STABILITY STUDIES FOR OFF-SHORE VSC-HVDC CONNECTED WIND GENERATION

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MASTER THESIS

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K.Z.

Abstract

For some applications, High voltage direct current (HVDC) transmission systems are more suitable than conventional ac transmission. With recent advances in this technology and the controllability that it offers, Voltage Source Converter based High voltage direct current (VSC-HVDC) systems have proven to be a more advantageous choice for integration of renewable energy sources, mostly for offshore wind power plants which are generally located far away from the main grid. Their interaction with the onshore system influences the power grid stability and calls for different dynamic analysis. As well as conventional generation, VSC-HVDC connected generation units have to fulfil strict grid codes determined by the Transmission System Operator (TSO). Consequently, the impact on the grid stability that regulations such as frequency support, Fault Ride Through (FRT) or post fault active power recovery rate needs to be studied.

This work aims to analyze the impact on of VSC-HVDC systems on the grid stability in response to large voltage and frequency deviations. The software tool *PowerFactory* is used as a platform for the studies, which original templates have been modified in order to include new ancillary services and control strategies. Through several case simulations, it was found that the implemented functionalities improved the VSC-HVDC dynamic performance.

Index terms: *VSC-HVDC, transient stability, Root Mean Square (RMS), ancillary services, frequency support, offshore wind generation, Double Feeded Induction Generator (DFIG), transmission, integration, grid codes.*

Contents

List of Figures

List of Tables

Chapter 1

Introduction

Whereas the most mature mercury-arc-valve based HVDC was implanted in the early 50s, the first VSC-HVDC had not been in operation until 1999. The main reason is the evolution in power electronics technology, which has enabled the viability of VSC in HVDC transmission systems. The use of VSC-HVDC has grown notoriously since it was first implemented. One of the main reasons is the integration of offshore wind power plants .e.g. the North Sea wind clusters (BorWin, HelWin and Sylwin), which are meant to be connected to the main German power system through VSC-HVDC links. Such kind of projects has led to a growing demand of dynamic studies for systems with VSC-HVDC technology.

In this work, the impact of VSC-HVDC on the system stability is studied. Existing models are enhanced with new functionalities in order to analyze the impact of grid code requirements, ancillary services and new control strategies. This work is limited to RMS simulations studying the dynamic response of the system due to large voltage and frequency deviations.

This work is part of the NETZ:KRAFT project by Fraunhofer Institute for Wind Energy and Energy System Technology (IWES). As an outcome, the existing VSC-HVDC models have been improved in order to be used in different dynamic studies. The models presented in this work are the base for models which also include power system restoration issues. This thesis will be evaluated in the Informatics and Electronics faculty of the German university of Kassel.

1.1 Problem formulation

VSC-HVDC transmission lines have rapidly increased, especially for large amounts of offshore wind energy generation into the main grid. This increase can be justified by factors such as environmental concerns, the restructuring of electricity market and the long distances between load and generation. Due to the unpredictable behavior of the renewable energy and the sharp increase of these, ancillary service requirements and converter control algorithm developments are becoming necessary to remain the grid stable. Frequency support and FRT mode play a big role in this topic and their study is obligatory. In order to carry out appropriate studies regarding the impact of the VSC-HVDC after large frequency and voltage variations, accurate model and software tools with the lowest computational cost as possible are required.

Which are the impact areas of HVDC in Alternate current (AC) grid stability? Which ancillary service can VSC-HVDC provide the AC grid? How can VSC-HVDC be modeled, which are the models available and in which software tool can it be implemented? Which is the impact of VSC-HVDC against large frequency variations? Is it possible to improve it through ancillary services? How can they be introduced in the control structure of the converter?

To answer these questions, a set of tools and methods are proposed in this master thesis.

1.2 Outline

- Chapter 1 is an introduction to the thesis, including its background and aim,
- Chapter 2 presents a general overview of the HVDC system in general; different ways of classifying the HVDCs, its basic working principle, advantages among alternate current and details of the most representative projects throughout the world,
- Chapter 3 presents some theory on HVDC system stability and slow dynamic studies based on a literature review from the most famous books and publications in power system stability area, covering the detailed grid code requirements and the ancillary services that HVDCs could offer,
- Chapter 4 describes in through the control strategy, modeling implementation and the

advantages of the VSC-HVDC,

- Chapter 5 presents the development that wind turbines have lived in these years and explains in thorough the WTG type 3,
- Chapter 6 explains the details of the template model used for the studies in this thesis, its leakages regarding the ancillary services and the procedure followed to implement the ancillary service control schemes in the base model, being verified in an equivalent network,
- Chapter 7 shows the results of a simulation of the modified model in a more realistic scenario.

Chapter 2

Introduction to HVDC

2.1 Classification

During the history of HVDC technology, different technologies and strategies have been developed for HVDC transmission system. They can be classified regarding three different factors: application, electric scheme or layout and the converter and control technology used.

2.1.1 Application

Regarding the HVDC applications, the electrical industry makes the following distinctions; connecting remote generation, interconnecting grids, offshore wind connections with HVDC, Direct current (DC) links in AC grids, power from shore, city center infeed and connecting remote loads. Depending on the control strategy and the characteristics of the connected AC grid, the Voltage Source Converter (VSC) control strategy will differ [5, 6].

2.1.2 System configurations

Different HVDC layouts have been until now developed, thus, in which way converters, rectifier and inverters are connected through DC links [7]:

- Back to back HVDC systems: It has two converter stations situated close to each other. It is used to connect grids with different frequencies.

- Multi-terminal HVDC systems: It connects different converter station through DC links and gives the possibility to connect also more than two AC grids. Different sub-classes could also be made.

- Monopolar HVDC systems: It uses a single line to connect two converters. A positive or negative DC voltage can be used for the power transmission and the second terminal of each converter is connected to ground. Depending on the grounding, the following subclasses are distinguished:

- Bipolar HVDC systems: It is the most commonly used topology. Positive and negative polarity conductors are used to link both sides. Although it is the more expensive than the monopole, it offers several advantages such as lower losses. Depending on the grounding, the following subclasses are distinguished:

2.1.3 Converter technologies

The converter is the device, which transform the alternate current in direct current and in the other way around. The HVDC line converters could be classified in two main groups: Self-commutated converters and line commutated converters.

Throughout the history, five different types of converters have been used; Electromechanical (Thury) systems, Mercury arc valves, Thyristor valves and Capacitor-commutated converters (CCC).

- Electromechanical (thury) systems: This system used series-connected motor-generator sets to increase the voltage. Each set was insulated and driven from a prime mover and the loads were fed in series. Other technique carried out in the 20th century was the charging of series-connected batteries, the reconnecting of the batteries in parallel to serve distribution loads.

- Mercury arc valves: Mercury arc valves require an external circuit to force the current to zero and turn off the valve; therefore, making power transmission into a passive load is impossible and is known as Line Commutated Converter (LCC).

- Tyristor valves: Like mercury arc valves, thyristors require connection to an external AC circuit in HVDC application to turn them on and off. Its development began in the late 1960s.

- Capacitor-commutated converters (CCC): This technology has series capacitors inside the AC lines to offset the commutation inductance and therefore regulating this existing time. However, self-commutated technology made a big step with the introduction of VSC and CCC has remained only in few applications.

- Voltage source converters (VSC): Widely used for motor drives, they started to appear for HVDC systems in 1997 and nowadays most of the projects use this system. Although Insulated-gate bipolar transistors (IGBTs) are the most used ones, gate turn-off thyristors (GTOs) and integrated gate-commutated thyristors (IGCTs) can also be used.

2.2 HVDC around the world

Since the beginning of the generation, transport, distribution and consumption of the electricity, alternate current was chosen as the best way to transport energy. The Central Electricity Board standardized the EEUU electricity supply and stablished the first synchronized AC grid. Due to the first boundary conditions, the big enterprises decided to bet for alternate current transmission grids. However, with the development of the technology, these conditions have suffered from several changes and direct current is being introduced in the high voltage level grid. Although its integration level in the grid has been low at the beginning in comparison with AC current, its use has become more appealing for the electrical industry, thus, its demand is increasing considerably.

Figure 2.1 shows the most significant projects of HVDC carried out all around the world. These projects pioneered in their field regarding the previous projects implemented until the moment. It can also be observed how the technologies of the converters, length of the line and transmission power levels have also improved with the years [8, 9].

1-Sweden Gotland, 2-Anglo french interconnector, 3-Volgograd-Donbass, 4-Pacific inertie, 5-Eel River [10], 6-Argentina-Brazil interconnection [10], 7-Gotland HVDC light [10], 8-XianJiba-

Shangai [11], 9-Trans Bay Cable [12], 10-Rio Madeira [10], 11-Nanao [11], 12-Zhoushan [11] (More details of the most significant HVDCs are shown in the appendix)

Figure 2.1: HVDC projects around the world

With the advances of the renewable energy, especially of offshore wind energy in the North Sea in Europe, huge investments have been done in this area. Moreover, this energy source will have even more importance in the future of the German grid, since more projects are under construction. Until now, there are four principal offshore windfarm clusters located in the North Sea (Figure 2.2); BorWin. DolWin, HelWin and SylWin. The transmission system operator responsible for the operation of these lines is Tennet [13] and the HVDC suppliers ABB [14] and Siemens [1], depending on the project(More details of the projects available in Appendix).

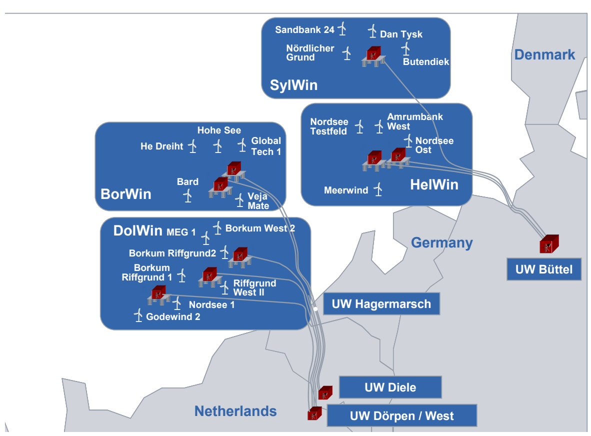


Figure 2.2: Projects HVDC connected to offshore wind parks in the North Sea [1]

Chapter 3

HVDC and stability studies

3.1 Grid stability

"Power system stability is the ability of an electric 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" [15].

Grid stability can be classified into three main groups: rotor angle stability, frequency stability and voltage stability. However, instability cases do not appear usually isolated and the relationship between them is required for each study case.

3.1.1 Rotor angle stability

Rotor angle stability is the ability of the synchronous machines of the power system to maintain its synchronism after having suffered a perturbation such as sudden change in load or generation or severe voltage variations caused by short circuits.

The stator rotating magnetic field interacts with the rotor magnetic field producing the electromagnetic torque that opposes the rotation of the rotor. The mechanical and the electromagnetic torque are opposite and the same in steady state condition. In addition, in steady-state the rotor is maintained at constant value. The internal rotor angle of the generator is the phase shift between the electromotive force of rotor and stator.

Any transition to a new operating state is oscillatory and involves the rotor angle; this is called electromechanical oscillation phenomena. The goal is to keep the equilibrium between the two torques and dump the rotor angle oscillations. Depending on the disturbance magnitude, it can be classified in small disturbance angle stability and transient stability analysis [7].

3.1.2 Voltage stability

Voltage stability is the ability of a power system to maintain the voltage level constant in all buses. Voltage instability can happen due to an equipment operational limit reaching or due to an outage of a line or generator.

Depending on the event magnitude, voltage stability can be classified in the following way: Large-Disturbance Voltage Stability and Small-Disturbance Voltage Stability. The first one studies stability events such as big sudden power changes or fault events while the second one studies events caused by little load changes [7, 16].

3.1.3 Frequency stability

The frequency stability of a power system is the ability to keep the frequency in stable values after an unbalance event between load and generation. Therefore, the main goal is to reduce the frequency deviations by maintaining the balance between load and generation. In order to fulfil this objective, it is of special interest to study the coordination of generation and the response time of certain equipment. Since system and angular frequency are considered global quantities, all the synchronous machines suffer from this phenomena. All the synchronous machines can be modeled together:

$$\dot{w}(t) = \frac{M(t)}{J} \tag{3.1}$$

where $w[rad/s]$ is the grid angular speed, $M[Nm]$ is the mechanical torque and $J[kgm^2]$ is total inertia of all rotating masses in the system.

Since only small deviations from nominal frequency are investigated, the approximation of the mechanical torque:

$$M(t) = \frac{P_a(t)}{w(t)} \simeq \frac{P_a(t)}{w_0} \tag{3.2}$$

Where $P_a(t)$ is the difference of the mechanical power of all power plants in the grid $\sum_i P_{m,i}$ and loads (frequency dependent P_f and frequency independent P_{50}):

$$P_a(t) = \sum_i P_{m,i} - P_{50} - P_f \tag{3.3}$$

As long as there is an active power imbalance, the frequency will continue changing. It will recover a stable state after upsetting the power imbalance and after suffering from oscillations. This oscillations and frequency changes will be directly related to inertia of the system that is composed of the inertia of each connected generator. The inertia of a turbine generator refers to the turbine generator´s resistance to changes in the rotor speed.

As previously mentioned, it is necessary to stablish a well-coordinated control and combination of automatic and manual control systems. Three main categories are distinguished: primary control, secondary control and tertiary control [7].

There has been previous works that investigate which is the impact of HVDC and VSC-HVDC on the grid stability. For instance, papers such as [17, 18, 19, 20] conclude that the integration of this technology in the nowadays grid affects positively in the voltage and transients stability. However, a good control strategy will be required to reach that positive support after grid perturbations.

On the other hand, other reports such as [17, 21, 22] which also study the effect of the integration of HVDC and VSC-HVDC lines into an AC grid, show the way this HVDC contributes to the frequency stability. In document [21] different control strategies for VSC-HVDC connected offshore wind farm are tested, and explains the difference between all of them.

3.2 Grid codes

With the introduction of power electronic developments, new technologies are substituting the old technologies. This substitution requires new codes and coordination in order to guarantee the grid stability. Therefore, regulatory agencies are imposing grid codes in order to make possible the integration of those devices. Therefore, nowadays the transmission system operator requires and imposes some magnitude ranges on HVDC connected power park modules. For this thesis, these codes, also applicable for HVDC offshore wind parks, are going to be taken into account.

In April of 2014 the European network Transmission System Operator (ENTSO) adopted a network code published in [4]. This specifies the operator requirements for the HVDC system in the onshore part. Consequently, depending on each case, the operator stablishes some parameters that the owner must take into account; these parameters could be discussed between both parts. The equipment shall comply with the requirements which are relevant to the planned work. It is necessary a good and detailed interpretation of all the articles to get a valid design of the controllers.

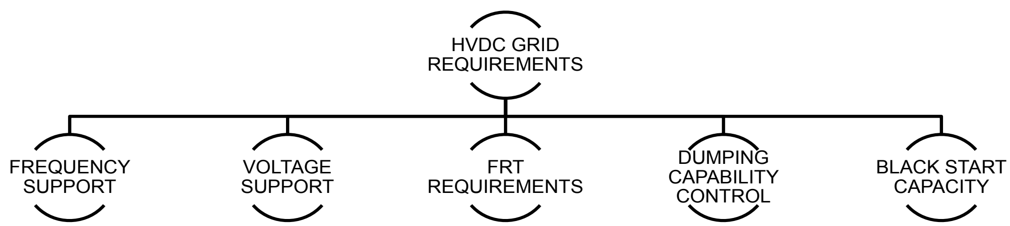


Figure 3.1: Grid code classification for HVDC

The terms and conditions for connection and access to networks or their methodologies shall be established by the National Regulatory Authorities, or by the Member States in accordance with the rules of national law implementing Directive *2009/72/EC*.

For this project only the most relevant articles in relation with the grid stability requirement for HVDC connected are going to be analyzed, especially for voltage and frequency support.

These grid requirements are explain in detail in the appendix.

3.3 Ancillary services

It is obvious that HVDC are required to support the grid stability, as it has been seen in the previous chapter. Eurelectric [6] describes the ancillary service as: ‘Services required by the transmission or distribution SO to enable them to maintain the integrity and stability of the transmission or distribution system as well as the power quality.’ However it is not well defined nowadays which are exactly the ancillary services for DC networks, since they cannot be the same than for the AC systems. In document [23], a classification of ancillary services provided in an AC/DC environment network is done:

- Ancillary services from AC equipment for AC grids [6],
- Ancillary services from DC equipment for AC grids (DC transmission reserve and DC power flow control)
- Ancillary services from AC equipment for DC grids (Active power/voltage control, DC loss compensation, DC black start and restoration, AC transmission reserve and AC power flow control);
- Ancillary service from DC grids to DC grids (Active power /voltage control, DC loss compensation and DC black start and restoration);

This project goes exclusively into active power and voltage control ancillary services from AC to DC grids and vice versa.

3.4 Simulation of dynamic studies

Figure 3.2 shows the time frame of interest in each electric or electromagnetic phenomenon. The range marked in gray represents the time reference in which power system dynamics are studied. When the time scale decreases, the phenomenon to study is more complicated and calls for more details in the modeling. On the other hand, when the time scale is higher, some simplification can be done in the modelling, which could also provide computational cost saving. Thus, it can be deduced that the simulation calculation method differs from one case to the other.

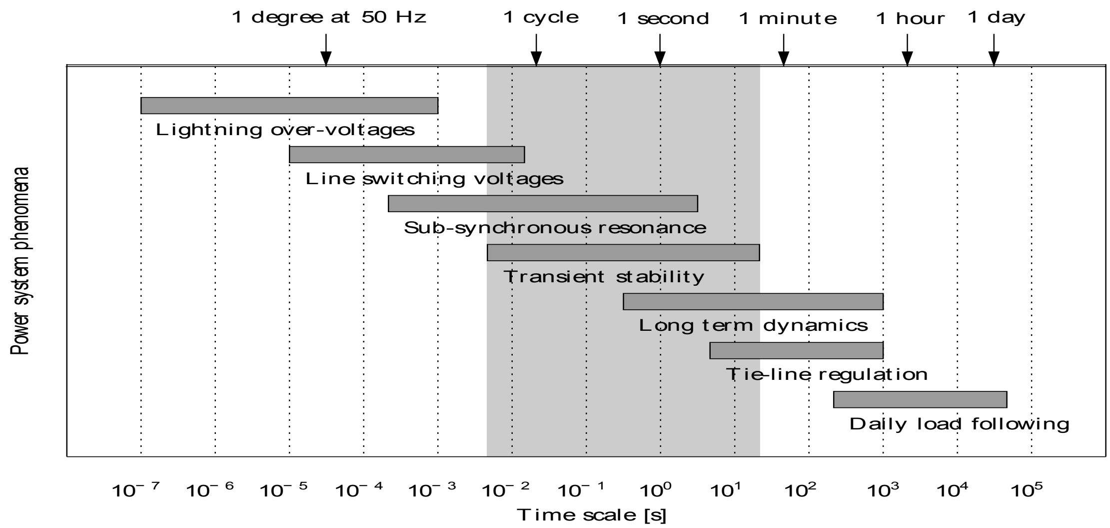


Figure 3.2: Dynamic analysis time range [2]

3.4.1 EMT and RMS

For dynamic studies, two main simulation methods are distinguished; Electhromagnetic Transients (EMT) and RMS. RMS simulation method is based on simplified electrical transient models and EMT, on the other hand, on detailed electromagnetic transient models [24].

In the RMS simulations, electromagnetic dynamics of the network are neglected and voltage and currents are represented with phasors [25]. In this way, most differential equations with voltage and current magnitudes can be avoided and they relation could be represented in the following way with phasors:

$$\vec{u} = jwL\vec{i} \tag{3.4}$$

$$\vec{i} = jwC\vec{u} \tag{3.5}$$

However, differential equations like swing equations are considered:

$$wJ\frac{dw}{dt} = P_{mech} - P_{el} \tag{3.6}$$

Another classification for RMS studies could be also done, when it comes to the symmetry. From one side, the network can be simplified to one only phasor when symmetrical events are studied. From the other side, three phases have to be taken into account for asymmetrical events such as asymmetrical faults.

This type of simulations requires less complexity, computational costs and simulation time than the EMT simulations; however, as shows the figure 3.2, some phenomenon cannot be studied through these simulations. The electromagnetic equation that represents a model of a converter, motor, generator, transformer… can be simplified by neglecting some terms of those equations. This allows the use of steady –state relationship for representing the interconnecting transmission network.

Depending on the models of generators, motors, controllers, power plants and motor driven machines used, the following studies may be carried out [26] (Transient stability, mid-term stability, oscillatory stability and motor start-up).

For EMT simulations, magnitudes are represented by their instantaneous values instead of being represented by phasors. Voltage and currents relation by differential equations:

$$\vec{u} = L\frac{d\vec{i}}{dt} \tag{3.7}$$

$$\vec{i} = C\frac{d\vec{u}}{dt} \tag{3.8}$$

These transients emerged in a VSC-HVDC are the consequence of one of the following events : pole-to-ground faults, pole-to-pole faults, lightning strikes, the operation of switching devices and the sudden loss of a terminal and the subsequent change in the DC voltage.

Cases like start-up and loss of generation of motors, load-shedding, line or transformer switching... can be analyzed. Each of the effect of these events should be studied independently and in thorough and could provide valuable information for the prediction of overcurrent and overvoltage resulting from system disturbances for the design parameters of valves, cables, protections…

Several simulation tools can carry out EMT simulations, but the most used ones for power dynamics are PSCAD or AMT. [55,56] describe a pole-to-ground and pole-to-pole fault in PSCAD/EMTDC environment respectively.

Chapter 4

Voltage Source Converter

Widely used for motor drives, they started to appear for HVDC systems in 1997 and nowadays most of the projects use this system. Although IGBTs are the most used ones, date turn-off thyristors (GTOs) and integrated gate-commuted thyristors (IGCTs) can also be used.

Inside the Self-Commuted-Converter group, output voltage VSC is the most advantageous for high Voltage transmission lines. Self-commuted VSCs are more flexible than the more conventional Current Source Converter since they allow controlling active and reactive power independently [17].

4.1 VSC capabilities

After having reviewed the difference between the mayor transmission lines technologies available, the main services offered by VSC HVDC to wind farms and TSOs are described below [17]:

- Conventional power plant behavior: The most important issue for the transmission system operator is that a VSC-HVDC connected wind farm installation has the capability to behave as a conventional power plant, since this one should be capable of maintaining short-circuit current to acceptable levels, avoiding grid bottlenecks and achieving voltage stability.

- Frequency support capability: The functionality of VSC allows a fast abortion or production of active power (during a short limited time) through the imbalance between the absorbed power from the wind farms and the power injected in the onshore side.

- Voltage support capability: The converter can be used to compensate the needs of the network in reactive power.

- Response to disturbances: Besides providing a good attitude for frequency or voltage support, the VSC-HVDC also offers a wide fast control that improves the dynamic performance of the system under disturbances. This high response speed enables the VSC to control the transients and flicker, keep the AC bus constant and provide effective dumping for avoiding electromechanical oscillations.

- Black start: Since the converter has the capability of the instantaneous switching over of the internal frequency and voltage level, it can behave as an AC source for a not energized grid or for a network without any voltage source.

- Difference towards LCC: HVDC transmission lines start having importance with the power electronics development, first with thyristor based LCC and after with IGBT based VSC. HVDC systems based LCC technology has a long and successful history, because thyristors are the key components of this converter topology and have offered high level of reliability and robust design. Nowadays, the second one is more promising and used for future projects; [27, 28] describe the main reasons for choosing VSC technology among LCC.

4.2 Modeling of VSC

In order to carry out simulations with a VSC-HVDC and understand its behavior, its principal components must be modelled and parametrized. As mentioned before, the main components of VSC-HVDC are mainly: Converter, transformer, phase reactor, DC lines and the DC capacitors. In documents [29, 30, 31] the modelling and parametrization of the components are studied. These components are modelled as follows:

4.2.1 Converter

This power electronic device will change the AC side current in DC or in the other way around. It can be considered as an equivalent voltage source that can shift the phase, the frequency and the amplitude of the sinusoidal wave. The following equation can represent the behavior of a VSC modulated with Pulse Width Modulation (PWM) [31]:

$$v_c = \frac{1}{2}u_{dc}Msin(w_c t + \delta) + harmonics \tag{4.1}$$

Where M, w_c, and δ are the pulse modulation index, the fundamental frequency and the phase angle.

The VSC supports sinusoidal and rectangular modulation. Rectangular modulation means that there is a fixed on-off ratio of the pulse stream. In case of sinusoidal modulation, also known as PWM, the average of every on-off pulse corresponds to the reference-sinus. However, the spectrum of their waveforms contains not only the fundamental frequency, but also higher order harmonics. The higher the pulse frequency, the higher harmonics frequency, therefore the harmonic losses will decrease considerably. On the other hand, the higher the number of commutation per second, the higher of switching losses [32].

In most cases, the Sinusoidal PWM is considered, where the basic working principle is to compare a sinusoidal voltage to a triangular wave. If the control signal is larger than the carrier wave, it will switch on the corresponding valve (normally IGBTs) in the converter and if it is smaller it will switch it off.

Finally, for achieving large converter ratings, series-connected valves are arranged in different topologies; two-level, three level or multi-level bridge [33]. The last one is the most complex one and normally the first two are the most used.

4.2.2 Phase reactor

The phase reactor can be modelled by an inductance in series with a resistance.

4.2.3 Transformer

As shown in [34], plenty of parameters can be taken into account in order to model a transformer and represent its behavior, where series reactance and resistance with parallel reactance and resistance together with a π model are used. However, in most of cases it is only represented with a reactance and resistance in series.

4.2.4 DC capacitor

The DC capacitors play a big role in the quality of power delivery of all HVDCs, since they can reduce the ripple and store energy from the grid and give it with flexibility in low frame of time. Therefore, the fluctuations in the DC voltage mean that the power balance in the HVDC could be broken. The power will depend directly on the intensity delivered by the capacitors, which can be found in any fundamental book about electronic devices as [35].

4.3 Control structures and strategies

Reference [36] makes the difference between the two major control modes of VSCs, direct control mode and vector control mode. The advantage of the direct control strategy is its simplicity itself, but the vector control mode can control better the active and reactive power independently. In this thesis, the second control mode will be reviewed below and used for the corresponding simulations. [37, 3] are one which is the most well-documented and widely used today. This thesis studies the behavior of HVDC connected offshore wind-parks, therefore, there are going to be two converters, one in the onshore side and another one in the offshore side. Although only the onshore controller is going to be controlled with the vector control method, this is the most complex and the most used and is going to play a big role in the control strategy in this thesis.

4.3.1 DQ Frame

To start, the voltage law for the VSC is given by:

$$\vec{v}_c^{ref} = \vec{v} \tag{4.2}$$

Where the superscript c denotes the converter *dq frame*, which means a rotating reference frame with the *d axis* aligned with the vector $\vec{E}_s$.

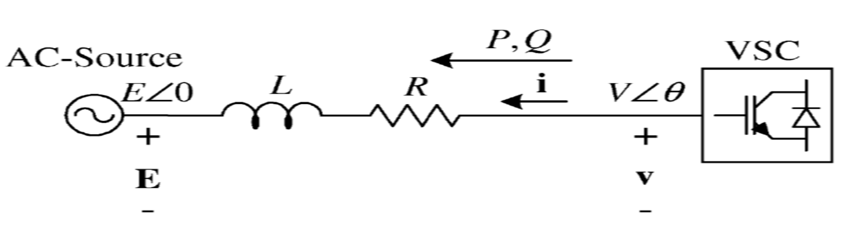


Figure 4.1: Single-line representation of a VSC-HVDC system [3]

Applying the Kirchoff´s law to the circuit of the figure 4.1 the following expression can be obtained:

$$L\frac{\vec{i}^s}{dt} = \vec{v}^s - \vec{E}^s - R\vec{i}^s \tag{4.3}$$

By aligning the *d axis* with $\vec{E}^s$ the following relations can be obtained:

$$\vec{E}^s = \vec{E}e^{jwt} \tag{4.4}$$ $$\vec{i}^s = \vec{i}e^{jwt} \tag{4.5}$$ $$\vec{v}^s = \vec{v}e^{jwt} \tag{4.6}$$

Combining equations 4.3 4.4 4.5 4.6 , an expression that represents the dynamic behavior could be reached:

$$L\frac{\vec{i}}{dt} = \vec{v} - \vec{E} - R\vec{i} - jwL\vec{i} \tag{4.7}$$

And written in *dq frame*:

$$L\frac{i_d}{dt} = V cos\theta - E - Ri_d - wLi_q \tag{4.8}$$

$$L\frac{i_q}{dt} = V sin\theta - Ri_q - wLi_d \tag{4.9}$$

If the *dq axis* and real and imaginary parts are aligned, the active and reactive power delivered by the AC grid can be expressed as below:

$$P = v_{s,d} i_{s,d} \qquad (4.10) \qquad\qquad Q = -v_{s,d} i_{s,q} \qquad (4.11)$$

And the DC power flow through the DC lines can be given by equation 4.12:

$$P_{DC} = -u_{DC} i_{DC} \tag{4.12}$$

4.3.2 VSC control scheme

A common control scheme of a VSC is shown below [30, 31]:

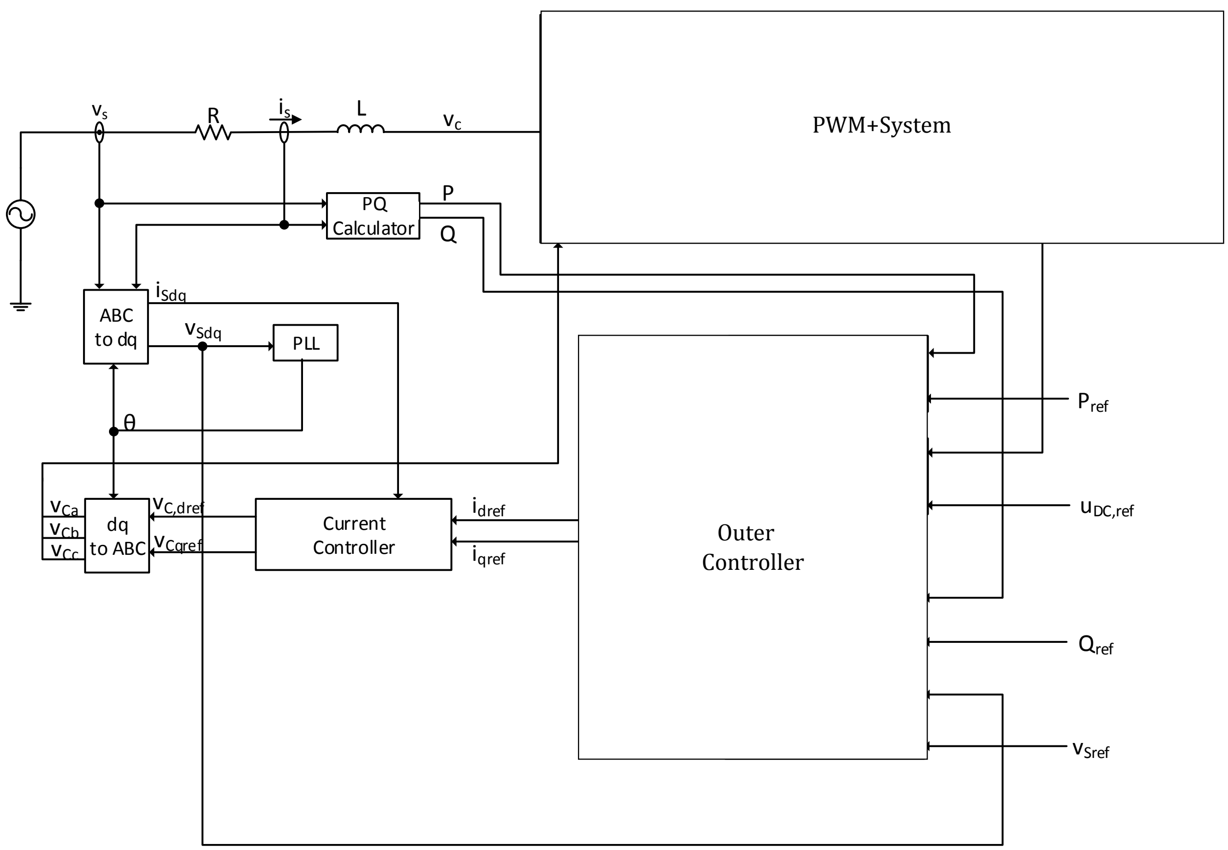


Figure 4.2: VSC control block system

4.3.3 Outer controller

The outer controller will ensure that the desired reference parameters are in the desired level. These parameters could be DC voltage, reactive power, AC voltage and active power. The current in the direct axis will control DC voltage or the active power and the current in the axis of quadrature will control the AC voltage or the reactive power.

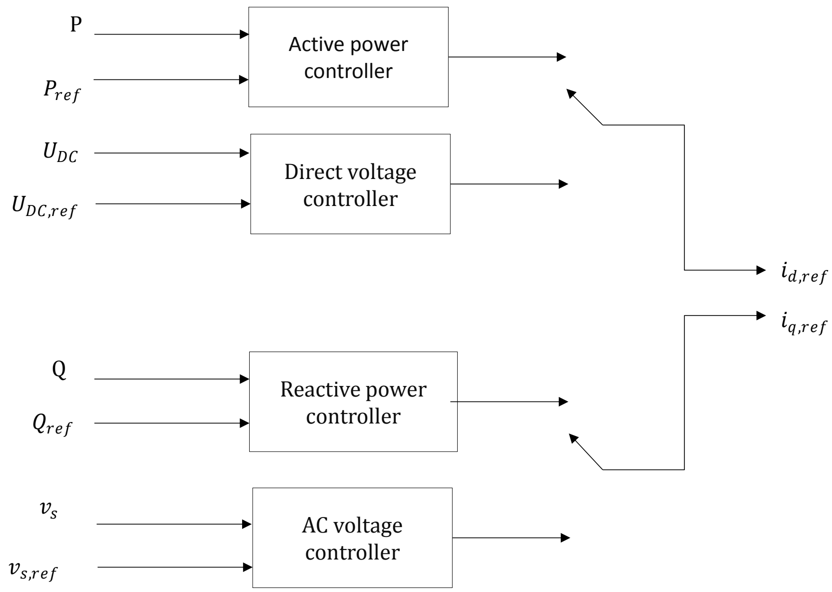


Figure 4.3: VSC outer controller block diagram

The control of the DC voltage ensures the balance of the active power through the DC lines. Apart from that, for some applications, such as frequency support, a controlled imbalance could also be of interest. An offset current must be added to the output of the PI, this offset could be static or a feedforward from the measured voltages.

$$(u_{DC}^{ref} - u_{DC})(k_p + \frac{k_i}{s}) + (\frac{u_{DC} i_L}{v_{s,d}}) = u_d^{ref} \tag{4.13}$$

Equation 4.13 could be simplified by equation 4.14:

$$(u_{DC_{error}})(PI) + u_{DC_{offset}} = u_d^{ref} \tag{4.14}$$

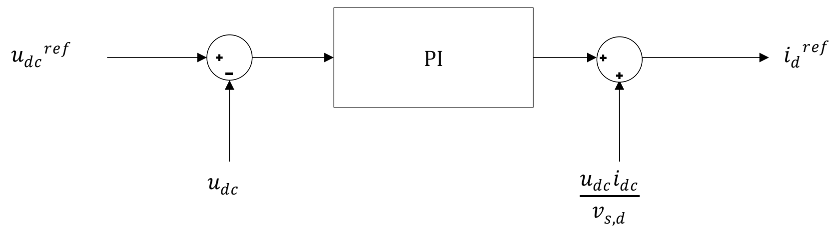


Figure 4.4: VSC DC voltage controller block diagram

The active power controller is a simple PI that regulates the error of the measured active power and the reference active power. Additionally, in order to create a current reference, a current offset has to be added, as done for the DC controller.

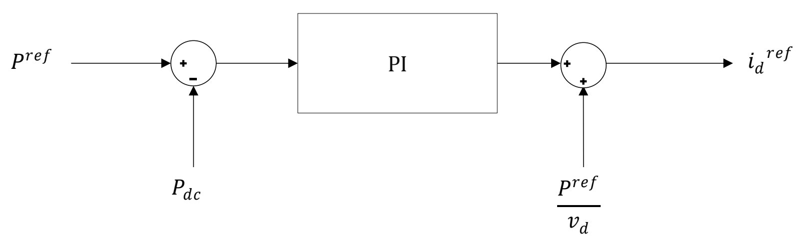


Figure 4.5: VSC active power controller block diagram

The reactive power controller will control the current in the axis of quadrature, but it is carried out in the same way as the previous one.
The AC voltage controller is usually implemented with a droop controller [37]. If the AC voltage magnitude is different from the reference voltage, the converter should consume or inject reactive power, depending on the sign of the error, thus, improving the alternate voltage profile in the AC side.

The AC voltage controller is usually implemented with a droop controller, although it may differ in different control strategy implementation. For this thesis, for instance, the control droop was implemented for the reactive current controller and it was combined with V_{ac} error, in order to provide better results.

4.3.4 Current controller

The current limiter block can be modeled just by a standard PI regulator. It will control the difference of the immediate and the reference current in both *dq axis* and calculate the pulse modulation for the real and imaginary part.

4.3.5 Current limiter

The synchronous generators could handle an overload state in some situation. VSCs, however, could get their valves damaged in an overload state (i.e. fault current). Therefore it is necessary to limit the reference current in the control scheme, in order to avoid damages in the structure [25].

This overload limiting is different when the converter is working in a steady state or in a fault condition (fault current limiter). Moreover, it usually depends also on the kind of grid we are connected. Therefore, the current limiting strategy can vary depending on several factors.
When the converter is working in steady state, three control strategies are distinguished in figure 4.6:

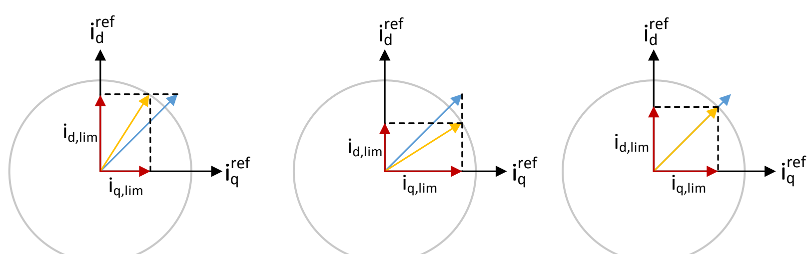


Figure 4.6: Current limiter [25]

In the three cases, the absolute value of the current in the moment is compared to a maximum value. If the value is higher, it will be limited and if it is lower, it will not be limited. In the first case, priority is given to the active power, so the VSC will try to deliver as much active power as possible. This case is appropriate for a DC transmission line which is connected to a strong AC grid. This one is going to be the current limiting strategy for this thesis. On the other hand, priority to reactive power is given in the second control strategy (AC weak grid). In the last one, the least common, the power factor is maintained constant.

Finally, the current is limited by the Fault Current Limiters (FCL), which limits fault current levels to a more manageable level. In this case, it is going to try to inject as much reactive power as it is possible in the grid.

4.3.6 Phase-locked-loop (PLL)

In vector control strategy, the real-/reactive-power controller and the controlled DC-voltage power port, is controlled in a *dq-frame* [37].

4.3.7 Physical model

In order to have an idea about how the control blocks interacts with the whole DC and AC system sides and converter, a simplified analysis has been done below. Figure 4.2 shows the most typical system for a VSC through vector control.

- System: Recombining the terms and applying Laplace conversion to equations 4.8 and 4.9, the following equations are given. It can be seen that there is a cross-coupling of the two axis.

$$V_{s,d}(s) - V_{c,d}(s) = sI_d(s) + RI_d(s) - wLI_q(s) \tag{4.15}$$

$$V_{s,q}(s) - V_{c,q}(s) = sI_q(s) + RI_q(s) - wLI_d(s) \tag{4.16}$$

- Converter: It is assumed that the input of the PWM should be the magnitude of the three components of the voltage, transformed from the *dq frame*. As the converter voltage will follow the reference without any delay and the harmonics caused by the switching will be removed by the phase reactors and AC filters, the following assumption can be made:

$$V_{c,dq} = V_{c,dq}^{ref} \tag{4.17}$$

Chapter 5

Wind parks and grid stability

The generation of the wind power has been developed during the history and nowadays there is a great variety to choose. Depending on the application, the good choice of the WTG plays a big role in the design of a wind farm. Classification in “types” is the most used:

- Danish Concept: Type 1
- Advanced Danish Concept: Type 2
- Standard Variable-speed WEC: Type 3+Type 4
- Direct-drive WEC: Type 4

Fixed-speed wind turbines are connected directly to the grid and the grid will hold the wind turbine speed constant, where optimal power extraction, maximum power point (MPP) cannot be done. Variable-speed wind turbines, in contrast, are connected to the grid through a power converter. This converter decouples the grid frequency and the generator speed and therefore, an optimal power extraction from the wind is possible.

5.1 Ancillary services in wind generation

Due to the variability and non-predictable behavior of the wind, the integration of the wind power plants in the grid is more complicated than conventional plants. Until now, the conventional power plants support the grid stability with its ancillary services while there were no or just few grid requirements for grid-connected wind farms. The most significant difference between conventional and wind generation is the energy source, since the wind energy as a fuel source is inherently uncontrollable and varies over time. Moreover, the electrical characteristic of the wind turbines in the grid have also a different responses and output than conventional generator. The first wind turbines did not have the same grid requirements, regarding to active and reactive power controllability, as they have now.

When it comes to active power, they were allowed to fluctuate with the available wind while maintaining the synchronizing speed, as they did not take part in voltage of frequency regulation of the grid. With reactive power, on the other hand, they could also absorb reactive power in some cases to maintain their power factor; whereas the conventional power plants can generally regulate the bus voltage they are connected to.

However, wind generation has now a much bigger penetration than it has in the past. At high level of wind power penetration, the need for ancillary services increases and it calls for a developpment of the wind power plant controls that allow them to behave in the same way than conventional power plants [18].

5.1.1 Active power control

- **Governor response:** In case of wind power plants, the available wind in every moment set the upper-limit of power that can be provided by a wind farm. The variable-speed generator is able to find this maximum power point, but they will never be able to cross this upper-bound. For underfrequency cases, in order to increase power over a sustained period, the generator must be limited at first to maintain a primary reserve, which leads to a continuous loss of energy productions and underutilization of the wind resource. However, the provision of governor shall be enabled by an ancillary service agreement and scheduled by the TSO (transmission system operator).

- **Fast-frequency response:** System events including the loss of generation and therefore, frequency excursions result in transient depressions of the system.

- **Power scheduling:** Wind generation can usually produce less power than is available from the wind, as discussed earlier. Limiting the output power also known as “curtailment” could be of special interest due to congestions (due to infrastructure limitation) and reserve limitations (constrains on other resources providing various reserve ancillary services) of the grid.

- **Ramp rate control:** The ability to hold and ramp the output power. This enables the wind generators to provide ramped power increase or decrease. Since it can be set faster and slower than big conventional power plants, this ancillary service could be more flexible in wind generators.

5.1.2 Reactive power control

Wind farms, especially large remote offshore wind power plants, may consist of hundred or individual wind turbines, separated by a great distance from the electrical collector system. The manufacturers use a hierarchical voltage control, where improved voltage/volt-ampere reactive (VAR) control is implemented in each turbine. In this way, the control of the wind farm coordinates all the reactive power support of each wind turbine hierarchically, which minimizes voltage flicker, improve network stability, reduces the voltage collapse and minimizes the impact of disturbances.

5.2 Modeling and control strategy of type3 DFIG generator

The VSC-HVDC used for the simulations in this thesis is connected to a wind farm composed by 80 type 3 WTGs, since it is one of the most widely used technology for wind energy production. Thus, only this type of WTG is going to be of interest. The working and control mode may differ from one generator to another.

It is based on an induction generator with a multiphase wound rotor and a multiphase slip ring assembly with brushes for the access to the rotor windings. Regarding to efficiency, cost and size issues, the better alternative is the brushless wound-rotor doubly-fed electric machine. The rotor windings are connected to the grid via slip rings and a back-to-back voltage source converter. The stator, on the contrary, is directly connected to the grid without any converter. Thus, only the 30% of the power exchange flows through a converter and therefore, the power losses and costs in power electronics decrease compared to a full-converter type 4 wind turbine.

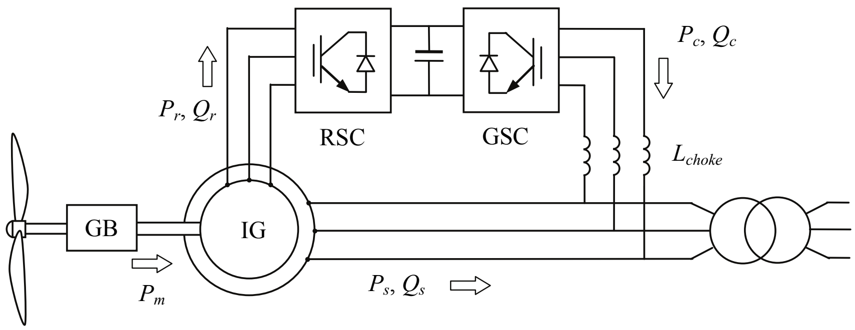


Figure 5.1: DFIG simplified scheme [38]

5.2.1 RSC (Rotor Side Converter)

The biggest characteristic of this generator is that it can control the voltage of the rotor and the currents that are exchanged with the grid through the rotor. By changing the rotor voltage, the generator torque-slip characteristic is changed and therefore, the rotor frequency can freely differ from the grid frequency. In figure 5.2 can be seen how the rotor speed changes when the wind-speed changes in order to find the maximum power point.

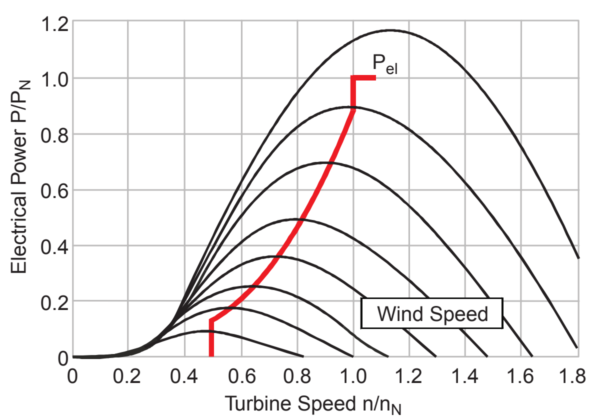


Figure 5.2: Wind turbines MPP curves[38]

On the other hand, by adjusting the rotor current, the exchanged active and reactive power can be shifted. When it comes to control strategy, two control strategies can be carried out; current vector control or direct torque control strategies. For this thesis, the current vector control is used.

5.2.2 GSC (Grid side converter)

There is a capacitor between the RSC and the GSC, which aims to maintain the DC voltage and avoid ripple effects. The grid-side converter will regulate the dc voltage in the capacitor. It is allowed to generate or absorb reactive power for voltage support requirements. The reactive power is regulated by shifting the current in the q axis and the dc voltage by shifting the one in the *d axis.*

The equations 5.1 and 5.2 show the dependency of the mechanical power in the rotor with the w_r rotor speed and the β pitch angle. The curves of the mechanical power can be seen in figure 5.1. By changing the β, the curve can be modified and thus, the absorbed mechanical power also.

$$P_m = Cp(\lambda, \beta) V_{wind}^3 \tag{5.1}$$

$$\lambda = \frac{w_r R}{V_{wind}} \tag{5.2}$$

5.2.3 Control frame

The power flow goes through the rotor P_r or the stator P_s. The flows are related as follows:

$$P_r = P_m - P_s = T_m w_r - T_{el} w_s = -T_m(\frac{w_s - w_r}{w_s}) w_s = -sT_m = -sP_s \tag{5.3}$$

$$s = (\frac{w_s - w_r}{w_s}) \tag{5.4}$$

Where s is the slip and w_r and w_s is the rotor and stator angular speeds, respectively. When s>1 the generator is working in sub-synchronous like a traditional induction generator. When s<1, the generator is working in super-synchronous mode. The rotor and stator power flow direction depends on the slip [38]. In this thesis, the generators are going to work only in super-synchronous mode, in constant wind speed and with β control, in order to simplify the analysis.

Chapter 6

Modeling and ancillary service implementation

6.1 "HVDC Connected Offshore Wind Farm" template

Regarding the simulation, a model for VSC-HVDC has to be created or chosen. There were already several models available from other sources, so it was thought that for this master thesis the most appropriate solution was to choose an already validated template and simulate it with the same programming tool. From the several models of VSC-HVDC until now developed [39, 40, 20, 37], the model of a HVDC link for 400MW offshore wind farm consisting of DFIG wind turbines was chosen. There were two reasons why the *PowerFactory* model was chosen:

- The model also includes a detailed DFIG type4 WTG windfarm and its offshore converter is specially designed for offshore wind park connected HVDC (as it is explained below in more detail), therefore, less changes have to be made to the converter control strategy.
- This model is appropriate to carry out RMS simulations for stability studies: In this thesis slow dynamics power system stability (symmetrical fault current frequency and voltage deviations and frequency stability) is studied. As explained previously in Chapter3, for power system stability studies there is a determined time range of interest that can be analyzed by RMS simulations. *PowerFactory* models can perform both EMT and RMS

simulation, depending on the study case. For every model in *PowerFactory* platform, both equations for EMT and RMS modeling has been done. However, RMS simulations are usually run in this program. A model reduction is usually of interest in the RMS simulations, in order to decrease computational time with the accuracy that may not be needed for the specified study. For example, in case of long-/mid- term stability study, transients that disappear quickly might not be of interest. The model reduction should be performed in order to eliminate small time constant related to the system, and this coincide with the assumption that fast dynamics are instantaneous compared to slower. One advantage is that there is no need for so much data as in the fast dynamics and therefore, it is possible to use a larger integration step size, increasing the calculation speed.

PowerFactory offers a library which contains pre-defined models such as bus-bar system models, converters or wind farms. There is also the possibility to use user-made models or macros from the library and combine them together with the predefined models via the use of so called composite frames. The software *Power Factory* contains a Dynamic Simulation Language (DSL) which enables the user to customize the given model [42].

In this thesis the VSC-HVDC connected offshore wind farm described in [43] has been taken as starting point. Also the behavior of the PWM-controller described in [32] and of the DFIG [44] have been of great importance.

The *PowerFactory* model is mainly divided in two main areas; VSC-HVDC(figure 6.1) and a 400MW wind farm(details in Appendix). The HVDC model provided by *DIgSILENT* is mainly composed by a bi-pole, mid-point grounded HVDC link, with onshore and offshore PWM controlled VSCs (Voltage Source Converters). Additionally, other components previously explained in chapter 4 (phase reactor...) also have been attached and modeled.

The wind farm connected to the HVDC link consists mainly of 80 wind turbines. Each wind turbine has a nominal active power of 5MW. The machines are equipped with doubly-fed induction generators (DFIG, wind turbine type 3). Only 10 of the 80 wind turbines are modelled as in individual machines (these are represented in the Detailed Feeder single line diagram). The other 70 turbines are represented in only 4 turbines. Three of those four models represent 20 WTGs each one and the other model represent 10 WTGs.

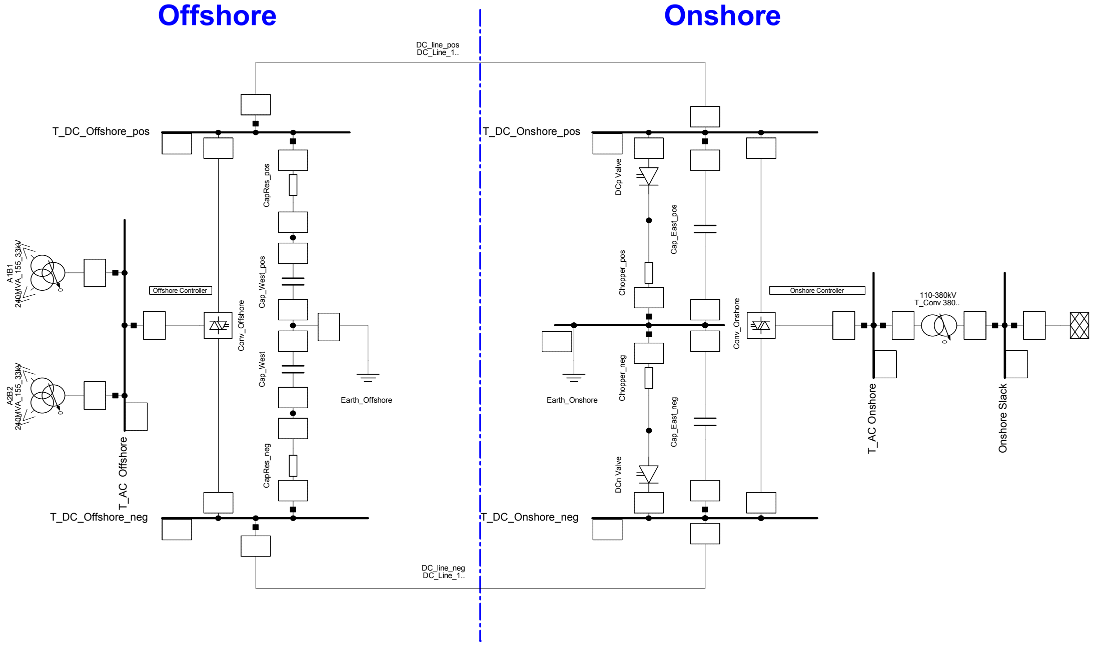


Figure 6.1: Single line diagram from the HVDC system as modeled in *PowerFactory*

6.1.1 VSC controller

PWM

The controllers of the converter´s output signal control directly the PWM converter. Through this method, the relationship between direct and alternate current and the frequency could be shifted.

As it can be seen in the PWM converter model in *PowerFactory* user manual [32], the model is based on a fundamental frequency approach where at fundamental frequency, the ideal converter can be modelled as a DC voltage controlled AC voltage source, described by the following equations.

$$U_{AC_r} = K_0 * P_{m_r} * U_{DC} \tag{6.1}$$

$$U_{AC_i} = K_0 * P_{m_i} * U_{DC} \tag{6.2}$$

Where U_{AC_r} and U_{AC_i} are the real and imaginary AC voltage, respectively, P_{m_r} and P_{m_i} are the real and imaginary pulse-modulation, respectively, and K_0 is the modulation constant

If no modulation is applied, the modulation indices P_{m_r} and P_{m_i} are equal to one and the converter cannot be controlled. For this project, sinusoidal modulation is used so the modulation indices can be shifted and the modulation index is the one given below:

$$K_0 = \frac{\sqrt[2]{3}}{2\sqrt[2]{2}} \tag{6.3}$$

The equations 6.1 and 6.2 can only be applied for values of $abs(Pm) < 1$ (where Pm is the modulation index magnitude). Thus, this magnitude shall be limited.

For stability studies, the stability model of the PWM in DIgSILENT [32] is used. For stability simulations, the same fundamental frequency model as described above is used and the converter is controlled by the PWM indices. Depending on the application, the input of the PWM changes.

- The inputs of the onshore converter uses P_{m_r} and P_{m_i} inputs: In this setting, the inputs to the converter are the real and imaginary part of the modulation index. This requires phase measurements devices as they are represented in a *dq frame*.
- The inputs of the offshore converter uses P_m and f_0: In this case, the magnitude of the PWM index can be set whereas the f_0 allows the frequency of the output voltage to be shifted.

For this project, the control strategy analysis was the most important; in order to know how the model is going to react to stability disturbances and which ancillary services are already implemented in the model. However, the model is going to be verified apart, with the simulations of several events. The HVDC has two converters, one in the onshore side and the other one in the offshore side. Each one uses different control strategies as explained below:

Onshore controller

The onshore controller, as its name indicates, is the VSC located in the limit between AC grid and the DC transmission system. It converts the DC current from the DC transmission cables to the AC current in the network. Although its functionality may differ something, the control strategy is similar to the *dq frame* control strategy explained in Chapter4.

The block diagram of the onshore control scheme is represented below:

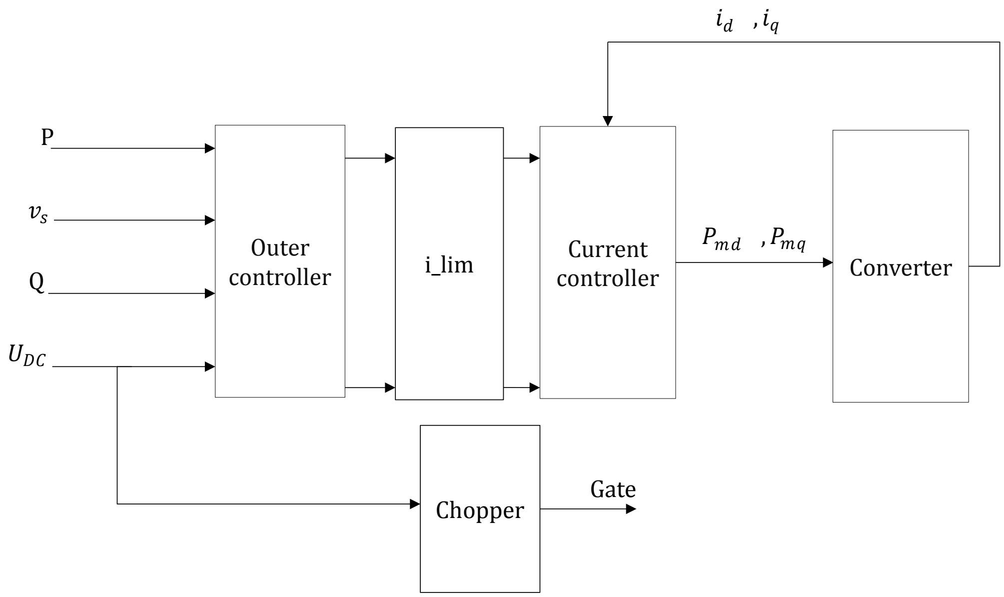


Figure 6.2: Onshore controller simplified block diagram

The outer controller calculates the current controllers of the pulse modulation index in both real and imaginary axis. The direct current axis outer controller controls the current value in the direct axis while the quadrature current controller controls the current in the axis of quadrature. These two i_d^{ref} and i_q^{ref} values should be limited according to the VSC requirements, the current limiter block covers that function.

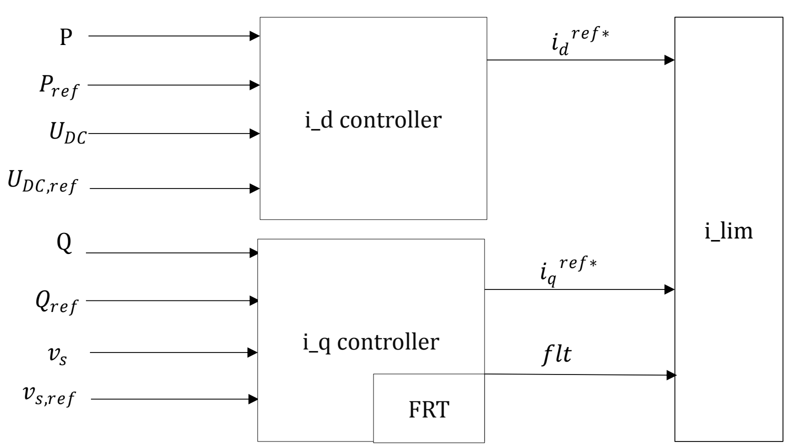


Figure 6.3: Outer controller simplified block diagram

As it is shown in figure, the onshore controller consists mainly in an outer controller, current controller (inner controller), chopper and the chopper controller.

- i_d controller: It estimates i_d^{ref} from the difference of U_{DC} and U_{DC}^{ref}. Since the HVDC carries the energy produced from a wind farm, the current will have a unique direction (from the wind park to the AC strong network) and could only store energy in the capacitor. This energy storage regulation could only be done by the regulation of the direct current; therefore, the active power regulation only depends on the direct current in the capacitor. As conclusion, we can suppose that the controller is also regulating the active power in this case. This property will be useful for the ancillary service implemented for the frequency regulation.

- i_q controller: First of all, it estimates i_q^{ref}, which could be changed depending on the control mode:

  -Reactive power: Calculates i_d^{ref} with a PI from the reactive current flow deviation.

  -Reactive power with droop: This is the control that is going to be used for this thesis. Its working principle is represented in figure. The i_q^{ref} parameter is calculated with a PI from the deviation of the drooped Q and the AC voltage reference.

  -AC voltage: It Calculates i_q^{ref} with a PI from the AC voltage deviation in the offshore AC network. In addition, it also sends a signal *flt* , which provides information about the "Fault-ride-through" activation. When the derivative of the V_{ac} is higher than a reference value U_t, the "Fault-ride-through" mode is activated. For this case the outer controllers are deactivated and the converter supports the grid with reactive current, with a value of the equation:

$$i_q = dU * K_{flt} \tag{6.4}$$

  , where the K_{flt} is established by the ENTSO [4].

- Current limiter: As explained in Chapter5, the module of the current has to be limited for the security of the valves. For this reason, the current limiter is used.

  -In normal conditions (FLT=0): Since the HVDC is connected to a strong AC network, the priority will be given to the current in the direct axis, and however, the assigned form should be decided by the ENTSO [4],

-In “Fault-Ride-Through” mode (FLT=1): When a fault occurs, priority is given to the current in axis quadrature and the module is limited. Active power will depend directly on the reactive power.

- Chopper controller: It activates the choppers when the direct voltage is higher than the reference. It will cause that part of the power stored in the DC lines will deviate to some resistors and dissipate there. It will be activated mainly in fault cases when a power imbalance occurs between the onshore and offshore sides of the line.

Offshore controller

While the onshore controller uses a *dq axis* control strategy, the offshore controller uses a more unusual control strategy, which only makes sense when the offshore controller is connected to an offshore wind farm, instead of being connected to a strong network. The PWM controls directly the offshore frequency and the AC voltage magnitude in the offshore AC network.

Figure 6.4 shows a simplified block diagram of the frame of the offshore HVDC control system. The parameter Pm regulates the magnitude of the network AC voltage and it is an output of the controller. The f_0 is the frequency and it is set in the nominal frequency 50Hz.

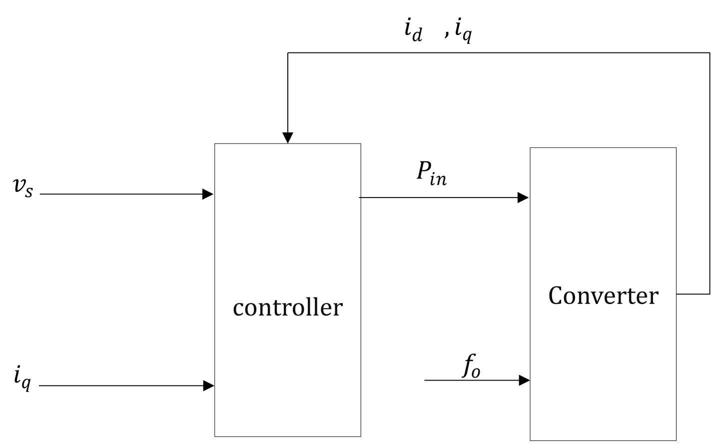


Figure 6.4: Frame of the offshore HVDC control system

The controller sends a pulse-modulation Pm signal depending on the input U_{AC}. It consists of a U_{AC} outer controller, a current regulator and a U_{dc} feedforward controller. The U_{AC_i} output of the current controller should be converted in a P_m signal for the converter. The pulse modulation signal will depend also on the U_{DC} of the moment (figure 6.5).

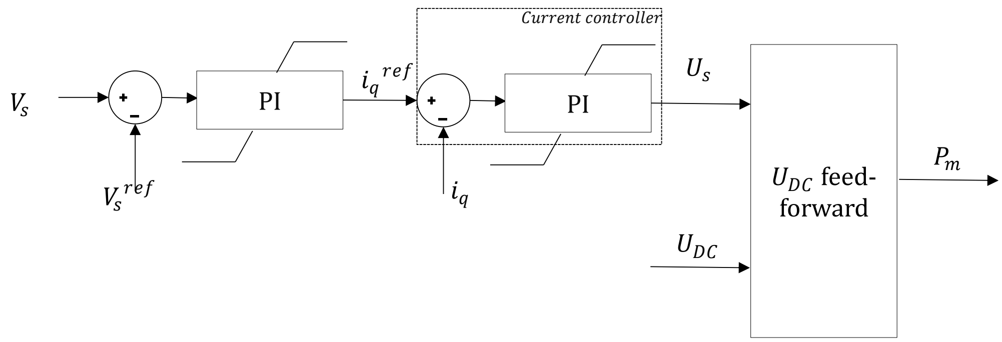


Figure 6.5: Controller structure of offshore converter

For values of $U_{ac}/U_{dc} > 0.7$, the linear relationship through the modulation index K_0 is not used anymore and the saturation curve starts for $P_m > 0$:

6.1.2 DFIG controller

The wind farm is composed by 80 WTGs (Doubly-fed induction generators). These generators are also provided with their control and protection system. Since the ancillary services that a DFIG can provide could be useful for the overall wind-farm and HVDC combination, the control scheme has been analyzed. A typical control structure is shown in appendix.

The most significant control blocks of the template are the following ones [10]:

- Maximum Power Tracker (MPT): Depending on the wind-speed of the moment, sends a signal with the tracked rotor speed that will give the maximum power. For this thesis it will be deactivated, since the wind speed will remain constant.

- Pitch control: Controls the pitch angle of the rotor. In this model the pitch angle is calculated from the speed deviation, and does not take into account the active power deviation directly, however, torque and rotor speed are directly related. Thus, if the rotor speed changes itself the torque will also change.

- PQ control: It calculates the rotor current in *dq frame*, in order to regulate the active and reactive power. This model also contains the "fault ride through" operation mode.
- Overfrequency power reduction: It changes the active power reference in overfrequency cases.
- Speed-reference: It gives the reference speed of the rotor. This speed can be either MPT speed or a chosen speed which is not exactly the MPT speed. For this thesis, the reference wind speed is 1.2[p.u.] always, which is not the same as the MPT speed.

Ancillary service

The following ancillary services valuable for this thesis studies have been identified inside the model code:

- Fault ride through mode: The model contains inside the PQ control a "fault-ride-through" block, which detects a voltage deviation and provide the fault with reactive current by changing the rotor reference current.
- Overfrequency power reduction: This block provides a decrease in the active power generation for overfrequency grid instability depending on the frequency.

6.2 Original model verification

In order to show the lack of ancillary services when it comes to voltage and frequency support, stability studies with the base model were performed. These studies were performed in a simplified network (More detail in Appendix), because the objective of these studies was merely to make an analysis of the voltage and frequency response of the HVDC, in order to prove that the base model control strategy lacks of ancillary services and would not fulfill the ENTSO [4] grid code requirements.

6.2.1 Overfrequency case due to a 200MW load shedding

In this simulation a 200MW load is disconnected from the onshore busbar at 1s and is not connected again. As it can be seen in figure 6.6, the base model does not perform frequency support. Due to the decoupling of the onshore and offshore grids, the wind farm does not detect any frequency or voltage deviation when a disturbance occurs at the onshore side. Since the direct current level remains constant, it can be observed that the VSC algorithm does not use the capacitor capacity to store energy in order to support the frequency stability by shifting the direct current of the lines.

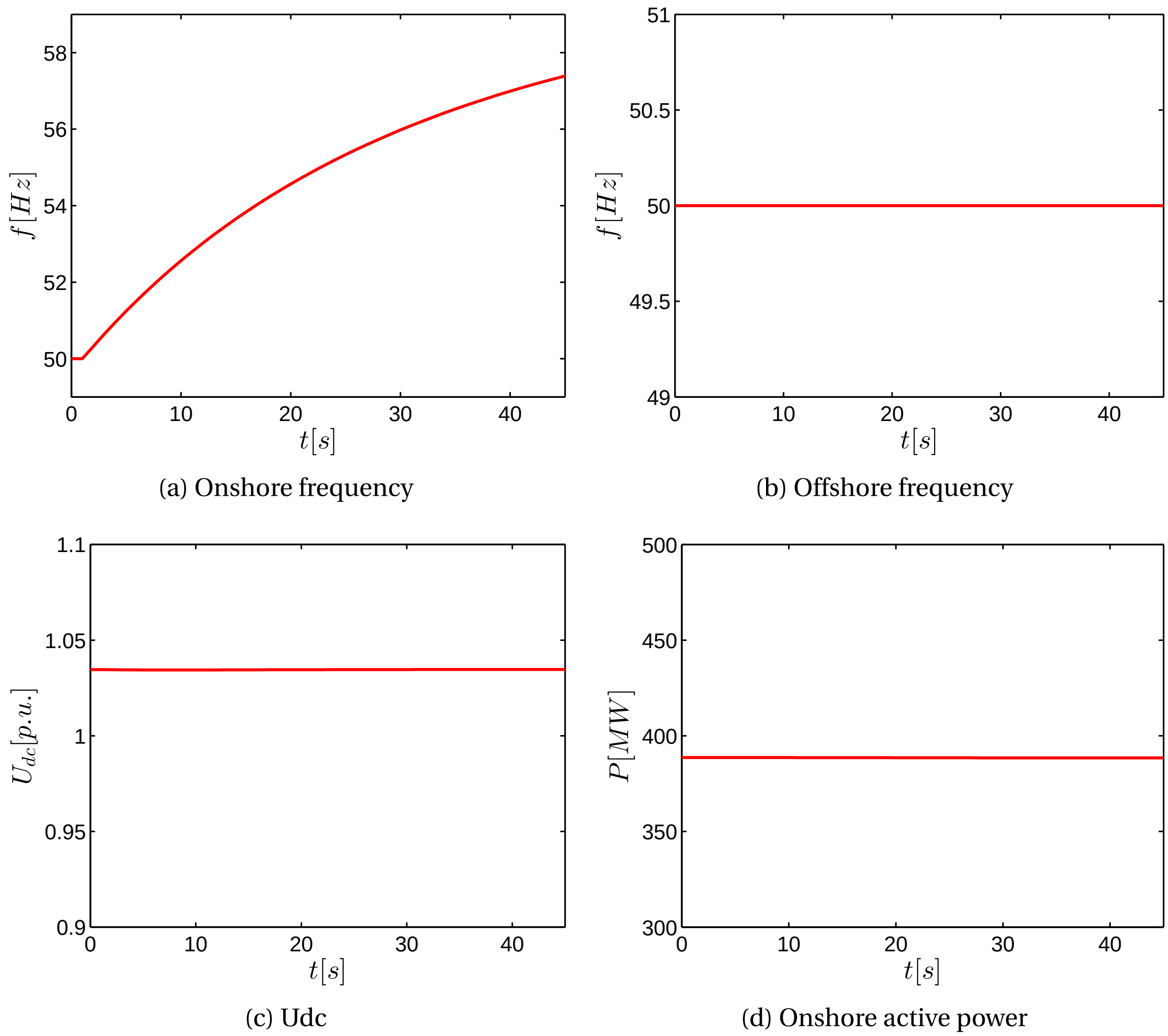
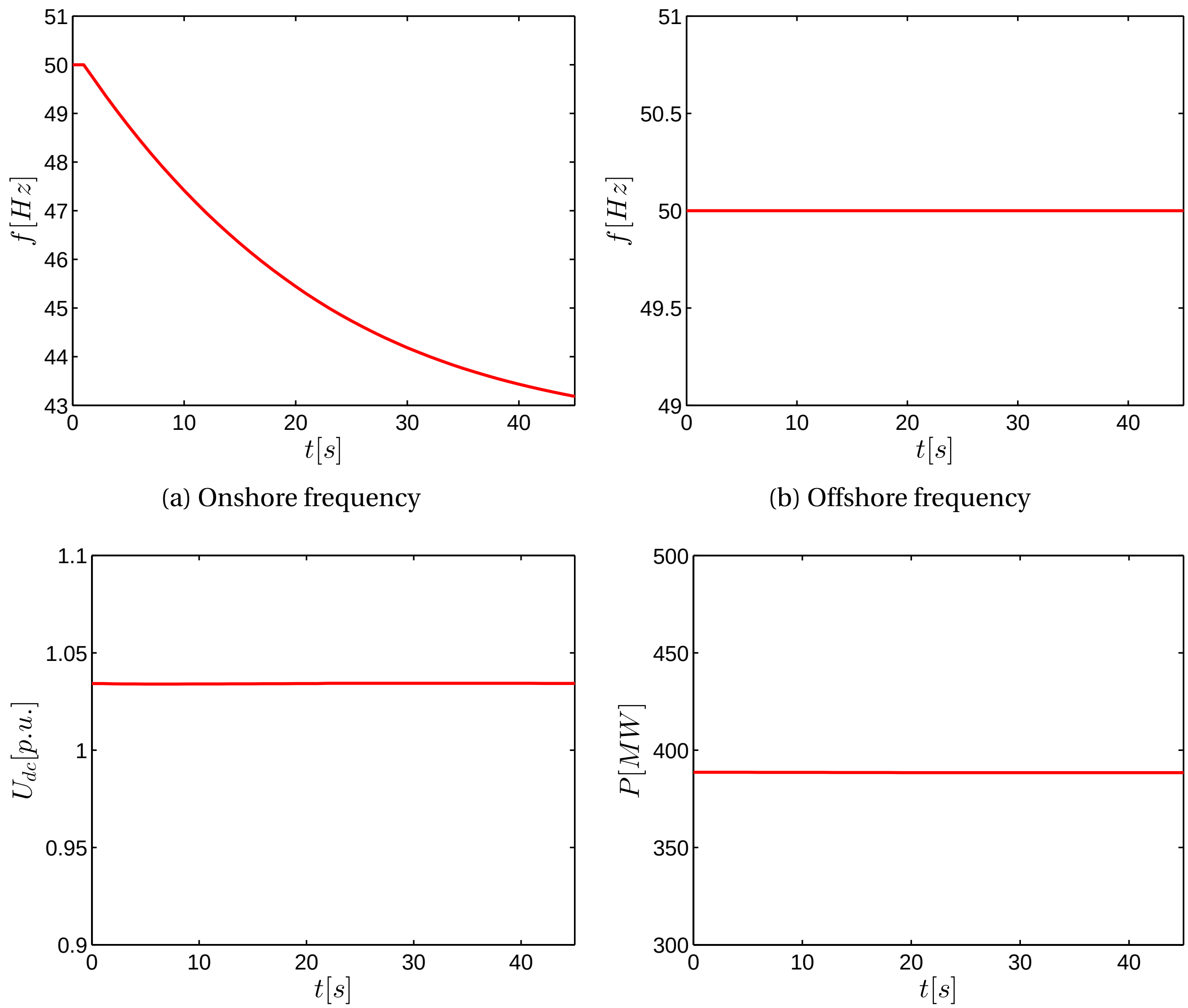


Figure 6.6: Overfrequency study with base model

6.2.2 Underfrequency case due to 200MW load connection



(a) Onshore frequency

(b) Offshore frequency

(c) Udc

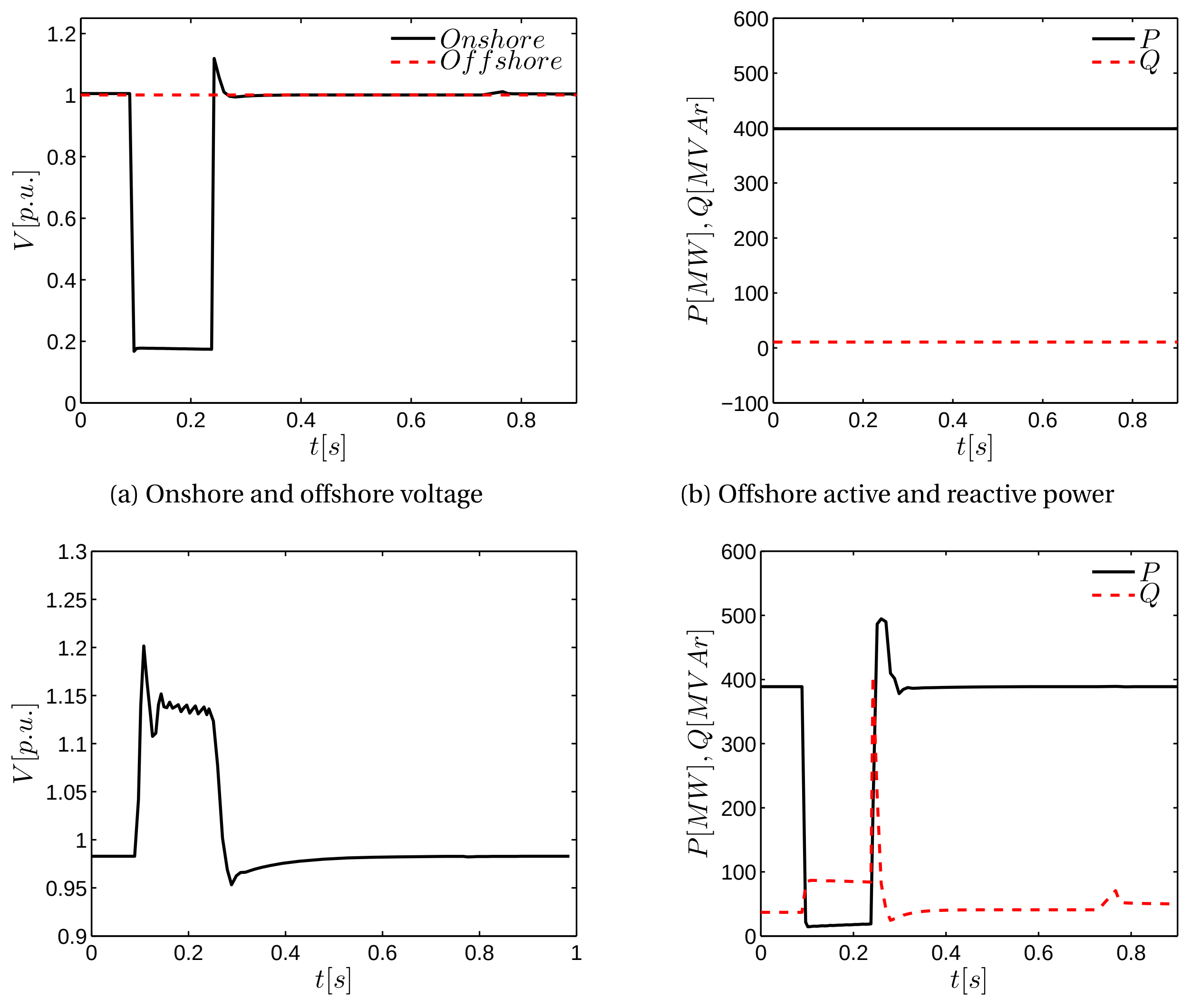
(d) Onshore active power

Figure 6.7: Underfrequency study with base model

6.2.3 Three-phase-fault in oshore bus bar

In this simulation, a three-phase fault is applied to the onshore AC terminal at 0.1 s and cleared after 0.15 s. The onshore converter has FRT capability and fast reactive current injection during faults. The voltage decrease rapidly, the FRT mode activates and the onshore converter starts to inject reactive current to the grid.

However, the WTGs do not active the FRT mode and do not make any reactive power support. Due to the decoupling of the onshore and offshore grids, the wind farm continues injecting active power during onshore faults (the active and reactive power that enters the offshore converter remains constant), and therefore chopper resistors are needed to disipate the injected active power and fulfill FRT requirements (Figure 6.8).



(a) Onshore and offshore voltage

(b) Offshore active and reactive power

(c) Udc

(d) Onshore active and reactive power

Figure 6.8: Onshore three-phase fault study with base model

6.3 Implementation of ancillary services

For implementing the ancillary services in the original model, the previous analysis and simulations of the implemented model and grid codes requirements have been needed. When it comes to frequency stability support, the following blocks have been added to the initial *PowerFactory* model; frequency support through capacitor charge or discharge, frequency support through changing offshore frequency level and Frequency support through sending a signal to the WGTs.

Regarding the voltage stability in a three-phase fault in the onshore side, active current ramp for post-fault state has been implemented.

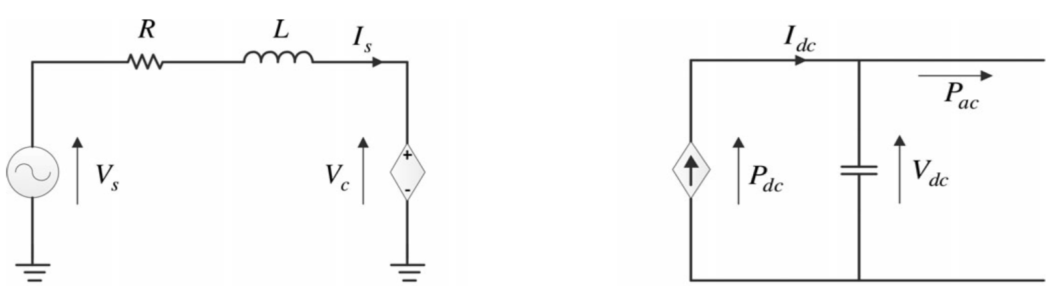
In order to guarantee stability support, changes and interconnection study of the WTG models and VSC-HVDC model are required. Therefore, changes will be carried out in the wind turbines models as well as in the VSC-HVDC model.

The model of *PowerFactory* uses DFIG wind turbines. As explained in the previous chapter, this kind of turbine does not contain the choice of primary reserve implementation in order to provide more active power in under-frequency events. Therefore, the DFIG type wind turbine control strategy has been studied and a primary reserve with its enhanced under-frequency controller has been implemented.

This passage will focus on how the ancillary services have been implemented in the base model. More details about the program coding in *PowerFactory* in the appendix.

6.3.1 Frequency support through the capacitors

An ancillary DC voltage control is implemented to regulate the frequency by increasing or decreasing the voltage level of the capacitors. The figure 6.9 shows how the DC and the AC sides are coupled with each other.



(a) AC side (b) DC side

Figure 6.9: Equivalent circuit of a VSC

As it can be seen, the two sides are coupled with each other with a controlled voltage and current source converter. The converter is controlled with magnitudes in quadrature strategy, the direct current control the active current while the direct in quadrature controls the reactive current. Only this control enables the independent control of active and reactive power flows. The output AC side power can be expressed as follows [35]:

$$P_{AC} = \frac{3}{2}(v_{d,c} * i_{d,s} + v_{q,c} * i_{q,s}) \tag{6.5}$$

The DC side can be given as:

$$P_{DC} = i_{DC} * v_{DC} \tag{6.6}$$

Applying the conservation law to figure 6.9 we can obtain the following equation:

$$P_{DC} = P_{AC} + C * \frac{v_{DC}}{dt} * v_{DC} \tag{6.7}$$

By combining the equations 6.5 and 6.7:

$$i_{DC} * v_{DC} = \frac{3}{2}(v_{d,c} * i_{d,s} + v_{q,c} * i_{q,s}) + C * \frac{v_{DC}}{dt} * v_{DC} \tag{6.8}$$

In the last equation it can be seen that to ensure the power balance between the onshore and the offshore side, the DC voltage maintains the same level. But from this expression it can also be deduces that the transmission line has also the possibility to unbalance the two power sources. In an underfrequency case, the transmission line can provide active power by discharging the capacitor and decreasing their voltages. On the other hand, in case of overfrequency, the HVDC could also store energy in the capacitors for a while by increasing the voltage level of them.

Following the law of energy conservation, the capacitor could store energy and absolve active power as follows [21]:

$$W_c = C * \int_{V_{DC}(t_1)}^{V_{DC}(t_2)} * v_{DC} * dV_{DC} \tag{6.9}$$

$$P_c = \frac{dW_c(t_1, t_2)}{dt} \tag{6.10}$$

In studies previously done [21, 45], it is shown how a big capacitor could inject or consume active power in overfrequency or underfrrequency events in the same way an HVDC could do.

Controller design

The next step would be to model the capacitor behavior and add it to the active current controller of the onshore side converter. The onshore side converter active current controller regulates the direct current voltage in the transmission line. Therefore, it is obvious that a change has to be made in the i_d controller.

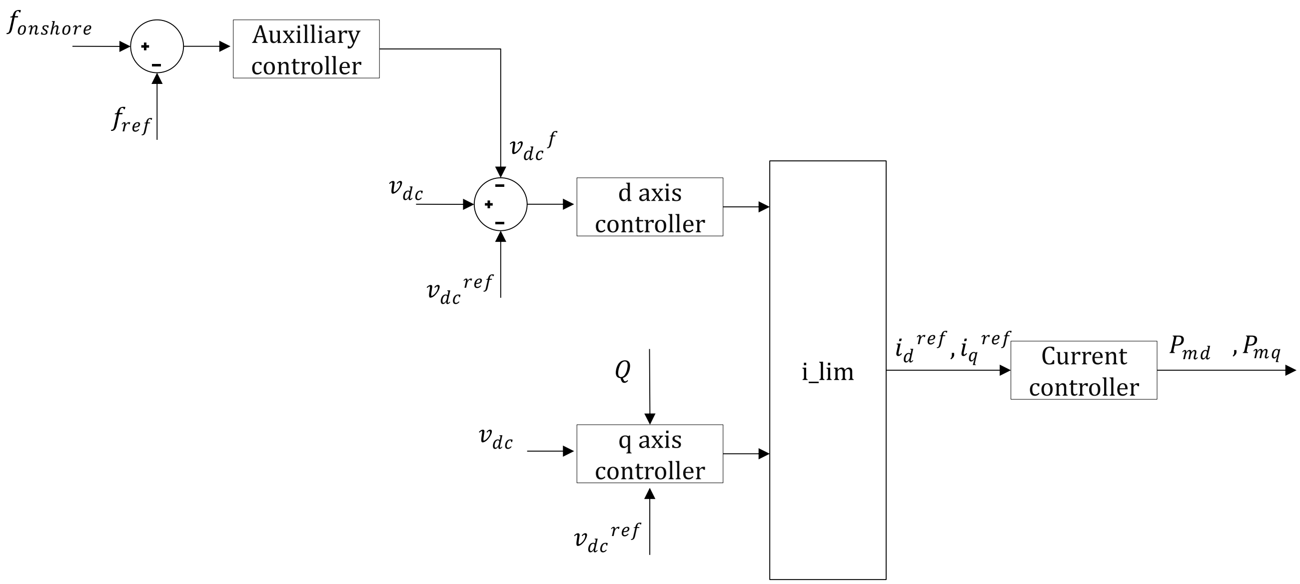


Figure 6.10: Modified onshore controller block diagram

An additional voltage reference v_{DC}^{f} is added to the nominal voltage reference when there are frequency variations. The additional dc voltage reference v_{DC}^{f} is determined by the frequency deviation, which is passed through a controller, that will modify the exchanged power through the capacitors.

The effect of the controller can also be observed in a more detailed inner-loop block diagram for further control investigations:

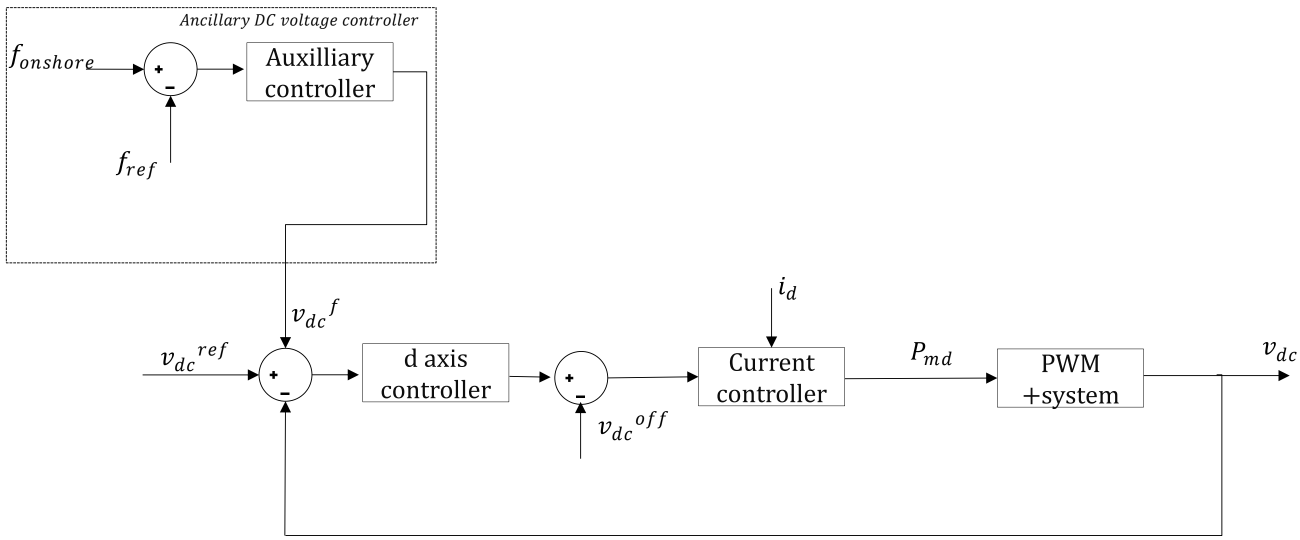


Figure 6.11: Modified onshore controller in interaction with the DC inner-loop block diagram

The controller of the ancillary service appears below in detail:

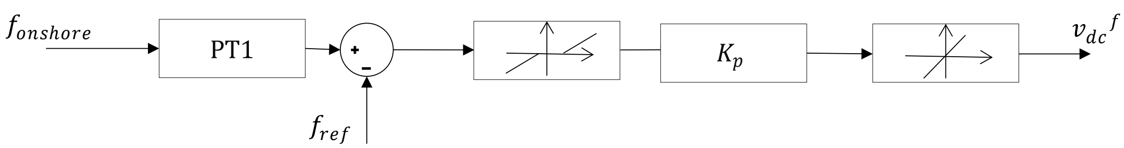


Figure 6.12: Detailed control scheme of the controller of the frequency support through capacitors

- Death band: As mentioned in the grid code [4] the frequency support shall only be activated when the grid frequency is out of the range 49.8-50.2Hz. Therefore, a dead band block is also needed in the ancillary DC voltage controller.
- Gradient limiter: The gradient limiter will control the v_{DC}^{f} slope. It has been deduced in this thesis that the best choice to control the power injected by the HVDC while respecting the stability issues from a control design (since the gradient limiter has a slow behavior), is limiting the gradient of the direct voltage. Like the equation 6.9 and 6.10 show, the slope of the direct voltage will determine the power deviation. If this is not controlled, v_{DC}^{f} will suffer from a sudden change and so the active power too. The objective of the v_{DC}^{f} gradient limiter is to maintain the injected active power in a certain limit for a certain time.

The gradient limiter will have different rate depending on the instability (overfrequency or underfrequency) and on the moment (if the capacitor is charging or discharging).
When the frequency measured is higher than the reference plus the death band, v_{DC}^{f} is limited to a ramp with a big slope, so the capacitors are charging progressively. When the disturbance disappears, the capacitors will be discharged very progressively in order to avoid a sudden active power injection in the grid. On the other hand, just the contrary happens when the frequency is decreasing.

- v_{DC}^{f} limiter: v_{DC}^{f} has to be limited in order to respect the maximum or the minimum DC voltage physically feasible in the system due to isolation issues. Therefore, when additional active power injection is needed, the DC voltage could only be decreased down to the minimum level and the same when active power reduction is needed.

6.3.2 Underfrequency support for DFIG

The DFIG already implemented in the original model [44] in *PowerFactory* had overfrequency support controller, therefore, only the underfrequency support block and the required primary reserve implementation were only needed.

Underfrequency support block

The underfrequency controller is used to enable the DFIG to provide inertial response and release active power reserve if applicable.

Ref.[21] describes how a full converter connected type 4 generator can make underfrequency support. The controller is composed by the inertia and the droop controller as can be seen in figure 6.13. The inertia controller does not have to emulate the inertial response of the generator as described in [21], since the stator is directly connected to the offshore grid. Apart from that, another reason is that the inertial response should be emulated for the onshore grid, instead for the offshore one. The droop is implemented to emulate the response of the speed governor. Hence, the underfrequency controller response can be modelled as shown in figure 6.13.

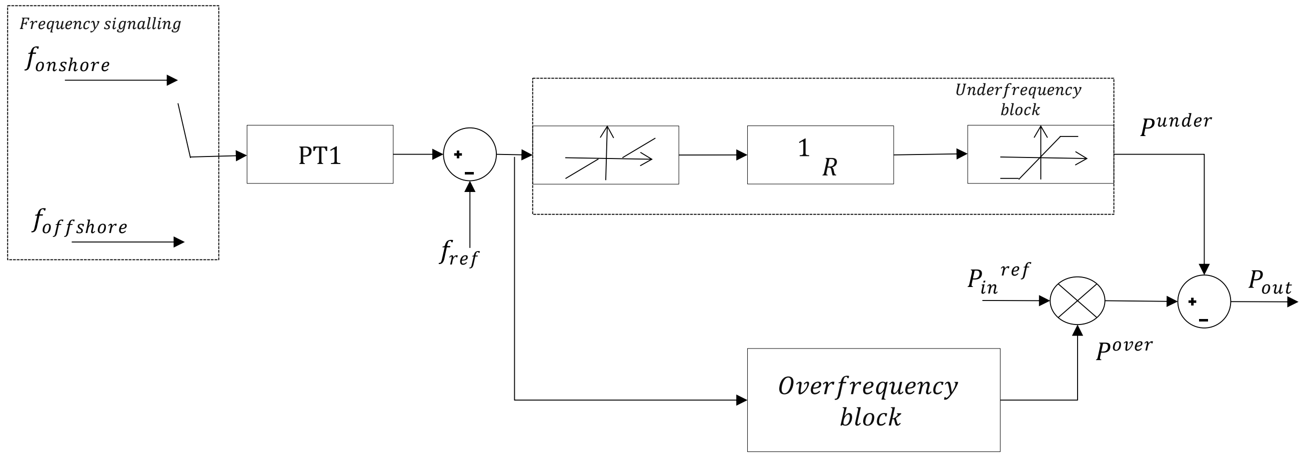


Figure 6.13: Detailed control scheme of the controller of the frequency support through capacitors

- Death band: According to the grid code [4] the controller shall be able to activate if the frequency drops lower than 49.8Hz. In order to decrease the ripple in of the read frequency a PT1 block is needed before the death band block.

- Active power limiter: The parameter P^{under} is going to be add to P_{in}^{ref}. Since P_{in}^{ref} means the active power reference in "p.u.", its value must be lower than 1. Therefore, since the primary reserve is going to be only of 10%, the P^{under} value has been limited to 0.1.

- Gradient limiter: The same strategy as in the overfrequency block has been carried out for the design of the underfrequency. The slope of the increasing active power in the turbines must be limited to have an optimal result in the result of frequency stability and avoid oscillations. The absolute value of the negative slope in [p.u./s] (underfrequency contingency) must be higher than the positive slope in [p.u./s] (when the injected nominal active power want to be recovered), however, the first one also has to be limited.

Primary reserve

When it comes to the primary reserve, conventional synchronous generators must be able to start providing primary frequency reserve up to 0.5s after the disturbance and providing the whole capability of primary reserve in 30s [4].

In Chapter 5 it has been demonstrated that the mechanical power of the turbine is not only a function of blade pitch angle but also a function of turbine rotor speed. Provision of primary control reserve by DFIG is feasible via their operation in sub-optimal mode [46]. This is achieved by reduction of the active power output from the maximum power point (MPP) curve to the so called sub-optimal curve, as indicated in figure 6.14. The maximal power point curve describes in which rotor speed we obtain the maximum mechanical power, in every time. The sub-optimal curve in 90% level describes in which rotor speed function are we obtaining the 90% of the MPP.

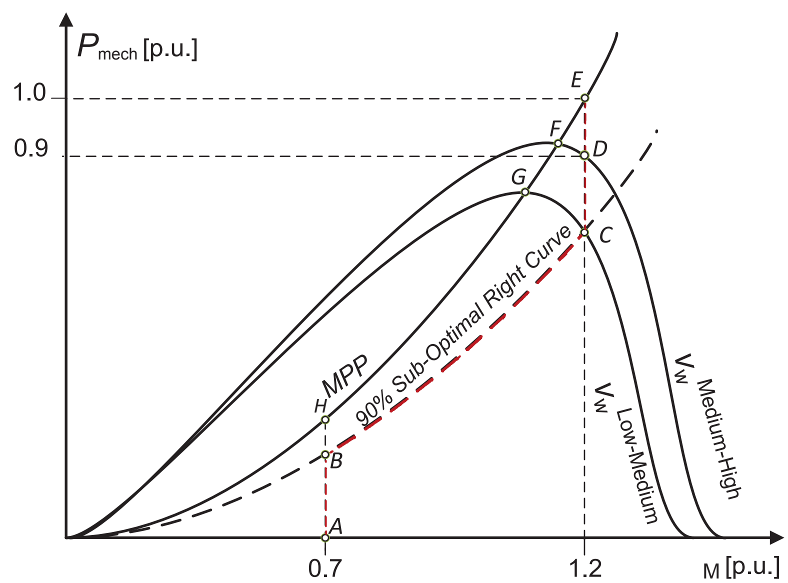


Figure 6.14: Wind turbine power-speed characteristics for maximum power point (MPP) and 90% sub-optimal power point operation [46]

Although different strategies consisting on pitch and rotor speed control in different speed areas are analyzed in paper [46], a constant high speed and pitch angle control is only considered for this master thesis, not taking into account the medium and low wind areas. In this wind speed area, pitch angle is the only controller which shifts the equilibrium point. We can see how it works in figure 6.15; the sub Optimal Curve is not working in the nominal rotor speed. In order to work in nominal electrical rotor speed at 90% mechanical power the pitch angle is the only controller which shifts the equilibrium point from $\acute{A}$ to A. Therefore, a $\Delta\beta$ is added as an offset to the pitch angle. It also shows the under-frequency (Line A-B-C) and over-frequency (Line A-F) responses of the machine.

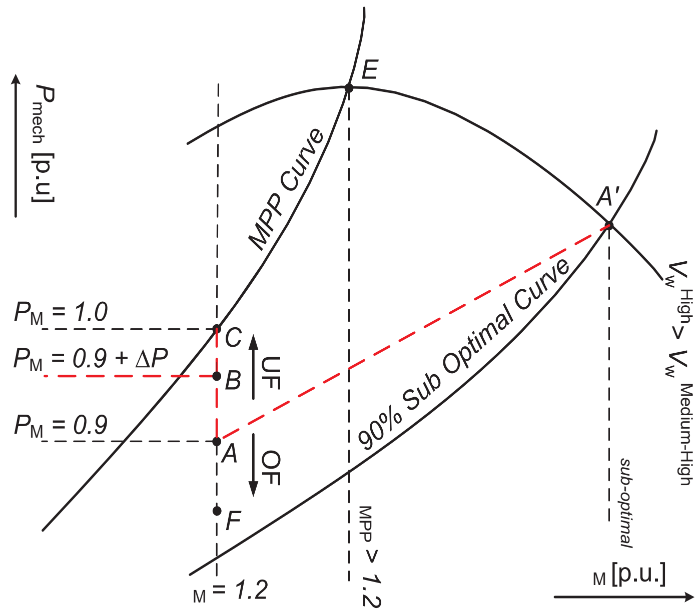


Figure 6.15: DFIG based wind turbine power-speed characteristics for 90% sub-optimal power point operation during medium wind speeds [46]

Changes were carried out in the base DFIG type model [44] in the following blocks:

- **Pitch angle controller:** The primary reserve can be modelled in the DFIG *PowerFactory* model by just adding an offset for the pitch angle as shown in the figure 6.16. In order to have a 10% primary reserve and be working in a 90% injected power capacity an offset value of 3.7° is added. In over-frequency events this angle will increase and in under-frequency events this angle will decrease until 0%, where a 100% mechanical power will be absorbed from the wind.

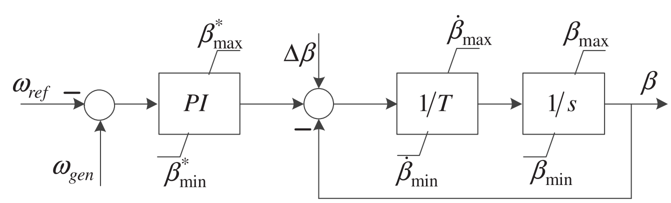


Figure 6.16: Modified pitch angle controller [21]

- **Rotor speed controller:** In sub-optimal mode for high winds, both active power and rotor speed will be regulated by the pitch angle regulator, therefore, the rotor speed regulator is deactivated for this thesis when a primary reserve is applied.

- **Initial conditions:** They must be changed to start with a pitch angle of 3.7°, an active power reference of 0.9 [p.u.]. Besides, the maximum power tracker must be deactivated and the initial rotor speed must be reduced, in order to work in a sub-optimal operation point.

6.3.3 Frequency signaling to the WTGs

The general method for frequency stability support of the wind turbine is to transmit the control and measurement data to individual DFIG converters via SCADA as it is shown in the figure 6.17 and 6.13.

Using this method, the offshore frequency will maintain its nominal value and the generators will be able to change the injected active power and take part in the frequency stability support. Apart from that, this way of frequency support is the best choice for the offshore wind farm owners, due to the fact that they do not have to modify the grid frequency itself, which brings often several problems regarding protection and transients issues.

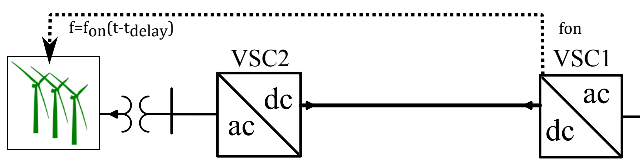


Figure 6.17: Signal to the WTGs

In order to be the most realistic as possible, transmission latency block is put in every measurement. Therefore, the DFIG controllers read the onshore side frequency with a latency (in this case this latency will have a value of 0.3s, instead of the offshore frequency as usual.

In case of frequency deviation the frequency controller will be activated and the generators will increase or will decrease their injected active power.

6.3.4 Frequency signaling to the offshore converter

Generally, the control and measurement data is transmitted as shown in the previous chapter. However, this direct communication could not be suitable for some events that require instant response from the generators.

Consequently, instead of setting the reference frequency at a constant value for the offshore grid, the offshore converter changes the offshore grid frequency by taking the onshore grid frequency measurement. It is carried out by only adding an additional control loop in the offshore converter control as shown in the figure 6.18.

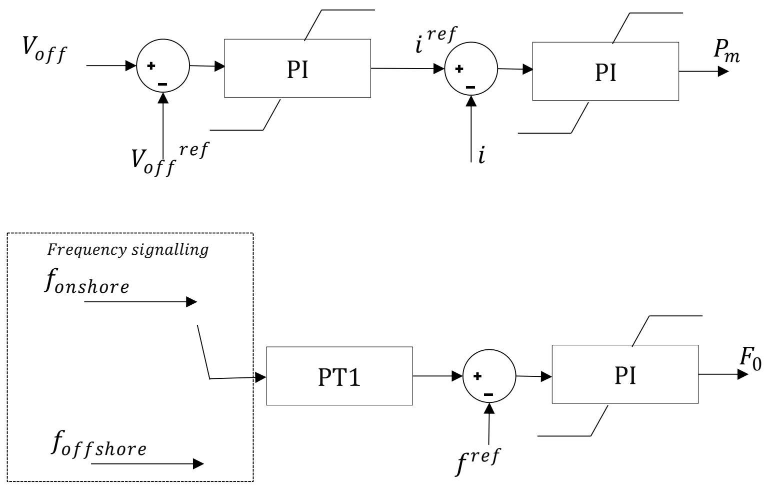


Figure 6.18: Modified offshore controller

6.3.5 Post-fault active current recovery ramp

When it comes to fault supports, three main states are distinguished; Normal (When there is not fault and the FRT mode is not activated. This shall be the state before and after any fault), FRT state (The converter makes voltage support with reactive current), Post-FRT state (This is the time range where the system recovers the active power rate from the FRT state to the normal state).

Regarding the grid code [4], the system operator must determine a P-t profile and magnitude after a fault clearance. The system operator often stablishes a determined minimum time delay for active power recovery and a minimum slope of the P-t profile.

The active power recovery rate will mainly affect the frequency stability and the active power imbalance, consequently, the speed and stability of all the synchronous machines. When the slope is too high, the synchronous machines will accelerate because there is a sudden active power injection in the grid. On the contrary, if the slope is too low, the synchronous machines will decelerate.

When it comes to implementing an active current slope in the *PowerFactory* model, the gradient of the active current reference must be limited. In the *PowerFactory* model a gradient limiter has been added to the i_d^{ref} output of the current limiter. This gradient limiter will be only being activated when the fault signal is activated. When the gradient of the active current reference is positive, the gradient limit will limit this reference depending on the slope established by the grid operator.

6.4 Dynamic studies in a simplified network

After modifying the basic model adding the respective ancillary services, different stability studies by subjecting the model to voltage and frequency deviations have been carried out. The objective of these simulations is to analyze the influence of different parameters in the power flows after voltage and frequency deviations. The HVDC was coupled with an infinite bus (more details in Appendix), in order to make simulation in the simplest environment as possible.

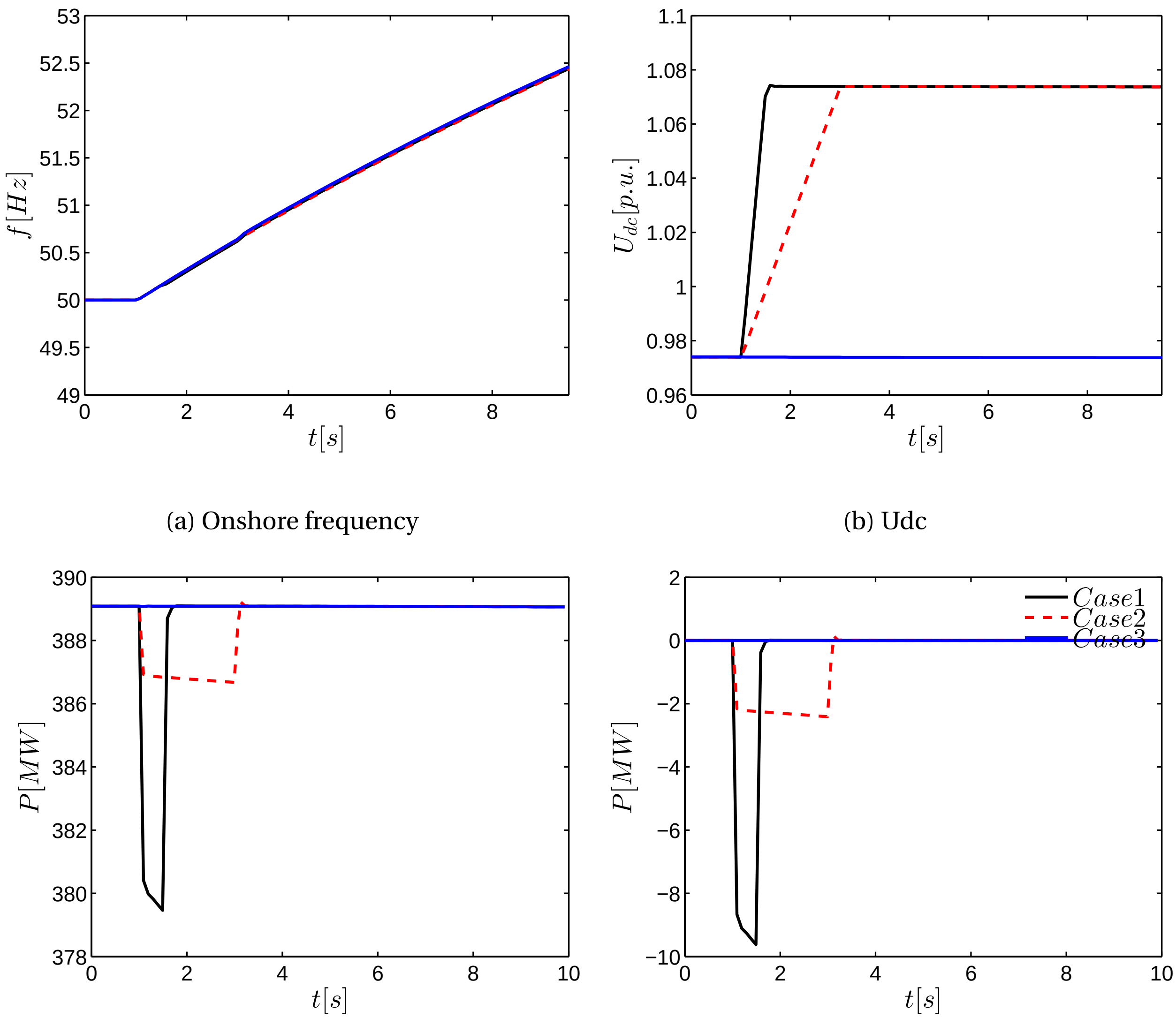
In this section, the results of the simulation study with the HVDC connected to the infinite bus are given. The main objective of this section is merely prove if the algorithm is working as expected. It is done by looking which are the control parameters that most influence the behavior of the results, in order to verify the models and tune them in the future in a more realistic scenario (IEEE9 bus bar system). The objective is not to improve the frequency or the voltage levels with the infinite bus.

Table 6.1: Description of scenarios

Scenario 1	Overfrequency case due to a 200MW load shedding with cappacitor support
Scenario 2	Overfrequency case due to a 200MW load shedding with WTG support
Scenario 3	Underfrequency case due to a 200MW load connection with cappacitor support
Scenario 4	Underfrequency case due to a 200MW load connection with WTG support
Scenario 5	Three-phase-fault in oshore bus bar with post-fault recovery rate

6.4.1 Overfrequency support with dc capacitors

In this simulation a sudden disconnection of 200MW load connected to the onshore AC terminal results in the frequency to be over the upper acceptable limit. Only the HVDC itself is going to make frequency support while the WTGs injected active power is going to remain constant. As the injected onshore active power depends directly on the direct voltage level, power is controlled by shifting the U_{dc} limits.



(a) Onshore frequency

(b) Udc

(c) Onshore active power

(d) Capacitor active power

Figure 6.19: Scenario 1 modified model in simplified grid. Case 1 (High ramp rate), Case 2 (Medium ramp rate), Case 3 (No capacitor support)

The U_{dc} is controlled with a gradient limiter tuned with a PI regulator that also includes a low delay to the VSC onshore controller. By controlling the ramp rate, the maximum active power absorption and the absorption time is controlled. This gradient control could be useful for adapting the controller to any grid while respecting the ENTSO grid code. In Figure5 it can be observed the effect that the Udc gradient has in the active power absorption. The red curve has a low gradient limiter, therefore, the capacitors injected active power peak is going to be lower but it will inject power for a longer time.

6.4.2 Overfrequency support through WTGs

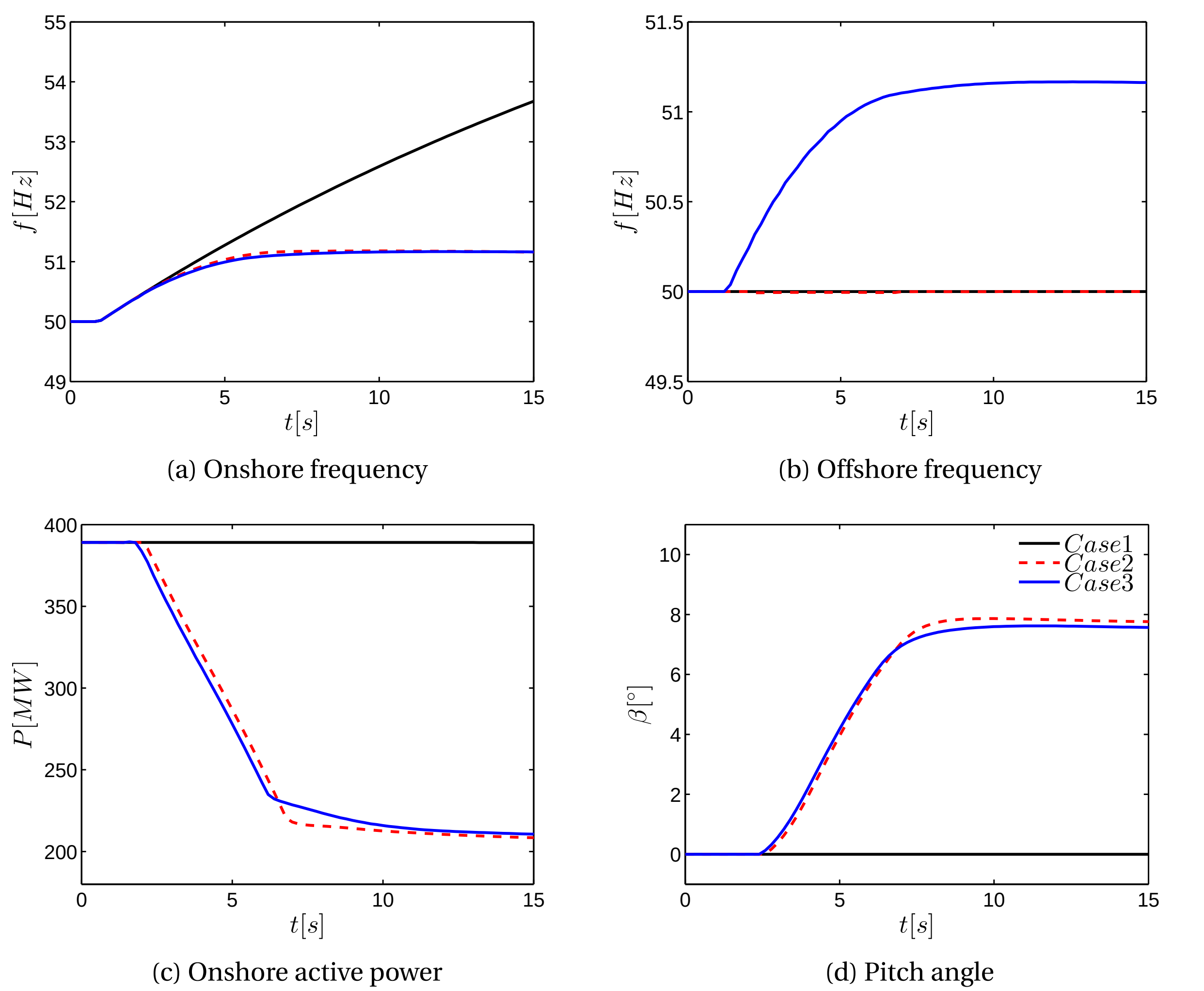


Figure 6.20: Scenario 2 modified model in simplified grid. Case 1 (No frequency support), Case 2 (0.3 Delay signal to offshore converter), Case 3 (0.5 Delay signal to offshore converter)

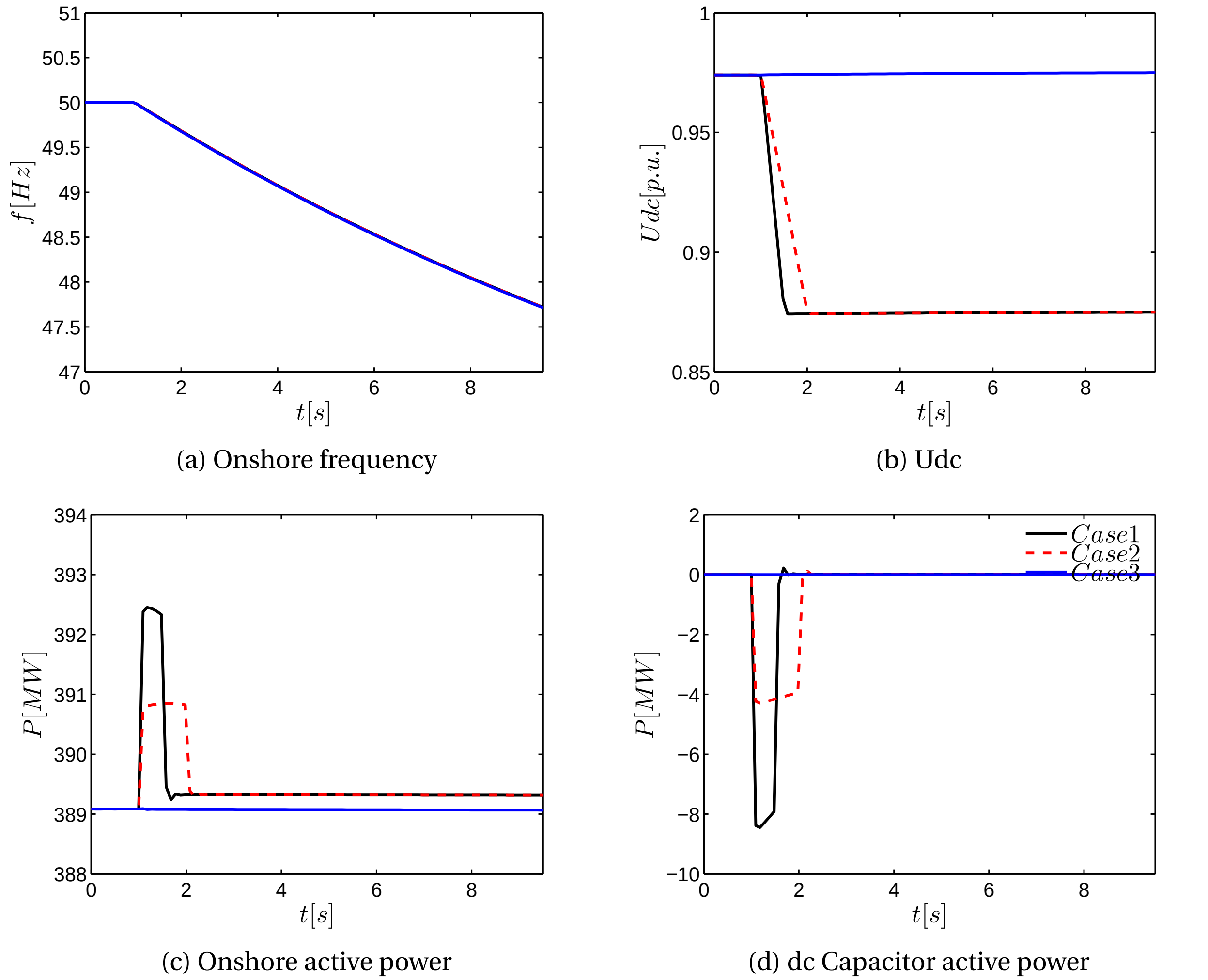
In this simulation a sudden disconnection of 200MW load connected to the onshore AC terminal results in the frequency to be over the upper acceptable limit. Only the wind park itself makes frequency support, while the capacitor does not absorb or inject active power. The objective is to study the influence that the different signaling methods have, in an overfrequency case.

However, the time delay in the second case is higher than in the first case, and that is also seen in figure 6.20. In Figure5, it can be seen how the WTGs reduce the active power with a gradient limiter because they receive a signal or just because they notice that the offshore frequency is decreasing. The DFIGs reduce the active power by means of pitch angle control (increasing it). Figure 6.20 shows that the frequency stabilizes due to the active power injection of the WTGs. Also the influence of the time delay can also be observed.

6.4.3 Underfrequency support with capacitors

In this simulation a sudden connection of 200MW load connected to the onshore AC terminal results in the frequency to be under the lower acceptable limit. Only the HVDC itself makes frequency support, while the WTGs injected active power remains constant. The objective is to study the influence that the Udc voltage gradient limiter has on the active power injected by the capacitors (how much power they can inject and for how long) for an underfrequency event.

The controller works in the same way like the overfrequency case, but the Udc must be controlled with a negative gradient limiter. In Figure7, it can be seen how the active power injection peak and its duration change by shifting the ramp rate, as it happened for overfrequency case, but with the capacitors injecting active power, instead of absorbing it.



(a) Onshore frequency

(b) Udc

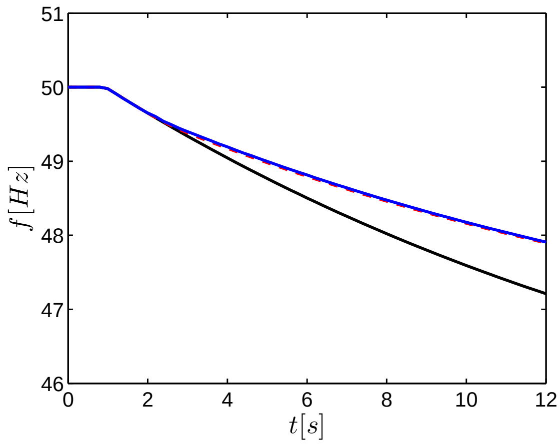
(c) Onshore active power

(d) dc Capacitor active power

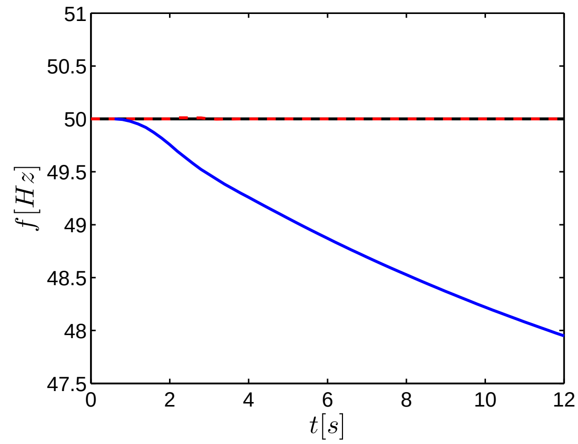
Figure 6.21: Scenario 3 modified model in simplified grid. Case 1 (High ramp rate), Case 2 (Medium ramp rate), Case 3 (No capacitor support)

6.4.4 Underfrequency support through WTGs

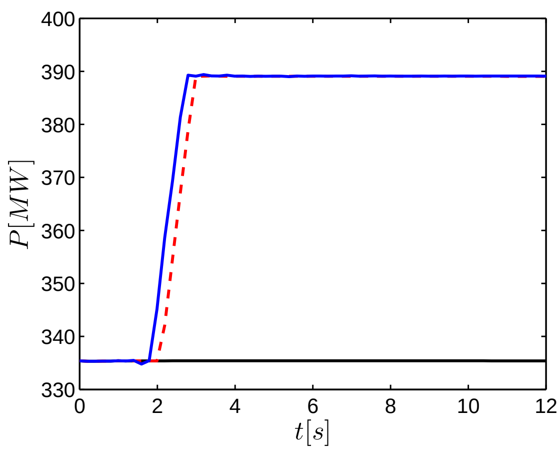
In this simulation a sudden connection of 200MW load connected to the onshore AC terminal results in the frequency to be under the lower acceptable limit. Only the wind park itself makes frequency support, while the capacitors injected active power remains 0. The objective is to study the influence that the Udc voltage gradient limiter has on the active power injected by the capacitors (how much power they can inject and for how long).



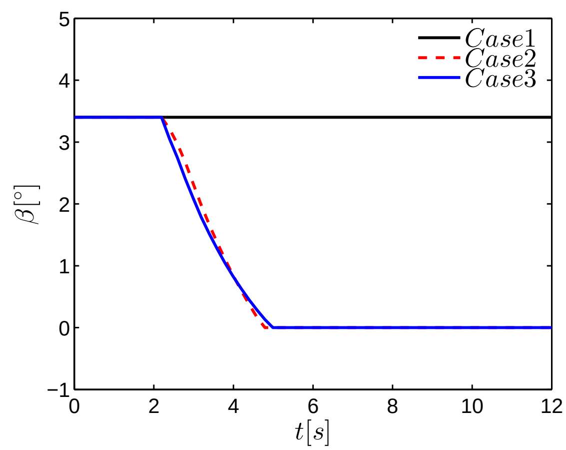
(a) Onshore frequency



(b) Offshore frequency



(c) Onshore active power



(d) Pitch angle

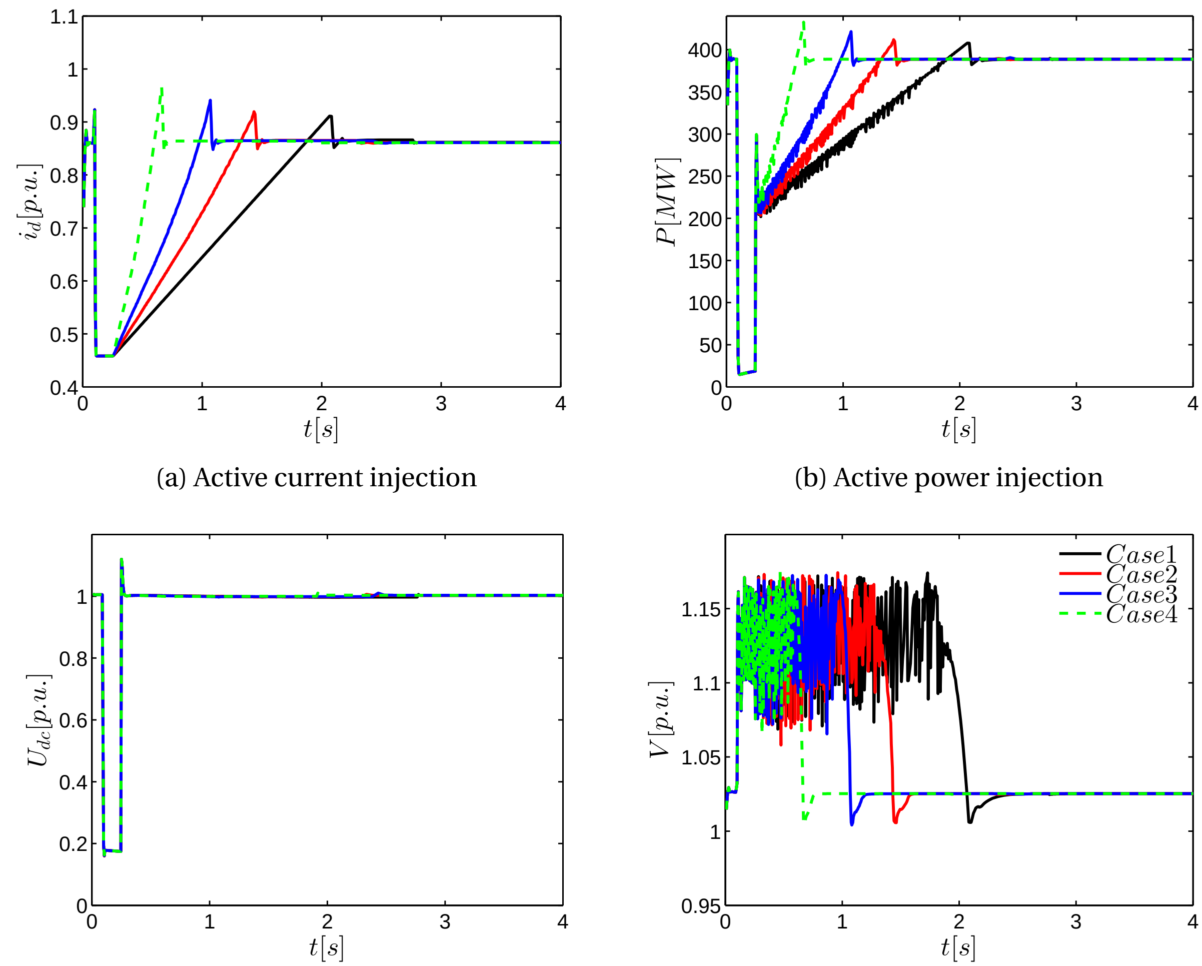
Figure 6.22: Scenario 4 modified model in simplified grid. Case 1 (No frequency support), Case2 (0.3s Delay signal to offshore converter), Case3(0.5s Delay signal to offshore converter)

It works exactly in the same way than overfrequency cases. But instead of the overfrequency mode a underfrequency mode should be activated in the WTGs.

In Figure 6.22 it can be seen how the WTGs increase the active power because they receive a signal from the onshore converter or just because they notice that the offshore frequency is decreasing. The DFIGs reduce the active power by means of pitch angle control (decreasing it). The pitch angle initial condition is 3.7, in order to maintain a primary reserve and it decreeases to 0 in order to increase the active power to the nominal.

6.4.5 Post- fault active current recovery rate

In this simulation a three-phase fault is applied to the onshore AC terminal at 0.1 s and cleared after 0.15 s. The onshore controller has been modified in order to specify different active power recovery rates and study the impact on the system stability. In Figure9, it can be seen how the implemented active current recovery rates work that the onshore voltage is not modified for each case.



(a) Active current injection

(b) Active power injection

(c) Onshore voltage

(d) Direct current voltage level

Figure 6.23: Scenario 5 modified model in simplified grid. Case 1 (Inf), Case 2 (7,00 [p.u./s]), Case 3 (2,50 [p.u./s]), Case 4 (1,20 [p.u./s])

There is only the posibility to control the active current recovery rate and not the active power recovery rate, since the last parameter is directly dependent from the voltage.

6.5 Conclusions

Significant parameters such as offshore and onshore voltage and frequency levels, the power flow throughout both converters and the internal control variables have been analyzed in order to understand better the model behavior and the offered ancillary services. The following conclusions have been reached:

- No over-frequency support: due to the decoupling of the onshore and offshore grids, the wind farm does not detect any frequency or voltage deviation when a disturbance is applied to the onshore side(figure 6.6).It was obvious looking at the onshore controller structure figure 6.5
- The WTGs have active power reduction (section 6.1.2) due to over-frequency, but this characteristic is not useful if the wind farm never detects frequency deviations(figure 6.6). The wind farm lacks of under-frequency controller.
- The onshore converter has fault ride through capability and fast reactive current injection during faults. Due to the decoupling of the onshore and offshore grids, the wind farm continues injecting active power during onshore faults, and therefore chopper resistors are needed to fulfill FRT requirements(figure 6.8).
- The HVDC cannot regulate the active power recovery rate after fault, which is an aspect of interest for stability studies(section 6.1.2 and figure 6.8).

Regarding the lack of ancillary services, the following modifications have been done to the original model and validated afterwards simulating the HVDC together with an infinite bus:

- Frequency support by changing the offshore frequency according to the onshore frequency. The onshore frequency is sent to the offshore converter (with a time delay), which modifies the offshore frequency.
- Frequency support by sending a signal directly to the WGTs. The onshore frequency is sent directly to the wind farm controller and the offshore frequency remains constant. This time delay is larger than for the offshore controller, but the offshore grid frequency has not

to be changed. For these simulations, the result is worse, since the WTG starts providing active power support after than if we where changing the offshore frequency through the offshore converter. Although the WTGs are type three and are directly grid coupled, the active power supported by the generators shows the same dynamic for overfrequency and underfrequency cases.

- HVDC active power support by its capacitors: A control which modifies the dc voltage according to onshore frequency deviations has been implemented. The idea of changing the dc voltage is to provide fast frequency response by using the energy stored in the dc capacitors. This is able to provide a fast response active power support to the onshore grid before the WTGs start to inject or absorb active power.

- Primary reserve and its respective under-frequency controller of the DFIG type3 wind turbine: The WGTs operate in a sub-optimal state and by varying the pitch angle they are able to inject active current in under-frequency events. As figure 6.30 shows, the under-frequency block implemented in the WTGs for active power injection in case of underfrequency case is working, by reduciong the pitch angle. Although the time delay difference between Case 4 and Case 3 can be observed, the generators behaves in the same way.

Chapter 7

Result from application study

7.1 Introduction

With the customized model verified in a single-area system, connecting the VSC-HVDC system into an infinite bus, it was later included in parallel with an AC multi-machine system (IEEE9 Busbar from DIgSILENT) to be used for evaluation of the impact of VSC-HVDC on the dynamic stability affected by large voltage and frequency variations. The following steps have been followed before the simulation:

- The types of each component of the bus bar system, the enhanced generator's AVRs and governors have been assigned. The generator controllers have been selected as EXAC4 and IEEEG1 [24] for the AVR and the governor, respectively. In addition, before running the initial conditions, power compensation has been necessary, the loads and the lines capabilities have been adjusted to the generation.

- Before dynamic simulations are made, the initial operation conditions have to be set as the base-case. For steady state operations, voltages magnitudes and angles as well as active and reactive power flows, are calculated for every bus and branch in the system.

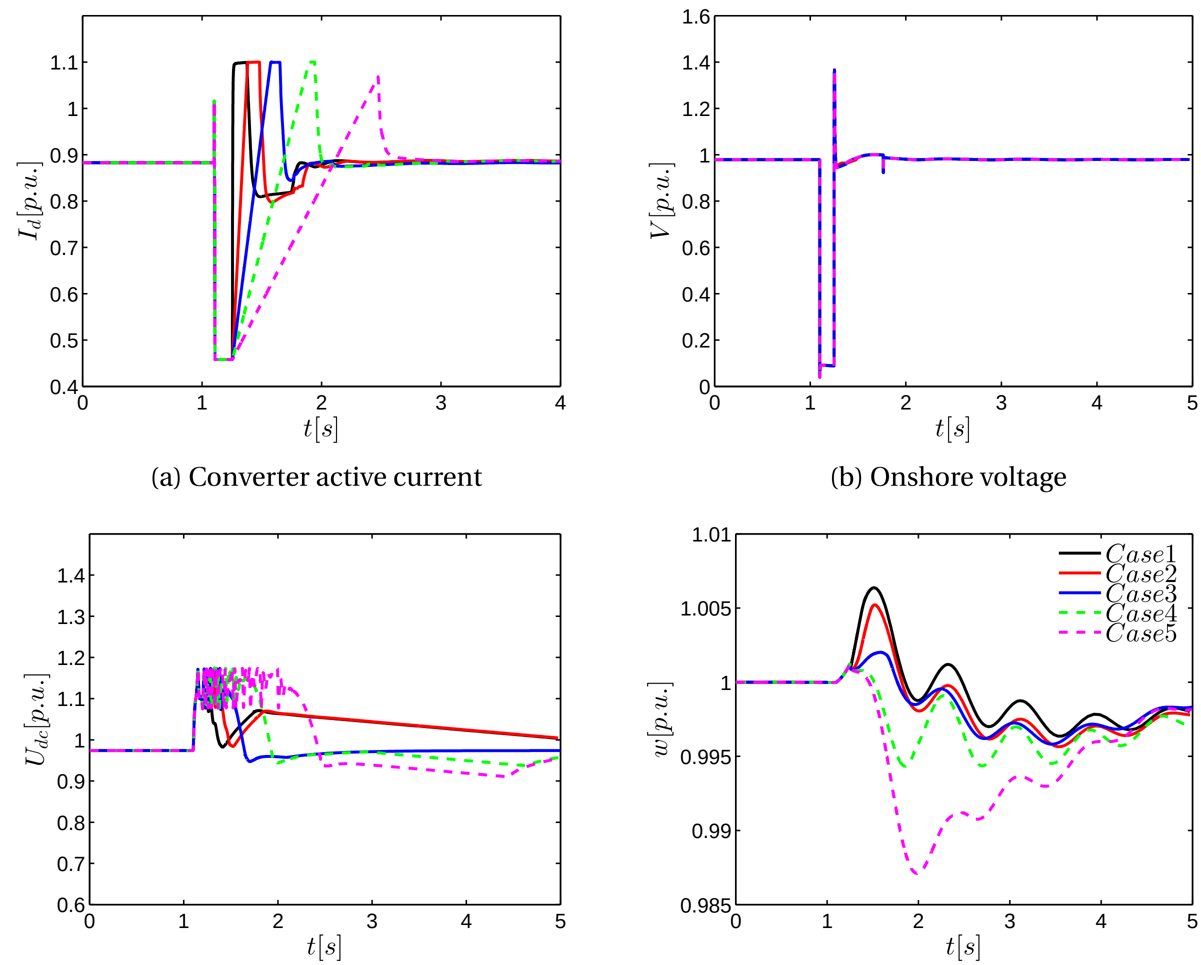
(Appendix for more detail about the controller schemes and their enhanced parameters selected)

7.2 Simulations

Table 7.1: Description of scenarios

Scenario 1	Three-phase-fault in oshore bus bar
Scenario 2	Overfrequency case due to a 60% active power and 40% reactive power decrease in 110MVA load
Scenario 3	Underfrequency case due to a 50% active power and 30% reactive power increase in 110MVA load
Scenario 4	Overfrequency case due to a 60% active power and 60% reactive power decrease in 400MVA load

7.2.1 Three-phase-fault in onshore bus bar



(a) Converter active current

(b) Onshore voltage

(c) Direct voltage

(d) G1 generator speed

Figure 7.1: Application scenario 1. Case 1 (Inf [p.u./s]), Case 2 (7,00 [p.u./s]), **Case 3 (2,50 [p.u./s]**), Case 4 (1,20 [p.u./s]), Case 5 (0.5 [p.u./s])

The first disturbance event simulates a three-phase-fault in the onshore bus bar at 0.1s. The fault is cleared by isolating the faulted bus bar after 100ms. This simulation analyzes the effect of the active power recovery rate after a three-phase-fault in parameters such as generator speed or DC voltage level of the cables.

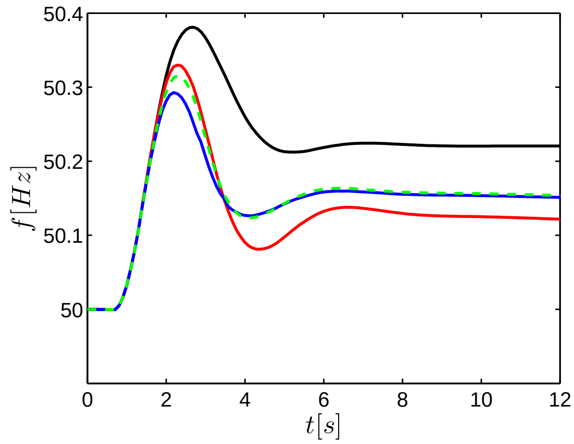
Figure 2 (c) shows that if the ramp rate is higher, the DC cables are overloaded and therefore, the DC level increases until the choppers start working. For high ramp rate recovery cases, the choppers will disipate much more energy in joule losses, since they are working for longer time frames.

Figure 2 (d) describes the speed behavior of the generator. If the ramp rate recovery is too high, the speed deviation increases and if the ramp rate is too low, the speed decreases considerably. This effect is directly related to the transient stability of the synchronous generator. Moreover, it can be also observed in the graphic that an optimal ramp-rate recovery exists, where the generator speed deviation is the lowest and the DC level recovers its steady-state in a short time range.

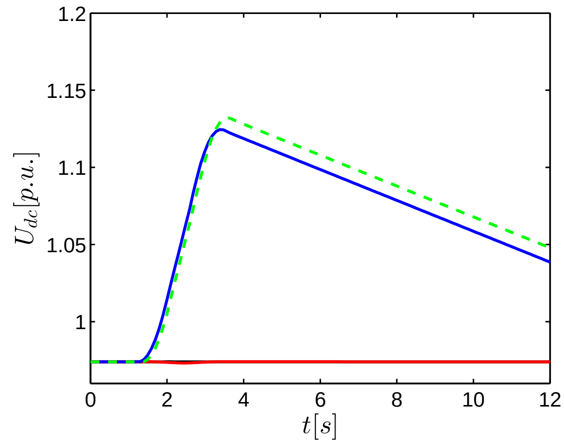
7.2.2 Overfrequency case with low load shedding

In this simulation a sudden disconnection of a total of 60MW and 12MVAr load connected to IEEE9 busbar results in the frequency to be over the upper acceptable limit. Both wind park and capacitor supports are studied. The objective is to study the influence that the different signaling methods have on the frequency and how are they combined with the HVDC frequency support, in an overfrequency event.

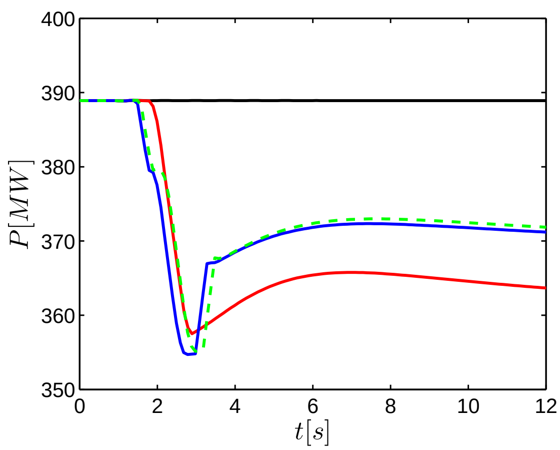
In figure 7.2, it can be seen that the frequency deviations are improved when the HVDC or the WTGs provide the grid with active power support. Other than that, it can also be observed how the onshore converter starts decreasing the provided active power by storing energy in the capacitors and increasing the direct volage level.



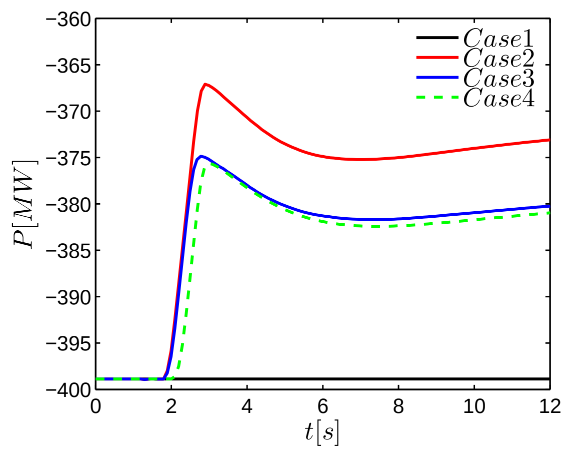
(a) Onshore frequency



(b) Direct voltage



(c) Onshore converter active power



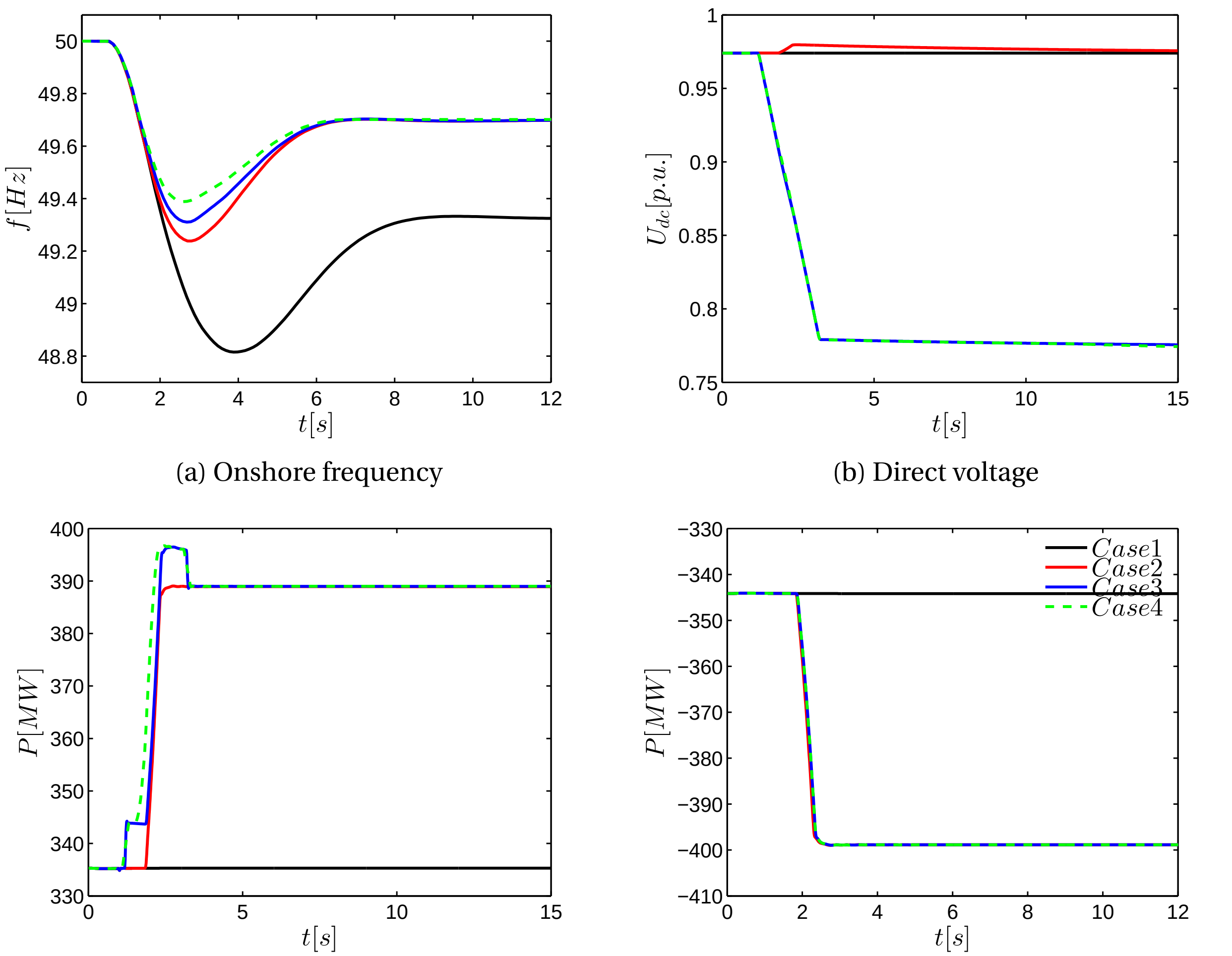
(d) Offshore converter active power

Figure 7.2: Application scenario 2. Case 1 (No frequency support), Case 2 (0.3s Delay signal to offshore converter), Case 3 (0.3s Delay signal to offshore converter+capacitor support), Case 4 (0.5s Delay signal to offshore converter+capacitor support)

The capacitors absorb energy faster than injecting it, in order to avoid further frequency swings. The frequency is not recovering its initial steady-state because a secondary control plan has not been done. When the capacitors are making frequency support, the frequency steady-state error that remains is higher and the maximun deviation lower than in the Case 1 and 2.

7.2.3 Underfrequency case with low load connection

In this simulation a sudden connection of a total of 50MW and 10MVAr load connected to IEEE9 busbar results in the frequency to be over the under acceptable limit. Both wind park and capacitor supports are studied. The objective is to study the influence that the different signaling methods have on the frequency and how are they combined with theHVDC frequency support, in an overfrequency event.



(a) Onshore frequency

(b) Direct voltage

(c) Onshore converter active power

(d) Offshore converter active power

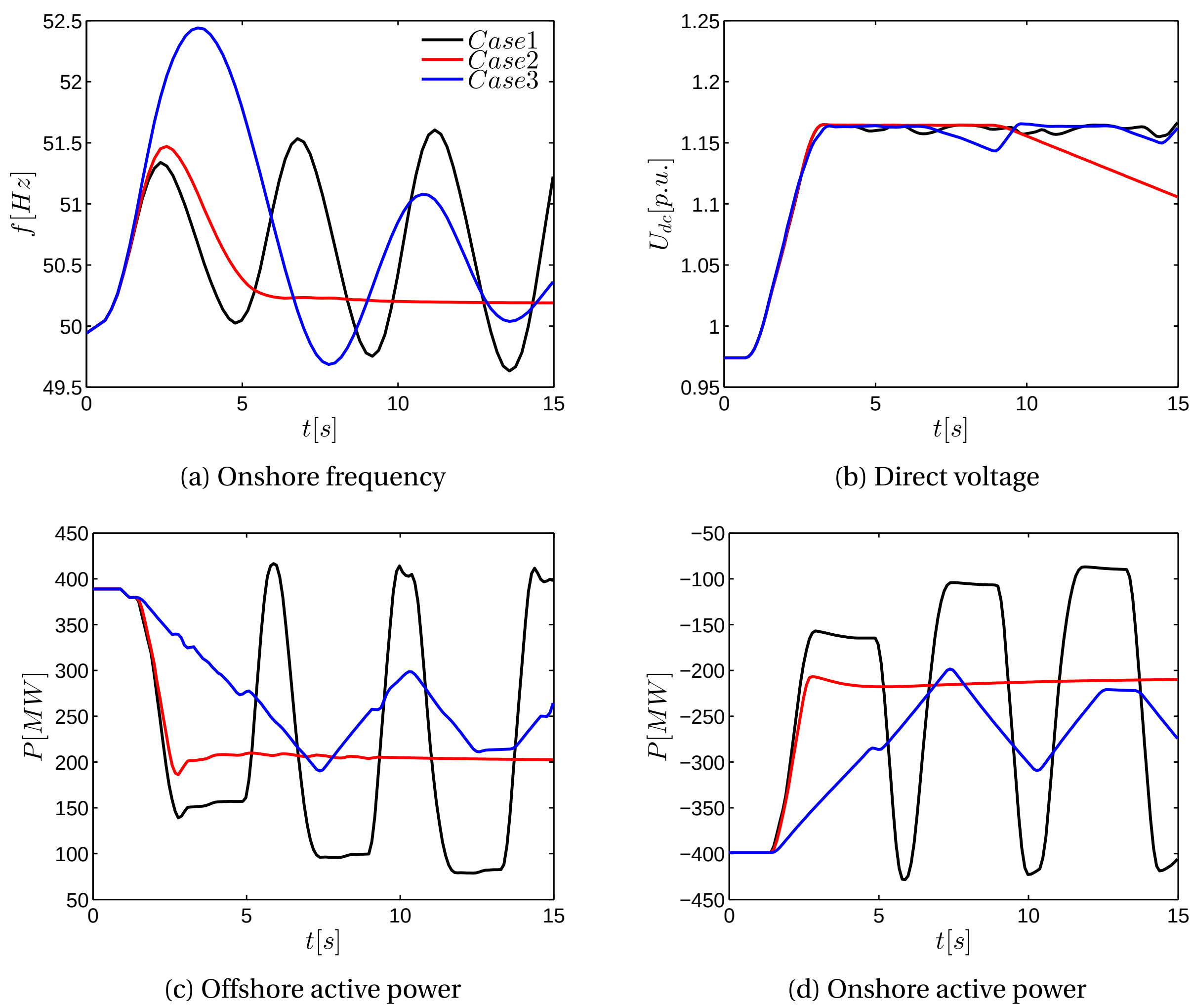
Figure 7.3: Application scenario 3. Case 1 (No frequency support), Case 2 (0.3s Delay signal to offshore converter), Case 3 (0.3s Delay signal to offshore converter+capacitor support), Case 4 (0.5s Delay signal to offshore converter+capacitor support)

It is observed that the frequency support from the offshore wind farm inject active power for the load increase and reduces the frequency drop significantly. The frequency is also stabilized much faster at a higher steady-state value compared to the case without offshore wind farm frequency support. Furthermore, for this event, the participation of frequency support from VSC-HVDC improves the frequency deviation further, , especially in the first frequency swing.

Figure 7.4(c) shows the output active power increase of the VSC-HVDC, that is the sum of the WTG and the capacitors support. It also can be observed that the capacitors provide faster frequency response than the WTGs due to the signal latency.

7.2.4 Overfrequency case with high load shedding

In this simulation a sudden disconnection of a total of 210MW and 30MVAr load connected to IEEE9 busbar results in the frequency to be over the upper acceptable limit. The objective is to study how the WTG controller parameters influence the frequency and to find the optimal gradient limiters.



(a) Onshore frequency (b) Direct voltage

(c) Offshore active power (d) Onshore active power

Figure 7.4: Application scenario 4.

As the frequency response in figure 7.4 shows, in case 1 and 3 the frequency starts oscillat-

Table 7.2: Case description of forth scenario

	Positive gradient limiter[p.u./s]	Negative gradient limiter[-p.u./s]
Case 1	0.5	0.5
Case 2	0.5	0.01
Case 3	0.1	0.1

ing. Case 3 shows a stable response with oscillation and with the highest peak, while case 1 is unstable. The optimal case is the second one, since the steady-state is reached after the first peak. This optimal case has a high positive gradient limiter and a low negative gradient limiter of the output active power of the WTGs.

7.3 Conclusions

The following conclusions have been reached through the simulations of Chapter 7:

- In the three phase fault study in the onshore busbar, the studies performed on the test system showed that FRT and post-FRT schemes may affect the rotor angle stability of the generators. It also shows that the choppers remain working until the active current recovers its steady state. It is deduced that there is an optimal ramp recovery rate which maintains the rotor angle the most stable as possible.
- When it comes to theHVDC response to low frequency variations, it can be seen that the frequency support provided only by the offshore wind farm does not improve the initial dynamics, but reduces the peak frequency and achieves significant enhancement on the frequency restoration. In addition, the joint frequency support provided by both offshore wind farm and VSC-HVDC further lowers down the peak frequency.
- Finally, it has been proved that the frequency starts oscillating for high disconnected loads. These oscillations can be controlled by the active power ramp-rate of the WTGs. Three cases with different positive and negative gradient limiters are studied and it has been deduced that the case with high positive gradient limiter and low negative gradient limiter is the only stable one, since it recovers its steady state after the first swing.

Chapter 8

Closure

8.1 Conclusions

The state of the art of the HVDC systems has been studied in order to analyze different types of technologies and their main differences. Current studies and publications regarding dynamic studies with VSC-HVDC systems have been summarized, as well as the most relevant grid code requirements and provision of ancillary services.

Control strategies for the implementation of ancillary service on an offshore wind park connected through a VSC-HVDC have been discussed in this thesis. Their implementation and validation are shown through several simulations. As a base model, a Power Factory template was used. The models are suitable for RMS simulations. Before the implementation of new capabilities, a deep study of the aforementioned template was carried out. It was deduced that the template lacked from post-fault recovery rate and frequency support.

After implementing new control strategies, the effect of the control parameters has been studied. As a first step, a two bus system was used, connecting the HVDC model to an infinite bus. Control parameters were tuned and the following was concluded:

- The onshore converter can operate with a user defined post fault active power recovery rate,
- The offshore wind power plant can provide frequency support in both, over-frequency and under-frequency cases,

- By quickly changing the dc voltage in the case of frequency deviations on the onshore grid, the dc capacitors can be used to support the first frequency swing.

As a next step, the model was connected to the IEEE 9 bus system.

- It could be seen that the active power recovery rate affects the rotor angle of synchronous generators. The ramp rate should be fast enough to avoid voltage or frequency instability, but slow enough to avoid larger rotor angle oscillations.
- The modification to the dc voltage controller allows the dc capacitors to support the grid in case of frequency deviations. Results were compared against results in literature.
- For frequency support by the wind turbines, two methods were compared: a) sending a signal to the offshore converter and replicating the onshore frequency on the offshore grid, and b) sending the signal directly to the wind controllers without modifying the offshore grid. The last one is used in practice, and no major differences were found between both methods.
- For large frequency deviations caused by loss of a big load, the gradients of active power reduction and recovery by the offshore plant have to be set to proper values in order to decrease the frequency oscillations.

8.2 Future work

- Since in this thesis only three-phase-fault event in the onshore bus bar has been simulated, other fault events like offshore fault, phase-to-ground fault and faults in the dc lines should be simulated and studied.
- Study the possibility to connect the HVDC to other types of WTG technology and extend the studies to other network, with real grid scenarios. Besides, it would be also of interest to change the level of HVDC penetration in the grid, to study its effect for different scenarios.

- Other areas, also important to cover the whole grid stability spectrum, should be carried out, such as dumping, voltage stability and black start.

- Validate the simulations already done with a EMT model. Apart from that, in order to design parameters of valves, cables or protections. It is required to ru EMT analysis, which calls for an EMT model and higher computational cost.

Appendix A

PowerFactory progamming additional information

In this appendix addition information for the state the art is attatched.

A.1 Projects around the world

Additional details about the most significant HVDC project around the world.

Table A.1: BorWind wind farm cluster

PROJECT	Borwin 1	Borwin 2	Borwin 3
HVDC SUPPLIER	ABB	Siemens	Siemens
COMMENT	First importing energy from offshore-windpark	Run in parallel to the first Borwin project	It links the EnBW, AlbatrosI and Albatros windfarms to the german mainland
COMMISSIONING YEAR	2009	2015	2019
POWER RATING	400 MW	800 MW	800MW
CONVERTER TYPE	VSC	VSC	VSC
AC VOLTAGE	170 kV (Platform BorWin alpha), 380 kV (onshore platform Diele)	300 kV (Platform BorWin alpha), 380 kV (onshore platform Diele)	-
DC VOLTAGE	±150 kV	±300 kV	±600 kV
LENGTH OF OVERHEAD DC LINE	2 x 75 km underground and 2 x 125 km submarine	2 x 75 km underground and 2 x 125 km submarine	-

Table A.2: DolWind wind farm cluster

PROJECT	**DolWin1**	**DolWin2**	**Dolwin 3**
HVDC SUPPLYER	ABB	ABB	Siemens
COMMENT	HVDC Light transmission system connects offshore wind farms located in the North Sea DolWin1 cluster to the German national grid	Connects the biggest offshore converter station in the North sea by HVDC	It is the third connection for DolWin cluster
COMMISSIONING YEAR	2015	2016	2017
POWER RATING	800 MW	916 MW	900 MW
CONVERTER TYPE	VSC	VSC	VSC
AC VOLTAGE	155 kV (Platform DolWin Alpha), 380 kV (onshore platform Dörpen/West)	155 kV (Platform DolWin beta), 380 kV (onshore platform Dörpen West)	-
DC VOLTAGE	±300 kV	±320 kV	±320 kV
LENGTH OF OVERHEAD DC LINE	2 x 90 km underground cable+2 x 75 km submarine cable	2 x 45 km underground and 2 x 90 km submarine	-

Table A.3: HelWind and Sylwin wind farm clusters

PROJECT	**Helwin 1**	**Helwin 2**	**Sylwin 1**
HVDC SUPPLYER	Siemens	Siemens	Siemens
COMMENT	HelWin1 links the two offshore wind farms Nordsee Ost and Meerwind to the mainland	HelWin2 links the two offshore wind farms Nordsee Ost and Meerwind to the mainland	Sylwin1 links the offshore wind farm in Sylt and Meerwind to the mainland
COMMISSIONING YEAR	2015	2015	2015
POWER RATING	576 MW	690 MW	864 MW
CONVERTER TYPE	VSC	VSC	VSC
AC VOLTAGE	400 kV (Platform Helwin), 380 kV (onshore platform Büttel)	150 kV (Helwin beta offshore Platform), 400 kV (onshore platform Büttel)	155 kV (SylWin 1 offshore converter), 400 kV (onshore platform Büttel)
DC VOLTAGE	±250 kV	±320 kV	±320 kV
LENGTH OF OVERHEAD DC LINE	2 x 45 km underground and 2 x 85 km submarine	2 x 45 km underground and 2 x 85 km submarine	2 x 45 km underground and 2 x 160 km submarine

Table A.4: HVDC projects around the world

PROJECT	**1-Sweden Gotland**	**2-Anglo french interconnector**	**3-Volgograd-Donbass**	**4-Pacific inertie**	**5-Eel River [10]**	**6-Argentina-Brazil interconnection [10]**
HVDC SUPPLYER	ASEA swedish Industry company	ASEA	Ministry for electrotechnical industry of USSR	ASEA/GE	ABB	ABB
COMMENT	First modern HVDC system	First cross channel link		First HVDC link in AC grid	World's first commercial HVDC station to be equipped with thyristor valves only	First back-to-back station with CCC
COMMISSIONING YEAR	1950	1961	1964	1970	1972	1999
POWER RATING	20MW	160MW	750MW	1440MW	350 MW	2,200 MW
CONVERTER TYPE	mercury arc	mercury arc	mercury arc	mercury arc	Thy	CCC
AC VOLTAGE	130 kV (Västervik), 70 kV (Ygne)				230 kV (Both ends)	500kV (Both ends)
DC VOLTAGE	±100kV	±100 kV	±400kV (100kV)	±800 kV	±80 kV	± 70 kV
LENGTH OF OVERHEAD DC LINE	7 km	64km	475km	1362km	82km	354 km
MAIN REASON FOR CHOOSING HVDC	Length of sea crossing	Length of land and sea cables	Long distance	Sending hydroelectric power to Southern California	asynchronous networks	Asynchronous link between a 50 Hz and a 60 Hz system
APPLICATION	Connecting remote loads	Connection of two AC grids	Connecting remote generation	connecting remote generation	Interconnecting grids	Interconnecting grids

PROJECT	**7-Gotland HVDC light [10]**	**8-XianJiba-Shangai [11]**	**9-Trans Bay Cable [12]**	**10-Rio Madeira [10]**	**11-Nanao [11]**	**12-Zhoushan [11]**
HVDC SUPPLYER	ABB	ABB	Siemens	ABB	SEPRI/DNV	C-EPRI
COMMENT	First VSC	First Ultrahigh Voltage Direct Current (UHVDC) of the world	First HVDC system to use the Modular Multi-Level Converter (MMC) system	The world´s longest transmission line	First multiterminal VSC-HVDC	First five-terminal VSC-HVDC
COMMISSIONING YEAR	1999	2010	2011	2013	2013	2014
POWER RATING	50MW	6400MW	400MW	3,150 MW 2 x 400 MW (back-to-back)	200MW-100MW-50mW	400/300/100/100/100 MW
CONVERTER TYPE	VSC	THY	VSC, MCC	VSC	VSC,MCC	Thy
AC VOLTAGE	80kV (Both sides)	525kV(both sides)	230kV(both sides)	Transmission link: 500 kV Back-to-back: 500 kV and 230 kV		
DC VOLTAGE	±60kV	±800 kV	±200 kV	± 600 kV	±160kV	±200kV
LENGTH OF OVERHEAD DC LINE	2 x 70 km	1980km	85km	2,375 km	32km	134km
MAIN REASON FOR CHOOSING HVDC	Easy to get permission for underground cables	Long distance	Length of land and sea cables	Long distance Back-to-back: Asynchronous networks	Length of land and sea cables	Length of land and sea cables
APPLICATION	Interconnecting grids	Connecting remote generations	City centre infeed	Connecting remote generation	Wind generation connection from an island	Critical interconnection between mainland and 5 isolated islands

A.2 Grid codes

Details about the grid codes required by the ENTSO.

A.2.1 Active power control and frequency support requirements

The relevant system operator shall require a frequency control and the operating principles with the characteristics described as follows *(14.article)*:
Frequency ranges (*7.article*): When frequency fluctuations happen, the equipment should be designed to behave as shown in table A.5. This table shows the minimum time periods a HVDC System shall be able to operate for different frequencies, deviating from a nominal value without disconnecting from the Network.

- Frequency ranges *(7.article)*: When frequency fluctuations happen, the equipment should be designed to behave as shown in table A.5. This table shows the minimum time periods a HVDC System shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the Network.

Table A.5: Frequency ranges [4]

Frequency range	**Time period for operation**
47.0 Hz-47.5 Hz	60 seconds
47.5 Hz-49.0 Hz	Defined by TSO
49.0 Hz-51.0 Hz	Unlimited
51.0 Hz-52.0 Hz	Defined by TSO

- Frequency rate of change withstand capability *(8.article)*: The system shall be able to be in operation after grid frequency deviations of **±2.5Hz** from the nominal value.

- Active power controllability, control range and damping rate *(9.article)*: The TSO shall have the right to:

  -Stablish a maximum and minimum power step size for adjusting the transmitted active power,

-Define the minimum HVDC active power transmission capacity for each directions,

-Specify a maximum time delay,

-Require fast active power reversal,

-Require the system to be capable of taking automatic remedial actions including the stopping of the ramping and blocking FSM, LFSM-O, LFSM-U and frequency control.

In case of disturbances, the system should modify the transmitted active power with an initial delay as short as possible.

- Synthetic inertia *(10.article)*: The system should be able of provide synthetic inertia in response to frequency changes. Therefore, it must adjust the active power injected in the AC network depending on the frequency fluctuations, in low frequency or in high frequency regime.
- Frequency sensitivity mode *(11.article)*: The system should respond to frequency deviations limiting its active power according to table A.6. It shall be able to adjust the drop in both regimes, respecting the death band. When it comes to the step size time of response, the delay time shall be the lowest as possible (0.5s is the maximum admissible delay and 30s is the maximum activation delay for a full activation). Active power deviations do not have any negative impact in the active power response.

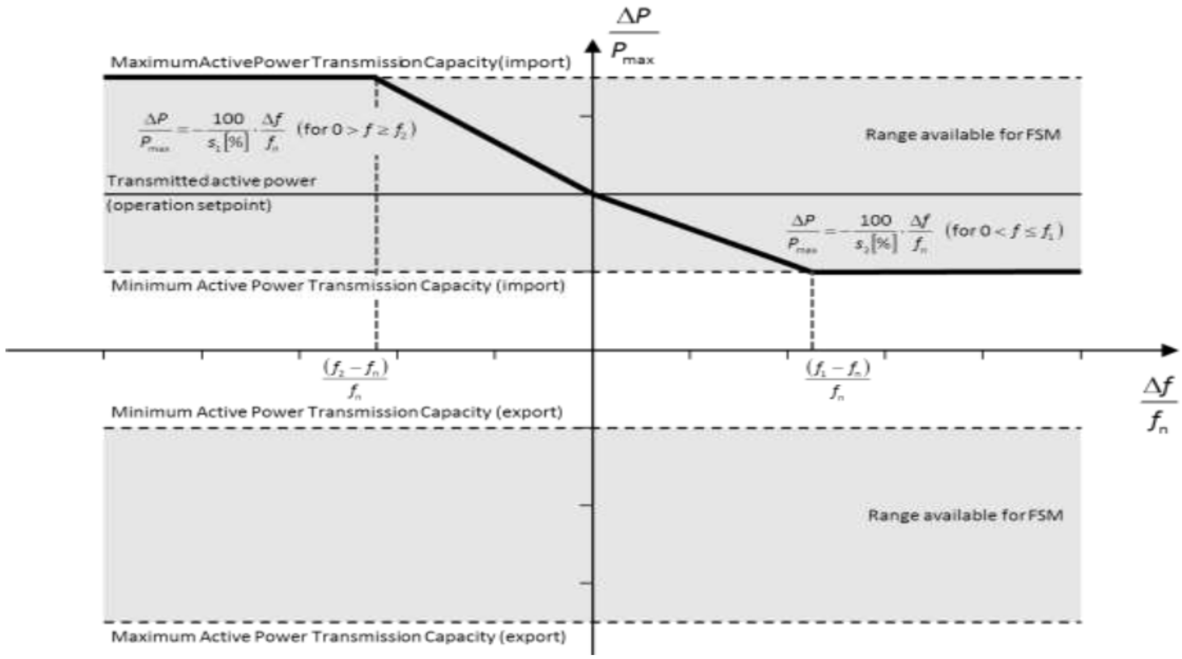


Figure A.1: $\Delta P - t$ [4]

Table A.6: Frequency sensitivity mode [4]

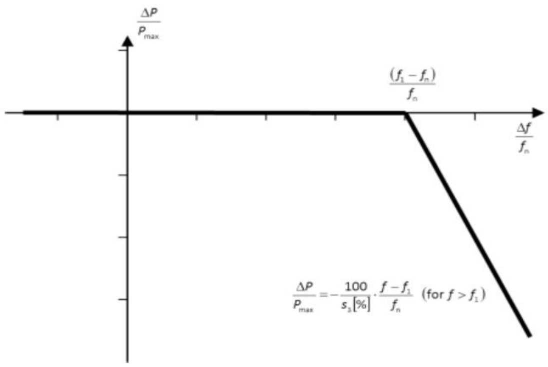
Paraters	Ranges
Frequency Response Deadband	0 – ±500mHz
Droop s1 (upward regulation)	Minimum 0.1%
Droop s2 (downward regulation)	Minimum 0.1%
Frequency Response Insensitivity	Maximum 30 mHz

- Limited Frequency Sensitivity Mode *(12. and 13. articles)*: These articles shall apply cumulatively in addition to the *article 11.*

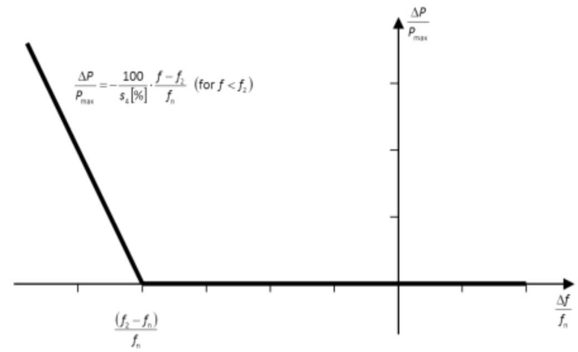
  The system shall have the capability to regulate its power in over and under frequency situations if it is required. It must operate stable in both cases (LFSM-O and LFSM-U) and the hierarchy of control functions shall be organized in accordance to the grid code *(arti-*

cle 33).

In over frequency mode threshold and droop settings shall be discussed with the transmission system operator. On the other hand, for under frequency events the threshold shall be adjustable between 49.8-49.5 and the droop up to 0.1% slope. The characteristics are described as follows:



(a) Overfrequency case [4]



(b) Underfrequency case [4]

A.2.2 Requirements for reactive power control and voltage support

- Voltage ranges *(article 16)*: The HVDC converter shall be able to stay connected to the grid in case of voltage fluctuations. These values change depending on the grid area, voltage level and voltage variations. The system operator could also specify the grid connection point and other values in order to maintain the system stability.

- Reactive Power capability *(article 18)*: The network operator could define the reactive power capability when varying the voltage. The U-Q/Pmax limits are determined by the system operator in the figure A.3. The system shall be capable of moving from one point to another point inside the limits when the operator requires it.

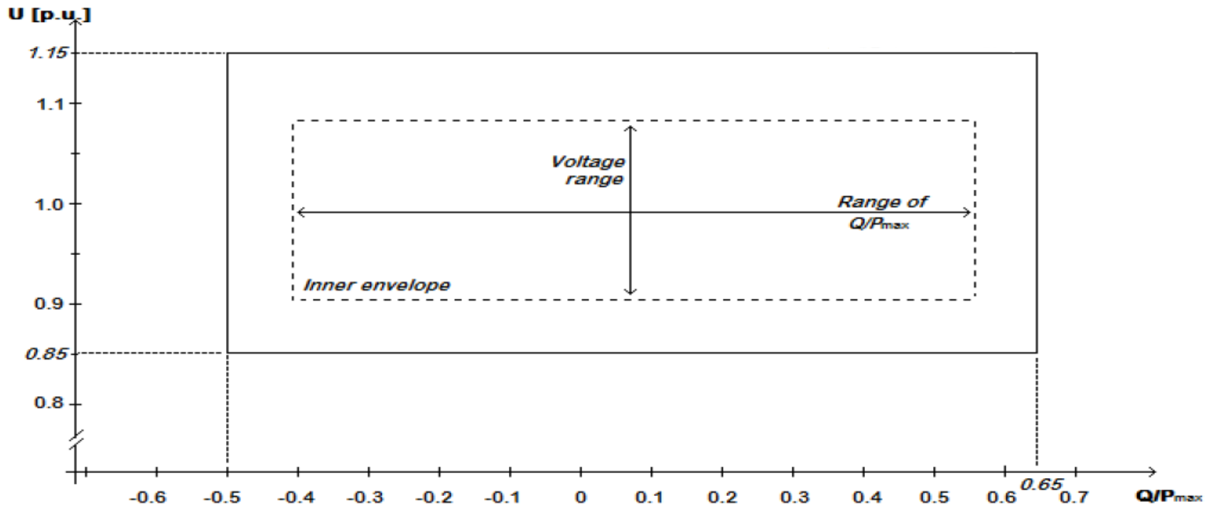


Figure A.3: U-Q characteristic [4]

- Reactive Power control mode *(article 20)*: The transmission system operator shall be in the right to specify the set point and the control mode (voltage, reactive power or power factor control mode) and their capabilities of the onshore side. The insertion of other equipment needed to enable the control modes could be required by the TSO.

  The voltage control may be operated with a death-band of 0%-5%. The Q-U droop shall be stablished between the owner and the system operator. The HVDC converter station shall be capable of achieving the **90%of the range in Reactive Power output** within a stablished time **(0.1-10s)**.

  Priority to Active or Reactive Power contribution *(article 21)*: The TSO assesses in which case the reactive power has priority against active power. When priority changes from reactive power to active power, a given time and droop after fault interception shall be stablished between the system operator and the HVDC owner.

- *Fault-Ride-Through*(FRT) characteristic and short circuit contribution during faults *(17. and 23.articles)*: In case of three-phase symmetrical faults, the HVDC converter shall provide Fast Fault Current. On the other hand, in case of asymmetrical faults asymmetrical current support could be required.

  The relevant system operator shall have the right to determine a V-t characteristic in the onshore side converter as well as the minimum short circuit capability in the pre-fault and post-fault scenarios. The curve and its values are expressed in figure A.4

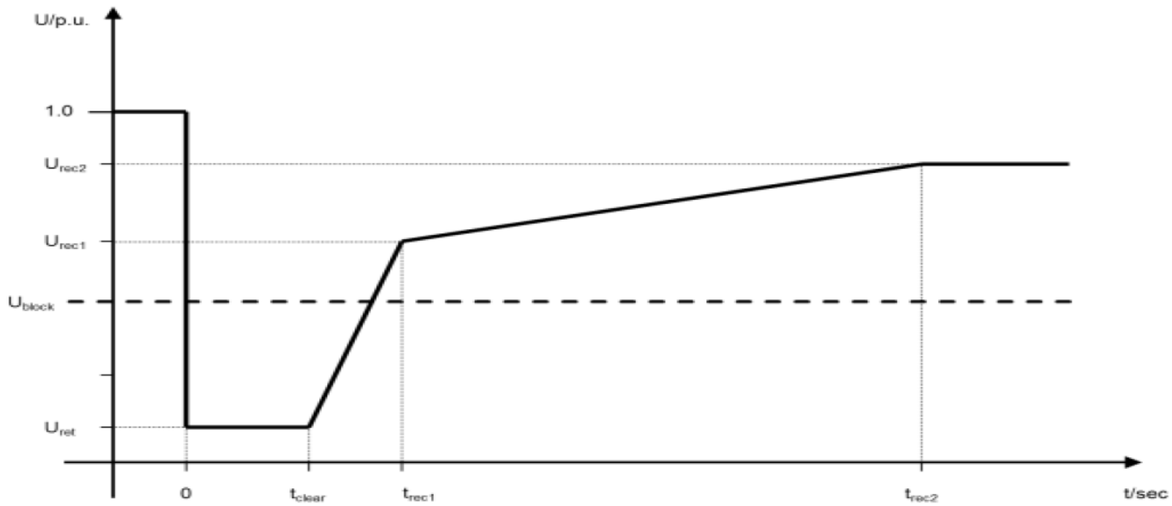


Figure A.4: FRT characteristic [4]

Table A.7: FRT characteristic parameters [4]

Voltage parameters [pu]		**Time parameters [seconds]**	
U_{RET}	0.00-0.30	t_{clear}	0.14-0.25
U_{REC1}	0.25-0.85	t_{REC1}	1.5-2.5
U_{REC2}	0.85-0.90	t_{REC2}	$t_{REC1} - 10.0$

When it comes to the post-fault active Power recovery *(Article 24)*, the system operator must determine a P-t profile and magnitude after a fault clearance.

A.2.3 Dumping capability contribution

Although there is not a general code that regulates the dumping oscillation support from the HVDC converter, the system operator shall specify it depending on the Network conditions and a frequency range of oscillations. However, the control system shall not reduce the damping of the power oscillations *(28 and 29.articles)*.

A.2.4 Black start capacity

Although **black start capability is not mandatory**, some properties related to black start shall be required by the system operator and the HVDC system owner shall agree with the capacity of the black start capability *(Article 35)*:

- If the system security is endangered by the lack of black-start capability, additional costs shall be specified,
- The system with Black Start Capability shall be able to energize the busbar of the remote AC substation to which it is connected, within a determined shut down time-frame.

A.3 DFIG control strategy and modeling

A.3.1 Modeling

The basic type 3 generator model-blocks can be seen in figure A.5:

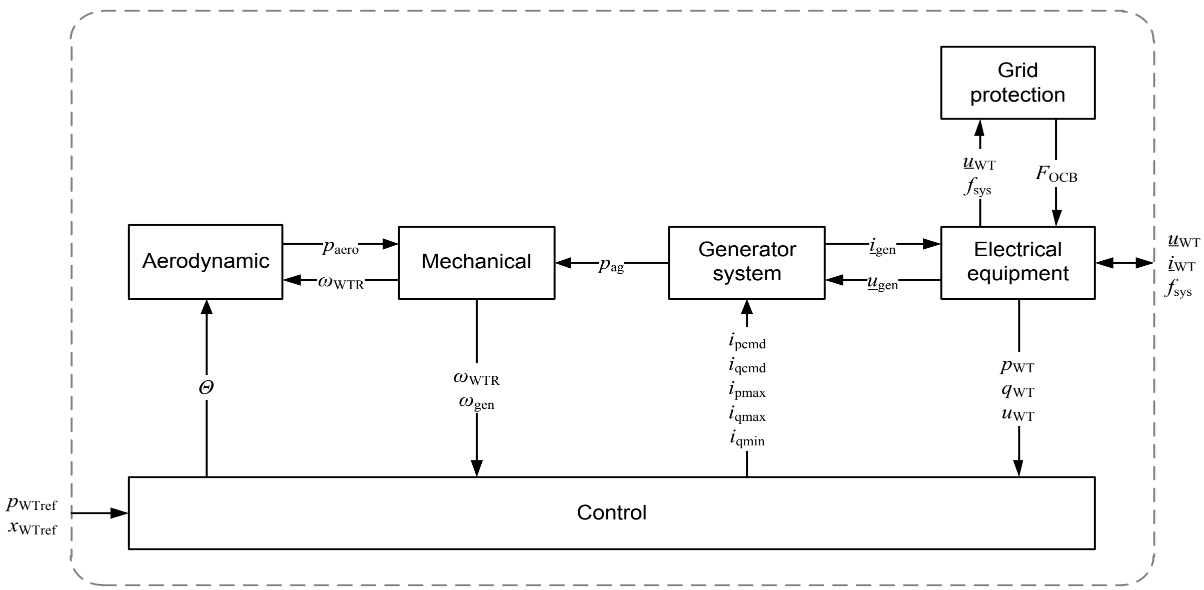


Figure A.5: DFIG simplified model [10]

Although in thorough they may differ from each other, all the DFIG models contains the following blocks [10], also the model implemented in power factory that will be used for this model:

- **Aerodynamic model:**The curves described in figure 5.1 are implemented in this block.
- **Mechanical model:**The behavior of the turbine is described in the mechanical equations implemented.

- **Generator system:**The electrical equations of the DFIG are inside.
- **Grid protection:**This block describes the behavior of the protections that are used to protect the DFIG and the network. The crowbar is also modeled here.
- **Electrical equipment:**Measurement equipment that measures the parameters from the grid.
- **Control:**It calculates the control parameters in *dq axis* for the converters and the pitch angle and the rotor optimal speed (when the maximum power tracker is activated), depending on the input parameters. Main blocks of the controller: QP controllers and pitch angle controller. Apart from these blocks, blocks to support the previous ancillary services for WTGs previously described can also be added [10].

Appendix B

PowerFactory progamming additional information

In this appendix the modified data in the original template for base-study case is shown.

B.1 Block diagrams in *PowerFactory* template

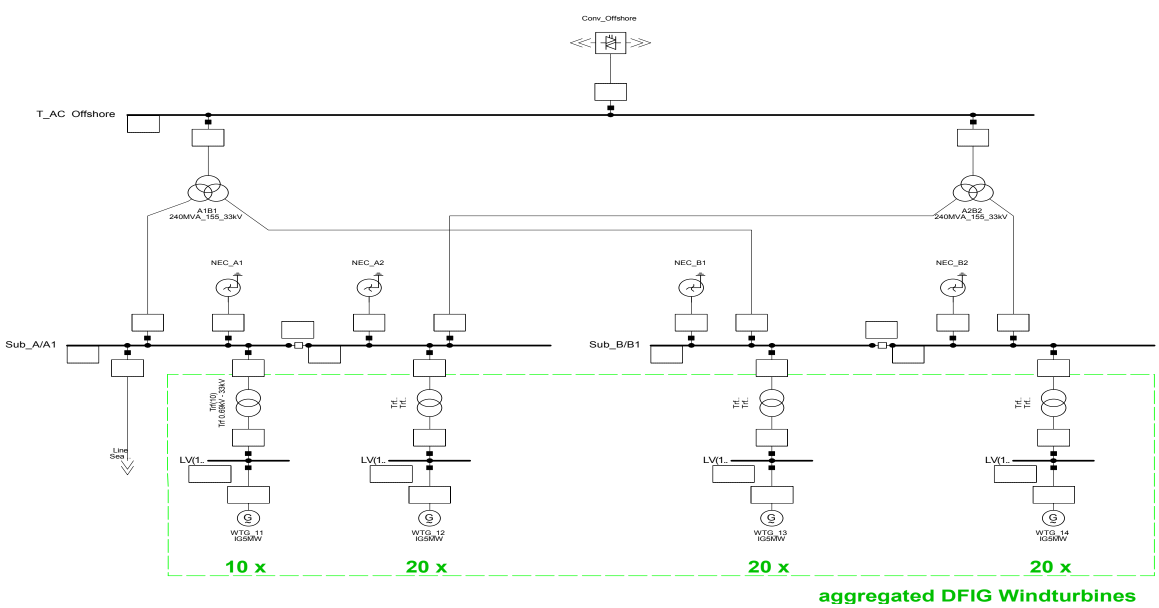


Figure B.1: 150-33kV Offshore Station system as modeled in *PowerFactory*

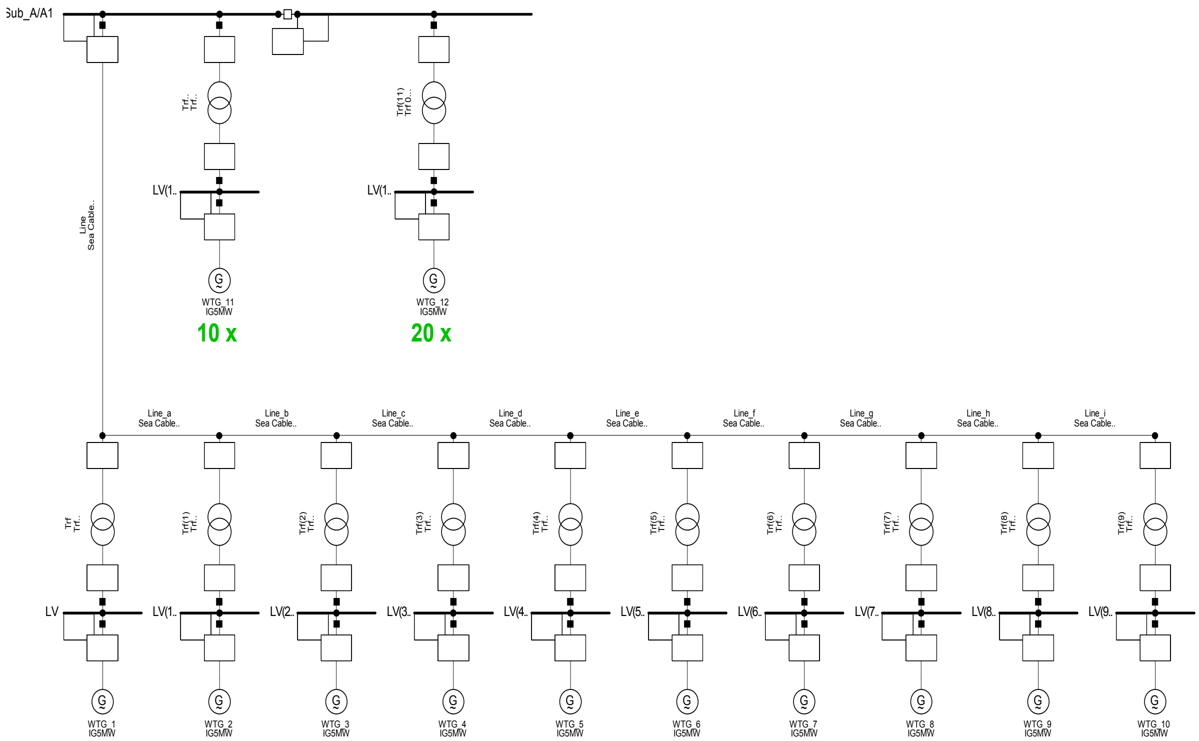


Figure B.2: Detailed wind farm feeder as modeled in *PowerFactory*

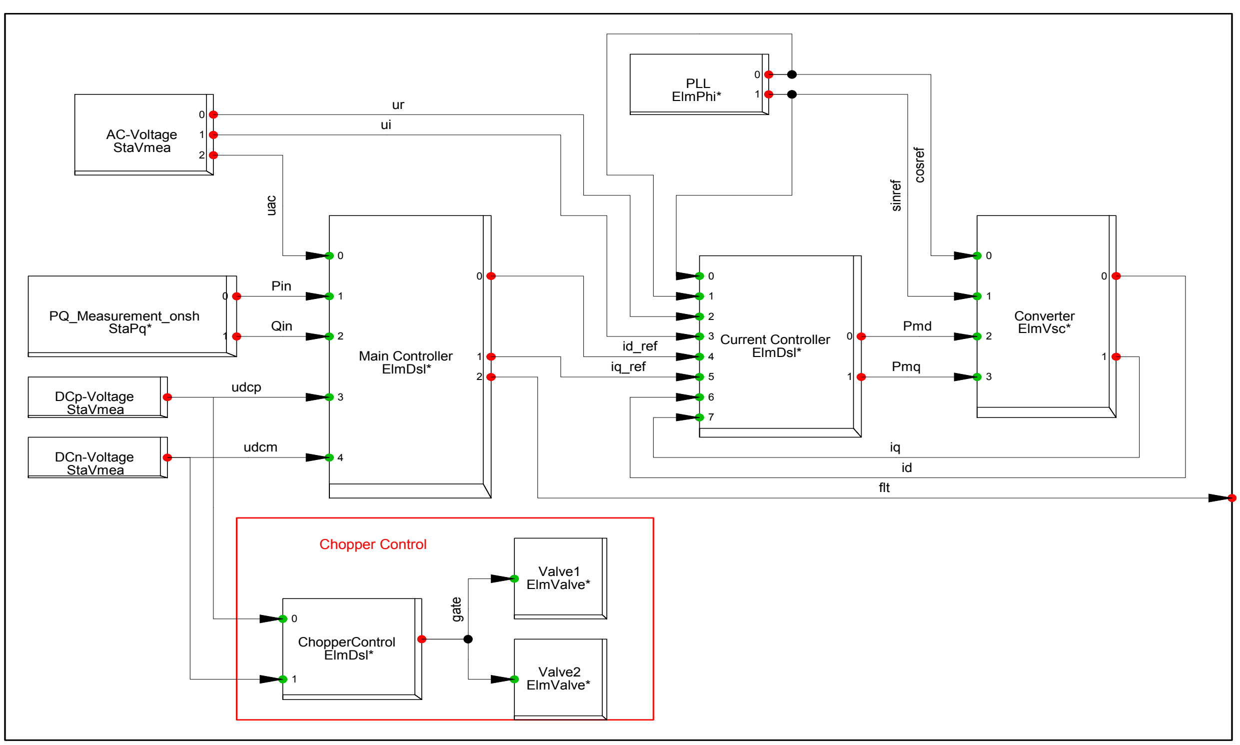


Figure B.3: Frame of the onshore HVDC control system

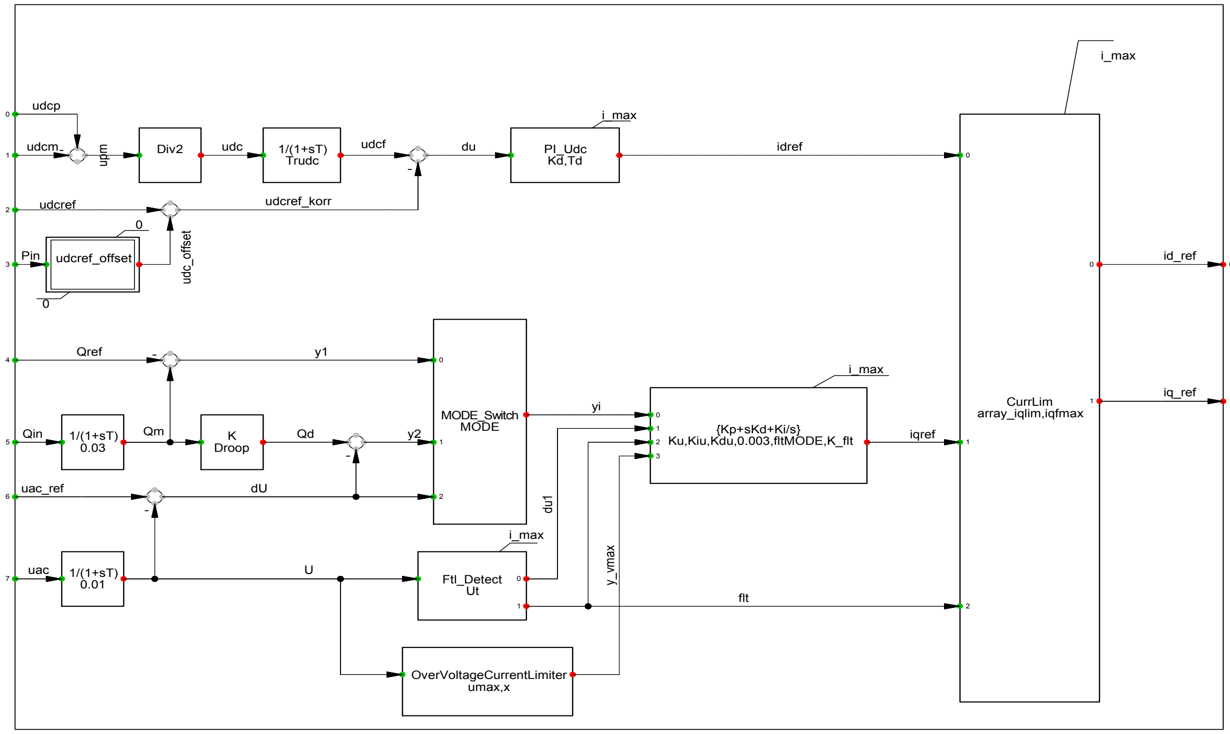


Figure B.4: Onshore converter control structure

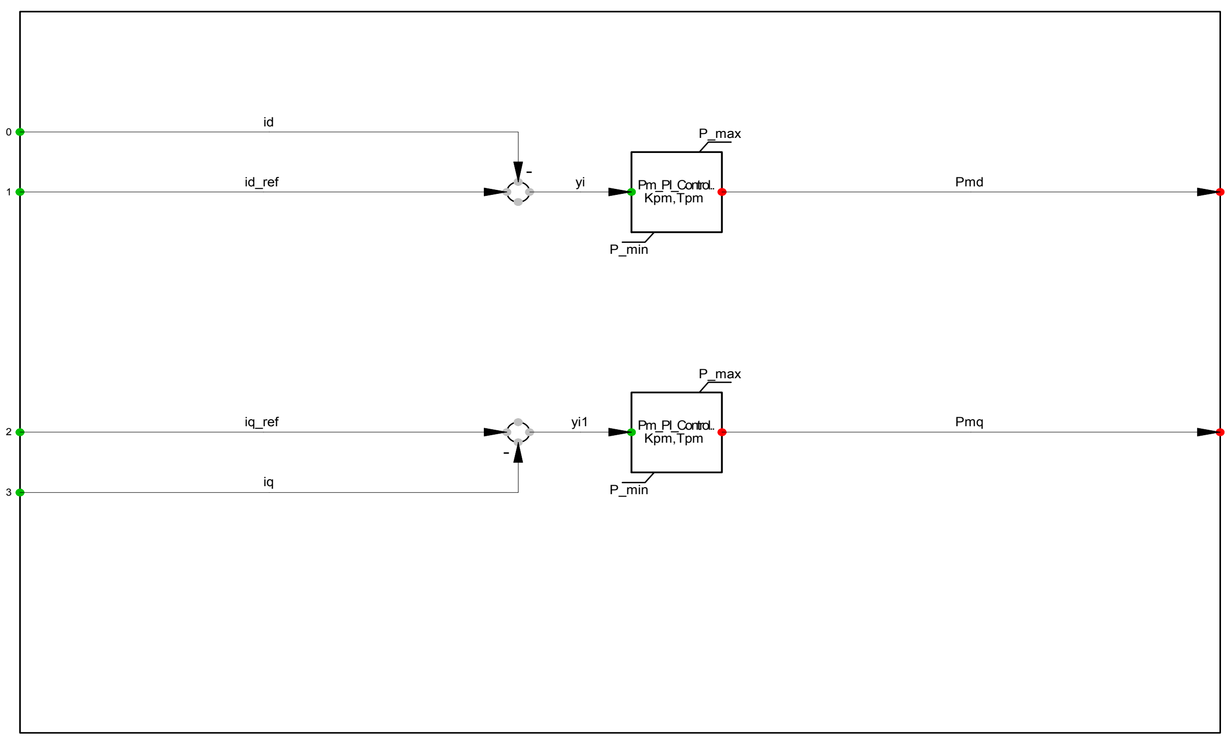


Figure B.5: onshore current controller control structure

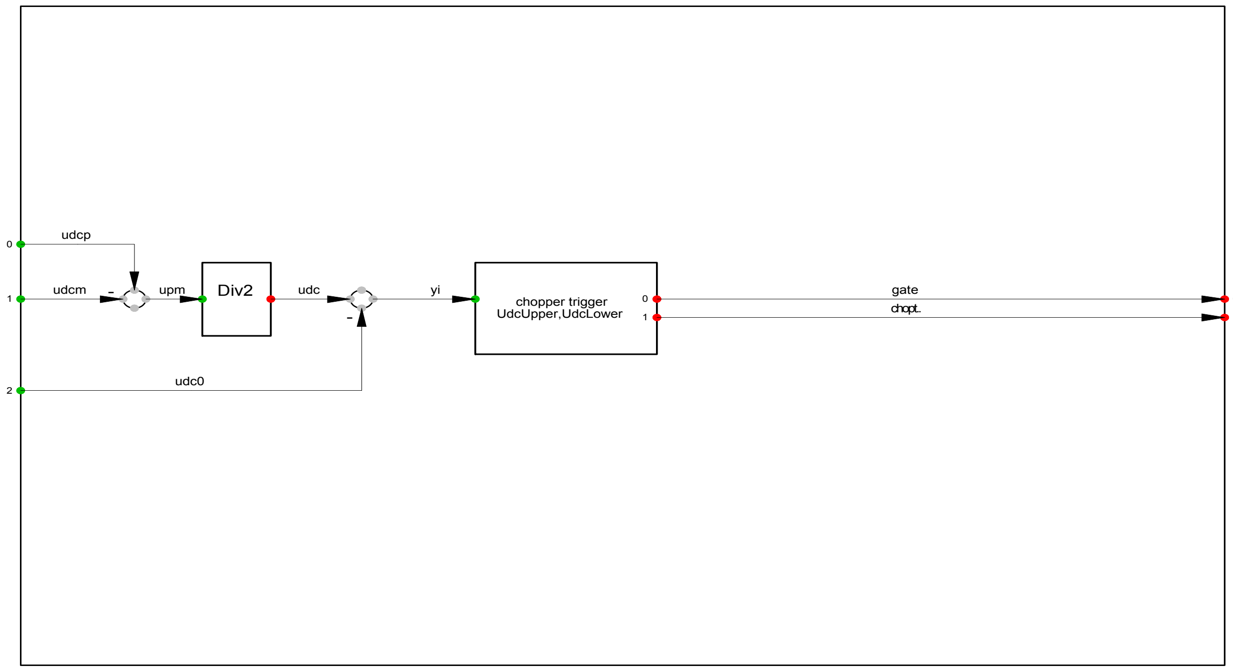


Figure B.6: chopper control structure

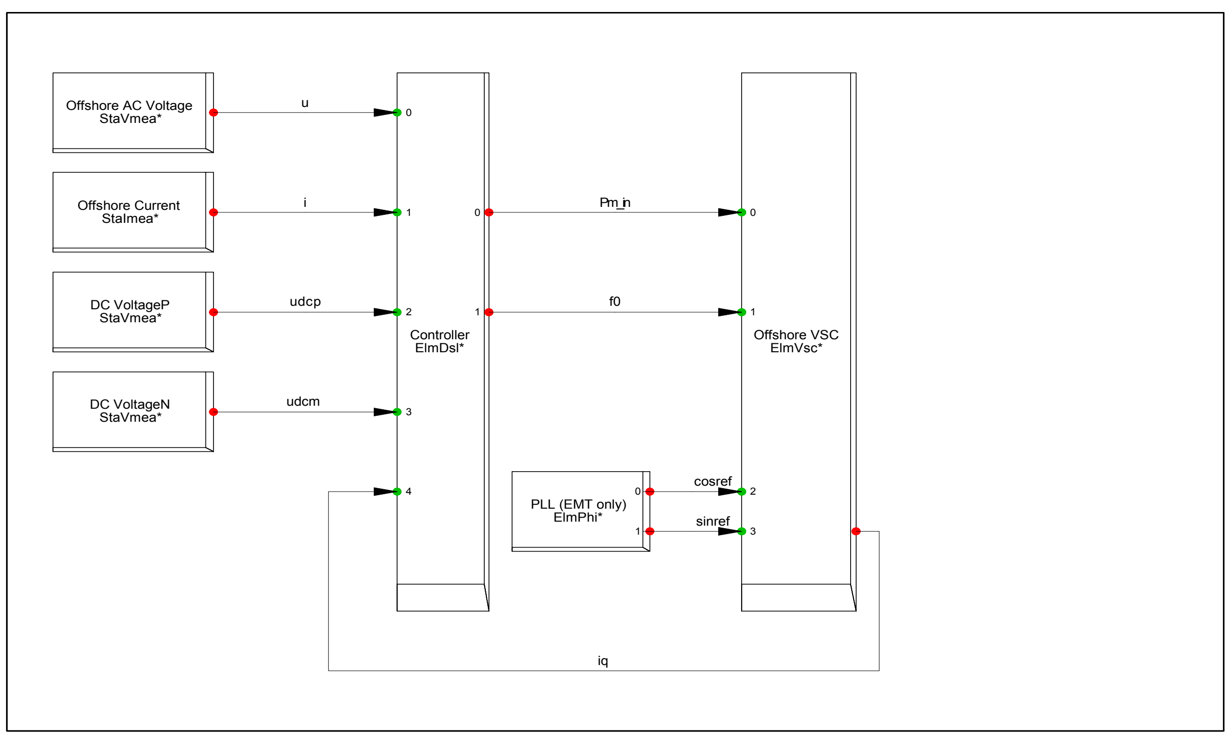


Figure B.7: Frame of the offshore HVDC control system

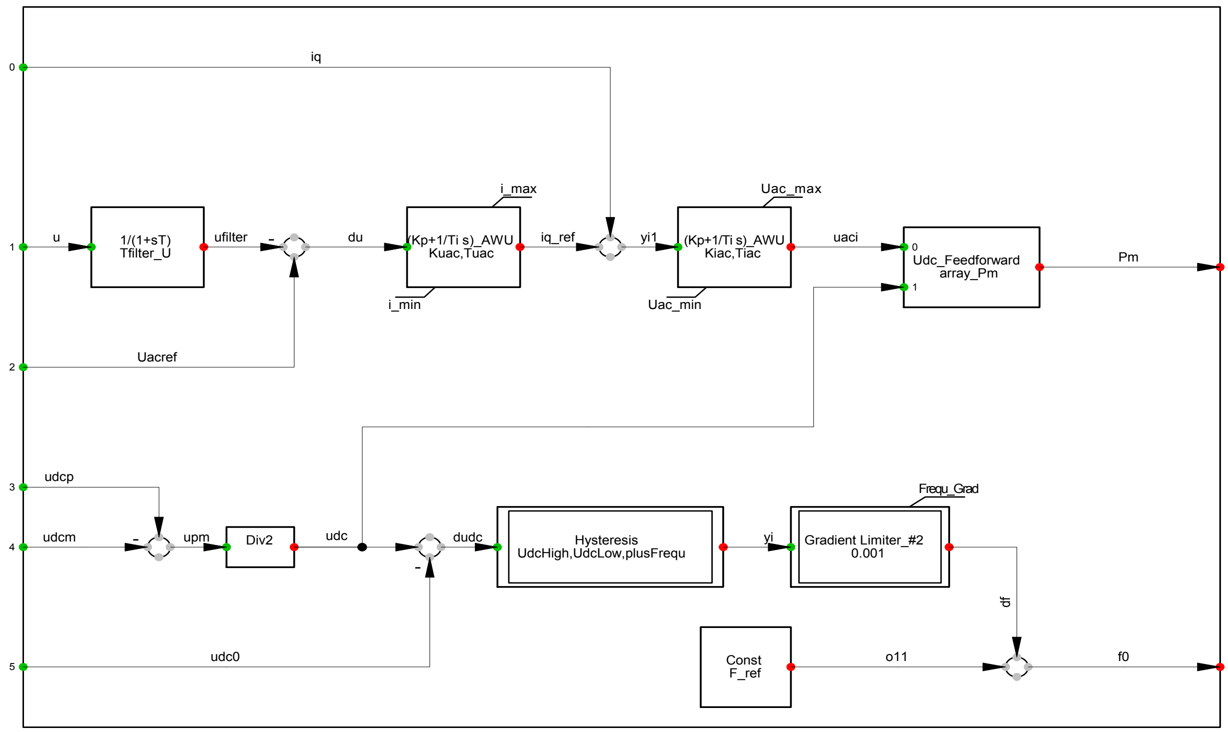


Figure B.8: Active power reduction block control structure

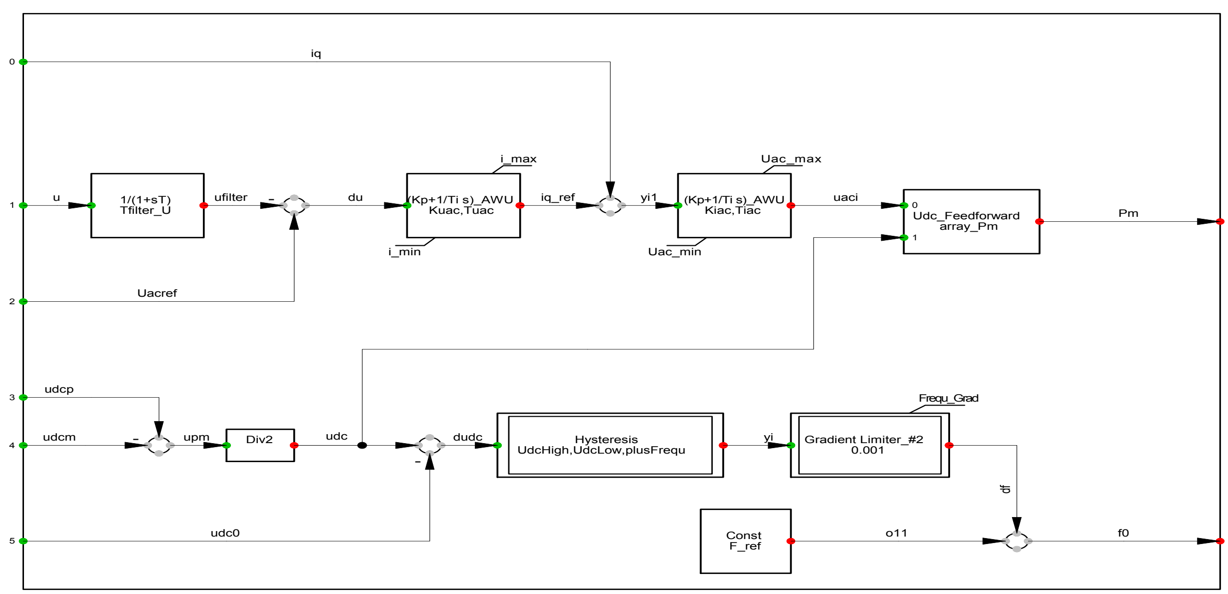


Figure B.9: control structure of offshore converter

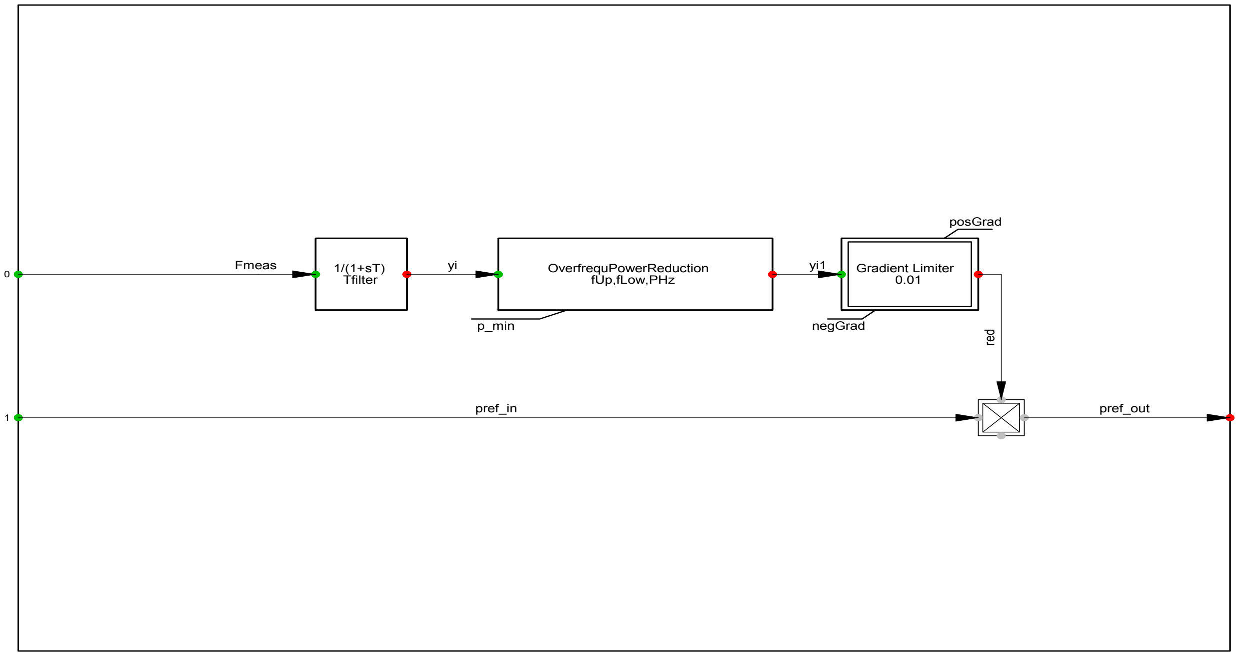


Figure B.10: control structure of DFIG

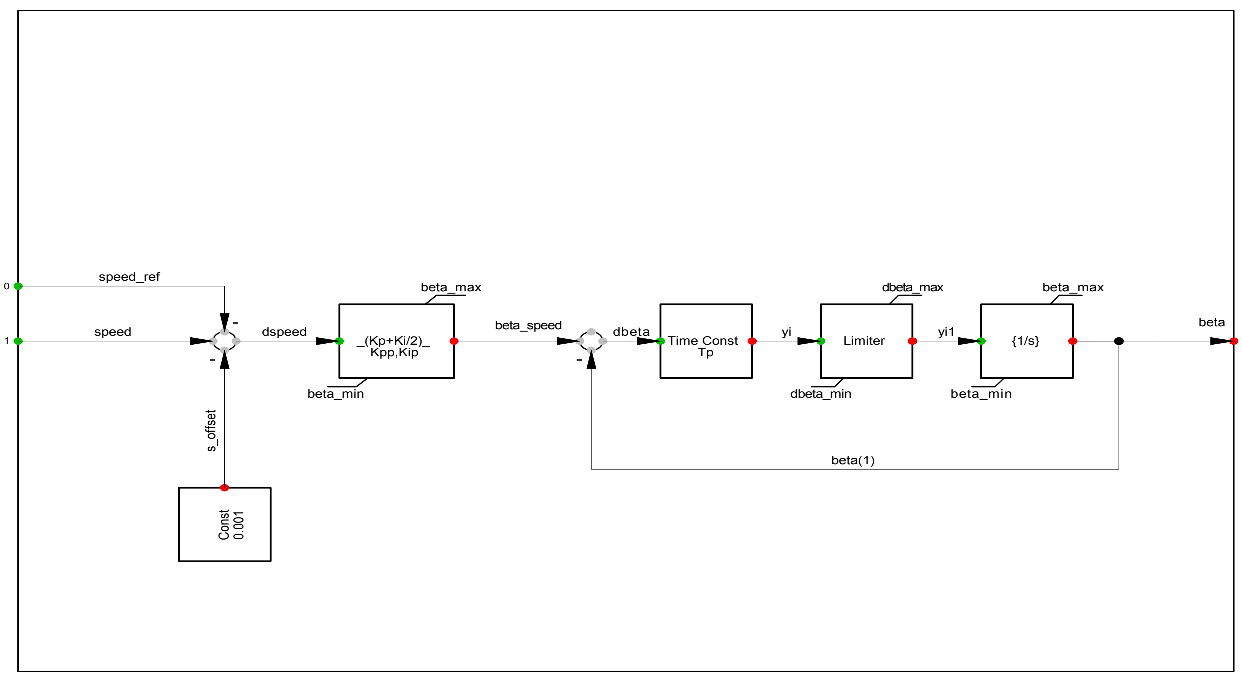


Figure B.11: Pitch controller control structure

B.2 Modified block diagrams in *PowerFactory* template

In this section the modified block diagrams in the original template programming code in *Power Factory* is shown.

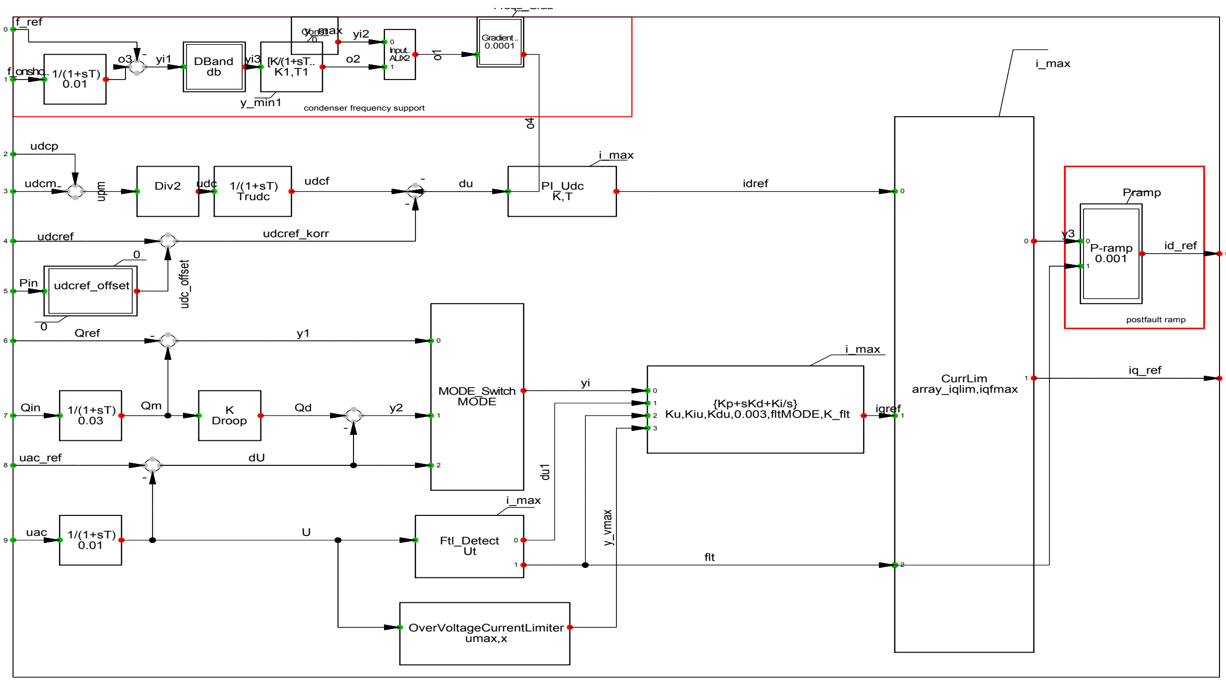


Figure B.12: Modified onshore converter control structure

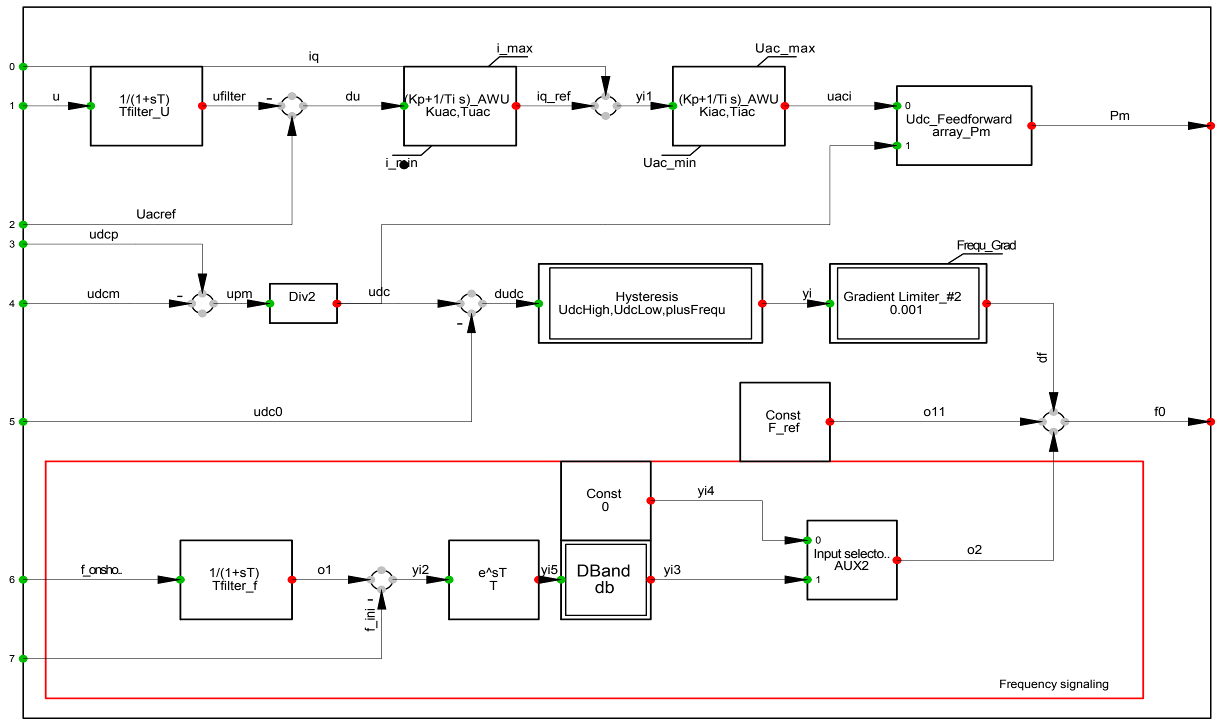


Figure B.13: Modified controller structure of offshore converter

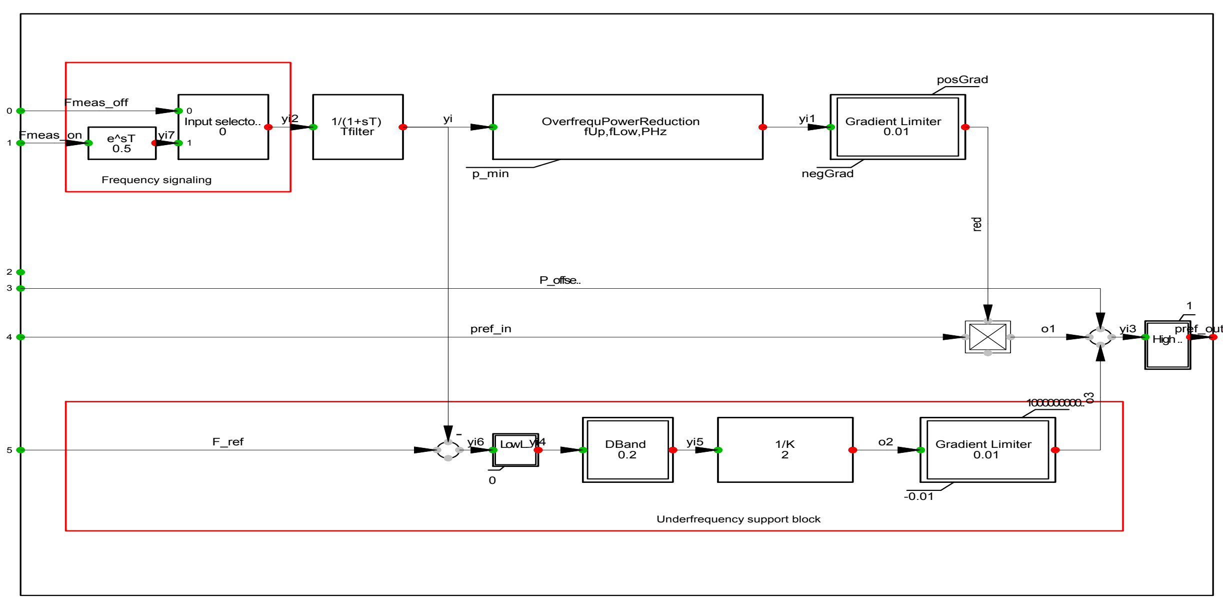


Figure B.14: Modified overfrequency support block for underfrequency support

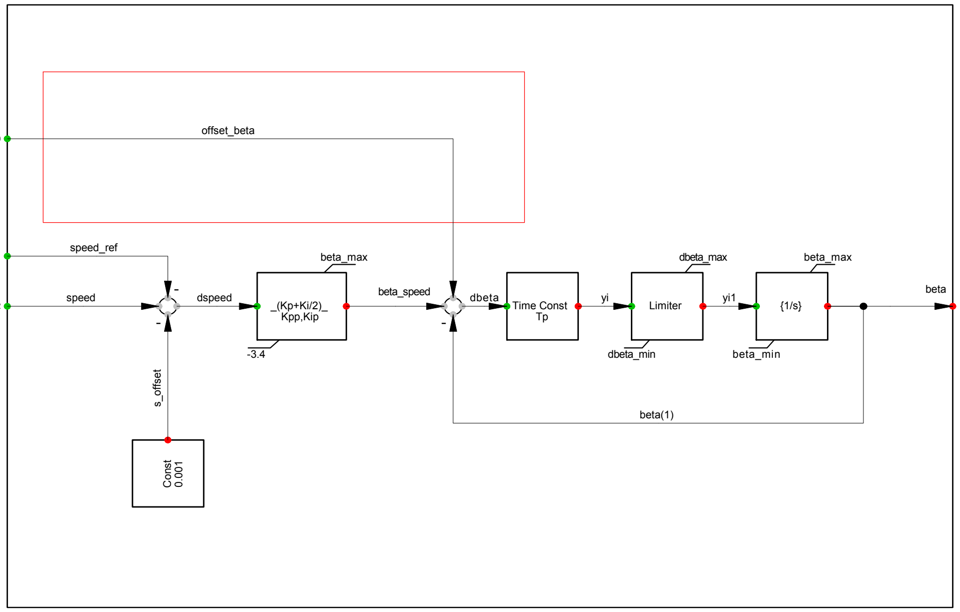


Figure B.15: Modified pitch controller control structure

B.3 Simulation with infinite bus additional data

In this appendix the modified data in the original template programming code in *Power Factory* is shown.

Table B.1: Infinite Bus Data

Infinite Bus Data	
Parameter	**Value**
Acceleration time constant(s)	20
Secondary frequency bias (MW/Hz)	20
Sk"max (MVA)	10000
lk"max(kA)	15,19343
c-Factor	1,1
R/X Ratio	0,1
X0/X1	1
Sk"min(MVA)	8000
lk"min(kA)	12,15474
c-Factor	1
R/X Ratio	0.1
X0/X1	1

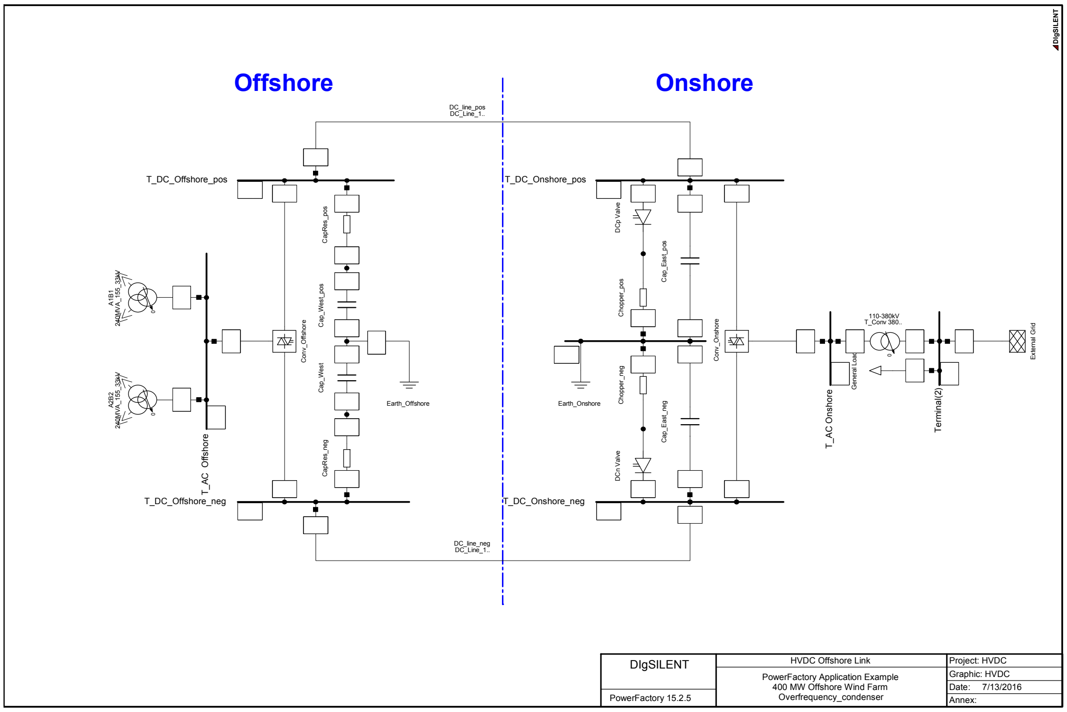


Figure B.16: Electrical system layout for stability studies connected to an infinite bus

B.4 Simulation with IEEE9 bus bar additional data

In this appendix the parametrization for the VSC-HVDC and IEEE9 busbar converter in *Power Factory* is shown.

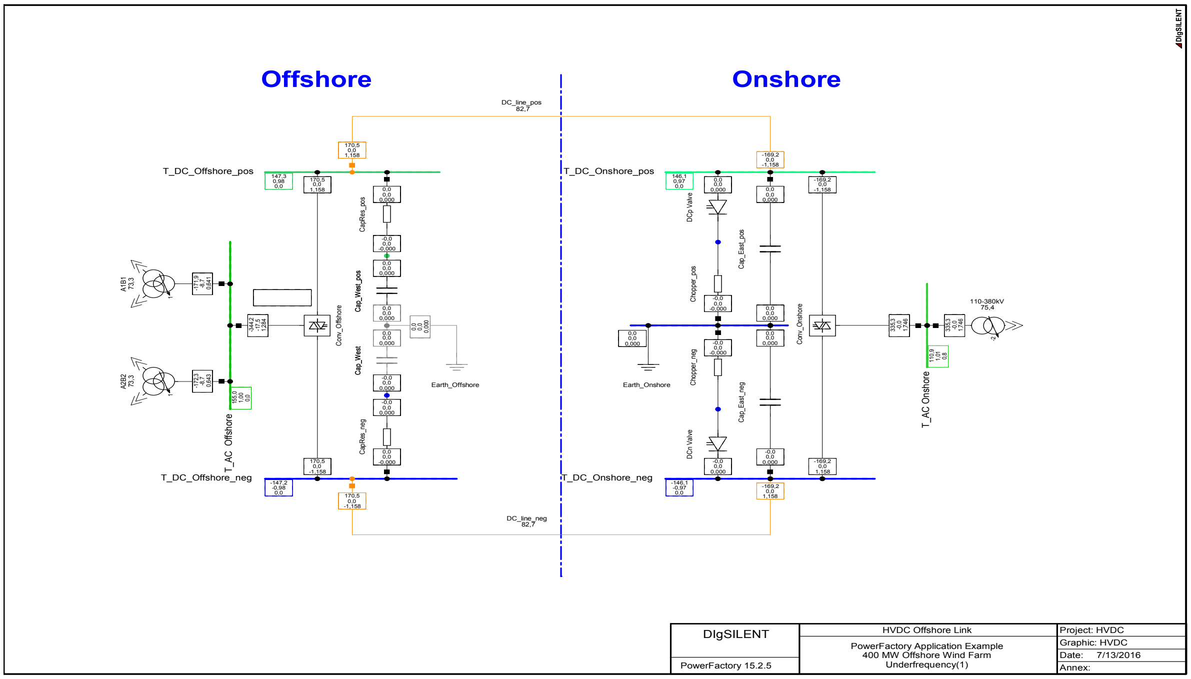


Figure B.17: Single line diagram for the HVDC system as modeled in *Power Factory*

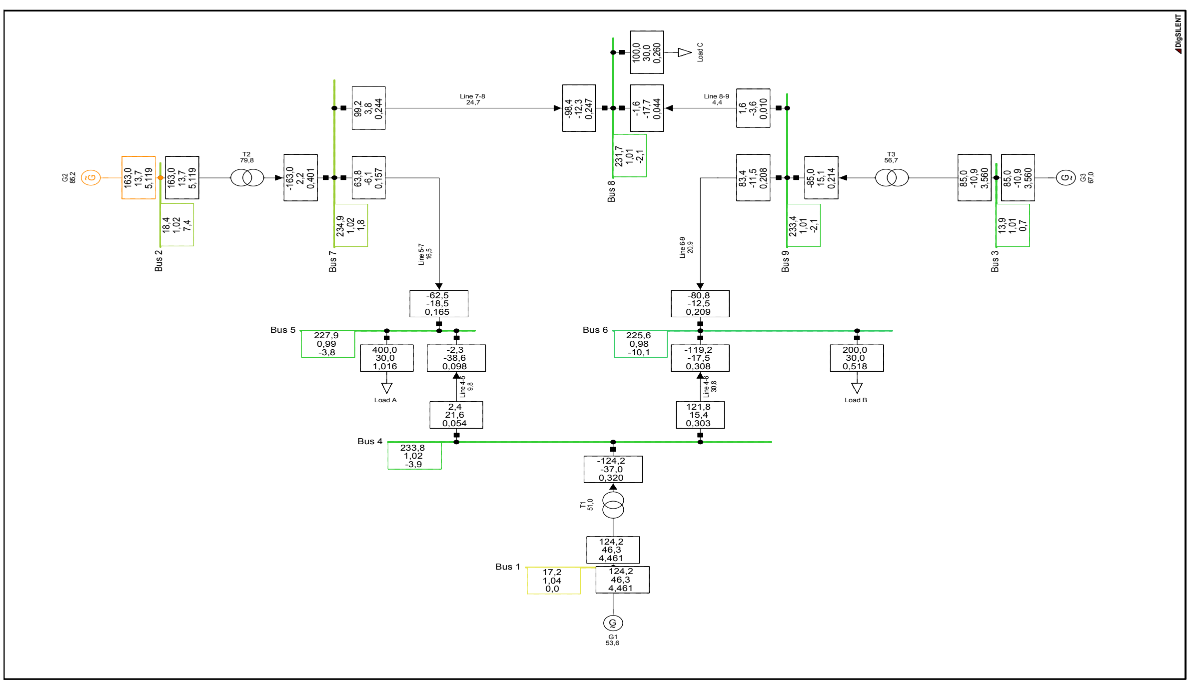


Figure B.18: Single line diagram for the IEEE9 busbar template of *Power Factory*

Table B.2: Loads nominal power parameters

Gen	P(MW)	Q(MVAr)
Load A	400	30
Load B	200	30
Load C	100	30

Table B.3: IEEE9 busbar generator dispatch

Gen	P(MW)	Q(MVAr)
G1	124,22	46,35
G2	163,00	13,68
G3	85,00	-10,90

Table B.4: Parameter definition for AVR

Name	Value	Unit	Description
T_r	0,02	[s]	Measurement Delay
T_b	12	[s]	Filter Delay Time
T_c	1	[s]	Filter Derivative Time Constant
K_a	200	[pu]	Controller Gain
T_a	0,04	[s]	Controller Time Constant
K_c	0,2	[pu]	Exciter Current Compensation Factor
$V_{i,min}$	-0,2	[pu]	Controller Minimum Input
$V_{r,min}$	-4	[pu]	Exciter Minimum Output
$V_{i,max}$	0,2	[pu]	Controller Maximum Input
$V_{r,max}$	4	[pu]	Exciter Maximum Output

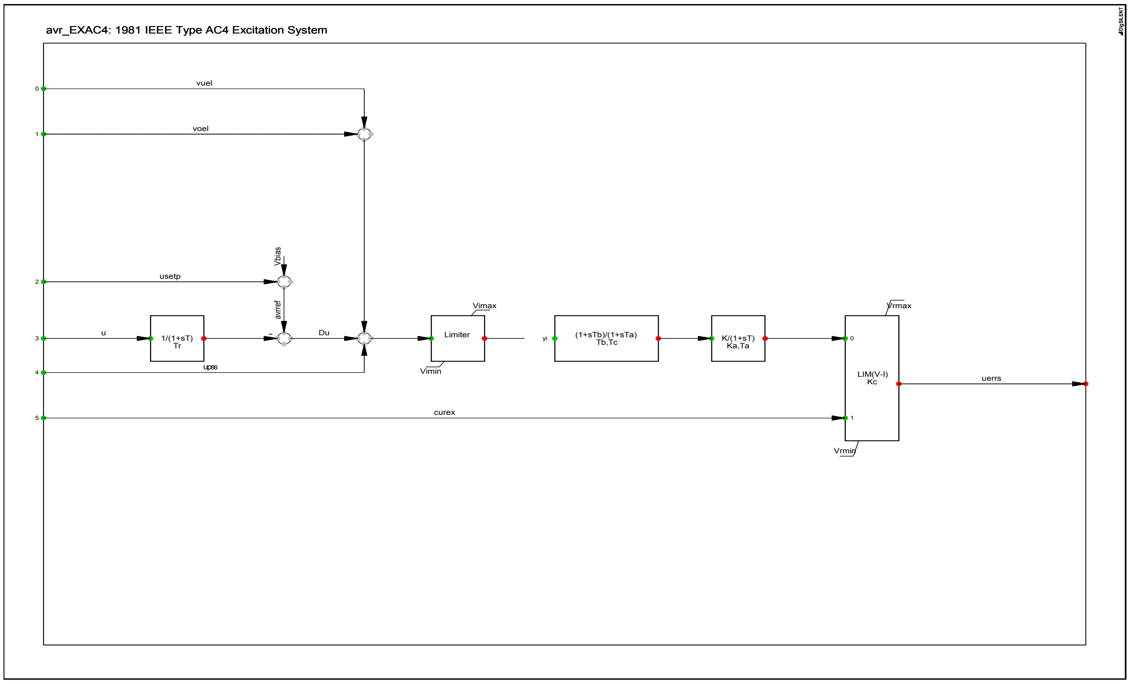


Figure B.19: EXAC4 AVR controller structure of *Power Factory*

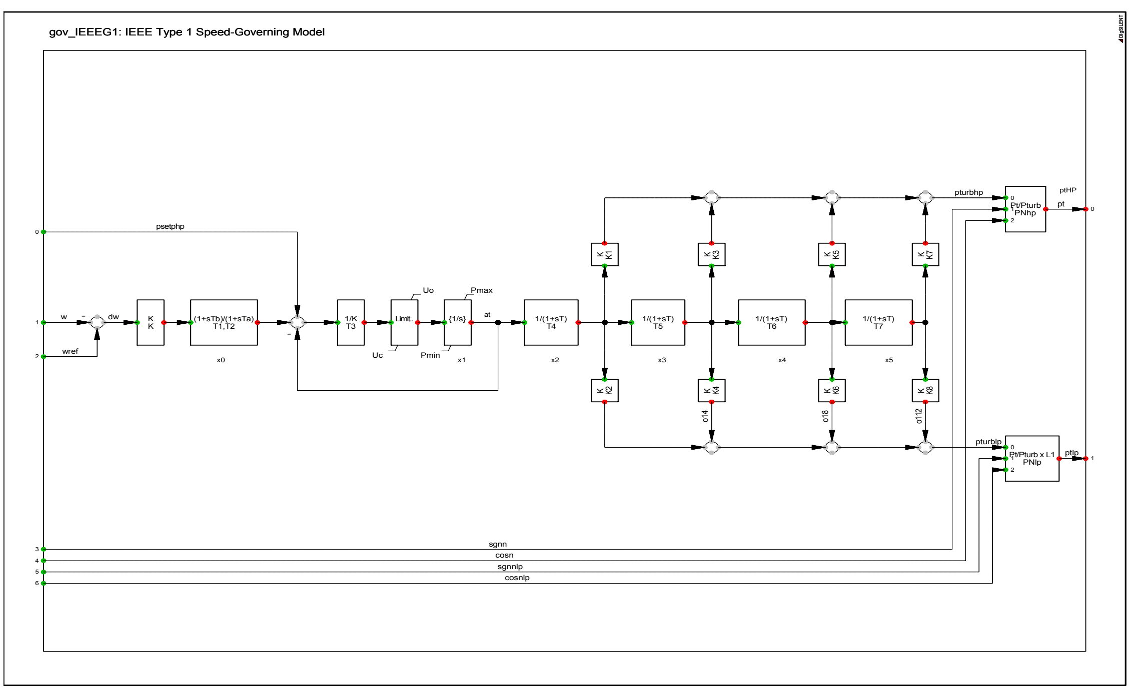


Figure B.20: gov_IEEEG1 governor controller structure of *Power Factory*

Table B.5: Parameter definition for PSS

Name	**Value**	**Unit**	**Description**
K	25,00	[p.u.]	Controller Gain
T_1	0,01	[s]	Governor Time Constant
T_2	1,20	[s]	Governor Derivative Time Constant
T_3	0,30	[s]	Servo Time Constant
T_4	0,30	[p.u.]	High Pressure Turbine Factor
K_2	0,00	[p.u.]	High Pressure Turbine Factor
T_5	0,50	[s]	Intermediate Pressure Turbine Time Constant
K_3	0,25	[p.u.]	Intermediate Pressure Turbine Factor
K_4	0,00	[p.u.]	Intermediate Pressure Turbine Factor
T_6	0,80	[s]	Medium Pressure Turbine Time Constant
K_5	0,30	[p.u.]	Medium Pressure Turbine Factor
K_6	0,00	[p.u.]	Medium Pressure Turbine Factor
T_4	0,60	[s]	High Pressure Turbine Time Constant
T_7	1,00	[s]	Low Pressure Turbine Time Constant
K_7	0,15	[p.u.]	Low Pressure Turbine Factor
K_8	0,00	[p.u.]	Low Pressure Turbine Factor
PN_{hp}	0,00	[MW]	HP Turbine Rated Power(=0->PNhp=PgnnHp)
PN_{lp}	0,00	[MW]	LP Turbine Rated Power(=0->PNlp=Pgnnlp)
U_c	-0,30	[p.u./s]	Valve Closing Time
P_{min}	0,00	[p.u.]	Minimum Gate Limit
U_o	0,30	[p.u./s]	Valve Opening Time
P_{max}	1,00	[p.u.]	Maximum Gate Limit

Abbreviations

AC Alternate current. 1, 2, 4–6, 10, 12, 16, 20, 52

DC Direct current. 4, 5, 11, 12, 14, 16

DFIG Double Feeded Induction Generator. ii, 2, 30–32, 38, 42, 54

EMT Elechtromagnetic Transients. 13, 14, 30, 69

ENTSO European network Transmission System Operator. 1, 11, 36, 39, 53

FRT Fault Ride Through. ii, 1, 2, 41, 66

HVAC High voltage alternate current. ii

HVDC High voltage direct current. ii–iv, vii, 1–7, 10, 11, 16, 18, 30, 32, 34–39, 44, 45, 52, 55, 58, 59, 61–63, 66–69

IGBT Insulated-gate bipolar transistor. 6, 15–17

IWES Wind Energy and Energy System Technology. 1

LCC Line Commutated Converter. 5, 16

MPT Maximum Power Tracker. 38

PWM Pulse Width Modulation. 17, 24, 31–34, 37

RMS Root Mean Square. ii, 1, 2, 13, 30, 31

TSO Transmission System Operator. ii, 15

VSC Voltage Source Converter. 1, 4, 6, 15–20, 23, 24, 34, 53, 68

VSC-HVDC Voltage Source Converter based High voltage direct current. ii, 1–3, 10, 14–16, 27, 30–32, 42, 58, 60, 64, 66, 67

WTG Wind Turbine Generator. v, viii, 2, 3, 25, 27, 30, 32, 38, 41, 42, 50, 52–59, 61, 62, 64–68

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