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Research report, October 2013

DTU Electrical Engineering
Department of Electrical Engineering

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Preface

This report was carried out during research assistance in a period from 19th of August, 2013 to 20th of October, 2013. The study has been performed at the Centre for Electric Power and Energy (CEE) at the Electrical Engineering Department of the Technical University of Denmark. The work was supervised by Qiuwei Wu.

Asimenia Korompili,

Lyngby,
Sunday, October the 20th, 2013

Executive Summary

Recently, more and more offshore wind farms have been integrated to the power systems. In the next years, these offshore power plants are going to be rated at higher capacities and located in larger distances from the coast. This results in greater interest in the transmission technologies, which are available for the grid connection of the offshore wind farms. In this report various transmission systems are presented. Precisely, the HVAC systems, which have dominated up until now in the power transfer sector, are briefly analysed, by providing their advantages, as well as the bottlenecks that occur in their applications. The main focus is given in the HVDC transmission systems, since they do not exhibit these disadvantages, whereas they additionally present beneficial attributes. This is the reason for which the applications of HVDC systems have been increased in the latest years. A brief description of different application cases is provided in the introduction of this report, while the rest chapters deal with the use of the HVDC technology for the grid connection of offshore wind farms.

The main structure of the HVDC system is analysed, by describing the role and operation of its main components. Especially the converter configurations, the devices for reactive power compensation, the filter systems and the DC breakers are presented in details. The presence of different components, with different characteristics, leads to alternative system structures. Therefore, a comparison between the different structures is performed, regarding power losses, costs, equipment aspects and control capabilities. It is concluded that the VSC-HVDC system exhibits the most advantageous features for the grid connection of offshore wind farms. In addition, various topologies of the HVDC converter stations are analysed.

Furthermore, the control schemes and strategies of the VSC are described in details. The capabilities of the VSC-HVDC technology, provided by its control system, are analysed. These attributes give the opportunity to the VSC-HVDC transmission system to provide grid support. They imply also benefits for the design of the wind turbines, as well as for the operation of the TSOs.

Special focus is given on control strategies for fulfilling requirements concerning LVRT and frequency regulation. The corresponding technical rules, included in grid codes, are provided and the relevant structures and methods are described.

Finally, more specific requirements are given for the grid connection of offshore wind farms through HVDC systems. These rules derived from the combination of grid

codes for the integration of offshore wind farms and grid codes for the operation of HVDC transmission systems, connecting power plants to the AC network.

Contents

Chapter 1

Introduction

1.1 Background

Nowadays, global climate change is no longer questionable and concerns about its significant impact on planet's life are increasing. For this reason, the EU has put specific targets to reducing the greenhouse effect and limiting the global warming. Furthermore, exhaustion of fossil fuels, higher energy prices, increasing demand of power and energy dependence between countries create huge challenges for governments all over the world. This situation implies changes in the current energy supply sector, leading to different shares between the various energy resources. The use of conventional primary energy types, such as oil and gas, has restricted; on the other hand, renewable energy resources with zero greenhouse gas emissions, like wind and solar energy, have gained worldwide attention in the recent years [1, 2].

Due to the wide distribution of potential large-scale wind resources all over the world, wind energy is the most exploited source among the renewable energy types. In 2007 wind was the second energy resource in the EU, with a share of 30 % of the installed power capacity. Its global average annual growth rate has reached to be 30 % in the last decade. This trend will hardly change in the next years, considering the aim of EU to produce $12 - 14\,\%$ of electricity from wind by 2020 [2–4].

1.2 Offshore wind energy

A key technology for achieving the aforementioned energy goal of the EU is the large offshore wind farms, with capacity of several hundred megawatts. Although the majority of the wind power is nowadays produced by onshore wind turbines, the offshore market is going to be of high interest for the energy policies in the near future [2, 4].

The most important advantage of the offshore location of the wind farms is the huge wind resources available, giving a high potential for power production. These resources are still unexploited; on the contrary, profitable onshore locations in Europe have been already used. Moreover, the wind conditions are better in offshore areas, since the wind speeds are higher and more predictable and the wind fluctuations are lower. This implies a higher capacity factor of offshore wind farms compared to that of the onshore installations. In addition, offshore wind turbines are less obtrusive than these on land and therefore projects for offshore wind farms experience less public resistance [4, 5].

At the moment, wind farms in offshore locations are still more expensive than those on land. Two factors characterise mostly their cost: the turbine foundation and the wind farm's distance from the shore. The foundation cost usually grows up rapidly with increasing water depth and wave height. The transmission distance strongly affects the grid connection costs. In addition, costs of repair and maintenance are significantly higher for offshore turbines. For these reasons, up until now, sites close to the shore, with shallow waters, were preferred for offshore wind farms [4].

However, there is still stimulus for locating the wind farms even further offshore. Often, near-shore sites are subject to various interests, like maritime traffic, coastal fishing, recreational or military activities. In contrast, in offshore areas such restrictions do not exist. Moreover, visibility, noise disturbance and environmental concerns regarding the impact on marine flora and fauna are mitigated [3, 4].

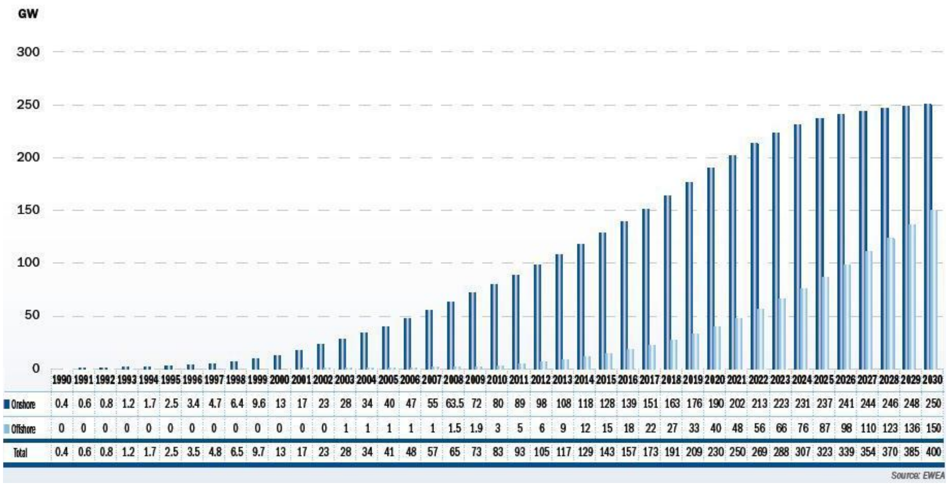
In Europe, an increasing number of offshore wind farms have been constructed or proposed, especially in the areas of North and Baltic Seas, where wind energy resources are rich and widely distributed. Figures 1.1a-1.1b present the growth of wind power capacity installed and energy produced by wind in the EU, for both onshore and offshore locations, from 1990 and projected till 2030. As it can be observed, by 2030 the total wind power capacity will be 400 GW, out of which 150 GW will be installed in offshore sites. However, due to higher capacity factor of the offshore wind farms, the latter will produce half of the total energy [1, 3, 6, 7]. Moreover, Figure 1.2 illustrates the worldwide trend of future offshore wind farms for being of higher power capacity, as well as in increased distances from the shore [4, 5].

Therefore, there exists a clear need to further develop the power transmission technology for connecting large wind farms, located in a long distance from the shore, to the nearby on-land network. Various transmission options should be analysed and investigated in terms of cost, as well as of stability and security of the power system [1, 2, 5].

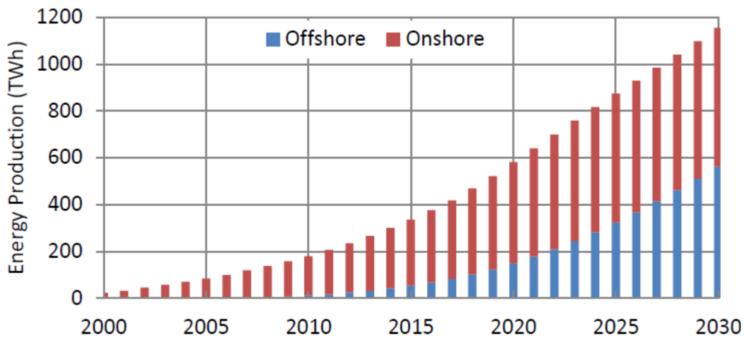
1.3 High voltage grid connection of offshore wind farms

The transmission of high power over long distances creates challenges for the network operator and the wind farm developer.

As it is known, the electric power is the product of current times voltage. For a given amount of power, low voltage requires high current and vice versa, i.e. high voltage requires low current. When transmitting power through metal wires, a small amount of power is lost as heat in the wires. This power loss is given by Joule's first law and it is proportional to the square of the current. Thus, for a specific amount of power, the power loss will be greater in systems with high current (and



(a) Installed wind power capacity (cumulative figure) [6]



(b) Wind energy production [3]

Figure 1.1: Growth of wind power capacity and energy production in EU

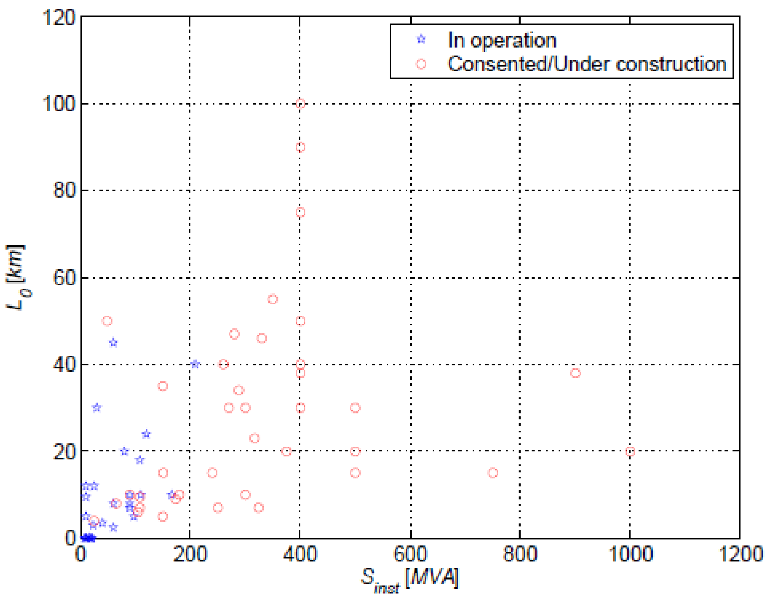


Figure 1.2: Trend of future offshore wind farm:
installed capacity vs distance from shore [5]

low voltage) than in the systems with low current (and high voltage). As a result, for reducing power losses in transmission systems, and considering the constraints of practical conductor size, high voltage is used [8, 9].

There are two alternative methods, both in high voltage, for connecting offshore wind farms to the grid: high voltage AC (HVAC) and high voltage DC (HVDC) systems. The selection of the suitable transmission type should be done by taking into consideration power efficiency as well as economical aspects [2, 10].

1.4 HVAC vs. HVDC transmission technology

In this section the two alternative transmission systems are going to be compared. The advantages of the HVAC transmission method, which are analysed in 1.4.1, explain its dominance in the power system up until now. However, its disadvantages, which are given in 1.4.2, led engineers to developing new transmission technologies based on DC links. The resulted higher technical and economical feasibility of HVDC connections give reason for their increasing use in the future. Their advantages are analytically presented in 1.4.4, which enable the applications of HVDC systems described in 1.4.5.

1.4.1 Dominance of HVAC transmission systems

In the late 19$^{\text{th}}$ century, during the initial years of electricity usage, transmission and distribution of electric energy were achieved through DC systems. However, they were found to be inefficient due to power losses in conductors. The voltage drop in the resistance of conductors was so high that power plants should be located within a mile from the load. In addition, converting DC from one voltage level to another required a large converter, which was expensive, inefficient and needed maintenance. As a result, higher voltage levels could not so easily be used, since there was no low-cost technology that would allow reduction of a high transmission voltage to a low utilisation voltage [8, 11].

The power losses in conductors and the difficulty in voltage conversion in DC systems were the key factors to the success of the AC systems and their dominance in the transmission and distribution of electric power. In AC systems, power could be transmitted more efficiently over long distances with far less power losses. Simple and efficient transformers, which have no rotating parts and therefore require very little maintenance, were used to down step high transmission voltage to low distribution voltage. These practically mean that fewer and larger power plants could serve the load in a wider area. Hence, AC technology was accepted as the only feasible method for transmission and distribution of electrical power [8, 11–13].

As a result of the dominance of AC power, HVAC transmission systems offer, up until now, a simple and cost-efficient solution for bulk power transmission and reliable integration of large-scale renewable energy sources. Most of the present large offshore wind farms are grid-connected through HVAC transmission systems. For example, "Thanet offshore wind farm", the largest offshore wind farm to date with total capacity of 300 MVA, is grid-connected via HVAC cables. The "Horns Rev I" offshore wind farm (160 MW) in the North Sea is connected to the nearest suitable 150 kV on-land substation through a 57 km long, 150 kV AC cable (21 km of submarine cable and 36 km of onshore cable). The "Horns Rev II" offshore wind farm (209 MW) is grid-connected utilising an almost 100 km long, 150 kV AC cable system, consisting of submarine and on-land cable sections [3, 5, 7].

1.4.2 Disadvantages of HVAC transmission systems

As explained above, important equipment aspects have been the key factors in deciding the use of an AC system up until now. Nevertheless, an AC system has its own associated bottlenecks, concerning mainly reactive power requirements and limitations of the cable transmission distance [5].

The reason of the restricted transmission length is the power losses in the cables or lines used. When AC systems are applied in cables, additional current should flow through the cable to charge its capacitance. This extra current flow increases the temperature of cable conductors, resulting in energy losses as heat. The reactive current generation increases with the rated voltage and the length of the cable. This capacitive effect of underground or undersea cables applies also to overhead lines, although to a shorter extent. However, in long AC overhead transmission lines the needed current for the capacitance charge could be significant. In any case, the entire current-carrying ability of the conductor could be needed only to supply the charging current. This practically means that the capacitive effect limits the power-carrying ability of AC cables and long lines [4, 8, 9, 13–15]. In cases where overhead lines are used, the useful current-carrying capability of the transmission system is furthermore reduced due to the skin effect: line conductor presents high resistance to alternating current, which causes a non-uniform distribution of the current over the cross-sectional area of the conductor. This issue is of practicable significance in the case of large conductors carrying thousands of amperes [3, 4, 8, 9, 13]. In addition to losses, the AC cable costs also increase rapidly with the transmission distance [2].

Consequently, the reactive current, drawn by the cable capacitance, forces reactive power compensation measurements. As mentioned above, the reactive power generation of HVAC cables increases with both voltage level and cable length and leads to sub-optimal utilisation of their inherent current-carrying capability. In general, long HVAC lines exhibit a wide variation in reactive power flow from peak load to light load conditions and, if the system is weak, this can result in operational problems. Such long lines can be the cause for voltage collapse situations and "low-voltage fault ride-through" requirements, derived from the grid codes, are difficult to be achieved. Thus, reactive power control devices may be required at both sending and receiving ends of the HVAC link, depending on the relative strength of the AC system at the connection point, for regulating reactive power and therefore avoiding voltage stability problems. In some cases, additional dynamic reactive power control devices, such as SVCs or STATCOMs, may be necessary [2–4, 7, 10, 16].

In conclusion, the usage of HVAC systems for bulk power transfer over long distances is not preferable. As far as the grid connection of renewable energy sources is concerned, the current offshore wind farms, which are located in relatively short distances from the coast, acquire HVAC transmission technology, but for longer distances the suitability of HVAC transmission is questionable [5].

1.4.3 Development of HVDC transmission systems

The aforementioned drawbacks of HVAC transmission systems led engineers to developing HVDC transmission methods as a supplement to the current HVAC links. In recent years, the rapid development of power electronics gives to the HVDC technology the opportunity to overcome its former bottlenecks and become technically and economically feasible for power transmission over long distances [1, 11]. Indeed, the invention of power electronic devices such as thyristor valves and rectifier improved reliability and efficiency of conversion between AC and DC. Thus, the design and development of current-source converters (CSC) became practically possible. In the next years HVDC transmission systems based on thyristors, which are called classic HVDC systems, have been proved to be feasible on an industrial scale [1, 5, 8, 11, 17]. The world's first commercial HVDC transmission link was built in 1954, connecting the island of Gotland in the Baltic Sea to the Swedish mainland via a submarine 20 MW cable. Ever since, the classic HVDC transmission technology has been developing to become mature and well-proven [1, 4, 11, 14, 15].

Recently the next-generation type of HVDC transmission systems has become available. It is based on the more advanced semiconductors technology, namely the insulated gate bipolar transistors (IGBTs). The invention of IGBTs has accelerated the development of voltage-source converters (VSC), which have come into use in the last years in HVDC applications in lower power ranges [1, 5, 11, 13–15, 17]. Since its first commercial application in 1999 in an undersea 50 MW, 80 kV link, the VSC-HVDC technology has been developed regarding losses reduction and voltage and power ratings increase. The evolution of IGBTs has reduced switching and conduction losses through more optimised components and schemes. In addition to switching patterns, development in converter topologies also reduce power losses. The evolution of losses and capacity in voltage-source converters can be seen in Figure 1.3. Apart from the converter development, cable technologies have also advanced, through research in extrusion methods and cable accessories (joints, terminations), resulting in higher link capacities. This has enabled HVDC applications to expand in voltage and power levels, supporting the grid in increased demand of security [18].

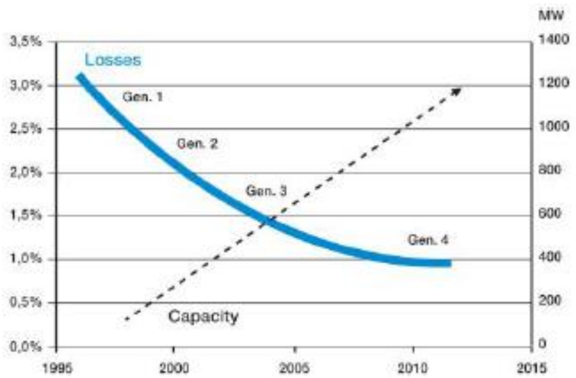


Figure 1.3: Evolution of station losses and power capacity in VSCs [18]

1.4.4 Advantages of HVDC transmission systems

For power transfer over long distances, the prospect of DC systems is considered very attractive due to the limitations of AC cable systems, as described in 1.4.2. Indeed, in DC technology there is no additional reactive current required for charging the cable capacitance; the capacitance is charged only when the cable is first energized or if the voltage level changes; during the static condition the cable acts as a resistor. Thus, the power-carrying capability of the DC cables and long lines is not restricted by the capacitive effect. This also means that there is no need for reactive power compensation for absorbing the excessive reactive current in the cable or line. Moreover, the line conductors operating with DC do not suffer from the constraint of the skin effect, as AC lines do. As a result, cables and overhead lines can carry more current to the load when operating with DC than AC, since the power losses per transferred MW over the transmission distance are less. [19] mentions that HVDC systems can carry 2-5 times the capacity of an AC line operating at the same voltage. This implies that DC transmission systems can increase the capacity of an existing power network, which is important especially in situations where additional wires are difficult or expensive to be installed. In addition to the increased power-transfer capability, the reliability of HVDC links at electrical disturbances is found to be enhanced, compared to that of HVAC connections [2–6, 9–11, 13–16, 20].

However, in HVDC systems the power losses in the converter should also be taken into account. On the contrary, in HVAC systems the only components which could contribute to power losses are the transformers and the compensating reactors; nevertheless, the major amount of power is lost in the transmission cables, so that the losses in the other modules could be assumed as negligible [5, 6, 9, 11].

In Figure 1.4 a comparison of power losses in HVAC and HVDC systems with increasing transmission distance is illustrated. At zero transmission distance, the power losses occur only in the other equipment apart from the cables. Thus, the losses in the converter of HVDC systems dominate. However, in HVAC systems power losses increase more rapidly with increasing transmission distance than in HVDC systems (higher slope of curve in Figure 1.4). As a result, above a certain distance, the "break-even" distance, the HVDC alternative presents always lower power losses and below this specific distance HVAC technology has lower losses [6]. [5] concludes that, for medium-scaled power transfer, the HVAC technology provides more efficient solution for distances below 90 km, while HVDC systems are more preferable for longer distances, above 110 km. In case of higher amounts of power ($>$ 500 MVA), [5] expects that HVDC systems will provide an even further efficient transmission solution, since they will present less power losses than HVAC systems at shorter distances.

Although total system power losses is one of the major factors, the process of decision between HVAC or HVDC transmission systems should also include many other factors, such as investment costs and operation and maintenance costs. The terminal stations are more expensive in the HVDC case due to the conversion equipment. However, HVDC transmission lines and cables cost less than in HVAC systems for the same capacity over long distances. This relies upon two factors: firstly, HVDC systems need fewer conductors, since there is no need for three wires to support three phases, but only for two for the two polarities; secondly, thinner

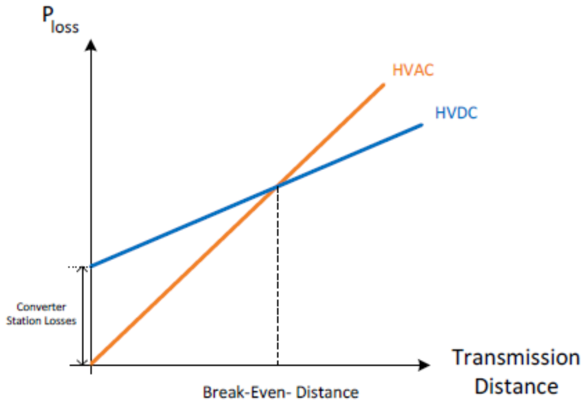


Figure 1.4: Power losses with transmission distance in AC and DC systems [6]

conductors can be used, since they do not suffer from the skin effect as AC lines. These can lead to large savings in transmission system costs. In addition, land acquisition/right-of-way costs, as well as operation and maintenance costs, are also lower in the HVDC case. Short schedules for manufacturing, transportation and installation minimise also the financial cost. Generally speaking, the relative cost of HVDC transmission systems is going to be further reduced, since their components become cheaper due to continuing innovative technological developments in the field of power electronics [2–6, 9–11, 13–16, 21].

In Figure 1.5 a cost comparison between HVAC and HVDC lines with increasing transmission distance is presented. At zero transmission distance the terminal cost (converter equipment cost) dominates, making HVAC systems more cost-efficient. The curve of DC costs is not so steep as the curve for the AC costs, since line costs per kilometre are lower in HVDC systems. The total costs in both cases are even higher if capitalised value of losses is taken into account. For long AC lines, the cost of losses is quite high due to reactive power compensation costs which should be included. Thus, above the "break-even" distance the total cost is higher for the HVAC technology, making HVDC transmission systems more preferable. The "break-even" distance is in the range of $500 - 800$ km, usually around 600 km, and it depends on cost of right-of-ways, loss evaluation, interest rates for financing, country-specific cost aspects and other factors [6, 11, 13]. In the case of submarine cables, HVDC systems provide an even more cost-effective solution, since the "break-even" distance is much smaller (less than 100 km, typically about 50 km) [11].

Hence, by taking into account the increase in power losses and cost with increasing distance in the two alternative transmission systems, HVDC solution is found to be more attractive for the transmission of bulk power over long distances. Furthermore, HVDC technology may also be selected because of additional technical benefits which can provide to the power system.

HVDC transmission systems do not contribute to the short circuit current of the interconnected AC system and therefore do not increase fault levels, contributing to the stabilisation of the power system [9, 11, 16, 22].

Moreover, HVDC systems can transfer power between separate AC networks, which

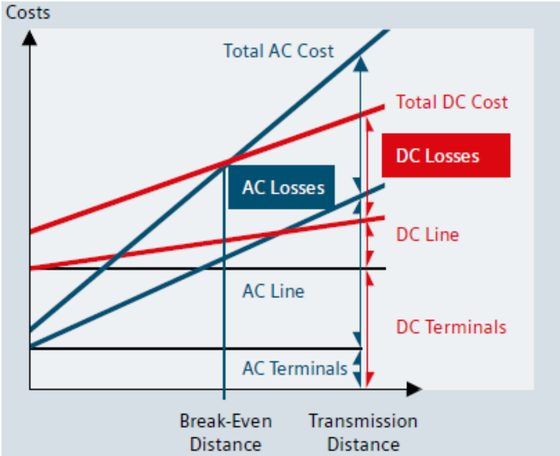


Figure 1.5: Cost with transmission distance in AC and DC systems [13]

are difficult to be connected due to stability reasons or even operation at different nominal frequencies (50 and 60 Hz). Since power transfer can occur in both directions, it increases the stability of both networks, by allowing them to exchange power with each other in emergencies and failures. Disturbances in one network would not affect the DC link and therefore the HVDC connection system prevents cascading failures from one AC system to the other. This ability implies AC/AC decoupling between the two power systems, so that transient conditions in one network do not affect the stability of the other. In other words, DC links insulate one AC network from the others. However, they offer the opportunity of adjusted power exchange, so that connected AC systems would contribute to the stabilisation of one failure-affected AC network [2–6, 9–11, 13–15, 22].

This ability of DC links becomes possible due to the fundamental advantage of HVDC transmission systems, i.e. their controllability: HVDC converters can control easily the active power flow through the link [5, 11, 14, 15]. In cases where power exchange has been agreed between two AC networks, HVDC systems can control the power flow through the tie links at all times, by automatically keeping the arranged pre-set value of power flow, i.e. the transmitted power is not dictated by the phase angle differences between the two AC networks. Even in a contingency event at one of the AC networks, the HVDC connection can be forced to adapt the power flow, which can support the troubled grid. Moreover, the transmission link becomes never overloaded, so that it is not led to disconnection and the fault condition does not spread to a wide area [16, 20, 22]. This also means that HVDC connections can be rated only for scheduled power transactions and agreed emergency support; therefore, they are more economically attractive than the HVAC links, whose capacity should be many times higher than the capacity needed for scheduled power transfers in the steady state [16]. The control system of the HVDC converter, as well as the capabilities that offers to the transmission system, will be described in Chapter 3.

The power exchange between interconnected AC networks could lead also to reduced pollution levels and increased fuel economy, since expensive and polluting peak-power generation in one network can be replaced by cheap and renewable-based power from another network [12].

1.4.5 Applications of HVDC transmission systems

Up until now, HVDC systems have been widely used for point-to-point power transmission over long distances or connection between two AC grids [9, 14–16, 19, 21–23]. For instance, in the mid 80's Quebec was interconnected with the power networks in New England and New York via four HVDC stations and one transmission line [14–16]. DirectLink in Australia connects the regional electricity markets of Queensland and New South Wales through a 60 km, 180 MVA HVDC cable. Similar to this, Murraylink connects the electricity markets of Victoria, New South Wales and south Australia and operates as a generator by participating in the spot market [20]. Several HVDC links are also in operation or in schedule, connecting the AC networks of countries in Scandinavia and continental Europe; therefore, a new HVDC grid for power exchange has been formed, as shown in Figure 1.6 [9, 23]. These interconnections through HVDC links improve effectively the transfer capability between regional networks. This was found to be of great importance especially in the latest years, since the AC tie lines are frequently fully loaded, restricting the economic power transfer between adjacent regions [19]. They enhance also the stability of the interconnected networks, by preventing outages or limiting the consequences of major disturbances, as explained in 1.4.4. An example of this capability of HVDC links occurred in the Scandinavian network, where the AC grids of Sweden and Norway are connected to the grid of Denmark through the Skagerrak link. On a contingency occasion, two 1000 MW nuclear stations in Sweden were disconnected and the frequency dropped to 48.5 Hz. At the time of the event the Skagerrak link was exporting its rated power (500 MW) from Norway to Denmark. When the frequency drop was detected, the power direction reversed and 500 MW were injected into the norwegian/swedish grid (a net contribution of 1000 MW) [22].

For transferring large amounts of power, up to 6000 MW, over very long distances, above 1000 km, ultra-HVDC links, i.e. systems at voltages above the highest in use (600 kV), have also been developed, since they are found to be economically more attractive. With few structure changes and proper control, protection and auxiliary systems, the reliability and availability of such links could be better than these of systems at lower voltages [24, 25]. Such a transmission system has recently been got into operation in the 800 kV, 6400 MW, 2000 km Xiangjiaba-Shanghai connection in China, designed and installed by ABB [14, 15, 25].

In some connections combination of a DC link in parallel with an AC network can also be used, as described in [14, 15, 25]. In these cases the bulk power is transferred via the HVDC system and the power needed from AC networks along the route is fed by the HVAC system. This hybrid transmission system is found to be the most cost-effective and flexible option for dealing with the drawback of HVDC systems that power tapping along the line is expensive [25]. In addition, the power in DC links can be controlled and automatically adapted to protect the parallel AC lines from being overloaded [14, 15, 22]. An example of such a hybrid system is the parallel operation of the Pacific HVDC Intertie and the AC network between the areas of Oregon and Los Angeles in the western USA [22].

In the opposite direction of AC networks interconnection, HVDC technology can be applied for decomposing large power systems into smaller, asynchronously operated sections, interconnected exclusively by DC links. In such DC segmented grids,

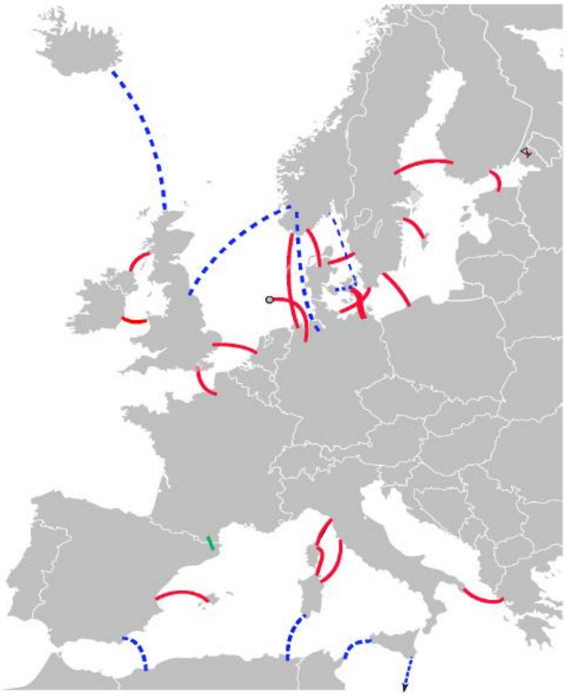


Figure 1.6: HVDC links in Europe [9]
Red: existing links, Green: links under construction,
Blue: proposed links

risks that exist in large AC networks, such as cascading of disturbances, transfer capability limitations and expansion restrictions, do not any more occur. In this way the reliability of the power system is enhanced [14, 15, 19, 22]. An example of such a HVDC grid is the North American Power Transmission Network: it is subdivided into five asynchronous regions that are connected through HVDC transmission links and stations. In total there are eight HVDC links and twelve HVDC stations for connecting the north-american regions. Some of the HVDC links are operating entirely within one region, in parallel with the conventional AC lines, while others connect two asynchronous networks [16].

DC links can also be used for directly feeding large urban areas, where there are high load densities, whereas simultaneously strict requirements for reliability and power quality have to be met. Apart from point-to-point systems, where power is directly delivered to in-city loads, there could be multi-terminal HVDC networks embedded in a city grid. Figure 1.7 presents such a DC network, where power is imported radially from outside sources and distributed through a DC ring to the inverter stations located at different load positions. Instead of multi-terminal systems with a DC ring topology, another scheme can be developed, with a closed loop at the AC circuit, for not increasing the short circuit power [19, 21]. These multi-terminal topologies are described in details in 2.6.2. For avoiding the difficulties to obtain right-of-way permit for new overhead lines in large and dense urban areas, there is the possibility of upgrading an AC line to a HVDC one. The conversion could be done in many ways, depending on the configuration of the existing line. So far, this procedure has been implemented in a few cases, but it is attracting considerable interest, while several applications are being studied [16]. Anyway, even if this conversion is not applicable, laying underground DC cables is a much easier, quicker

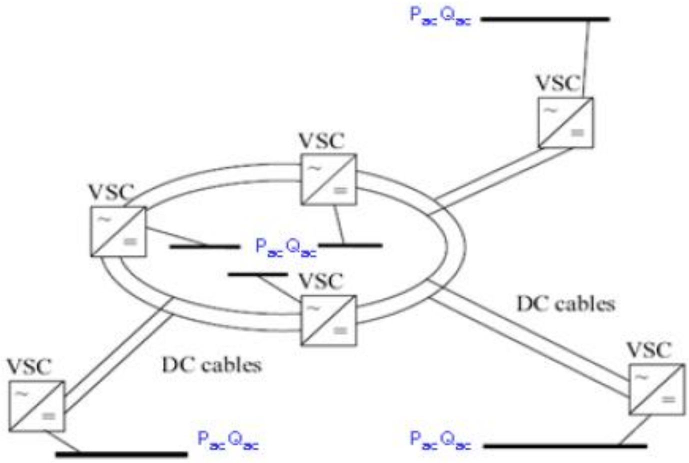


Figure 1.7: DC grid feeding city network [19]

and cheaper procedure than for building overhead AC lines. Cables rarely meet public opposition, since they do not change the landscape and their electromagnetic field is lower and static. Thus, HVDC systems are ideally suited for powering metropolitan areas [12, 20].

On the other side, HVDC transmission systems are also useful for connecting remote loads, such as islands, mining areas, gas and oil fields or drilling platforms. In this way, building a local power plant based on fossil fuels is avoided. This approach leads to costs reduction, higher operation efficiency and GHG emissions minimisation [12, 14, 15, 18, 21]. The first installation powering an offshore platform comprised of a 70 km subsea HVDC link, for power transfer from hydro resources in Norway to two compressors at the Troll A oil and gas platform in the North Sea [14, 15, 18].

Today, an emerging application area for the HVDC transmission technology is the renewable energy resources integration to the power system. A large part of these resources is located in remote areas (at sea, in desert or in unpopulated areas) and the utilisation of their huge power potential is to a considerable extent a matter of power transmission technology. Their use often requires the construction of new power networks affecting the existing grids of several regions [14, 15]. For instance, Itaipu HVDC link in Brazil transmits power (6300 MW) from remote hydroelectric plants to the Itaipu region for more than 20 years. Two other HVDC links in Brazil connect hydroelectric power plants in the Amazon area to country's main load centres in Rio Madeira and Belo Monte, respectively, both located more than 2000 km away [26]. Several projects have also been proposed or already constructed for transferring power from offshore wind farms in North and Baltic Seas, hydro power plants in Scandinavia and solar power plants in northern Africa through a developing HVDC grid to large load centres in the central Europe.

In the specific case of the grid connection of large offshore wind farms located in long distances from the coast, HVDC systems are commonly considered as the optimal method and their increasing use in many new projects worldwide has challenged the market dominance of HVAC transmission technology. One of the world's most remote wind farms in the North Sea, "BARD offshore 1", with total installed capacity of 400 MW, is connected through a 200 km VSC-HVDC cable to the coastal network in Germany. The wind farm is commissioned in 2012 and is scheduled to be in operation during 2013 [5, 14, 15, 18, 19]. Several other HVDC links are under development for the grid connection of large offshore wind farms in the North Sea, like BorWin-II, DolWin-I and DolWin-II, HelWin-I. Similar projects are also developed in many countries worldwide, such as in UK, Canada, USA and China [1, 3, 4, 7, 17, 18]. For example, the Atlantic Wind Connection in the mid-atlantic region of USA consists of an offshore HVDC transmission system, of 7000 MW capacity, with multiple delivery points on the mainland grid [18].

Chapter 2

HVDC transmission systems

The first HVDC system came into operation 50 years ago. Since then many HVDC transmission schemes have been developed. In this chapter the development of these systems is described. The system structure is given and its components are analysed. Research activities for new technologies are also presented. The most modern transmission method, i.e. VSC-HVDC, is applied in the grid connection of offshore wind farms. Finally, various system configurations and topologies for this transmission scheme are provided.

2.1 Classic HVDC transmission system

The HVDC system is made up of a number of equipment. In Figure 2.1 the main components of the classic HVDC transmission system are depicted. The station requires considerable big area of land, since transformers, filters and auxiliary capacitors are located outdoors. The valves converter and the control equipment are placed in a closed air-conditioned and air-heated building. However, it should be borne in mind that the enclosed systems require high spatial distribution and therefore a large building, which is too expensive [11].

In the followings the main modules are described, concerning their role in the whole system, their structure and operation, as well as the latest trends in their technical development.

2.1.1 Converter

The converter is the most important module, since it performs the conversion from AC to DC (rectification) at the sending end and from DC to AC (inversion) at the receiving end of the DC link. The converter of classic HVDC systems is based on thyristor valves. Thyristors require connection with an external AC circuit to turn on and off. This means that, in conventional HVDC transmission systems, the connected AC power system provides the means of commutating the current to the valves in the converter. This is the reason for which converters in the classic

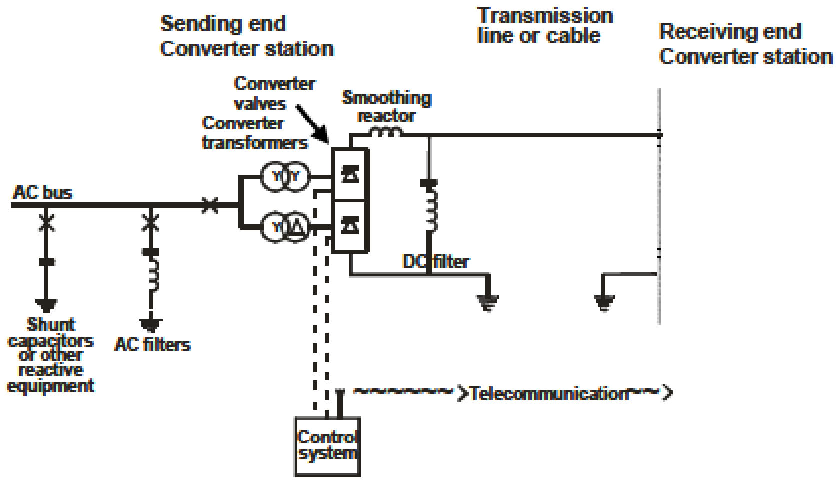


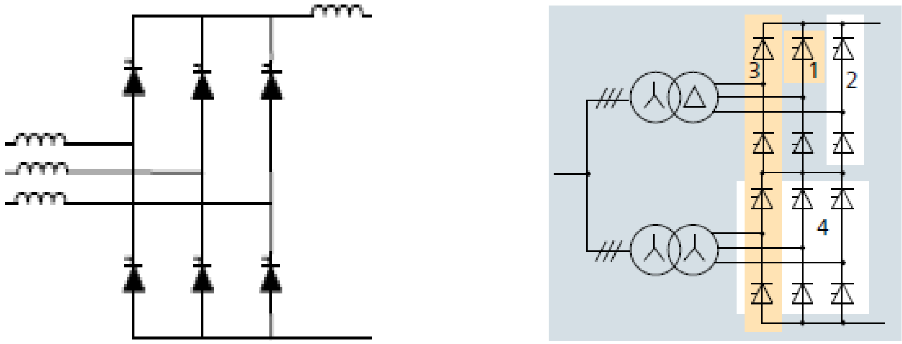
Figure 2.1: Classic HVDC transmission system [27]

HVDC systems are known as line-commutated converters (LCC). Such converters require rotating synchronous machines in the connected AC system and therefore cannot be connected to passive loads [9, 17, 19, 28].

Due to high voltages in HVDC systems, which far exceed the breakdown voltage of the thyristors, large numbers of them are usually connected in series, building one unit. For ensuring the even share of voltage between the thyristors of such a unit, each thyristor is connected in parallel with additional passive components, such as grading capacitors and resistors. The complete switching unit, consisting of series-connected thyristors with their auxiliary circuits, is referred to as a valve and each thyristor with its grading circuits and the other auxiliary equipment is known as valve branch or thyristor level [9, 13].

The basic converter configuration for classic HVDC systems uses a three-phase bridge, also called 6-pulse bridge, since it contains six valves, each connecting one of the three phases to one of the two DC rails. This converter unit is illustrated in Figure 2.2a. However, this arrangement produces considerable harmonic distortion at AC and DC sides, since the phase changes only every 60°. For enhancing this arrangement, a 12-pulse system, shown in Figure 2.2b, has become standard on most LCC-HVDC systems. A 12-pulse circuit is a serial connection of two 6-pulse bridges which are connected separately to the AC network through two transformers. One of these is configured to have a star secondary (Y-Y winding structure), while the other a delta secondary (Y-Δ winding structure). In this way, a phase difference of 30° is established, cancelling the six-pulse harmonics and reducing the distortion: fifth and seventh harmonics at the AC side are eliminated, reducing significantly the cost of harmonic filters; sixth and eighteenth harmonics are eliminated at the DC side, reducing the DC voltage ripple. Converters with more than two bridges are also possible (three-bridge or 18-pulse converter, four-bridge or 24-pulse converter), leading to even less harmonic distortion. Nevertheless, the required transformer connections are getting more complex and therefore it is more practical to use a 12-pulse converter and provide the necessary harmonic filters [9, 11, 13, 17, 28, 29].

HVDC systems with a single 12-pulse converter per pole are in commercial operation in several projects demonstrating excellent performance. Based on this



(a) Six-pulse bridge [17]

(b) Twelve-pulse bridge [13]
1: Valve, 2: Double valve,
3: Valve tower, 4: Six-pulse bridge

Figure 2.2: Converter bridges

experience, such configurations could be used in applications of 3000-4000 MW at 800 kV. For higher power ratings, above 4500 MW, at 800 kV two series-connected or parallel-connected 12-pulse converters per pole should be used, as shown in Figure 2.3. These configurations, with the two converter groups per pole, increase reliability and availability of the transmission system, since in an outage of one converter only one quarter of power is lost. In addition, the division of converter into more groups helps the transportation of converter transformers, considering their size and weight [25, 26, 30].

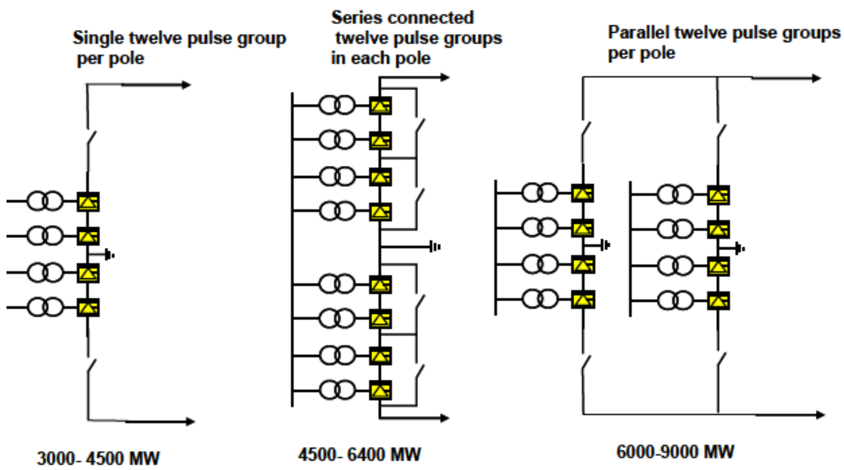


Figure 2.3: Series/Parallel-connected twelve-pulse converters [25]

In LCCs, the DC current cannot usually change direction. At the AC side, the converter behaves as current source, injecting current to the AC network. Hence, such converters are also known as current-source converters (CSC) [9].

2.1.2 Transformers

The converter transformers, often three physically separated single-phase transformers, transform the voltage of the AC busbar to the required entry voltage of the converter. In this way, they isolate the converter station from the AC system, providing a local earth, and ensure the voltage insulation, to make possible the connection of converter bridges in series at the DC side. The main insulation of the transformer in the valve-side winding is subject to the combined load stress of both AC and DC voltage. For ensuring the correct valve voltage, the transformers are equipped with tap-changers [9, 13].

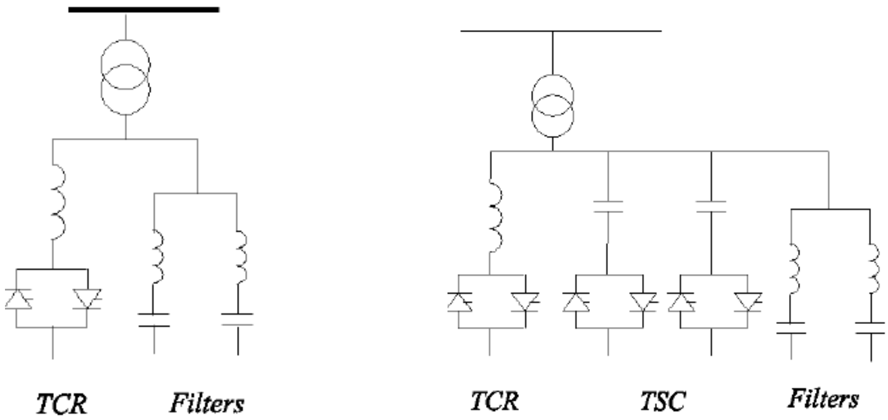
The transformers in LCC-HVDC systems are quite specialised, due to high level of harmonic currents flowing through them. The design of the insulating structure inside the tank is also affected, since the valve-side winding experiences a permanent DC current, requiring more solid insulation. In addition, the transformers in these transmission schemes should provide the 30° phase shift for the cancellation of harmonics [9, 13].

2.1.3 Reactive power supplies

In LCC-HVDC systems the converter inherently consumes reactive power. Independent of the direction of the active power flow, the current flowing into the converter from the AC system lags behind the AC voltage, meaning that the converter always absorbs reactive power. The amount of reactive power absorbed is at least 50 % of the active power transmitted in steady-state conditions. Under transient conditions, the amount of reactive power needed can be much higher. Faults in the AC network at the inverter side of the transmission system will cause the cable to discharge, resulting in voltage collapse in the AC network. The inverter should counteract the increased transient current by increasing each own terminal voltage. This implies increased need for reactive power. Therefore, reactive power sources are required close to the converters. When the converter station is connected directly to power stations, an amount of the reactive power can be provided by the generators themselves. In most cases, however, other reactive power compensation devices should be applied to the HVDC system. These devices can be connected to the network in series or in shunt connection. Shunt compensation devices are applied for voltage control, whereas series compensation is employed to control the longitudinal behaviour of the power system. Any surplus or deficit in reactive power from these local supplies should be accommodated by the AC network. The unbalance in reactive power should be kept within a given range, in order to maintain the AC voltage in a desired tolerance. This implies that the weaker the AC system is, the tighter the reactive power exchange should be, for keeping the voltage within the required band [9, 28, 29, 31, 32].

2.1.3.1 Shunt reactive power compensation

The most common reactive power compensation devices are in the form of shunt capacitor banks connected at the AC terminals of the converter. They can be connected directly to the grid voltage or to a lower voltage through a tertiary winding of the converter transformer. The shunt capacitors are usually grouped in switchable banks (typically four per converter), so that the appropriate amount of reactive power is supplied to the system, according to active power transferred (the reactive power consumed by the converter depends on the active power transmitted by the system). In this way, a surplus of reactive power is prevented in cases of low power transmission [9, 29].



(a) SVC with fixed capacitor [32] **(b)** SVC with thyristor-switched capacitor [32]

Figure 2.4: Configurations of static var compensator (SVC)

Shunt reactive power compensation can also be provided by synchronous condensers or static var compensators. A static var compensator (SVC) is a static shunt reactive device, whose reactive power injection or absorption is controlled by means of thyristor switches. Unlike synchronous compensators, it has no rotating parts, which is the reason for the "static" denomination. It combines a passive capacitor bank in parallel with a thyristor-controlled reactor (TCR). Instead of fixed capacitors (FC), thyristor-switched capacitors (TSC) are often used to enhance the control capability of the TCR. The two common configurations are shown in Figure 2.4. The capacitor bank produces the required amount of reactive power and the controlled inductive branch consumes in each instant the possible excess of reactive power, which is generated but not requested by the system. In this way, the capacitor stabilises the system, and the TCR eliminates the excessive voltage rise which could occur in low load conditions and furthermore reduces surges during switching operations. The generated harmonic current components can be eliminated by designing the capacitor bank as passive filter bank. Installation of SVCs in transmission systems lead to maintaining a smooth voltage profile, under various network conditions. Hence, these devices enhance the voltage control and stability, even in weak systems. Moreover, they contribute to the reduction of transmission losses, resulting in increased transfer capability and minimisation of the need for new lines. In addition, the dynamic stability of the grid can be improved, by increasing the mitigation of power swing and minor disturbances. Thus, SVCs have been used in a great number of applications as easily and rapidly controllable shunt compensator, like in the interconnection link between USA and Canada in Minnesota state [32, 33].

Another device that can be used for shunt reactive power compensation is a static synchronous compensator (STATCOM). It is based on a synchronous voltage source which generates a balanced set of three sinusoidal voltages at a fundamental frequency, analogously to a synchronous machine. However, this machine has no rotating parts and therefore no inertia, for which reason it is called "static". The reactive power is generated or absorbed internally. A STATCOM comprises the DC energy source, the voltage-source converter, the control system and a coupling transformer, as shown in Figure 2.5. The DC source can be a DC capacitor; therefore, the STATCOM exchanges only reactive power with the system. The fre-

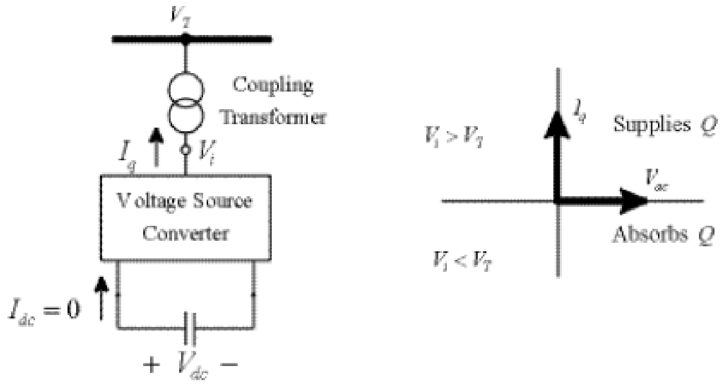


Figure 2.5: Static compensator [32]

quency, amplitude and phase of the AC voltage (converter output), and therefore the reactive output of the converter, can be properly controlled. If the converter voltage is higher than the voltage at the coupling point, the STATCOM injects reactive power to the AC system; if the converter voltage is lower than the voltage at the coupling point, the STATCOM absorbs reactive power. Hence, by proper control STATCOMs can contribute to voltage variations reduction, enhancing dynamic voltage stabilisation and steady-state voltage support. In this way, power transfer capability increases and power system damping is also improved, meaning increased transient stability and dynamic load balancing. In general, the overall power quality is enhanced [32].

In the latest years a new generation of SVC has been developed, consisting of a STATCOM with an IGBT voltage-source converter, as illustrated in Figure 2.6. The basic operation principle of the VSC-based SVC is the generation of a three-phase symmetric voltage with desired frequency. The control concept is the same as in a STATCOM device, as depicted in Figure 2.6. If the VSC voltage is phased-advanced from the network voltage, active power is injected by the converter to the network; if the VSC voltage is phase-delayed concerning the network voltage, then active power flows from the network towards the converter. In this way the DC voltage can be controlled: when the DC voltage is below its setpoint, the VSC voltage is controlled to be phase-delayed, for creating active power flow towards the converter; when the DC voltage exceeds its desired level, the VSC voltage is controlled to be phase-advanced, for transferring active power from the converter to the network. The voltage amplitude is also controlled to regulate the reactive power flow: if the VSC voltage has higher amplitude than the network voltage, the compensator delivers the needed reactive power to the network; if its voltage amplitude is lower than the amplitude of the voltage at the connection point, the converter will consume reactive power, acting as inductor [33]. The VSC operation is determined by the maximum voltage on the converter terminals and the maximum converter current; by taking into account these two limits, under-voltage and over-voltage conditions can be dealt with. Moreover, the DC link in a SVC system is not connected externally and hence the DC voltage level can be freely selected at an optimal value regarding VSC's economies. Another advantage is the short response time: the semiconductor valves can respond almost instantaneously and therefore the only limiting factors for the response speed are the time for processing voltage measurements and control procedures. A response time shorter than a

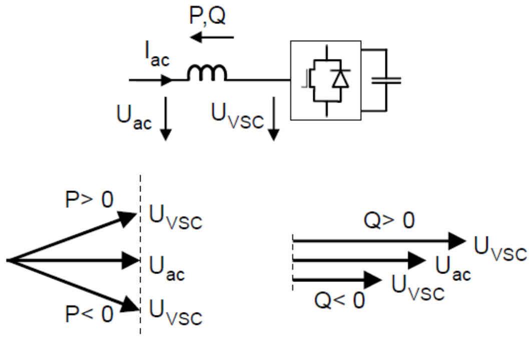


Figure 2.6: Configuration and control principle of VSC-based SVC [33]

quarter of a cycle is nowadays achievable. In addition, the transmission system can be designed without harmonic filters. The high switching frequency results in an inherent capability of producing voltages at high frequencies. By injecting harmonic currents into the network with proper phase and amplitude, this property can be used for counteracting and therefore filtering harmonic voltages already present in the power system. The reduction of equipment needed leads also to a more compact layout, decreasing thus the converter station costs. Up until now, ratings of around 100 Mvar per converter are available; when higher reactive power is required, an assembly of more than one converter can be used or additional devices, such as fixed capacitors or thyristor-switched capacitors, can be applied [32, 33]. The introduction of IGBT-based SVCs for reactive power compensation in the classic LCC-HVDC transmission system led to the development of a new configuration of transmission systems (Figure 2.7), based on VSCs (VSC-HVDC), which enables an advantageous system operation; this transmission system, as well as its enhanced capabilities is described in the next section.

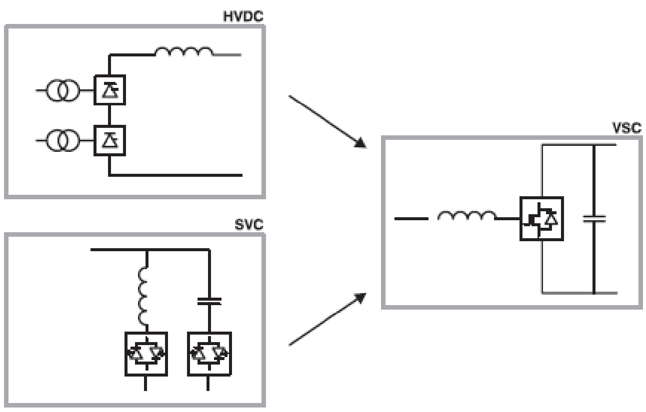


Figure 2.7: Development of VSC-HVDC transmission system [34]

2.1.3.2 Series-connected reactive power compensation

The introduction of synchronous condensers or switching reactive shunt banks increases the technical complexity, as well as investment and maintenance costs [31]. As a result, the development of another configuration of the HVDC transmission system was desirable. In the new design, capacitors are connected in series to the valves. The choice of their location requires special study in each particular case,

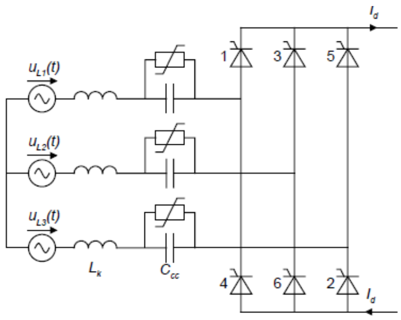


Figure 2.8: Converter with series-connected capacitors [36]

taking into consideration the overall economy and system reliability. They are often located in the line side of the converter transformer and switched as part of the lines [32]. However, [31, 35] propose their location to be between the converter transformers and the valve bridge, in parallel with varistors for their over-voltage protection (Figure 2.8). The main reason for selecting this position is that the operating voltage across the capacitors is controlled by the converter. Hence, the capacitor stresses are much lower. Furthermore, the transformer inductance limits the current in a fault case, meaning lower stresses for the varistor. Besides, if the capacitors were located along the lines, there would be the risk of their asymmetrical charging at AC system faults [31, 35].

There are several advantages of the configuration with series-connected reactive power compensation, concerning the design of the transformer and valves. First of all, the phase-to-phase voltage at the valve side of the transformer is reduced, leading to reduced reactive power flow through the transformer. Thus, its ratings could be decreased. Moreover, the total secondary-side impedance increases (by inserting the impedance of the series-connected capacitor), reducing transformer and valve currents during short circuits at the DC side. These lower current stresses allow the optimised design of transformer and valve, although implying higher valve voltage ratings. The main benefit of the new configuration regarding the converter operation is the leading phase shift that the series-connected capacitor introduces between the transformer secondary and the valves. This compensates the inherently lagging characteristic of the converter; thus, the converter's power factor can be kept to unity or even become leading [31, 35, 37].

Series-connected capacitors improve voltage control and reactive power balance, since reactive power generation in series-connected compensation increases with the transferred power. Thus, the reactive power requirement becomes very low and flat. Therefore, the need for capacitive shunt banks, switching in steps, is eliminated, leading to less cost of the transmission system. Low shunt compensation leads to even larger transient advantages, i.e. lower over-voltages upon load rejection. Another benefit regarding dynamic stability is associated with the fact that the commutation voltage results in positive inverter impedance characteristics. This means that when the DC current increases, the DC voltage at the inverter side of the classic HVDC system decreases due to a reduction in the AC network voltage, whereas in this new scheme it raises due to the capacitor voltage, which offsets the drop in the AC voltage. This helps in mitigating faults and implies a large improvement in the inverter dynamic stability. This factor implies also stable operation with low short-circuit ratios and better commutation failure immunity.

The latter is explained by the fact that the series capacitors act as an extra voltage source for the commutation of the valves, in addition to the synchronous machines of the AC system. This is the reason for which this design is denominated as capacitor-commutated converter (CCC). Thus, the transmission system is able to withstand an AC voltage drop of 15-20 %, while still preserving a sufficient commutation margin for stable operation and thereby maintaining constant DC power flow during disturbances in the AC network. This advantageous behaviour can be observed in Figure 2.9, where the response of the CCC-HVDC system in a remote AC fault is compared to this of the conventional LCC-HVDC system. This means improvement in commutation performance and therefore minimisation of the risk of commutation failures. In general, the transient performance is found to be better than this of the conventional scheme, demonstrating a better damping characteristic. In addition, as a result of the increase in the transient stability limit, the power transfer capability also increases [9, 28, 31–36, 38–41].

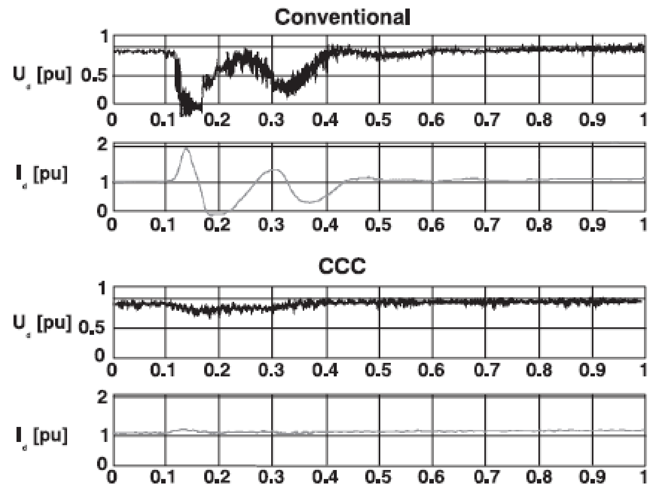


Figure 2.9: Behaviour of LCC-HVDC and CCC-HVDC systems at a remote AC fault [34]

It should be mentioned, though, that voltage contribution of CCCs in the system can lead to increased harmonic production. The voltage from capacitors will support the commutation of the direct current from one valve to the other. This implies that the overlap angle will be reduced, resulting in a somewhat higher AC harmonic currents. This, in combination with higher extinction voltage steps, leads to increased harmonics at the DC side. The increased harmonic distortion can be of the order of 20 % and can be dealt with by high performance filters at both AC and DC sides. This requirement is, however, offset by the smaller size of shunt-connected LC branches, due to less reactive power requirements [40]. In addition, although steady-state results determine CCC-HVDC superiority compared to LCC-HVDC, transient analysis concluded in non-uniformly favourable performance in a long cable HVDC transmission system compared to the conventional scheme. Under balanced remote- and close-in faults the new scheme is found to be superior; however, with unbalanced disturbances the conventional system demonstrates better performance. This behaviour could be explained by the additional dynamics due to the energy storage in the series-connected capacitors of the CCC-HVDC system: in cases of unbalanced faults, the voltage of each of these capacitors impacts the system operation in a different extent. The performance of the CCC-HVDC technology under unbalanced contingencies should be therefore further investigated [41].

In recent years, the technology of series-connected compensation has undergone dramatic development, regarding the reliability of capacitors, as well as the control systems of the converter. For instance, the evolution in the control scheme of CCC-HVDC is described in [42], where ordinary and advanced control systems are compared. The new control scheme regulates the DC voltage, by keeping the AC voltage constant at the connection point. In this way, not only the active power flow is controlled through the converter, but also the reactive power exchange with the network is managed for regulating the AC voltage at the connection point. This implies that the inverter emulates the operation of a voltage-source converter. The study results have shown that the connection of the inverter to a very weak AC network becomes possible with the new control method: the HVDC transmission exhibits very good recovery from faults in the system, without the risk of voltage or power instabilities, whereas it is unstable, when operating with the traditional control system [42].

Today, CCC technology has become well proved. In general, CCC-HVDC systems are found to be a technically and economically beneficial solution, particularly in cases of connection to weak AC networks, with low short-circuit capacity, or in cases of very long transmission cables. Several HVDC transmission systems all over the world operate according to CCC technology, like the Garabi interconnection between Argentina and Brazil [32, 37].

With the development of thyristors, the usefulness of series-connected compensation has been further augmented. The evolution of controllable series-connected compensation is depicted in Figure 2.10. Mechanically-switched series-connected capacitors (MSSC) offer flexibility of power flow control. However, the introduction of thyristors in thyristor-switched series-connected capacitors (TSSC) or thyristor-controlled series-connected capacitors (TCSC) brings the concept of this compensation concept even further [31, 32].

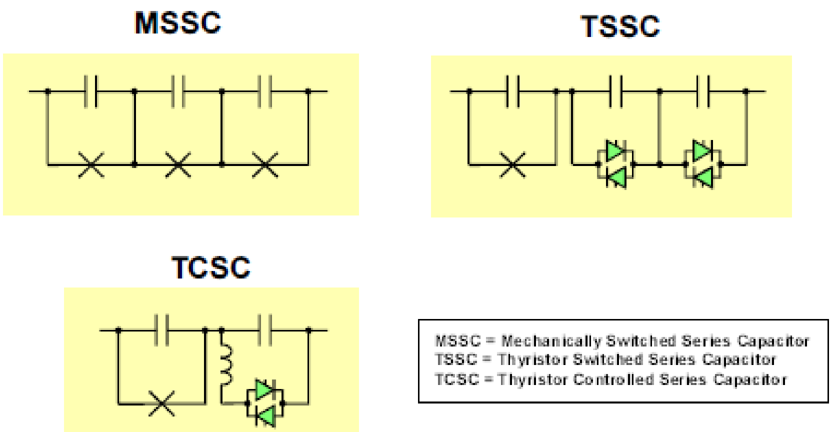


Figure 2.10: Evolution of controllable series-connected compensation [32]

The ratings of the TCSCs in the converter configuration are determined by several factors. The Mvar ratings depend on the overload requirements of the converter. The impedance of each TCSC depends on the requirement to maintain a constant impedance as seen by the converter. TCSC converter has the same configuration as CCC, with the main difference of the location of the thyristor-controlled capacitor. In the case of CCCs, the capacitor is placed at the valve side of the transformer, as described above, since its placement along the AC line could lead to ferro-resonance problems. However, this issue does not occur with the thyristor control of the capacitor. Thus, the position of the TCSCs is at the AC system side of the converter transformer [31, 32]. In [31], different TCSCs positions are described, regarding additionally the location of the filters.

TCSCs offer many possibilities of control in the AC system. Supplementary to the tap changer of the transformer, TCSCs can contribute to controlling the steady state DC voltage, the firing angles of the converter and the reactive power. One other potential benefit is the power balancing along the AC lines between the converter and the AC system. Apart from power flow control, TCSCs provide damping of active power oscillations: the introduction of a time varying capacitive element in series with the inductive line reactance offers the possibility of modulating in time the overall reactance to counter active power oscillations along the AC line. This benefit is significantly important, since these power oscillations limit the power transmission capability of HVDC links. A crucial feature of the TCSC is its inherent mitigation of sub-synchronous ferro-resonance oscillations due to the control of the capacitors by thyristor valves. This inherent characteristic of TCSCs has been investigated in research activities for a long time resulting in practicable solutions. With the sub-synchronous ferro-resonance oscillations not being an obstacle any more, the usefulness of series-connected compensation will be appreciated even more and the technology is going to be put to a more widespread use. Nevertheless, the significantly increased costs due to additional valve equipment should be taken into consideration [31, 32].

Another possibility of series reactive compensation is the connection of a VSC in series with the line through a booster transformer. If the VSC does not have any active power exchange with its DC side, its impact on the network resembles that of a series-connected reactance, which maybe inductive or capacitive. This arrangement is called static synchronous series-connected compensator (SSSC). If another, shunt-connected, VSC is used to energise the DC side of the series-connected converter, the control of several parameters is possible, e.g. active power flow and the voltage in the transmission line. The two VSCs constitute then a unified power flow controller (UPFC). This configuration can also be used to mitigate variations in the voltage that feeds an important industrial load. A possible voltage collapse can be compensated by the voltage of the series-connected VSC and the voltage profile in the sensitive load can appear to be almost undisturbed. This application is named dynamic voltage restorer (DVR). Protection of the series-connected VSC against over-currents and over-voltages should be taken into consideration, since the VSC has limited current handling capability. In the case of a short-circuit, a fast acting bypass switch is necessary to be connected across the primary or secondary of the booster transformer, for avoiding the surge current passing through the VSC [33].

2.1.4 Passive harmonic filters

Harmonic voltages and currents are generated by the electronics-based converter at both AC and DC sides, even under ideal conditions, i.e. ideal smoothing of DC current, symmetrical AC voltages, ideal transformer impedance and firing angles in the converter. The characteristic harmonic components are those with the highest level, however, other, non-characteristic, components are important, such as the third harmonic, which is mainly produced by the negative-sequence component of the AC system. The harmonic components of voltages and currents can cause overheating of capacitors, as well as generators which are located in close distance. They can also lead to interference issues with telecommunication systems. Therefore, filters are applied at both AC and DC sides in the converter station [13, 29].

The 6-pulse bridge of an LCC-HVDC transmission system produces very high levels of harmonic distortion by injecting harmonic currents of low order (6th order) into the AC system and generating harmonic voltages of the same order superimposed on the DC voltage. The suppression of such harmonics by filters is very expensive. This is the main reason for applying the variant configuration of the 12-pulse bridge. With this arrangement harmonics are still produced but only at higher orders (12th order and higher). Hence, suppressing such harmonics is much more manageable, though still challenging [9].

2.1.4.1 AC harmonic filters

The aim of the filter is to provide sufficiently low impedances for the harmonic components, for reducing the harmonic voltages to an acceptable level. The distortion level on the AC bus depends on grid and filter impedances, which are connected in parallel. The design process of AC harmonic filters is complex and computationally intensive regarding the modelling of the grid impedance. With both network and filter impedances known, the highest harmonic voltage (the highest voltage distortion) can be determined and compared to acceptance criteria. The criteria depend on local conditions and regulations. Another challenge in the design procedure is the risk of resonance between the filters and other components elsewhere in the AC system [9, 13].

An additional duty of the filters at the AC side is to contribute to the reactive power compensation. This will determine the size and number of filters. The rest of the reactive power demand should be covered by the devices described above [13, 17].

2.1.4.2 DC harmonic filters

Harmonic distortion in DC voltage does not imply problematic issues by itself, since loads are not connected directly to DC terminals. However, harmonic components in the DC voltage (ripple) cause currents which are superimposed on the current in the DC transmission link. These current components of higher frequencies can cause interference in neighbouring telecommunication systems. DC filters, connected in parallel to the station poles, can contribute to combating this problem. Usually, there is no need for DC filters in applications with cable transmission systems; only in cases of overhead HVDC lines DC filter installation is necessary [9, 13, 17]. It should also be mentioned that nowadays, with the development of digital mobile telecommunication systems, the acceptance criteria for harmonic distortion are irrelevant, since digital telephone systems are insensitive to harmonic interference [9, 13].

2.1.5 Active harmonic filters

The development of HVDC transmission systems has led to an increased stringency in filtering requirements. This has resulted in more shunt filter branches (in ratings of full pole voltage) or even in series-connected reactors (in ratings of full pole current). AC and DC filters have occupied more than 40-60 % of the converter station area. In addition, inordinate amount of insulators between pole and ground, with lower probability of flash-over per insulator, have been needed, which has had detrimental effects on the reliability of converter stations. These trends have been proving to be too costly for the utilities. The decrease in the converter station area, with the consequent decrease in the station cost, has been a stimulus for the development of more efficient filters, able to achieve very high levels of harmonic reduction, without increasing the number of circuit components. Two new technologies have recently come into operation, continuously tuned AC filters and active DC filters [34, 39, 40, 43].

2.1.5.1 Continuously tuned AC filters

The size of the AC filter can be decreased, provided that there is the possibility of its sharp tuning. Continuously tuned (ConTune) filters are used for this purpose. ConTune filters are on the borderline of passive and active filters: they have passive components, but the tuning frequency is supervised and controlled actively. Through the years many different designs have been suggested. A solution attempted in the past used mechanically adjustable reactors, but it could not match reliability requirements [34, 38, 43]. In recent HVDC projects a design with a variable-inductance reactor has been used. The variable inductance is achieved by a structure of an iron core, coiled with a winding; this structure is placed inside the reactor. The control system feeds the winding with the corrective DC current and thereby tunes the total magnetic flux in the reactor, changing therefore its inductance. The varying inductance tunes the filter to the correct frequency of the harmonic. The control system is given in Figure 2.11. The system detects the phase shift between the harmonic voltage in the AC bus and the harmonic current in the filter and a PI-controller adjusts the DC current of the winding appropriately. A small 6-pulse controlled rectifier is used as amplifier. In this way, the reactor inductance is controlled [34, 39, 40, 43]. While designing the ConTune filter, its bandwidth should be taken into consideration: it should have a certain value, so that filter detuning risk is eliminated. Detuning can be caused by frequency excursions or component variations, e.g. capacitance changes due to temperature differences [40].

Following frequency and component variations with ConTune filter offers many benefits to the system. Automatic tuning of the filter ensures the elimination of resonance and current amplification phenomena. This implies the reduction in the ratings of the filter components [34, 40]. Due to these advantages, this type of filters have been used in several applications, e.g. in the Pacific Intertie HVDC

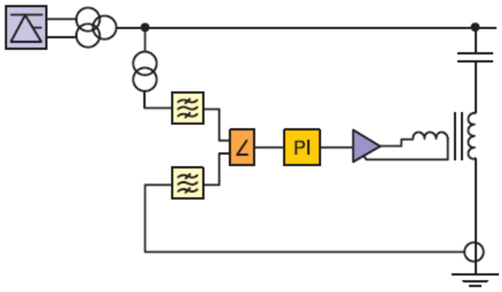


Figure 2.11: Continuously tuned AC filter [34]

Transmission, in the Swe-Pol link, in the Garabi I and II connections (combined with a CCC-HVDC transmission scheme) [43].

Up until now, in the current HVDC projects there is no need for explicitly active AC filters. There are certainly more strict requirements for the filter design than in the past, but conventional passive or ConTune filters provide still the most technically and economically beneficial solution. The main reason for this trend is that the devices for reactive power compensation can also provide sufficient filtering. In classic HVDC systems, with high reactive power deficit, the number and size of compensators, in addition to conventional passive filters, is sufficient for harmonic filtering; in CCC-HVDC systems, with lower reactive power deficit, ConTune filters are used [43].

2.1.5.2 Active DC filters

The development of pulse width modulated (PWM) amplifiers of high power and the improvement of digital signal processors (DSP), enabling signal processing at a high rate, made active DC filters attractive from both technical and economical points of view [43]. There are several possible configurations of active DC filters. They can be connected in series or in parallel with the load, directly or through a coupling connection e.t.c. All the present active DC filter schemes in HVDC transmission systems are hybrid filters: their active part (amplifier) is connected to the HVDC link through a passive part (a conventional shunt filter). This arrangement results in reduction of the voltage level and transient stresses on the active part, and therefore in comparatively low equipment ratings. A typical configuration of an active DC filter is depicted in Figure 2.12. The active part consists of the measuring system, the control system, the amplifier, the transformer, protective devices and bypass disconnectors. The design of the measuring system is essential, since its resolution determines the limit of the system's dynamics. The measuring system communicates with the control system via a fibre optic link. The control system is a DSP operating at a high sample rate. Its aim is to convert measured levels to signals appropriate for amplifier inputs. It is a rather complex system, since it must also cope with changes in the main circuit configuration and handle recovery from contingencies in the network. The amplifier is a PWM voltage-source converter. The control system adjusts the output current of the amplifier, so that it has the same magnitude but opposite phase with the current in line, coming from the converter through the smoothing reactor. Thus, by adding the amplifier's current with the line current, the latter is cancelled. The cancellation level depends on the measuring system resolution. This means that complete cancellation does not

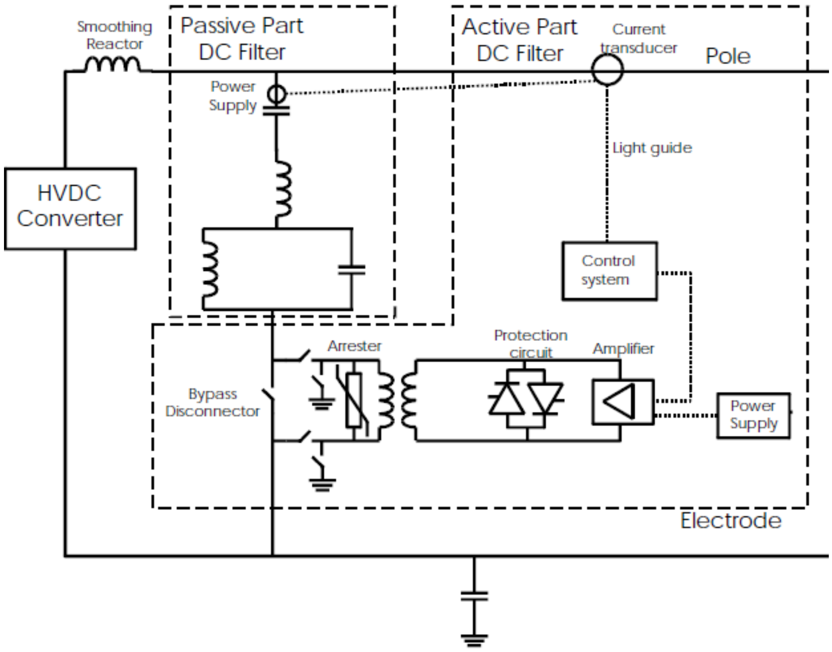


Figure 2.12: Active DC filter [43]

occur never in practice, but the obtainable levels are more than sufficient for any practical purpose. The protection system provides to the amplifier protection from over-voltages and over-currents in the system. The aim of the transformer is to provide a galvanic separation between the amplifier and the HVDC system and to raise the amplifier's output voltage to a level suitable for the system, usually a raise from 0.3 or 1.0 kV to 3 kV. The bypass disconnector allows the disconnection of the active part of the filter from the HVDC system, while the conventional LC branch (passive part of the filter) remains in service, tuned to the fundamental frequency of the system. This can enable the reduction of the required ratings of the amplifier [13, 34, 39, 40, 43]. The successful performance of an active DC filter can be concluded via Figure 2.13, where it can be observed that the harmonic content of the current in a typical DC line is reduced with the addition of the active filter.

In the future, the guidelines for active DC filter design should be revised to reflect expected changes in telecommunications, with the development of digital systems. However, there are still occasions where active DC filters can be an alternative system. Examples of such situations could be the refurbishment of an existing DC filter scheme with unsatisfactory performance, the change or rebuilding of the DC-side configuration of the transmission system (e.g. addition of a new pole), like in Skagerrak 3 project, the existence of short overhead lines followed by cables, as in the Baltic Cable, and occasions with very stringent performance requirements or with critical switchyard areas [43].

2.1.6 Transmission circuit

The DC transmission system consists of the DC links, the high-speed DC switches and the earth electrode. The DC links could be overhead lines or cables. DC lines

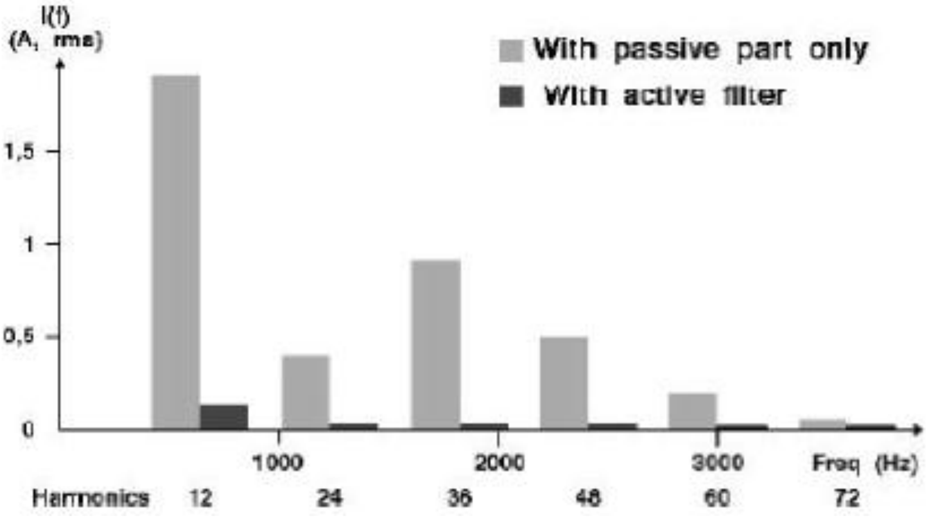


Figure 2.13: Harmonic current content on a typical DC line with and without an active DC filter [40]

are similar to AC lines. The main differences are the number and configuration of conductors, the electric field requirements, the insulation design and space required. For transmission systems over long distances DC cables are preferred. Also in cases of submarine power transfer, cables are the only suitable solution. [13] presents the different types of HVDC submarine cables, which are currently available or under development. The different types of DC switches are also mentioned in [13] and their duties are briefly described. Regarding electrodes, most DC links use earth as neutral conductor; if there is need for restricting the current flow through earth, a metallic return conductor should be provided [29]. [13] provides information about the design of several kinds of earth electrodes.

The whole transmission system includes also AC circuit breakers, which are used for fault clearing in the transformer or for breaking the DC link out of service. It should be mentioned that they are not applied in cases of AC fault clearing, since this can be performed more rapidly by the control system of the converter [29].

2.1.7 Smoothing reactors

Smoothing reactors are large reactors with inductance in the range of 100 to 300 mH. They are usually connected in series with the DC line of each pole of the converter. There are two types of reactor design: the air-insulated dry-type reactors and the oil-insulated reactors in a tank. The selection between the two alternatives should be made by taking into consideration several aspects, such as their inductance, their costs, their maintenance as well as seismic requirements. These aspects are briefly analysed in [13] for the two types of reactors. In the HVDC transmission systems, smoothing reactors serve a series of purposes. First of all, they prevent the current interruption at low load conditions, which could cause high over-voltages in the transformer. Furthermore, they limit the fault current and its rate of rise during short-circuit on the DC link. In this way, they prevent commutation failures in inverters. In addition, they are used to avoid resonance in the DC circuit at low order harmonic frequencies. Thus, the amplification effect of harmonics from the

AC system is avoided. Finally, they participate in reducing harmonic currents, in association with DC filters, for limiting telephone interference [13, 29].

2.1.8 Surge arresters

The main duty of an arrester is the protection of equipment from over-voltages. This means that the arresters should be able to withstand typical surges without occurrence of any damage. On the other hand, they should have no negative effects on the power system during normal operation. For the fulfilment of these requirements non-linear resistors are used. These resistors should present low resistance during surges, for restricting over-voltages, but high resistance during normal operation, for avoiding affecting negatively the power system [13].

2.2 VSC-HVDC transmission system

The most advanced HVDC transmission technology is the VSC-HVDC scheme. Its configuration is similar to the classic system, with some differences due to several technological developments in its components. A typical VSC-HVDC transmission system is shown in Figure 2.14. This system allows more compact HVDC stations, suitable for power transfer to places where it is very difficult to get build permissions, due to restrictions regarding environmental impact or scarcity of land [44]. The structure and operation of each module of the transmission system are described in the followings, explaining the advantages of this technology.

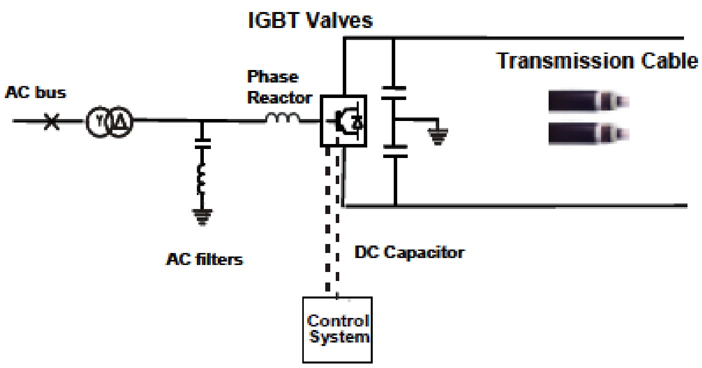


Figure 2.14: VSC-HVDC transmission system [45]

2.2.1 Converter

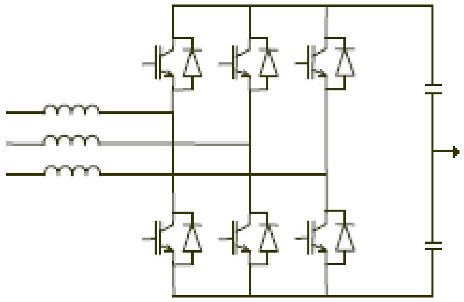
The converter in this system employs IGBT power semiconductors. This device allows control of both turn-on and turn-off operation, in contrast to thyristors which allow only turn-on control. As a result, the IGBT valves can compose self-commutated converters (SCC), implying that the converter operation does not rely on synchronous machines in the AC system. Hence, such a converter can be connected to a totally passive AC network, which is impossible in the case of the LCCs. In addition, the ability of turning-on and turning-off the semiconductors many times per cycle leads to improvement of the harmonic performance of the converter. Less harmonic distortion means that VSC-HVDC systems do not have to use necessarily the 12-pulse configuration and they normally use the 6-pulse bridge (unless this is forced for other purposes explained in the followings). The converter enables the conversion of the three phases of the AC system to a symmetrical DC voltage, which is considered constant, with fixed polarity. This explains the denomination of converters of this type as voltage-source converters. Furthermore, the converter does not consume reactive power from the AC network, but instead it can control the reactive power exchange with the system, meaning no need for reactive power compensation [9, 32].

Each valve consists of a number of series-connected IGBTs, determined by the DC voltage level. Across each IGBT a gate unit and voltage divider are connected, to ensure even voltage distribution between the series-connected IGBTs of the valve. The proper voltage sharing within the valve is performed not only during normal switching conditions, but also during system disturbances.

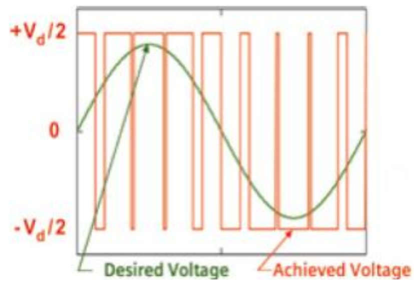
Each valve includes redundant devices for enabling the continue of operation in case of failure of an IGBT. The faulty component should not create an open circuit, since the current along the valve will continue flowing and the source voltage is very high and stiff. On the contrary, the IGBT should enter into its short-circuit condition and remain in this situation until the operation is stopped for scheduled maintenance. This capability is very crucial, especially for series-connected IGBTs. Thus, a reliable mode of short-circuit failure should be determined for each individual IGBT and verified by long-term tests.

IBGTs are switched on and off with frequencies defined by pulse-width modulation (PWM) algorithms. In this way, PWM enables the creation of any desired voltage waveform, meaning any phase angle and magnitude of the fundamental frequency component. The PWM switching frequencies range typically between 1-2 kHz, depending on converter's topology, system frequency and specific application [9, 17, 32, 33]. Research continues developing new more efficient modulation methods, for achieving reduced switching frequency and therefore reduced switching losses. For this purpose, several other modulation methods have been proposed, such as space vector modulation (SVM) [46] and tolerance band modulation [47].

The currently available IGBTs present limited voltage and current handling capacity and therefore they can not individually follow the entire voltage and power requirements. Series-connected valves are arranged in either a two-level or three-level bridge, resulting in larger converter ratings. The two-level bridge is the simplest configuration for a three-phase converter. As shown in Figure 2.15a, it is a 6-pulse bridge, in which the thyristors have been replaced by IGBTs with inverse-parallel diodes and the DC smoothing reactors by DC smoothing capacitors. The outlets of each phase can be connected to the positive or negative DC terminal, generating a discrete, two-level output voltage ($+U_d/2, -U_d/2$, where U_d is the DC voltage), as shown in Figure 2.15b. The output voltage can be modulated by PWM algorithms for mitigating harmonic distortion. For keeping the current ripple relatively low, the switching frequency must be chosen comparatively high, resulting in high switching losses. This configuration has been used at a wide range of power levels, in many applications, although it presents the highest harmonics content and highest converter losses of all the VSC configurations, mainly due to its simplicity



(a) Configuration [17]

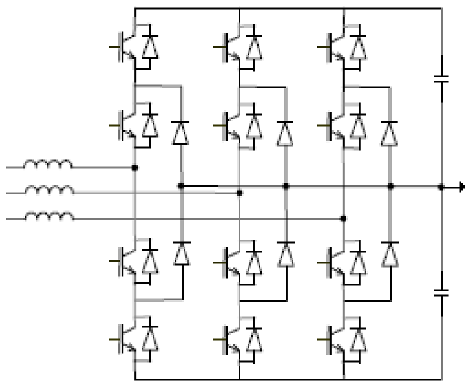


(b) Voltage waveforms [48]

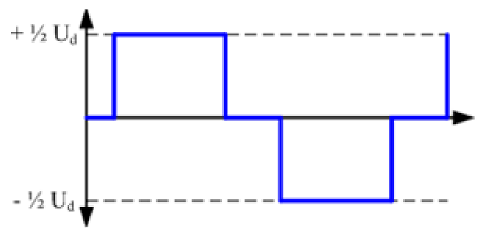
Figure 2.15: Two-level VSC

[4, 5, 9, 17, 33].

Another possible converter topology is the three-level converter, which has similar configuration as the conventional two-level device, with the addition of a clamping diode or flying capacitor, for clamping the neutral point of the DC link. In this way, three different levels of the voltage output are possible at each phase, i.e. positive DC voltage, zero voltage and negative DC voltage ($+U_d/2, 0, -U_d/2$, where U_d is the DC voltage), as illustrated in Figure 2.16b. The resulted voltage resembles much more the ideal sinusoidal waveform than the output of the two-level converter. This implies less harmonic distortion and therefore less filtering required. The topology of a diode-clamped three-level converter, with four valves in one arm is illustrated in Figure 2.16a [4, 5, 17].



(a) Configuration [17]



(b) Voltage waveform [49]

Figure 2.16: Three-level VSC

For increasing the number of voltage levels and thus generating a better waveform (closer to sinusoidal), an extension of diode- or capacitor-clamped converters is necessary. This will lead to increased number of devices and therefore increased complexity. As a result, a strictly modular construction is needed, by cascading the same hardware, namely the same module. A typical solution is the cascaded H-bridge, which however requires an isolated DC power supply for each module [4]. Other cascaded converter topologies have been also suggested, with two-level modules (Figure 2.17) [50, 51] or five-level cross-connected modules combined with half-bridge modules [52]. The development of more advanced multi-level VSCs

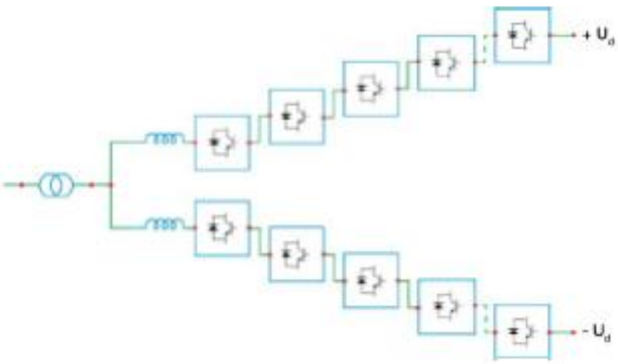


Figure 2.17: Cascaded two-level converter [51]

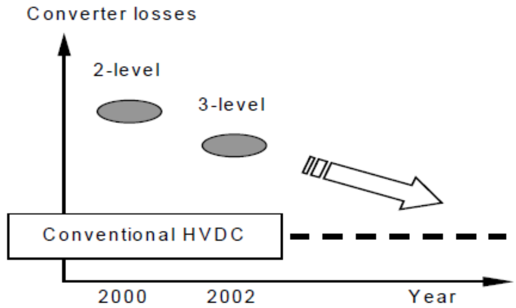
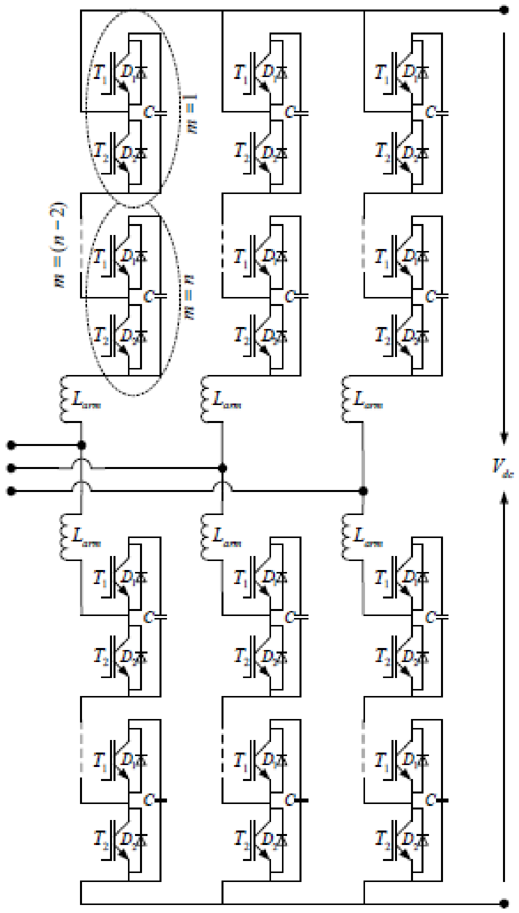


Figure 2.18: VSC and LCC losses in HVDC applications [33]

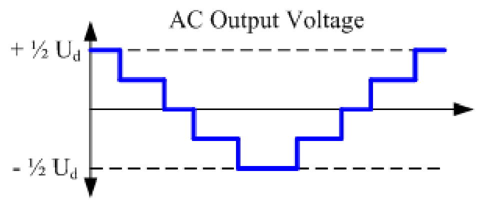
can lead to lower losses, like these that occur in conventional HVDC transmission systems, as can be concluded from Figure 2.18.

A new multi-level converter topology has been recently developed, called modular multi-level converter (MMC). In this configuration each phase leg consists of two arms; the total voltage of the two arms of each phase equals the DC voltage. Each arm consists of n submodules. Each submodule includes two IGBTs, two diodes and a capacitor, comprising a two-terminal structure. This configuration has a common DC link, but no common DC capacitor and filter. Figure 2.19a depicts the MMC topology. The operation principle is that the switching devices of each submodule either bypass the capacitor or connect it into the circuit, depending on the state of the two switches. When T_1 is on and T_2 is off, the submodule is turned-on and the capacitor voltage is applied to the terminals of the structure. Current can either flow through D_1 and charge the capacitor or through T_1 and discharge the capacitor; this depends upon the direction of the current flow. On the contrary, when T_1 is off and T_2 is on, the submodule is turned-off and the capacitor voltage is not applied to the terminals, remaining unchanged. The state in which both switches are turned-off should not be applicable in normal operation, since all submodules will identically follow this state and the converter will be blocked.

The per phase AC voltage of the converter can be controlled by turning on a number of submodules in upper and lower arms of the same phase. Thus, by adjusting the ratio of arm voltages in each phase, the desired sinusoidal waveform is achieved. The switching frequency applied to the devices of each submodule can be reduced, resulting in reduced switching losses; however, the effective frequency of the final waveform is very high due to the large number of submodules connected in series. In this way, the valve is able to synthesise a stepped voltage, with more-in-number but lower-in-size voltage steps, as shown in Figure 2.19b. This means reduced voltage gradients, leading to very low harmonic distortion and low high-frequency noise; this low rate of voltage rise makes the system more robust. A result of low harmonic content of the voltage is the reduction in the number of tuned filters, which are mandatory in a two-level or three-level converter, due to the high and steep steps of their voltage output; on the other hand, a drawback of MMC configuration is the double number of switches compared to the two-level converter. In addition, due to sinus-shaped voltage, standard types of AC transformers can be applied in the transmission system. From the perspective of the DC circuit, the DC voltage can be adjusted independently and therefore there is no need for isolated DC power supply in each submodule, as in the case of the cascaded H-bridge. In general, MMC systems present easy scalability, leading to high power ratings, up to 1000 MW. This, in association to the high modularity of the topology, allows more flexible and economical solutions for the transmission systems [3–5, 9, 48, 53].



(a) Configuration [5]



(b) Voltage waveform [49]

Figure 2.19: Modular multi-level VSC

2.2.2 Transformers

The VSC is coupled to the AC bus via a power transformer. Its role is the same as described in 2.1.2 for the LCC-HVDC systems. However, in the VSC-HVDC scheme, its design is usually simpler and more conventional, due to lower harmonic content of current [9, 17].

2.2.3 Phase reactors

These are standard single-phase air-cooled reactors. Their aim is to control active and reactive power flow, by regulating currents through them. They are used also as AC filters, for reducing high-frequency harmonics of the AC current, caused by the switching operation of the VSC. In addition, they reduce the inrush currents upon energisation from the AC system [17, 32].

2.2.4 AC filters

Due to the switching process of IGBTs, AC output currents and voltages are not sinusoidal, i.e. the spectrum of their waveforms contains not only the fundamental frequency component f_1, but also higher-order harmonics. This harmonic content consists of components around the carrier frequency f_c of the PWM and its multiples. The higher the number of IGBT commutations per second, the higher the frequency of the lowest-order harmonics produced, meaning reduced harmonic losses. On the other side, the higher the number of commutations per second, the higher the switching losses. Therefore, the frequency modulation ratio in the PWM process should be selected accordingly, to keep a balance between switching and harmonic losses. These high-order harmonics have to be mitigated, for preventing their emission into the AC system, since they could cause malfunction of AC equipment or radio and telecommunication disturbances. For this purpose, passive high-pass filters are installed in the transmission system, providing the AC system with almost sinusoidal currents and voltages. In VSC-HVDC systems, the harmonic distortion is lower than in LCC-HVDC systems, since the harmonic spectrum is shifted to higher frequencies; this, in association with the fact that no reactive power compensation is required, allows the smaller size and simpler type of the filters required [9, 17, 32].

2.2.5 Transmission circuit

The transmission circuit is similar to that of the classic configuration. New technologies have been developed regarding the DC cable types, since the current underground cables were found to be heavy, difficult to install and prone to faults; many of them used oil, requiring oil pressure plants; even the cable joints were cumbersome, demanding heavy concrete constructions and requiring frequent maintenance. A first new type of DC cables, applied in the Cross Sound Cable project, was a solid dielectric submarine cable. Apart from the absence of oil, its main advantage was its fast installation. In recent VSC-HVDC systems, a new kind of cable is used, with insulation from extruded polymer, which presents particular resistance to the DC voltage. It employs aluminium conductor, which is more economic and lightweight than copper conductors. Moreover, it exhibits lower power losses and thus its design can be smaller in weight and diameter. Polymeric cables offer mechanical strength, flexibility and low weight, and they are therefore preferable for installations in rural areas, where there is limited load-bearing capacity. Their advantages led to more applications, as submarine cables or overhead cables; in the case of submarine links, the cable can be laid in very deep waters and on rough bottoms. For instance, this type of cable is used in the Murraylink project and has proven to be very reliable. Up until now, this cable has been installed in systems up to 150 kV and 400 MW; its next generation is going to be applied in systems of 1100 MW at 320 kV. A new type of cable, the mass impregnated cable, has started being applied in systems of higher power capacity and at higher voltages, since it exhibits higher voltage capabilities [17, 51, 54–58].

In the recent VSC-HVDC grids, there are two options for the DC breaker: a mechanical and an electronic type. Existing mechanical DC switches, e.g. active resonance breakers, are capable of interrupting DC currents within several tens of milliseconds, around 60 ms, duration which is considered to be too long to fulfil requirements for a reliable DC grid. The electronic DC breaker is an IGBT-based switch and therefore is much faster. However, it is more expensive and, most importantly, exhibits relatively high losses, typically around 30 % of the losses in VSC station. For overcoming this drawback, a new generation of DC breakers has recently been proposed, known as hybrid DC breakers (Figure 2.20). In this new type of DC switches, the main breaker preserves the capability of fast interrupting the full-load short-circuit current, while the by-pass path carries the load during normal operation, so that transfer power losses are reduced to negligible levels. Thus, the hybrid DC breaker is fast, efficient and reliable, as well as modular, meaning that it is easily adapted to actual voltage and current ratings [59–62].

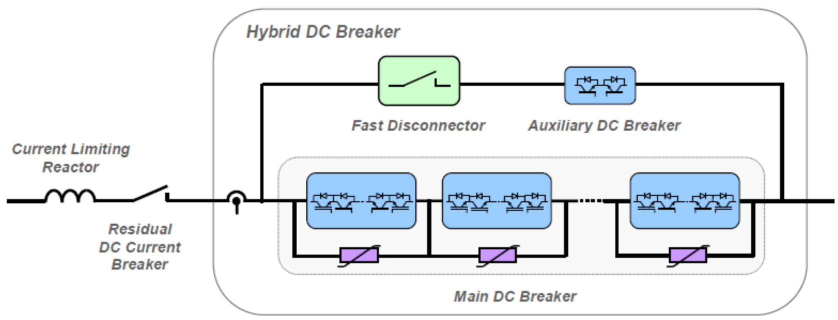


Figure 2.20: Hybrid DC breaker [60]

2.2.6 DC capacitors

The PWM switching process in the IGBTs of the VSC causes harmonics in the current flowing the DC side. This results in a ripple in the DC voltage. For providing a low inductive path for the current, and therefore for reducing this DC voltage ripple, two DC capacitor stacks of the same size are introduced to the system, each connected to one pole to ground. These capacitors are also used for keeping the power balance during transients, by providing an energy storage. The design of the DC capacitors is an important procedure during the development of the whole transmission system. Their size depends on the required DC voltage. The main design factor is the capacitor's time constant, which determines the time needed to charge the capacitor to the rated voltage. This value should be selected to be sufficient for satisfying the voltage ripple and transient over-voltages. On the other hand, a relatively small time constant allows fast control of active and reactive power flow [17, 32, 63]. In addition to DC capacitors, DC filters and zero-sequence blocking reactors could also exist on the DC side of the transmission system for mitigating interference on metallic telephone circuits, which could run adjacent to the DC links. The low harmonic content of currents and voltages in VSC-HVDC systems, allow these filters and reactors to be smaller and simpler than in LCC-HVDC systems [45].

2.3 VSC-HVDC transmission system for grid connection of offshore wind farms

The aforementioned advantages of VSC-HVDC transmission systems, regarding the design and operation of their components, led to their wider application in the grid connection of large offshore wind farms. The system configuration of such a VSC-HVDC connection is illustrated in Figure 2.21. The scheme consists of the offshore wind power plant (WPP) with its collector system, the offshore substation with the relevant transformers and converters, the DC link and the onshore substation connected to the AC grid [5]. In some cases, paralleling the DC links may be advantageous. An appropriate power dispatch between the links can minimise the power losses. In addition, the loss of one DC tie could result in lower power losses than in the case of independent DC links. However, this is found to be valid only in cases with large number of parallel links. The risk of cascaded tie losses should be taken into account: given the loss of one link, the remaining ties should share the additional load, but this could lead to serious overload problems, which could cause a cascading loss of all of them. This process could be extremely fast, so that breakers could not handle it. Power curtailments can become necessary, which is extremely expensive. The decision of paralleling the DC ties or not depends upon several factors, such as the wind turbine generator types and the control schemes of the HVDC converters (which affect the transient behaviour of the HVDC links), the dispatch constraints from regulation and market environments, the costs of space and weight for the equipment installed on the offshore platform, etc. [64] investigates all these aspects regarding the parallel DC links, concluding that new operating principles have to be developed.

2.4 Suitability of transmission systems for grid connection of offshore wind farms

Bearing in mind the configuration and operation aspects analysed above for the different transmission systems, a brief comparison could be performed, regarding their suitability for the grid connection of offshore wind farms. The three transmission schemes (HVAC, LCC-HVDC, VSC-HVDC) are compared considering power

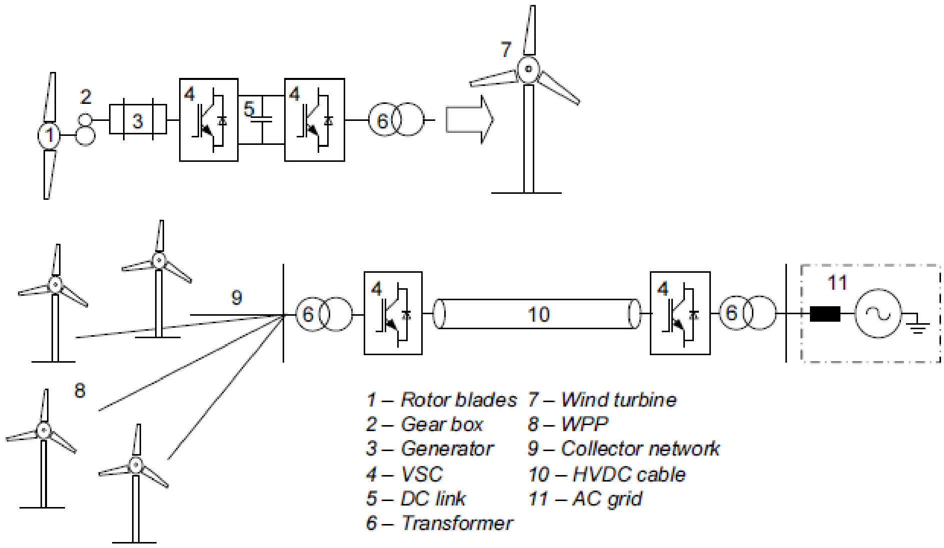


Figure 2.21: Grid connection of offshore wind farm through VSC-HVDC transmission system [5]

losses, current ratings of cables and converters, the size of the offshore substation and environmental issues. These technical aspects affect investment and operating costs. By taking into consideration this analysis, the feasibility of each transmission scheme for the grid connection of offshore wind farms can be concluded, according to the wind farm capacity and its distance from the shore.

2.4.1 Power losses

As described in 1.4.2, in HVAC systems, power losses increase significantly with wind farm size and distance from the coast. If HVAC systems apply to higher voltage ratings, the power losses will increase. In addition, losses depend on the characteristics of the AC cable. On the contrary, HVDC schemes present only very limited correlation with the transmission distance, as explained in 1.4.4. Power losses in HVDC systems depend more on the efficiency of the converter. In LCC-HVDC transmission technology, the total conversion efficiency lies in the range of 97-98 %, depending on the design of the converter. Higher efficiency implies, however, higher investment cost of the converter. Comparatively low losses (2-3 % for a 500 MW power transfer over 100 km, including losses in both converter stations) is the main advantage of LCC-HVDC systems. Nevertheless, it should be taken into account that this percentage does not include losses in the auxiliary devices at the offshore station, for providing commutation to thyristor valves, as well as for reactive power compensation. VSC-HVDC systems present lower efficiency, 90-95 % including both converter stations. This occurs due to higher losses per converter station, around 2 %, depending upon the switching frequency, as mentioned in 2.2.1. By reducing the switching frequency, lower switching losses in the converter can be achieved. On the other hand, high switching frequency means lower harmonic content of voltages and currents and therefore less need for filters. Fewer filters mean lower losses in filters, smaller size of the station and lower investment cost. Hence, a balance between lower switching losses and less equipment should be managed [65]. Multi-level converters can contribute to this attempt, as described in 2.2.1.

As a result, converter losses depend significantly on its design.

2.4.2 Ratings of cables and converters

Up until now, the rating of AC cables is limited to 200 MW per three-phase cable at voltages of 150-170 kV, with reactive power compensation at both ends of the link and maximum transmission length of 200 km. This implies that, for the grid connection of larger wind farms, more cables will be needed, apart from possible additional requirements for redundancy. For shorter distances, higher voltage ratings, up to 245 kV, are possible, and as a result the power ratings will increase to 350-400 MW. Even higher voltage levels, up to 400 kV, are under development; these applications will allow power transfer of up to 1200 MVA over a distance of 100 km. However, it should be borne in mind that higher voltage levels will result in higher power losses, as well as in larger and more expensive transformers and submarine cables. Consequently, an increase in voltage ratings is often only acceptable if an increase in power capacity is required. In LCC-HVDC systems, converter and cable ratings are not limiting factors for maximum power transfer in the current offshore wind farm projects ($<$ 1000 MW). On the contrary, the present technologies of cables in VSC-HVDC systems can transfer only 600 MW at voltage level of 150 kV. In addition, only converter stations of maximum rating of 300-350 MW are in operation; converter stations of higher capacity, up to 500 MW, have been announced to become available. This means that more than one converter stations should be constructed for utilising the full capacity of the current cables. For even higher power transfer of more than 600 MW more cables will be needed. It should be also taken into consideration that links in VSC-HVDC systems are not usually connected to ground, meaning that two conductors are always needed, instead of one single cable in the case of LCC-HVDC systems. In general, for the grid connection of large offshore wind farms, the smallest number of cables is required when LCC-HVDC systems are applied and the largest number of cables is needed in the case of HVAC systems. The number of cables affects total investment costs. Nevertheless, the overall system reliability might increase, if more cables are used. To maximise reliability benefits, different cables should follow different routes; however, this might be not always feasible [65].

2.4.3 Size of the offshore substation

HVAC systems require reactive power compensation, as explained in 1.4.2. As a result, reactive power suppliers should be placed at both ends of the cable. This leads to larger offshore substations. Moreover, the application of higher voltage ratings results also in larger substation, due to larger transformers that required. However, the size of an AC offshore substation is much smaller than that in the HVDC schemes, around one third of their size, mainly due to the significant space which is required by the converter station. Converter stations in LCC-HVDC systems need considerably more space than in VSC-HVDC systems, due to auxiliary devices required for the commutation of the converter valves. This equipment is usually comprised by some diesel generators, which should be able to keep a strong AC system at the offshore converter, for enabling the commutation of LCCs even during periods of now or very little wind. Another possibility is the existence of STATCOMs, which could provide the necessary commutation voltage. In addition, converter stations in LCC-HVDC systems include reactive power compensation devices, which are not needed in VSC-HVDC systems, as explained in 2.1.3 and 2.2.1. This leads to even larger size of the offshore substations. Nevertheless, when STATCOMs are applied for providing the commutation voltage, the same device can be used for reactive power compensation, reducing the station equipment and therefore the size of the substation. Furthermore, LCC-HVDC systems need more filters than VSC-HVDC systems, due to higher harmonic distortion of currents and voltages. In general, in offshore substations of LCC-HVDC systems, more equipment is required than in those of VSC-HVDC systems, leading to higher investment costs. This implies the reduced likelihood of applying LCC-HVDC transmission systems for the grid connection of small or medium wind farms, rated less than 300 MW. Up until this capacity, VSC-HVDC systems will be preferred for the grid connection of offshore wind farms. For higher capacities (larger offshore wind farms), multiple VSC stations are required, resulting in larger offshore substations, since the present maximum capacity of a VSC is 300 MVA. Therefore, for very large capacity demands, the advantages of VSC-HVDC systems over the LCC-HVDC solutions, concerning space requirements, might be significantly reduced [65].

2.4.4 Environmental issues

Submarine cables installed for the grid connection of offshore wind farms usually pass through environmentally sensitive areas, a fact that causes difficulties in obtaining construction permits. Authorities prefer solutions with the lowest environmental impact. The effect of submarine cables on the environment depends on two factors, namely their magnetic field and their number. The solution with the lowest influence on the environment is the combination of the minimum number of links with the lower magnetic field of these cables. This combination is not always possible, since AC cables have generally lower magnetic field than DC cables, but HVAC systems need usually more cables than HVDC schemes. Moreover, the required diesel generators installed on the offshore platforms of LCC-HVDC systems, as well as diesel storage capacity, should also be taken into account, since they cause environmental concerns. In conclusion, the best transmission technology, from an environmental point of view, is very much case-dependent [65].

2.4.5 Feasibility of each transmission system according to wind farm capacity and distance from the shore

Taking into consideration the aforementioned issues, some general conclusions can be risen, regarding the suitability of each transmission system for the grid connection of a wind farm, according to its capacity and distance from the shore. The feasibility of each option is determined by taking into account the total system cost, consisting of the investment and operating costs, including converter and transmission losses. Investment costs depend on equipment ratings, whereas operating costs change with the distance from the connection point. A diagram presenting the most feasible transmission option for each level of wind farm capacity and at each distance from the coast is illustrated in Figure 2.22. For short distances, less than 100 km, where investment costs dominate over operating costs, HVDC systems are not suitable due to high converter cost. However, this is valid only for small capacities, up to 200 MW, since for transferring larger amount of power requires more AC

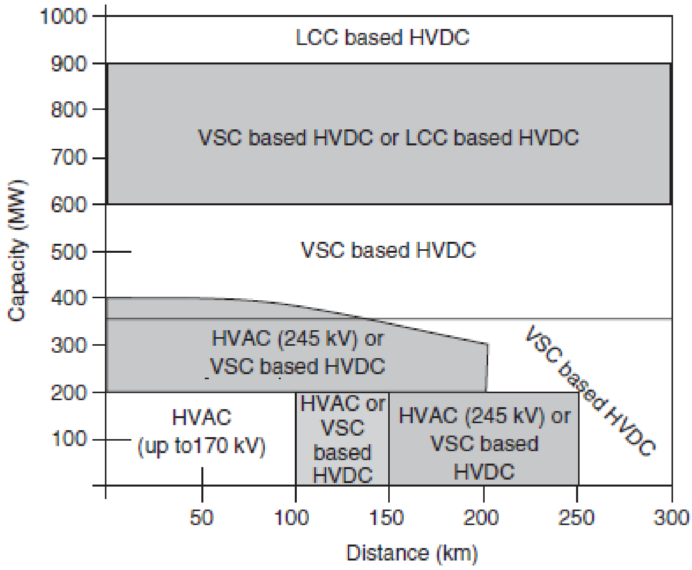


Figure 2.22: Transmission technology options according to wind farm capacity and distance from the shore [65]

cables, leading to higher transmission losses and therefore higher operating costs. Thus, for capacities larger than 200 MW, the HVDC system may be an economically competitive solution, even for short distances. Increased transmission losses in HVAC systems justify also the dominance of HVDC systems in longer distances. For capacities up to 600 MW, in cases where HVDC systems are more suitable, the VSC configuration is preferable, mainly due to the lower platform equipment (absence of auxiliary devices) and therefore the lower investment cost. For capacities larger than 600 MW, the presently low ratings of VSC-HVDC technology (both of cable and converter) are obstacles for the application of this transmission scheme. For transferring such amounts of power, more VSC stations are required on the offshore platform and more cables should be installed, leading to higher costs. Therefore, the LCC-HVDC concept is found to be more economically attractive. Nevertheless, reliability issues may force the use of more cables, for avoiding losing the whole amount of power in the case of one cable is lost. In this cases, VSC-HVDC systems will be the best solution. Besides, VSCs and cables of larger ratings have been developed fast and are applied during the latest years. Apart from aspects regarding configurations and their corresponding costs, the enhanced control capabilities of the VSC-HVDC technology should be taken into consideration. The ability of this transmission scheme to provide grid support, through e.g. active and reactive power control, voltage regulation, black-start capability, makes it even more advantageous for the grid connection of large offshore wind farms [65].

2.5 HVDC system topologies

HVDC converters, rectifier and inverter, can be connected through DC links in a number of topologies. The main system topologies are shown in Figure 2.23 and described in the followings.

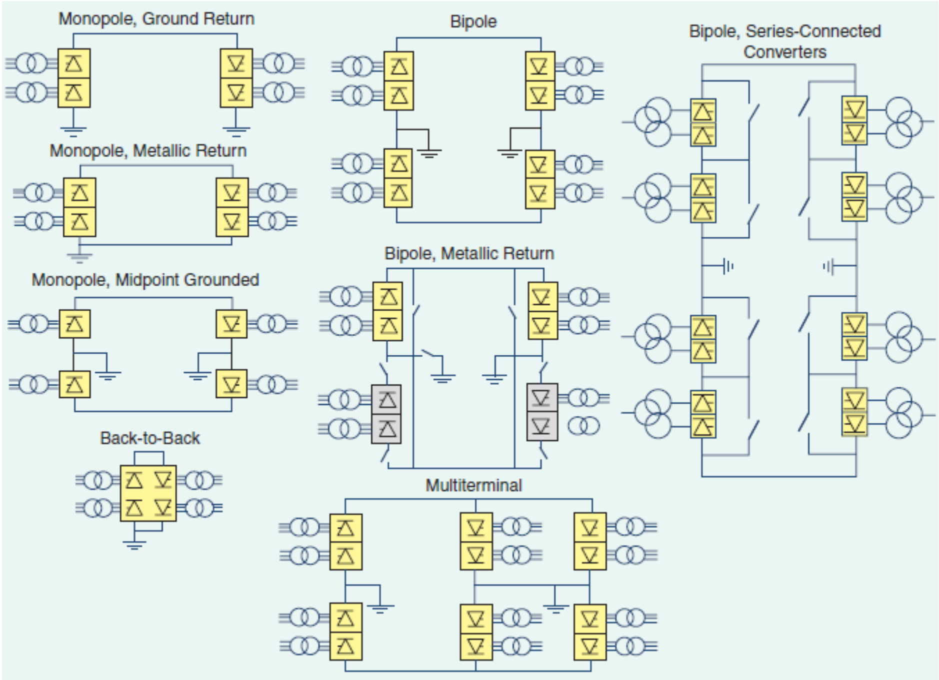


Figure 2.23: HVDC system topologies [28]

2.5.1 Monopolar HVDC systems

These systems are the simplest and least expensive for transferring moderate amount of power. In this topology, two converters are connected by a single pole link, at a positive or negative high voltage. The link can be insulated cable or line conductor. Most monopolar systems are designed for being expanded to bipolar topologies in the future: there are two transmission conductors, but initially only one is used for the monopolar system, whereas the other is either unused, used as electrode line or connected in parallel with the main transmission conductor (like in the case of the Baltic Cable project) [9, 17, 28, 66].

2.5.1.1 Monopole with ground return

In this arrangement, the return current flows in the ground or sea at two earth electrodes. The electrodes are located some kilometres from the stations and their design depends on whether they are placed on land or at sea. The return current is carried to the earth electrodes through medium- or low-voltage electrode lines. This current is unidirectional, implying a complex design for the anode electrode, but a simple one for the cathode electrode. Monopoles with ground return are considerably cheap for power transmission over long distances. However, they could lead to problems, like electrochemical corrosion of the buried metal objects, influences on water chemistry or magnetic navigation compasses in case of unbalanced currents [9, 28, 66].

2.5.1.2 Monopole with metallic return

For eliminating these effects, a metallic return conductor can be installed between the two ends of the monopolar transmission link. Since the converter terminal is connected to earth, the return conductor does not need insulation for the full transmission voltage, meaning that it costs less than the high-voltage conductor. The selection or not of a metallic return conductor relies upon technical, economical and environmental factors. In cases of congested areas or areas with high earth resistivity the monopolar topologies with metallic return are suggested [9, 28, 66].

2.5.1.3 Monopole with grounded midpoint

This topology is an economic alternative to monopole with metallic return, since it does not use conductors at full transmission voltage. In this topology, the midpoint of the converter is connected to earth, directly or via an impedance, to provide a reference to the DC voltage. This means that the conductors operate at half DC voltage, one positive and the other negative. The converter can be arranged only in 12-pulse configuration, so that there is never any stray earth current. This topology, known also as symmetrical monopole, is very common with VSCs when cables are used [9, 28, 66].

2.5.2 Back-to-back HVDC systems

In these systems, two converter stations are located at the same site, so that the length of the transmission line or cable is kept as short as possible. Due to the short conductor length, the DC voltage can be selected as low as possible, so that a small valve hall, with a reduced number of series-connected thyristors, can be built. These systems are used to connect two adjacent asynchronous AC networks, even at different nominal frequencies and/or no fixed phase relationship. It should be mentioned that the power transfer is limited by the relative capacities of the AC systems at the point of connection [9, 17, 28].

2.5.3 Bipolar HVDC systems

2.5.3.1 Bipole

This is the most common topology for modern HVDC transmission systems. In this arrangement, a single 12-pulse converter is used for each pole at each terminal. The two terminals are connected by two conductors as positive and negative poles. If both neutrals are grounded, the two poles can operate independently, creating two independent DC circuits of half capacity. Under normal balanced conditions, the currents flowing at both poles are identical and therefore no earth current flows. This results in reduced earth return losses and environmental effects. During outages in one pole line, monopolar earth-return operation can be performed, by allowing the flow of half of the rated power, using the earth electrodes as return path. In this operation mode, losses could increase, if ground electrodes and lines are not designed for the extra current [9, 17, 28, 66].

2.5.3.2 Bipole with metallic return

For avoiding the aforementioned problem during outages at one pole, the opposite pole line can be used as metallic return, increasing the reliability of the system. For this purpose, pole/converter bypass switches should be installed at each end of the line, as shown in Figure 2.23, so that line segments can be switched off or parallelised. The usage of the line as metallic return requires also a metallic-return transfer breaker in the electrode line at one of the DC terminals, for commutating the current from the relatively low resistance of the earth into that of the DC conductor. This operation is effective during converter outages, but also in cases of line insulation failures, if the remaining insulation is adequately strong to withstand the low resistive voltage drop in the metallic return path [9, 17, 28].

2.5.3.3 Bipole with series-connected converters

As mentioned in 2.1.1, for HVDC transmission of very high power and at very high voltages, 600 kV or 800 kV, series-connected converters can be used. This topology allows reduction in energy unavailability in cases of individual converter outages or partial line insulation failures. For instance, in a bipolar system with two series-connected converters per pole, only one quarter of the transmission capacity is lost, in the case of a single converter outage or of a degraded line insulation, able to support only half of the DC voltage. In addition, with this arrangement there is not a need to change the operation mode to monopole with metallic return for limiting the duration of emergency earth return [28].

2.5.4 Multi-terminal HVDC systems

In this topology, three or more HVDC converter stations are connected through HVDC lines or cables, in series, parallel or hybrid (combination of series and parallel connections) configurations. Parallel systems, in which all converters are connected to the same voltage, are used in large capacity stations, whereas series systems, in which converter stations are connected in series in one or both poles, are usually applied in lower capacity stations [9, 17].

Multi-terminal systems are difficult to be realised with the LCC-HVDC technology, since power reversal is achieved by reversing the polarity of the DC voltage, which affects all converters connected to the system. On the contrary, VSC-HVDC systems do not present this problem, since the power direction is changed by changing the current direction, whereas the polarity of DC voltage is fixed. Hence, several VSC stations (multi-terminal systems) can be connected to DC buses with fixed polarity, creating therefore DC grids, similar to AC networks [19, 67].

These VSC-HVDC grids, consisting of multi-terminal systems, are very attractive for the integration of renewable energy sources, such as offshore wind farms, and for the reinforcement of interconnected AC networks [19, 67]. Many projects investigate the potential benefits and cost-effectiveness of the multi-terminal configuration, such as [68]. The number of power systems with two or more HVDC links feeding power to different points of the same AC network area is increasing. As a result, a greater interest in studying the performance of such DC links has been risen. There are a number of technical aspects that should be considered, regarding the strength of the system compared to the amount of power transferred by the multiple DC links. Basic issues, such as voltage and power stability, frequency stability, over-voltages and harmonic instability due to resonances, commutation failure interaction between different converters, are analysed in several research activities [69–71]. In addition, the need of coordination of power modulation, as well as of the recovery control during faults, is also investigated in many studies [23, 69, 70].

2.6 HVDC grids with multi-terminal systems

One of the most important issues during the operation of the HVDC grids is the fault handling. In this section the procedure for properly handling a fault in a DC system is described. In addition, various topologies of multi-terminal systems for the grid connection of offshore wind farms are given and compared regarding their reliability during DC faults.

2.6.1 Handling of faults at the DC side of the transmission system

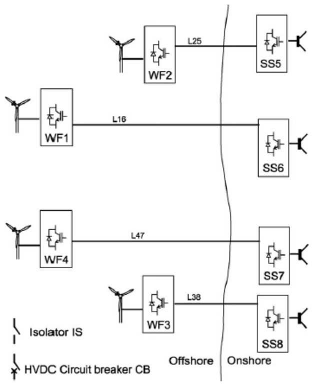
The HVDC system should react in faults in a way that the fault does not put the entire system on risk. The faulty part should be switched out of the network and, immediately after the fault clearance, the remaining healthy parts of the grid should undertake again the system's operation. The main components for the fault handling are the AC and DC switches of the system, which can isolate the faulty part. Faults at the AC side of the system will not affect the DC side, apart from a possible power loss. In such cases, the fault handling may not necessarily include activation of the DC switches; instead, the converters themselves can handle types of faults momentarily through their control systems. However, a fault at the DC side will affect the whole system. The first step for the fault handling is the trip of the AC breakers at the AC side of the converters. Thereafter, the relevant DC breakers open to isolate the faulty section of the DC network. Finally, the AC breakers are reclosed and the remaining healthy parts of the system can continue to operate. After clearing the fault, the converter stations and DC links can be reconnected and the system will be brought to its pre-fault state. In the case an interruption can be accepted by the system operator, the DC switches can be slow; on the other hand, if only short interruption is acceptable, the DC switches should be of high speed type, managing to bring the system back to operation in 0.5 seconds after the fault. For immediate fault clearance, a detection system is also required, so that it localises the fault and gives order for disconnecting only the faulty parts [59].

2.6.2 VSC-HVDC multi-terminal system topologies

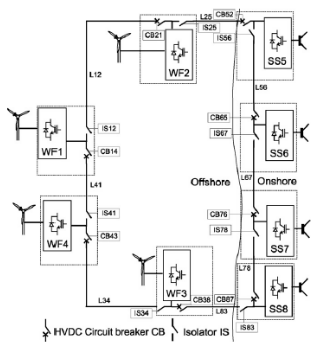
There are several different VSC-HVDC multi-terminal topologies for transferring power from large offshore wind farms to the AC grid. In the followings the main configurations are described and their operation under converter or DC link faults is discussed.

2.6.2.1 Point-to-point topology (PPT)

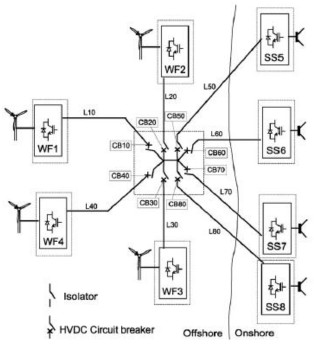
This topology consists of multiple point-to-point links, each one connecting one wind farm to the grid, as shown in Figure 2.24a. In the case of a converter failure or a fault in a DC link, the AC breakers at the grid side of the converter open and the faulted part is disconnected by the AC network. DC breakers are not needed and each line is rated for the power of a single substation. The turbines of the corresponding wind farm are let to trip off and their power is lost. Hence, this topology lacks flexibility [72].



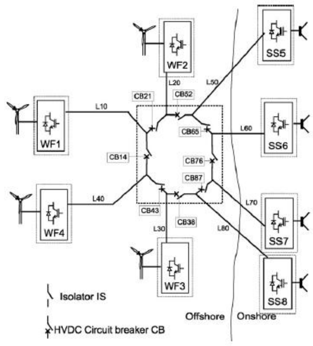
(a) Point-to-point topology



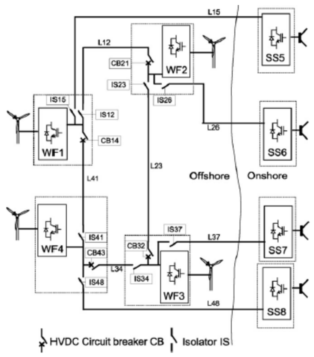
(b) General ring topology



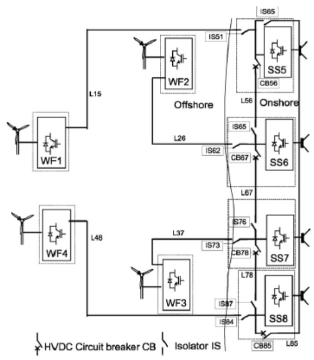
(c) Star topology



(d) Star with central switching ring topology



(e) Wind farms ring topology



(f) Substations ring topology

Figure 2.24: Multi-terminal topologies

2.6.2.2 General ring topology (GRT)

In this multi-terminal HVDC system, the lines connect all the nodes of the network comprising a ring, as illustrated in Figure 2.24b. Under normal conditions, the ring operates in a closed loop, with all the circuit breakers and isolators closed. Nevertheless, the ring can operate also in an open loop, having a breaker or isolator opened due to a fault. When a fault occurs in a DC line, the breakers at the ends of this line open, disconnecting the corresponding wind farm. However, the rest of the circuit can continue operating. After the fault current reaching zero, the isolator between the faulty line and the disconnected wind farm opens, allowing the breaker of the wind farm to close again and the wind farm to be connected to the rest of the system. At the end, the DC grid works in an open loop circuit. By replacing the isolators with DC breakers, the wind farm will not be disconnected at any moment, but the cost will be increased. Some lines should be rated for the whole power of the system, since they transfer the power from all wind farms during the open-loop operation. The open-loop mode offers flexibility to the topology, at the cost of $N_{WF} + N_{SS}$ breakers, as well as lines, some of which should be of full power ratings (N_{WF} is the number of the wind farms of the network and N_{SS} is the number of the onshore substations) [72].

2.6.2.3 Star topology (ST)

In this multi-terminal configuration (Figure 2.24c), each line from a wind farm or a substation is connected to a star node. A possible converter or DC link fault is handled by opening the DC breaker and therefore disconnecting the corresponding line. Thus, the lines are rated according to the ratings of the connected VSC. The topology needs the same number of breakers and lines as the ring topology, but additionally an offshore platform for the central node. Furthermore, its flexibility is not as good as of the ring configuration, since a permanent fault in a line, connecting a wind farm to the central node, will cause the permanent loss of the power from this plant. Besides, a fault at the central node will lead the entire system to go offline. Hence, this topology is not feasible for connecting wind farms to the grid [72].

2.6.2.4 Star with central switching ring topology (SGRT)

This topology is depicted in Figure 2.24d. It is a combination of the star and ring topologies, forming a star configuration with a central node of ring configuration (which is placed on an offshore platform). A fault in a line is handled in a same way as in star topology, by disconnecting the corresponding part. This implies, however, that the same problem in the case of permanent line fault occurs also in this circuit arrangement, as in the star topology. The lines connecting each wind farm or substation to the central node should be rated according to the relevant VSC. Nevertheless, the central node lines should be rated to the total capacity of the entire system, as in the general ring topology. This configuration offers the combined advantages of ring and star topologies, at the cost of the same number of breakers and lines [72].

2.6.2.5 Wind farms ring topology (WFRT)

This topology consists of a wind farm ring, which additionally has links connecting each wind farm to an onshore substation, as shown in Figure 2.24e. In the event of a fault in a line, connecting a wind farm and a substation, the DC breakers will open, disconnecting the wind farm from the substation, as well as from the wind farm ring. Therefore, the ring operates temporarily in the open-loop mode and the power from the corresponding wind farm is lost. Once the current in the faulty line becomes zero, the isolator opens. Then, the breakers close again to connect the wind farm to another substation. This operation requires that each line to a substation should be rated according to the capacity of the corresponding station, whereas each line of the wind farm ring should have capacity equal to the sum of the capacities of the two wind farms at the line's ends. The topology offers an excellent flexibility, since it copes with line faults without a permanent loss of the power of a wind farm. This feature is achieved at a cost of the same number of lines as the aforementioned topologies ($N_{WF} + N_{SS}$), but of a minimised number of breakers (N_{WF}) [72].

2.6.2.6 Substations ring topology (SSRT)

In a similar way to the previous topology, a ring of the onshore substations is formed in this configuration, as illustrated in Figure 2.24f. This topology operates similarly to WFRT during a fault in DC link, with the difference that the converter in the wind farm is brought to isolation, instead of the converter of the onshore substation. This implies that, at the same cost of breakers and lines, this topology offers more flexibility in the main grid side, but less flexibility in the wind farm side than the WFRT. As a result it is more convenient to use the WFRT in most applications, as it allows the extraction of power from all wind farms [72].

2.6.2.7 Other topologies

At the cost of adding more breakers and lines, more complex configurations can be formed for higher performance. Examples of such topologies are a combination of HVAC and HVDC links, a combination of a WFRT and a SSRT, a double GRT, a double ST with different central nodes, a combination of a GRT and ST by superposing one topology to the other, etc [72].

2.6.3 Comparison of topologies

Taking into consideration the discussion regarding the aforementioned topologies, a comparison according to several factors can be performed between the various configurations. As far as the number of breakers is concerned, PPT does not need any DC switches, whereas GRT, ST and SGRT need the largest number, i.e. one for each converter unit ($N_{WF} + N_{SS}$). The partial ring topologies, WFRT and SSRT, need DC breakers only for the converters of the ring, i.e. N_{WF} and N_{SS} respectively [72].

Regarding the ratings of the DC links, in PPT, ST and SGRT lines can be rated at the capacity of the converter to which they are connected. In WFRT and SSRT, the lines of offshore to onshore circuits should be rated to the capacity of a single station, whereas the lines of the ring circuit should be rated to the double of the capacity of a station. The worst case, concerning this factor, is the GRT, where lines have to be rated to the power capacity of the whole system, which makes this topology economically unattractive. However, studies have reached the conclusion that lines with the highest ratings have the lowest utilisation, whereas lines with the lowest ratings operate at full utilisation. This can be explained by the additional redundancy that higher-rated lines provide. [72].

Flexibility of the system during a fault event is a crucial factor. All multi-terminal systems are supposed to present flexibility under fault cases, meaning that they should allow redirection of the power flow in an event of a fault. In this sense, PPT is not considered as a multi-terminal topology, since the single wind farm is lost permanently, when a fault occurs in its connection line. In GRT, the faulted part, line or converter, can be disconnected and isolated, and the rest of the system can continue operating in an open ring. In ST and SGRT, only a fault in a line can be handled properly, by disconnection of one converter. On the contrary, a fault in the central node will lead the whole system to go offline. In WFRT, a fault in a line from offshore to onshore station will lead to disconnection of an onshore substation and the opened ring can be in service, for handling possible faults in the ring. Similarly, in SSRT, a fault in a line from offshore to onshore circuits results in the disconnection of a wind farm, while the open ring will remain under operation, able to handle faults in the ring [72].

Considering additional equipment or constructions, GRT, WFRT and SSRT require fast communication devices to coordinate protections. On the other hand, ST and SGRT need an offshore platform for the central switching node or ring [72].

In general, the selection of the optimum topology for a given application depends on operation and robustness requirements, as well as on the geographical location of the substations and the wind farms. An essential factor is the cost of the DC breakers and lines. Taken into account the recent cost of DC breakers, the most appropriate topology is found to be the WFRT, since it is able to meet the required flexibility with the least number of breakers and without needing an offshore platform. If shorter line lengths are required, GRT can also be attractive, but it requires higher ratings of some lines. Since distances between nodes, cable and breakers costs and availability of communication systems vary with the specific project, detailed analysis is required for selecting the best topology for a given application [72].

Chapter 3

Converter control schemes in a VSC-HVDC transmission system

As mentioned in 2.4.5, the benefits, that the VSC-HVDC technology offers to the grid, make it more attractive than other transmission systems for power transfer over long distances, e.g. for the grid connection of large offshore wind farms. The grid support is the result of several capabilities that VSC-HVDC systems present, enabled by their control systems. These control schemes and the capabilities that provide are described in this chapter.

3.1 Converter control schemes

In a VSC, the switching process of the IGBTs is controlled by a PWM scheme. Therefore, with constant DC voltage, simultaneous adjustment of the magnitude and the phase of the AC voltage output of the converter can be achieved. This implies the capability for power control, since the active power is regulated by changing the phase of the AC converter voltage, whereas the reactive power is controlled by adjusting the magnitude of the AC converter voltage. By adjusting these two quantities of the AC converter voltage, operation in all four quadrants is possible. This enables the operation of the converter close to unity power factor, and thus the maintenance of dynamic reactive power reserves, for voltage support in contingencies, similar to a SVC. The independent control of the magnitude and the phase of the AC converter voltage allows the separate active and reactive power control. This means that the active power can be adjusted rapidly, without changing the reactive power exchange of the converter with the AC network [28, 45].

The active and reactive power control loops take place at both sides of the DC link (rectifier and inverter). The active power control loop can be set to regulate the active power flow according to the DC voltage, the frequency variation or an active power reference value. The reactive power control loop can be set to control the reactive power flow according to the AC voltage or a reactive power reference value. However, not all control strategies can be used simultaneously. The selection of different control functions depends on the application. For instance, in the case of a passive load, the VSC should control frequency and AC voltage, whereas in the case of an established AC system, the VSC should regulate AC voltage and active power flow. Nevertheless, the DC voltage control is necessary for achieving active power balance in the DC link. Therefore, one terminal of the DC link must undertake the DC voltage control, while the other should be set to control the active power or frequency. Concerning the reactive power regulation, either of the two control strategies can be selected independently at either terminal of the DC link, as presented in Figure 3.1 [17, 28, 45, 73].

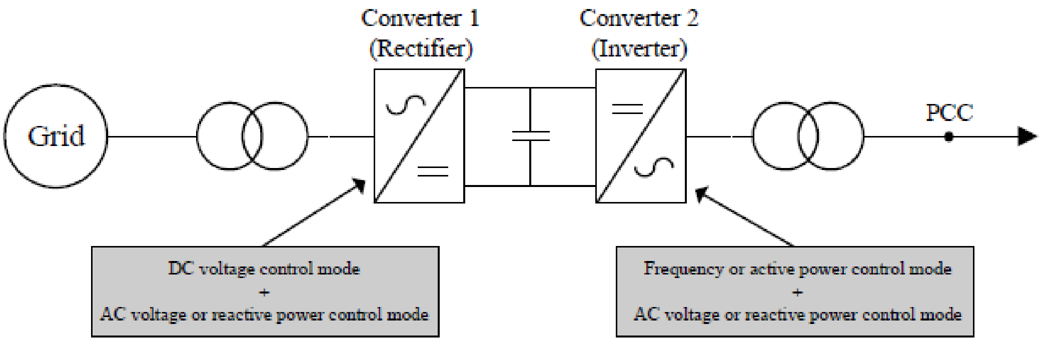


Figure 3.1: Control strategies in VSC-HVDC transmission systems [17]

Hence, the control functions of a VSC include AC voltage control or reactive power control, as well as DC voltage or active power control, as shown in Figure 3.2, in which a VSC control system is illustrated. The control system recognises also the converter current limitations, as determined in the inner current control function [73]. The system is a cascaded control system, which consists of the inner loop, namely a fast vector controller for converter current control, and the relatively slower outer loop, including the DC voltage controller, the AC voltage controller, the active power controller, the reactive power controller and, possibly, the frequency controller [17].

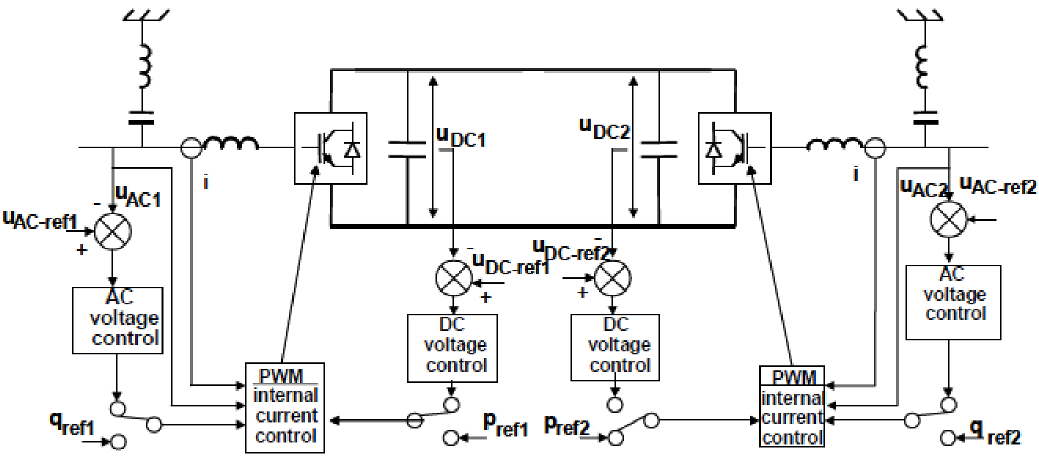


Figure 3.2: Control system of VSC-HVDC transmission technology [45]

3.1.1 Inner current controller

The aim of the converter current controller is to take current reference values from the outer controllers, to apply current limits to these values, according to the PQ characteristics of the converter, and finally to determine voltage reference values for the VSC modulation unit. This control loop operates in a *dq* rotating reference frame, synchronised by a PLL (phase locked loop) to the AC voltage at the point of connection. The d-axis value of the reference current is generated by the outer controllers of either the active power, the DC voltage or the grid frequency. The q-axis value of the reference current comes out from the outer controllers of either the AC voltage or the reactive power. Therefore, the d-axis current controls the active power, whereas the q-axis current controls the reactive power. These current reference values are used to determine reference values for the terminal voltage. In this way, the power exchange of the VSC is determined by the converter terminal voltage with respect to reference voltage values [5].

The inner current control can be implemented by a PI-controller, as described in [17]. The gain factors of this controller should be defined according to stability requirements. Specifically, [17] concludes that the gain of the P-part of the controller should not present high value, since this leads to instability.

3.1.1.1 Limitations

As it is known, converters do not present any overload capability, like synchronous generators. Therefore, a current limit should be introduced in the control system, for avoiding stress or damage of the converter valves, in the case of large transient currents due to disturbances. In addition, the voltage reference values produced by the inner controller should be limited, so that the actual converter voltage will be limited according to the voltage capability of the converter [5, 17].

These current and voltage limits of the converter determine its PQ characteristics, i.e. its capability for active and reactive power transfer. In Figure 3.3 various PQ capability curves are illustrated. The upper flat part of each curve is determined by the converter's voltage limit, whereas the rest part of the curve is determined by the converter's current limit. In some cases, an under voltage limit is also required, so that the reactive power is restricted above -1 p.u., for allowing adequate AC voltage to transmit the active power. The magnitude of the AC voltage at the point of connection affects the PQ characteristics of the converter: increase in AC voltage magnitude results in decrease in reactive power exchange capability and in increase in active power exchange capability, as it is depicted in Figure 3.3 for various AC voltage magnitudes [5].

For following the current limits, the reference current, consisting of the active and reactive reference currents (d-axis and q-axis reference currents), is compared to the current limit. If the limit is exceeded, both reference currents should be decreased. The decision of the way to limit both reference currents depends on the application. When the converter is connected to a strong grid, higher priority will be given to the active reference current, for producing more active power. On the contrary, when the converter is connected to a weak power system or used to supply an industrial plant, high priority will be given to the reactive reference current, for keeping up the AC voltage, and the rest of the power transfer capability is left available for

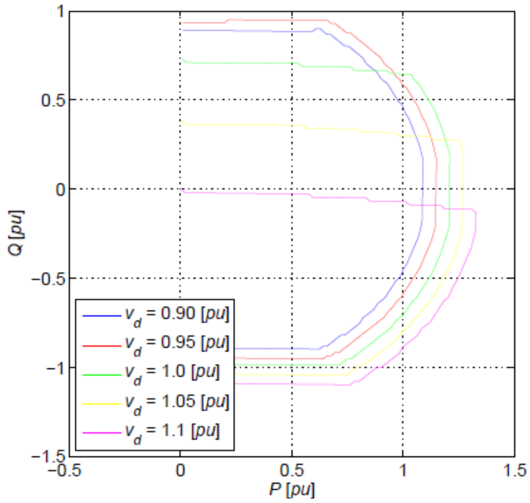


Figure 3.3: P-Q characteristics of grid-side VSC [5]

active power transmission [17].

3.1.1.2 Negative-sequence current

In case of unbalanced voltage conditions, i.e. asymmetrical voltages, a negative sequence of quantities should be taken into account for describing the operation of the VSC (the zero-sequence components can be assumed zero). Small imbalances in three-phase voltages (imbalance factor $\mathrm{u_n}/\mathrm{u_p} < 5\,\%$) are usually caused by unbalanced loads, uneven impedances in transmission lines, etc. Larger imbalances in three-phase voltages are generally caused by asymmetrical faults, e.g. single-line-to-ground (SLGF) faults. Unbalanced voltages mean ripple in the DC voltage and active power profiles. The peak-to-peak magnitude of the DC voltage ripple depends on the amplitude of the negative-sequence voltage and the capacitance of the DC link. From the converter prospective, it is important to preserve the stability of the system under unbalanced voltage conditions, by eliminating high peak-to-peak DC voltage oscillations. In addition, the compensation of the imbalance in the three-phase voltages may be advantageous also for the host power system, since in many cases the DC link is connected to a part of the grid with industrial loads sensitive to voltage and power deviations. As a result, VSC-HVDC transmission systems should include control schemes for regulating negative-sequence currents. In this way, the negative-sequence current can be controlled, for avoiding exceeding the limits and causing triggering of the over-current protection equipment and thus the trip of the DC link. Therefore, the inner current control loop is divided into a positive- and a negative-sequence current controller and reference values, in d-axis and q-axis, should be provided for both positive- and negative-sequence currents. The reference values for the positive-sequence current are determined by the outer controllers, as described above. However, the reference currents for negative sequence cannot be generated in a similar way. One approach is to define zero reference values for the negative-sequence currents, meaning that the three-phase currents are forced to remain balanced, regardless of the imbalance of the grid voltage. With this current controller, the DC voltage presents oscillations, but lower than these in the case of the original controller. Therefore, it provides a perfect solution, when there is no room for negative-sequence current control, i.e. when the amount of the active power transferred through the VSC-HVDC system is very close to the rated value. Another improved approach is to produce non-negative, limited or unlimited, reference values for the negative-sequence currents. In this way, the current is unbalanced, but its imbalance counters the voltage imbalance, for exchanging non-oscillating active power. As it can be observed in Figure 3.4, the DC voltage presents the lowest oscillations when the controller with limited, non-negative reference values is used [5, 17].

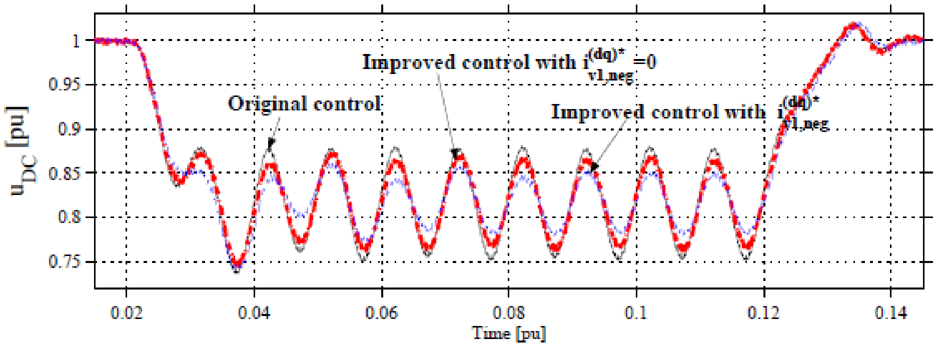


Figure 3.4: DC voltage during SLGF in VS-HVDC systems with and without negative-sequence current control [17]

[5] proposes two other control strategies for providing the reference values of the negative-sequence currents. The first is the negative-sequence voltage compensation scheme, which aims to produce the appropriate negative-sequence currents for eliminating the negative-sequence voltages. In that sense, the reference values of negative-sequence currents can be derived from the inner current controller, by setting the reference values of negative-sequence voltage (output of inner current controller) equal to zero. This open-loop control scheme provides simple control design, but restricts the level of voltage compensation, since the negative-sequence voltage is maintained constant at zero. For improving and broadening the performance of this controller, a combination of open-loop control with feed-back control (implemented by a PI-controller) is also proposed. In the case that the connection point is far away from the terminal, the feed-back control of the negative-sequence voltage will provide better accuracy. This control strategy provides a very good compensation of the negative-sequence component of the AC voltage at the point of connection. Nevertheless, this is achieved at the cost of higher negative-sequence current and higher DC voltage and active power oscillations [5].

The last control strategy is performed by controlling the negative-sequence reactive current, while the reference value of the negative-sequence active current is set to be zero. The control is implemented through a proportional gain applied to the negative-sequence voltage error $\tilde{e} = u_n^{ref} - u_n$. This gain depends on the capacity of the converter and the tolerance limits of the DC voltage oscillations. This control scheme is suitable for compensating large voltage imbalances during asymmetrical faults [5].

The aforementioned control schemes premise enough room for controlling appropriately the value of the negative-sequence current. In general, the room for negative-sequence current control can be increased under the following conditions [5]:

- The transmitted active power is lower than the rated, leaving room for negative-sequence current. For instance, this could occur when the wind farm produces lower power than the rated, due to lower available wind speed.
- The current rating of the converter is increased, giving space to negative-sequence current. This option might be not enough economic advantageous, especially for large wind farms, and therefore is open to further investigation.
- The injection of active power is reduced, to leave space for negative-sequence current.

In the case of small imbalance factor, the required negative-sequence current is also low, so that the current capability of the converter can be sufficient to produce it. On the contrary, if the imbalance factor is high, the reduction of the active power export might become necessary to create room for the negative-sequence current. However, during a fault event, reference values for negative-sequence currents are assigned the lowest priority, to leave room for active and reactive power. In the case of rated active power, the situation is similar as applying zero reference value to negative-sequence current [5].

3.1.2 Outer controllers

The outer controllers are assumed to be slower than the inner current controller, so that the AC current is considered to be equal to its reference value, when it is taken into account in the outer control loop [5, 17].

3.1.2.1 DC voltage controller

One of the main targets of the grid-side converter of a HVDC transmission system is to regulate the DC voltage at a pre-defined value. The main principle of the DC voltage controller is to keep the energy balance over the capacitor of the converter. In this way, active power control is achieved, meaning that the appropriate exchange of active power between converter and grid is ensured and the system balance is maintained [5].

In Figure 3.5 a simple diagram of the DC voltage outer controller feeding the inner current controller is illustrated. The "*" quantities imply reference values. The reference value of the DC voltage can be determined according to the grid frequency. The difference between the DC voltage reference value and the DC voltage measured in the DC capacitor defines an error input to the PI-controller, which provides the d-axis of the reference current. This reference value should be limited according to converter current limits described in 3.1.1.1 and compared to the actual active current, providing the difference as input to the PI-controller of the inner current control loop. Finally, the output of the PI-controller, as well as the d-axis component of the AC voltage at the point of connection and the total reactance (transformer, AC filter and phase reactor), determine the d-axis component of the AC output voltage at the grid-side converter terminal [1, 6].

3.1.2.2 AC voltage controller

As mentioned in 3.1.1, the reactive current reference value can be determined by an AC voltage controller. The control function can be distinguished depending on the operation conditions. Under normal operation, a combination of a feed-forward

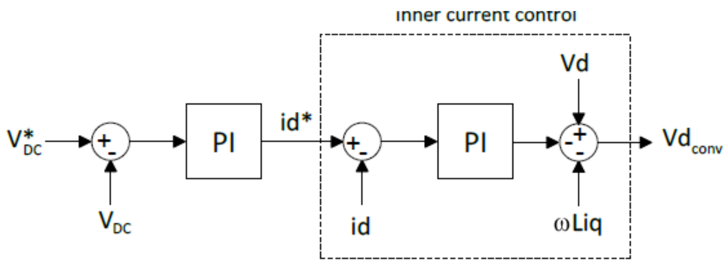


Figure 3.5: DC voltage and inner current controllers [6]

and a PI-controller is activated, enabling the voltage control mode. In the case of a fault, the PI-controller is by-passed and only the feed-forward section is activated, enabling the LVRT mode. The feed-forward part of the controller comprises only a proportional gain and therefore the stability of the control scheme can be ensured relatively easily for the entire range of possible voltage dips [5]. A simpler control system is proposed in [1, 6], in which the AC voltage controller is implemented only by a PI-controller. Hence, its diagram is similar to the DC voltage controller, with the difference that the outer controller provides the q-axis component of the reference current and the inner current controller provides the q-axis component of the AC voltage at the converter terminal [1].

3.1.2.3 Active power controller

Instead of using a DC voltage controller to determine the d-axis of the reference current, which is required by the inner current controller, an active power controller can be implemented. A simple method for active power control is an open-loop controller, i.e. a reference value. For a more accurate control of the active power, a feedback loop can be implemented through a PI-controller, which regulates the difference of the actual active power from its reference value, in order to determine the reference value of the active current [1, 6]. This implementation is shown in Figure 3.6.

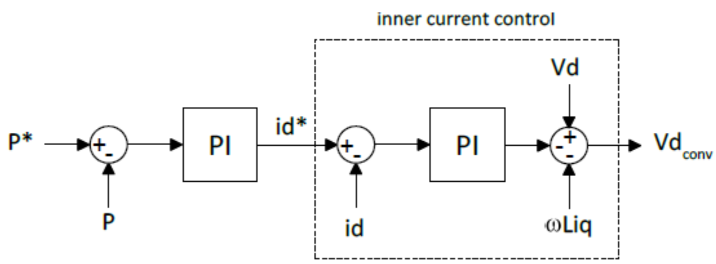


Figure 3.6: Active power and inner current controllers [6]

3.1.2.4 Reactive power controller

In a similar way as in the active power controller, a reactive power controller can be used to determine the q-axis of the reference value of the current. The reactive power can be regulated by its reference value or by a PI-controller, which is illustrated in Figure 3.7 [1, 6].

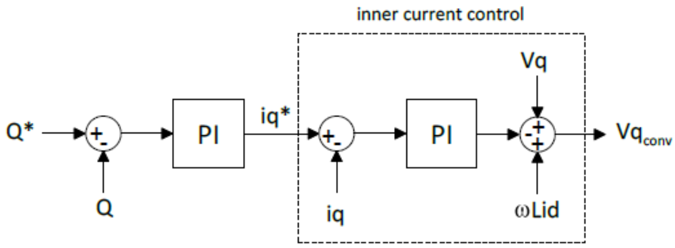


Figure 3.7: Reactive power and inner current controllers [6]

3.1.2.5 Frequency controller

Another control possibility in the offshore-side converter is achieved by a frequency controller. [17] describes four different types of frequency controllers, which are briefly described in the followings.

Frequency controller I controls the frequency at a fixed reference value, equal to the nominal frequency. This frequency value is provided directly to the AC voltage of the converter. It should be mentioned that this type of frequency controller can only be used in a system without other sources of frequency control [17].

Another fixed frequency controller is the frequency controller II, in which the new frequency is determined by the voltage dynamics in the DC link and a gain. Thus, this controller is of proportional type.

Frequency controller III is based on the relationship between active power and frequency in a power system. The principle is to introduce a PI-controller for transforming a possible deviation in offshore frequency to a change in the active power of the VSC. The changed active power of the converter is then introduced to the dynamic model of the offshore system for calculating the mismatch between generation and consumption in this system. Finally, using the transfer function of the system the new frequency is determined, as shown in Figure 3.8. The transfer function of the system is defined by the equivalent inertia constant H_{sys}, a damping coefficient D and an active damping term B_a for better rejection of disturbances. The inertia constant of the system includes the inertia constant of synchronous machines, wind turbines and gear boxes, as well as the inertia constant of induction machines and their mechanical loads [17]. Although it is difficult to obtain an accurate value for the inertia constant of the system, due to large changes depending on the trip of synchronous machines of the system, [17] notes that the estimation of this value is crucial, since it can significantly affect the system behaviour. An overestimation of the system's inertia constant is suggested, for keeping a greater stability margin.

Instead of using a PI-controller, frequency controller IV proposes the introduction of a droop function, associating the frequency deviation with a change in the active power of the converter, as depicted in Figure 3.9. This type of frequency controller can be applied in cases when the system is able to tolerate small frequency deviations in steady state conditions or when there are other sources of frequency control in the system [17].

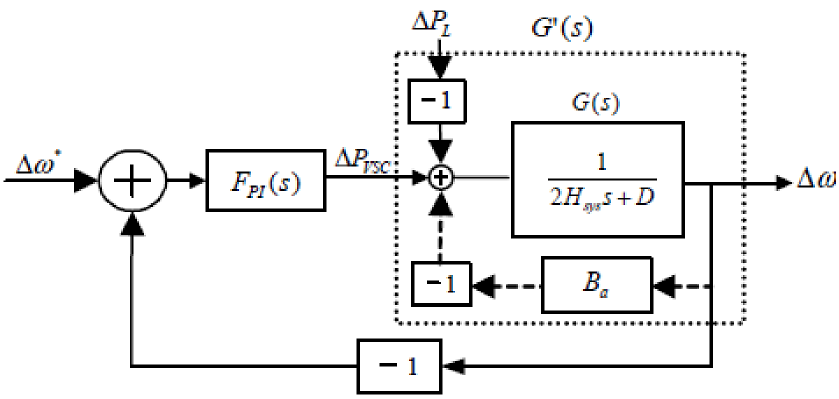


Figure 3.8: Frequency controller III [17]

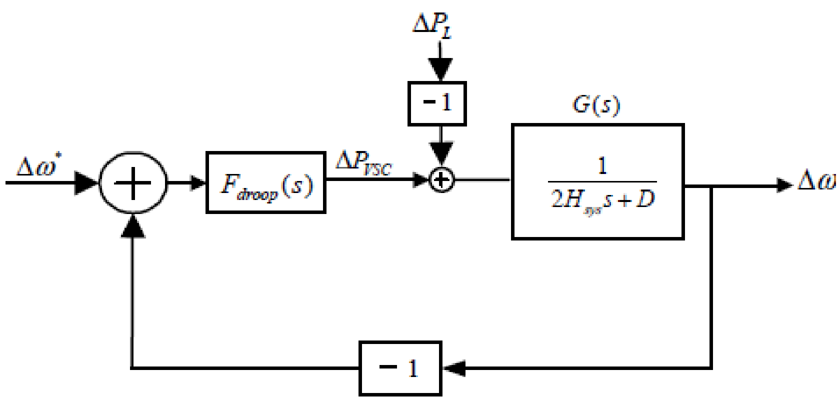


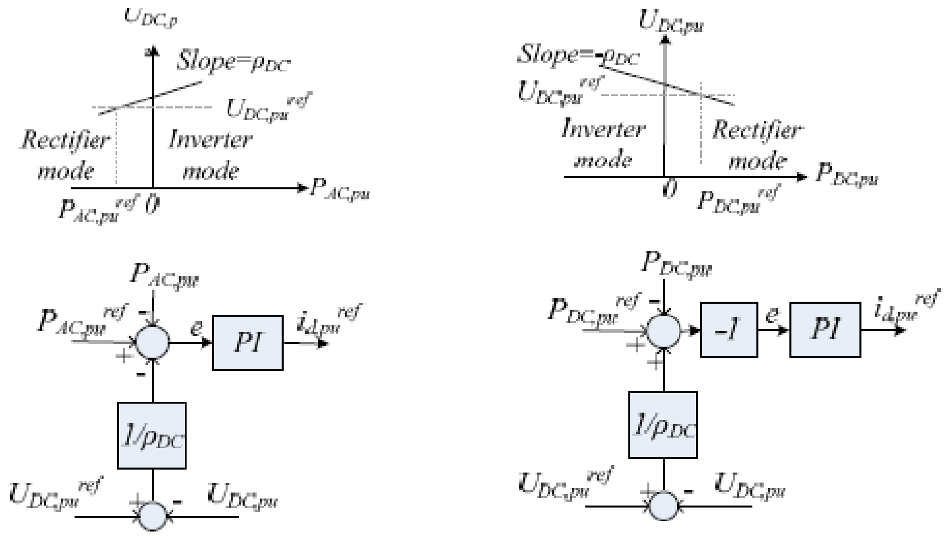
Figure 3.9: Frequency controller IV [17]

3.1.2.6 DC voltage droop controller for multi-terminal VSC-HVDC systems

An extension of control strategies regarding active power and DC voltage can be applied in the multi-terminal VSC-HVDC systems. In this case, one terminal regulates the DC voltage, whereas each of the other terminals regulates its own power flow. This control approach is known as master-slave control. However, the main disadvantage is the lack of reliability during large disturbances, such as failure or disconnection of master terminal. Under these conditions, the DC voltage regulation is lost and the DC grid experiences over-voltages or under-voltages. For overtaking this obstacle, a modified version of master-slave control has been suggested, known as voltage margin control. Nevertheless, models of multi-terminal systems with this control scheme become too complicated, due to the large number of reference values that are required [74].

For achieving higher reliability of the system, while keeping the control structure simple, another approach has been recently developed, the DC voltage droop control: all the terminals participate in DC voltage control and therefore share the duty of power balancing in the DC grid, rather than trying to keep their active power references. This implies that the system can deal with the outage of one or more converters, by distributing the resulting power imbalance among the remaining stations. The power share of each terminal is determined by its droop constant. This DC voltage droop constant is defined as the percentage of change in the DC voltage for 100 % change in the power of the converter. Equal droop factors result in equal power sharing among the converter terminals. In the case of unequal droop constants, the converter stations with the higher values of droop will participate more in the DC voltage control and therefore their power share will be smaller. The DC voltage droop controller is shown in Figure 3.10, with the corresponding droop curve. In Figure 3.10, two controller systems are provided, depending on the converter side at which the power is controlled. When the power control is desired at the DC side of the converter, a negative sign block should be introduced, due to the opposite sign conventions of the power measurements at the two converter sides [6, 74, 75].

The main idea of the DC voltage droop control is to use the DC voltage as a universal indicator of DC grid loading, as the frequency is used in AC systems. In AC systems, active power-frequency droop is used in the governor control loop, for avoiding conflicts in reference values of frequency. In a similar way, in the DC grids, the active power-DC voltage droop can be used to modify the reference values of the DC voltage, for avoiding conflicting DC voltage set values at the terminals [75]. For a more precise control scheme, the steady-state power deviations at the terminals should be taken into consideration during the calculation of the initial reference values (before their modification according to droop factor). One possible source of power deviations from the desired levels are the DC line voltage drops. In the majority of cases, the DC grid consists of significant line resistances and thus the DC bus voltage at different terminals will present differences due to voltage drops. Only in DC systems with very short DC links, the line resistances are small enough to be assumed negligible, so that the steady-state DC voltage (reference value) can be considered the same at all DC buses. Power flow deviations can also be produced due to power losses in DC links and converters. [74] proposes the use



(a) Power measured at AC side

(b) Power measured at DC side

Figure 3.10: DC voltage droop controller [74]

of DC load flow analysis and converter loss estimation, for determining reference values for the converter power and the DC voltage. These values can be computed offline by a central dispatcher and sent to each terminal of the DC grid. This approach could enable better control of power flow in the DC grid. However, more research is required on this field [74].

In a fixed droop scheme, the droop factor at each terminal is calculated according to the corresponding converter ratings. However, under particular operating conditions, not all the converters are equally loaded and therefore some of them might not be able to participate equitably in power sharing. Hence, it is desirable that the converters participate in power sharing according not only to their ratings, but also to their spare capacity (headroom), i.e. the difference between the rated capacity and present loading. For dealing with this issue, [75] suggests a modification of the DC voltage droop controller. In the new control scheme, the droop factor is not fixed, but a function of the available headroom of each converter. The proposed function gives higher droop factors for lower available headrooms. In this way, converters which operate very close to their operational limit (low available headroom) will not share the burden of an outage to the extent that converters with higher spare capacity will do. This approach with the variable droop factor would be also useful in the future, when the multi-terminal HVDC grids enter the power market. It will allow the owners of the converter stations to share the power mismatch appropriately, so that they could use spare capacity also as ancillary service [75].

3.1.3 Comparison of converter control schemes

The typical converter control strategies for the grid connection of an offshore wind farm are the following [1]:

- active and reactive power control in the converter at the wind farm side - DC voltage control and reactive power control in the converter at the grid side (Scheme 1)

- active power and AC voltage control in the converter at the wind farm side - DC voltage control and reactive power control in the converter at the grid side (Scheme 2)

[1] compares these two control schemes in the cases of a short-circuit grounded fault at the wind farm side or at the grid side, when DFIG or PMSG turbines are used. In all these four cases, the control Scheme 2 is found to be more suitable, causing oscillations of less strength in the profiles of active and reactive power and AC voltage at the non-fault side. Therefore, the AC voltage control, instead of reactive power control, at the wind farm side is preferable for the grid connection of offshore wind farms.

3.2 Capabilities of VSC-HVDC transmission systems

The aforementioned control systems of a VSC enable several capabilities of the VSC-HVDC transmission technology. The most advantageous of the provided attributes are described in this section.

3.2.1 Controllability

As it is mentioned in 3.1, due to the self-commutated properties of the IGBT valves, the converter can be controlled through PWM methods to create AC voltage with desired magnitude, phase angle and frequency. This means that control signals to the converter can change the AC output voltage and current to the network almost instantaneously. By varying the magnitude and phase of the grid-side AC voltage, active and reactive power exchange between the converter and the grid can be controlled. In this way, operation can take place in all four quadrants of active-reactive power plane, i.e. active power transfer in any direction can be combined with reactive power exchange in any direction (injection or absorption) [65, 76].

3.2.2 Active power control and frequency response capability

Converters can be controlled to transmit active power to the grid, equal to the produced power from the wind farms, disregarding losses, by maintaining constant DC voltage. In addition, the converter provides the capability to follow the power output fluctuations from wind power generation and therefore to even out, within a certain limit, short dips in power generation. This allows the support of frequency control in the grid [65, 76].

Instead of just exporting to the grid the active power produced by the wind farm, the wind plant converter can also adjust the frequency of the wind farm network and thereby send signals to turbines to modify their production. In this way, the capability of turbines for power modulation is enhanced, allowing the adjustment of their production according to the on-line load, as many grid codes require. It should be mentioned, though, that active power production can only be reduced, unless the turbines operate in advance with a reserve [76].

During temporary emergencies of very low frequency, the grid-side VSC can avoid regulating the DC voltage for power balance; instead, it can reduce the active power injection to the grid or even start absorbing active power from the network. This allows considerably faster power damping control and thus faster frequency response than an AC-connected wind farm can achieve, since turbines cannot change their production faster than 0.1 p.u./ms. In this case, the excess active power in the DC link, which is not transmitted to the grid, is dissipated in a DC chopper. Still, the active power production of the wind farm should be reduced, for reducing the duration of the DC chopper operation. However, the rate of change of power does not have to be high for following grid code requirements, since the latter can be fulfilled by the fast frequency response of the VSC [76].

The capability of power modulation can also be applied in cases of AC and DC parallel transmission lines. The power in the DC link can be controlled to reduce the power swing of parallel AC lines in an event of system disturbance. This means that the power order to VSC-HVDC system varies continuously to counteract power oscillations in the AC line, as shown in Figure 3.11. This feature eliminates the risk of system collapse and therefore it can contribute to system stabilisation [16].

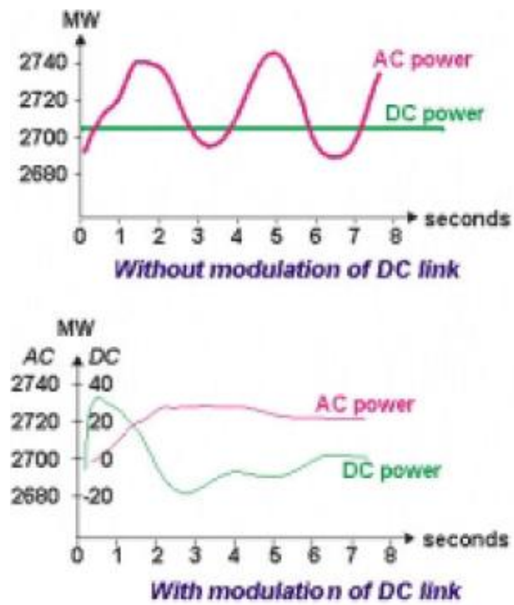


Figure 3.11: Stabilisation of AC transmission with parallel DC link [16]

3.2.3 Reactive power control and voltage support capability

The control of reactive power flow between the converter and the grid can be used for compensating the needs of the network in reactive power. This can be achieved within the ratings of the converter (current ratings of switching devices), but it also depends on the DC voltage ratings, the allowed tap-changer interval of the transformer and the AC voltage ratings. The ratings of the converter are based on maximum current and voltage and can be determined by a P-Q diagram, as explained in 3.1.1. This implies that reactive power capabilities of a converter are traded off for its active power capabilities [65, 76].

The reactive power control capability of the converter is used to regulate the AC voltage of the connected network. The converter adjusts its reactive current, so that the set voltage at the bus is retained. In addition, the fast switching capability of the converter and its intelligent control systems enable the transmission system to sustain any fault in the AC network. Even during low or no wind power production, when the converter is switched to stand-by mode for reducing no-load losses, it can be rapidly (within milliseconds) switched back to operation during a fault, in order to control its reactive power production and therefore contribute to voltage support. The contribution to AC voltage control can be applied at both grid and wind farm sides [65, 76, 77]. [78] analyses in details the voltage support that the VSC can provide, regarding the grid configuration of its connection with the AC system (connection of the VSC and the AC system in series, in parallel or VSC-HVDC connection between asynchronous systems).

[79] investigates the contribution of VSC-HVDC systems to the short-circuit current during a fault in the network. The influence of various factors, such as the control mode, the fault location and type, is analysed. The fault location is found to be irrelevant to the level of the short-circuit current, whereas the fault type slightly affects the value of the current, namely it is smaller for an one-phase fault than for a three-phase fault, under same load and operation condition. Regarding the control mode, it is concluded that, with AC voltage control mode, the short-circuit current contribution is increased, since reactive current generation is automatically increased, when the AC voltage decreases. Therefore, with this control mode, the VSC-HVDC system can improve the voltage stability, by minimising the dip of bus voltage during faults. In contrast, with reactive power control mode, there is the risk of voltage instability or even voltage collapse, if the AC system is weak and no protection action has been taken. This can be explained by taking into consideration that the current order limit is decreased with a decrease in voltage, meaning that the short-circuit current also decreases. Hence, its contribution during faults will be negligible [79].

3.2.4 Fast response to disturbances

Fast control of the converter's active and reactive power improves the dynamic performance of the system under disturbances. Indeed, the time range of converter's response to a voltage change is approximately 50 ms. With such a response speed, the VSC is able to control transients and flicker and keep the AC bus voltage constant. Transient phenomena are difficult to be mitigated by normal synchronous generators, since they regulate voltage too slow. In addition, asynchronous generators affect the voltage profile during AC faults, due to synchronised flicker contributions. These problematic situations can be dealt with by the fast voltage control scheme of the VSC-HVDC transmission system, enhancing the transient stability of the system.

Furthermore, through fast active and reactive power modulation, VSCs provide also effective damping for mitigation of electromechanical oscillations [19, 65, 77, 78, 80, 81]. For achieving this, the VSC-HVDC transmission system can operate in any of the following strategies [78]:

- Modulation of active power, while keeping AC voltage as constant as possible
- Modulation of active and reactive power

- Modulation of reactive power, while keeping active power constant

[81] presents specific research results regarding the improvement of subsynchronous torsional damping by VSC-HVDC systems, concluding that the choice of active power control mode, instead of DC voltage control, is more beneficial for the damping function. [78, 82] suggests the combination of active and reactive power control modes for even better damping characteristics, as illustrated in Figure 3.12.

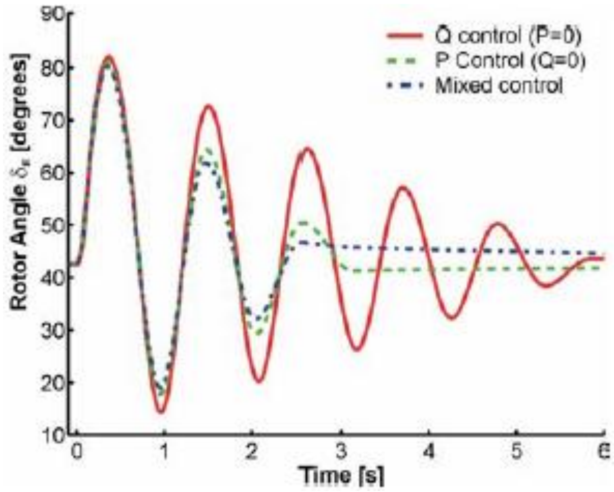


Figure 3.12: Rotor oscillations during AC fault for three control strategies in VSC-HVDC transmission system [82]

3.2.5 Decoupling AC systems

Since the converters of the VSC-HVDC transmission system decouple the grid side and wind farm side, AC disturbances at one network will not be transferred to the other side. Indeed, despite some transients in the DC voltage at both DC terminals, the AC voltage at the wind farm side is not influenced by any disturbance in the grid, and vice versa. In addition, voltage flicker is not also transferred from the one side to the other. Moreover, the transients caused during wind farm's energisation are isolated from the grid. Therefore, the power quality characteristics at both sides are improved [76].

3.2.6 Black start capability

In a traditional scheme, small-sized diesel generators should have been reserved and installed in the wind farm system, specifically for starting the wind farm and restoring the network after a blackout. On the contrary, in VSC-HVDC systems, active and reactive power can be controlled by the VSC. Thus, the small island network of the wind farm can have sufficient strength in voltage and frequency, independent of the system's size. This means that the VSC-HVDC transmission system can provide an AC source for the energisation of the wind farm.

In general, in the case of a blackout, the VSC can instantaneously switch over to its own internal voltage and frequency reference (PWM-based self-commutation) and therefore operate in frequency control mode as an idling "static" generator (without moving parts), able to supply and energise a "black" system, i.e. a passive islanded network without its own generation. VSC-HVDC systems present several advantages regarding black start and grid restoration after blackouts. First of all, they can control the voltage, easily and fast, avoiding harmful voltage dips associated with the energisation of large machines, as well as harmful over-voltages associated with the self-excitation phenomenon during energisation of long HVAC lines. Moreover, VSC-HVDC technology can control fast the frequency of the network, keeping it within acceptable values, without requiring the network plants to participate in frequency control. Indeed, during the black start and the restoration of the AC grid after a blackout, generation does not have to match consumption, since the VSCs of the transmission system are able to compensate for frequency and voltage imbalances, by injecting or absorbing active and reactive power. Furthermore, possible unsuccessful energisation of transformers can also be avoided: the large inrush current, due to the energisation of un-loaded transformers, will not cause tripping problems to the converters, since they are rated at higher power capacity than the transformers. Finally, the voltage in lines and transformers is ramped up smoothly, minimising the risk of high transient inrush current and high transient voltage and harmonics. Therefore, transient voltage and current stresses at equipment are avoided and the restoration process speeds up. Concluding, VSC-HVDC transmission systems are found to be an ideal stand-by facility for black start and restoration of the AC grid [10, 76, 82–85].

3.3 Benefits for wind turbines

The aforementioned capabilities imply several benefits in the design and operation of the wind turbines. These advantages are basically caused by the decoupling of the wind farm from the grid. The main of these benefits are the following [7, 76]:

- Wind farm is not responsible for the grid code compliance, since this is a duty of the VSC-HVDC transmission system. This allows the wind turbine developers to put more effort on cost reduction issues, on the standardisation of the wind turbine design, as well as on efficiency and reliability.
- Wind turbines with an electrical coupling between stator and grid will experience less mechanical stresses, since the turbine is isolated from disturbances in the main grid. Ride-through operation will occur less frequently and phase imbalances will be lower. As a result, the mechanical drive trains of the turbine will not be subjected to torque oscillations of 100 Hz. In addition, issues like harmonic resonance and transient over-voltages can be avoided.
- The proper connection to a weak system becomes duty of the VSC-HVDC transmission system. Hence, simpler breakers and protection design can be implemented in the wind farm.
- Since the VSC-HVDC transmission system presents reactive power control capabilities, the wind farm is not responsible of reactive power control in a wide range. Therefore, the reactive power setpoint can be adjusted to minimise losses within the wind farm. Furthermore, the grid-side VSC can deliver reactive power directly to the connected network, which enhances

power system stability. Moreover, the reactive current contribution does not depend on the number of turbines that are on-line. Thus, this capability offers higher predictability of the reactive power offered to the system.

- The control of the frequency at the wind farm side can be achieved by the corresponding VSC according to the wind speed. This will allow the increase of wind farm's efficiency.

3.4 Benefits for TSO

The higher integration of renewable energy sources brings new challenges for TSOs to maintain power quality and reliability of the power system. The main responsibility is to identify necessary grid reinforcements, for maintaining short-circuit currents to acceptable levels and avoiding grid "bottlenecks", achieving, thereby, voltage stability. Regarding these issues, VSC-HVDC transmission systems are a viable alternative for the following reasons [76]:

- First of all, the fast, continuous and wide-ranged reactive power control capability of the VSC-HVDC systems enhances the voltage stability. Furthermore, the control of reactive power at both sides of the DC link makes the HVDC transmission system to behave like a series-connected compensator, which could enable the connection to a weak AC network.
- The short-circuit current contribution can also be controlled to the desired value within the ratings of the converter. In addition, it becomes independent of the size of the wind farm.
- Uncontrolled active power or unsuitable grid connection points can cause grid "bottlenecks" and undesirable load-flow paths. Active power control in VSC-HVDC transmission systems can contribute to avoiding these problems. Moreover, due to underground cables and the compact design of the converter station, VSC-HVDC systems can be connected at any desirable connection point, e.g. to an area with large consumption.
- The most important for the TSO is that a wind farm which is grid-connected through a VSC-HVDC transmission system becomes comparable to a normal power plant. The grid-side converter can be connected directly to a control or power dispatch center. This direct access gives the opportunity to the TSO to dispatch active and reactive power and control emergency power and AC voltage in a straight-forward way. Hence, time delays for the communication between SCADA systems and the wind turbines are no longer a problem.

Chapter 4

LVRT methods at VSC-HVDC grid-connected wind farms

In association with the capabilities described in Chapter 3, control systems in VSC-HVDC technology enable wind farms to fulfil LVRT requirements, as they refer in grid codes. The control methods, that are used to achieve this, are presented in this chapter, i.e. the way in which the converter's control systems are triggered to provide voltage support, for meeting LVRT requirements.

4.1 LVRT requirements in E.ON. grid code

When a wind farm is connected to a grid, it is required that it fulfils various orders from the power system operators, as these are described in grid codes. These requirements are essential for the stability of the power system and therefore very strict. One of the major requirements is that the wind farm should stay connected to the grid during a fault, at least temporarily or for a specified period of time. According to E.ON. Netz grid code [3, 86], in the event of a fault, large power plants, with capacity 100 MW or higher, must stay connected and provide voltage support to the power system for a period of up to 150 ms after the fault occurrence, as illustrated in Figure 4.1. The power unit must remain connected as long as the operating point is above the limit line 2. A disconnection could be allowed if the operating point lies between the limit lines 1 and 2. Moreover, the power unit should provide voltage support during grid disturbances. A reactive current should be exchanged, when the voltage level lies outside the $\pm 10\,\%$ dead-band, at a rate of 2 p.u. per p.u. voltage change, as shown in Figure 4.2. Specifically for offshore wind farms, this dead-band is $\pm 5\,\%$ referring to the voltage at the offshore point of common connection [3, 87].

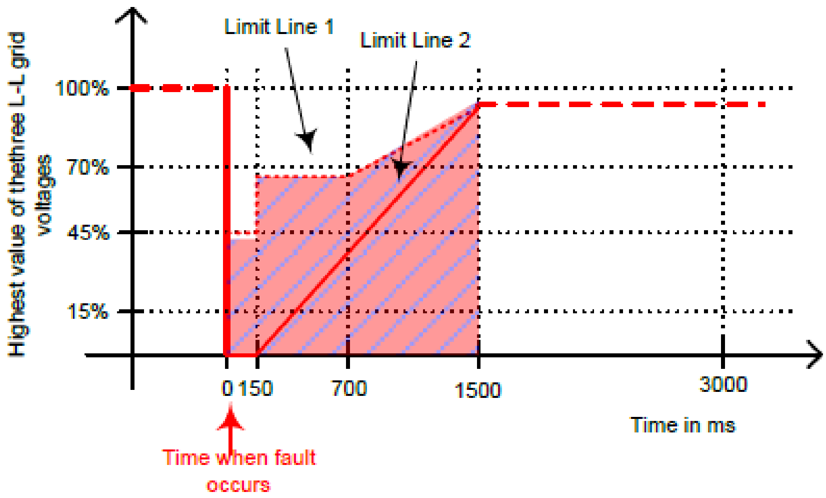


Figure 4.1: LVRT requirement of E.ON. Netz grid code [3]

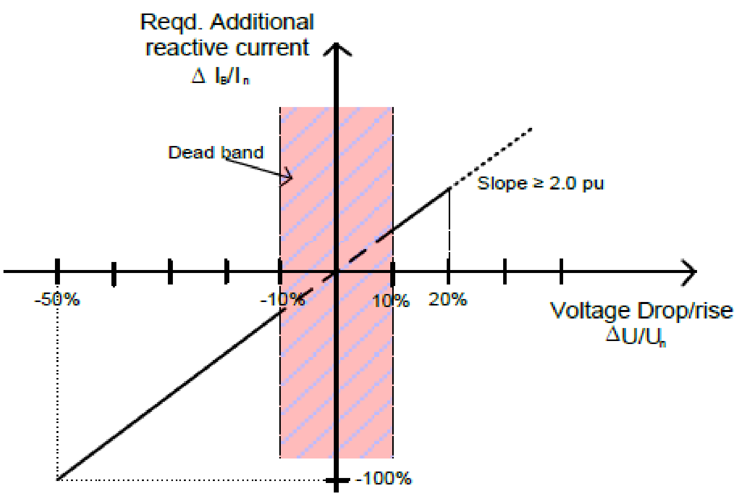


Figure 4.2: E.ON. Netz requirement for reactive current exchange during grid disturbances [3]

4.2 Dealing with faults in the AC grid

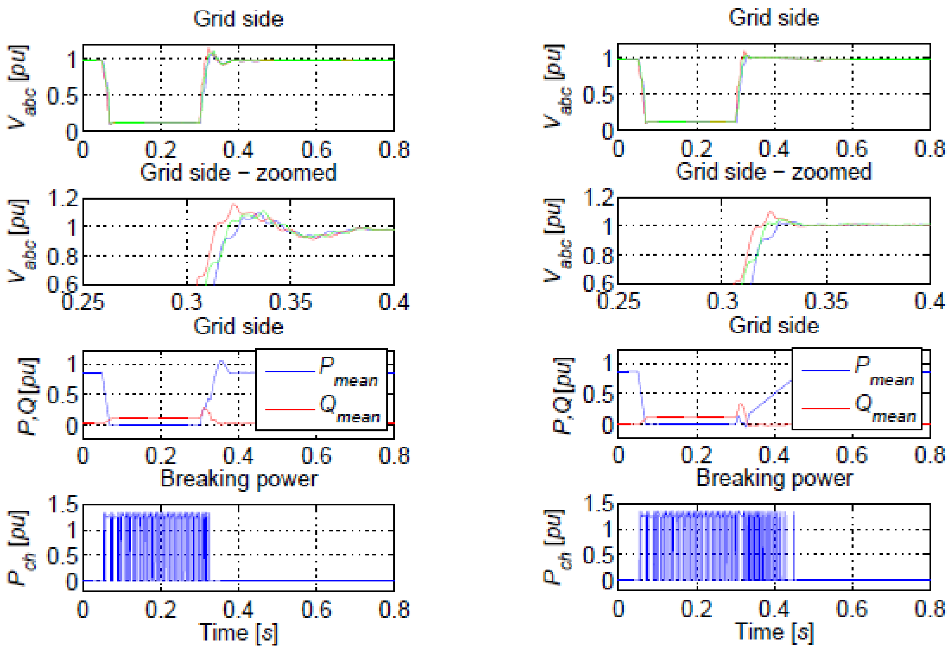
When a fault occurs in the host power system, the AC voltage at the point of common connection is reduced. Therefore, the grid-side converter detects a voltage dip, whose level depends on the nature of the fault and the electrical distance of the faulty point from the converter. The converter will then respond by injecting more active power into the grid, for balancing the DC voltage and thus the energy. This means that, if the voltage drop is large, the converter should inject a high active current. Nevertheless, the active power capability of the converter is limited, due to the converter current limits. Besides, the injection of reactive current takes the highest priority over the injection of active current, for compensating to the voltage dip. This further reduces the active power exchange capability. As the active power which is transferred from the grid-side converter to the host power system is reduced or limited, if the wind farm continues having the same power production as in the pre-fault condition, the excess power is accumulated in the capacitance of the HVDC transmission system and thereby the DC voltage starts rising. The rate of the rise of the DC voltage is determined by the active power produced by the wind farm, the power delivered to the AC system by the grid-side converter and the capacitors in the HVDC system. In order to prevent the DC voltage from reaching its upper limit, a reduction of the wind farm production is necessary. However, the wind farm is not able to respond directly (without any external influence) to the changes in the grid, due to the AC/AC decoupling between the wind farm network and the host power system. Subsequently, if no action is taken, the HVDC system will trip off and therefore LVRT requirements are not met. In order to deal with this issue, additional control structures and schemes are necessary [3, 5, 88].

4.3 Control structures and methods in VSC-HVDC transmission systems for LVRT requirements

4.3.1 DC chopper

A DC chopper is a power electronic switch device, usually an IGBT, which controls energy burning in a resistor. Typically, a full-power rated DC chopper is connected in the DC link close to the grid-side converter. The DC chopper is activated when the rise in the DC voltage, which occurs after a fault in the grid, exceeds a threshold value. At this moment the DC chopper starts burning the excess energy in the DC link, mitigating therefore the rise of the DC voltage. The frequency of operation during DC over-voltages should be determined by the size of the resistor and the amount of active power. For controlling the operation of the DC chopper, a hysteresis control or a PWM control method can be applied. When the fault is cleared, the grid-side converter is able to restore the active power back to the pre-fault value, which allows also the DC voltage recovery [3, 5, 88, 89].

It should be mentioned that the DC voltage does not recover instantaneously. A slight delay occurs, caused by the recovery time of the grid-side converter controller and mainly by the ramp rate or power gradient limit applied during the power recovery process. Typically, the minimum permissible power ramp rate is determined



(a) No active power ramp applied **(b)** Active power ramp applied

Figure 4.3: Active power recovery process [5]

by the grid code requirements of the host power system, for achieving short recovery period. On the other hand, special concerns are risen in the case of a weak grid, since a very fast power recovery can result in an overshoot in the recovering AC voltage and consequently in significant voltage back-swings. This can be observed in Figure 4.3, where the power recovery process is illustrated in a relatively weak grid, with and without power ramp rate or power gradient limits applied. Without ramp rate limits, the fast recovery causes voltage overshoot and significant back-swing, as shown in the zoomed parts of Figure 4.3. Generally, the voltage presents more swings as the strength of the grid decreases, which might trigger consecutive FRTs. However, a slower power recovery period implies the utilisation of the DC chopper for a longer time period, as depicted in Figure 4.3 [5].

The major advantage of this LVRT method is that the DC chopper can be implemented to any HVDC system connecting an offshore wind farm, irrespectively of the type of turbines used. Moreover, the power production of the wind farm is totally uninterrupted during any disturbance at the grid side. Hence, mechanical stresses in the turbines are also significantly reduced. Furthermore, in a case of unbalanced fault, during the time period when the DC chopper is activated, the control of negative-sequence currents is not necessary, for eliminating the DC voltage ripple, since the DC voltage oscillations are suppressed by the chopper. Therefore, more room is left for active and reactive power, for voltage support and fault handling. In addition, the usage of DC chopper can be advantageous in cases when a fast power regulation is required at the grid side. In a short period of time, the active power transferred to the grid can be reduced or even its direction can be reversed, by burning the power excess in the resistor of the DC chopper. In this way, a very fast power damping is achieved [5].

Nevertheless, the DC chopper solution presents also some major disadvantages: the additional cost of the chopper components and the amount of heat that should be removed during the fault. The heat removing capacity of the resistor is determined by its surface area. This means that the higher the power to be dissipated, the bigger the required surface area. Thus, in many cases, an enormous physical size of the resistor is required, which is practically impossible [5].

4.3.2 Use of fast data communication

If a DC chopper is not desired, lowering the power production of the wind farm is the other possible solution to achieve LVRT. Since the host power system and the wind farm network are AC/AC decoupled, information about conditions at the grid should be transferred to the wind farm side through data signals. Usually, the information is in the form of active power reference, directly delivered to the control system of each individual turbine. The new power reference should be written over the reference value generated locally by the controller of the turbine. Alternatively, the voltage magnitude at the grid side can be communicated to the converter at the wind farm side. In this way, the voltage conditions at the grid side are directly mirrored at the wind farm side. This means that the wind turbines must be able to detect and mitigate the voltage dip by themselves, which implies that turbines are required to have LVRT capabilities [3, 5, 89].

The speed of responding to the fault is determined by the time which the grid-side control system needs for measuring data and calculating the reference signal plus the time for the transmission of the signal over the DC cable plus the time required by the control system at the wind farm side for the execution of the command. As a result of this time delay, a peak transient DC voltage occurs. When the communication time delay increases, the DC over-voltage also increases. It is essential to ensure that this time period is less than the time the DC voltage needs to rise above the maximum allowable limit at rated active power transmission. The time duration of the process is related to the energy that can be stored in the DC link, and thus to the DC capacitance of the DC cable. By increasing the DC capacitance, more energy can be stored and therefore the reaction time of the system can be effectively decreased. However, even a large increase in DC capacitance gives only a very small decrease in reaction time. This implies that such a solution, although simple, is not reliable in long HVDC transmission systems, like these used for the grid connection of offshore wind farms. Besides, the increase of the DC capacitance is not practical in applications of high power and voltage [3, 5].

4.3.3 Frequency control at the wind farm network

During steady-state operation, the offshore control system regulates frequency and voltage to reference values, set by the control system of the wind farm, in order to optimise the wind power production. Nevertheless, during faults, the control system of the offshore converter can be assigned to regulate the frequency, which is determined as function of the DC voltage, while still keeping a constant nominal AC voltage magnitude. Thus, as DC voltage rises, the wind turbines detect a fast increase in frequency and ramp down their power reference, by control means similar to the droop factor of conventional plants. This implies that the time for achieving the decrease in power output depends on the time that PLL in turbines needs to detect the frequency rise and the time that the turbine controllers need for reducing the power production. The turbines are assumed to be equipped with fully-rated converters and therefore capable for fast power reduction. This method causes large and persistent DC over-voltages, since there is no means to evacuate power and therefore to decrease the DC voltage, unless the grid is restored. When the fault is cleared and the DC voltage is recovered, the frequency control is restored to its operation under normal conditions, as described above. Therefore, the production of turbines is again optimised. However, the recovery of the power production at the wind farm is found to be slow [3, 5, 89].

4.3.4 Other methods for reducing the active power output of the turbines in the wind farm

Instead of detecting the increase in the frequency of the wind farm network, determined as function of the increase in the DC voltage, another technique for forcing the turbines to decrease their production, is to apply to the turbine converter a droop controller, acting on the DC voltage. Below a certain threshold of the DC voltage, a droop gain is 1; above this upper limit, the droop factor decreases linearly to zero. The droop gain is then multiplied by the torque demand, determined by the maximum power extraction curve of the turbine, as shown in Figure 4.4. In this way, the generator torque is rapidly reduced, which results in an increase of the rotor speed; however, this is not a major concern, owing to the turbine capability for variable-speed operation. Instead of the generator torque, the gain of the de-loading droop controller can be multiplied to the output of the active power controller of the offshore HVDC converter. Thus, for a DC voltage value higher than the threshold, the output of the power controller is multiplied with a value lower than 1, leading to reducing the active power. A third technique to achieve the decrease in power output of the turbines is to send a signal of power reference, which is temporarily written over the system's power order, as described in 4.3.2. In this case, the frequency and voltage of the wind farm network remains at its nominal value [5, 10, 88].

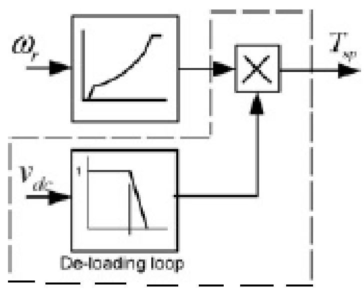


Figure 4.4: De-loading droop control applied in generator torque [88]

4.3.5 DC voltage control switch-over between converters at the two sides of the transmission system

When a fault occurs at the grid side of the system, the grid-side converter is no longer able to control the DC voltage. Due to power imbalance in the DC link, the DC voltage will increase. If this increase in the DC voltage is recorded at both sides of the transmission system, a switch-over of the DC voltage control can be applied between the two converters. The grid-side converter relinquishes the DC voltage control and its role is to limit the current. On the other hand, the converter at the wind farm side can be set to take over the DC voltage control when the DC voltage exceeds a pre-defined threshold. In this way, a smooth transition during the exchange of DC voltage control between the two converters is ensured. The reduction of the power production of the wind farm can be achieved as described in 4.3.3 and 4.3.4 [5, 10, 88].

When the fault is cleared, the AC voltage at the grid recovers rapidly; therefore, the reactive current export starts decreasing, allowing the increase of the active power injection from the onshore converter to the grid and consequently the decrease of the DC voltage. The DC voltage decrease is monitored by the converters, which switch their control modes back to the pre-fault situation, as soon as the DC voltage jumps back to the rated value. The power reference signal is removed when the control modes change back. In the case of frequency dependence on the DC voltage, after DC voltage recovery, the power recovery is achieved as described in 4.3.3 [5, 10, 88].

In order to undertake the DC voltage control, the offshore converter detects if the DC voltage at its side has exceeded a certain threshold value. However, the value of DC voltage also at the grid side should be taken into consideration, to ensure that it does not exceed any critical upper limit. If no data communication is used, the DC voltage at the grid side should be predicted by the offshore converter. During steady-state operation, this is an easy process, since the DC voltage at the grid side can be calculated by the known cable resistance and the DC current at the wind farm side. However, this procedure cannot be applied in the case of a fault, since the DC current at the wind farm side cannot be used to predict precisely the dynamics of the grid-side DC voltage. Hence, the predicted value of the grid-side DC voltage will be different from its actual value. For this reason, the upper threshold limit at the wind farm side should be chosen carefully. It should be borne in mind that, if it is set too small, it may trigger a false FRT mode during other events, causing an unnecessary switch-over of the DC voltage control between the two converters [5].

4.3.6 AC voltage control at the wind farm network

Instead of regulating the frequency according to DC voltage, the offshore converter can control the AC voltage regarding the DC voltage. The detection of the DC voltage, instead of the AC voltage at the grid-side converter, implies that no communication signals are needed. The DC voltage rise is monitored by the offshore converter, which in response ramps down fast the AC voltage. The controller for achieving this procedure is illustrated in Figure 4.5. A de-loading droop gain acts on the DC voltage value for determining a factor introduced into the PWM of the offshore converter, for adjusting properly the amplitude modulation index. Hence, when the DC voltage increases due to a fault in the AC system, the de-loading droop controller reduces the amplitude modulation index and therefore the AC voltage at the offshore converter terminal. In this way, a fault in the offshore network imitates the actual fault in the onshore network. This implies that an offshore converter with high current ratings is required. Short-circuit currents with high DC components can occur, caused by an abrupt voltage reduction, leading to high

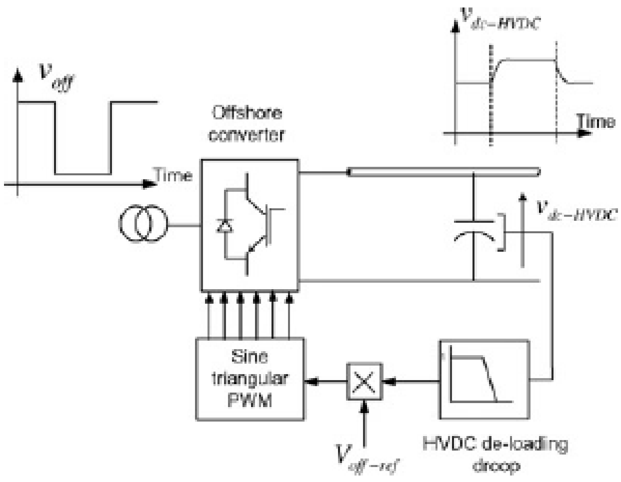


Figure 4.5: Control system for AC voltage reduction in offshore HVDC converter [88]

mechanical stresses for the drive train of the turbines and high electrical stresses for the IGBT valves of the converters (including the converter of the transmission system and the turbine converters). A solution to this issue could be the voltage reduction with lower gradient, but this approach limits the performance of the control strategy, since it affects the desired fast power reduction. An enhanced method is proposed by [89], in which machines are demagnetised in a fast and controlled way. Hence, fast voltage reduction is allowed, but high stresses to mechanical and electrical equipment are avoided [3, 5, 88, 89].

Given that full-scale converters are used in turbines, wind turbines are able to control their active and reactive power as a function of the voltage at the wind farm network. Therefore, by decreasing the AC voltage of the offshore converter, the power flow in the offshore network is impaired and the turbines cannot inject power into the wind farm grid, eliminating the need of a common DC chopper. The power excess in an individual turbine can be either stored as inertia in the mechanical system or dissipated into the turbine DC chopper resistor, depending on the type of LVRT control strategy of the turbine. Even though a DC chopper is utilised to dissipate the power excess of a single turbine, the amount of energy to be removed is significantly lower compared to the case of a common DC chopper at the DC link, as described in 4.3.1 [3, 5, 88, 89].

A switch-over of the DC voltage control between the converters at the two sides can also be applied in this method: when the exchange of active power between the grid-side converter and the host power system is restricted, the duty of balancing the energy in the DC link is assigned to the offshore converter. As the grid fault is cleared, the current limit mode of the grid-side converter is turned off, as explained in 4.3.5. This allows the energy stored in the capacitors to be dissipated or momentary inrush active current to be exported to the grid, resulting in fast DC voltage recovery. Simultaneously, the decrease in the DC voltage is also detected by the offshore converter, which allows the AC voltage to increase back to its nominal value. This also causes a momentary inrush active current from turbines to the DC link. Once the AC voltage at the wind farm network fully recovers, turbine controllers apply a ramp to the recovering active power, which is followed by active power damping control. Therefore, the smooth exchange of DC voltage control between the two converters is ensured. With this method, the DC over-voltages are limited. In addition, the power flow to the terminal decreases rapidly and the power recovery after the fault clearance is faster than in the frequency control method. This occurs due to the full-scale converters of the turbines, which respond fast to the change in the voltage, like current sources [3, 5, 88, 89].

4.3.7 Blocking of the converter

Another approach for limiting the current in the converter is the blocking of the converter valves. The blocking process takes place for a temporary, pre-defined period, which is equal for all types of faults. In this way, over-currents in the converter are avoided. In addition, the wind turbines are allowed to remain connected during and after the fault, which is a grid code requirement [90].

In many fault conditions this strategy achieves a satisfactory reduction of over-currents. But in cases of more severe faults it is found to be not effective enough. In these cases, over-currents are higher and therefore longer blocking periods are required. If the applied blocking period is not long enough, over-currents are not totally avoided, causing damages to cables and electronic devices of the converter, leading to turbine trip-off and power quality problems at the AC host power system. On the contrary, in the case of less severe faults, a longer blocking period than required can cause additional fluctuations at the connected power system [90].

For dealing with this issue, [90] proposes a variable blocking period, as function of the severity of each type of fault. Moreover, a special controller is suggested, which is activated after the de-blocking of the valves, for alleviating the oscillations at the power system caused by the blocking process. The suggested control strategy is found to provide optimal confrontation of faults, by totally avoiding over-currents and the tripping of the turbines. Thus, it helps the system to reach a steady state quickly [90].

4.4 Dealing with faults in the wind farm network

In the case of offshore wind farms, where submarine cables are used, faults in the wind farm area are quite rare. However, most of the faults in a stand-alone wind farm will be difficult to clear. Following a severe fault, the system will trip off, until maintenance takes place [5].

Nevertheless, in most cases, faults can be localised to an individual turbine or a single feeder connecting a group of turbines. In the case that there are more than one park transformers, each allocated to a certain number of feeders, the faulty circuit can be isolated from the wind farm and a normal operation can be resumed after a temporary disturbance. In this case, the offshore converter will either be blocked temporarily, and energy will not be exported from the wind farm, or it will go into current limit operation. In the latter control method, turbines will respond to the voltage dip and limit the active current injection. This is one of the advantages of the AC voltage control mode at the wind farm side.

However, for making the control system of the offshore converter simpler, the inner current controller is not usually implemented. Therefore, the offshore converter can be over-loaded by the fault current. To prevent this issue, an indirect current control is applied. In this technique, the fault current can be limited, by limiting the voltage at the wind farm network. When the current through the offshore converter exceeds a pre-defined upper threshold, the AC voltage limit is applied. The AC voltage at the converter terminal is reduced to a level such that the current through the converter is restricted within its maximum limit. There is always a minimum voltage, based on the equivalent system impedance, which ensures that the current does not exceed safe limits. When the fault is cleared by the corresponding circuit breaker, the fault current will stop and the nominal AC voltage will be re-established. This control approach during faults in the wind farm area implies that there is no need to implement two different detection and control systems for faults in the main grid or in the offshore network. In both cases of fault location, wind turbines respond to the change in the AC voltage of the wind farm network [5, 10].

One important aspect is that the host power system remains unaffected, since the DC voltage is maintained to its set value by the onshore converter. Only a power loss occurs, due to the limited or totally cut-off of the active power injection from the wind farm [5, 10].

In the case of a fault in the transmission cable, it is not possible usually to ride-through the disturbance and the shut-down of the transmission system is necessary. However, like disturbances in the wind farm area, such faults are very rare [5].

Chapter 5

Frequency regulation by VSC-HVDC grid-connected wind farms

Nowadays, with the increase in wind power integration into the power system, operators set regulations for the contribution of wind farms to frequency regulation. In this chapter this capability of wind farms, which are grid-connected through VSC-HVDC transmission systems, is analysed.

5.1 Frequency regulation by wind farms

Power plants should provide capabilities of frequency control, as specified by grid codes. An over-frequency implies an excess of power production compared to the load demand. Therefore, power plants should reduce their production. In the case of wind farms, this can be achieved by controlling the pitch angle and the tip speed ratio. On the other hand, dealing with under-frequency conditions requires the increase of power production. However, this is not easily applicable in the case of wind farms. If turbines operate already under maximum power point tracking regime, they are not able to ramp up further their production. As a solution, de-rated operation has been proposed, i.e. production of less than maximum available wind power. Hence, a margin for possible frequency support in under-frequency cases is provided. However, a de-rated operation implies undue loss of energy and revenue in normal frequency conditions [3].

5.2 Frequency regulation requirements in the Danish grid code

Figure 5.1 illustrates the requirement for frequency regulation derived from the Danish grid code [3, 91]. There are two frequency control curves: according to

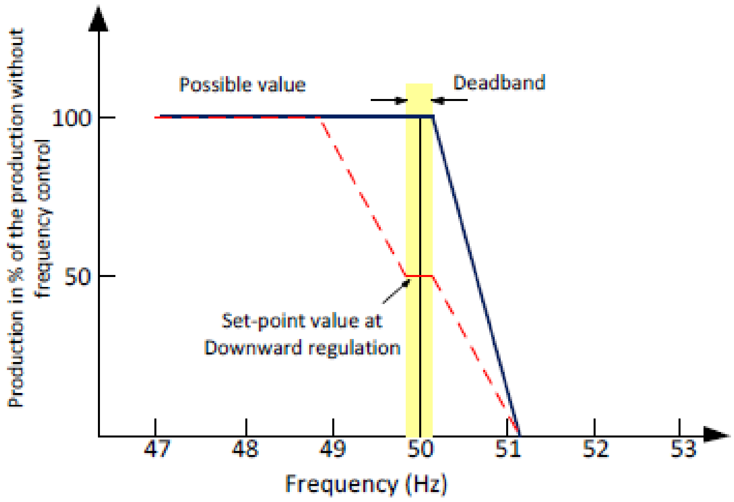


Figure 5.1: Frequency control curves with and without margin for upward regulation [3]

the first, only downward regulation is allowed, during over-frequency conditions; according to the second curve, both upward and downward frequency regulation is provided. In the case that a wind farm operates according to the first curve, it produces the maximum available wind power under normal frequency conditions and therefore it cannot contribute to upward regulation in under-frequency cases, but only to downward regulation when over-frequency occurs. On the contrary, if the wind farm operates according to the second frequency regulation curve, it produces a de-rated amount of power, as given by the set-point value, under normal conditions, and thus it can participate in both upward and downward frequency regulation [3].

5.3 Frequency regulation strategies in VSC-HVDC transmission systems

Since the frequency of the offshore network is decoupled from the onshore grid frequency, the contribution of the wind farm to frequency regulation can only be achieved if the onshore grid frequency is communicated to the offshore network. In this way, the wind farm can adjust its production according to the onshore grid frequency. There are three control schemes for accomplishing this task, which are described in the followings.

5.3.1 Use of DC voltage

The reference value of the onshore DC voltage changes in proportion to the onshore grid frequency, i.e. if the onshore grid frequency increases, the reference value of the onshore DC voltage also increases. Consequently, the DC voltage value at the offshore VSC-HVDC terminal increases too. The DC voltage at the offshore terminal is measured and adjusted to compensate the voltage drop across the DC link. Therefore the DC voltage at the onshore terminal is estimated and then compared to the nominal value. The error derived from the comparison is used to adjust the frequency reference of the offshore network. In this way, if there is an increase in the onshore grid frequency, the DC voltage rises and consequently the offshore network frequency is raised. The turbine converters detect this frequency increase and decrease their generation according to the droop characteristics of their frequency regulation curves [3].

5.3.2 Communication of the onshore grid frequency to the offshore HVDC converter

In this method, the onshore grid frequency is directly communicated to the offshore converter of the VSC-HVDC transmission system. Then, the offshore HVDC converter changes accordingly the frequency of the offshore network, which is monitored by the turbine converters for adjusting their production. In this way, the onshore grid frequency is directly replicated in the offshore network and, hence, change in the DC voltage is not needed [3].

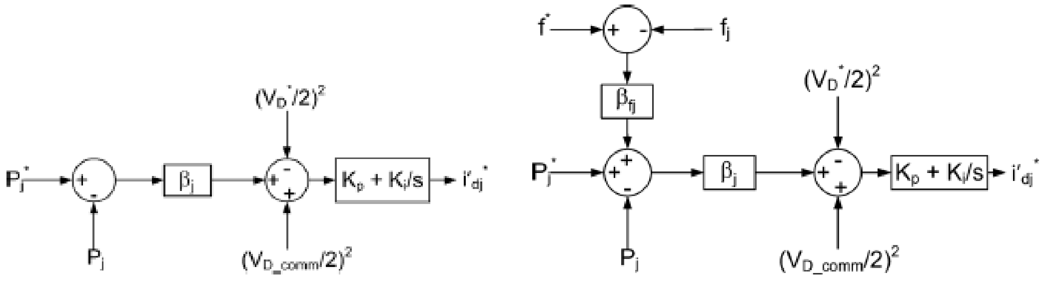
5.3.3 Communication of the onshore grid frequency to the turbine converters

In this technique, the onshore grid frequency is communicated directly to the turbine converters, for regulating accordingly their production. Therefore, no change in the DC voltage or the offshore network frequency are required. This is the most suitable method, as the only delay is caused by the communication process, without delays for calculations. It requires, of course, a reliable communication frame available, as the previous strategy [3].

5.4 Frequency regulation strategies in multi-terminal VSC-HVDC transmission systems

Appropriate control schemes should be developed in the multi-terminal VSC-HVDC transmission systems for reducing frequency deviations in the connected AC grids. These frequency deviations can be caused by disturbances in the AC power system, e.g. by a loss of infeed power, as well as in the DC grid, e.g. by a loss of a converter [92].

In a case of a converter loss, without appropriate control systems, the entire burden of the change in power flow would be undertaken by the slack converter. The sudden change in power import/export of the slack converter will lead to frequency deviations in the AC system which is connected to this converter. The droop control scheme which is described in 3.1.2.6 deals with this problem. The control system is given again in Figure 5.2a. The voltage reference is modified according to the droop coefficient β_j of the jth converter and is introduced to the PI-controller, which derives the d-axis current reference I_{dj} for the inner current controller of the corresponding converter. Normally, squared values of half reference and measured DC voltages are used. Since local voltage feedback leads to a non-unique power flow solution for the multi-terminal HVDC grid, a common voltage V_{Dcomm} at any converter station is communicated as feedback signal to the control system of



(a) Autonomous power sharing

(b) Power sharing and frequency support of adjacent AC system

Figure 5.2: DC voltage droop control in the jth converter of multi-terminal VSC-HVDC grid [92]

the converters. With this control structure, power sharing between the remaining converter stations is achieved and therefore none of them undertakes the entire burden. This reduces the change in power import/export from the converter stations to the connected AC systems; consequently, the frequency deviation is distributed amongst different AC networks connected to different converters [92].

However, this autonomous droop control still leads to inappropriate frequency deviations in different AC systems due to the following reasons [92]:

- In the case of a disturbance in an AC system, the frequency of that power system changes according to the equivalent governor droop function. This means that the autonomous power sharing control system does not participate in reducing the frequency deviation, since there is no change in the net power exchange with the concerned AC system.
- Following a converter loss, the power deviation is distributed appropriately amongst different converter stations. However, this power sharing might result in higher frequency deviations in some AC power systems, depending on the number of stations that are connected to each AC system and the governor droop coefficients of different AC grids.
- The autonomous power sharing takes place only between the converters in the affected pole, i.e. in the pole where the lost converter was connected. The converters in the other pole will keep on operating at their pre-contingency conditions and therefore do not participate in power sharing. This means that frequency deviation in some AC power systems could be large.
- With autonomous power sharing control, the frequency support cannot be appropriately shared among the AC grids interconnected through the multi-terminal VSC-HVDC transmission systems.

For dealing with these issues, the standard autonomous power sharing control scheme is modified with the introduction of a frequency droop control loop. Indeed, the power reference of the converter is adjusted by a supplementary frequency droop control, as illustrated in Figure 5.2b. The frequency f_j of the AC power system, which is connected to the jth converter, is used as a feedback signal, to produce a frequency error, which is then multiplied by the frequency droop coefficient β_{f_j}, to regulate the power reference. $P_j{}^*$ is considered positive for converter operation as inverter. In the case of frequency decrease (increase), the active power injected to the AC system should be increased (decreased), by changing the power reference accordingly. It should be noted that, with the modified control scheme, converters at both poles participate in frequency support. The improved control scheme in the multi-terminal VSC-HVDC transmission systems is found to be effective in reducing the frequency deviation in the connected AC systems following disturbances at both AC and DC grids [92].

Chapter 6

Requirements for the grid connection of wind farms through HVDC systems

In chapters 4-5 grid code requirements regarding LVRT and frequency regulation for the grid connection of power plants were provided. In this chapter more specific grid code requirements for the integration of offshore wind farms into the power system are given. These requirements, [93], are supplementary to the general grid code rules provided in [86]. In addition, they are enhanced by technical rules applied to power plants connected to the grid through HVDC transmission systems, as defined in [94]. The two grid codes should be combined in the case of offshore wind farms grid-connected through HVDC systems, so that technical restrictions of wind farms are taken into consideration but without limiting the capabilities provided by the HVDC connection system.

6.1 Frequency range

The nominal frequency for the offshore network is 50 Hz. In contrast to the frequency range as specified in [86], an extended range is applicable, as shown in Figure 6.1:

- For an uninterrupted continuous operation within a limited duration of 10 minutes: $47.5 - 51.5$ Hz.
- For operation within a limited duration up to 10 seconds: $46.5 - 53.5$ Hz.

The following emergency control actions should be implemented in the wind farm system:

- The offshore wind farm must be disconnected from the grid, when the frequency at the offshore network reaches a level of less than 46.5 Hz or greater than 53.5 Hz and after a time delay of 300 ms.

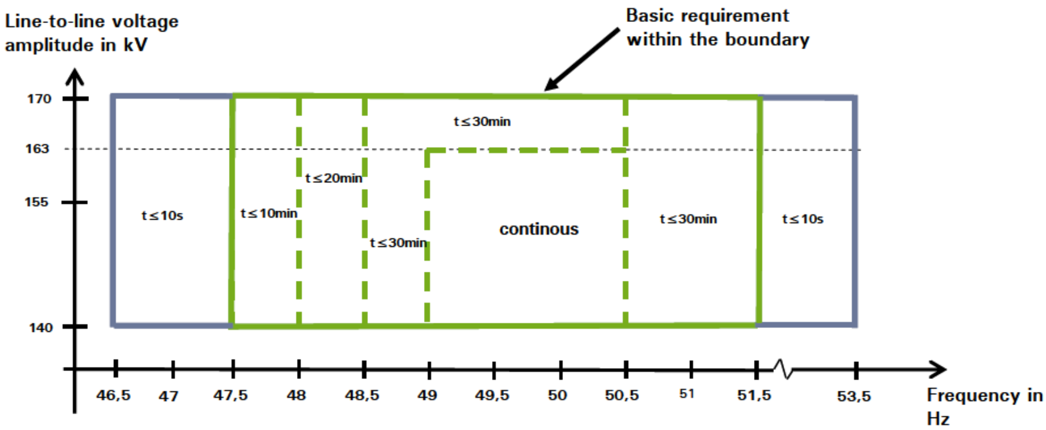


Figure 6.1: Duration of operation of an offshore wind farm in different frequency ranges [93]

- The offshore wind farm must be disconnected from the grid, when the frequency at the offshore network reaches a level of less than 47.5 Hz or greater than 51.5 Hz and after a time delay of 10 s.

The aforementioned system protection functions are associated with the basic requirements for the duration of the wind farm's operation, as illustrated in Figure 6.1. There are no requirements until the maximum time values of the respective frequency regions are reached. Nevertheless, the maximum possible active power is assumed to be available for delivery.

However, for power plants connected to the grid through HVDC links, the frequency ranges and the maximum duration of operation could be defined according to Table 6.1. Wider frequency ranges or longer time periods for operation can be agreed between the relevant TSO and the owner of the power plant, to allow the best use of the technical capabilities of DC-connected power plant for preserving or restoring the system security. Nevertheless, the DC-connected power plant should be able for automatic disconnection at specified frequencies, if required by the relevant TSO. In addition, the DC-connected power plant should be able to operate at rates of frequency change up to 2 Hz/s based on a measurement of frequency over a 500 ms window value.

Table 6.1: Time periods for operation of DC-connected power plant for different frequency ranges

Frequency range	Time period for operation
47.0 – 47.5 Hz	15 minutes
47.5 – 49.0 Hz	90 minutes
49.0 – 51.0 Hz	Unlimited
51.0 – 51.5 Hz	90 minutes
51.5 – 52.0 Hz	15 minutes

6.2 Active power controllability

With regard to the capability for controlling the transmitted active power, the HVDC system should be able to adjust the transmitted active power in both directions within its maximum capacity. The relevant TSO has the right to define a minimum active power transmission capability for both directions and a maximum delay within which the HVDC system should adjust the active power upon receipt of request from the TSO. In case of disturbance in one of the connected AC networks, the HVDC system should be able to modify the transmitted active power in accordance with pre-defined regulation sequences with an initial delay of maximum 1 s after receiving the triggering signal; time delays greater than this should be justified by the relevant TSO.

In addition, the relevant TSO has the right to require from the HVDC system fast active power reversal, from the maximum capacity in one direction to the maximum capacity in the other direction, within 2 s; responses to this request after longer time period than 2 s must be justified by the TSO.

In general, the TSO has the right to require that the control functions of the HVDC system are able to take automatic remedial actions for active power control and frequency regulation, when system's reserve capacity is exhausted or reduced under a critical level, defined by the TSO.

6.3 Frequency sensitive mode

The HVDC system should be able to operate in frequency sensitive mode, meaning that it should be capable for adjustment of the active power transmission, for responding to frequency deviations, as indicated in Figure 6.2, with frequency response dead-band of $0 - 500$ mHz and a minimum droop s_1 of 0.1 %. In a frequency step change, the HVDC system should start adjusting its active power output after an initial delay of 0.5 s and achieve within 30 s full activation up to the limit of active power range requested by the TSO.

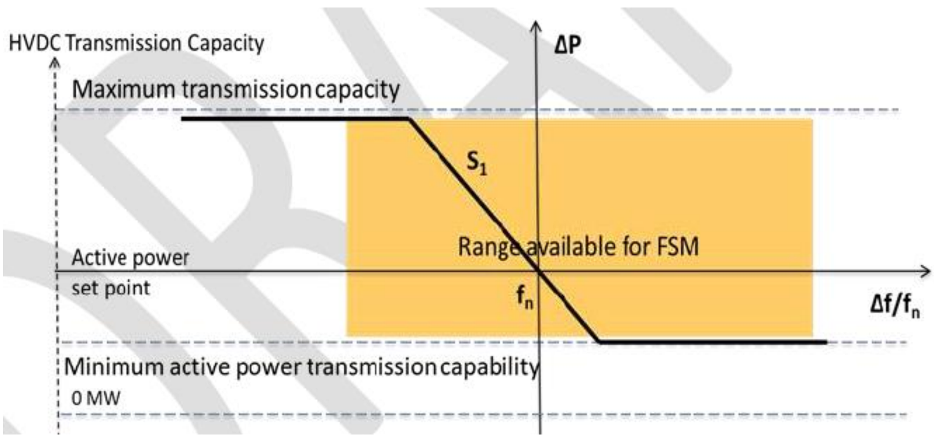


Figure 6.2: Active power frequency response capability of a HVDC connection system [94]

6.3.1 Active power reduction during over-frequency

In a frequency range of 47.5 − 50.2 Hz, the wind farm should be able to unrestrictedly feed active power into the grid. Under the frequency of 47.5 Hz, the active power supply may be shortened due to founded technical restrictions. Over the frequency of 50.2 Hz, a frequency dependent active power reduction is required. The reduction of active power should be 40 % of the currently available power per Hz, as shown in Figure 6.3. A maximum rate of the speed of power variation equal to 25 % of the currently available power is permitted.

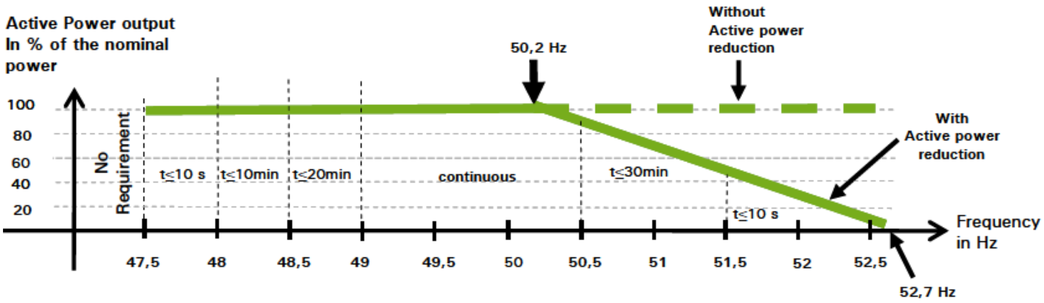


Figure 6.3: Basic requirement for the active power output of an offshore wind farm regarding the frequency [93]

Moreover, a HVDC system should have the capability for power reduction when the frequency is above a threshold. The frequency threshold for activation of power adjustment is laid between 50.2 − 50.5 Hz and is defined by the TSO. The droop settings for the power reduction are also defined by the TSO, but they should be at least 0.1 % regarding the maximum transmission capacity of the HVDC system.

6.3.2 Active power increase during under-frequency

Although grid codes for wind farms do not provide specific requirements for active power increase as response to under-frequency cases, the grid codes for power plants connected through DC links require the active power adjustment of the HVDC system in such occasions. The HVDC system should be able to increase its power transmission when the frequency falls under a threshold. The frequency threshold is determined by the TSO and is laid in the range of 49.5 − 49.8 Hz. The power increase should be achieved according to a droop factor of at least 0.1 %.

6.4 Voltage range

The nominal voltage at the grid connection point of an offshore wind farm (the end of the connection cable at the side of the wind farm) is usually specified at 155 kV, but other levels of nominal voltage are acceptable in single cases, after agreement with the TSO.

In the case of power plants connected to the grid through HVDC systems, the voltage ranges and the corresponding time durations of operation are given in Tables

6.2 and 6.3, for nominal voltage values below 300 kV and between $300 - 400$ kV, respectively. Wider voltage ranges or longer time periods for operation can be agreed between the relevant TSO and the owner of the power plant, to allow the best use of the technical capabilities of DC-connected power plant for preserving or restoring the system security. In addition, the TSO has the right to specify voltage values at the connection point, at which the HVDC system should be capable for automatic disconnection.

Table 6.2: Time periods for operation of DC-connected power plant for different voltage ranges (nominal voltage below 300 kV)

Synchronous area	Voltage range	Time period for operation
Continental Europe	0.85 − 1.118 p.u.	Unlimited
	1.118 − 1.15 p.u.	Decided by TSO (not less than 20 minutes)
Nordic	0.90 − 1.05 p.u.	Unlimited
	1.05 − 1.10 p.u.	60 minutes
Great Britain	0.90 − 1.10 p.u.	Unlimited
Ireland	0.90 − 1.118 p.u.	Unlimited
Baltic	0.85 − 1.12 p.u.	Unlimited
	1.12 − 1.15 p.u.	20 minutes

Table 6.3: Time periods for operation of DC-connected power plant for different voltage ranges (nominal voltage between 300−400 kV)

Synchronous area	Voltage range	Time period for operation
Continental Europe	0.85 − 1.05 p.u.	Unlimited
	1.05 − 1.0875 p.u.	Decided by TSO (not less than 60 minutes)
	1.0875 − 1.10 p.u.	60 minutes
Nordic	0.90 − 1.05 p.u.	Unlimited
	1.05 − 1.10 p.u.	60 minutes
Great Britain	0.90 − 1.05 p.u.	Unlimited
	1.05 − 1.10 p.u.	15 minutes
Ireland	0.90 − 1.05 p.u.	Unlimited
Baltic	0.88 − 1.10 p.u.	Unlimited
	1.10 − 1.15 p.u.	20 minutes

6.5 Reactive power exchange and voltage stability

In contrast to the voltage operating range given in [86], the allowed voltage operating levels at the grid connection point of an offshore wind farm, in dependency to the power factor (at maximum capacity), are given by Figure 6.4.

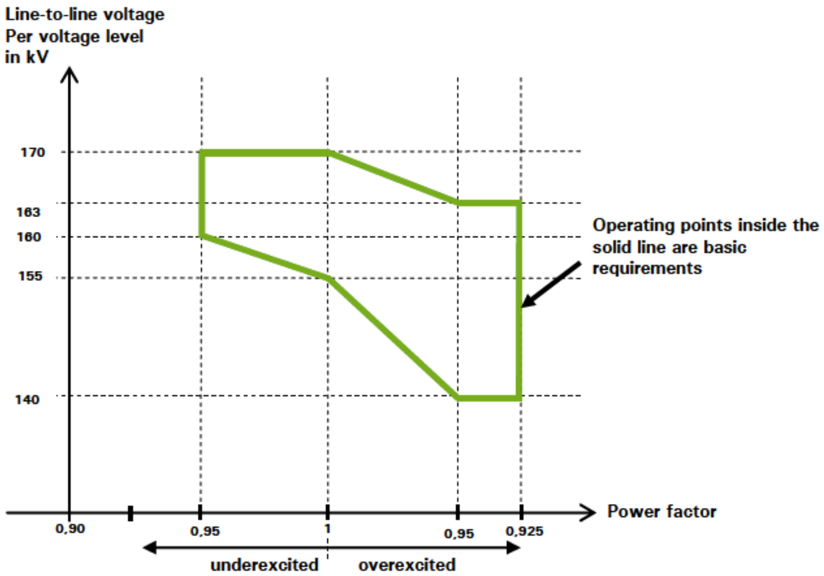


Figure 6.4: Voltage operating range of an offshore wind farm according to power factor (with unrestricted active power) [93]

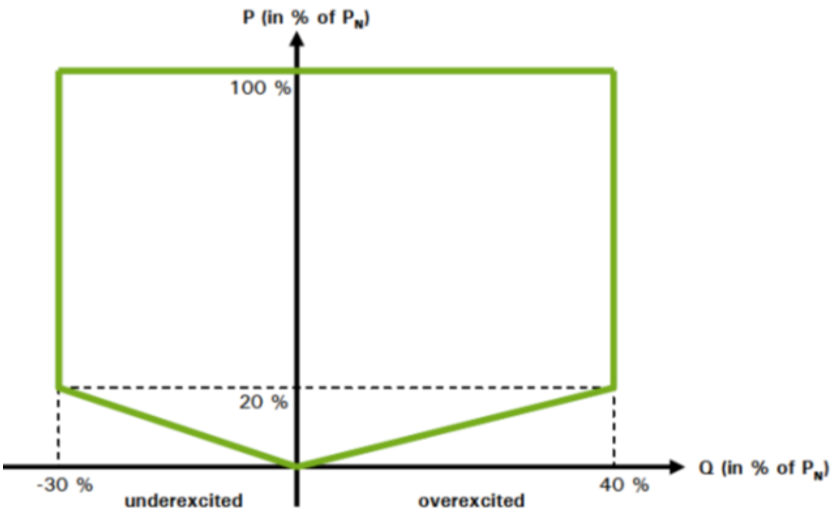


Figure 6.5: P/Q operation range of an offshore wind farm within the voltage range of $\pm 5\,\%\,U_N$ [93]

Figure 6.5 presents the minimum requirements regarding the reactive power supply capability of the offshore wind farm. Capability for reactive power supply beyond the range of these requirements is allowed, but is not defined or quantified in the present grid code requirements. The wind park is expected to set any operating point inside the boundary limits within maximum 30 s. In a frequency range of 47.5 − 51.5 Hz, the reactive power supply must be unrestrictedly possible. Beyond this frequency range, the reactive power supply may be shortened, due to founded technical restrictions at the wind farm. The P/Q operation range as illustrated in Figure 6.5 applies for the static operation of the respective offshore wind farm. The requirement is valid for voltage variation range of ± 5 % of the nominal voltage. The active power, reactive power and voltage values of the requirement refer to the under-voltage side of the transformer. Beyond the aforementioned voltage variation range, shortening of the required levels of the reactive power supply is allowed, in case of founded technical restrictions at the wind park. If the reactive power delivery through the wind farm can not be totally fulfilled for a power generation range above 90 % of the nominal power, the necessity of external complementary reactive power sources or an extension of the requirement according to Figure 6.5 is to be decided in agreement with the TSO for each project specifically.

In the case of DC-connected power plants, the relevant TSO should define the boundaries of a U-Q/P_{max} profile, within which the HVDC system should provide reactive power at its maximum capacity. This profile should not exceed the Q/P_{max} inner envelope, lying within the limits of the outer envelope, as illustrated in Figure 6.6. The dimensions of the profile, Q/P_{max} range and voltage range, are determined for various synchronous areas in Table 6.4. If the profile is not rectangular, the voltage range values represent the highest and lowest voltage points.

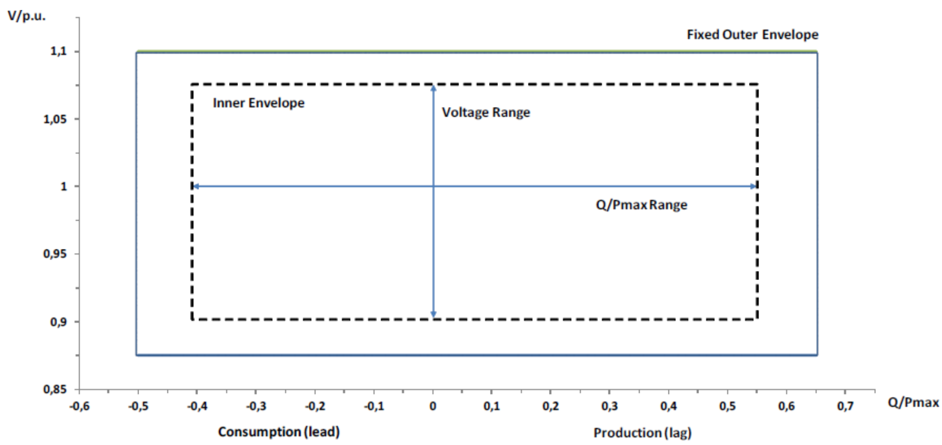


Figure 6.6: Boundaries of U-Q/P_{max} profile of a HVDC system at the connection point [94]

If the HVDC system operates at active power output below its maximum capacity, it should be able to operate in every possible operating point in the P-Q/P_{max} capability diagram defined by the TSO for various per unit voltages at the connection point. These voltage values should be within the inner envelope of the voltage range defined in Table 6.4 and within the fixed outer envelope of Figure 6.6.

Table 6.4: Parameters of U-Q/P_{max} profile of a HVDC system at the connection point

Synchronous area	Maximum range of Q/P_{max}	Maximum range of steady-state voltage in p.u.
Continental Europe	0.95	0.225
Nordic	0.95	0.150
Great Britain	0.95	0.100
Ireland	1.08	0.218
Baltic	1.0	0.220

6.6 Required reactive current during grid faults

The following characteristics of the wind farm's operation should be applied:

- The voltage support of the wind farm is to be activated when a voltage dip/rise of over 5 % of the RMS value of the generator voltage occurs, as illustrated in Figure 6.7. The voltage support must start within 20 ms after fault detection and the reactive current droop can be of $2 - 10$ p.u..
- Within the dead-band, the wind farm should operate with constant power factor, constant reactive power or constant voltage, as defined in [86], in accordance with the follow-on contract.

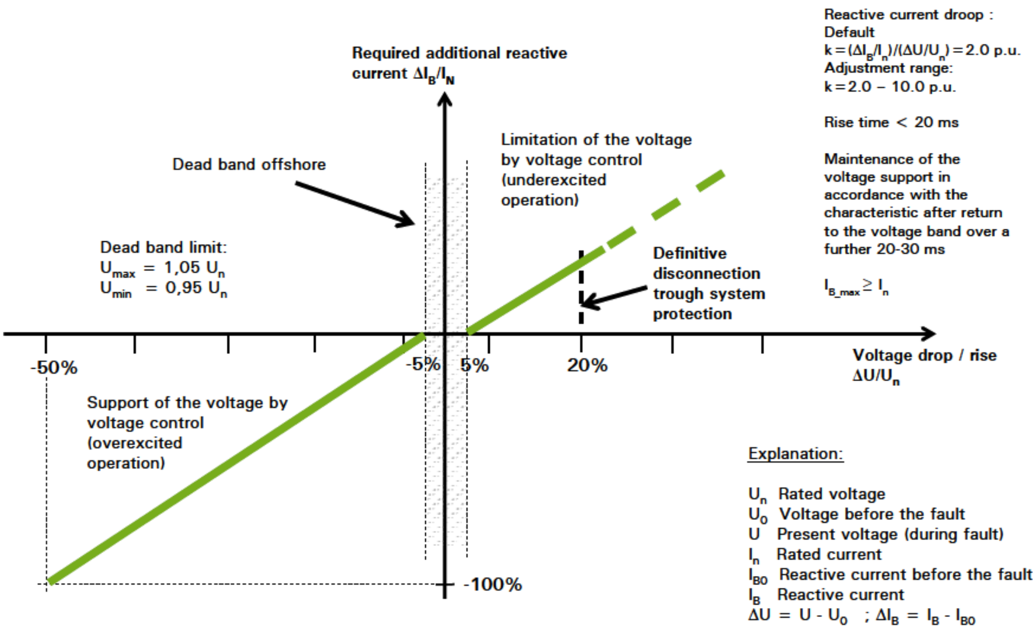


Figure 6.7: Voltage support through an offshore wind farm during grid faults [93]

Regarding HVDC connection systems, the converter station should be able to achieve 90 % of the required change in reactive power output within a time period lying in the range of $0.1 - 5\,\mathrm{s}$ and settle at a pre-defined value within a time period between $5 - 60\,\mathrm{s}$.

In the case of symmetrical faults, the TSO has the right to require at least 2/3 of the nominal reactive short-circuit current within a time period defined by the TSO. In case of asymmetrical faults, the TSO has the right to additionally require asymmetrical current injection.

Figure 6.8 provides a voltage profile during a symmetrical fault, according to which the HVDC substation should remain connected and in continuous operation. In this Figure, U_{ret} is the retained voltage at the connection point during the fault and t_{clear} is the duration of the fault. U_{rec} and t_{rec} specify the lower accepted point of voltage recovery following the fault clearance. U_{blc} is the blocking voltage at the connection point at time t_{blc}. The blocking mode of the HVDC system is allowed within the boundary defined by the red solid line, t_{clear} and t_{blc}; t_{blc} is the moment when the HVDC system is deblocking. The system is allowed to trip within the boundary defined by the red solid line, t_{blc} and t_{rec}. The value ranges for these parameters are given in Table 6.5.

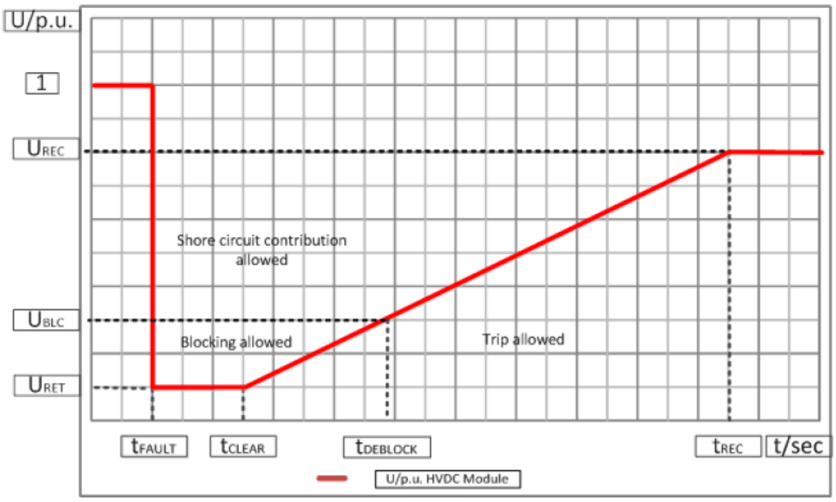


Figure 6.8: Fault-Ride-Through profile of a HVDC substation [94]

Table 6.5: Parameters for Fault-Ride-Through capability of a HVDC substation

Voltage parameters [p.u.]		Time parameters [seconds]	
U_{ret}	0-0.30	t_{clear}	0.14-0.25
U_{rec}	0.85	t_{rec}	1.5-10.0
U_{blc}	0-0.75	t_{blc}	0.1-0.5

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