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Considerations in design of an offshore network

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SUMMARY

The vast potential of offshore wind energy and the challenge of connecting it into onshore AC systems from possibly very distant locations is attracting interest in offshore networks based on HVDC technology using voltage source converters (VSC). However, while a number of visions have been expressed for how an offshore grid in, for example, the North Sea in Europe might look, investors are yet to commit to the development of offshore grids as such and a number of design and economic questions should be considered.

The paper discusses various engineering, regulatory and economic issues associated with offshore networks. In particular, it compares AC and HVDC options for simple connections, considers the benefits of coordinated offshore network development and asks whether, in an offshore context, conventions on secure operation that are customary in design and operation of onshore transmission networks are still relevant. It is argued that, except where a loss of infeed issue would be caused for an onshore grid to which an offshore DC grid is connected, the lack of demand offshore means that rules can re-evaluated. This leads into a discussion of the need for DC circuit breakers and reliable fault detection and selection on a multi-terminal DC grid and options for the control of a DC grid.

Finally, a number of institutional issues are described including the role of offshore transission owners and sharing of the costs and benefits of an offshore network.

KEYWORDS

HVDC, offshore grids, transmission system design, regulation, economics.

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1 INTRODUCTION

It is anticipated that between 2013 and 2030 as much as 200GW of offshore wind generation capacity might be installed in the North Sea, Baltic Sea, Irish Sea and English Channel, while a further 200GW of onshore wind energy has been envisaged continent-wide [1]. This is set against a backdrop of the planned closure of up to 55GW of nuclear capacity [2]. These changes will have profound implications for the European transmission system as the centres of production shift and the characteristics of the generation fleet change. Upgrades to grid capacity, whether offshore or onshore, have often been described as being essential to the facilitation of renewable energy [3] and, hence, to reduction of carbon emissions associated with production and use of electrical energy. However, some have observed that transmission upgrades might lead to carbon emissions increasing if they facilitate the displacement of CCGTs by cheaper coal across a wider area [4].

One aspect of transmission network development that is attracting particular interest is the optimal configuration for connecting offshore wind farms to shore. (See, for example,[5]). Until now, most offshore wind farms have been connected directly to a single shore via high voltage AC (HVAC) transmission cables but as generation assets are shifted farther offshore, high voltage DC connections become attractive. Against a background of growing interest in new interconnection capacity between regions across the seas of Europe [6], attention is being devoted to exploring whether such interconnections can be combined with connections of offshore wind farms which, in turn, will have connections to multiple shores. This, it is postulated, might increase the utilisation of offshore network branches, thus improving the cost-benefit of offshore transmission, and provide more reliable access to market for the offshore generation and mitigate wind curtailment. From a regulatory perspective, the branches of the resulting offshore grid serve two functions: connections of offshore wind generation and interconnection.

The paper discusses issues associated with the development of offshore networks. It is organised as follows: section 2 discusses the benefits of coordination of connection of multiple wind farms; section 3 discusses some offshore grid design considerations; section 4 addresses regulatory and economic questions; finally, section 5 draws some conclusions and highlights areas of future work.

2 COORDINATION OF OFFSHORE NETWORK DEVELOPMENT

2.1 Expected benefits of coordination

The very considerable investment required to connect wind farm developments far offshore to mainland grids mean that the opportuinities to reduce costs through a coordinated approach to the connection of multiple wind farms may be considerable. Morevoer, a coordinated approach may have benefits in terms of environmental impact or system operation that go beyond simple reduction of the capital cost of assets. Such benefits include those listed in Table 1.

Table 1: benefits of coordination in development of offshore networks

Objective	Comments
Maximising utilisation of network assets	• Exploit spatial diversity of wind • Combine wind collection and inter-area transfer capability
Minimising environmental impact	• Sharing of cable routes • Minimisation of number of sub-station / converter stations
Simplifying planning	• Sharing of cable routes • Minimisation of number of sub-station / converter stations
Reducing deployment costs	• Reducing frequency and time of use for offshore deployment vessels
Achieving scale economies in substation and platform design	• Relatively smaller size of units for larger capacity plant (i.e. smaller volume / weight per MW output)
Improving reliability	• May arise if coordination envisages multiple paths to shore for wind farms / wind farm clusters

As shown in Figure 1, coordination can take place at different levels. For example, area A in the figure may have two separate offshore wind farm developments, OWF1 and OWF2, each with different developers. Within OWF1, capacity might be developed in two stages – array 1 and array 2. Links 1a and 1b would represent independent connections of these two OWF1 arrays to shore whereas link 2 shows a shared connection for OWF1. Link 3, on the other hand, represents a higher capacity connection shared between OWF1 and OWF2. A separate area, area B, may also be developed. This might build link 4 in order to utilise spare capacity on Link 3 and connect to the East Market or instead build link 5 to connect to the West Market. If both Link 4 and Link 5 are built along with connections between area A and the East Market, the two markets would be interconnected.

What design is preferred depends on the factors discussed in the following subsections. Institutional issues associated with links 2-5 are discussed in section 4.2.

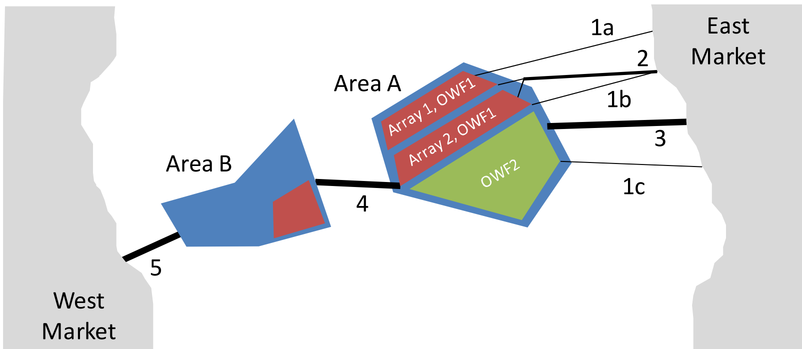


Figure 1: illustration of levels of coordination

2.2 Size of wind farm developments

The total wind farm capacity in an area considered for coordinated network development may be so large that multiple cables to shore may be required regardless of consideration of the possible benefits of redundancy to reliability of access to onshore markets. Moreover there are limits to the lift capability of cranes on vessels [7]. These considerations suggest that, at a certain level, coordination is unnecessary and a 'modular'/semi-independent approach to the connection of each wind farm array will suffice. (Reliability/redundancy issues are discussed further in section 3).

2.3 Staging of wind farm development

Not only the total size of the envisaged wind farm developments should be considered but also the staging of developments. Developments in a certain area might all have different developers; even a single developer might develop their project only in stages with later stages committed to only when market and financial conditions seem right. That is, at the time of development and connection of the first wind farm array, there cannot be certainty that the rest of the mooted capacity in the area will be developed. Nonetheless, some decisions are still required at the outset:

- Will HVAC or HVDC be used?
- If HVDC is to be used, will monopole or bipole connections be used [8]?
- If the earliest connected wind farm array has a capacity less than that of the largest HVAC cable or HVDC monopole, should the largest capacity cable connection still be provided in order to give the option of a second wind farm array using the same connection?
- Should sufficient platform space be built early on to provide the option for installation of additional substation equipment or interconnection of other platforms at a later date?
- What nominal voltage is to be used?

Particular answers to the above questions in advance of connecting the first wind farm array do not preclude the connection of later arrays, but they might mean that the costs of doing so will be higher than would otherwise have been the case. There are likely also to be benefits in terms of planning and management of environmental impacts associated with coordination, e.g. utilisation of common cable routes, minimisation of the number of onshore landing or reduction of the number of points of connection to the onshore grid.

The initial decisions can be seen as designing the initial offshore connection for extensibility or adaptability. The extra cost of building in such extensibility or adaptability may be referred to as the ‘option cost’, i.e. the cost of facilitating later developments at a lower cost than would otherwise have been the case. Such up front investment in extensibility is sometimes referred to as ‘anticipatory’ or ‘strategic’ investment. However, there is the possibility that later developments will not be taken forward or not on the scale originally envisaged and the additional assets associated with extensibility may be regarded as stranded. On the other hand, the lower cost of adapting the offshore network to accommodate further wind farm capacity may act as an incentive to developers to commit to building that extra wind farm capacity, i.e. to encourage generation to follow transmission.

In many jurisdictions, regulated transmission owners have found it difficult to justify anticipatory investment, either not being guaranteed to recover the money or being at risk to a later regulatory decision. Ofgem in Britain claims to have addressed similar issues in an onshore context by declining to guarantee recovery of the option cost but instead promising a higher rate of return on ‘anticipatory’ assets should they prove to have been justified [9]. One way for the utility to make sense of the different options for an initial network investment against different generation scenarios is to quantify the cost of adaptation of an initial design against each future development, i.e. the ‘regret’ associated with each initial decision given what later occurs. However, although such an approach is now starting to be used in different parts of the world, e.g. [10][11], it does still depend on judgement as to which future scenarios should be considered.

2.4 Regulatory arrangements and market conditions

A number of different perspectives and considerations need to be aligned before investment in development of an offshore grid will actually proceed. Some of these are discussed in [12] from which Figure 2 has been adapted.

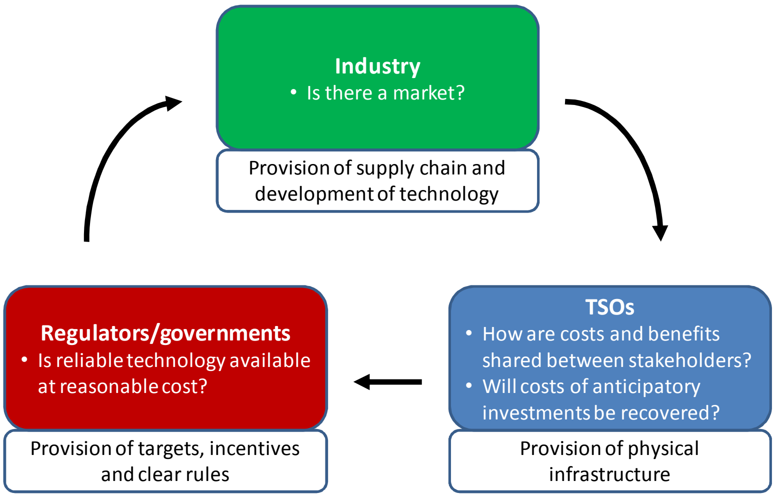


Figure 2: offshore grid development perspectives (adapted from [12])

The nature of the funding for offshore network development and of responsibility for its design will have a profound impact on whether it is developed in a coordinated manner. In particular, the following actors will all have different interests depending on the prevailing regulatory arrangements:

- owner of the offshore wind farm (OWF);
- offshore transmission owner (OFTO);
- onshore transmission owner (TO);
- system operator (SO).

In some areas, there may be a transmission system operator (TSO) that both owns and operates the transmission system within a certain geographic footprint. Some of these different perspectives are discussed further in section 4.

3 OFFSHORE GRID DESIGN CONSIDERATIONS

3.1 HVAC versus HVDC

The majority of offshore wind farm developments to date have been in waters relatively close to shore. Even though onshore planning issues may dictate use of underground cables from the shore to the point of connection to the existing onshore network, the total length of cable, onshore and offshore, has not been so long that the total cable susceptance has caused significant problems. However, newer offshore locations further from the existing onshore network have been mooted for such large wind farms that HVDC utilising voltage source converter (VSC) technology becomes an attractive proposition [13]. Assuming in both cases a basic compliance with an existing offshore design standard such as that in chapter 7 of the GB Security and Quality of Supply Standard (SQSS) [14], which option is preferred depends, in the main, on the total cost comprising the capital cost of the network connection assets plus the discounted cost of losses over the lifetime of the connection.

When using cables, it has commonly been assumed that, depending on the size of the wind farm being connected, HVDC becomes the cheaper option at a cable length of around 50km. However, some recent studies, e.g. [15] have suggested that the cross-over distance at which HVDC is preferred is more like 80km or more. For longer distances, compliance with voltage standards at the point of connection to the onshore system dictate that a minimum amount of reactive compensation should be installed. At especially long distances, in order that the thermal capacity of the cable can be used as much as possible for active power rather than reactive power associated with the charging current, a number of developers are now giving active consideration to installation of shunt reactors on platforms not only at the point of connection to the main grid but also at the mid-point of the cable connecting the wind farm to the main grid. (See, for example, [16]). In addition, delays to the commencement of operation of the VSC connected offshore wind farm Borwin 1 [17] seem to be leading investors to approach the use of VSC in relatively untested environments with caution and instead to pursue HVAC connections wherever possible.

Assuming use of 220kV three-core cable (the highest rating at which three-core cable can still be deployed from cassettes on existing deployment vessels) with a continuous rating of 350 MVA, ensuring compliance with the SQSS and the GB System Operator – Transmission Owner Code (STC) [18] and using costs of equipment quoted in [19] including for the necessary shunt reactive compensation, high level analyses described in [20] report cross-over distances of between 200 km for a 500MW wind farm and 160 km for a 1GW wind farm. However, additional engineering issues do need to be considered including the exact routing of the undersea cable to minimise the number of crossings of existing seabed pipeline and cable infrastructure and follow suitable gradients and seabed conditions. In addition, remedial measures may need to be introduced to limit transient over voltages during both controlled and uncontrolled operations. Furthermore, for both AC and HVDC options, the possibility of harmonic resonances having been introduced should be checked and damping circuits introduced if necessary [16][21][22].

3.2 Differences between onshore and offshore grids

Existing onshore power networks have been designed with two purposes: to improve reliability of supply to demand when generation local to that demand has limited availability; and to provide access to the most economic generation that may be remote from the demand location. The structure of the network in terms of where nodes (substations) and branches (overhead lines, underground cables and transformers) are located is determined predominantly by the respective locations of generation and demand. The detail of the design in terms of number of branches into each node, how many circuit breakers are used and where they are placed has been driven by the balance between cost and reliability: in the event of network faults, protection systems and suitably sited circuit breakers can succeed in limiting the number of branches that must be removed from service to isolate the fault and hence improve continuity of supply to demand or access to the market for generation.

Assuming that sufficient reserve is carried somewhere on the system to cover the loss of generation resulting from any one fault event, particular attention is paid to the connection of demand. At least for large demand groups, the main interconnected network is generally designed such that demand is still connected following the unplanned loss of one branch while another branch is out of service for maintenance (as must happen from time to time).

Offshore networks depend on undersea cables (or, potentially, gas insulated lines laid along or beneath a seabed). The number and total length of these are scalable and dictate the total cable cost. The determination of branch capacity and cost might therefore be determined in a similar way to onshore branch capacity and cost. However, in other respects, there are some key ways in which offshore networks differ from existing networks onshore:

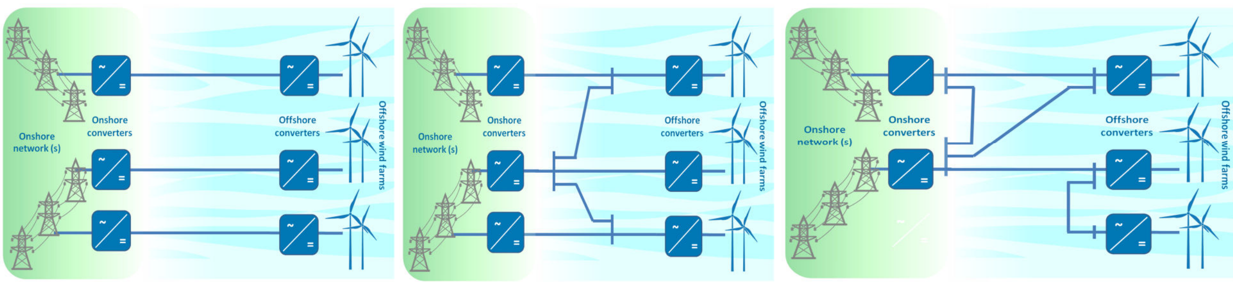
1. Undersea cables are very much more expensive than onshore overhead lines.
2. Offshore substations are very much more expensive than those onshore since they depend on purpose built platforms and 'marinised' equipment.
3. For HVDC branches at a certain voltage, a connection to the AC system must use a power converter that will incur a certain minimum cost that is very large.
4. High-voltage DC circuit breakers (DCCB) have not yet been demonstrated in such a way as to fully establish commercial viability and are likely to be both large and expensive relative to AC circuit breakers at comparable voltages.
5. Aside from oil and gas production platforms, there is no demand connected offshore.

Consequently, relative to established onshore transmission systems, the balance between cost and reliability for an offshore HVDC network will be shifted significantly towards minimisation of the number and size of physical assets and, arguably, away from high continuity of supply. However, another key consideration for offshore grids is that the time to repair any network faults is likely to be very long. This suggests that, notwithstanding the very high cost of cables and converters, some redundancy among routes may be justified, albeit not sufficient to export full wind power under all conditions following a single cable loss [23].

The lack of demand connected offshore suggests that continuous availability of network capacity on an offshore grid is less important than it would be onshore. Nonetheless, loss of access to generation connected offshore would increase the risk of failing to meet demand onshore. Moreover, an offshore network might also serve as an interconnector providing access to generation in another country. However, the onshore system already operates in such a way as to survive, with no loss of load, a certain level of 'loss of infeed'. Provided no single offshore fault event leads to an excessive 'loss of infeed' to any single onshore system, no loss of load will occur.

3.3 Possible offshore grid structures

Three general types of DC connection of offshore wind farms (OWFs) to one or more onshore AC transmission systems were identified in the TWENTIES project [24]: point-to-point; trees/radial DC grids (that have no closed paths except possibly via an AC system); and meshed DC grids. (Figure 3 (a), (b) and (c) respectively). The latter two of these could either be part of the same AC synchronous area (in which case the DC grid can be said to be 'embedded' within the AC system) or interconnect two different AC synchronous areas.



(a) (b) (c)

Figure 3: possible DC offshore network structures: point-to-point, radial and meshed [24]

As the capacity of offshore generation increases or extra power is carried between shores, the drive to minimise the number of power converters means that, instead of two-terminal HVDC branches being connected around AC hubs, HVDC nodes become attractive since they do not require converters at the

DC bussing points. Meanwhile, the use of HVDC bussing points gives rise to multi-terminal HVDC networks that in turn entail or exacerbate a number of operation, control and protection challenges. (See sections 3.4 to 3.7). In addition, minimisation of the required number of very expensive devices (not only in terms of the costs of the devices themselves but also of the platforms on which they would be installed) suggest that DCCBs should be deployed only very selectively.

3.4 Identification and clearance of faults

On any power network, the presence of short circuit faults needs to be detected very quickly. On a DC grid, this can be done through the identification of a collapse in voltage and rise in current but accurately locating the fault is more challenging, especially if it is to be done suffciently quickly for the fault to be successfully cleared.

Work reported in [24] notes that only very simple algorithms can be processed within the required time frame which, according to [25], is of the order 10 ms including time to detect the fault, to discriminate between the faulty and healthy parts of the grid and open the circuit breakers. This is due to current limits on the diodes of the converters and the rate of rise of the current. In [25], a current differential scheme is proposed based on a comparison of currents at the ends of each device or link. The main disadvantage of this is the communication delay that can be problematic when protecting DC lines longer than 200 km (1 ms transmission delay in fibre optics).

Reference [24] reports that the demonstration of a large-scale DCCB at Alstom's testing facility in Villeurbanne, France in March 2013, succeeded in interrupting currents exceeding 3,000 amperes in less than 2.5ms with a further 150kV test at the end of 2013 in which 7.5kA was interrupted in 5ms.

If DCCBs are not used, faults must be cleared by action at the terminals of the DC grid. This might be achieved by operation of AC circuit breakers or the use of fault-blocking VSCs such as the design proposed in [26]. In the former case, fault isolation will take longer (e.g. 60-100ms) and places requirements on the capacity of anti-parallel diodes, but allows more time for location and isolation of the faulted DC branch while the faulty DC network section is being isolated. The use of fault blocking converters at the terminals of the DC grid would present different performance requirements to any DCCBs installed on the network.

A key aspect of system performance will be post-fault recovery/re-energisation and the impact this has relative to expected fault ride-through capabilities as written into existing or proposed grid codes for wind farms and HVDC links in order that there is no undue effect on the operation of a main AC system to which the DC grid is connected.

3.5 Design and operation of HVDC grids without DC breakers

It might be expected that DCCBs will be required to operate to ensure that single fault events neither cause disconnection of demand nor an excessive 'loss of infeed'. However, if there is no demand that might be disconnected and the maximum loss of infeed is acceptable, the value of circuit breakers lies in reducing the volume of curtailed energy generated offshore. This is determined by the level of power initially curtailed and the time taken to restore it. Without DCCBs, faults on a DC grid must be cleared from the AC side and the converters' anti-parallel diodes must be rated sufficiently for the current that flows in the meantime. Given the relative infrequency of fault events and the variability of power supplied from wind farms, the expected cost of losing access to that energy may not be sufficient to justify investment in multiple DCCBs [23]. In that case, the DC grid should be configured in a number of partitions where a fault anywhere on a particular partition would result in that entire partition being isolated by clearance from the AC side. The partitioning should be such that the power being supplied from any partition to any AC system to which it is connected is less than the 'loss of infeed' limit of that AC system [27]. However, such partitioning reduces the operational flexibility of the DC grid.

A further option to the management of DC grid faults is the use of fault-blocking DC/DC converters at strategic locations. These would be capable of responding in tens of μs and may allow the full DC grid to be operated interconnected but partitioned into islanded sections following faults. This reduces or avoids a pre-fault partitioning of the network but incurs a cost in terms of both the additional converter and the associated losses. In all cases, options exist regarding the converters that connect the DC grid to an AC system. Some designs, while likely to be more expensive and have a larger footprint than standard configurations, have the capability to block the passage of fault current from the AC side in the event of a DC side short circuit fault. (See section 3.4).

As already noted, on a DC grid that is not using DCCBs, the maximum power that could be generated on a single electrical island will be restricted not only by the ratings of individual cables and converters but also by the maximum loss of infeed that could be survived by the AC system to which it is connected were that particular island of the DC grid to experience a fault and be isolated. The maximum loss of infeed equals the primary reserve carried on the AC system, with the precise level dependent on a cost-benefit analysis of the cost of additional primary reserve versus the benefit of allowing a higher loss of infeed. In addition, taking account of expected unavailability of individual turbines, wake effects or, for spatially quite well separated OWFs connected within a single cluster, the likely diversity of output, the most economic level of total export capacity designed into a DC grid partition is likely to be less than the installed OWF capacity connected to the partition.

An example of a DC grid that does not have DCCBs is shown in Figure 4. Each converter is assumed to have a capacity of 1GW. In the operating condition shown, 3GW of power is being generated offshore; 2 GW of that power is being directed to AC synchronous area 1 and 1 GW to AC synchronous area 2. If there were to be a short-circuit fault anywhere on the DC grid, without DC breakers, the passage of current from all of the terminals would need to be blocked. This would result in a loss of infeed to area 1 of 2GW and to area 2 of 1GW. If the primary reserve in area 1 were only sufficient for a loss of infeed of 1.32GW (as is currently the case in GB, for example), this would lead to an unacceptable deviation of system frequency in area 1.

Figure 5 shows the same DC grid with the DC grid configured in a different way. In particular, disconnectors have been opened pre-fault at location B to separate onshore converters OCS1 and OSC3 plus WF2 from converters OCS2 and OCS4 plus WF1 and WF3. In order to generate 1GW at WF2 and area 1 to receive a total of 2GW and area 2 a total of 1GW, the dispatch of power should be as shown. In this way, two contiguous DC grid partitions have been formed.

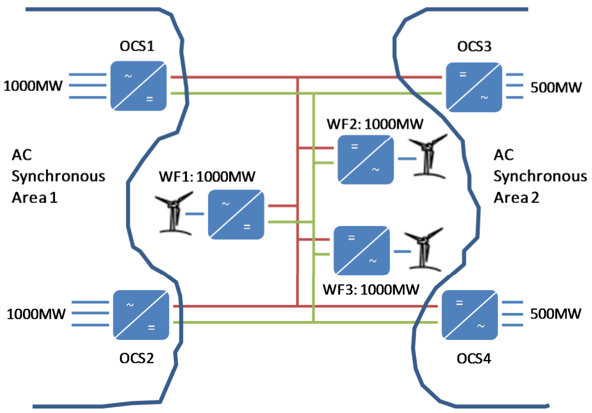


Figure 4: example DC grid and dispatch of power totalling 2GW to area 1 and 1GW to area 2

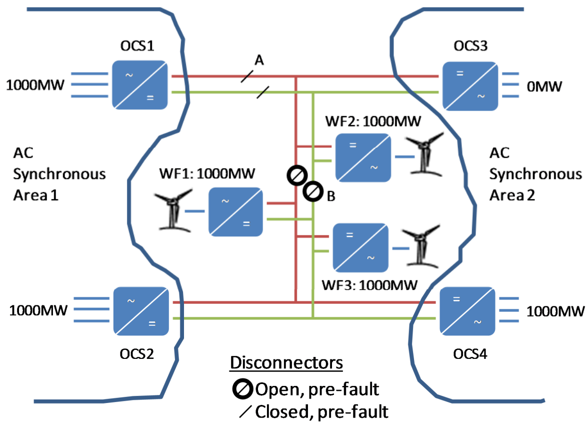


Figure 5: example DC grid with a pre-fault split introduced at location B

Consider a short circuit fault on the branch connecting OCS1 to location A. In this case, only currents through OCS1 and OCS3 need to be blocked onshore and surplus power from WF2 dissipated. The power flow through OCS2, OCS3 and OCS4 can continue. This results in a loss of infeed to area 1 of only 1GW (within the current GB limit of 1.32GW). Provided the location of the fault can be correctly identified, disconnectors can be opened at location A as in Figure 6. Assuming that the loss of infeed limit in area 2 is at least 2GW, the disconnectors at location B can be closed to provide flexibility in the export of power from WF2. OCS3 can be returned to service and WF2 restarted. (In this case, the total power being generated offshore equals the total remaining onshore converter capacity so the disconnectors at location B could have been left open).

Figure 7 shows the same system with fast acting DCCBs installed. In this case, provided DC protection correctly identifies the location of the fault and the DCCBs operate successfully, it would not have been necessary to partition the DC grid pre-fault. Only OCS1 would be disconnected and the power from WF2 could have flowed continuously, without interruption. However, the value of this continuous operation should be compared with the cost of the DCCBs since large numbers of DCCBs would be required to cover all the possible fault scenarios.

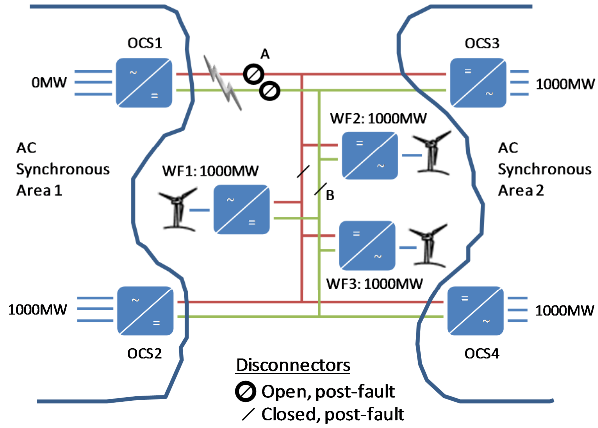


Figure 6: post-fault reconfiguration of the example DC grid

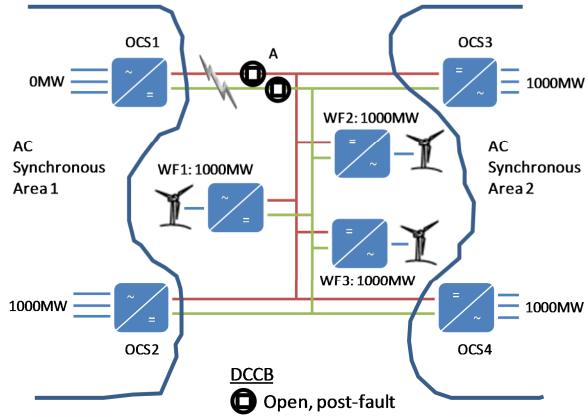


Figure 7: example DC with DCCBs at location A that succeed in clearing a fault between OSC1 and location A

The main benefit of a meshed DC grid is the availability of a parallel path in the event of a fault on one branch. This would allow transfer of at least some power to be continuous but only if faults can be located and isolated on the DC side. This, in turn, depends on installation and successful operation of DCCBs. The limit to operation is then determined by the power flow condition (how much power is being transferred into each AC system to which the DC grid is connected), the location of the DCCBs and the impact of any one fault outage. This impact in terms of loss of power transfer into any one AC system must be less than the loss of infeed limit for that system or else power must be restored quickly enough for the AC system frequency not to deviate outside of statutory limits.

3.6 Coordination of terminals

The terminals of a DC grid need to be actively controlled to ensure that currents passing through the converter do not exceed the components' limits and that voltages are not excessive. Initial concepts of multi-terminal DC grids left one converter responsible for DC voltage regulation (analogous to a 'DC slack bus') while the others controlled current or power. However, this left the grid vulnerable to the loss of the voltage control master converter and required fast communication to allow its function to be transferred to another converter. More recently, a shared voltage control using droop characteristics has been proposed that is not vulnerable to a converter loss (see, for example, [24]). This can be seen as being analogous to the use of governors on an AC system for the control of system frequency, i.e. a 'distributed slack bus', albeit that the DC analogue has much shorter time constants [28]. As a consequence, because the overall behaviour of the grid can be securely managed for a variety of network topologies using appropriate autonomous controls, even with variable wind power and for pre-defined power exchanges between AC zones, telecommunications are only required to adjust control set points from time to time. However, in a meshed grid arrangement such as in Figure 2 (c), power flows and voltages around the DC grid cannot be solely managed by control of the terminals; additional branch controls of some kind are required.

A number of different schemes have been suggested for the exact implementation of droop control. These involve use of deadbands or different slopes in different parts of the characteristic in order to distinguish behaviour between normal operating conditions and fault conditions. Although the principles of operation are quite clear, the parameters of these controls should still be designed taking into account overall performance of the DC grid and this may be challenge if different terminals are provided by different manufacturers.

As noted in [24] and [20], the use of VSC on a DC grid promises certain benefits to operation of each AC system to which it connected. These include:

- on a grid connecting geographically dispersed wind farms, the smoothing of wind power fluctuations;
- an interconnection function between different AC areas;
- ancillary services functions (e.g. voltage support, frequency support to onshore AC grids, etc.);
- security enhancement (e.g. through supplemental controls to contribute to damping of power oscillations or permitting adaptive redirection of power between AC locations).

3.7 Options available in respect of different converter designs for a DC grid

Compared to two-level voltage source converters, the increased efficiency and suitability for higher DC voltages make modular multi-level converters (MMC) the most probable candidate for future HVDC networks. By raising efficiency, the MMC converter will bring down the connection distance at which DC connection becomes preferred. It also provides improved power quality and a reduction in AC filter requirements. However, this reduction in converter footprint has to be balanced against the additional DC capacitors used within each cell. However, as discussed in section 3.4, certain designs of MMC have the capability of blocking current from the AC side under DC side fault conditions.

4 ECONOMIC AND REGULATORY ISSUES

4.1 Economic principles

In theory, given a number of different network designs that would connect one or more offshore wind farms to one or more onshore networks and/or provide transfer capacity between different onshore network areas, the design that should be preferred is the one that maximises the ‘social welfare’, i.e. the sum of ‘consumer surplus’ (consumers’ total savings relative to the price that, in theory, they were willing to pay for electrical energy or the compensation they would want in order to consume less), and the ‘producer surplus’ (the money received by generators over and above their costs) [29]. In the absence of fullly articulated supply and demand curves, the sum of consumer payments and generator revenues in a locational marginal pricing arrangement might be minimised. However, based on short-term marginal prices, wind farms would normally be priced at zero or even less (if they are willing to pay in order to physically produce power and hence receive financial support via feed-in tariffs or such like). Alternatively, the trading arrangements might allow them to self-dispatch and the system operator would have to pay for any curtailment that is a consequence of lack of network capacity. Assuming that curtailment is priced in a fully competitive context, this may succeed in revealing the network design option that is most economic from a societal point of view, except where wind farms have priority access and cannot be curtailed in which case they have the effect of sterilising network capacity for other users and distorting the apparent total cost.

4.2 Institutional arrangements – the role of Offshore Transmission Owners

The simplest institutional arrangement for the connection of OWFs involves each wind farm developer taking responsibility for connecting its own wind farm. It is likely that the wind farm developer will be primarily concerned with minimisation of the capital cost though, if the development is large enough, they may also be interested in the improved reliability of access afforded by some level of redundancy among the assets; or, if the development is to be undertaken in stages, they may be interested in extensibility. Although there might be societal benefits in some degree of coordination with other developers’ projects, the primary private interest is likely to be in minimising complexity and dependency on other parties.

An offshore transmission owner (OFTO), whether it is simply an extension offshore of an incumbent onshore TSO’s responsibility or, as in GB waters, some separate entity [30], might normally be thought of as having some interest in coordination, not least if it minimises their own costs. However, this depends on remuneration arrangements. If the OFTO receives an income proportional to the value of the assets, minimisation of their cost will not be the sole incentive (though cost of finance and risks to delivery timescales may deter ‘gold plating’); if the income is fixed regardless of the assets, minimisation of cost is a clear driver, possibly at the expense of reliability of an OWF's access to the onshore market. Instead, as in Britain, certain minimum offshore design standards may be defined with which the connection must comply and the connection proposal may be subject both to regulatory approval and subsequent adjustment of income dependent on availability of the connection [30]. However, the extent to which the latter might motivate a change to the design is arguably limited by the existence of both a 'cap' and a 'collar' on availability related adjustments and the 'lumpy' nature of a connection design.

When an offshore network facility is proposed to interconnect two separate jurisdictions or markets, it is likely that two or more TSOs will be involved. If the new facility's immediate connections are to facilities owned by independent OFTOs or wind farms, further institutional interfaces will be opened up and agreement must be reached on sharing of the costs given where the main benefits might lie. (Issues around sharing of costs and benefits are discussed further in section 4.4).

In Britain at present, particular areas of the sea in which 'Round 3' offshore wind farm developments are proposed are being put out to tender to independent OFTOs [30]. However, while the original vision was that OFTOs would be responsible for coordinated design of the offshore network facilities in their areas, wind farm developers' concerns about the speed of the tendering and offshore network development process have led to them lobbying for and being given the right to develop their own connections and then sell them on to the relevant OFTOs that will then be responsible for maintaining them. Although this seemingly loses the main opportunity for coordination, the remuneration arrangements for the OFTOs that finally acquire the network assets are seen as being low risk and hence investors seem willing to make relatively cheap finance available for offshore connection development. Even though the power system engineering may seem less than optimal, there do thus seem to be benefits in terms of 'financial engineering'.

4.3 Further institutional issues

Further issues concern levying of charges for use of offshore network facilities, the metering of power generated offshore and the relationship between an OFTO and the onshore TO.

In Britain, the offshore network assets finally owned by OFTOs are charged for via Transmission Network Use of System (TNUoS) charging that is, to some extent, socialised among network users. Thus, it might be argued that offshore wind farms are not exposed to the full cost of the offshore network assets [31][32].

With the offshore network assets regarded as part of the main transmission infrastructure, the metering point is where the OWF array connects to the OFTO's assets. This means that the OWF developer that may very well have determined the design of the connection to the onshore grid is not exposed to the cost of losses associated with that design. In contrast, a TSO that was exposed both to the capital cost of the offshore network assets and the cost of losses would have an incentive to minimise the sum of the two over the lifetime of the assets.

In Britain, while an OFTO finally owns the connection of an OWF to the onshore system, the OWF applies for a connection through the System Operator (SO) which will subsequently operate the whole transmission system, including offshore. However, the onshore end of the offshore connection physically connects to assets owned by a further party, an onshore transmission owner (TO). The relationship between the OFTO and the TO and associated technical issues are governed by the SO-TO Code (STC). Precedent with respect to onshore connections suggests that technical issues around the point of connection between a generator and a TO should be managed by the connected TO in the presence of the SO. However, with all offshore connections to date having been wind farm developer led and OFTOs currently occupying mainly a financing role, it has been suggested anecdotally that OFTOs are seeking to deny any responsibility with respect to the technical interface between the OWF and the offshore connection point and to leave the resolution of any issues to the TO at the other end of the assets that the OFTO will final own.

4.4 Who pays and who benefits

The intuitional complications around offshore grids are thrown into particularly sharp relief when they cover multiple national jurisdictions that have different sets of market arrangements and financial support mechanisms for renewables.

In spite of significant grid constraints, wind farm development continues to attract interest in the Republic of Ireland, to such an extent that one recently mooted project – Energy Bridge [33] – is proposed for development onshore in Ireland but to connect only to the GB transmission system via an HVDC link across the Irish Sea. This would permit power to be exported to the GB market and, by being directly connected to the GB system, is hoped would qualify for the more generous financial support for renewables currently available in GB. However, in its simplest form, it would not bring any added benefits in respect of grid capacity in Britain or Ireland or add to interconnector capacity.

The ISLES project considered some case studies of offshore developments around the coasts of the UK and the island of Ireland and whether coordinated development of offshore grids, as distinct from simple wind farm connections, might bring such added benefits – for which network users are willing to pay – as to enhance the commercial viability of offshore wind farm developments. Once the different markets are interconnected with each other and with wind farms, the trading, regulatory and planning arrangements become complex. Furthermore, the level of financial support required remains large, of the order of £800m - £1 billion for the 'southern ISLES' concept [34].

As with the Energy Bridge project, the envisaged scenario in ISLES is that of the bigger market opportunity for sale of renewable energy being in Britain. However, under status quo regulatory arrangements, around 2 million Republic of Ireland consumers would be subsidising energy consumed by more than 27 million consumers in Britain. Instead, the ISLES project proposed a straw man in which market boundaries were moved offshore such that generation is in the market where most of the energy is consumed (Figure 8). This would mean the subsidy would be paid by consumers using the energy. In the case of moving the boundary of the GB market almost to the shoreline of the island of Ireland, the benefits to Britain would be meeting the renewables target at a lower cost. The benefits to the Republic of Ireland would be lower energy price volatility and cheaper energy under low wind conditions, both arising from the greater interconnection capacity.

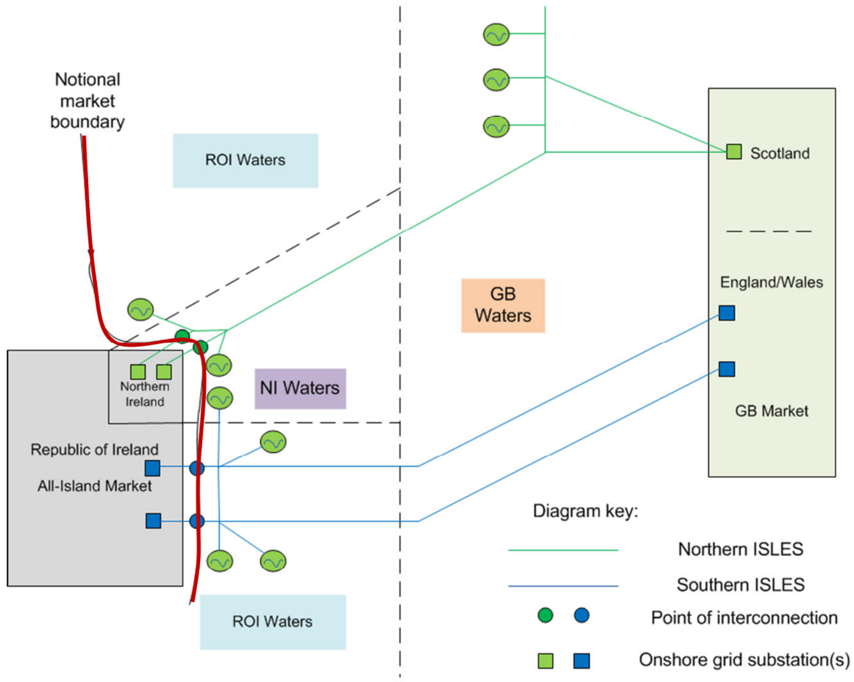


Figure 8: ISLES market boundary 'straw man' [34]

5 CONCLUSIONS

Interest in Europe in offshore wind power and in the exploitation of quite shallow waters relatively far from shore plus the very high cost of offshore developments has led some policy makers and parts of the industry to propose the building of HVDC connections to offshore wind farms and to ask whether the value of such connections can be enhanced, the costs reduced or the utilisation maximised by making them part of coordinated offshore networks, in particular multi-terminal DC grids.

This paper has discussed a number of considerations in respect of design of an offshore grid. In particular, it has highlighted the dependency on a number of different actors, the design choices available and a number of economic and regulatory issues. However, it has also been noted that no offshore network has yet been developed in Europe and been shown that a number of complex interactions, at both the regulatory and engineering levels, still exist. The associated issues, while continually becoming better understood with candidate solutions beginning to be proposed, are not yet fully resolved and require further exploration. This includes work in the following areas:

- the development of common or at least compatible arrangements for ownership and operation of offshore networks;
- compatibility between regulatory treatments of 'connections' of offshore generation and 'interconnectors';
- testing and demonstration of the inter-operability of HVDC converters of different designs and from different manufacturers;
- methods for the fast and reliable the identification and location of faults on a DC grid;
- further innovation in HVDC converter design and control with demonstration of the benefits;
- development of a set of simple grid design rules taking into account cost and the availability of power transfer paths;
- whether there is a need for a single design authority responsible for determining the form of an offshore network in a given area.

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