Chapter 4

Simulation Results: Three-phase fault

In this chapter the simulation’s results of a three phase fault analysis are discussed. The first part report a brief explanation about damping capability of DFIG control system while the following paragraphs report rotor angle, voltage and frequency transient stability issue after the defined event. The conducted analysis has shown that the stability in general is getting worse with increasing wind power penetration in place of conventional generators due to the decreasing of system inertia. Despite of this in some cases the behaviour after the fault is getting better with more inverter connected generation as the after fault oscillations are no longer present.

4.1. Introduction

The most severe disturbance allowing for transients stability assessment is a three-phase fault applied to a network element (i.e. lines or buses). It has thus been decided to perform a three-phase fault in a tie line to study in the worst circumstance the transient behaviour of the Pan-European Grid. For every conducted analysis the fault event is intended as a three phase fault in the tie line 3.7-4.3b with fault resistance and reactance respective $R_{\text{fault}}=0.001 \, \Omega$ and $X_{\text{fault}}=0.001 \, \Omega$. The fault occurs in the middle of the line and it is intended to be cleared at 150 ms. This value has been chosen because the most common fault clearing time in Europe is currently 150 milliseconds. The analyzed scenarios, with different RES penetration and number of synchronous generator active, are the one explain in detail in Chapter 3.1.
In the following sections, after a first paragraph with consideration regarding the damping capability of DFIG, attention will be focused on rotor angle, voltage and frequency transient stability issue caused by the three-phase fault.

### 4.2. Damping capability of DFIG

As explained in Subparagraph 2.1.2 the PI block in the Speed-Ctrl controller, part of the DFIG model, has the task to damp the oscillation excited at a grid fault in the drive train system. The influence of this controller has been analyzed observing the speed trend of the DFIG with the damping controller enabled or not. This analysis has been conducted, as could be seen in Figure 4-1, for the DFIG 1.9 in Scenario 7. In the plot it is shown also the speed trend with different values of the proportional gain $K_p$ of the PI controller, i.e. for one case the standard value assigned in the DIgSILENT model ($K_p = 1$) as well as $K_p = 10$ and $K_p = 50$.

![DFIG 1.9 Speed](image)

*Figure 4-1: Speed of DFIG 1.9 with different setting of the Speed-Controller*

As could be seen with the presence of the damping controller the speed reaches faster the steady-state values while with increasing proportional gain the speed is more damped. On the contrary, as could be seen in Figure 4-2, higher value of the proportional gain $K_p$ leads to
more stress in the machine. Notably the power output is pushed to change much more to follow the reference given by the speed controller in order to damp the oscillation in the drive train system.

The system analyzed is a strong grid so should also be said that different values of the gain do not influence the overall stability as could be in a smaller and weaker grid.

Figure 4-2: DFIG 1.9 active power with different setting of the Speed-Controller.

4.3. Rotor angle stability

Transient stability is defined as the ability of synchronous generator rotor angle to regain their operating equilibrium following a transient fault in the network. As seen in Subparagraph 1.3.4 an indicator that can be used for rotor transient stability consideration is the TRASI index. In its definition the rotor angle is defined with the reference to the reference machine angle. Therefore, as could be seen in Figure 4-3, rotor angle can be also specified based on the following reference frames. To clarify the respective name in the software environmental is reported in bracket.
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- Rotor angle with reference to (w.r.t.) reference machine voltage \( (\text{firat}) \);
- Rotor angle w.r.t. a reference machine rotor angle \( (\text{firel}) \);
- Rotor angle w.r.t. local bus voltage \( (\text{fipol}) \).

![Figure 4-3: Rotor angle definition](image)

In the following analysis the rotor angle is specified w.r.t. the rotor angle of the reference machine, so with the \( \text{firel} \) angle in the software environment.

In a first analysis the TRASI index has been used for compare different scenarios with the same amount of synchronous machines active but with different wind power penetration. Two different cases have been analyzed: Scenario 1 as the reference one only with conventional generation and Scenario 2, with the same number of synchronous machines active but with 25% of wind power penetration. Other two cases are then compared: Scenario 3, with 25% of wind penetration, and Scenario 4 with 50% wind power penetration and both with six synchronous generators enabled. Finally it has been done a comparison between 4 scenarios respectively, Scenario 1, 3, 5 and 7 with the same power set-point of the synchronous machines active but with increasing wind power penetration. To complete the analysis it has been calculated for all the scenarios the maximum rotor angle deviation from the steady state value after the fault.

4.3.1. \( \text{TRASI} \) Scenario 1-Scenario 2

For each of the analyzed case has been calculated within the software the maximum rotor angle difference \( \delta_{\text{max},d} \) as reported in Figure 4-4 and Figure 4-5.
Figure 4-4: Maximum rotor angle difference $\delta_{max}(t)$ SCENARIO 1

Figure 4-5: Maximum rotor angle difference $\delta_{max}(t)$ SCENARIO 2
The resulting index TRASI, transient rotor angle severity index, defined in Subparagraph 1.3.4 in Equation (1-1), is reported in Figure 4-6.

![TRASI Graph]

*Figure 4-6: Comparison of TRASI index in the two scenarios with different wind penetration*

It can be seen from the comparison that there is an improvement in rotor angle stability from Scenario 1 to Scenario 2. That is due to the power rush flow contribution of the DFIGs in the moment of the fault so the fault power contribution of synchronous generator is reduced, which reduced the impact in the electromagnetic forces of the synchronous generators. As could be seen in Figure 4-7, the power injected by the DFIGs, immediately after the fault, is increasing, except the case of DFIG 3.12 due to the proximity of the faulted line.
4.3.2. **TRASI Scenario 3-Scenario 4**

The two scenarios analyzed respectively Scenario 3 and Scenario 4 are characterized by wind power penetration of 25% and 50% and six synchronous generators on-line. The maximum rotor angle difference for the two cases is displayed in Figure 4-8 and Figure 4-9.
Figure 4-8: Maximum rotor angle difference $\delta_{max,d}(t)$ SCENARIO 3

Figure 4-9: Maximum rotor angle difference $\delta_{max,d}(t)$ SCENARIO 4
As could be seen in Figure 4-10 the TRASI index is improving in Scenario 4 respect to the one with 25% of wind penetration (Scenario 3).

![TRASI Comparison](image)

*Figure 4-10: Comparison of TRASI index in the two scenarios with different wind penetration*

The improvement could be due to the difference power set-point of the synchronous generator. In Scenario 3 the six synchronous machines in the grid are working with a steady state power of 325 MW while in Scenario 4 they are working at 217 MW. In fact if the generators work at less power than the nominal one, they have more power to support the restoring after the fault. In Figure 4-11 has been compared the power injected, after the clearance, by the generators nearer to the fault (SG 3.12) in the two scenarios. Could be seen that the power has a bigger variation in Scenario 4, so in the case with lower set-point of the synchronous generator. The machine in Scenario 4 is accelerating less in the moment of the fault due to the lower difference between the mechanical torque, constant, and the decreased electrical torque, as could be clearly seen in Figure 4-12. Equally after the clearance the machine in Scenario 4 is decelerating more due to the bigger difference between the constant mechanical torque and the increased electrical torque. This behaviour brings to lower speed oscillation that led to a more stable behaviour. However the improvement could be also due to the increasing penetration of RES.
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Figure 4-11: Comparison between active power injected and Speed by the SG3.12(1) following the fault in Scenario 3 and 4

Figure 4-12: Comparison between electrical and mechanical torque in scenario 3 and 4
Deeper analysis, briefly presented below, has shown that the better behaviour in term of rotor angle stability in the analyzed case is due to the lower set-point of the generators instead of the increasing wind penetration. To clarify it has been done a comparison between Scenario 4 and Scenario 5 with the same wind power penetration (50%) while with a different power’s generator set-point respectively of 217 MW and 315 MW. As could be seen in Figure 4-13 the TRASI index is better in the case with more synchronous generating units and lower generator’s set point, i.e. Scenario 4.

![TRASI Comparison](image)

*Figure 4-13: Comparison of TRASI index in the two scenarios with different generator set-point but same amount of RES penetration.*

### 4.3.3. TRASI between scenarios with the same set-point of power

It is interesting investigate the TRASI index in the case of same set-point of power of the synchronous generators while the amount of wind power production is increasing. It has been compared Scenario 1, Scenario 3, Scenario 5 and Scenario 7: the power set-point is 325 MW in all the four cases while the amount of conventional generator is becoming lower to make room to the increasing wind power generation, respectively 0%, 25%, 50% and 75%.

The comparison between the TRASI index in these four scenarios is shown in Figure 4-14.
As could be seen the TRASI is becoming lower in the first three cases with the increasing of wind power penetration, in fact the inertia of the system is decreasing and thus the angular separation of the synchronous generator is increasing. On the contrary in Scenario 7 the TRASI index seems to be better in comparison with all the three previous cases. Even though the inertia of the system is lower and the wind power generation is increased till 75%. In this scenario only two conventional units are enabled, the slack generator SG 2.11(2) and the generator in bus 1.10, SG1.10 (1). The stability behaviour is better in Scenario 7 due to the fact that both of the synchronous generators in the bus nearer to the fault, bus 3.12, are disabled. On the contrary in the other scenarios, Scenario 1, 3 and 5, both of them or at least one are feeding the grid. These machines due to the vicinity of the fault are more subjected to oscillations, and this led to a worst transient behaviour.

In general comparing the speed, the frequency, the electrical torque and the active power injected in the grid by one synchronous generator could be seen that there is more variation in the frequency, torque and in the electrical power after the fault with more penetration of wind. This is shown for the generator SG 1.10(1), enabled in all the four analyzed cases, in Figure 4-15 and Figure 4-16.
Figure 4-15: Comparison between frequency and rotor speed in bus 1.10 in Scenario 1, 3, 5, and 7

Figure 4-16: Comparison between active power and electrical torque in bus 1.10 in Scenario 1, 3, 5, and 7
4.3.4. **Maximum rotor angle deviation**

For completing the rotor angle stability evaluation is interesting the estimation of maximum generator’s rotor angle deviation from the steady-state value that occurs after the fault. In fact the TRASI index is a comprehensive approach and it refers to the overall system while the maximum rotor angle deviation is a local issue. In that sense a generator could has a lower maximum angular deviation than another case but the TRASI of the system where is connected could be worse.

For every different scenario analyzed it has been calculated the maximum rotor angle deviation $|\Delta \varphi_{\text{max}}|$ that occurs after the fault from the steady state values. The rotor angle deviation $|\Delta \varphi|$ could be defined as in Equation (4-1) with $\varphi$ the rotor angle of each synchronous generator w.r.t. the reference machine’s rotor angle, i.e. the \textit{firel} angle in PowerFactory environment.

$$|\Delta \varphi| = \max( |\varphi_{\text{max}} - \varphi_{\text{steady-state}}|, |\varphi_{\text{min}} - \varphi_{\text{steady-state}}| )$$ \hspace{1cm} (4-1)

The maximum rotor angle deviation $|\Delta \varphi_{\text{max}}|$ in each scenario could finally be calculated considering the maximum between the rotor angles deviation of each generator. In fact considering the maximum deviation of the \textit{firel} angle it has been considered the maximum angular deviation of the generator’s rotor that occurs respect the SL generator’s rotor.

The maximum rotor angle deviation and the respective synchronous generator where it occurs in each scenario are reported in Figure 4-17.
Figure 4-17: Maximum rotor angle deviation respect to the rotor of the SL generator. The considered angle is the one w.r.t. the reference machine rotor angle.

The maximum rotor angle deviation in the first scenario is bigger than the other scenario because in this scenario there are only conventional generation units and thus there isn’t the contribution of the DFIG and the converter connected generation that mitigate the synchronous contribution during the fault.

Scenario 2 and 3 has the same amount of RES penetration, 25%, but in Scenario 3 there are less synchronous generators enabled and consequently the system present less inertia, the stability behaviour is worst and the maximum angular difference is bigger.

Scenario 5 has a lightly lower maximum angular deviation comparing with Scenario 4 even if two of the synchronous generators are switched off. On the contrary the previous analysis with the TRASI index has shown that is Scenario 4 which behaves better in term of overall stability. Figure 4-18 reports the rotor angle w.r.t the rotor angle of the reference machines of all the generators enabled in Scenario 4 and 5. As could be seen in the plot in Scenario 4 there are lower oscillation in the rotor angular position apart in the generator near to the faulted lines (SG 3.12). In Scenario 5 bigger oscillations are present also in the generator 1.10. Could be concluded that Scenario 5 behaves in the overall point of view worse in term of rotor angular stability as seen with the TRASI index analysis.
Figure 4-18: Rotor angles w.r.t reference machines angle of the enabled generator in scenario 4 and 5.

The maximum rotor angle in the last three cases is really small comparing to the previous analyzed cases. That is due to the shut off of both of the generators SG 3.12 that are nearer to the faulted line. The synchronous generators behaviour is not so severe because the machines enabled are far from the faulted line and there’s the DFIG contribution.
4.4. Frequency stability

Frequency stability is defined as the ability of a power system to maintain a steady-state frequency following an imbalance caused by fault. To evaluate the frequency behaviour after the defined event it has been used the initial frequency nadir, which is the largest drop following a fault event in the network. It is also interesting the evaluation of the frequency peak after the clearance of the fault. The analysis was done considering a simulation time of 1 s following the fault. A first comparison between four scenarios has been done; Scenario 1, 3, 5 and 7 was compared considering increasing wind power penetration, respectively 0%, 25%, 50% and 75%. The analysis was performed comparing the measured frequency by PLL (phase measurement device) in the generators buses and in the main ac grid buses. It is also interesting evaluate for each cells which is the more critical bus in term of frequency stability, i.e. determinate the buses with the bigger frequency nadir and peak in each cell.

In Scenario 1, the base case scenario, without any renewable resources, the frequency bigger variation following the fault occurs in bus 2.5 as could be seen in Figure 4-19.

![Figure 4-19: Frequency trend in the main buses after a three-phase fault in Scenario 1 (no RES)](image-url)
The frequency drops till the value of 49.682 Hz and rise up to the value of 50.560 Hz. Also the near bus 2.4 is subjected to a big excursion. A comparison analysis between each frequency trend in each of the three AC cells has shown that the critical buses are: bus 1.2 for Cell 1, bus 2.5 for Cell 2 and bus 3.6 for Cell 3. Should be noted that critical frequency buses are placed in buses where loads and principal transmission lines are connected.

In Scenario 3 two generation conventional units, SG 1.9(2) and SG 1.10(2), are switched off to make room to 25% of renewable wind generation. As could be seen in Figure 4-20 also in this case the deeper frequency occurs in bus 2.5, with a deep of 49.7 Hz and a peak after the clearance of 50.249 Hz. Also the frequency in bus 2.4 and 2.8 are varying more than the frequency in other parts. As the base case, critical buses are bus 1.2 in Cell 1, bus 2.5 in Cell 2 and bus 3.6 in Cell 3.

Figure 4-20: Frequency trend in the main buses after a three-phase fault in Scenario 3 (25% of RES.)
In Scenario 5 the wind power generation is increased till 50% and four synchronous generation units, SG 1.9(1)&(2), SG 1.10 (2) and SG 3.12 (2), are disabled. As shown in Figure 4-21 the bigger excursion occurs in the bus 2.5 and the frequency drops till 49.703 Hz and reach the value of 50.265 Hz after the clearance of the fault. Bus 3.6 and 2.4 has also deep variation. The critical buses in term of frequency stability in Cell 1 are bus 1.9 and 1.1 as well as bus 1.2. In this scenario the dip of frequency is bigger also in generation bus like 1.9 because both of the synchronous machines in this bus are disabled to make room at the increasing wind. In Cell 2 the critical bus is bus 2.5 while in the third cell the critical one is bus 3.6.

Figure 4-21: Frequency trend in the main buses after a three-phase fault in Scenario 5 (50% of RES)

In Scenario 7 the wind power penetration is increased till 75% and only two synchronous generators are working, one of the slack machines SG 2.11(2) and synchronous generator SG 1.10(1). The frequency trend in the main buses is shown in Figure 4-22.
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**Figure 4-22:** Frequency trend in the main buses after a three-phase fault in Scenario 7 (75% of RES)

**Figure 4-23:** Over-frequency in bus 2.8 and the behaviour of the near PWM 4.3 master converter
The bigger drop occurs in bus 2.5 till the value of 49.722 Hz. The max over-frequency occurs instead in bus 2.8, in which the frequency reaches the value of 50.356 Hz. The over-frequency peak in this bus is due to the after fault behaviour of the near PWM converter, PWM 4.3. As shown in Figure 4-23, the converter is pushing power in the AC side after the clearance of the fault to bring again the voltage in the respective bus to a constant value. In fact this PWM converter has to work as the master controller so has the task to maintain constant voltage in the AC and DC bus. The critical buses in each cell are bus 1.9 and 1.1 for Cell 1. In fact all the synchronous generators in that bus are turned off so the frequency presents more variations. For Cell 2 and Cell 3 the critical buses are respectively bus 2.5 and 3.6.
Regarding the previous plot one fact should be clarified, the frequency in the moment of the fault and after the clearance has a step variation. This frequency trend is not realistic in a power grid where there is synchronous generator active with inertia capability; the frequency cannot have such an instantaneous variation. In fact the step that can be seen in the plot is due to the measurement, the measured frequency is coming from a Phase Measurement Device (PLL) connected in the relative bus. PLL gives as output the frequency deriving it from a voltage angle measurement in the relative bus. Observing the speed, see Figure 4-24, of the synchronous active generators could be seen that there is no step variation as is expected.

Figure 4-24: Synchronous generator speed in Scenario 1, 3, 5 and 7. The legend is reported below:

- SG 1.10
- SG 1.9
- SG 2.11 (SL)
- SG 3.12
The frequency analysis has shown that the more critical bus in term of larger drop and peak is bus 2.5 in all the scenarios apart in Scenario 7 in which the biggest peak occurs in bus 2.8 as motivated before. In Figure 4-25 is reported the comparison between the frequencies in bus 2.5 for all the four analyzed scenarios. The biggest peak occurs in case of no RES penetration, in fact the grid has only synchronous generators without converter connected generation that contributed to shapes the after fault characteristics.

![Figure 4-25: Frequency trend comparison in bus 2.5 and 1.9 in the 4 analyzed scenarios](image)

A comparison between the frequencies in bus 1.9 is also reported in Figure 4-25 to visualize the difference between the presence or not of active synchronous generator in that bus. In bus 1.9 there are synchronous generators enabled till Scenario 3. In Scenario 5 and 7, where only DFIG are feeding the bus, the frequency reaches a bigger undervalue. In fact without synchronous generator that gives to the frequency a reference, the frequency follows the DFIG speed changing due to the variation of the electrical torque. The behaviour is shown in Figure 4-26 for the DFIG 1.9 in Scenario 5, for comparison the trend with also a conventional unit connected in the bus, e.g. Scenario 3, is as well reported in the plot. As could be seen the electrical torque in the moment of the fault is increasing (in absolute values) and so the DFIG is decelerating and the frequency has a deep too. Then the torque
start to decreases and consequently the machines accelerate and the frequency follows. This behaviour in the case with only DFIG in the bus is emphasized.

The frequency ranges, defined by the EU normative, in distribution system in case of grid fault are 50 Hz -6%/+4% (47.0 – 52.0 Hz). Furthermore in generation buses, to ensure the connection of the generation units, the frequency ranges should stay between 47.5 and 51.5 Hz, i.e. 0.95-1.03 p.u. with a base of 50 Hz. As could be appreciate in the above plots in all of the main buses in the Pan-European grid the frequency stay within the limits in all the scenarios. The system security is ensured as it should be possible for all the generators to remain connected to the grid.

4.3.1. **Fast Fourier Transform-FFT**

A longer time simulation, following the fault for 20 s, has shown that there is different behaviour with different penetration of RES and disabling of conventional generators in term of reaching of a steady-state condition without oscillation after the clearance of the fault. An interest analysis is the FFT (Fast-Fourier-Transform) of the frequency magnitude following...
the fault. In fact the frequency oscillates from the steady state value (50 Hz) after the clearance of the fault. Calculating with the predefined analysis function in PowerFactory the Fourier coefficient of the magnitude of the frequency could be seen the preponderant harmonics in the frequency and their amplitude. A comparison between the behaviour in different scenarios was done comparing the frequency in two main generation buses for observe the difference in case of turn off of conventional units to make room at higher penetration of wind generation. The comparison was done between the base case, Scenario 1 and Scenario 3, Scenario 5 and Scenario 7 observing the frequency in bus 1.9 and bus 3.12. The plots are reported in Figure 4-27, for bus 1.9, and Figure 4-31 for bus 3.12.

Figure 4-27: FFT in bus 1.9 in four different scenarios

In Scenario 3 in bus 1.9 there is only one synchronous generator enabled while in the Scenario 5 and 7 there is only wind power production whom is feeding that bus. In the base case the preponderant harmonics are around 0.8-0.9 Hz so there are main oscillations with a period of 1.11-1.25 s. In particular, as could be seen in Figure 4-28, the principal oscillation are around 0.86 Hz (oscillating period of T=1.162 s), i.e. this oscillation are inter-area oscillation. Inter-area oscillations are associated with the swinging of units of generation in one area against a group of generators in another area. This concept can be translated into an
inter-cell grid by considering group of generators in one cell swinging against a group of
generator in another cell. Usually inter-area oscillations are in the range of 0.1 to 1.0 Hz
while local oscillations, i.e. swinging of units in a small part of the system respect to the rest
of the power system, are from 1.0 to 2.0 Hz. Observing in Figure 4-29 the rotor speed and
the supplied active power of synchronous generators could be notice that generator SG 1.9 in
Cell 1 is oscillating against the slack generator SG 2.11 in Cell 2 with a phase shift of almost
180°.

Figure 4-28: Frequency in bus 1.9 in Scenario 1
With the disabling of conventional generation, Figure 4-27, the preponderant frequency harmonics, principally due to the inter-area oscillation contribution, is damped while the frequency oscillation are moved to smaller values, that means to higher values of period of oscillation. In the last case, Scenario 7, the harmonics around 0.8-0.9 Hz are completely disappeared and the main harmonics are around 0.25 Hz so with a bigger period of oscillation, i.e. around 4 s, and around 1.3 Hz, so with a period of 0.77 s. The presence of harmonics with bigger period of oscillation in the last analyzed scenario, i.e. the increasing of lower frequency harmonics, is due to the initial frequency bigger variation immediately after the fault and its clearing. Could be concluded that with increasing converter controlled generation, even if the behaviour immediately after the fault is worse, the frequency oscillation are eliminated as could be appreciated in Figure 4-30.
The behaviour in the generator bus 3.12 regarding the frequency magnitude oscillation is similar to the previous analyzed bus. The FFT of the magnitude of the frequency in bus 3.12 is reported in Figure 4-31 for the four analyzed scenarios.
In Scenario 1 and 3 both of the synchronous generator is feeding the bus while in Scenario 5 one of the synchronous machines is disabled and in Scenario 7 there is only DFIG production. Also in this case could be concluded that with increasing wind power penetration the main harmonics observed in the base case are no longer present and without synchronous generation in the bus there are frequency magnitude components with bigger period of oscillation.
4.5. Voltage stability

Voltage stability is the ability of a power system to regain a stable behaviour after being subjected to severe events like faults. As summarized in Chapter 3.3 the EU normative fixed predefined ranges of variation of the voltages in generation buses. Within these ranges it should be possible for the generators to remain connected to the system and ensure system security. For observe if the voltage is staying within the defined ranges the voltages variation in all the generator buses such as bus 1.10, bus 1.9, bus 2.11 and bus 3.12 in all the scenarios are plotted above from Figure 4-32 to Figure 4-39.

Figure 4-32: Voltages in the generators buses in SCENARIO 1
Figure 4-33: Voltages in the generators buses in SCENARIO 2

Figure 4-34: Voltages in the generators buses in SCENARIO 3
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Figure 4-35: Voltages in the generators buses in SCENARIO 4

Figure 4-36: Voltages in the generators buses in SCENARIO 5
Figure 4-37: Voltages in the generators buses in SCENARIO 6

Figure 4-38: Voltages in the generators buses in SCENARIO 7
SIMULATION RESULTS: THREE-PHASE FAULT

In all the analyzed scenarios the voltages are staying within the LVRT and the OVRT variation limits. Only in the last two scenarios, Scenario 7 and Scenario 8, the voltages in generation bus 2.11 is going over the limits of 115% (1.15 p.u.) respectively for 47 ms and 61 ms so the security is guaranteed being the period of over-voltage lower than 1 s.

Observing two scenarios with the same amount of conventional generator active but increasing wind power production is interesting for detect if there is or not a difference behaviour in term of voltage response after the fault. A comparison between Scenario 3, 25% of RES, and Scenario 4, 50% of RES, both with six synchronous generators active is carried out as an example. Analyzing in both of the scenarios the voltage trend could be seen which bus in each cell has the larger drop and overvoltage. The critical buses in term of larger overshoot and sag are reported in Table 4-1.
Table 4-1: Critical buses in each cell for Scenario 3 and 4

<table>
<thead>
<tr>
<th>Cell</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>larger sag</td>
<td>larger overshoot</td>
</tr>
<tr>
<td>1</td>
<td>1.2</td>
<td>1.3</td>
</tr>
<tr>
<td>2</td>
<td>2.5</td>
<td>2.5</td>
</tr>
<tr>
<td>3</td>
<td>3.7</td>
<td>3.12</td>
</tr>
<tr>
<td>4</td>
<td>4.3_b</td>
<td>4.3</td>
</tr>
</tbody>
</table>

The comparison between the voltages in the critical buses in each cell in the two analyzed scenario is reported in the plot in Figure 4-40.

Figure 4-40: Comparison between voltages in more critical buses of each Cell in Scenario 3 (25% RES) and Scenario 4 (50% RES)

As could be seen the voltage dip is not changing significantly from one scenario to another. Moreover could also be said that there is a little improvement with more renewable penetration as the voltage, in comparison, has a larger drop in Scenario 3. The principal reason of this not so different behaviour is the fact that the DFIG in the two cases has the same capability of Q providing. In fact from Scenario 3 to Scenario 4 it has been increased the set-point of each wind generators but the number of wind power plants is remaining the same, i.e. 65 units. It’s clearly that due to the presence of power converters in the DFIG the
active and reactive power control is decoupled and the capability of reactive power suppling is defined by the capability curve, which fixes the limits of reactive power operating limits. The number of DFIG is kept unchanged so the reactive power capability in the two scenarios doesn’t change. As could be appreciated in the plots in Figure 4-41 the DFIG reactive power contribution of the three machines is not changing from one scenario to the other.

The little voltage improvement in Scenario 4, with more RES penetration, is clarified observing synchronous generator behaviour. Synchronous generators in Scenario 4 are working with a lower active power set-point to make room at the increasing wind generation. For that reason the conventional generation has a larger possible range of variation of active as well as reactive power supply. Notably they could provide to the grid reactive power with a bigger range of variations to sustain the voltages. In Figure 4-42 and Figure 4-43 are plotted in comparison the reactive and active power contribution of the synchronous generators in Scenario 3 and 4. How could be appreciate the Q contribution in the two scenarios has a small difference; for example for the generator SG 1.9 the reactive power contribution from the pre-fault value has a lower variation during the fault in Scenario 4, i.e. the Q contribution is decreasing less, and consequently the voltage has a lower variation.
Figure 4-42: Reactive and active power contribution of the synchronous generators SG 1.9 and SG 1.10 in Scenario 3 and 4

Figure 4-43: Reactive and active power contribution of the synchronous generators SG 3.12 and SG 2.11 in Scenario 3 and 4
In Figure 4-44 is plotted the generator buses’ voltage in the two scenarios. The voltage behaviour, as motivated before, is not changing significantly from one scenario to another apart from a little improvement in Scenario 4.

![Voltage behaviour in generator buses in Scenario 3 (25%RES) and 4 (50% RES)](image-url)

*Figure 4-44: Voltage behaviour in generator buses in Scenario 3 (25%RES) and 4 (50% RES)*
Chapter 5

Simulation result with load step

In this chapter simulation’s results of a load step analysis are presented and discussed. After an imbalance between generation and consumption the frequency has variations that are closely related to the inertia of the system. For that reason the analysis has been focused on frequency stability issue after the disturbance with increasing inverter connected generation. In particular it has been calculated the rate of change of frequency ROCOF in the moment of the imbalance. The conducted analysis has shown that the frequency has faster variation with increasing wind power production. However regarding the capacity of reach steady state stability after the disturbance there is an improving with increasing RES.

5.1. Introduction

In power system in normal operating condition could occur an imbalance between power generated by generation units and the power requested by loads due to a sudden increase of load or turning off of a generation units. Thus it is interesting analyze how the Pan-European grid behaves after a more common disturbance like a load step. The analyzed situation considers an increasing of 2% of power demand by loads in the entire grid, represented by a load step of 10% in load 1.3 in Cell 1.
In the following section attention will be focused on frequency stability after this type of disturbance. The analysis has been done between four Scenario 1, 3, 5 and 7 respectively with increasing wind power penetration: 0%, 25%, 50% and 75%.

5.2. Frequency stability

The frequency, with reference to EU normative, shall be stay in the range of 50 Hz ± 1% (49.5-50.5 Hz) under normal operating condition, so also in the case of increasing/decreasing load demand. After a load step, the increasing request of power by the load cause a frequency drop due to the imbalance between the generation and load power. The entity of the frequency drop after the disturbance is correlated to the amount of rotational inertia present in the grid. As, in the analyzed scenarios, there is an increasing of wind power penetration, with a consequently decreasing of inertia, it should be expected a worst frequency behaviour. It is interesting, in this view, the evaluation of the ROCOF, i.e. rate of change of frequency, in the analyzed scenarios. The rate of change ROCOF [Hz/s] may be either the time derivative of the frequency, namely \( \frac{df}{dt} \), typically evaluated in the time of perturbation, or the incremental ratio \( \Delta f / \Delta t \) of frequency across a suitable time interval \( \Delta t \); from 200-300 ms to 500 ms. In the conducted analysis this parameter has been calculated with the plot function in PowerFactory as incremental ratio taking a time interval \( \Delta t \approx 0.371 \) s.
As could be observed in Figure 5-1 the ROCOF is increasing, as expected, from Scenario 1 to Scenario 7. Clearly the inertia of the system is decreasing due to the reduction of synchronous machines active to make room to wind power increasing penetration. Lower rotational inertia means faster frequency dynamics, so in case of the analyzed loads step larger frequency variation after the disturbance. As could be seen, observing in Figure 5-2, the minimum frequency reached value in the analyzed cases is lower from Scenario 1 to 7 and the minimum value is reached faster with more RES penetration.
Even though there is an increasing of wind penetration and less inertia response from Scenario 1 to 7 the normative fixed frequency limits (±1%) are not reached in none of the scenarios.

In Scenario 1 and 3 the minimum frequency value is reached by the frequency in bus 1.9 while in Scenario 5 the minimum is in bus 3.12 and in Scenario 7 in bus 1.10. All of these buses are generation buses and in all the cases there is at least one synchronous generator enabled. In fact the frequency reaches a lower value due to the inertial response (IR) of the synchronous machines and the initial imbalance between electrical and mechanical power; the generator from few second from the event is decelerating, and the frequency follows.

For better understand the previous consideration a clarifying explanation is shown below. The synchronous machine SG 1.10 behaviour in Scenario 7 is reported in Figure 5-3.
After the disturbance, the IR acts, for few second at most; IR of synchronous machines is the inherent release of kinetic energy stored in rotors rotating generators, the electrical power increases as well as the electrical torque. Within few second from the event, the primary frequency response is activated by the governor. The governor activates PFC (primary frequency control) when frequency deviation exceeds certain limits and changes the power output set-point to the prime movers. Mechanical torque as well as mechanical power is increased and thus also the electrical power increases to balance the difference between requested and generated power. When the mechanical torque is becoming greater than the electrical torque the synchronous generator starts to accelerate and also the frequency recovers. Usually the primary frequency control, which should be completely deployed by 30 s from the events, stabilizes frequency to a steady state value which is different from the nominal frequency one. The secondary control reserve has then the task to bring frequency back to its nominal value and free up the primary frequency reserve.

Figure 5-3: IR (inertial response) and PFC (primary frequency control) contribution in Scenario 7 in SG 1.10
Observing the frequency trend in a bigger time interval, e.g. 50 s in Figure 5-4, could be seen that the frequency recovers to a stable value that is lower than the nominal frequency of 50 Hz as said before. Is a task of the secondary frequency control (SFC) brings back the frequency to the pre-event steady state frequency value; this should be done within 15 minutes. In our model the SFC is not implemented as is interest of the analysis the transient behaviour (i.e. within 10 s).

The frequency in all the scenarios recovers to a stable value. However in Scenario 1 the frequency after the primary control intervention recovers to a “stable value” but with low frequency oscillation. In fact by zooming in the plot, Figure 5-5, could be seen that the principal oscillation are around 0.859 Hz (oscillating period of T=1.164 s), i.e. this oscillation are inter-area oscillation. Inter-area oscillations are due to the swinging between generators in different cells. As could be seen clearly in Figure 5-5 in plot C the generator units in Cell 1, SG 1.9, is swinging, with a phase shift of 180°, against the generators SG 2.11, i.e. the slack units in Cell 2.
This trend could also be noted observing the injected power by the two generators: where the power has a peak in generator SG 2.11 there is the minimum in the power of synchronous generator SG1.9 in Cell 1.

The inter-area oscillations, except the base case, are no longer presents in the other scenario, with increasing RES, notably wind power generation. The wind penetration has a worst contribution to the frequency initial variation due to the consequently decreasing of IR but has a positive contribution to the achievement of steady-state equilibrium after disturbances. In fact inter-area oscillations are more probable in big interconnected system connected with long tie lines of limited capacity. In the analyzed case from Scenario 1, without RES generation, to the following scenarios the power flow will change due to the HVDC contribution in Cell 4 and thus the power will come also from cell 4 bringing all the system to a better behaviour.
Chapter 6

Conclusion

This work has presented the simulation studies carried out in the Pan-European grid with the software DigSilent PowerFactory where the aim was to study the stability behaviour of new interconnected power grid with increasing RES penetration after severe disturbance and power imbalance cause by fault or load increasing.

The analyzed grid was the modelled Pan-European test grid for the European project Electra Task 5.4. The studies involved the definition of eight scenarios with different increasing wind power penetration percentage respect to the total power demand by the loads. In the performing simulation not all the scenarios were considered but case by case only the relevant result regarding different scenarios have been presented.

As first analysis a three-phase fault in a tie line has been considered and the rotor angle, frequency and voltage stability have been analyzed.

Regarding the rotor angle the analysis has been conducted considering the TRASI index as a comparative indicator. It has been found that the transient stability in general is getting worse with increasing inverter connected generation (wind power plants) due to the decreasing of the system’s inertia. But the stability could improve with the increasing wind power penetration if the fault is far from the enabled synchronous machines. Notably if the synchronous generator, are in a “safe” area, i.e. with a low probability of severe fault, the stability of the system is ensure equally with a lot of distributed not rotating generations. Moreover the stability in a grid with conventional as well as RES wind power generation is better compared to the case with same amount of synchronous generation but without wind. In fact the transient stability is improving if the conventional generators enabled are working with a lower set-point of power, notably there is also power supplied by other generation resources.
Regarding the frequency behaviour after the disturbance observing the frequency nadir and the frequency peak has been concluded that the frequency variation ranges are not exceeded and the security of the system is ensured also with high wind penetration. The analysis has shown that the frequency reaches a bigger peak with no RES penetration but with increasing wind generation there are more oscillations immediately after the fault. In fact the presence of converter connected generation contribute to shapes the after fault frequency characteristic. Even if the behaviour immediately after the fault is worse with increasing inverter connected generation the frequency oscillations after the clearance are no longer present. In fact without wind power production the system after the clearance of the fault is subjected to inter-area oscillation, while with increasing RES this oscillation are no longer present. To prevent inter-area oscillation power system stabilizer (PSS) can be used. PSS could be added to generator’s automatic voltage regulator (AVR) to improve stability but an appropriate parameter design is very important to operate in an effectively way, notably power system stabilizer should be tuned to obtain an efficient damping of the inter-area oscillation. In the conducted analysis PSS weren’t added to the model because the scope of the project was analyzing the Pan-European grid with increasing wind production and inter-area oscillation were registered only in the base case without wind production.

With relation of voltage stability the simulations have shown that the voltage is staying within the predefined admissible variation ranges and the system security is guaranteed. A comparison between two scenarios with increasing wind has shown that the voltage dips are not changing significantly with different wind power penetration.

The second sets of simulations involve studying of the behaviour of the grid after a power imbalance caused by a load step in one cell. Frequency stability has been analyzed with particular focus on the rate of change of frequency (ROCOF). It could be concluded that the frequency behaviour, i.e. the ROCOF value, is worse with increasing wind power penetration. Notably there is a decreasing of inertia with the reduction of the synchronous generator enabled and the frequency dynamics are faster. In fact the wind power penetration has a worst contribution to the frequency initial variation due to the consequently decreasing of inertia response but there is a positive contribution in term of the achievement of steady-state equilibrium after the disturbance. Inter-area oscillation presents in the base case after the stabilization of the system are no longer present with increasing of the wind generation.
It can be finally said that the increasing of the renewable resources, i.e. in the analyzed case wind power penetration, is not leading necessary to worst stability behaviour. In fact, for example, the presence of renewable generation could contribute to shape the after disturbance steady-state characteristic even if the initial behaviour seems to be worse due to the decreasing of system inertia. But it is also true that future regulations prompt always more the RES units to deliver frequency stabilizing services, e.g. frequency sensitive mode (FSM) capability and connected storage with synthetic inertia capability (see Annex) to address this problem.
Chapter 7

Bibliography


[19] Italian technical standard CEI 0-16;V1, “Reference technical rules for the connection of active and passive consumers to the HV and MV electrical networks of distribution Company”, 2014
Annex

Frequency stabilizing services

Distributed generating plants, such as wind power plants and solar generation units, are increasing more and more nowadays in power grids causing new issue in the frequency control of the system. A typical wind plants appears to the grid as a substantially different generation source than a conventional power plants. The most significant difference is that the wind energy source is inherently uncontrollable. That is due to the fact that most rotating machines in modern wind turbines are decoupled from the grid by an inverter so they not provide the “natural” inertia response that other conventional generation provides. The same could be said for PV units. Such uncontrolled power output can have an impact on the grid, including frequency variations. Without special control, a wind plant does not inherently participate in the regulation of the grid frequency while synchronous generator naturally contributes to system inertia. When inverter connected generation displaces conventional synchronous generator the burden of frequency regulation placed upon the remaining synchronous generator is increased. There is thus a need of prompt future generating units to deliver frequency stabilizing services to the grid. This could be realized with frequency sensitive mode FSM or with the provision by the inverter connected generation of a fast frequency response called “synthetic inertia”.

The FSM (Frequency sensitive mode) is defined as an operating mode of a power generating modules or a HVDC system in which the active power output changes in response to a change in system frequency. FSM limits the deviation of the current power system frequency from the target frequency of 50 Hz in case of an unbalance between generation and consumption. ENTSO-E new code [8] has defined different FSM with distinction regarding the type of the generator. The regulation distinct between LFSM-O, limited frequency sensitive mode-over frequency, ad LFSM-U, limited frequency sensitive mode-under frequency. The first one, LFSM-O, is an operating mode which will result in active power output reduction in response to an over frequency while LFSM-U will result in active power
output increase in response to under frequency. The distinction between generators in the regulation is not reported but has been already explained in Subparagraph 1.5.1.

Regarding to the limited frequency sensitive mode-overfrequency of type A, B, C and D power generating modules shall be capable of decreasing the active power output $\Delta P$ as shown in Figure 8-1. At overfrequency where $\Delta f$ is above the threshold $\Delta f_1$ the power generating module has to provide a negative active power output change according to the droop $s_1$ defined between 2% to 12%. The frequency threshold is between 50.2 Hz and 50.5 Hz.

\[
\frac{\Delta P}{P_{nf}} = 100 \times \frac{\left| \frac{\Delta f}{f_n} \right|}{\frac{P_{nf}}{\Delta P}} \frac{\left| \Delta f_1 \right|}{f_s}
\]

* Synchronous Power Generating Modules: $P_{nf}$ is the Maximum Capacity
* Power Park Modules: $P_{nf}$ is the actual Active Power output at the moment the LFSM-O threshold is reached or the Maximum Capacity, as defined by the Relevant TSO

![Figure 8-1: Active power response capability of a power generating modules in LFSM-O](image)

In addition, regarding to the LFSM-U of type C and D generator, the power generating module shall be capable of increasing the active power output $\Delta P$ as shown in Figure 8-2. At underfrequency where $\Delta f$ is below the threshold $\Delta f_1$ the power generating modules has to provide a positive active power output change according to the droop $s_2$, in the range of 2-12%. The threshold shall be between 49.8 Hz and 49.5 Hz. In LFSM-U the power generating module shall be capable of providing a power increase up to its maximum capacity. In case of overfrequency the active power frequency response is limited by the minimum regulating level.
Inverter connected based generation units can emulate the inertial response of conventional generator by a special control structure and the availability of energy storage. A disturbance, as an imbalance between generation and load, will result in a rate of change of frequency which is inverse proportional to the system inertia. A generating units delivering inertia will inject extra power to the grid with decelerating frequency and respectively absorb extra power from the grid with accelerating frequency. This behaviour could be emulated by inverter connected generation with storage. New regulation will state rules for the active power regulation of storage units, to have an idea of the possible requirements the Italian standard CEI0-16 V1 [19] is reported as an example.

For the standard [19] storage system connected in the system should respect the following requirement. If the power system frequency is exceeding the default underfrequency and overfrequency threshold there should be a variation of the active power injected or absorbed as in Figure 8-3. The under frequency and over frequency threshold are defined as default respectively 49.7 Hz and 50.3 Hz.
The activation of the regulation is without delay for the default settings but could be changed from 0 to 1 s. In Figure 8-3 $P_{\text{SMAX}}$ is the maximum discharge power while $P_{\text{CMAX}}$ is the maximum charge capacity of the storage system.