Econnect

BWEA GB Grid Code Representation

Applying the GB Grid Code Offshore

Econnect Project No: 1484

Prepared For	BWEA Renewable Energy House 1 Aztec Row Berners Road London N1 0PW

	Name	Date	Signature
Prepared By	Charles Parker	30 March 2006	Charles Parker
Checked By	Simon Cowdroy	07 April 2006	Si Cowdroy
Approved By	Sara White	10 April 2006	S.h.B. White

Document History		
Issue No	**Description**	**Date**
01	Original Document Issue	10/04/2006

Copy No.	Copy Issued To	Company
1	Richard Ford	BWEA
2	Econnect (Client File)	Econnect Ltd
3	Econnect (Project File)	Econnect Ltd

Table of Contents

1. Introduction

The development of offshore electricity generation, in particular offshore wind farms, is crucial to meeting the government's renewable energy targets. The development of these wind farms, especially those which were awarded Crown Estate Agreements for Lease as Round 2 projects, will require the development of offshore electricity transmission infrastructure in order to meet the grid connection requirements of these wind farms. As the number and capacity of offshore wind farms increases the Grid Code is likely to need to evolve to ensure that offshore generating stations can integrate with the GB transmission system as a whole.

At present the GB Grid Code only relates to the onshore transmission system, though the *Energy Act 2004* provides powers for the Secretary of State for Trade and Industry to put in place new regulatory arrangements for offshore electricity transmission. The DTI and OFGEM recently undertook a joint public consultation on the subject of regulatory arrangements for offshore electricity transmission. The consultation period ended on 19th October 2005. The Secretary of State for Trade and Industry has responded to the consultation and has stated that the government intends to extend the current onshore electricity transmission arrangements offshore. This provides clarification as to the direction of the regulatory approach to offshore electricity transmission, but further work will be required to address the issues relating to the GB Grid Code, which is likely to require updating to take into account the special circumstances of offshore wind farms. It will be necessary to clearly define how the GB Grid Code will be applied to new offshore generators, electrical assets and their connections with the onshore transmission system. This report aims to highlight some of the issues likely to arise when considering how the current GB Grid Code could be applied to these offshore generators.

The current GB Grid Code[1] specifies a variety of criteria which must be complied with by any user (i.e. including generators and DC converters) already connected to, or seeking a connection with the GB transmission system, as well as generators and DC converter stations connected to or seeking connection with a user's system that is located in Great Britain.

In order to consider the various issues involved in this review, two possibilities have been considered regarding the application of the Grid Code in each scenario. These are:

The onshore Grid Code is to be applied at the onshore connection point
The onshore Grid Code is to be applied at the offshore connection point

Furthermore, two possibilities exist regarding the technology of the HV sub-sea cables. These could be constructed using either:

High Voltage Alternating Current (HVAC) transmission cables; or
High Voltage Direct Current (HVDC) transmission cables.

It has been assumed for the purposes of this report that, where the Grid Code is applied at the offshore connection point, the sub-sea cables (and any additional equipment such as DC converters) are to be owned by an Offshore Transmission Owner (OTO). It is also assumed that the offshore transmission assets, though owned by an OTO, will be operated by NGET in its role as GB System Operator.

[1] The Grid Code, Issue 3, Revision 14, dated 3rd March 2006 (National Grid Electricity Transmission plc)

2. Grid Code – technical requirements

The GB Grid Code currently specifies a detailed list of Connection Conditions applying to new generators and DC converters and these conditions are summarised in this section.

Wind turbines are included in the definition of a Power Park Module and this definition encompasses wind farms connected with a DC converter[2].

Power Park Module	A collection of Non-synchronous Generating Units (registered as a Power Park Module under the Planning Code) that are powered by an Intermittent Power Source, joined together by a System with a single electrical point of connection to the GB Transmission System (or User System if Embedded). The connection to the GB Transmission System (or User System if Embedded) may include a DC Converter.

Figure 1: Power Park Module Definition extract from GB Grid Code[3]

2.1. Reactive power capability

The Grid Code, in Connection Condition 6.3.2, specifies minimum reactive power capability requirements, which must be met at the Grid Entry Point (for generators connected directly to the transmission system) and also met at the User System Entry Point (in the case of embedded generators).

A reactive power capability chart is provided which indicates that the Grid Code requires, for non-synchronous generators, DC converters and Power Park modules (i.e. wind turbine generators), the ability to operate at 0.95 leading or 0.95 lagging power factor when supplying rated active power to the grid. The Grid Code also specifies that:

a) For operation at lagging power factor, the generators must be capable of supplying the maximum quantity of reactive power (as required to reach 0.95 lagging power factor at rated active power output), when supplying any quantity of active power between 20% and 100% of rated active power

b) For operation at leading power factors, the reactive power capability required is the same for active power outputs between 50% and 100% of the machine rating, but decreases linearly and proportionately to the level of active power supplied for active power outputs of between 50% and 20% of rated active power

c) A maximum tolerance on reactive power output applies, which is +/- 5% of rated active power. (Reactive power may in some cases come from switched capacitor banks, which do not allow a continuous variation in reactive power output)

d) For active power outputs below 20% of the rated output, the only requirement is to ensure that the actual reactive power produced or consumed does not exceed 5% of the rated active power (consistent with the allowed tolerance above)

These requirements are illustrated in Figure 2.

[2] The precise definition needs to be reviewed for offshore installations in case the definition of GB has an impact

[3] The Grid Code, Issue 3, Revision 14, dated 3rd March 2006 (National Grid Electricity Transmission plc)

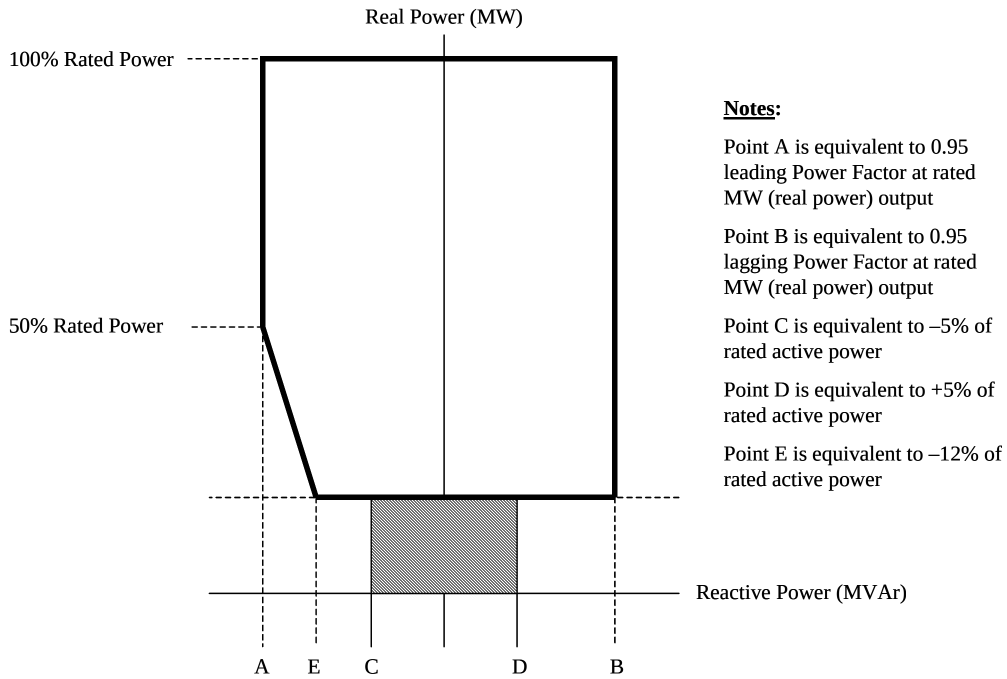


Figure 2 – Reactive Power Capability Requirements

2.2. Frequency capability and response

A minimum frequency response capability is required by the Grid Code in Connection Condition 6.3.6, and applies to synchronous generators, DC converters and Power Park Modules (referred to hereafter collectively as generators). The requirements are somewhat detailed, and are set out in full in the GB Grid Code (Appendix 3 of the Connection Conditions).

The ability to provide a response (in the form of a minimum change in active power output following a specified change in system frequency) is required in order that generators are able to contribute towards frequency control of the GB system. Whether a particular generator participates in frequency response is a commercial decision. The ability of a wind farm (offshore or onshore) to provide the required frequency response will depend on the characteristics of the wind turbines.

The Grid Code specifies that, under normal operating conditions, the frequency of the GB system will be controlled within the range 49.5 to 50.5Hz, and generators must be able to deliver the same active power irrespective of frequency when operating within this frequency range. However, the frequency of the GB system may in exceptional circumstances be outside that range. For frequencies between 47Hz and 49.5Hz, the Grid Code permits active power output from generators to drop linearly between 49.5 and 47Hz, but not by more than 5% at the lower end of this range (i.e. at 47Hz).

2.3. Fault ride-through capability

The ability to ride-through faults is required by Connection Condition 6.3.15 of the Grid Code for all generators. This condition specifies the minimum fault ride-through capability requirements for generators connected to the transmission system or embedded within user systems. The requirements are somewhat detailed, but essentially they require generators, DC converters and Power Park Modules to remain stable and connected to the transmission system for a total fault clearance time of up to 140ms following a fault on the grid at supergrid voltage (i.e. 275kV or

400kV in England and Wales). Generators and Power Park Modules are also required to restore active power output to at least 90% of the output before the fault, no later than 0.5 seconds after restoration of the voltage at the Grid Entry Point (or User System Entry Point) to 90% of nominal voltage (or other minimum voltage as may be agreed between the user and National Grid Electricity Transmission Ltd (NGETL)).

For faults (or other events) causing voltage dips on the supergrid for longer than 140ms, generators must initially remain connected and stable, and generate maximum reactive current within their transient rating limit. Following the first 140ms, and if recovery of the supergrid voltage occurs as quickly (or more quickly) than specified in the relevant diagram, then generators and Power Park Modules must remain connected to the system, and also begin to restore active power output in proportion to the voltage level to which the supergrid voltage at the Grid Entry Point (or User System Entry Point for embedded generators) recovers. D.C. converters must meet the active power recovery characteristics as specified in the relevant bilateral agreement. As with short-term faults, generators and Power Park Modules are required to restore active power output to at least 90% of pre-fault output within one second of restoration of the voltage to 90% of nominal[4]. However, relaxation of the requirements relating to restoration of active power may be made in the case of Power Park Modules if the variable power source available falls while the fault is being cleared and the system voltage recovers.

2.4. Dynamic voltage response

Generators are required, under Connection Condition 6.3.6 of the GB Grid Code, to contribute towards voltage control by providing continuous changes to the reactive power supplied to the GB transmission system (or to the user's system in which the generator is embedded). This is a dynamic voltage response capability, the minimum requirements of which may be specified in detailed, project specific Bilateral Agreements.

[4] Where a user system connected to the GB transmission system operates at a voltage below 132kV, the voltage on the GB transmission system at the connection site with that user system will normally remain within the limit +/- 6% of nominal

3. Offshore wind farm connections

A number of the proposed Round 2 offshore wind farms are likely to connect to the transmission system at various onshore Grid Supply Point substations. Econnect has previously examined the issue of offshore electricity transmission for offshore wind farms. Econnect's report[5] for the DTI concluded that the most economic designs of grid connection infrastructure for Round 2 offshore wind farms would utilise subsea cables operating at voltages at 132kV and higher voltages. These would be treated as transmission voltages. The purpose of this report is to review the application of the current GB Grid Code to these wind farms and the electrical connections required to effect grid connections for these projects. Some of the issues arising may be of concern to wind farm developers and some to other parties.

3.1. HVAC Connection

Figure 3 below illustrates the high voltage AC (HVAC) connection arrangements, which may typically be used to connect a large (Round 2) offshore wind farm to the GB transmission system.

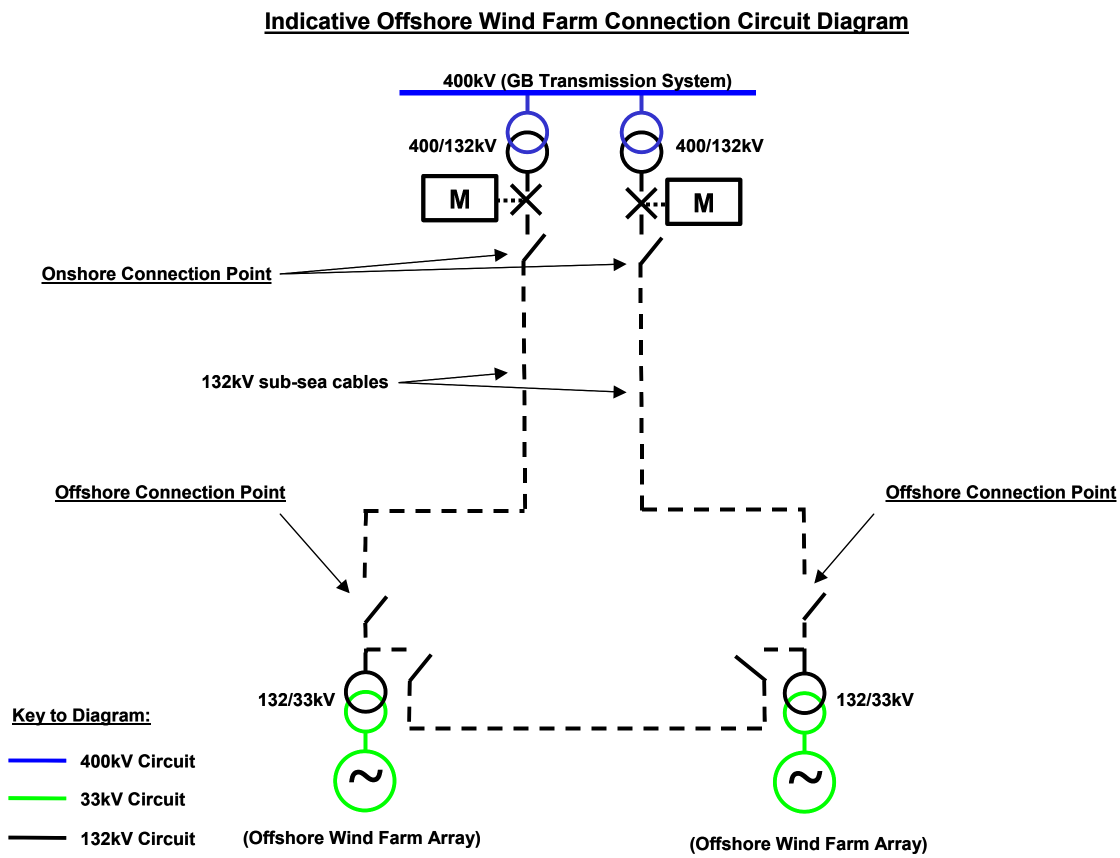


Figure 3: Offshore wind farm with HVAC connections

Figure 3 above illustrates a connection arrangement in which two sub-sea cables are used to connect an offshore wind farm with an onshore connection point with the transmission system (such as a 400 / 132kV Grid Supply Point). The connection arrangement illustrated above could be adopted for a single wind farm, with two sub-sea cables and two metering points at the HV

[5] Econnect "Study on the Development of the Offshore Grid for Connection of Round 2 offshore wind farms", January 2005 for DTI Renewables Advisory Board

side of 132 / 33kV transformers. The arrangements provide partial redundancy[6] for the output of the wind farm (these issues have been discussed in a previous report prepared by Econnect for the DTI[7]).

3.2. HVDC connections

Figure 4 below illustrates the high voltage DC (HVDC) connection arrangements, which may typically be used to connect a large (Round 2) offshore wind farm to the GB transmission system.

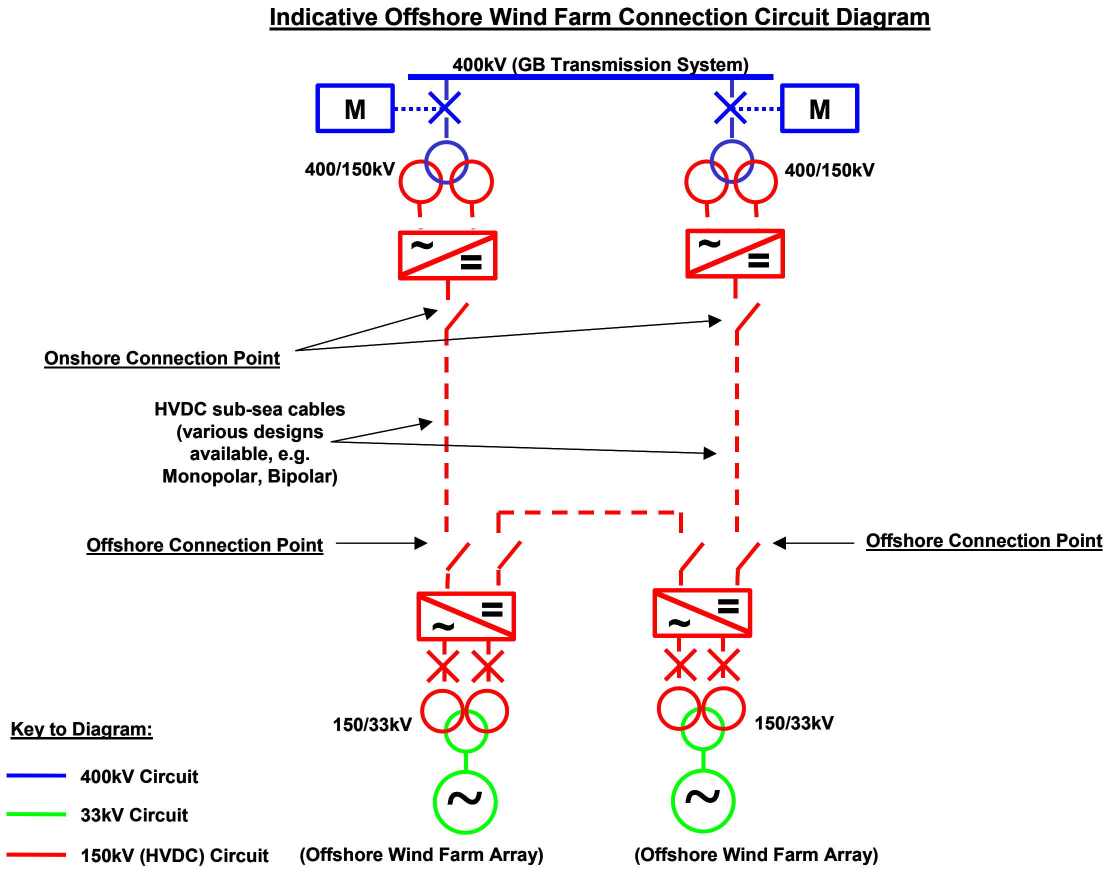


Figure 4: Offshore wind farm with HVDC connections

Figure 4 above illustrates a connection arrangement in which two sub-sea cables are used to connect an offshore wind farm with an onshore connection point with the transmission system. The use of HVDC technology may be considered for some large offshore wind farms. The main benefit of this technology would be in alleviating the issues associated with reactive power flows in cables. However, due to the cost of HVDC converter stations required to provide the HVAC to HVDC links, it is likely that they will be considered only for large wind farms located some distance from the shore (such as some of the Round 2 offshore wind farms currently proposed).

[6] "Partial redundancy" means that following any single failure the design allows all parts of the wind farm to generate, but not necessarily at full power

[7] Econnect: "Study on the Development of the Offshore Grid for Connection of Round 2 offshore wind farms", January 2005 for DTI Renewables Advisory Board

The connection arrangement illustrated in Figure 4 could be adopted for a single wind farm, with two sub-sea cables and two metering points at the HV side of 400 / 150kV transformers. The arrangements provide partial redundancy[8] for the output of the wind farm (these issues have been discussed in a previous report by prepared by Econnect for the DTI[9]).

HVDC links with converter stations may also be used to transmit power from offshore generating stations. The following diagram illustrates the concept of HVDC transmission, using converter stations at both the offshore connection point with the wind farm, and the onshore connection point. Converter technology divides into two basic groups: current source converter (CSC, also called conventional line-commutated, or thyristor technology) and voltage source converter (VSC, also called self-commutated or insulated gate bipolar transistor (IGBT) technology). CSCs are dependent on an external voltage source to drive the converter and feed its inherent reactive power demand (i.e. need a local operating grid system to connect into). VSCs are independent voltage sources that can supply or absorb active and/ or reactive power, and therefore require no independent power source, hence being ideal for offshore deployment. VSCs also allow instantaneous change of direction of power flow. Figure 5 shows the diagrammatic arrangement for a bipolar design, requiring two HVDC cables.

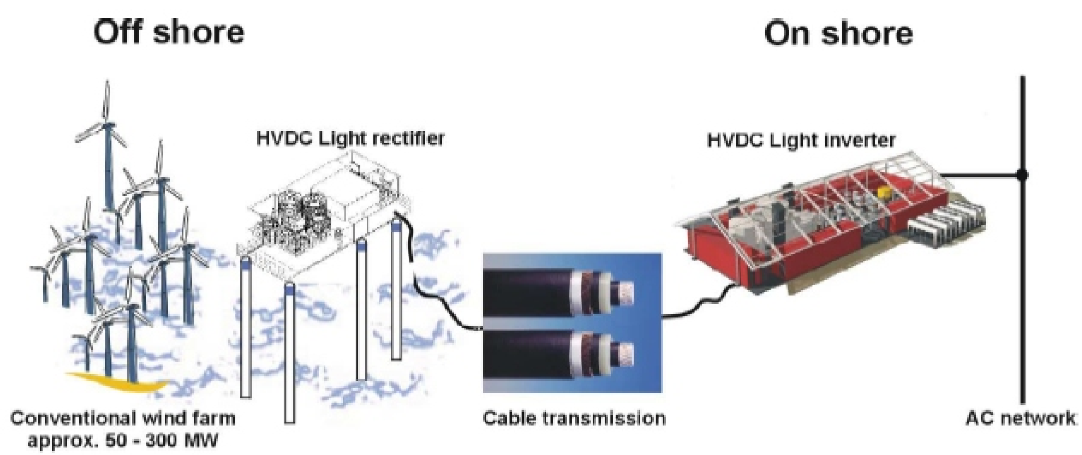


Figure 5: Overview of HVDC light (VSC) bipolar transmission for offshore wind farms (picture courtesy of ABB)

It has been assumed in this study that Voltage Source Converter technology would be used in the converter stations because it is known that Current Source Converters have poor operating characteristics when used between weaker networks (in this case, the weaker network would be the offshore wind farm electrical system). Voltage Source Converters also provide much more flexibility in reactive power control. Please see Appendix 2 for a comparison of the two technologies in terms of their operating characteristics.

8 "Partial redundancy" means that following any single failure the design allows all parts of the wind farm to generate, but not necessarily at full power

9 Econnect: "Study on the Development of the Offshore Grid for Connection of Round 2 offshore wind farms", January 2005 for DTI Renewables Advisory Board

3.3. Application of onshore Grid Code to onshore connection point (HVAC transmission)

In this scenario the offshore transmission assets are owned by the generator and the connection point for the Power Park Module is at an onshore location to an existing transmission (or distribution) network. In this case the metering will also be placed at the onshore connection point.

The existing, relatively small offshore wind farms are connected in this way. Effectively, the offshore wind farms and their subsea connections are treated in their entirety as Power Park Modules.

The following sections assess and comment on the application of the aforementioned connection conditions separately.

3.3.1. Reactive power capability

For the proposed Round 2 offshore wind farms, Econnect has previously concluded that it is likely that the subsea cables will operate at either 132kV or higher voltage such as 220kV or 245kV[10]. When considering offshore wind farms, the relatively long lengths of subsea cable generate significant charging currents due to the capacitive effect of the cable insulation. To meet the Grid Code requirements at low/zero power generation, (see Figure 2 sector C-D) the capacitive currents generated by the cable must be corrected, e.g. through the installation of switched reactors. Reactors could be located onshore, offshore or at both ends of the subsea cable.

In order to illustrate the issues associated with meeting the reactive power capability of the Grid Code, a generic model of an offshore wind farm has been constructed using power systems analysis software. The load flow results are illustrated in Figures 6 to 8. It has been assumed that the installed capacity of the offshore wind farm is 100MW, and that it would be connected to the onshore transmission system via a 132kV subsea cable of 50km in length. This cable would be connected to an onshore 400 / 132kV transformer, and, at the offshore point of connection, to a 132 / 33kV transformer.

It has been assumed that the generators would be capable of delivering maximum active power at power factors from 0.98 lagging (i.e. exporting VAr) to 0.96 leading (i.e. importing VAr). This is in line with the typical capabilities of modern wind turbines using Doubly Fed Induction Generators (DFIGs).

A large offshore wind farm would also be expected to contain a significant length of 33kV subsea array cabling to collect power from each of the wind turbines, and for modelling purposes it is assumed this would be 100km.

It is further assumed that the offshore wind farm would contain some reactive compensation equipment such that the wind farm would (at the offshore, 33kV point of connection) be able to provide a reactive capability compliant with the Grid Code, i.e. 0.95 leading to 0.95 lagging power factor for maximum active power export.

For modelling purposes, parameters for typical 132kV and 33kV subsea cables and typical 400 / 132kV and 132 / 33kV transformers have been used. Three scenarios have been examined for the purposes of identifying reactive compensation requirements for the onshore point of

[10] "Study on the Development of the Offshore Grid for Connection of Round 2 offshore wind farms", produced January 2005 for DTI Renewables Advisory Board

connection. These reflect the most onerous requirements of the GB Grid Code, and are as follows.

1) Maximum generation at 0.95 lagging power factor at the onshore connection point
2) Maximum generation at 0.95 leading power factor at the onshore connection point
3) Zero generation (but with subsea cables and transformers energised)

Scenario 1 (Figure 6) demonstrates that a relatively modest quantity of capacitance would be required (3.46MVAr) to be capable of operating at 0.95 lagging power factor at the offshore connection point. The 33kV cable network of the wind farm would exhibit a capacitive effect, and this has been included in the model as generating 9.02MVAr and consuming an active power of 0.2MW (which represents losses due to reactive power flows in the 33kV cables). The generator (represented as a lumped equivalent) is shown generating 100MW at 0.98 lagging power factor.

The 132kV subsea cable (connecting the wind farm with the onshore connection point) also exhibits a capacitive effect, and is shown to generate a significant quantity of reactive power, which is delivered at the onshore connection point. In order to meet the Grid Code requirement that the power delivered at onshore point of connection is at 0.95 lagging power factor, some additional reactive compensation equipment in the form of an inductance is shown to be necessary in this scenario, which amounts to approximately 25MVAr.

Scenario 1 power flow diagram

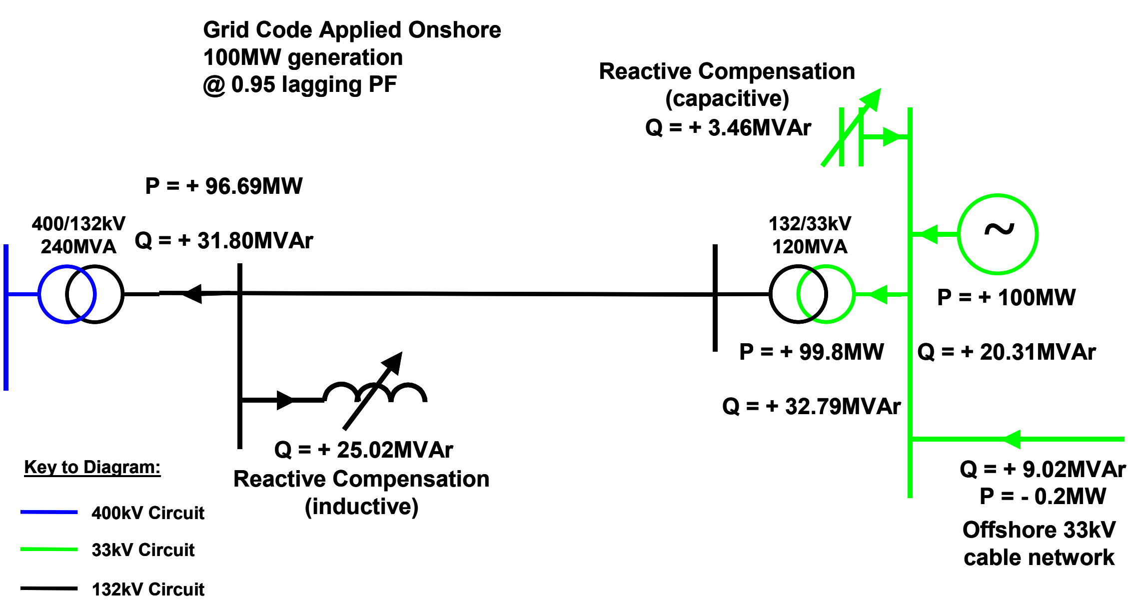


Figure 6: Power flows for generation at 0.95 lagging power factor, HVAC transmission, Grid Code applied at onshore connection point

Scenario 2 power flow diagram

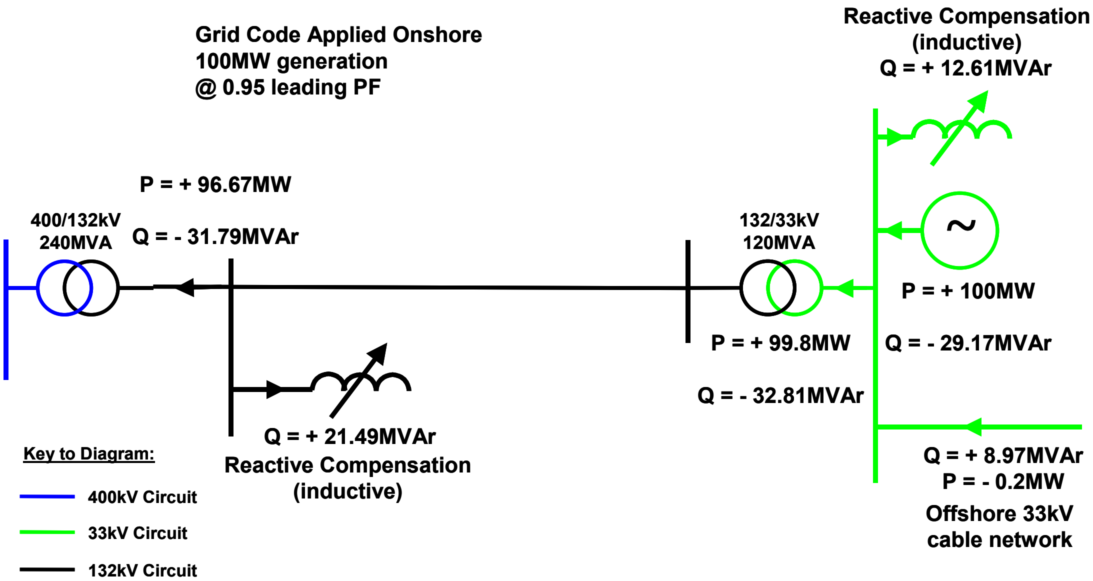


Figure 7: Power flows for generation at 0.95 leading power factor, HVAC transmission, Grid Code applied at onshore connection point

Scenario 2 (Figure 7) demonstrates that an inductance would be required (12.61MVAr) to be capable of exporting the power at 0.95 leading power factor from the offshore connection point. The 33kV cable network is generating 8.97MVAr and consuming an active power of 0.2MW (due to losses). The generator (represented as a lumped equivalent) is shown generating 100MW at 0.96 leading power factor. In order to meet the Grid Code requirement that the power delivered at onshore point of connection is at 0.95 leading power factor, some additional reactive compensation equipment in the form of an inductance is shown to be necessary in this scenario, which amounts to 21.49MVAr.

Scenario 3 power flow diagram

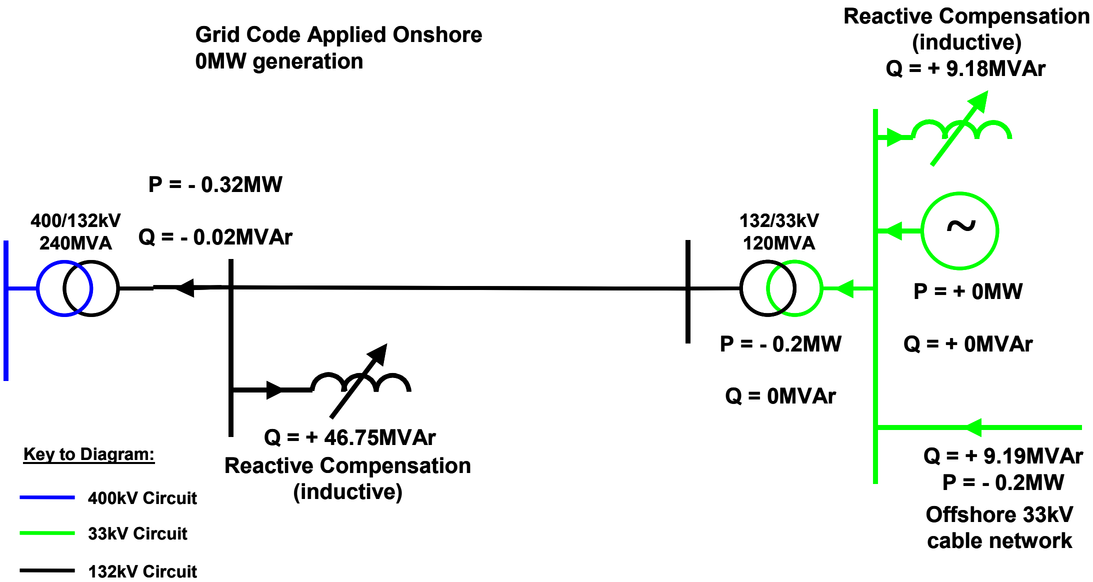


Figure 8: Power flows for zero generation, HVAC transmission, Grid Code applied at onshore connection point

Scenario 3 (Figure 8) demonstrates that an inductance would be required (9.18MVAr) to be capable of achieving an overall reactive power export of zero from the offshore connection point. The 33kV cable network is generating 9.19MVAr and consuming an active power of 0.2MW (due to losses). In order to ensure that the reactive power delivered at the onshore point of connection is zero (or close to zero), some additional reactive compensation equipment in the form of an inductance is shown to be necessary in this scenario, which amounts to 46.75MVAr.

The most onerous scenario is therefore the zero generation scenario, because the generators would not be able to absorb reactive power, and it would not be permissible to export reactive power to the onshore transmission system. As shown earlier, there is a tolerance on the levels of reactive power permitted when generation is operating at below 20% of it's rated active power, but this is intended to allow a degree of freedom due, for example, to reactive power compensation being available only in discrete steps, (i.e. not continuously variable). It is assumed that it would be prudent to target achieving a zero reactive power flow when the generation is not operating – i.e. in this case during periods of low wind speeds. Hence, there is an onerous requirement for reactive compensation when the wind farm is not generating.

3.3.2. Frequency response

There are no specific issues with providing frequency response in this offshore configuration.

When designing and specifying the control system the developer should take account of the losses in the transformers and the subsea cables. For example, if the wind farm is operating at reduced power and is called on to increase power (to respond to a frequency dip), the system losses will rise proportionally more than the power generated at the turbines. The same effect will be present in onshore wind farms but to a lesser extent as the collection system is generally smaller and therefore has lower losses.

3.3.3. Dynamic voltage response

There is no significant difference in the dynamic voltage response compared to an onshore wind farm.

3.3.4. Voltage control

With an onshore application of the Grid Code, the generator would be responsible for operating the wind farm and subsea cable in combination so as to achieve a voltage target set by the transmission operator at the onshore connection point. If this voltage target is set by the onshore transmission operator, it may result in non optimal operation of the subsea cable. The generator will choose to operate the cable at as high a voltage as possible in order to minimise losses. Some target voltages may not in fact be achievable due to power transfer limits for the cable.

Accordingly, under this approach there would need to be negotiation between the generator and the transmission operator on the appropriate range of target voltages at the onshore connection point, and the permitted variation in voltage with wind power output.

3.3.5. Fault ride-through

The ability of the offshore wind farm to “ride-through” faults is not expected to be any more onerous than that for an onshore wind farm as the relevant faults are only applicable to 275/400kV onshore networks. Indeed the severity of the fault seen by the offshore wind farm is likely to be mitigated due to the impedance of the sub sea cable.

3.4. Application of onshore Grid Code to offshore connection point (HVAC transmission)

In this scenario, the GB System Operator (i.e. NGETL) would apply the conditions of the Grid Code at the offshore connection point. An independent offshore transmission owner (OTO) would assume responsibility for the operation of the subsea cable(s) connecting the onshore GB transmission system with the offshore wind farm(s). The metering point would be offshore.

3.4.1. Reactive power capability

In order to demonstrate the issues associated with meeting the reactive power capability of the Grid Code, a generic model of an offshore wind farm has been constructed using power systems analysis software, similar to that used in Section 3.3.1. The same assumptions have been made in every respect, except that now the Grid Code requirements for reactive capability must only be met at the offshore point of connection. The load flow results are illustrated in Figures 9 to 11.

Three scenarios have been examined for the purposes of identifying reactive compensation requirements for the offshore point of connection. These reflect the most onerous requirements of the GB Grid Code, and are as follows.

1) Maximum generation at 0.95 lagging power factor at the offshore connection point
2) Maximum generation at 0.95 leading power factor at the offshore connection point
3) Zero generation (but with subsea cables and transformers energised)

Scenario 1 (Figure 9) demonstrates that a relatively modest quantity of capacitance would be required (3.42MVAr) to be capable of operating at 0.95 lagging power factor at the offshore connection point. The 33kV cable network of the wind farm would exhibit a capacitive effect, and this has been included in the model. The 33kV cable network is generating 9.09MVAr and consuming an active power of 0.2MW (which represents losses due to reactive power flows in the 33kV cables). The generation is shown generating 100MW at 0.98 lagging power factor.

The 132kV subsea cable (connecting the wind farm with the onshore connection point) also exhibits a capacitive effect, and is shown to generate a significant quantity of reactive power, which is delivered at the onshore connection point. However, no reactive compensation equipment would be required at the onshore point of connection, as in this scenario it would not be necessary for the OTO to meet the Grid Code requirements for generation connection at that location.

Scenario 1 power flow diagram

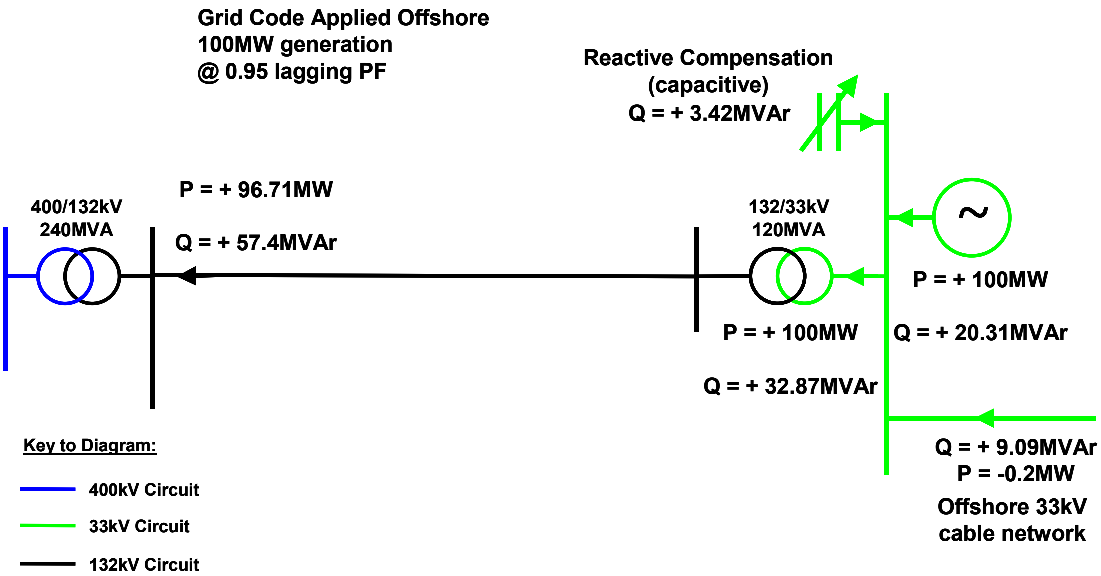


Figure 9: Power flows for generation at 0.95 lagging power factor, HVAC transmission, Grid Code applied at offshore connection point

Scenario 2 power flow diagram

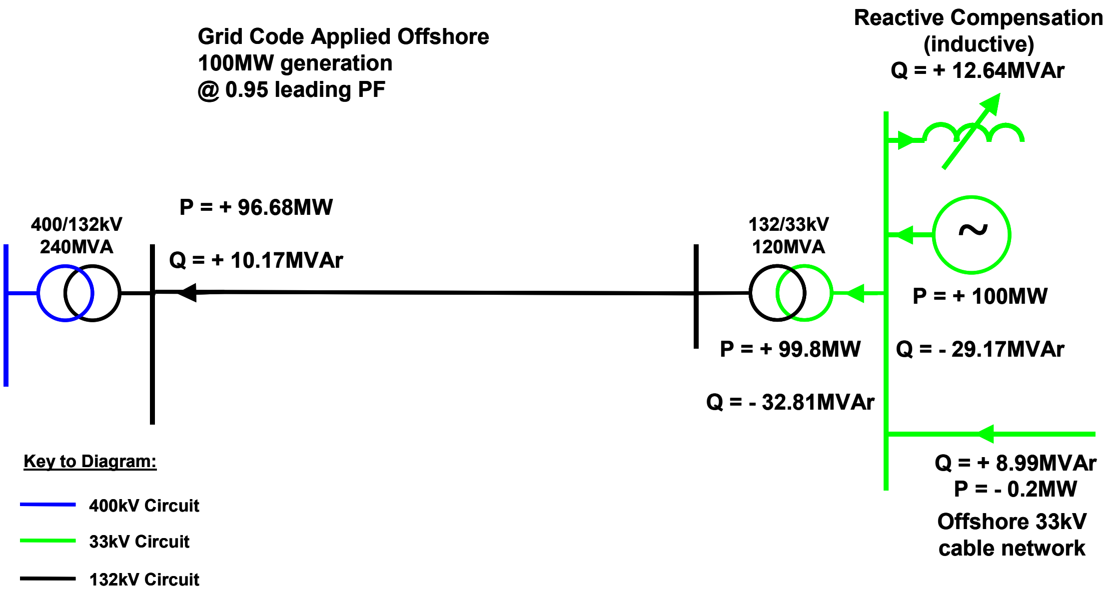


Figure 10: Power flows for generation at 0.95 leading power factor, HVAC transmission, Grid Code applied at offshore connection point

Scenario 2 (Figure 10) demonstrates that an inductance would be required (12.64MVAr) to be capable of exporting the power at 0.95 leading power factor from the offshore connection point. The 33kV cable network is generating 8.97MVAr and consuming an active power of 0.2MW (due to losses). The generation is shown generating 100MW at 0.96 leading power factor. As in scenario 1, no reactive compensation equipment would be required at the onshore point of connection, as in this scenario it would not be necessary for the OTO to meet the Grid Code requirements for connection of generation at that location.

Scenario 3 power flow diagram

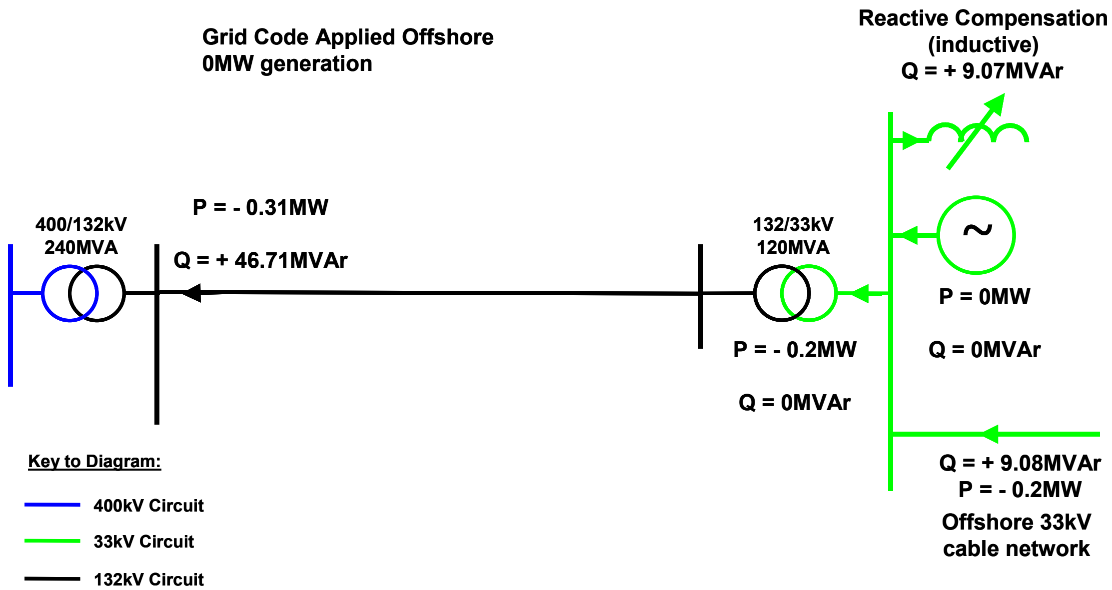


Figure 11: Power flows for zero generation, HVAC transmission, Grid Code applied at offshore connection point

Scenario 3 (Figure 11) demonstrates that an inductance of 9.07MVAr would be required to offset the inherent capacitance of the wind farm array cabling and hence be capable of achieving an overall reactive power export of zero from the offshore connection point. The 33kV cable network is generating 9.08MVAr and consuming an active power of 0.2MW (due to losses). As in scenarios 1 and 2, no reactive compensation equipment would be required at the onshore point of connection, as in this scenario it would not be necessary for the OTO to meet the Grid Code requirements for generation connection at that location.

The most onerous scenario in terms of the quantity of reactive compensation equipment required is therefore scenario 2. However, this is a significantly less onerous requirement for reactive compensation than those where Grid Code compliance, and hence reactive compensation equipment, is required at the onshore point of connection.

3.4.2. Frequency response

There are no specific issues with providing frequency response in this offshore configuration.

3.4.3. Dynamic voltage response

There is no significant difference in the dynamic voltage response compared to an onshore wind farm.

If the Grid Code must be adhered to at the offshore connection point, the ability of the wind farm to provide the dynamic voltage response would not be affected by the subsea cables connecting the wind farm with the onshore connection point, as the dynamic voltage response would need only to be demonstrated at the offshore connection point.

3.4.4. Voltage control

The GB System Operator (GBSO) (or the OTO), rather than the wind farm owner, would be responsible for selecting an operating voltage at the offshore connection point in order to optimise network performance. Compared with onshore application of the Grid Code, there would be no requirement for the generator to control the reactive power flows on the subsea cable in order to achieve any given voltage target at the onshore connection point. Assuming the generator has control of the tap changer on the grid transformer (e.g. 132/33kV) the generator can operate the 33kV array network at the optimum voltage.

3.4.5. Fault ride-through

The ability of the offshore wind farm to “ride-through” faults is not expected to be any more onerous than that for an onshore wind farm as the relevant faults are only applicable to 275/400kV onshore networks. Indeed the severity of the fault seen by the offshore wind farm is likely to be mitigated due to the impedance of the sub sea cable.

3.5. Application of onshore Grid Code to onshore connection point (HVDC transmission)

In this scenario the offshore transmission assets, including the HVDC link, are owned by the generator and the connection point for the Power Park Module is at an onshore location to an existing transmission (or distribution) network. In this case the metering will also be placed at the onshore connection point. The Grid Code is applied at the onshore connection point.

3.5.1. Reactive power capability

The reactive power capability requirements of the Grid Code would need to be met at the onshore connection point. In the case of an HVDC link, this would apply to the AC output from the onshore converter station.

Voltage Source Converter technology (i.e. Insulated Gate Bipolar Transistor technology), because of its ability to inject AC current into the grid with almost any phase shift subject only to power limits, provides a high degree of reactive power control. This is usually more than sufficient to meet the requirements of the Grid Code. However, the precise capabilities of any particular converter technology would need to be confirmed with the manufacturer. If we assume that the converter costs are proportional to the current, then specifying the converter to meet the Grid Code requirements will have an impact on the capital costs of connecting the wind farm.

The reactive power balance at the offshore terminal of the HVDC link is driven by the reactive output from the wind farm and is independent of that at the onshore terminal (reactive power is not conserved in AC/DC converters). If a wind turbine technology is used that is capable of reactive power control, the turbines are best operated at unity power factor in order to minimise losses in the array collector system. With HVDC transmission, there is no direct link between onshore Grid Code requirements for reactive power and wind farm control.

Wind turbine manufacturers should therefore be aware that building reactive capability into turbines would be a stranded investment in this case.

3.5.2. Frequency response

The AC frequency on the offshore AC system is not linked to the supergrid AC frequency due to the interposing HVDC link. Indeed the offshore AC frequency will be dependent on the ability of voltage source converters to control the level of active power. This control is however capable of maintaining a stable frequency on the AC offshore system under normal operating conditions particularly if short-term energy storage in the form of capacitors or batteries is available on the DC link.

If the wind turbines are to respond to changes in the supergrid AC frequency the control systems must

- control the HVDC active power transfer to match the frequencies at both ends of the DC link
- provide a frequency signal from the onshore AC system to each turbine, e.g. via a fibre optic link

In the second case the wind turbines must be equipped with a suitable control signal input to enable such control to take place.

3.5.3. Dynamic voltage response

In this scenario, the wind turbines cannot contribute towards this requirement due to the intervening DC link. Hence, this requirement falls on the onshore converters to meet, and any issues with this would be associated with the specification and manufacture of the converters. Providing dynamic response in addition to the steady state requirements of real and reactive power ranges would add to the cost of the converter equipment.

3.5.4. Voltage control

Technically, there is no issue with the ability of an HVDC converter to respond to changes in its AC terminal voltage by changing its reactive power output to compensate, thereby stabilising the AC voltage at any desired set point (subject only to device voltage and current limits). The degree of control achievable is similar to that of AVRs on conventional synchronous plant, although the mechanism is of course different. The precise capabilities of any particular converter technology would need to be confirmed with the manufacturer and the costs would be dependent on the overall capability range.

3.5.5. Fault ride-through

As the wind turbines are “decoupled” from the transmission system by the HVDC link, they do not automatically respond in the event of a fault on the onshore transmission system. The voltage dips experienced at the onshore connection point on the transmission system would not be seen at the offshore connection point through the DC link, other than as a secondary effect on DC voltage. Hence, there is a need for a control system at the wind farm to run-back the output of the wind turbines in the event of a rise in DC link voltage. Alternatively, the wind turbines could be allowed to speed up through an increase in the offshore AC frequency (i.e. the energy captured from the wind immediately following a fault is used to accelerate the wind turbine rather than being converted to electrical energy). A further option is to use a “dump load” such as a resistive load on the DC link or on the offshore AC system into which the excess energy is dumped. Reducing the energy captured by the wind turbines through pitch operation is another possibility, but the speed of response, and the ability to restore active power output following clearance of the fault would also require detailed consideration.

In the event of a fault on the onshore supergrid transmission system, the collapse in voltage at the onshore connection point would, without control action, cause the current on the DC link to increase substantially. Consequently, the DC link may block (firing of the IGBT switching devices is temporarily interrupted and the converter appears as an open circuit on the AC side). This stops the DC link from feeding power to the onshore transmission system, but allows the DC link to revert to normal operation once the voltage at the (onshore) connection point with the transmission system recovers. The main issue that arises when a DC link is blocked is increase in the DC voltage due to continued power infeed at the offshore terminal. The length of time a DC link can block and the minimum AC voltage at which it can restore output of active power would also affect whether the wind farm and HVDC link would comply with the minimum requirements of the Grid Code.

If on the other hand the DC link is blocked during a fault and power input from the wind farm is low, the DC link voltage and consequently the wind farm voltage may fall to levels that cause the wind turbines to lose rotor excitation and trip. This is however only likely to occur at very low wind farm output levels, when the wind farm is contributing only slightly to energy and voltage support in the grid.

It is therefore expected that HVDC technology and the connected wind turbines can be configured to meet the minimum requirements of the Grid Code subject to further studies.

3.6. Applying onshore Grid Code to offshore connection point (HVDC transmission)

In this scenario, the GBSO (NGETL) would apply the conditions of the Grid Code at the offshore connection point. An independent offshore transmission owner (OTO) would assume responsibility for the operation of the HVDC link connecting the onshore GB transmission system with the offshore wind farm(s). The metering point would be offshore.

3.6.1. Reactive power capability

Meeting the reactive power capability requirements of the Grid Code at the offshore connection point would be of no benefit to the GBSO because the HVDC link does not carry the reactive power generated by the wind farm.

There is no requirement on the OTO to meet any requirements at the onshore connection point and the OTO is free to operate the link at unity power factor to minimise costs.

If the Grid Code requirement to meet the reactive power capability at the offshore connection point were enforced it would also require the offshore converters to be specified such that they are able to handle the increased current resulting from that reactive power, creating extra costs, in spite of the fact that the onshore transmission system would derive no benefit from that reactive power capability.

3.6.2. Frequency response

As the wind farm would be decoupled from the onshore transmission system via the HVDC link, the offshore wind turbines would be connected to a small, and potentially weak AC network. The control of frequency on an AC network “decoupled” from the main onshore transmission system may require a different control action and system to be employed, and would normally be handled by the offshore HVDC converter.

Application of the current Grid Code requirements for frequency control offshore could potentially increase costs to the offshore wind farm owner without deriving any benefits to the onshore transmission system operator.

3.6.3. Dynamic voltage response

A voltage dip on the onshore AC system will not be seen at the offshore connection point with the wind farm.

3.6.4. Voltage control

If the Grid Code requirements (a continuously varying reactive power output) were imposed at the offshore connection point, it would be necessary for the offshore converters to be rated to handle the required levels of reactive power, despite the fact that the DC link negates any benefit of this capability as far as the onshore GBSO is concerned.

3.6.5. Fault ride-through

In the event of a fault on the onshore supergrid system, the drop in AC voltage may cause the DC link to block and stop feeding power to the onshore transmission system. In this case it is expected that the wind farm would need to respond and carry on operating through this disturbance, however the fault appears to the AC offshore system. The FRT requirement for the wind turbines is likely to be different to that for an AC connection due to the interposing HVDC link.

4. Conclusions

4.1. Application of Grid Code with HVAC transmission

4.1.1. Onshore application of Grid Code

If the Grid Code is applied at the onshore connection point with the transmission system, the main issues of concern are likely to be

- The quantity of reactive power compensation equipment required at the onshore connection point (to compensate for the capacitive effects of the sub-sea cable). Depending on the length of the sub-sea cables and capacity of the wind farm, this may be significant
- That the generator would be responsible for operating the wind farm and subsea cable combination in order to satisfy voltage targets for the onshore transmission system. This may require the subsea cable to be operated sub-optimally, increasing losses and reducing income for the generator

There are no significant additional concerns in comparison with onshore wind farms with respect to the following.

- Fault ride-through
- Frequency response
- Dynamic voltage control

4.1.2. Offshore application

If the Grid Code is applied at the offshore connection point with the wind farm, the main issues of concern are likely to be

- Though it may be possible to meet the reactive power capability requirements of the Grid Code at the offshore connection point without significant reactive compensation equipment being required, the subsea cable may generate a significant quantity of reactive power (depending on length), which would change the achievable reactive power outputs at the onshore connection point. This may be an issue for the GBSO

There are no significant additional concerns in comparison with onshore wind farms with respect to the following.

- Fault ride-through
- Frequency response
- Dynamic voltage control

4.2. Application of Grid Code with HVDC transmission

4.2.1. Onshore application

If the Grid Code is applied at the onshore connection point with the transmission system, the main issues of concern are likely to be as follows.

- The reactive power capability required at the onshore connection point would be entirely met by the onshore DC converters (or other ancillary onshore equipment) because an HVDC link does not carry reactive power. This means that there is no benefit to the onshore transmission system of any reactive power capability of the wind turbines
- Due to being connected via a DC link, the wind turbines would not necessarily be subject to a changing AC frequency if called upon to change their active power output, and hence there could in this case be a need to provide additional communications equipment between the onshore connection point and the offshore wind farm
- The wind turbines cannot contribute towards dynamic voltage response (in terms of providing a continuously varying reactive power output) through a DC link. Hence, this requirement falls on the onshore converters to meet, and any issues with this would be associated with the specification of the converter control system. No issues are expected to arise with the dynamic response capability of HVDC converters, however there are cost penalties for stretching the capability envelope of the converter
- At the onshore connection point, the ability to "ride-through" a fault in accordance with the Grid Code depends on the characteristics of the HVDC link, and also the control system of the wind turbines; it is expected that existing HVDC technology can meet the minimum requirements of the Grid Code but further studies would be required to confirm this capability

4.2.2. Offshore application

If the Grid Code is applied at the offshore connection point with the wind farm, the main issues of concern are likely to be as follows.

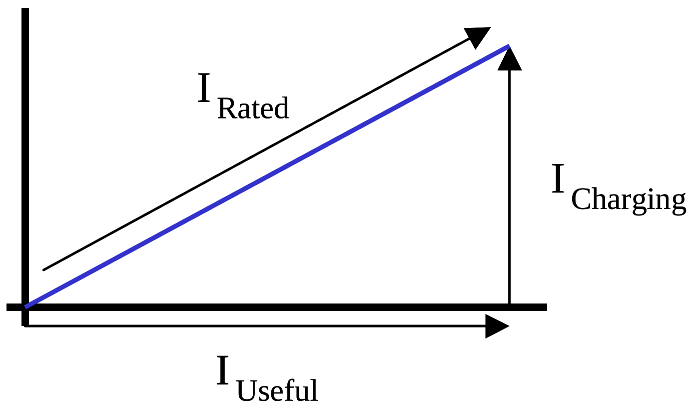
- The reactive power capability required by the Grid Code at the offshore connection point would need to be met by the wind turbines and may necessitate additional reactive power compensation. However, as a DC link does not carry reactive power, there is no benefit to the onshore transmission system of any such reactive power capability from the wind turbines. Furthermore, the offshore DC converters would need to be rated sufficiently to handle the additional current due to the reactive power, which may be produced by the offshore wind farm, in spite of the fact that this would be of no benefit to the onshore transmission system
- The control of frequency at the offshore connection point may be desirable, but, as it is connected to the onshore transmission system via a DC link, any action taken to control frequency at the offshore connection point is of no benefit to the onshore transmission system
- In order to demonstrate the ability to meet the required voltage control capability at the offshore connection point, it would be necessary for the offshore converters to be rated to handle the required levels of reactive power, despite the fact that the DC link negates any benefit of this capability as far as the onshore GBSO is concerned
- As the Grid Code is in this scenario being applied at the offshore connection point, the requirements relating to restoration of active power from the generators are not significantly different to those applying to onshore wind farms. However, in this scenario

the Grid Code must be met at the offshore connection point. This may pose a problem for the DC converters, which would need to be adequately rated to handle the required response from the generators (maximum reactive current following a fault etc) in spite of the fact that the transmission system would not benefit from this reactive power (which is not transmitted through a DC link). With a DC link, the voltage dip experienced at the onshore connection point would not be seen at the offshore connection point except secondarily as a rising DC voltage due to blocking. Hence, there is likely to be a need for a control system to provide adequate control of the wind turbines in the event of a high DC link voltage

5. Appendix 1

5.1. Current carrying capacity of AC cables

Alternating currents and voltages have both a magnitude and a relative phase shift. The effective current in a cable (which we will assume is limited by the thermal rating) consists of two components, illustrated in the following diagram. The reactive component (in this case capacitive, charging current) has a 90° phase shift relative to the active (or useful) component of current in the cable. The real and reactive components must be added as perpendicular vectors to obtain the effective current magnitude.



Where:

I_{Rated} is the current rating of the cable

$I_{Charging}$ is the charging current of the cable

I_{Useful} is made up of the current required by the load and the current due to the losses

Figure 12: Active and reactive components of current

Therefore with capacitance data for a cable, total capacitance of the cable can be obtained by

C_{Cable} = Length x $C_{/km}$

This capacitance value is used to calculate the charging current of the cable, at AC frequency F and voltage V, according to

$I_{Charging}$ = 2*Pi*F*C_{Cable}*V/SQRT(3)

From this the maximum useful current is gained from

$I_{Useful} = \sqrt{(I_{Rated}^2 - I_{Charging}^2)}$

And subsequently from this the equivalent useful MVA capacity (at unity power factor) can be calculated:

MVA = (I_{Useful} * V * $\sqrt{(3)}$) / 1,000,000

The above calculations assume supply at unity power factor. It is possible to 'compensate' AC lines by connecting shunt reactors at the endpoints. The current in shunt reactors is also 90 degrees out of phase with the voltage but in the opposite sense to charging current. This means the effective charging current is reduced and the maximum useful current increased. (All AC lines also possess an internal reactance that partly compensates the charging current, but for underground or subsea cables the capacitive charging currents dominate).

Due to the effects of cable capacitance, the useful current carrying capacity of a cable decreases significantly with the length of the cable. For example a 132kV cable will, due to charging current, suffer a significant reduction in useful current carrying capacity for lengths greater than approximately 60km if no reactive power compensation is used, as illustrated below in Figure 13.

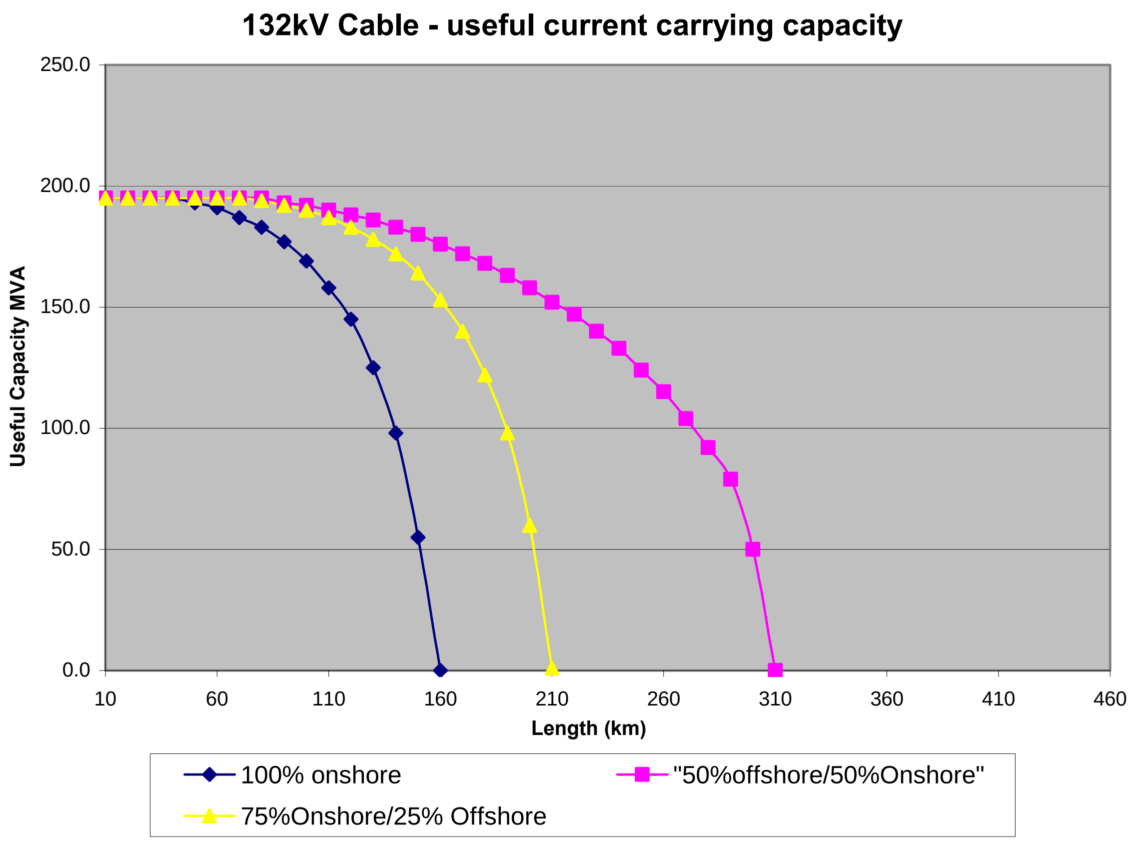


Figure 13: Useful Current Carrying Capacity of 132kV cables

Figure 13 above illustrates the effective current carrying capacities of 132kV cable at lengths of up to 310km with and without reactive compensation. Where compensation has been taken into consideration, the proportion at the onshore connection point and the proportion at the offshore connection point are stated. As can be seen, the effect of reactive compensation equipment, which may be installed at each end of a cable, has a limited effect on cables above certain lengths. Because charging current is drawn at all points along an AC line, longer lines require shunt reactors at several points along the line in order to achieve proper compensation, a measure that is usually prohibitive in cost for subsea cables. However, it can be shown that if compensation is restricted to the endpoints of the line, placing 50% of the reactive compensation equipment at each end of a cable maintains the highest useful current carrying capacity, especially for cable lengths above approximately 110km.

6. Appendix 2

6.1. Comparison of HVDC technologies

Table 1 provides a comparison of Voltage Source Converter and Current Source Converter Technologies in terms of their operating characteristics.

	Current Source Converter (CSC)	Voltage Source Converter (VSC)
Alternate names	Line Commutated Thyristor technology	Line Commutated IGBT technology “HVDC Light” “HVDC Plus”
Control of reactive power	No	Yes
Control of active power	Yes	Yes
Contribution to grid stability	Poor	Good
Fault ride-through	No[1]	Yes
Diesel or gas fuelled generator required at offshore platform	Yes	No[2]
Power reversal without interruption	No	Yes
Typical losses	1.5%	4%
Operating experience	>20 years	<5 years

Notes:

1. A CSC requires external voltage for commutation. In the case of a severe fault on the AC network, the converter will cease commutation and will shutdown within a few milliseconds but can re-establish full power in less than 1 second of voltage recovery. This characteristic would need to be confirmed as meeting UK Grid Code requirements.
2. Although a VSC does not require a synchronous generator on the offshore platform to operate the converter, it will be prudent to consider standby generation facilities to allow station auxiliaries to be supplied in the event of a complete loss of supply from the mainland unless the project has been designed with partial redundancy.

Table 1: Comparison of Current Source and Voltage Source Converters for HVDC schemes