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A Reliability Evaluation of Offshore HVDC Transmission Network Options

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A thesis submitted for the degree of

Doctor of Philosophy

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Abstract

There are ambitious targets in place for the development of large amounts of offshore renewable energy in the coming years. The offshore wind sector is expected to provide the vast majority of the projected growth which means large scale and far from shore projects are likely to become common. The transmission distances involved suggest HVDC technology is likely to be deployed and analysis to date has suggested there will be value in delivering co-ordinated offshore grids as opposed to simpler radial connection to shore. However, there are numerous technology and design options available for the delivery of offshore HVDC networks and, given the offshore climate can make access for component maintenance or repair challenging, the reliability performance of different options is an important factor which has not been explored in much of the existing literature.

This thesis details a novel methodology for investigating the reliability of different offshore grid design options for the connection of offshore wind power to shore or the interconnection of regions. A sequential Monte Carlo simulation methodology is used that allows investigation of realistic offshore phenomena such as the weather dependency of component repair times. A number of case studies are examined and a full cost benefit analysis is performed which compares the capital and operational costs, electrical losses and reliability performance of each grid option. There is shown to be clear value in options that include a degree of inherent redundancy and it is also shown that alternative protection strategies which avoid the use of expensive DC circuit breakers are potentially viable at lower cost and little expense to performance. An investigation of the key drivers behind overall offshore grid reliability is also made and it is found that low probability, high impact faults such as transmission branch failures have the greatest influence.

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Abbreviations

HVAC	High voltage alternating current
HVDC	High voltage direct current
CSC	Current source converter
VSC	Voltage source converter
MI	Mass impregnated paper cable
XLPE	Cross-linked polyethylene cable
SCR	Short circuit ratio
PWM	Pulse width modulation
MMC	Modular multilevel converter
HB-MMC	H-bridge modular multilevel converter
AA-MMC	Alternative arm modular multilevel converter
IGBT	Insulated gate bipolar transistor
DCCB	Direct current circuit breaker
TSO	Transmission system operator
OFTO	Offshore transmission owner
O&M	Operations and maintenance
TTF	Time to fail
MTTF	Mean time to fail
MTTR	Mean time to repair
LOLP	Loss of load probability
SAIDI	System average interruption duration index
COPT	Capacity outage probability tables
E_{und}	Undelivered Energy
CTV	Crew transfer vessel
HLV	Heavy lift vessel
FSV	Field support vessel
TTC	Time to change
NPV	Net present value
ROC	Renewables obligation certificate
CfD	Contracts for Difference
CAPEX	Capital expenditure
OPEX	Operational expenditure

1. Introduction

In recent years there has been a growing global consensus that nations should move to reduce their dependency on finite and heavily polluting fossil fuel generation to service their energy needs. To achieve this, ambitious targets for renewable energy have been specified, not least in Europe. In 2009 the European Commission set an objective that requires 20% of Europe's gross final energy consumption to be met by renewable generation sources by 2020 [1]. Wind energy is one of the most mature renewable energy technologies meaning that a large proportion of the targets are due to be met through rapid expansion of both the onshore and offshore wind energy sectors across Europe. The proposed expansion of the offshore wind energy sector brings with it many challenges which must be addressed to enable both reliable and affordable provision of energy from a previously unexploited resource. Among these challenges is the task of providing a reliable means of transmitting increasingly far offshore wind energy to onshore load centres. This has the potential to stretch traditional HVAC transmission technology beyond the limits of its capability and so emerging HVDC technologies are being considered as a means of developing future offshore transmission systems.

1.1 Development of Offshore Wind Energy Sector

As Figure 1.1 demonstrates, the installed capacity of wind power globally has grown exponentially over the past two decades from just 7.6 GW in 1997 to almost 370 GW as of the end of 2014 [2].

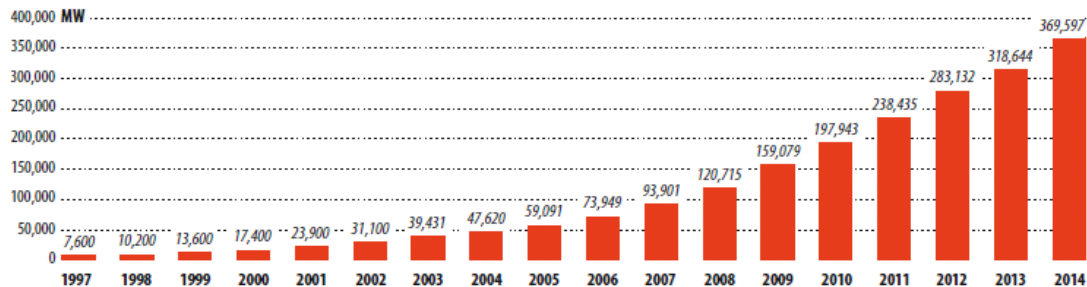


Figure 1.1 - Global cumulative installed wind capacity to 2014 [2].

This expansion has been led by developments in Europe, North America and Asia primarily and the vast majority of installed capacity to date has been realised through onshore developments. In 2014 China represented 31% of global installed wind capacity, the USA 17.8% with European countries supplying the majority of remaining capacity as illustrated in Table 1.1 [2].

Table 1.1 - Breakdown of installed global capacity by country in 2014 [2].

Country	MW	% SHARE
PR China	114,609	31.0
USA	65,879	17.8
Germany	39,165	10.6
Spain	22,987	6.2
India	22,465	6.1
United Kingdom	12,440	3.4
Canada	9,694	2.6
France	9,285	2.5
Italy	8,663	2.3
Brazil*	5,939	1.6
Rest of the world	58,473	15.8
Total TOP 10	311,124	84.2
World Total	369,597	100

Offshore wind energy on the other hand has not developed at the same scale or pace as the onshore sector due to the significant costs and challenges inherently involved. There are, however, a number of advantages associated with locating wind farms offshore, some of which are listed below with reference in part to [3]:

1. Introduction

- Large areas available for development with limited environmental impact.
- High mean wind speeds which lead to high capacity factors.
- Wind turbulence is low.
- Landfall of cables and points of connection to the power network can be close to load centres.
- Avoid visual impact issues that often hold back onshore developments.

The advent of large scale multi-MW turbines in recent years offers economies of scale that bring overall costs down and allows the large offshore wind resource to be tapped into thus paving the way for similar future growth in this sector. As stated, high mean wind speeds in offshore regions are one of the key reasons for a desire to harness wind energy from the otherwise undesirable offshore environment and Figure 1.2, illustrates that the offshore wind resource is considerably better than most onshore regions in Europe [4].

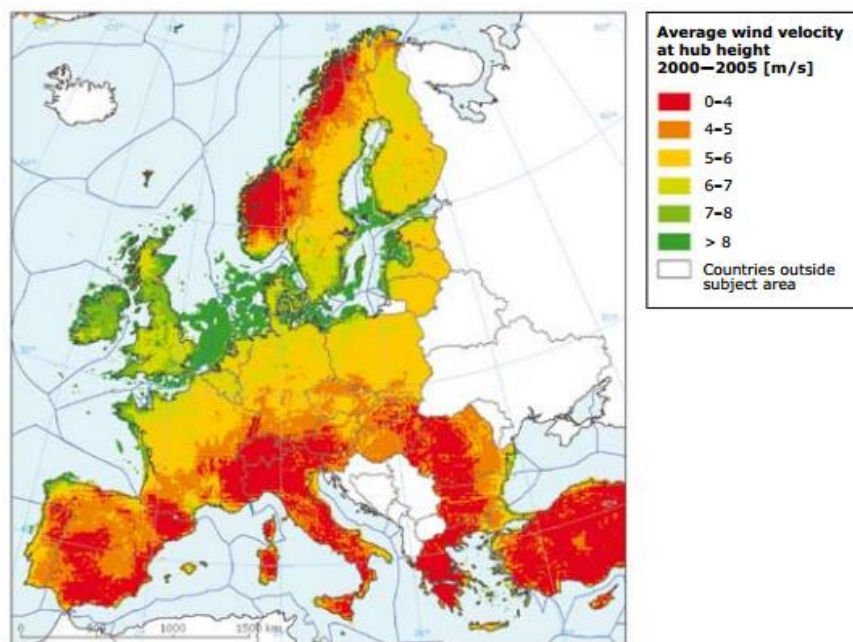


Figure 1.2 - Average measured European wind velocity onshore and offshore 2000-2005 [4].

The offshore wind energy sector has thus far been dominated by growth in Europe with over 90% of the 8.76 GW global installed offshore capacity, as of 2014, being in the North Sea, Baltic Sea, Irish Sea or English Channel [2]. The UK has led this growth to date with 4GW of operational offshore wind capacity in UK waters as of

1. Introduction

the end of 2014 [5]. There are a number of reasons why the UK has been well placed to lead the growth of offshore wind, the most obvious of which is it being an island nation entirely surrounded by seas with excellent wind resource. Additionally, large areas of, for example, the North Sea are relatively shallow with water depth typically below 100m with some Southern regions below 40m [6]. This means that fixed installation of wind turbines to the sea bed is both technically and commercially viable and so a number of relatively close to shore projects have been developed.

Looking to the future there are some extremely ambitious plans for the development of offshore wind power in the UK and across Europe. The European Wind Energy Association estimate that offshore wind capacity in Europe could reach up to 28 GW by 2020 and 150 GW by 2030 [7, 8]. Such an expansion in development means the scale and distance from shore of projects is likely to become increasingly large. This is exemplified by the extent of the UK Round 3 offshore development zones which were released for tender by the Crown Estate in 2009 as shown in Figure 1.3 [9].

The largest UK wind farm to date is London Array which has a capacity of 630 MW and sits 20 km from shore [10]. The Dogger Bank offshore Round 3 development zone in comparison sits between 125-290 km from the UK shore and has an agreed target for the development of 7.2 GW of wind capacity [11]. This highlights the scale of planned development which will bring with it many logistical obstacles, not least the challenge of developing a cost effective and reliable grid infrastructure to deliver the offshore wind energy to shore.

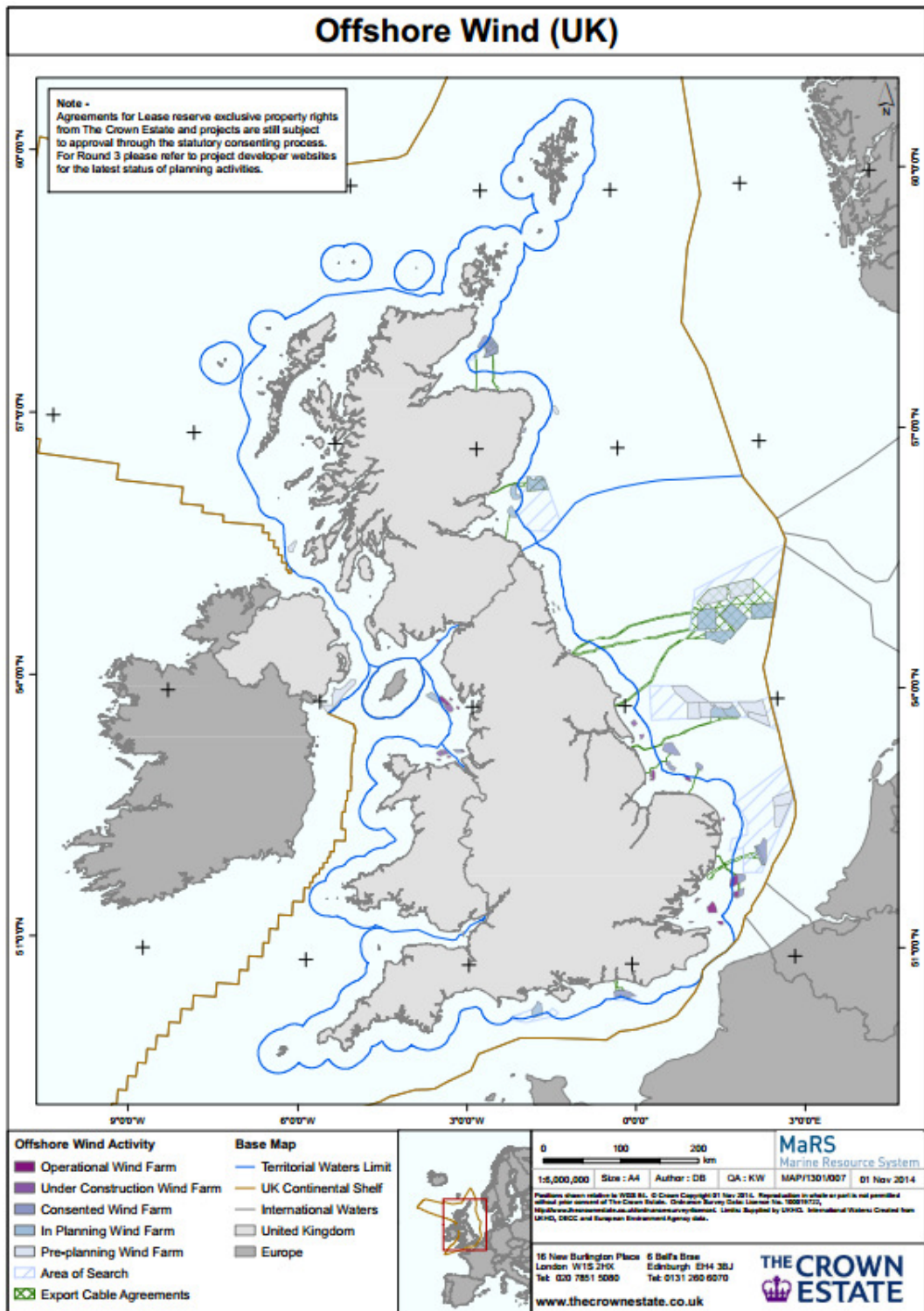


Figure 1.3 - UK offshore wind map [9]

1.2 The Need for Offshore Grids

To facilitate the expansion of wind energy and other renewable energy sources across Europe there is also a need to increase interconnection capacity between the different distinct electrical islands that operate on the continent. Amongst the other benefits of bringing increased generation capacity to a wider market, a high level of interconnection helps aid the security of supply in regions with increasing penetration of intermittent renewable generation. The European Network of Transmission System Operators predicts that by 2030 interconnection capacity within Europe must double on average [12]. This means that in addition to the proposed expansion of offshore wind in Europe there are also plans to increase the level of interconnection between the different distinct electrical islands that operate on the continent. The UK already operates several point to point interconnection projects with two 500 MW links to Ireland, a 2 GW connection to France and a 1 GW connection to the Netherlands and this is expected to at least double out to 2030 [12, 13]. New electrical infrastructure in the North Sea is therefore required for both the connection of wind power and the interconnection of regions.

There is a general consensus that some kind of co-ordinated approach is necessary to deliver the required offshore grid infrastructure in a cost-effective manner. This is evidenced by the fact that ten countries are signed up to the North Seas Countries Offshore Grid Initiative (NSCOGI) which seeks to provide ‘a framework for regional cooperation to find common solutions to questions related to current and possible future grid infrastructure developments in the North Seas’ [14]. Much of the high level analysis on the topic points towards the use of HVDC technology and that there is a strong case for a highly co-ordinated design. There are numerous publications on the topic of an integrated, multi-terminal or meshed offshore HVDC grid, often termed the ‘supergrid’ which could be created with the dual purpose of delivering offshore renewable generation and providing interconnection capacity between regions [14-16]. Two of the most obvious benefits of a multi-terminal network are the ability to re-route power under fault conditions and the capacity to share resources and minimise the total number of network components required [17]. There exist, however, some significant barriers to delivering such a concept in terms

of the vast economic outlay, technological advancements and regulatory alignment that would be required. A move towards a co-ordinated design is also in contrast to the preferred method of wind farm developers to date, which has been to build individual projects with simple radial solutions which can be developed relatively quickly and free from financial, technical and regulatory complications.

Several European wide initiatives and cooperatives have been established to try and tackle the issues surrounding offshore grid development and a review of the progress of these and associated works is presented in this thesis and underpins the focus of the work. This process highlighted a number of areas relating to the development of offshore grids that require ongoing research. It is clear that the technology is largely available to deliver far offshore grids and it is most likely that an HVDC solution will be applied. The development of HVDC circuit breakers is one area that is yet to be fully addressed however with proposed solutions expected to be expensive. It is also clear that there is as yet no consensus on preferred grid topology and configuration although a number of options are available. Further to this very few studies to date are found to have considered the impact of a lifetime of fault conditions on the overall cost effectiveness of grid options or looked to characterise the inherent difficulties of responding to and addressing failure of components in the harsh and often inaccessible offshore environment. There is therefore an obvious requirement for a detailed method of assessing the reliability of various offshore network design options which this research looks to address.

1.3 Objectives of Research

This research project looks to address a number of key questions relating to future offshore grid development through the development of a full cost benefit analysis of different offshore network design options. To deliver this the following research objectives were identified:

- **Technical Review** - A thorough literature review is required to assess the current status of technology development and to gain an understanding of the unresolved issues to be addressed to allow delivery of future offshore network options. The technical review highlights the range of options available to offshore network developers and unearths knowledge gaps that in turn guide the focus of work for this research project.
- **Develop Reliability Model** - The main novelty of this research project is the application of a comprehensive reliability model to offshore network design options. The key requirements of the model are as follows:
 - The model should be capable of handling various offshore network design options.
 - Realistic faults should be applied to the network options.
 - The appropriate post fault network response and or network reconfigurations should be applied.
 - Realistic constraints such as the dependency of offshore component repair times on weather conditions and delays to procurement of vessels and spare components should be incorporated.
 - Calculation of reliability performance should be measured through the ability of each grid option to meet its objective of delivering offshore wind power to shore and providing inter regional transmission capacity if applicable.
- **Develop Cost-Benefit Analysis** - To deliver a comparison of different grid options a number of features need to be modelled on top of reliability performance to fully cost each option. Project capital costs are developed through application of published cost estimates; electrical losses are calculated using published data relating to component efficiency and estimates of power flows under different operating conditions; and finally a consideration of operational maintenance costs is made. These features, applied in conjunction with the main reliability analysis allow

1. Introduction

full consideration of the costs and associated benefits of different network configuration and technology options.

In performing these tasks this research project looks to address some of the key outstanding questions relating to offshore network development:

- What is the value of having redundant transmission paths in offshore network designs compared with more traditional radial solutions?
- Are multi-terminal or meshed offshore HVDC grids incorporating the widespread use of potentially costly HVDC circuit breakers financially viable and are there any alternative options?
- Which grid design options provide the most value for money in terms of revenue potential against capital expenditure and running costs?
- What are the key drivers behind the reliability of electrical infrastructure in the offshore environment?

1.4 Publications

The following publications have been obtained as a direct result of work relating to this thesis:

Journal Contribution

C. MacIver, K. R. W. Bell, and D. P. Nedic, "A Reliability Evaluation of Offshore HVDC Grid Configuration Options," *Power Delivery, IEEE Transactions on*, vol. PP, pp. 1-1, 2015.

Conference Proceedings

C. MacIver, K. R. W. Bell, and D. P. Nedic, "A comparison of design options for offshore HVDC networks through a sequential Monte-Carlo reliability analysis," presented at EWEA 2014, Barcelona, 2014.

C. MacIver and K. R. W. Bell, "Reliability Analysis of Design Options for Offshore HVDC Networks," presented at the Cigré Paris Session, paper B4-111, Paris, 2014.

In the duration of the project the author has also been the main contributor to the following unrelated publication:

Journal Contribution

C. MacIver, A. Cruden, W. E. Leithead, and M. P. Bertinet, "Effect of wind turbine wakes on wind-induced motions in wood-pole overhead lines," *Wind Energy*, vol. 18, pp. 643-662, 2015.

1.5 References

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- [17] S. Cole, K. Karoui, T. K. Vrana, O. B. Fosso, J.-B. Curis, A.-M. Denis, et al., "A European Supergrid: Present State and Future Challenges," presented at the 17th Power Systems Computation Conference, Stockholm, Sweden, 2011

2. Technical Review: State of Knowledge on Offshore Networks

As the offshore wind industry expands into deeper waters that are much further from shore there will be a need to abandon existing methods of delivering power to shore and make use of new and untested technologies. This chapter of the thesis will give an overview of the different proposed technologies that could be used to deliver future offshore grids as well as an examination of the various topology, configuration and protection options available to offshore developers. There is also a discussion of the regulatory issues surrounding cross jurisdiction offshore networks and a consideration of the work that has been done to date on offshore network reliability before a scope of work for the remainder of the thesis is set out.

2.1 Technology Status

This section provides an overview of the key competing and enabling technologies that are likely to be used in the development of offshore networks. The development status and readiness for use of technologies is assessed along with potential for future advancement.

2.1.1 HVDC vs. HVAC

The vast majority of offshore wind farm installations to date have used conventional AC connections to shore via subsea cables. For example, in the UK to date, Greater Gabbard is the operational commercial wind farm that is both farthest from shore, 26 km, and in deepest waters, 34 m. It makes use of three 45km long 132 kV HVAC export cables to transmit power from the 504MW capacity wind farm [1]. However AC cables are inherently subject to capacitive charging effects which limit the amount of real power that can be transferred over the cable. Over short distances these effects are relatively minor but as you move to longer circuit lengths the effects become more pronounced. In onshore applications reactive compensation units can be used to alleviate some of the capacitive charging effects and free up more of the cable's current carrying capacity for the transfer of active power. Generally such units are placed at either end of the cable route but over long distances it is sometimes necessary to have compensation placed mid route. This naturally adds costs and when you go to offshore environments reactive compensation would require either separate platforms or increased converter platform size. Space and cost are at a premium in offshore applications meaning that reactive power compensation can be prohibitively expensive. Compensation can be placed onshore alone but the effectiveness of such a regime is severely mitigated meaning at a certain distance the economics of using HVAC transmission for offshore applications become difficult to justify [2]. Figure 2.1 illustrates the limitations of 275kV and 400kV HVAC cabled transmission as distance increases for regimes with a 50/50, 70/30 and 100/0 split of onshore/offshore reactive compensation.

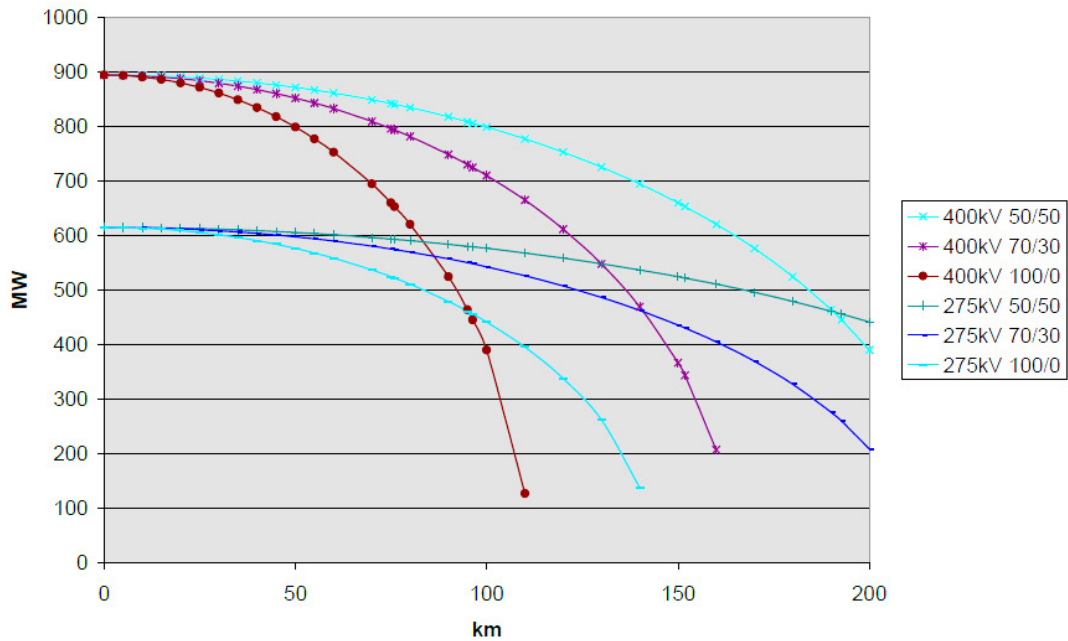


Figure 2.1 - Real power transfer vs circuit length for AC cables under different compensation regimes [2]

The alternative to HVAC is of course HVDC, which requires converter stations to transform AC power to DC for transmission along DC cables and then back again for distribution to load centres. The base costs of HVDC are higher than that of AC transmission due to the converter stations but the use of direct current for transmission means the cables are not subject to the same capacitive charging effects so cable losses are much lower. The cable requirements themselves are also reduced due to the move away from 3 phase power transfer. As such, HVDC has been popular for long distance bulk power transmission and there are several long standing examples of existing HVDC schemes both onshore and offshore. Offshore, these have almost exclusively to date been point to point regional interconnection projects such as that between the UK and France [3]. There have been several studies comparing the costs of using HVAC and HVDC transmission methods in an offshore grid context and all have come to the conclusion that there is a breakeven distance at which HVDC projects become more cost effective than HVAC projects. The exact value of this point differs from project to project and depends on many factors which have led to different conclusions. Reference [4] asserted that HVDC becomes more economic at between 30-40km offshore whereas [5] concludes that HVAC offshore projects can be feasible up to between 70-100km offshore and [6] reported a scenario where a 1GW HVAC wind farm connection could be pushed as far as 160km

offshore economically. Figure 2.2 outlines how this breakeven point is determined for a particular project.

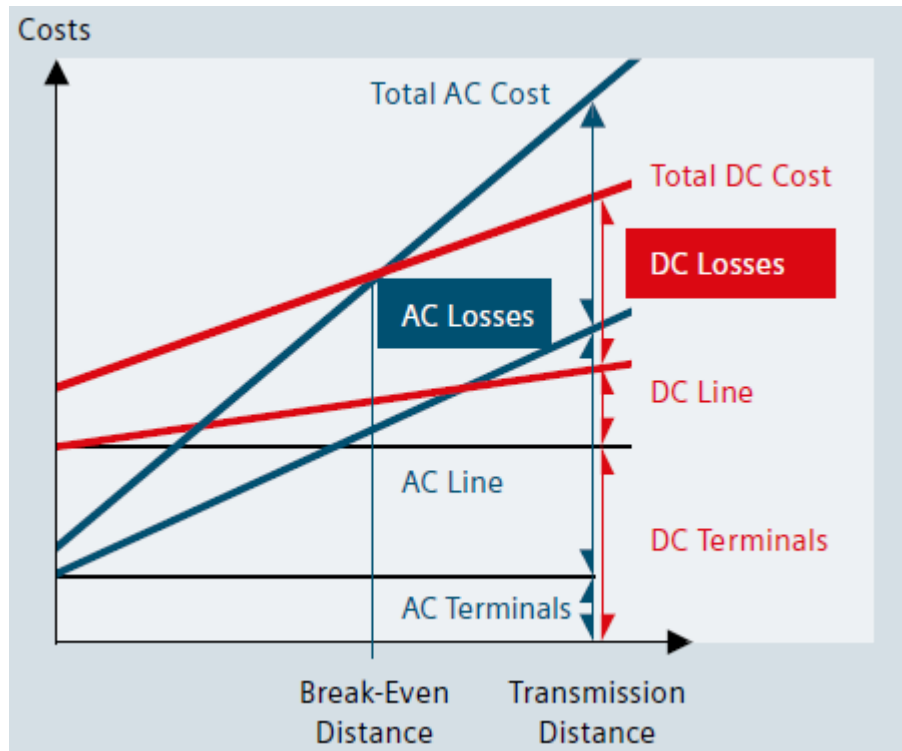


Figure 2.2 - Example plot of cost comparison vs. distance for HVAC and HVDC transmission projects [7]

Given that the proposed distances to shore of many future offshore developments could greatly exceed 100km, it is clear that HVDC technology is likely to be the most feasible option for electrical transmission in many cases. This presents a huge challenge in that the use of HVDC technology, until recently, has been restricted to mainly point to point interconnection between regions. The 400 MW Bard 1 German offshore wind farm, commissioned in 2013, is the first to be connected to shore using HVDC via the ± 155 kV Borwin1 offshore HVDC platform [8]. Borwin1 is the first of several HVDC projects planned for the German offshore wind sector with larger projects such as the ± 300 kV, 800 MW BorWin2 and the ± 320 kV, 800 MW DolWin1 schemes due for commissioning in 2015 and beyond [9, 10].

2.1.2 HVDC Converter Technology: VSC vs. CSC

There are two distinct versions of HVDC conversion methods for connection to AC systems; current source converters (CSC) which require an external synchronous AC voltage source for commutation or voltage source converters (VSC) which are built

with self-commutated devices. Within each of these categories there are also numerous variations on converter design. Historically HVDC projects have been based on CSC technology but the advent of technology advancements has led to the increased use of VSC technology. This section presents an overview of each of these technologies, comparing their relative benefits and limitations.

2.1.2.1 Current Source Converter Technology

2.1.2.1.1 Operation

The first HVDC projects were made possible in the 50's with the development of mercury-arc valves. This technology made high power DC transmission commercially viable for the first time. Thyristor based valves appeared in the early 70's allowing for simpler and scalable converter designs and since then has been the technology of choice for CSC projects [11]. Thyristors are a semiconductor component that allow current to pass in one direction when triggered by an externally fed gate signal. They can be arranged to form converter bridges which can be stacked in series and parallel to achieve the desired voltage and current ratings. CSC HVDC has been used for long distance bulk power transmission projects using both overhead lines and underground or submarine cabling as well as the connection of independent asynchronous AC systems. Line commutated converters (LCC) are the most commonly deployed CSC converter type and typically consist of two six-pulse thyristor bridges connected in series as shown in Figure 2.3.

Power conversion is achieved through a synchronised firing sequence of the thyristor valves whereby current is commutated from one phase to the next in a so called full wave conversion process. To ensure commutation and avoid voltage instability line-commutated CSCs require to be connected to a relatively strong AC grid with short circuit ratio (SCR) which is typically a minimum of 2 [12]. SCR is defined as the ratio of three phase AC short circuit capacity to the converter power rating. It should be noted that in certain applications LCC type CSCs have been successfully operated in networks with SCR less than 2 and that the capacitor-commutated converter (CCC) design variant allows connection to AC grids with SCR as low as 1 [12]. The more commonly used LCCs also absorb reactive power during operation in both inverter and rectifier mode and this has to be provided by the installation of large

switched capacitor banks or other reactive compensation units. Further to this AC and DC filters and DC reactors all have to be installed to mitigate the impact of harmonics introduced on both the AC and DC side via the conversion process [5].

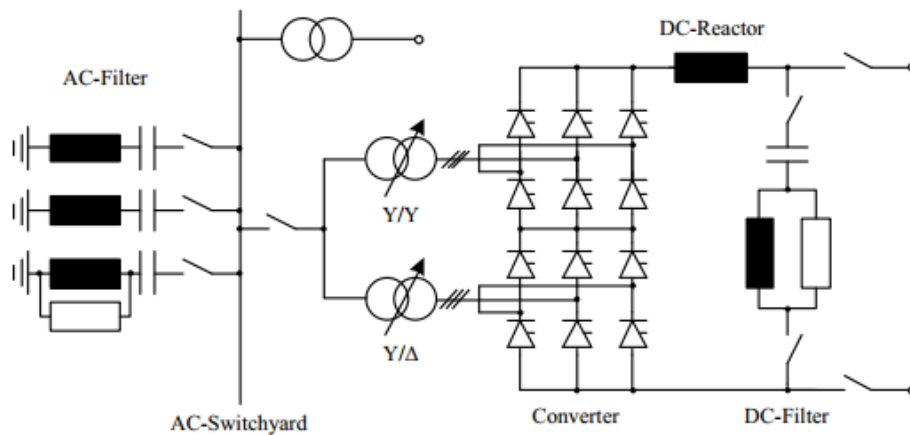


Figure 2.3 - Typical 12-pulse LCC HVDC converter configuration [11]

2.1.2.1.2 Capability

CSC HVDC as mentioned previously is well suited to bulk power transfer and interconnection of two asynchronous systems. There are a large number of CSC installations world-wide and as the technology has matured the voltage levels, power capability and transmission distances achievable through CSC projects have greatly increased. Bipolar operation at $\pm 800\text{kV}$ for overhead line (OHL) onshore projects has been achieved allowing for the implementation of single projects with transmission capacity of over 7GW [5]. In the next few years it is expected that projects in China could be installed at $\pm 1100\text{kV}$ with transmission capacity of up to 10GW [13]. Cable based projects have also advanced in scale with the UK Western Link project set to be installed at $\pm 600\text{kV}$ to provide 2.2GW of transmission capacity [14]. A key advantage of CSC is that it offers a low loss transmission option with the dominant converter losses said to be in the region of 0.75% per converter for a 1GW system [11]. CSC is therefore a mature and low risk technology that is a proven alternative to AC transmission and is highly suited to bulk power transfer over long distances.

2.1.2.1.3 Limitations

The need to connect to a strong AC grid limits the potential use of CSC HVDC for the connection of relatively weak offshore wind farm AC grids to shore. CSCs also have a comparatively large station footprint due to the need for a range of supplementary reactive power sources and filtering equipment. Large station footprint could significantly add to the cost of installation in the offshore environment. Reversal of power flow in a CSC converter system is achieved by polarity reversal which means it is difficult from a power control perspective to use CSC within a multi-terminal system, although there are two examples of three terminal CSC systems in operation [4]. This same issue also means CSC can only be used with Mass Impregnated cables and not modern XLPE systems (see Section 2.1.3.3) as polarity reversal can lead to the breakdown of XLPE cable insulation through a space charge phenomena. The fact that thyristor valves rely on a gate signal fed from the operational AC network to allow them to conduct current means line commutated converters have no inherent black start capability [12]. This is another limitation which makes CSC HVDC largely unsuitable in the context of connection to offshore wind farm networks.

2.1.2.2 Voltage Source Converter Technology

2.1.2.2.1 Operation

The advent of insulated gate bipolar transistors (IGBTs) with comparable power capabilities to thyristors made voltage source HVDC possible with the first project demonstrated in 1997 [15]. IGBTs are solid state semi-conductor devices which are, unlike thyristors, self-commutating meaning they can be switched on or off independently of the current flowing through them. This feature allows pulse width modulation (PWM) or multi-level conversion techniques to be applied. There are numerous versions of VSC converter technologies which apply these techniques in different forms but a generic VSC set-up is shown in Figure 2.4.

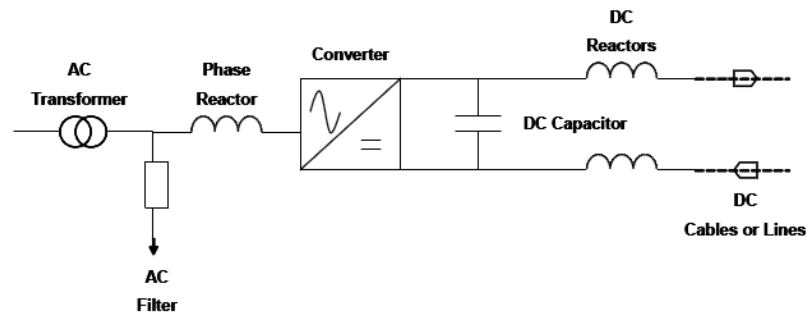


Figure 2.4 - Typical VSC HVDC system layout [5]

The transformers used in any HVDC system are subject to high electrical stresses and are specially designed compared with conventional power transformers. The AC filters along with the phase reactors work to produce a clean sinusoidal AC waveform at the AC grid side. The phase reactors also limit short circuit currents as well as being the key component that allow VSCs to independently control active and reactive power. This is because the fundamental frequency voltage across the phase reactor sets the power flow between the AC and DC sides. The DC capacitor acts as an energy store and a low inductance path for turn-off current as well as aiding with harmonic filtering of the DC side voltage. Finally the DC reactors provide smoothing of the DC output to further remove harmonics [5].

The most established VSC configuration is the two-level converter which employs PWM as the method for synthesis of an AC waveform. Such an arrangement consists of two devices per phase which allow the voltage to be switched between two distinct levels, $\pm \frac{1}{2} V_{DC}$. The switching frequency between the two levels is fixed and can be as high as 2 kHz but the ‘on time’ of each voltage level is sinusoidally varied to give a fundamental sinusoidal AC output waveform which can then be smoothed and filtered. Figure 2.5 gives an example to illustrate this process.

Such a technique allows the direction and magnitude of Real and Reactive power to be controlled independently of one another making VSC technology much more flexible than CSC. The high frequency switching however means the on state losses within such a set-up are high compared with CSC technology, around 1.75% per converter for a 1GW station [16], although the harmonic content is significantly reduced. This reduces filter requirement meaning the footprint of VSC stations can

be up to 50% smaller than CSC stations making them more appropriate for offshore applications [5].

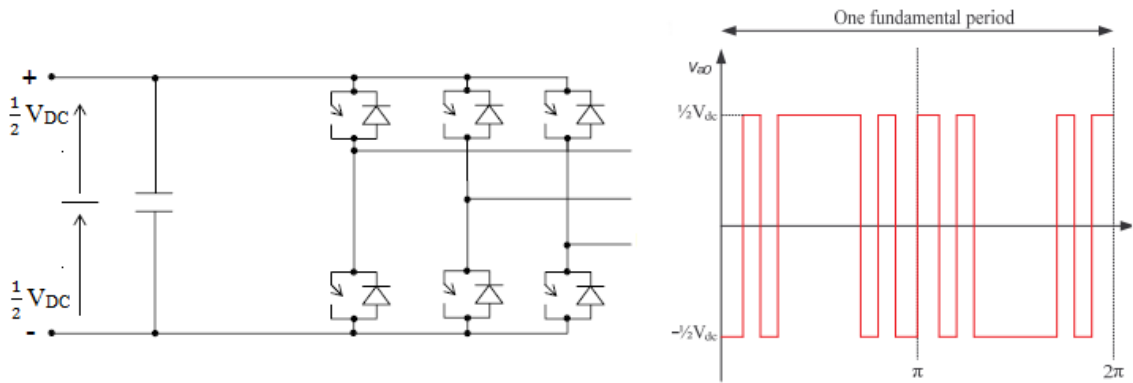


Figure 2.5 - Three-phase two-level converter and associated single phase voltage waveform [12, 17]

Three level converter set-ups, also known as neutral point clamped (NPC) systems, have also been implemented where a third voltage state, 0V, is added. This design, shown in Figure 2.6, allows for a lower switching frequency which reduces losses compared with a two level converter but requires more components leading to a larger footprint and a higher capital cost as trade off [12].

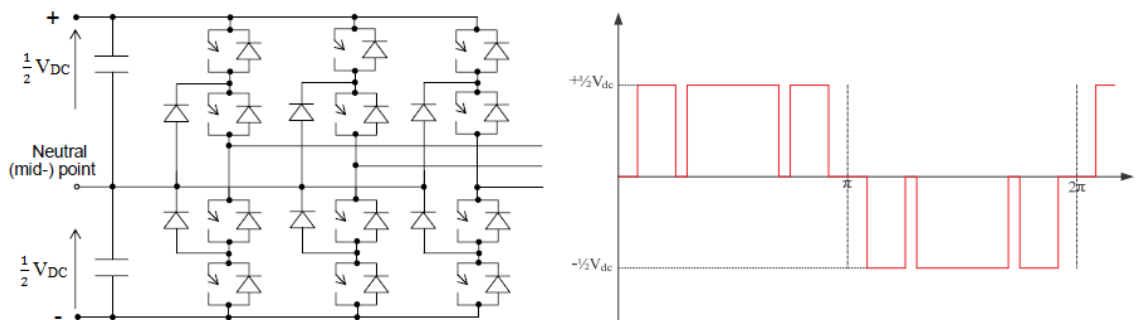


Figure 2.6 - Three-phase NPC converter and associated single phase voltage waveform [12, 17]

Modular multilevel converters (MMCs) are an alternative design option for VSC transmission and make use of a large number of cascaded half-bridge IGBT sub modules which act to construct the AC voltage profile in discrete steps rather than through PWM techniques. Figure 2.7 shows one phase of an MMC configuration and illustrates how this set up constructs a very close approximation to a sinusoidal AC waveform using numerous discrete voltage steps.

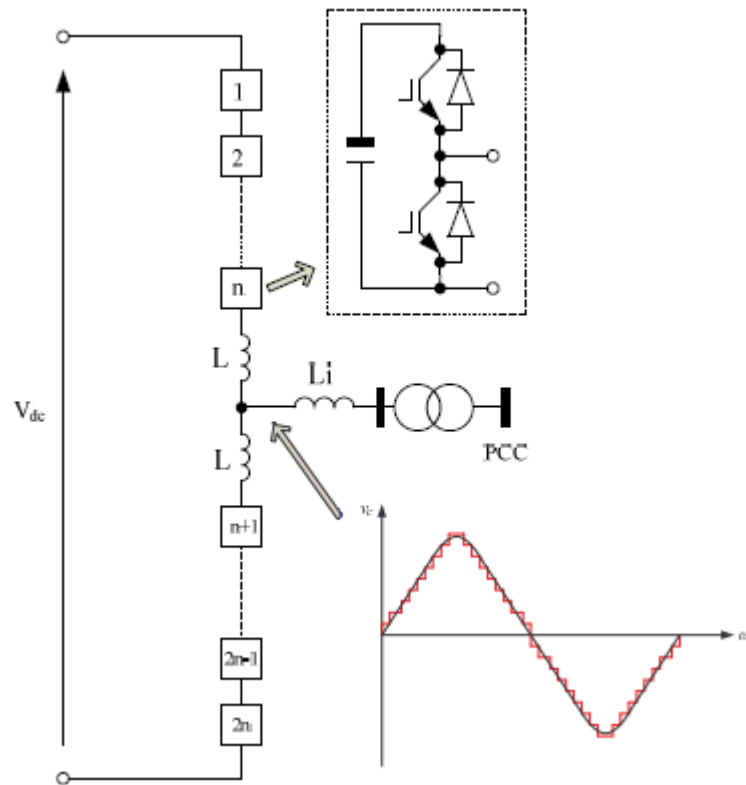


Figure 2.7 - One phase of a MMC converter showing IGBT sub module and construction of voltage waveform [12, 18]

MMCs are a relatively new concept with the first example installed by Siemens in late 2010 [19]. Despite a lack of operational history the benefits of such a system appear clear. MMC technology offers broadly the same controllability features as PWM methods but the filter requirements are much lower due to the close approximation of the output sinusoid. The main advantage however is that the required switching frequency per IGBT is significantly lower meaning losses for MMC HVDC systems can approach levels close to CSC systems, estimated at 0.9% per converter for a 1GW station, despite having higher on state losses than two or three level HVDC converters [5, 11, 12]. The use of half-bridge converter cells means that, in the event of a fault on the DC side, current will flow through the free-wheeling diodes leading to high fault currents and voltage collapse on the DC system. To avoid this scenario, accompanying HVDC circuit breakers (DCCBs) would be required within a DC grid utilising MMC converters. As explained in Section 2.1.4 the design of affordable DCCBs at the required power rating is a significant challenge to the industry.

A number of new VSC design concepts are also under development and this is an active area of research. One of the most promising concepts is that of an H-bridge based multilevel converter (HB-MMC) [20]. The HB-MMC makes use of full-bridge converter sub modules meaning that there are double the number of IGBT units required which increases both the cost and on state losses of the system compared with the half bridge MMC option. The HB-MMC design, however, offers reverse current blocking capability which would significantly reduce the technical requirements placed on DC side protection equipment. The alternative arm modular multilevel converter (AA-MMC) [21] option is a proposed design which looks to deliver the reverse current blocking capability of the HB-MMC option but with reduced system losses. The AA-MMC uses only half the number of H-bridge sub modules as the HB-MMC design and each arm of the converter only operates over 180°. Various other options have been proposed as alternatives to existing converter set-ups such as hybrid multilevel converters with and without fault blocking capability which look to reduce station footprint further. Investigation of the trade-offs between the most likely converter design options is required to find the most cost-effective approach to delivering offshore grid developments.

2.1.2.2.2 Present Capability

VSC HVDC is a less mature concept than CSC and despite the benefits introduced by IGBTs the power throughput of these devices is less than that of thyristors which means the maximum size of individual VSC projects is smaller than that of CSC projects. However, as the technology grows so too does the capability and the biggest single VSC project to date is the 2GW INELFE onshore connection between France and Spain which has two $\pm 320\text{kV}$, 1000MW bipoles operating in parallel. The maximum realised capacity of a single system is the 500kV, 700MW Skagerrak 4 monopole system which implies a 1400MW bipole system could be implemented with current technology as is planned for the NorGer cable route expected to link Norway and Germany in the coming years [5]. These figures are likely to increase further in the future with incremental improvements in areas like the current carrying capability of IGBTs.

2.1.2.2.3 Limitations

VSC HVDC is a very promising technology with a high degree of power controllability, black start capability and ever increasing transmission capacity. VSC technology is clearly the best option for connection of the next generation of far offshore wind farms and provides flexibility for the development of co-ordinated multi-terminal or meshed grids which in the offshore setting could also facilitate regional interconnection. The main drawbacks of the technology are its relative immaturity and the potential need for additional DCCBs which are yet to be commercially delivered. The reliability of VSC components in the ocean environment is unknown due to the very limited field experience which can be drawn upon so best estimates must be made. There are a number of different converter configurations within the VSC bracket and a suitable trade off must be found in terms of capital cost, losses and reliability to allow for confident investment in any given VSC HVDC based project. Standardisation between different manufacturers could allow for cross compatibility between separate converter options integrated within the same grid. Strong indicators of future investment should continue to drive industry developments forward.

2.1.2.3 Overview

It has been found that there are viable technologies presently available for future development of an offshore grid interconnecting large wind farm projects and European countries with some form of VSC HVDC likely to be the preferred technology. The capability of several technologies and their applicability in an offshore grid scenario has been discussed and the main findings are summarised with reference to [11] and [12] in Tables 2.1 and 2.2. Given the findings, it is most likely that some form of modular multilevel VSC converter topology would be preferred for use within an integrated offshore DC grid.

2. Technical Review: State of Knowledge on Offshore Networks

Table 2.1 - Overview of transmission capabilities of CSC and VSC HVDC projects to date

	CSC		VSC	
Transmission Type	OHTL	Cable	OHTL	Cable
Max Voltage Level	800 kV	600 kV	640 kV	500 kV
Max Power rating	7600 MW	2200 MW	1600MW	1400 MW
Max Transmission Distance	Unlimited		Theoretically unlimited but for voltage drop over line	

Table 2.2 - Summary of performance features of CSC and VSC HVDC topologies considered

Features	LCC	Two level	Three level	MMC	HB-MMC	AA-MMC
Active Power Control	Discrete	Continuous (100% both directions)	Continuous (100% both directions)	Continuous (100% both directions)	Continuous (100% both directions)	Continuous (100% both directions)
Reactive Power Control	Lagging only	Continuous leading and lagging	Continuous leading and lagging	Continuous leading and lagging	Continuous leading and lagging	Continuous leading and lagging
Black Start Capability	None	Possible	Possible	Possible	Possible	Possible
AC Fault Ride Through	Very Poor (commutation failure a risk)	Very Good	Good	Very Good	Very Good	Very Good
DC Fault Ride Through	Good	Poor	Poor	Poor	Good	Good
Fault Current limiting/blocking	Blocking capability	None	None	None	Blocking and Limiting capability	Blocking and Limiting capability
DC Grid	Limited Complexity	Straightforward but requires DCCBs	Straightforward but requires DCCBs	Straightforward but requires DCCBs	Straightforward	Straightforward
On State Losses	Very Low	Low	Low	Low↑	High	Medium
Switching Losses	No	Very High	High	Low	Medium	Low
Station Footprint	Very Large	Large	Large	Medium	Medium	Small
Design Complexity	Very Complex	Relatively Simple	Medium	Very Complex	Very Complex	Very Complex
Design Maturity	Very Mature	Mature	Mature	New	In Development	In Development

2.1.3 Cable Technology

It has been established that offshore power transmission requires the use of cables. For short distances HVAC solutions can and have been implemented but as the analysis in Section 2.1.1 confirms, beyond a certain distance HVDC solutions must be utilised. There are a number of cable technologies that can be used, some established and some new. This section discusses the status of different cable technologies and their suitability for use in potential offshore grid applications.

2.1.3.1 General Cable Structure

Figure 2.8 highlights the constituent parts that go into designing a cable that is both robust to the marine environment and capable of large scale power transmission. The conducting core of most cable types is stranded copper although some applications will use aluminium due to its reduced weight and cost. Surrounding the conductor is a layer of insulation and this is generally the distinguishing feature between different cable types as will be illustrated. A metal sheath is placed outside the insulating layer to prevent moisture ingress and add mechanical strength to the cable. A further layer or two of steel wire armouring, usually helically wound, is also added to increase the cables tensile strength and ability to support its own weight during the installation process. Between each layer is some form of insulating screen and finally the cable is covered with a hard wearing outer layer of polypropylene yarn [5].

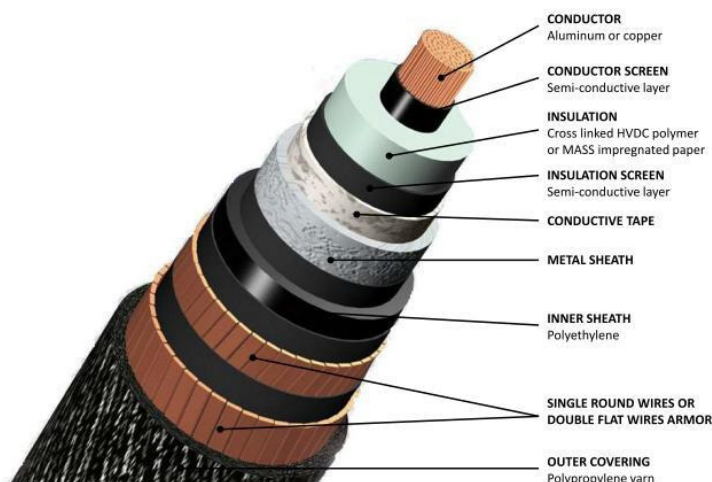


Figure 2.8 - Layout of a single core XLPE submarine cable for AC or DC technology (courtesy of EUROPACABLE)

2.1.3.2 Mass Impregnated Paper (MI)

Mass impregnated paper cable insulation consists of specially treated layers of oil impregnated Kraft paper as the insulation medium. The technology is very mature and has been the most common cable type used within marine HVAC and HVDC applications to date with service use dating back to the 50's. Mass impregnated cables are suitable for both VSC and CSC HVDC applications and can operate at voltages and current levels that currently outstrip the ability of many converter stations. The maximum temperature limit of 55°C associated with traditional MI technology however restricts further development [5]. New technology utilising polypropylene laminated papers (PPLP) with temperature limits in the region of 80°C enables higher rating and allows for the delivery of the ±600kV, 2200MW UK Western link which is the largest offshore system using MI cables and is due for completion in 2016 [14]. The industry does not expect major future development beyond current capabilities although at least one manufacturer expects that 750kV, 1500MW MI PPLP cables will be available within 15 years [16, 22].

2.1.3.3 Cross Linked Polyethylene (XLPE)

Extruded XLPE insulated cable is a relatively new cable technology with the oldest operational example project being the 2002 Cross Sound Cable in the USA [23]. XLPE suffers from a space charge phenomenon which means that the insulation becomes polarised after a long period of exposure to a constant electric field as in the case of HVDC transmission. A reversal of voltage polarity could lead to the breakdown and failure of the insulation, thus rendering XLPE cable incompatible with CSC HVDC topologies which use exactly this method for power reversal. XLPE can however be used in VSC projects and have some advantages over MI cable. XLPE cable is generally more physically robust and lighter than MI cable and the maximum temperature limits are higher. This means the current throughput for a given cross section of conductor can be higher for XLPE cable. This also means that aluminium conductors can be used instead of copper to reduce weight and cost for some projects with equal power rating although copper conductors are still generally used in subsea applications [5]. For land applications XLPE cables can be manufactured more quickly than MI cables but this is not strictly true of submarine cables which require time consuming factory joints to be implemented during

manufacture. XLPE cables are currently limited to lower voltage limits than MI cables and therefore the power levels of projects to date are lower than for projects using MI cable.

The most advanced offshore XLPE project to date is the $\pm 320\text{kV}$ Dolwin1 offshore wind connection which after completion will have 800MW bipole capacity or 400 MW/cable [24] whereas the onshore INELFE link between France and Spain utilises XLPE technology at $\pm 320\text{kV}$ and 500MW/cable [25]. It is anticipated that there are few barriers to XLPE cables continuing to improve capability and 550 kV systems allowing capacities of 1000 MW/cable are expected to be available in the near future and within 15 years it is expected that XLPE cables will match the expected 750kV, 1500MW that should be available with MI PPLP cables [5, 16, 22]. The sea depth at which cables can be buried is also expected to increase from a present limit of around 500m to 2500m [22].

2.1.3.4 Conclusions and Delivery Risks

It has been shown that both MI and XLPE cable types will be viable options for implementation within an integrated offshore HVDC grid. MI cables are commercially proven and offer high power capabilities already whereas XLPE is a new technology that is catching up in terms of potential capacity. There are benefits to either technology and it is likely that a combination of both will be used going forward. It is expected that technology will be developed to a level that will allow 1500MW single pole projects to be installed in the near future [16] and beyond this there is ongoing research looking at the potential for even greater advances in cable performance with one project looking to develop a 5000MW cable in the long term [26].

The main risks associated with subsea HVDC cable projects are the fact that there are very few factories capable of manufacturing the products. This means that if demand is to be on the scale required to meet 2020 renewable targets then supply chain bottlenecks could emerge. A BWEA report in 2010 suggested this could be a potential issue given the required 2 year lead time and suggested an increased number of factories across many supply chain industries including cable manufacture would need to be installed to meet targets [27]. Clear, policy driven incentives for

industry are required to encourage investment and tackle the challenge of supply chain bottlenecks.

2.1.4 HVDC Circuit Breakers

2.1.4.1 Introduction

Fault currents in multi-terminal and meshed DC grid systems can become very large, very quickly. This is especially true using VSC technology due to the very low limiting impedances that are present in the system design [16]. In the event of a DC side fault conventional converters would block their IGBT switches under localised overcurrent protection. The VSCs then become uncontrolled diode bridges which allow fault current to feed into the DC grid from the connected AC systems. In current point to point systems AC side protection is used in the event of a DC side fault to stop the flow of current to the DC grid and prevent damage to converters. This however leads to the temporary shutdown of the whole DC system. When expanded to large DC grids this option is likely to be unacceptable as the effects of losing the entire grid, when all AC side protection acts, becomes increasingly severe. To avoid the collapse of voltage on a VSC based DC grid, in the event of a fault, some form of fast action protection is required. If standard half-bridge VSC configurations are used and a large multi-terminal DC grid is desired then there is a requirement for fast acting, fully rated DCCBs to be implemented. The requirements of such a DCCB are sensitive to the converter design and configuration however it is expected that breaking times of less than 2ms are required [16, 28]. The use of DCCBs could be avoided, or their requirements reduced, if H-bridge converter configurations with reverse current blocking capability are used to block current flow to the DC grid. This option however comes at the cost of additional semiconductor components as discussed in Section 2.1.2.2. It should also be noted that there is research, such as that of [29], which questions the need to avoid voltage collapse on the DC grid and suggests that converters could survive DC side faults with much slower DC side breaking requirements. A reduction of the stringent requirement could allow for the use of cheaper DCCB technology but the prevailing industry consensus is to pursue the development of high speed DCCBs and this is viewed as a key technological advance which could facilitate the advent of large HVDC grids.

Interrupting current in an AC system is inherently simple due to a natural zero crossing every cycle which enables current flow to be broken by the opening of simple switches. Onshore meshed transmission systems have thus been designed to incorporate cheap and reliable circuit breakers at each end of every line allowing individual circuit sections to be isolated from the network in fault or maintenance conditions such that the rest of the network can remain operationally intact. In DC grids the current does not naturally drop to zero and this means extinguishing the arc, which forms when the conducting path is physically broken, is extremely difficult, especially at the voltage and current levels expected to be employed within an offshore DC grid. Conventional low to medium voltage DCCBs employ current limiting methods which make use of additional resistive components to reduce the current to a low enough level for arc extinction however such designs have never been scaled to higher voltage and current levels meaning they are inadequate for use in an HVDC system [16, 28, 30]. Key requirements of DCCBs are that they generate a counter voltage of equal or greater magnitude than the system voltage to generate a zero crossing and that they dissipate the large amount of energy that is stored in the system inductance. It is common, therefore, to have several parallel paths in a DCCB that share the requirements of the process. Figure 2.9 shows a typical topology of a DCCB with a primary branch with low loss switch, a commutation branch and an energy absorption branch

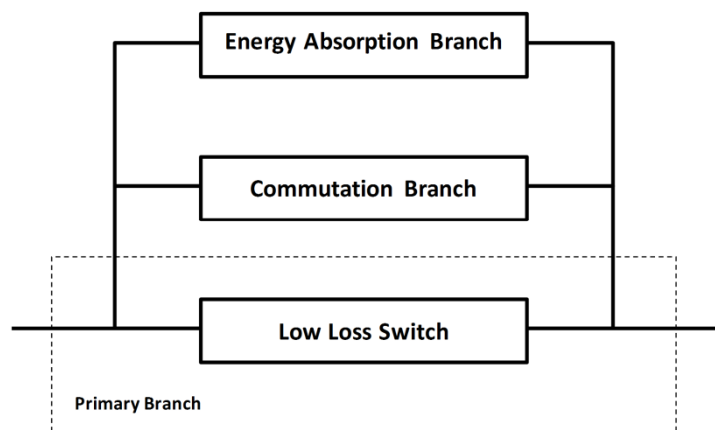


Figure 2.9 - Typical HVDC circuit breaker topology

The remainder of this section will outline current design options for DCCBs and discuss their relative merits.

2.1.4.2 Resonant Circuit Breaker

Figure 2.10 shows a typical topology of a resonant DCCB. The nominal current path contains a mechanical switch with low on state losses. Placing the additional breaker components in parallel paths means that in normal operation the on-state losses of the breaker are negligible. The commutation path in this design contains capacitive and inductive components. Upon opening of the mechanical switch these act to create a divergent current oscillation between the commutation path and the nominal path which eventually produces a large enough counter voltage to give a zero current crossing whereby the current through the mechanical switch is broken and the input current, I_0 , flows to the commutation branch. The capacitor is then charged and once its voltage exceeds a set level the energy absorption path operates introducing a resistive element which acts to bring I_0 to zero as illustrated in Figure 2.11 [30].

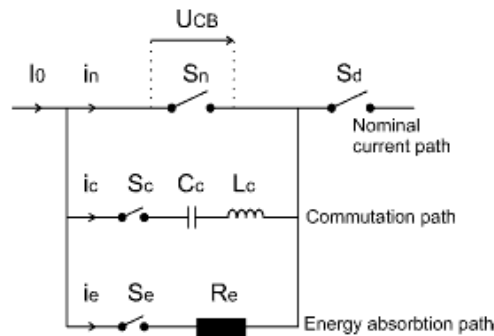


Figure 2.10 - Typical layout of a conventional HVDC DCCB [30]

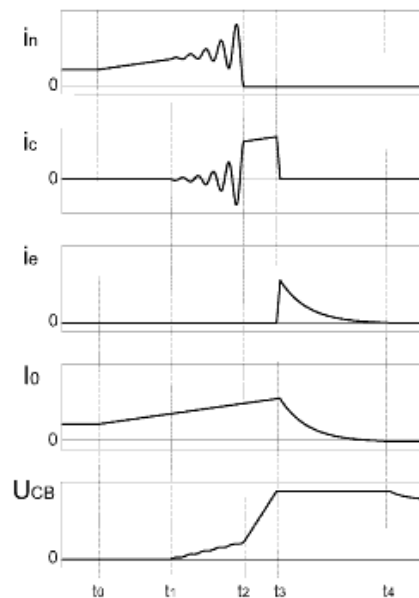


Figure 2.11 - Typical current and voltage levels during operation of DCCB [30]

Devices like the one illustrated have been demonstrated, however maximum ratings have been limited mainly due to inadequate operating times which can be as high as 60ms [30, 31]. It has been established that VSC technology is likely to form the backbone of an offshore DC grid and this technology in particular suffers from very fast current rise under DC faults meaning that resonant DCCBs are not capable of providing the extremely fast operating times that are required. This essentially rules out the use of resonant DCCBs for use within a large offshore grid where fast isolation is a determined requirement.

2.1.4.3 Solid-State Breaker

A solution that has been proposed to meet the requirement of fast operating time is that of a solid-state DCCB. This would consist solely of semi-conductor devices placed in the current path. Figure 2.12 shows the basic principle behind the solid state DCCB where the semi-conductor devices operate in the main current path with an energy absorbing arrester bank in parallel. The solid-state arrangement essentially consists of two reverse parallel inverter legs rated at full DC network voltage via the combination of series and parallel stacked IGBT semi-conductors. It is expected that the required semi-conductor capability is equivalent to one third of that required in a VSC converter station for bi-directional capability [32]. However, the breaker would not require any of the additional filtering, transformer, switchgear and controls that are required in the converter so its overall size would be significantly less than a full converter station but likely still considerable in its own right.

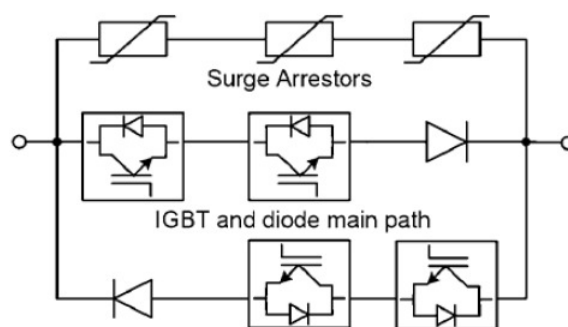


Figure 2.12 - Basic solid state DCCB topology [31]

The clear advantage of such a system is that total operation times are likely to be 1ms or less as opposed to a few tens of ms as offered by a mechanical switch method and

so is presently the only available option capable of meeting the proposed requirements of VSC based DC grids [30, 31]. This is due to the fast response nature of the power electronics which can be switched off almost instantaneously providing an appropriate fault detection scheme is in place. The drawback of such a system however is that the conducting mode resistance is in the order of $m\Omega$ compared with $\mu\Omega$ for a mechanical switch system meaning high on-state losses are present [33]. Reference [34] demonstrates a concept with on state losses in the region of 0.4% per breaker which tallies with other estimates that semiconductor based DCCBs generate transfer losses in the range of 30-40% of the losses of a voltage source converter station [28, 31]. The use of solid state DCCBs throughout a large DC grid would therefore have a considerable impact on the final deliverable energy within the system and the financial implications of that could be considerable meaning alternative design concepts are being commercially pursued.

2.1.4.4 Hybrid Solid-State Breaker

Hybrid solid-state DCCB concepts have recently been proposed and prototypes tested [28, 35-37] by both ABB and Alstom which look to merge the requirements of fast response time and low on-state losses. The design by ABB, shown in Figure 2.13, utilises a main, IGBT based, solid-state DCCB configuration as discussed above but removes this from the on-state conducting path as with conventional DCCB designs.

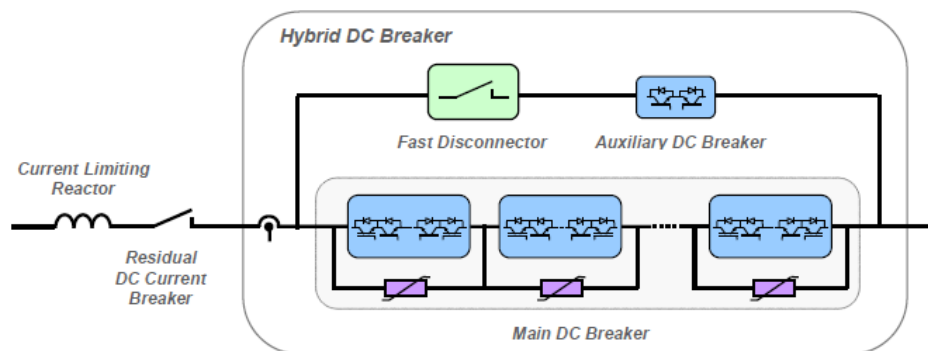


Figure 2.13 - Modular hybrid IGBT DCCB [28]

The main conducting path instead consists of an auxiliary DC breaker and fast mechanical disconnecter. Conventional DCCB designs are limited by slow opening mechanical switches however the auxiliary DC breaker of this design is able to

commutate current to the main DC breaker almost immediately in the event of a fault. After commutation occurs, the fast disconnecter, likely to be made up of several series connected mechanical isolators, is operated and the main DC breaker interrupts the current. The residual DC current breaker can finally be used to isolate the line from the DC grid to protect the arrester banks from thermal overload.

For application in an offshore grid, operating times of below 2 ms are expected to be required to avoid the need for excessively big DC reactors in the system and to allow time for correct fault detection [28]. For a 320 kV system with 2 kA rated current and the stated clearance time the proposed breaker is designed to interrupt a peak fault current of 9 kA which is also within the capabilities of current IGBT technology.

The main advantage of this design is that the on-state losses are reduced to a small percentage of those for a full solid-state DCCB because the on-state voltage drop across the auxiliary breaker path is in the range of several volts only. The design is modular and as such can easily be altered to suit different system voltage and current levels. New advances in technology, such as the use of Bi-mode Insulated Gate Transistors (BiGTs) instead of IGBTs, which can double the maximum current breaking capabilities of existing designs, are expected to enhance the capabilities of hybrid solid state DCCBs even further [38]. Hybrid solid state breakers do however face the same high costs associated with the use of a large number of semiconductor devices.

2.1.4.5 Conclusion

DCCBs have been cited in the past as a potential technological barrier to the implementation of meshed HVDC grids however it has been shown that the technology, in concept at least, does exist at present and it is expected that breakers rated up to 500kV with 32kA breaking capacity will be available within 10 years [16]. There is however, as yet, no fully deployed DCCB system meaning it could be a number of years before the concepts are proven and trusted for widespread use. Further to this there is a large degree of uncertainty as to the final cost of breaker devices with little published material. Assumptions therefore have to be based on comparisons of proposed designs compared with the cost of full converter stations given the overlap in equipment requirements. One paper [32] asserts a cost figure for

DCCBs of 20-30% of the cost of a full VSC converter but until a design is made commercially available this remains an estimate. As the cost of full VSC converter station can exceed £100 million it appears certain that the cost of protecting a, pan European, fully meshed DC grid using DCCBs would be considerable. The 20-30% figure stated falls within the region found in [39] to allow for a financially viable meshed grid which stated a requirement for DCCBs to be at most one third of the price of a full converter station. Another study which looked into the cost feasibility of a meshed DC grid in the North Sea concluded however that costs of breakers would need to be less than 10% of the cost of a full VSC station so that benefits brought through additional system redundancy and availability compared with other design options are not outweighed by cost [40]. Further to this it must be established whether or not the introduction of offshore DCCBs would require significantly increased offshore platform space or even separate platforms entirely which could again add significantly to overall project costs.

It is therefore less than clear that DCCBs will be an economically attractive option for widespread implementation in offshore grids. There is a clear need to compare the benefits and costs of DCCB protection against potential alternative options. A number of protection options are discussed in Section 2.3 and the comparison of these in terms of their impact on overall system reliability and in turn overall system costs forms a key part of this thesis.

2.2 Offshore Grid Topology Options

There are several options available to developers of offshore grids in terms of how to connect offshore wind farms to shore. These options range from simple radial connections of single wind farms to shore to the development of a fully meshed DC grid and a number of recent studies have discussed and sought to make comparisons between some of the available options [40-44]. The range of options and their merits are discussed in more detail in the following sections.

2.2.1 Radial Connection to Shore

The vast majority of current offshore wind projects are realised with a single connection to shore or multiple independent connections depending on project size as illustrated in Figure 2.14.

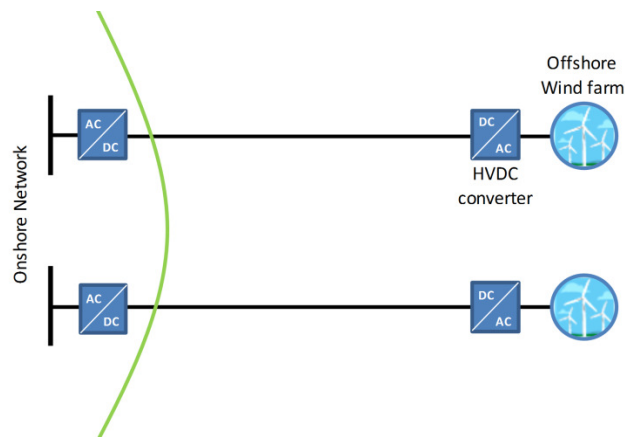


Figure 2.14 - Radial connection of wind farms to shore

This is the easiest method for developers to pursue in terms of project delivery and financial remuneration because the number of interested parties is minimised, all expenditure is accountable to the wind farm in development and the income revenue is clearly defined and solely based on the ability to deliver power to the single onshore connection point. The regulatory systems that have governed wind farm developments to date have been built around this format of connection and developers are accustomed to the processes involved. Assuming large distances from shore, such that HVDC connection is required, all wind farms that are radially connected to shore require both an offshore and onshore converter station along with a suitable landing and connection point to the onshore grid. A suitable subsea cable

route from each wind farm to shore must also be found along with an onshore transmission route to the point of connection to the grid. In theory it would be possible to remove the need for a large offshore AC to DC converter station through the use of an entirely DC network from the point of connection to the wind turbines. This would instead require DC-DC conversion techniques to step up the DC voltage from the wind turbines to a suitable level for transmission. Such methods are explored in [45, 46] however the design concept is immature and there is no evidence it is being actively considered by industry so is not discussed further in this thesis.

As the size and number of offshore wind developments expands, the viability of using radial connections to each and every wind farm is much reduced. Obtaining permission for major onshore grid infrastructure developments is becoming an increasingly difficult task as evidenced by difficult consenting processes experienced by a number of recent proposed projects [47, 48]. Further to this, finding a desirable cable route for offshore installations is a considerable task which must minimise the impact on a multitude of constraints such as shipping routes, fishing ground and areas of special protection and have suitable seabed composition for the laying and trenching of cables [49]. When considering overall costs, studies have shown that use of radial connections to shore for each proposed new offshore wind farm is likely to be uneconomical due to this option requiring the maximum possible circuit length and number of converter stations [42]. This means that a continuation of the current principle of independent radial connections of wind farms to shore is likely to be practicably infeasible at the scale required to meet targets and a degree of co-ordination is required to minimise the level of required infrastructure and to reduce costs. The following sections discuss the different options available in terms of co-ordinated offshore grid design.

2.2.2 Wind Farm Clusters

The first step that can be taken to address some of the issues with purely radial connections of wind farms is to cluster multiple wind farms, in relatively close proximity to each other, such that they share a common transmission route and connection point. This concept is depicted in Figure 2.15 and forms the basis for the

idea of grouping large clusters of wind farms in close proximity such as those proposed within the UK Round 3 development zones.

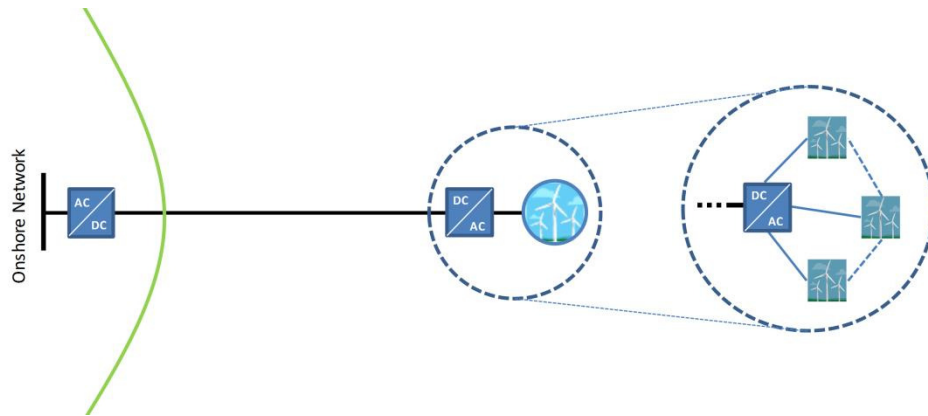


Figure 2.15 - Wind farm cluster

Limits in converter and cable capacity dictate how much electrical infrastructure can be shared but even if multiple offshore and onshore converters are still required for a given project cluster they can at least share a common cable route and onshore grid connection point. It is shown in [42] that a wind farm cluster design can be considerably more cost effective than using individual radial connections, especially if the wind farms are far from shore and relatively close to the hub point. If each wind farm is connected radially to the offshore converter then there is still a single point of failure for each wind farm from shore.

Figure 2.15 depicts an additional option which would be to add connections between the individual wind farms to provide an alternate power route in the event of certain failures. This can be done using either AC or DC connections (although the DC option would require multiple offshore converter stations) and inevitably adds capital cost to the project. However it has been shown in [43] that this method can lead to significant reductions in the amount of curtailed energy that would occur annually due to fault outages. Such a design would require careful consideration as to the best way to rate the cables given that some circuits, which would normally be fully rated to the wind farm capacity, could potentially have to carry output from more than one wind farm suggesting the need for increased capacity. The optimal level of additional system redundancy when compared to the capital cost involved is a factor which requires further consideration. Both options, however, are still subject to single

points of failure on the main transmission route that would lead to the inability to transmit the entire connected wind resource to shore.

2.2.3 Multi-terminal Grid Options

2.2.3.1 Wind Farm Tee-in

A further option for connection of offshore wind farms is to make use of pre-existing point to point interconnection between two regions. The wind farm or wind farm cluster can be teed-in somewhere along the interconnector line as illustrated in Figure 2.16 giving two routes for power transmission. The tee-in option can potentially be realised either by addition of a converter station linking to the interconnector circuits or by a more straightforward DC switching station although the first relies on the implementation of new technology [42].

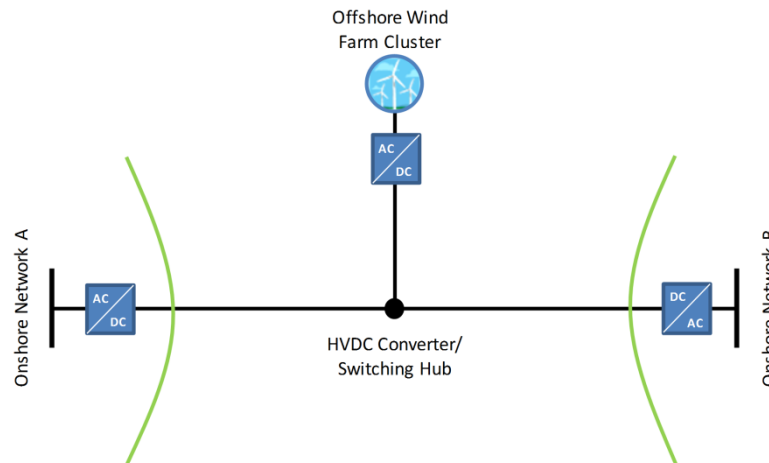


Figure 2.16 - Wind farm tee-in to existing regional interconnector

This option can have lower capital cost than connecting the wind farm to shore however opens up a series of regulatory complications. For example there is the potential in such a scenario for three different countries and/or entities to have a stake in the project as is the case with the proposed Cobra project investigated in [42] which has looked at the potential for connecting German wind farms into an interconnector between Denmark and the Netherlands. In such a case it is found that the project can be financially beneficial but that co-ordination and new regulatory frameworks must be established between the participating parties to allow this. There can also be issues around the distribution of capital cost and remuneration with some

parties likely to benefit more than others. The other important factor in such a project is that the transfer capacity for interconnection is subsequently limited after connection of the wind farm(s) by the level of output from the wind farm(s). This could potentially lead to a conflict of interest whereby one country may want to export power but is restricted by the presence of wind power on the interconnector. This again shows the need for robust regulations and prior agreement as to how such events are managed.

2.2.3.2 H-Grid

Two wind farm clusters with radial connections to shore can be connected together to form a multi-terminal DC grid. The H-Grid configuration shown in Figure 2.17 could be realised with the connection as an integral part of the original project or as an addition after the completion of two separate wind farm cluster to shore projects. The H-Grid configuration also gives the additional benefit of interconnection capacity between onshore locations A and B, which may be within the same synchronous AC area or part of two separate synchronous AC systems.

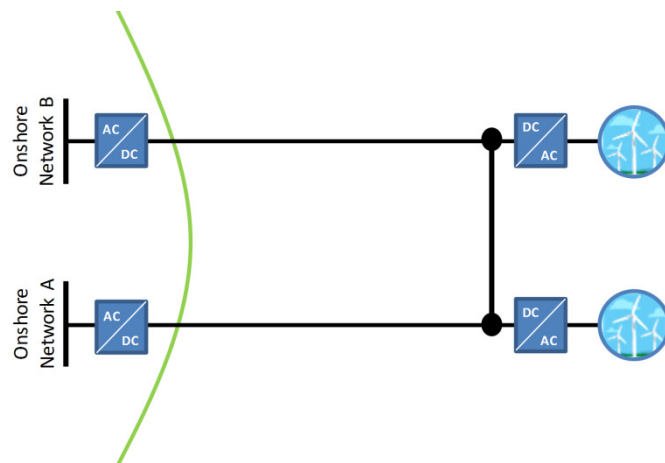


Figure 2.17 - H-Grid connection

In this case interconnection and energy trading between the two locations is not necessarily the main project driver but can be a relatively simple and cheap additional benefit on top of providing alternative transmission routes to shore for the offshore wind energy. The value of this extra redundancy when compared against the additional capital cost to the project is an issue which depends heavily on the

reliability of the individual grid components and has not been fully investigated in the literature to date.

The H-Grid configuration provides a degree of modularity that allows simple extension to additional wind farm connections. The multiple H-Grid scenario is depicted in Figure 2.18 and can be realised in two different ways. The simplest method is to have a tree like structure with one link between each transmission route. This provides a degree of redundancy against faults to any of the transmission links or onshore stations. A further step would be to have a meshed connection between each of the wind farms which provides an additional degree of redundancy which allows power transfer in the event of failures to any of the offshore links. This could require significantly increased circuit length however so the additional value of this must be weighed against the high upfront costs of cabling.

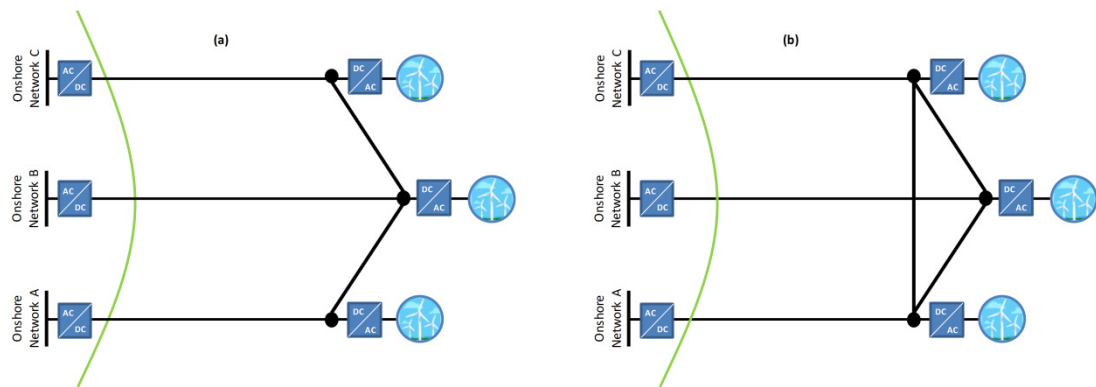


Figure 2.18 - Multiple H-grid with (a) 'tree' connection; (b) meshed connection

2.2.3.3 Ring Network

Another option that can be pursued as an advance on the H-Grid topology is that of a Ring network which would connect additional wind farms into the multi-terminal DC grid without a bespoke connection to shore as depicted in Figure 2.19. If the wind farm is added into an existing H-Grid network then it may be the case that the total rating of the connected wind farms exceeds the total transmission capacity. This could lead to the need for curtailment of wind energy during periods of high wind output. It would also reduce the capacity available for interconnection between regions. If the extension is part of the original design for the network then these issues could be factored in and, for example, additional transmission capacity built in from the beginning in anticipation of future connections. Such a move requires

strong co-ordination between parties and a willingness to incur upfront option costs which allow for expansion down the line. Compared with the H-Grid options the Ring network could be an effective way of minimising the circuit length of transmission cable and therefore costs. This option can again be achieved using both ‘tree’ and meshed connections.

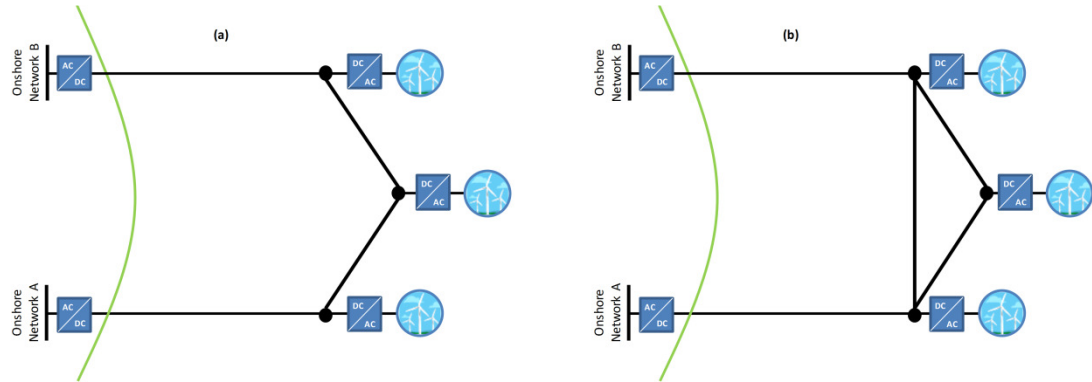


Figure 2.19 - Ring network with (a) 'tree' connection; (b) meshed connection

2.2.4 Meshed Grid

Any of the discussed multi-terminal DC grid options could be used as the first building blocks towards a fully meshed offshore DC grid connecting multiple offshore wind farms and interconnecting multiple regions as depicted in Figure 2.20.

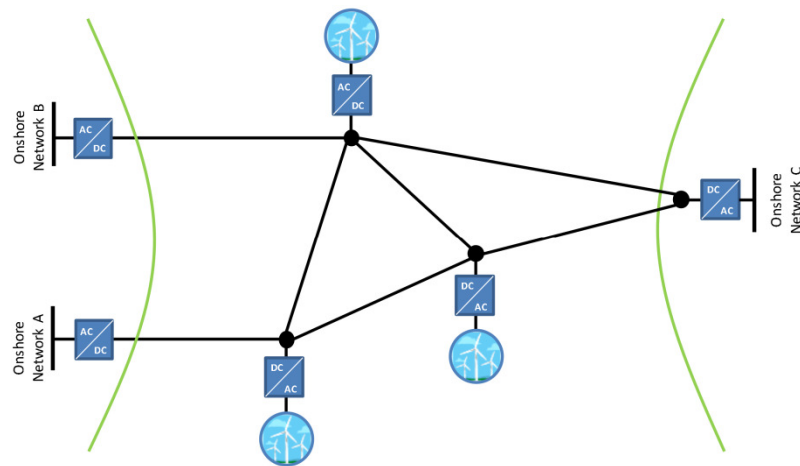


Figure 2.20 - Meshed grid

The key aspect of a meshed HVDC grid is that it provides multiple transmission routes to shore for connected offshore generation which facilitates continuity of supply provided you have branch-specific fault detection and clearance and can

control the power flow in parallel routes [50]. Once again the meshed grid provides the opportunity for energy trading between regions although this is again restricted by the level of wind energy present on the system.

The OffshoreGrid consortium [42] found that using such a system design, as opposed to the connection of wind farm clusters to shore and separate point to point interconnection between regions, can lead to infrastructure costs that are 70 to 80% lower. This is mainly accounted for by a large reduction in total circuit length and a reduced requirement for converter units. It should be noted that other studies have also looked at cost comparisons between radial and meshed or co-ordinated grid options and the benefits of meshing were found to be less clear cut. An NSCOGI study looked at a two feasible solutions for a North Sea offshore grid by 2030, one based on Radial and Interconnector solutions and one using a meshed approach where possible [51]. It found that the cost reductions through utilising a meshed solution were apparent but marginal at less than 5% for a reference case scenario with 55GW of offshore wind connection. Only when a very high assumption is made for offshore wind development of 117GW by 2030 did the cost benefits increase to around 20% for the meshed option. Another study looking at the merits of such designs with specific regard to future UK wind farm cluster connections found that when including costs of onshore reinforcement, cost reductions through co-ordination were not always apparent and varied from project to project [52]. As discussed, the dual use of connections for both wind farm export and regional energy transfer does inherently reduce the system trade benefits that can be achieved with a link purely used for regional transfers. OffshoreGrid, however, examined three separate case studies and found that, to a varying degree, in all cases there was a net benefit with reduced infrastructure costs outweighing reduced trade benefits over the lifetime of the projects [42].

2.2.4.1 'Supergrid' Concept

Several large studies have come to the conclusion that some form of co-ordinated multi-terminal or meshed offshore grid is the preferred option for connection of offshore wind in the North Sea and beyond. As previously discussed the OffshoreGrid consortium, consisting of a number of influential industry bodies has

outlined a belief that a fully co-ordinated, meshed HVDC offshore grid provides the most economic method of integrating large scale offshore wind installations in the North and Baltic seas into European electricity networks [42]. Figure 2.21 shows a proposed network layout for the North and Baltic seas which follows the principles of co-ordinated multi-terminal or meshed connection of wind farm clusters as far as possible allowing both export of wind power to shore and additional interconnectivity between the different island networks within Europe.

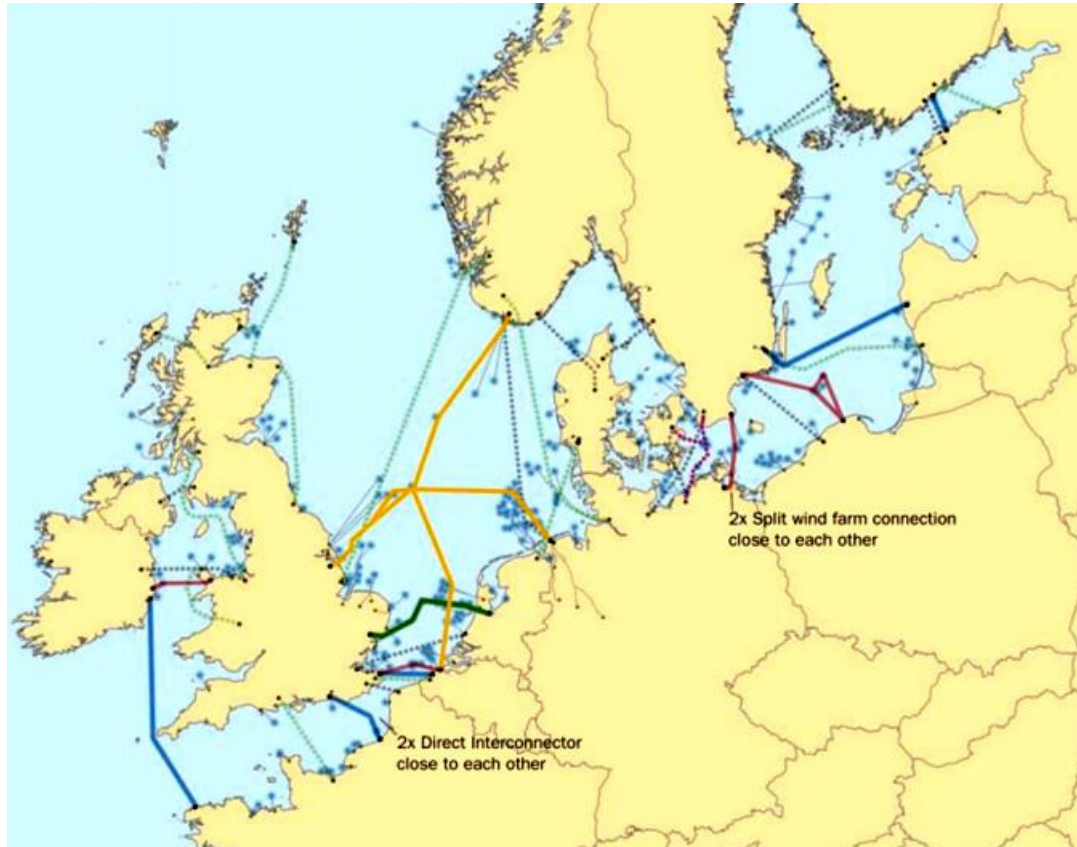


Figure 2.21 - OffshoreGrid proposal for meshed North and Baltic Sea grids [42]

Other entities such as the ‘Friends of the Supergrid’ consortium and Desertec have produced equally wide ranging proposals for the development of HVDC overlay transmission networks not just at sea but across the whole of Europe [53, 54]. These both envisage large scale connection of offshore wind energy from predominantly the North and West of Europe and onshore solar energy from predominantly the South via a pan-European HVDC network or ‘supergrid’. The Friends of the Supergrid vision for a 2050 HVDC European Supergrid providing the backbone of future bulk power transmission over the continent is shown in Figure 2.22. The

Desertec plans had even proposed the connection of huge solar energy resources from North Africa into Europe via HVDC links.



Figure 2.22 - Friends of the Supergrid vision for 2050 HVDC pan European grid [53]

There are also a number of other groups and organisations incorporating both industry bodies and research institutes that have looked at the viability of implementing an HVDC offshore grid. One of these is the Twenties project which includes a number of system operators, industry manufacturers and research bodies [55]. This is an extensive project with a broad scope looking for specific answers to a number of questions surrounding how best to facilitate onshore and offshore wind development. Other more specific projects such as ISLES (Irish-Scottish Links on Energy Study) and the Offshore Transmission Coordination Project conducted by TNEI on behalf of Ofgem [52, 56] have looked in more specific detail at options for integrating currently proposed offshore wind projects around the UK in the most cost effective manner.

2.2.5 Conclusions

It is clear that a number of studies have attempted to make broad comparisons between some of the different grid topology options. A general consensus has been arrived at which suggests there is likely to be clear financial benefits to the use of coordinated multi-terminal or meshed DC over the business as usual radial connections plus regional interconnector scenario. There are however a number of factors which have not been considered in these studies. For example both the OffshoreGrid and the NSCOGI reports appear to acknowledge the potential need for DCCBs but neither account for the potentially large additional cost of these. Further to this neither study makes a consideration of the impact of reliability on the overall performance of the network in terms of resilience to the fault conditions that could be expected in a project lifetime. There has thus been no clear expression in the literature of the added value of having redundant transmission paths available for power delivery in the event of faults although some studies have made consideration of reliability implications. This will be discussed further in Section 2.6.

2.3 Offshore Grid Protection Strategies

As discussed previously there are numerous ways in which offshore grids might be protected depending on the size of grid, available technology, cost constraints and technical requirements. This section will look to outline the main protection strategies available for implementing an offshore HVDC grid and discuss the implications of these in terms of system control and other design parameters.

2.3.1 HVDC Grid with DC Breakers

A multi-terminal or meshed HVDC grid utilising DCCBs is considered to be the ideal technical solution for future offshore grids. Such a design would mimic the high levels of system performance delivered by the current onshore HVAC transmission systems. Any individual fault can be isolated locally using the nearest DCCBs and the remainder of the HVDC grid would be able to carry on unaffected. The concept of a meshed DC grid is discussed in a number of papers [4, 57, 58] as well as in a number of the reports already discussed. Figure 2.23 gives a simplified single line diagram representation of a four terminal grid with DCCBs at each end of every line.

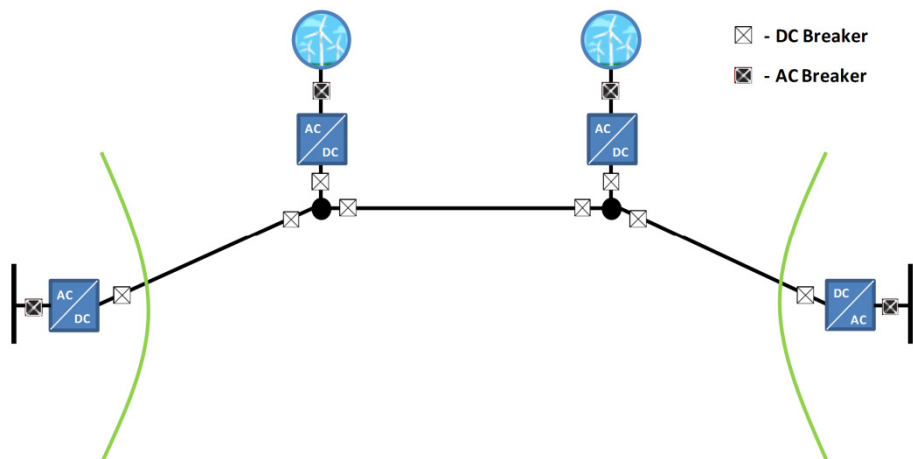


Figure 2.23 - A four terminal HVDC grid protected with DCCBs

All offshore grids will also be equipped with AC breakers at the AC side of each converter station which would act in the event of converter station faults. The number of DCCBs could feasibly be reduced in this scenario by removing the DCCBs that sit at the onshore converter stations and allowing the AC breakers to

isolate the onshore side from a fault on the DC link. This however would disconnect the onshore converter station which could otherwise be used to act as a STATCOM and provide ancillary services to the onshore system [59].

To implement such a configuration it must be assumed, first and foremost, that DCCBs become commercially available within a reasonable timeframe. If they do, there is the requirement for an effective fault detection and discrimination scheme such that fault location is determined and action taken within only a few milliseconds as required for DC grid faults as discussed in Section 2.1.4. HVAC transmission systems rely on traditional distance protection methods to measure the impedance to a fault and thus determine its location. In a DC grid the line impedance is negligible in comparison meaning fault current is almost independent of fault location rendering distance protection unsuitable. As such protection detection and discrimination methods are an active area of research and a robust solution must be developed before this grid design concept can be implemented. It is expected that current differential or directional protection methods could be utilised [32, 60].

2.3.2 HVDC Grid without DC Breakers

It was observed in Section 2.1.4 that the availability and, more so, cost of DCCBs is an uncertain factor and as such there has been considerable thought put into options for an offshore DC grid which would not require the large scale roll out of DCCBs. The first of these is to maintain a similar DC grid structure but instead of DCCBs there would only be switching stations and isolators based within the DC grid. DC fault conditions would be interrupted using AC side protection meaning the entire DC grid would have to power down. The faulted region could then be isolated and power re-routed if necessary through switching arrangements before the DC grid could be re-energised. This concept, illustrated in Figure 2.24 would clear the DC fault using the AC side protection at all four converter stations before disconnectors could be used to isolate the faulted grid section. Existing protection technology could be used which is likely to be substantially cheaper in terms of capital cost than a system dependent on the implementation of a number of DCCBs.

2. Technical Review: State of Knowledge on Offshore Networks

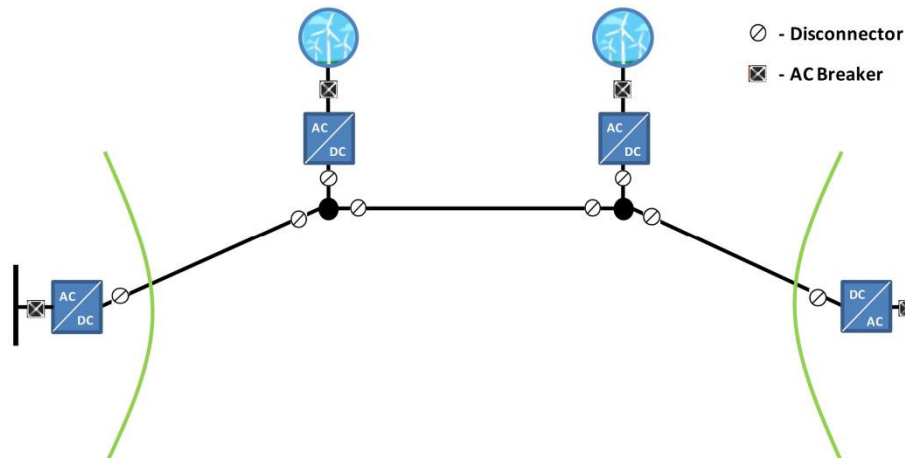


Figure 2.24 - A four terminal DC grid protected without DCCBs

It has been reported in some quarters that the need to shut down the entire DC grid makes this method unacceptable when applied to a multi-terminal DC grid [57, 61]. Some system studies have proposed HVDC links in the order of 10GW [62] which if lost in their entirety would indeed lead to unmanageable consequences for the connected onshore AC system. Practically speaking however there are limitations both technical and practical which indicate that such links would require to be delivered by a number of parallel converter stations and cable systems. The size of these parallel units would be limited both by the technical capability of the components implemented as well as the maximum loss of infeed limits of the connected AC systems as defined in their grid codes. At present the power capability of VSC converter stations and cable technology is the limiting factor with links above 1.4GW yet to be implemented with VSC technology as shown in Section 2.1.2. Even if this were to drastically improve in the coming years maximum loss of infeed limits would still need to be adhered to which currently stand at 1.8GW for the UK and 3GW for continental Europe [63, 64]. It stands to reason therefore that a large scale offshore multi-terminal DC grid would require some degree of sectionalisation.

The proposed option therefore suggests that these parallel DC grid sections need not be electrically connected to each other but would rather operate as distinct electrical networks under normal operating conditions. A fault scenario in this case would only require one section of the overall grid to be disconnected while the remainder could remain fully operational. Such a system should be tolerable so long as each grid

section was no larger than the loss of infeed limits of the connected AC system although the implications of whole DC grid shut-downs on overall undelivered wind energy and the onshore system requires further investigation. Given that individual wind turbines can be restarted within a few minutes of being shut down and that switching sequences for re-configuration of onshore networks can be applied within a few minutes it seems reasonable to assume that the process of grid shut-down, reconfiguration and restarting can be undertaken in, at most, tens of minutes though this has yet to be tested.

Other potentially detrimental effects would also have to be considered. For example, if a whole DC grid section was to be de-energised under a fault condition it stands to reason that all wind turbines connected to that section would be forced into an emergency stop situation. It has been seen in [65] that emergency stops lead to significant load amplification and can cause backlash events within the turbine drive train, both of which are likely to increase fatigue and so reduce life expectancy of turbine components. As such, the likely increase in the number of these events that would occur through use of this protection strategy would need to be quantified and some measure of the implications examined. Nonetheless, such a grid concept has been suggested by consultancy TNEI in proposals for HVDC grid connections between Ireland, Scotland and Wales. Their ISLES concepts are outlined in [66, 67] and one option is depicted in Figure 2.25. This concept is designed to be deliverable with current technology capabilities and therefore to not require DCCBs. As discussed, the design utilises three distinct DC grid sections which are linked at switching hubs whereby power can be re-routed under fault conditions.

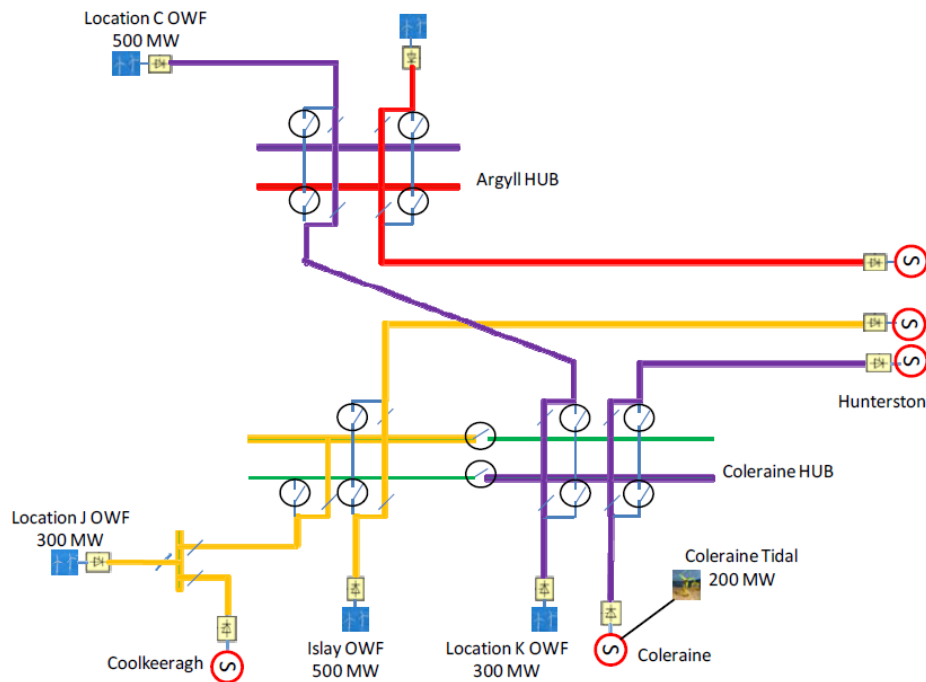


Figure 2.25 - North ISLES multi-terminal DC grid concept [67]

2.3.3 HVDC Grid with Reverse Current Blocking Converters

As discussed in Section 2.1.2.2 the advent of full-bridge VSC converters with the ability to block fault current flowing from the AC grid to the DC grid offers the possibility of greatly reduced protection requirements on the DC grid side. In the event of a DC side fault the converters would be controlled to bring the current level in the DC grid to zero. Cheap disconnectors could then be used to isolate the faulted grid section allowing power flow to be restored in the healthy grid sections. According to [59] this process could be achieved in the order of hundreds of milliseconds rather than the minutes or tens of minutes proposed for AC side protected DC grids. This potentially would allow offshore wind farms to avoid emergency shutdown procedures assuming suitable fault ride through could be put in place and so avoids the accumulation of undelivered wind energy. However it is possible that the loss of a large HVDC grid for even a few hundred milliseconds would be unacceptable to the connected onshore systems.

It has also been proposed therefore that this protection strategy could be used in conjunction with a reduced number of strategically placed DCCBs for larger DC grids [59]. This would allow the grid to be rapidly split into smaller sub sections using the fast acting DCCBs to separate healthy grid sections from the protection

process. This would give similar functionality to the proposal of having separate parallel grid sections pre-fault in that a fault on one grid section would not influence neighbouring grid sections. The DCCBs could be placed such that a large DC grid is essentially split into a number of sub-sections each with capacity that is within the required loss of infeed limit of the connected AC systems, the loss of which for a short period would therefore be manageable. It would also be possible to re-configure the network such that healthy parts of the affected grid section could be reconnected back into the overall system post-fault. A depiction of such a concept is given in Figure 2.26.

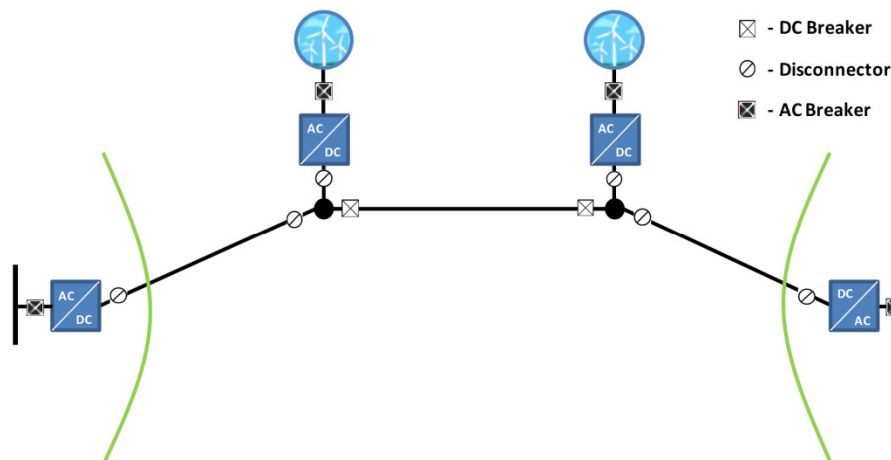


Figure 2.26 - A four terminal DC grid with full-bridge converters and limited DCCBs

2.3.4 HVDC Grid of Independent DC links

Another suggestion that has been made is that of a DC network that essentially consists of a number of AC collection hubs interlinked by independent point to point DC links. A depiction of such a concept is given in Figure 2.27. The Friends of the Supergrid consortium discussed in Section 2.2.4.1 is one of the entities that has considered such an option with the concept of an AC ‘supernode’ being proposed in [53]. Figure 2.28 shows a graphical depiction of the ‘supernode’ concept with four separate point to point DC links connecting into it. As with the previous option, the main advantage of this design topology is the fact that it could largely be implemented using existing and proven technology.

2. Technical Review: State of Knowledge on Offshore Networks

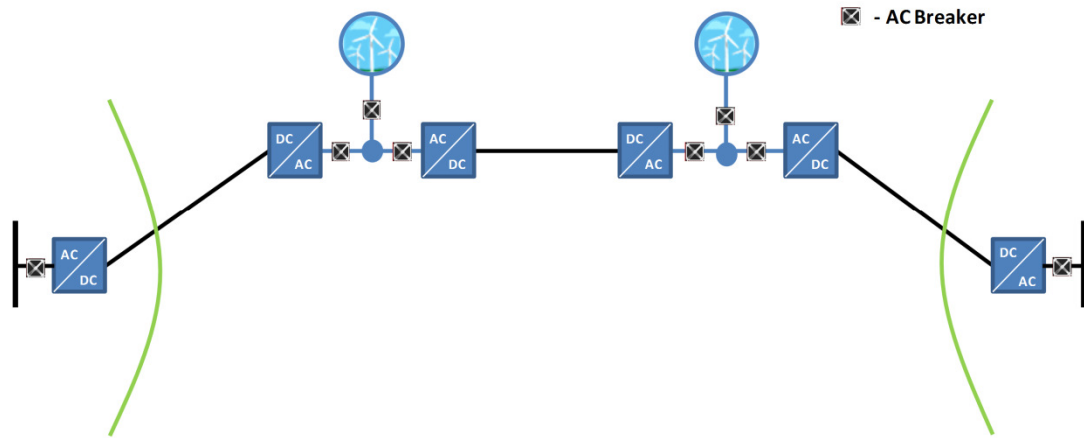


Figure 2.27 - A four terminal grid with independent DC links

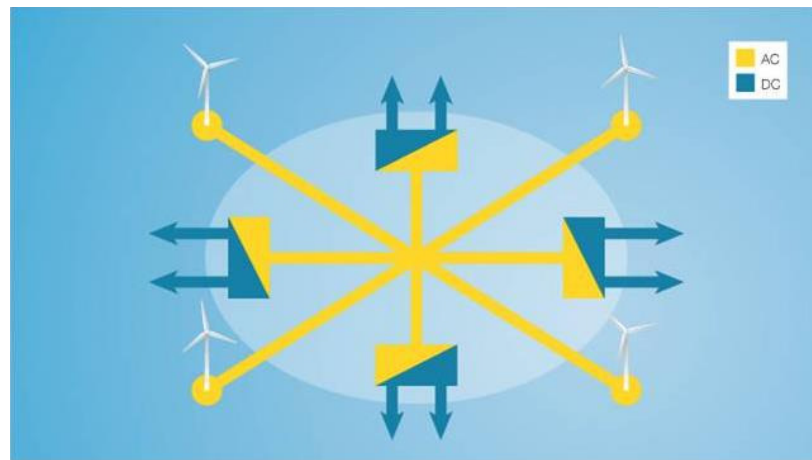


Figure 2.28 - 'Supernode' concept proposed by Friends of the Supergrid [53]

The concept uses a series of point to point DC interconnections which have a long established track record and would be protected via the AC hubs using existing, proven and relatively cheap AC circuit breaker technology. This option would also avoid the costs associated with DCCBs, however, crucially the system would require between 1.5 and 3 times the number of converter stations than the other two options as highlighted in [4]. Converter stations are a significant contributor to both system costs and system losses so in terms of total expenditure and system performance such a design could be significantly less cost efficient than the others.

Although the protection equipment used for such a topology could be established technology the protection philosophy however would require new innovations. The offshore low inertia AC hubs would be a new and untested entity with unanswered issues surrounding how they would actually be controlled and protected. This is

therefore an area that is actively being researched, for example in [68], and before solutions are proven there remains a small degree of uncertainty surrounding the overall feasibility of such a design. Another issue that could hamper deployment of such a concept is that wind farms are connected into the ‘supernode’ via HVAC cabling which has been shown in Section 2.1.1 to become both uneconomical and technically problematic beyond a certain distance. Given the distances involved in bringing together offshore wind farms even within the same round 3 zones (Dogger bank has an east to west span of 165km [69]) the feasibility of using AC cables to connect into a ‘supernode’ may be limited in some cases. It is questionable whether this design method could be described as a true DC grid however there is little doubt that it could be implemented for connection of certain offshore wind clusters to multiple onshore AC systems.

2.3.5 Additional Requirements for DC Grid Operation

Control of power flow in a true DC grid configuration as described in Sections 2.3.1-2.3.3 is governed by the voltage differential between each node on the system and by the power injections of each converter unit [4]. A common control methodology for a multi-terminal DC grid is for one converter to act as the DC slack bus whereby it acts to maintain a constant reference voltage. All other converters act in power control mode whereby they regulate the power injected or withdrawn from the DC grid at their bus via the local bus voltage. The slack bus maintains DC grid reference voltage by setting the power injection at the slack node to balance all other node injections and the losses in the DC grid [70].

Such a control methodology however leaves the grid vulnerable to the loss of the DC slack bus converter meaning some means of fast acting communication would be required to set a new system slack node in this scenario. An alternative method has therefore been more recently proposed which suggests a shared voltage control, analogous to distributed slack bus control in AC systems, through power-voltage droop characteristic control which allows local measurements to be used for control at each converter [41]. In this method the voltage set-points are set locally to control power flows based on linear DC voltage to power characteristics. For a meshed DC grid however power flows and voltages around the DC grid cannot be solely

managed by control of the terminals and additional branch controls of some kind are required as was noted in [50]. As highlighted, control of multi-terminal DC grids is another active area of research with methods in development as opposed to being fully commercially tested. Again a robust solution must be developed in order that a true, large scale DC grid could be implemented in reality. Further to this a consensus would need to be reached on who would run and control the DC grid with a single independent entity probably preferred to avoid a conflict of interests between the different individual TSOs that would be connected to it. A grid of independent DC links would manage each link separately but would also require co-ordinated high level control to manage power flows.

There are also a number of pre-requisites which must be met if an offshore HVDC grid is to be implemented. Logistically speaking it is very likely that any offshore DC grid would be developed as an incremental build out based on the premise of expansion of existing HVDC projects. Compatibility between projects is a key enabler and a common voltage level would be a fundamental first step to allow for staged build out of DC grids. To date, such co-ordinated forethought has not been evident and many existing offshore wind farm installations operate at unique system voltages making them incompatible for future connection without the use of DC to DC converters which could add considerable expense to the system. For two systems with relatively similar but not identical voltage levels it may be possible to re-design one of the systems to operate at the same voltage level as the second by changing the transformer on the AC side and altering the voltage control set point and certain components in the converter, however this would likely lead to sub-optimal operation relative to the design of the altered section. To facilitate a future DC ‘supergrid’ without excessive cost or re-working of existing installations there is a need for future wind installations to co-ordinate voltage level especially for larger projects on the scale of UK Round 3 projections and there is an active Cigre working group currently investigating recommended voltage levels for HVDC grids [71]. A counter argument to this is that imposing pre-prescribed voltage levels could negate the ability for optimisation within certain projects so there is a trade-off to be made between design freedom and design compatibility.

Further to a common voltage level it is very likely that a ‘supergrid’ would have to be capable of incorporating different converter topologies and other infrastructure provided by a number of different suppliers. There is the need for common standards to be developed and followed such that connection between different VSC converter topologies is not hampered by conflicting control algorithms or unwanted dynamic interactions. Compatibility should also be present in terms of protection systems, harmonics and communications systems all of which calls for the development of a comprehensive DC grid code which has not as yet been developed [4, 61]. It could be argued that the use of a grid with independent DC links would somewhat negate the need for strict co-ordination between different offshore projects in terms of voltage level and component compatibility. This could make such a concept more attractive for potential investors but the high costs of additional converter stations are still likely to be prohibitive.

2.3.6 Conclusions

It has been shown that there are numerous options available as to how offshore DC grids might be protected and the choices around these are also interdependent on the choice of technology employed on the grid. Each of these choices will have a varying degree of impact on the overall cost and performance of the offshore grid and there is a need for a comprehensive comparison to be made between the different options to better understand the trade-offs involved. This has yet to be covered in the literature.

2.4 Converter Configuration Options

Another consideration which has a large impact on the cost and performance of an offshore DC grid is the exact configuration of converters and cables used. There are again, a number of different options available to developers and these have been discussed in a number of studies [7, 16, 72-74]. The remainder of this section discusses the merits of some of these different options with illustrations reproduced with reference to [16, 74].

2.4.1 Asymmetric Monopole Systems

The simplest and cheapest method of implementing an HVDC grid would be through the use of the single cable asymmetric monopole arrangement as shown in Figure 2.29(a) with a ground return path.

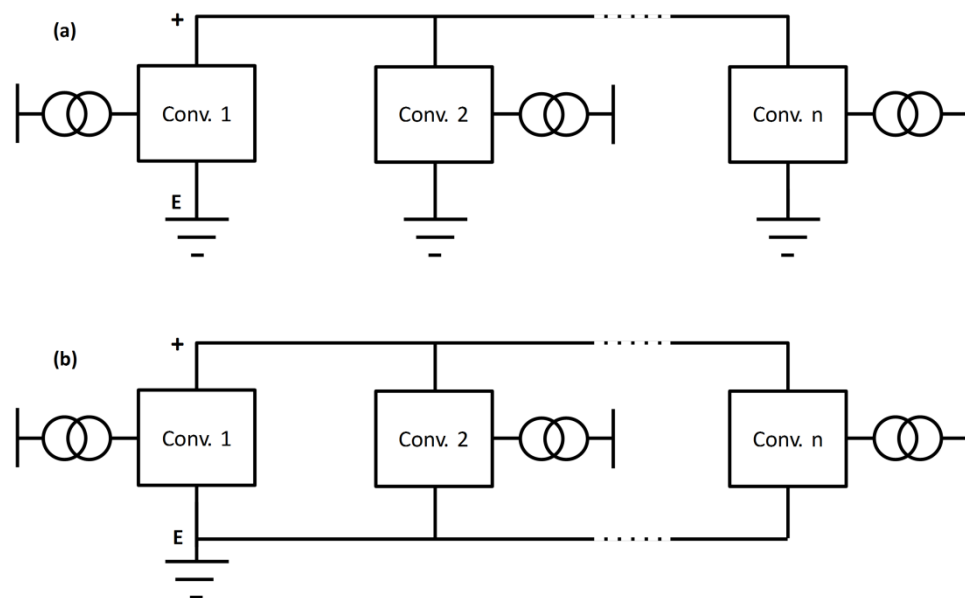


Figure 2.29 - Asymmetric monopole grid configuration with (a) earth return; (b) metallic return

The system is solidly earthed at each converter station so current flows through the high voltage cable and returns through earth. In European waters however, due to interference with existing infrastructure and environmental concerns, the use of a ground return path is generally prohibited [7, 16]. Even the simplest HVDC projects therefore require a metallic return conductor, which can be solidly earthed at just one location, meaning a minimum of two cables are required as shown in Figure 2.29(b). The low voltage earth return may not however require the same level of insulation as

the main high voltage cable so could be realised at lower cost. There is inherently no redundancy built into a monopole system, however, meaning a fault anywhere within the system, either on one of the cables or converter stations will result in loss of full power transfer capability of that grid section.

2.4.2 Symmetrical Monopole Systems

A popular grid configuration in existing VSC based HVDC projects has been the symmetrical monopole configuration which connects the DC side of converters between two high voltage cables of the same magnitude but of opposite polarity as illustrated in Figure 2.30. This configuration offers double the power rating of an asymmetric monopole system with the same voltage magnitude and can be achieved without additional insulation requirements. In this configuration the earth reference can be provided in several ways, including the connection of the DC capacitors midpoint to earth or via high resistance inductors on the AC side of the converters [16].

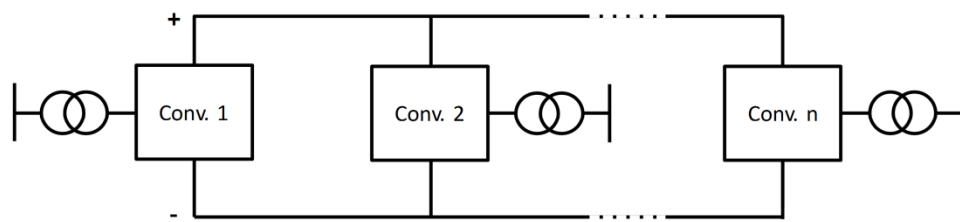


Figure 2.30 - Symmetrical monopole grid configuration

In the symmetrical monopole configuration power is transmitted through both conductors but in the event of a fault these cannot operate independently as there is no directly available earth return path for monopolar operation [74].

2.4.3 Bipole Systems

In situations where it is desirable to have a high level of availability or the power requirement exceeds the capability of a single pole system, use of a bipole system is generally desirable. This configuration makes use of two converters connected in series at each terminal, one connected between the positive pole and the neutral midpoint and the other connected between the midpoint and the negative pole. In balanced operation no current flows through the midpoints which are connected via a

low voltage metallic return conductor. The configuration, shown in Figure 2.31, is preferable to the use of two separate monopole systems for equal power transfer due to the need for only one return conductor.

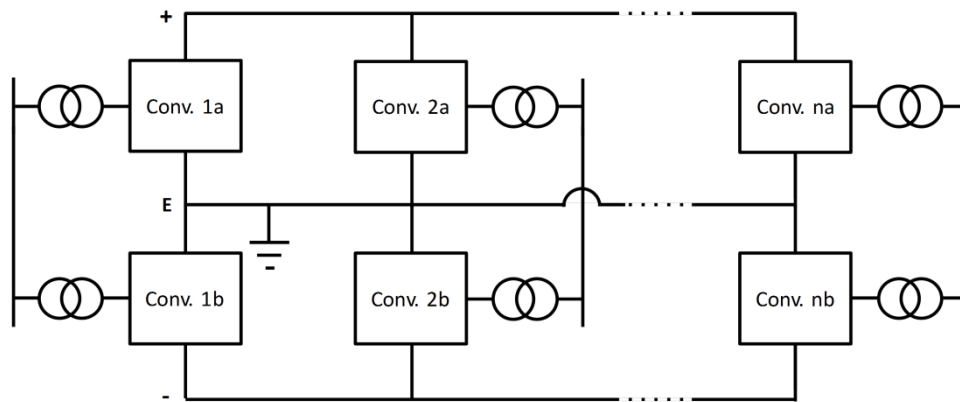


Figure 2.31 - Bipole grid configuration with metallic return

For a given rated pole voltage and rated current the power transfer of a bipole is double that of the asymmetric monopole and equal to that of the symmetrical monopole. However, bipole systems provide an inherent redundancy allowing for continued but reduced transmission capability to be utilised by switching to monopole operation under certain fault or maintenance conditions. The benefits of this redundancy need to be investigated and weighed against potential additional infrastructure costs. For example a bipole configuration requires the implementation of specially designed transformers capable of withstanding a DC voltage offset that is inherent to the configuration [75]. To avoid damage to both pole cables occurring simultaneously, for example via an anchor drag, and gain the benefit of possible operation in monopole mode it may also be necessary to lay the cables in separate trenches which would again incur additional costs compared with, for example, the symmetrical monopole system which could be delivered through bundled conductors laid together.

The bipole system shown provides 50%, plus overload, transmission capacity in the event of either a single pole converter or pole to ground cable fault through a transfer to monopole operation via the healthy pole and the metallic return. The bipole system could also be implemented without the low voltage dedicated metallic return conductor which would reduce costs but means monopole operation could

only be utilised if a fault were to occur on a single pole converter unit allowing the healthy pole to be used in monopole configuration with the high voltage cable of the damaged pole being switched to act as the low voltage return conductor. Any cable faults in such a configuration however would entail the removal of full transmission capacity. This option is the chosen design for the subsea Western HVDC Link project due to provide additional transmission capacity between the Northern and Southern areas of the GB transmission system [14].

Multi-terminal or meshed DC grids could conceivably be constructed via an amalgamation of different grid configurations. Figure 2.32 shows how both asymmetric and symmetrical monopole converter configurations could be connected into a bipolar grid with a metallic return path meaning this configuration is a promising option as it would allow flexibility for future expansion.

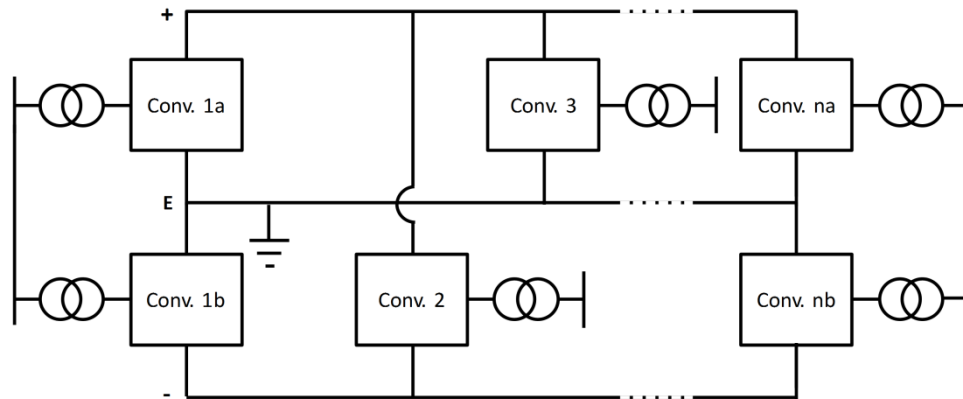


Figure 2.32 - Bipole grid configuration with symmetrical monopole and asymmetric monopole tapplings

2.4.4 Conclusion

It is clear that the choice of grid configuration is another key element that will impact on both the costs and performance of any future offshore DC grids. The merits of these options should be explored in conjunction with the implications associated with utilising different protection strategies, choices of technology and overall network topologies.

2.5 Regulatory Issues

Previous sections have highlighted the technical barriers that need to be overcome to facilitate an offshore DC grid in an environment such as the North Sea. However, just as important to delivering the end goal is the need to overcome parallel regulatory, policy and financing issues. The technical arguments have shown that in terms of delivering a cost optimised offshore grid, there should be a degree of co-ordination between projects and that early investors in the offshore grid should develop assets that allow for incremental future expansion in as modular a fashion as possible. Although this approach is desirable and manageable in terms of technical delivery it raises a number of practical issues that need to be overcome.

2.5.1 Anticipatory Investment

Anticipatory investment is the concept of early developers of the offshore grid investing in and installing infrastructure that, although not necessarily directly relevant to their own project delivery, facilitates future modular connections of further projects. The lack of such investment does not preclude future expansion but it does mean the overall costs are likely to be much larger. Important investment decisions made by early developers include the choice of DC voltage level, the amount of extensibility built into offshore platform designs and the potential oversizing of transmission routes to allow future connection of additional projects [76]. The choice of converter configuration could also influence future connections as demonstrated in Section 2.4.3. Entities carrying out anticipatory investment will not necessarily benefit directly from it and are also exposed to the risk of future planned projects being cancelled effectively leaving ‘stranded’ assets. Such risk comes in addition to the naturally high risk premiums already associated with the implementation of relatively unproven offshore grid infrastructure which means securing the necessary level of investment in offshore projects is already likely to be a substantial task. It appears clear then that appropriate incentives are necessary to allow investors to be suitably remunerated for any anticipatory spending. Where this remuneration comes from is another issue given that the later projects that would benefit most from the anticipatory investment may not occur for several years meaning, at least initially, the developers of these cannot be expected to contribute.

Governments and regulators therefore have a duty to develop remuneration methods that incentivise lowest cost grid development overall and there may be a need to socialise some of the expenditure in an offshore grid. However, the risk of some assets being stranded due to non-completion of the projects they are designed to facilitate would also need to be considered. Organisations such as the previously mentioned NSCOGI collaboration [77] could potentially enable the development of common policy and finance initiatives to help deliver an offshore grid and the European Commission began to tackle some of the issues relating to how these investments can be delivered in [78].

2.5.2 Design and Ownership of Offshore DC Grids

Early development of offshore wind assets have followed the simplest constitutional arrangement whereby offshore wind farm developers (OWFs) have designed and built the transmission infrastructure for their project. For large projects there may be some incentive to develop a degree of redundancy or connect into neighbouring projects but more often than not the main incentives would be to minimise capital expenditure and reduce exposure to outside influences and secure a risk free project as far as possible. However, such an arrangement is likely to incentivise the development of numerous simple radial transmission solutions and not necessarily a co-ordinated approach. The concept of an offshore transmission owner (OFTO), responsible for design, build and operation of the offshore transmission asset was therefore introduced in the UK which in theory could incentivise more co-ordinated design. This is dependent on the type of remuneration they receive, however. If the OFTO is paid a fixed income regardless of their assets then minimisation of costs is the clear incentive, potentially at the cost of reliability in terms of access to shore for generated offshore energy. If they are paid in relation to their assets then the incentive is perhaps to ‘overdesign’ the network [76]. Current arrangements in the UK mean OFTOs are remunerated based on availability targets [79] which may incentivise some optimisation but the system may for example still penalise designs that can operate at reduced transmission capacity even if actual energy curtailment is minimised. Due to fears around the speed of tendering and development of OFTO built transmission projects in the UK, wind farm developers have successfully lobbied for the right to build their own transmission assets. They are then obligated

to sell these onto an OFTO to operate and manage. This arrangement again seems to be at odds with an ambition for co-ordination in offshore grid design.

If a large scale North Sea offshore grid is eventually implemented then a further issue arises relating to the overall management and control of such a system and what overriding objectives it should be governed by. Any grid is likely to be connected to several onshore systems so one option is to allow all connected TSO's a share of the operational responsibility although the roles of each would need to be clearly defined. Another possibility is the creation of an independent offshore TSO specifically tasked with managing the offshore DC grid. Either way, there will be a large number of conflicting objectives whereby a grid dispatched to deliver overall societal benefit will inevitably leave some parties as winners and others as losers. How this is governed and how remuneration is fairly divided are matters that require further investigation but fall outwith the remit of this thesis.

2.5.3 Financial Arrangements

Another issue that will inevitably need to be overcome to facilitate an integrated North Sea grid is how financial support schemes for offshore wind energy are delivered across Europe. Currently there are a number of different schemes in place with some countries using feed-in-tariffs, others using certificate schemes and some with hybrid schemes [42]. If multiple wind farms, potentially with multiple different project owners connect into the same transmission infrastructure with links to multiple shores a number of complications surely arise as to who pays for both the transmission infrastructure and the produced energy and who benefits most from this.

The ISLES project looked at this issue and discovered that traditional market boundaries do not necessarily provide the best incentive for development. For example, a small country like Ireland, in the case of ISLES, could not feasibly be expected to subsidise the cost of infrastructure and energy production of offshore wind farms built in its waters but connecting to both Ireland and the UK. The much larger market of the UK on the other hand could more easily socialise those costs so a proposal was made whereby the UK market boundary for offshore renewable projects in the region would be moved to the shores of Ireland. Such a scenario would give both parties the opportunity for affordable investment to provide mutual

benefits, namely interconnection to the UK for exports for Ireland and an affordable means of reaching renewable targets for the UK [80]. To drive investment in projects inventive solutions like this may need to be found across Europe.

Clear rules will also be required to determine how the dual functionality of both delivering offshore wind power to shore and providing cross border trading are handled and remunerated. At present, with regards to the GB system, almost all interconnectors are merchant projects with the sole purpose of trading with other synchronous AC systems, although elsewhere in Europe this is not always the case. It is likely that energy trading on an integrated offshore grid would be viewed as a secondary function to power delivery so the management of this and the markets which drive its use will require careful consideration.

2.5.4 Conclusion

It is clear that one of the main obstacles to delivering integrated offshore DC grids in Europe is the need to attract large sums in capital investment. The regulations that have driven the offshore wind market to date allow for investment but tend to favour individual, clearly defined projects and don't necessarily encourage co-ordination of design. Studies such as OffshoreGrid and Tradewind [42, 81] have asserted that there are large overall cost savings to be made through co-ordinated design so there is a need for regulatory issues to be resolved such that the barriers to co-ordination are removed and there are clear market incentives for delivery of the lowest overall cost options. Providing the opportunity and incentives for an offshore grid design authority to implement offshore connections as opposed to individual developers could drive more optimised solutions as could incentivising early grid developers to build extensibility into projects to allow for later expansion.

A strong governmental role is likely needed to drive such policies and there are other areas of offshore grid development that are likely to be dependent on policy driven incentives. For example, supply chain bottle necks can be envisaged [42] without sufficient investment by governments in the required industries and development of essential infrastructure like the upgrading of ports. It is clear that the regulatory concerns involved with the delivery of an offshore grid have at least been recognised although there are still many challenges to be overcome.

2.6 Consideration of Reliability

There are a number of differences between proposed offshore DC transmission grids and existing onshore transmission systems. The latter have generally been designed to serve two main purposes, namely to provide access to the most economic generation sources which may be remote from load centres and also to enhance the reliability of supply to load centres through connection to a variety of generation sources. This has driven investment in highly meshed, interconnected systems with extremely high reliability for the end user. As such onshore transmission systems are often designed such that demand remains connected and system limits unaffected even under the loss of a full transmission circuit [82]. Offshore networks in contrast have the same purpose in terms of connection of remote generation sources but are unlikely to carry substantial demand on the system. From a wider system perspective, offshore grids could be viewed as equivalent to generators on the onshore system in so much that they serve onshore demand and could therefore be expected to be managed in a similar loss of infeed limited manner. In addition to this, as has been discussed, the costs associated with the implementation of offshore grids is substantially higher, as is the likely cost of protecting that network in a similar fashion to the onshore system. The main drivers in an offshore sense are ability to transmit offshore wind energy reliably to shore and perhaps the ability to transmit energy between regions but a key driver would also be to achieve these goals in a manner that is economically viable and so minimises upfront costs.

Conversely, it is also true that the offshore environment is far more challenging and problematic than onshore which has profound implications for system reliability. Failures in offshore grids are inherently more difficult to gain access to and repair meaning there is a much longer time and cost penalty associated with failed offshore infrastructure. This could then in theory be a driver for increased upfront capital expenditure if the lifetime cost savings were to be beneficial. It is clear then that a balance must be struck between the level of capital expenditure invested in offshore grids and their relative reliability and it is unlikely that an offshore grid can justifiably be designed with the same levels of reliability as is customary in onshore

networks. Research to determine the costs and savings associated with reliability in offshore grids, is therefore vital to assess such trade-offs in detail.

Although reliability of offshore wind turbines and by association wind farms is an area that has attracted a large amount of research attention the same cannot be said for reliability of offshore grid options. Only a handful of studies have considered in any depth the issue of reliability when considering offshore networks. Major reports such as OffshoreGrid and NSCOGI that have sought to compare different grid options do not include reliability within their calculations and thus compare only on a capital cost and market benefits level [42, 51]. The ISLES study includes calculations of system adequacy and security which highlight the value of the redundancy built into their designs but make no comparison of their chosen design with other options [67]. Another study [83] has looked at options around the connection of a single offshore wind farm involving the costs of introducing increasing levels of redundancy in the offshore transmission link and within the wind farm inter-array design. This study used a methodology which looked at the trade-offs between cost of installed redundancy against lifetime costs of undelivered energy for a number of reliability scenarios. This allows not only an assessment of which options provide good value under good reliability performance but also which options provide least regret under poor reliability performance allowing a decision to be based on knowledge of a range of possible outcome scenarios. This study, however, is limited in that it addresses the impact of single faults separately and does not account for the existence of overlapping faults.

Two large studies have been working to address to some extent the gap in research on offshore grid reliability. The REMARK software tool, developed as part of the wider Twenties study has recently published initial findings of its study into the comparison of radial versus meshed North Sea grid topologies [40, 84]. Another study, led by a dedicated Cigre working group on the ‘Reliability of HVDC Grids’, has yet to publish its findings. Both these pieces of work have been carried out either partially or fully in parallel to the work in this thesis so have not been drawn upon to a meaningful extent.

The REMARK software is based on a market simulation of the whole European network that uses an optimal power flow based solution to determine power flows from hypothetical offshore grid scenarios to sophisticated models of the onshore AC networks. It is comprehensive in that it considers the level of undelivered offshore energy, electrical losses, fuel consumption and CO₂ emissions to make an economic assessment of the viability and potential benefits of different grid scenarios. It considers, however, only radial grids with and without varying degrees of interconnector capability with a particular, not necessarily optimal, multi-terminal grid with particular levels of transmission capacity. The multi-terminal grid is realised through a DCCB approach only and no intermediary solutions or alternative protection methods are explored. The reliability study is based on a non-sequential Monte Carlo analysis which means the impact of the offshore environment on overall reliability can only be estimated by making the assumption that repair times in winter are higher than summer rather than directly quantifying this based on actual constraints.

The main findings of the REMARK study are that although there are significant benefits to be gained through the use of the multi-terminal grid in terms of delivered offshore energy and reduction in CO₂ emissions the benefits of these do not necessarily outweigh the significant costs required to implement the meshed grid using DC breakers. The study found that the radial solution, which includes a degree of co-ordination at wind farm level, with an intermediate amount of merchant interconnector projects was the most cost effective solution overall although the benefits in terms of delivered wind energy and CO₂ emissions are significantly less. The study concluded that further work to optimise the design of the multi-terminal offshore grid may yield different results meaning it is difficult to state, one way or another whether or not a multi-terminal approach is better than a radial approach for offshore HVDC.

2.7 Scope of Work

A thorough review of the present state of the offshore transmission industry has been presented and a number of findings have been made. A summary of the key issues raised can be found below:

- For connection of far offshore wind farms HVDC technology is likely required.
- VSC converter technology is likely to be preferred in the offshore setting due to its small footprint and flexibility for use in multi-terminal DC grids.
- There are a number of converter configurations that can be adopted each with different implications for the overall cost and performance of the DC grid.
- There are presently limits to the capacity of converter and cable systems although this is increasing as time goes on meaning that in the future multi-GW projects will be realisable offshore.
- DCCBs are not yet commercially viable but it is likely that they will be in the near future although they are likely to be bigger and more costly than their AC equivalent.
- There are various topology options for delivering DC grids ranging from radial to meshed solutions.
- There are obvious benefits to co-ordinated designs with redundant transmission paths, although there is as yet no clear determination as to how this compares against potential additional costs under different scenarios.
- There are a number of different protection strategies that could be employed for offshore grids with varying need for DCCBs, the relative costs and benefits of these are yet to be explored in detail.
- There are different methods for configuring DC grids with monopole solutions minimising costs but bipole solutions introducing the opportunity for inherent system redundancy.
- A number of regulatory barriers remain to be overcome to allow for cost effective development of offshore DC grids.
- Reliability of components in the offshore setting takes on much greater importance than in onshore networks due to limited access for repairs leading to potentially long down times.
- Only a few published studies have considered reliability of offshore grid options in any detail.

It is clear from the findings that there are a host of options relating to how offshore DC grids might be delivered and that an investigation of reliability in the context of the offshore setting is an area that could add to the published knowledge base. It has been found that there are competing issues that will drive the development of offshore DC grids with the task of minimising upfront costs through reduced capital expenditure on expensive infrastructure being weighed against the desirability for high reliability to mitigate the impact of potentially long down times in the event of component failure. The remit of this thesis was therefore decided as follows:

Develop a bespoke reliability analysis modelling tool and use it to compare the performance of different offshore DC grid options through a cost-benefit analysis.

A number of key parameters were defined as being important requirements to allow for a meaningful comparison of offshore DC grid options.

- The model should be capable of handling various offshore network design options including different technology options, protection strategies, grid topologies and converter configurations.
- Realistic fault conditions should be applied to the network options.
- The appropriate post-fault network response and or network reconfigurations should be applied.
- Realistic constraints such as the dependency of offshore component repair times on weather conditions and delays to procurement of vessels and spare components should be incorporated.
- Reliability and associated cost benefits should be measured through the ability of each grid option to meet its objective of delivering offshore wind power to shore and providing inter-regional transmission capacity, if applicable.
- Detailed cost modelling should include the capital cost of network infrastructure, the cost of electrical losses in the system and O&M costs.

In performing these tasks this thesis should address some of the key outstanding questions relating to offshore network development:

- What is the value of implementing increasing levels of redundant transmission paths in offshore DC grids compared with more traditional radial solutions?

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- Are multi-terminal or meshed offshore HVDC grids incorporating the widespread use of potentially costly DCCBs financially viable?
- What are the costs and penalties associated with alternative protection strategies that avoid the use of DCCBs?
- Which grid design options provide the most value for money in terms of revenue potential against capital expenditure and running costs?
- What are the key drivers behind the reliability of electrical transmission infrastructure in the offshore environment?

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3. Methodology

This chapter will outline the methodology used to develop a bespoke reliability software tool the additional analysis undertaken to allow for a cost-benefit analysis of various options for the delivery of offshore DC grids. A review of available modelling options is undertaken before a comprehensive overview of the chosen methodology is presented covering the model inputs, processes and outputs.

At various points in this chapter reference will be made to discussions with industry experts. These discussions took place sporadically throughout the duration of the project and included face to face meetings, telephone calls and e-mail exchanges. There were two main industry contacts involved in the project, one of whom works for a major power systems consultant and the other for an offshore wind farm developer with direct experience of the operation and maintenance of offshore wind farm transmission systems.

3.1 Reliability Modelling Options

3.1.1 Reliability Metrics

The inherent lack of studies into the reliability of HVDC grids means that guidelines need to be taken from comparable studies. As such, the study of reliability in the context of onshore AC transmission systems provides a good reference place for the development of modelling methods relating to future offshore scenarios and the definition of key metrics can be clarified. Reliability, for example, although used thus far as a broad reference to the performance of the whole system, has a generally accepted definition as the probability that an item or system will perform a required function under stated conditions for a stated period of time [1]. When applied to power systems there are typically two required functions which relate to the ability of the network to provide uninterrupted electric power and electric energy to users with acceptable quality and required quantity. This study does not look to consider the issues of power quality delivered from offshore grids which would require detailed modelling of the dynamic operation under fault conditions and instead focuses on determining the static reliability of the grid options. Given the key purpose of an offshore grid is to deliver energy to one or more onshore systems, the main reliability assessment metric in this thesis is to quantify the expected value of energy, in terms of offshore generation or interconnection transfer, that is not delivered due to forced or scheduled system outages. To achieve this assessment of undelivered energy, E_{und} , a probabilistic assessment is made of the occurrence and duration of component outages. The method for calculating the metric is defined in percentage terms for a given period in Eqn. 3.1.

$$E_{und\%} = \frac{\textit{Total Undelivered Offshore Energy}}{\textit{Total Available Offshore Energy}} * 100 \quad (3.1)$$

Availability is the probability of finding an individual component in an operational state but can also be used in reference to the overall systems ability to transmit power. The availability of individual components is determined by two separate parameters, namely the Mean Time to Failure (MTTF), which is the inverse of the oft quoted component failure rate, and Mean Time to Repair (MTTR). Availability is determined using Eqn. 3.2 [2].

$$Availability = \frac{MTTF}{MTTF + MTTR} \quad (3.2)$$

Availability in reference to the overall offshore grid system is perhaps more difficult to define given that the analysis would need to account for not only the obvious extreme positions of full and zero transmission capacity but also the potential for periods of reduced or partial transmission capacity depending on the system design.

A number of alternative reliability indices are often utilised within studies of onshore networks such as the loss of load probability (LOLP) or the system average interruption duration index (SAIDI) [3]. These approaches are applicable when trying to evaluate the economic impact to customers of lost load but are not considered further in this study. In the offshore context electricity consumers, in the main, are not directly connected to the offshore grid so it is considered that the single clear method of evaluating the economic impact of reliability is to take the perspective of the offshore wind farm developer and consider the costs associated with undelivered generation.

3.1.2 Analytic Approach

There are a number of methods that can be used when assessing the reliability of electrical systems, the simplest of which is the analytic, state enumeration or frequency-duration method as discussed in [2] and demonstrated in various forms in [4-8]. This approach makes use of probabilistic methods which calculate annual E_{und} based on a wind power frequency curve which is used to determine available energy and estimations of the failure and repair rates for each of the system components. Figure 3.1 shows a sample wind power frequency plot whereby the delivery of power from a wind farm over a year is sectionalised into bins ranging from zero to full power output. Such a chart has been generated by the author by combining the Weibull distribution of wind speeds with an appropriate power curve.

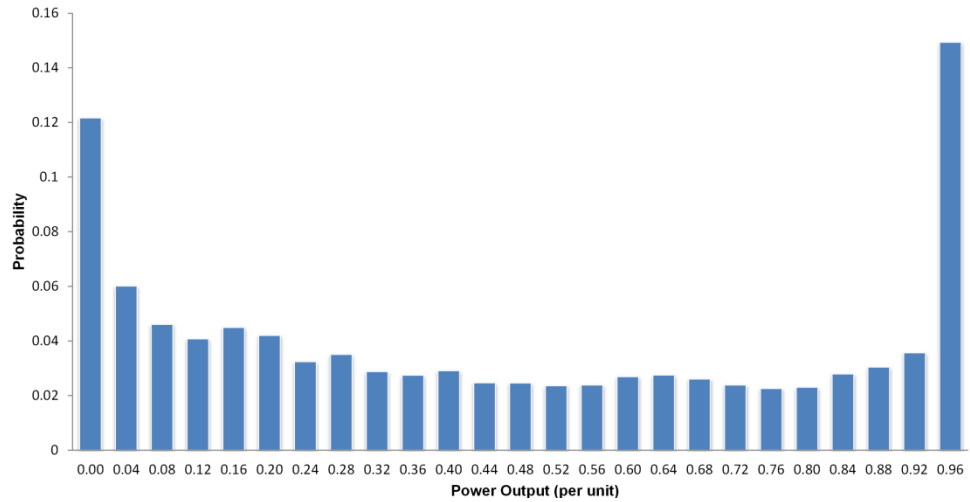


Figure 3.1 - Generic wind power/frequency curve

The power frequency curve can then be utilised in conjunction with Eqn. 3.3 to calculate the contribution to E_{und} of any single component outage:

$$E_{und} = \left[\sum_{i=1}^n P_i \cdot P_b \cdot H_b \right] \cdot \lambda \cdot MTTR \quad (3.3)$$

Where P_i is the Power interrupted, P_b is the power in bin b , H_b is the number of hours per year spent in bin b , λ is the failure rate of the component and $MTTR$ is the mean time to repair of the component. Applying this methodology to all components in conjunction with Capacity Outage Probability Tables (COPT), as described in [3] to determine the probabilities of overlapping faults, can yield a total average annual E_{und} figure for the network in question. For relatively small systems this methodology is said to be advantageous in terms of computation time. However, the process does not lend itself to detailed analysis as the chronology of events and so the interdependencies of certain features, for example the influence of weather on time to repair cannot be modelled [2].

3.1.3 State Sampling

For larger systems a state sampling approach is often used also known as non-sequential Monte Carlo simulation. This method differs from the state enumeration approach in the manner in which fault outages are simulated for the system. Whereas the state enumeration approach takes each possible fault outage and applies an average failure rate and $MTTR$, the non-sequential Monte Carlo method generates system states by randomly sampling component states, and then evaluating the

system impact of each sampled combination of component states [9]. Each system state is independent of the previous state but knowledge of average repair time can be used to calculate values for the required reliability metrics. The process of evaluating new system states continues until the number of sample system states gives convergence on a pre-defined stopping criteria, for example the variance of undelivered energy [2]. This method is less computationally intensive for very large systems than the state enumeration method but still suffers from an inability to accurately model chronology of events and so incorporate dependence on previous or parallel variables. The REMARK software developed as part of the TWENTIES project [10] makes use of this process as part of wider analysis of the reliability of offshore grid designs within a zonal electricity market and does consider seasonal implications but only by estimating a longer repair rate for winter months.

3.1.4 Sequential Monte Carlo Approach

When it is necessary or desirable to incorporate historical dependencies or detail the effects of seasonality and weather dependencies it is necessary to use a sequential Monte Carlo simulation [11]. This is also known as the state duration technique and works by generating a sequential time evolution of each system state for each component in the system. The inputs to such a method are the MTTF and MTTR of each component from which time to fail (TTF) and time to repair (TTR) values can be generated based on a given distribution. This method also requires a stopping criterion such that for each component type the average value of all generated TTFs and TTRs converge towards the MTTF and MTTR values used as input and the final reliability metrics such as E_{und} are accurate within a specified confidence interval. Concurrent weather time series can be incorporated to help calculate reliability metrics and also to influence parameters, for example incorporating the dependence of repair time on appropriate weather windows. As such a far more detailed analysis can be performed with a sequential Monte Carlo process. However, the trade-off for the level of detail is a high level of computational intensity. No published studies into offshore HVDC grids have so far incorporated a sequential Monte Carlo based reliability study within their analysis although studies have used this approach in relation to, for example, wind turbine and wind farm reliability analyses [12, 13].

3.2 Overview of Chosen Methodology

Given the discussion in Section 3.1, reliability in the context of this thesis has been defined as the ability of a chosen grid design option to perform the task of transmitting offshore renewable energy to shore and if applicable facilitate the cross border trading of energy. This will be measured through an evaluation of the level of undelivered energy due to outages on the offshore transmission system based on the appropriate modelling of failure and repair rates of individual system components.

Considering the available reliability modelling options and given the stated aims of the project the Sequential Monte Carlo simulation methodology was chosen as the most appropriate solution. This allows for a more detailed level of reliability modelling that is capable of not only providing a means of comparing the overall reliability of different offshore grid options but also a way of investigating some of the underlying interdependencies and drivers behind the reliability of offshore grids as set out in the project scope discussed in Section 2.7. Key to this is the ability to investigate the dependence of offshore reliability on weather conditions given that access to faulted components and the ability to carry out repairs in the offshore environment often requires persistent periods of favourable wind speed and wave height conditions.

The final methodology used to investigate offshore grid reliability meets a number of requirements to ensure it handles a range of input scenarios and generates results that consider not only the reliability of different options but also the associated costs. The overall methodological structure of the reliability study, as described in the following sections, is illustrated in Figure 3.2. A number of system inputs are required, including the offshore grid design being explored, a representation of weather at the site in question and a knowledge of the failure and repair rates of the sub-components in the system. This information is fed into the main Monte Carlo analysis which runs through time chronologically applying faults into the system. Several functions have been developed to appropriately handle the fault situations by restoring the network to a new operating state and to determine the length of time required to repair the system. Online calculations are made of the level of

undelivered energy and other performance metrics such as the level of cross-border energy trade if applicable to that network.

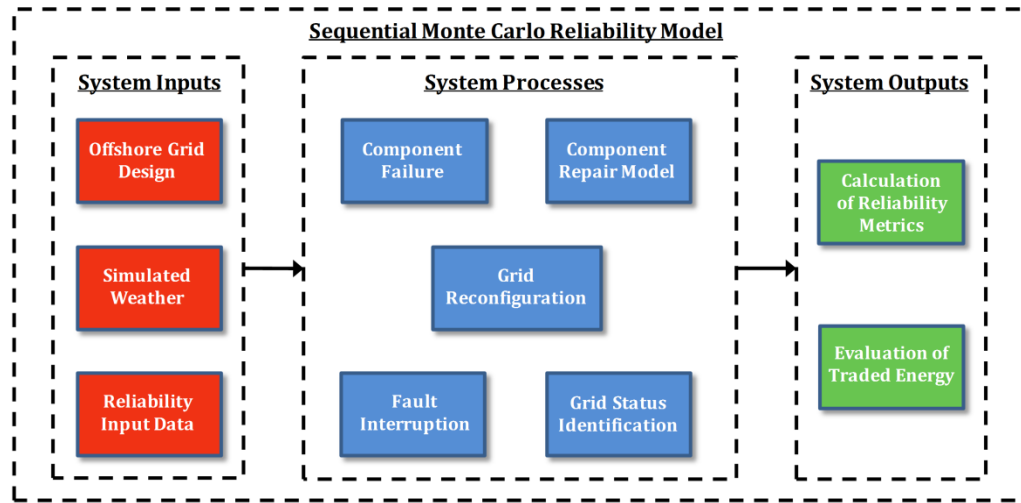


Figure 3.2 - Overview of sequential Monte Carlo reliability methodology

Each aspect of the methodology is described in detail in Sections 3.3-3.6 along with a description of any underlying assumptions that have gone into the modelling process. Sections 3.7 and 3.8 describe the accompanying calculations of project capital expenditure, operational costs and electrical losses which together with the outputs of the reliability analysis can be used to determine a full cost-benefit analysis of each grid option.

3.3 Model Inputs

3.3.1 Network design

Figure 3.2 shows that a number of inputs are required as a basis for the reliability software tool. The first of these is the input network design. This study makes use of PSS[®]E load flow software for the design and representation of all network inputs. The availability of a purpose built Python extension allows for easy interaction between the Monte Carlo reliability tool developed in Python and the PSS[®]E network [14]. Although PSS[®]E is a comprehensive package that allows detailed design and modelling to be performed on a variety of grid designs there are a number of issues relating to its use for detailed studies of HVDC grids and in the context of a reliability study. For instance, the package does not, at the time of use, support the flexible modelling of all the individual components within an HVDC grid. This means that an HVDC converter station and associated transmission branch are represented as a lumped component. For the purpose of assigning faults to these components separately an alternative approach is required. PSS[®]E, or other detailed modelling packages could be used to make online calculations of load flow and therefore electrical losses under each new system state within a sequential Monte Carlo simulation. It is found, however, that this would add a level of computational complexity that is incompatible with running scenarios over a sufficiently large time period to reach suitable convergence on the reliability metrics being investigated so is not pursued. For reference the final run-time of a single Monte-Carlo reliability analysis in this thesis is 40-120 minutes depending on the grid design in question and other variables. To introduce a full PSSE load flow analysis at each time step would be expected to increase this runtime by an order of magnitude or more. Given this issue, and the difficulty involved in modelling individual failure events the package is instead used to define the physical components that exist within each DC grid scenario and the purpose built Python reliability tool performs all other calculations.

Modelling of offshore grids down to wind turbine resolution is possible. However, to enable investigation of DC grid compositions and compare the main DC grid design options, it is desirable to reduce the complexity of the grid and thus model wind farms as a single lumped input parameter. The reliability of offshore wind farms to

the point of connection to their offshore transmission grid is not the focus of this investigation and it is assumed that their design is common to each of the main DC grid options being compared. The design of wind farm collector arrays is the subject of many other studies and can be considered in the modelling of energy output derived from the wind farm as explained in Section 3.3.3. The network representations developed for final investigation are therefore accurate in that they represent each of the main physical components present in each grid scenario (offshore wind farms, converter transformers, converter stations, transmission branches and circuit breakers or switches/isolators) and a number of key attributes such as voltage ratings, transmission capacity and transmission branch length. The application and handling of faults, calculations of transmission capacity and any associated E_{und} as well as the calculation of electrical losses are all handled within the Python reliability model or through offline external calculation. This provides a large degree of flexibility and for the investigation of DC grid options that cannot be accurately modelled in available licensed software.

3.3.2 Simulated Weather Time Series

To allow for a thorough investigation of the influence of weather conditions and seasonal variations on the reliability of offshore grids the Monte Carlo analysis relies upon accurate modelling of wind speed and wave height time series. There is a paucity of long term weather monitoring campaigns in the offshore environment that provide data on both mean wind speeds and mean significant wave height for the same location and with an acceptable resolution. An exception to this is the FINO 1 offshore meteorological mast [15] which has over eight years' worth of concurrent wind speed and wave height data from an offshore site situated in the vicinity of the, Alpha Ventus, German offshore wind farm and is publicly available material. The wind speed data gathered for use is taken from the highest available measurement height of 80m which corresponds to a typical hub height of existing offshore wind installations [16].

The data has been processed using a Multivariate Auto-Regressive approach (MAR) outlined in [12] which captures not only the trends and attributes of the data itself but also the cross-correlations between the wind and wave height output. This is used to

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generate larger sets of concurrent wind speed and mean significant wave height time series that maintain the characteristics of each dataset, in terms of seasonal trends, mean values and variance, as well as the cross-correlations observed between the wind speed time series and the wave height time series. This study makes use of 100 years' worth of simulated wind speed and wave height time series which are repeated throughout the much longer Monte Carlo simulation process. The resolution of the data is 1 hr and as such this is the resolution used for the entire Monte Carlo process.

To enhance accuracy it is possible to model the spatial variation between wind speed and wave height data between different wind farms connected to the same offshore grid. Meso-scale weather models such as the COSMO-EU model [17] or the Weather Research and Forecasting Model [18] as used in the OffshoreGrid modelling process [19] can be used to determine the cross correlation between wind speed time series at different locations. These take weather data as input and can be used to generate wind speed data for heights ranging from 100km to 1km above ground. This data can then be transformed to hub height and the correlation between wind speed time series at different locations can be determined. Some studies have looked at regional cross-correlations and shown that some areas of Europe have strongly correlated wind speed profiles whereas as others do not. It stands to reason that the closer two locations are to each other the more likely it is that their wind speeds at any given time will be highly correlated with one another however the OffshoreGrid study concluded that direction is also important. They found that over the whole of Europe there were strong correlations between wind speeds in East to West locations but that correlations dropped when considering locations in the North compared with the South. Work by Houghton et al [10] however found less strong relations and concluded this was an area requiring further research.

To implement such a method for wind speeds alone would have been possible but to maintain the cross correlations between mean significant wave height and wind speeds and the cross correlations between each of these respectively across different sites is a task that is highly challenging, especially given the difficulty of getting access to appropriate cross-validated wave and wind data, and was therefore deemed out of scope for this project. In order to make what is judged to be a reasonable first

pass assessment, it is assumed that the wind speed and wave height input time series apply equally to all wind farms within each case study examined. For a Dogger Bank style case study such as that described in Section 4.2 the effects of this are likely to be minimal as the wind farms in question are tightly clustered anyway and would likely experience high cross-correlation between wind speed time series. However, for the study of offshore grids with highly dispersed offshore generation it would be preferable if this issue were addressed in any future work.

It is also of interest to study the effects on reliability of applying weather time series from a range of geographical locations which may have significant variations in their overall characteristics such as mean wind speed and seasonal variations. An investigation of the reliability is therefore performed using data obtained from existing operational offshore wind farm sites. The results of this are presented and discussed in Section 5.3. Additional sources of concurrent wind and wave height data from locations with potentially harsher conditions than FINO were sought but none found with comparable resolution and quality so the comparison is confined to locations with calmer conditions than FINO.

3.3.3 Wind Speed – Wind Power Conversion

Another input that is required to accompany the wind data is a means of converting the wind speeds to appropriate wind power output. Given that the FINO wind speed data used is taken from 80m height it is assumed for this work that this is a suitably typical representation of the hub height for offshore wind farms so no further conversion has been performed. Future offshore wind farms may well have increasingly high turbine hub heights and so it is possible to address this issue by conversion of the existing data through one of two main methods. The first method is the log law transformation which determines the wind shear profile as follows:

$$U(z) = U(z_r) \left[\frac{\ln\left(\frac{z}{z_0}\right)}{\ln\left(\frac{z}{z_r}\right)} \right] \quad (3.4)$$

where $U(z)$ is the wind speed at hub height, z , $U(z_r)$ is wind speed at input data height, z_r , and z_0 is the surface roughness length, a subjective measure based on the physical surroundings of the area in question which is naturally very low in offshore

applications [20]. Another method is the empirical simplified power law which can also be applied as shown [21]:

$$U(z) = U(z_r) \left(\frac{z}{z_r} \right)^\alpha \quad (3.5)$$

where α depends on the surface roughness length z_0 . The power law, unlike the log law has no physical basis and is an empirical solution that is not recommended for use in most situations. It was argued in [22], however, that the Power law provides accurate results in the higher 98% of the atmospheric boundary layer (ABL) whereas the log law seemed to prove accurate in the lower 3-5% of the ABL. Turbine hub heights typically lie in the upper region of the log law's accuracy range assuming the ABL to be between 1-2km thick, meaning accuracy of either method is questionable. If available, wind speed data taken at a range of heights from the source met mast can be used to validate the results derived from either method.

After obtaining a representative wind speed time series it is necessary to develop a method of translating wind speed to wind power. At the individual turbine level it is possible to make use of published manufacturer wind speed – wind power conversion curves such as that shown in Figure 3.3.

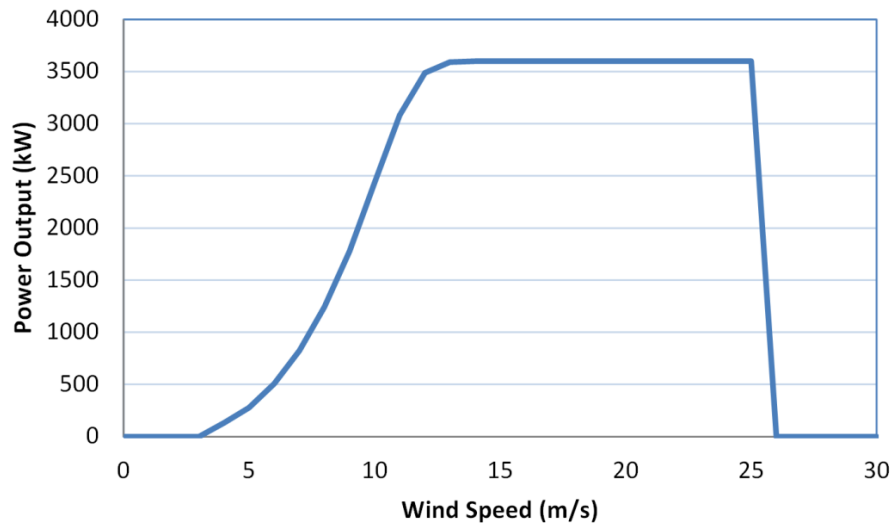


Figure 3.3 - Siemens SWT-3.6-107 power curve (reproduced from [23])

When looking at wind farm level power output the use of individual wind turbine power curves is no longer suitable as a number of factors could contribute to reduced power output over a full wind farm when compared with an individual turbine. These

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include wake effects, wind speed variation across the site, system electrical losses and system faults. As such it is desirable to have a wind farm power curve and such a curve was developed for a generic offshore wind farm by Garrad Hassan, now part of DNV GL, and published as part of the Tradewind project [30]. The derivation of this power curve however has not been published and as such it is unclear how many and what contributing factors have been considered. Given the nature of this project is to investigate reliability it would be desirable to have a power curve that is known to reflect only internal wind farm loss factors to make certain there is no ‘double accounting’ of unsupplied energy. Some work has been done to identify and separate out some of these contributing factors in the offshore setting in [24] for example and other methods to convert wind speed to wind power data have also been explored including the use of historical information for concurrent wind power output and wind speed data to build statistical models as used in [25] but no definitive conclusions have been arrived at in terms of how to derive an accurate offshore wind farm power curve. A method of synthesising wind output over a large area through knowledge of the site wide wind speed distribution curve and the individual wind turbine power curves was developed in [26] and gives a similar smoothed result to that developed in the Tradewind project. In the absence of a more refined or transparent alternative for the specific offshore case the Tradewind power curve, recreated in Figure 3.4, is used in this thesis. It shows that the maximum expected power output from the wind farm is just 89% of the installed capacity.

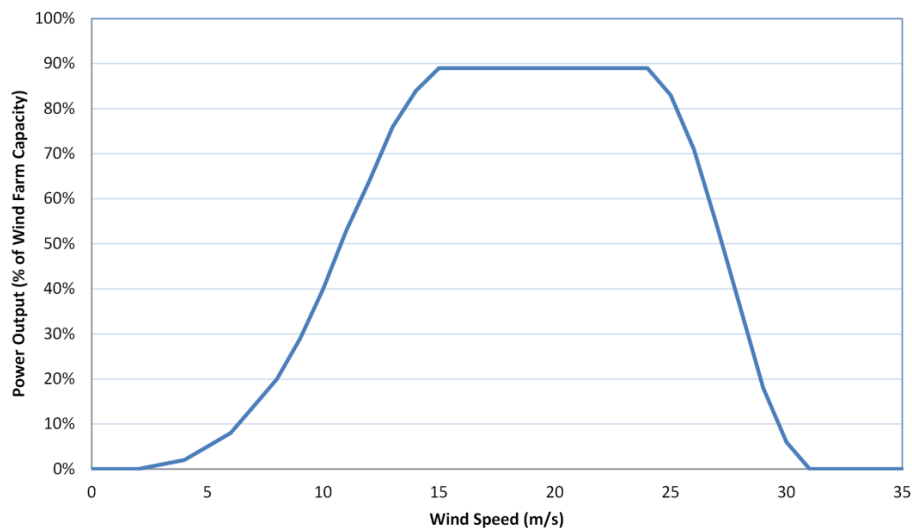


Figure 3.4 - Generic offshore wind farm wind speed – wind power conversion curve [27]

3.3.4 Reliability Input Assumptions

Reliability data for offshore DC grid infrastructure is generally sparse due to the fact that many of the proposed technologies are either new or relatively young meaning data simply doesn't exist in some cases or has not been gathered over a long enough time period to be considered robust. Where established technology is to be used there are some publicly available sources of fairly robust reliability data relating to onshore performance. The direct application of these, however, when considered in the harsh marine environment is questionable. There are a number of sources that have published reliability data for offshore grid components with Cigré providing the most consistent publication of both existing real system data as well as projections as to future reliability expectations [28-32]. Given the infancy of the industry the figures are likely to be ever evolving. Along with Cigré, a number of other studies have attempted to estimate the reliability of individual component sub-systems for offshore HVDC grids. Tables 3.1-3.6 show the MTTF and MTTR estimations from five separate sources that have each attempted to attribute reliability figures to some or all of the major constituent components and sub-systems that will make up offshore HVDC grids. The Twenties REMARK study [33] also estimated reliability figures but based the figures on Cigré data so this is not included to avoid double accounting from single sources. Best case and worst case estimates are shown where given and are equal where only one estimate is offered. All results are translated into MTTF and MTTR values and given in hours.

Table 3.1 - Published reliability estimates for onshore converter system

Reliability Estimates - Onshore Converter				
	MTTF (Hours)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	17532	17532	24	24
2: SKM 2012[34]	8766	2922	14	14
3: Hodges 2012 [35]	-	-	-	-
4: ISLES 2012 [36]	8766	4383	13	44
5: Linden 2010 [29]	5930	5930	4	4

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Table 3.2 - Published reliability estimates for offshore converter system

Reliability Estimates - Offshore Converter				
	MTTF (Hours)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	17532	17532	168	168
2: SKM 2012[34]	8766	2922	14	14
3: Hodges 2012 [35]	-	-	-	-
4: ISLES 2012 [36]	8766	4383	13	44
5: Linden 2010 [29]	5930	5930	4	4

Table 3.3 - Published reliability estimates for onshore transformer system

Reliability Estimates - Onshore Transformer				
	MTTF (Hours)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	-	-	-	-
2: SKM 2012[34]	-	-	-	-
3: Hodges 2012 [35]	461368	438300	1440	4320
4: ISLES 2012 [36]	876600	438300	1440	1440
5: Linden 2010 [29]	365250	365250	2160	2160

Table 3.4 - Published reliability estimates for offshore transformer system

Reliability Estimates - Offshore Transformer				
	MTTF (Hours)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	-	-	-	-
2: SKM 2012[34]	-	-	-	-
3: Hodges 2012 [35]	461368	292200	2160	4320
4: ISLES 2012 [36]	292200	292200	4320	4320
5: Linden 2010 [29]	365250	365250	2160	2160

Table 3.5 - Published reliability estimates for HVDC transmission cables

Reliability Estimates – HVDC Transmission Cable				
	MTTF (Hours/100km)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	245448	245448	1440	1440
2: SKM 2012[34]	168577	168577	1560	2160
3: Hodges 2012 [35]	417428	5844	-	-
4: ISLES 2012 [36]	438300	109575	720	2160
5: Linden 2010 [29]	-	-	-	-

Table 3.6 - Published reliability estimates for HVDC circuit breakers

Reliability Estimates – HVDC Circuit Breaker				
	MTTF (Hours)		MTTR (Hours)	
Source	Best	Worst	Best	Worst
1: Cigre 2015 [31]	175320	175320	50	50
2: SKM 2012[34]	584400	584400	192	192
3: Hodges 2012 [35]	-	-	-	-
4: ISLES 2012 [36]	-	-	-	-
5: Linden 2010 [29]	116880	116880	4	4

As Tables 3.1-3.6 show, most studies looking into the topic of HVDC reliability have considered some or all of the six distinct component sub-systems identified. These represent the major constituent components of future offshore DC grids and are the components modelled within the reliability analysis of this thesis. It is known that auxiliary systems such as cooling systems for transformers can often be major contributors to component downtime rather than failure of the major components themselves however precise data for auxiliary systems is not available and as such these are not explicitly modelled. It is assumed that auxiliary system failures are to a great extent factored into the existing published projections in any case, i.e. when an auxiliary failure leads to an outage of the primary equipment, this is reflected in the primary equipment MTTF and MTTR data. Some components have an inherent degree of redundancy such as MMC VSC converter designs which can tolerate a degree of module failure before the converter can no longer transmit energy. Again

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there is little in the way of specific data to break down the causes of failure and it must be assumed that the published data already factors in this inherent attribute meaning all converter failures are assumed to remove the entire unit from service.

The spread of results within the estimations in Tables 3.1-3.6 is substantial so it is necessary to consider a range of potential reliability scenarios. It was therefore undertaken to make use of all the compiled estimations, along with discussions with industry experts to develop a unique set of reliability inputs based around three scenarios giving a central case, a best case and a worst case estimate of failure rate and repair times. These discussions led to some of the published data being disregarded and also gave an indication as to the figures that seem most plausible. For example, the worst case MTTF for transmission cables given in source 3 was found to be an extreme outlier and leads to extremely poor reliability performance as highlighted in previous work done in [37]. It is stated in [38] that cable failure rates are often highly skewed by individual cases of badly engineered or installed systems and on reflection it is concluded that this estimate is likely to have been based on a cable system that experienced a serial defect and as such is considered unrepresentative and is not considered in the final worst case scenario that is developed. The three scenarios form the basis of the studies performed in this thesis and the central case is also used as the basis to examine a range of sensitivity studies which investigate the impact of a number of individual contributory factors. The unique scenarios developed for use in this study are outlined in Tables 3.7-3.9.

Table 3.7 - Central case reliability scenario

Central Case Reliability Scenario			
Components	MTTF (Hours*) <small>* Transmission cable - Hours/100km</small>	TTR (Hours)	
		Fixed Delay	Repair time
Onshore Converter	6480 (10 months)	-	6
Offshore Converter	6480 (10 months)	-	6
Onshore Transformer	438300 (50 years)	2160 (3 months)	72
Offshore Transformer	350640 (40 years)	2880 (4 months)	120
HVDC Transmission Cable	219150 (25 years)	2160 (3 months)	144
DC Circuit Breaker	219150 (25 years)	-	6

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Table 3.8 - Best case reliability scenario

Best Case Reliability Scenario			
Components	MTTF (Hours*) <small>* Transmission cable - Hours/100km</small>	TTR (Hours)	
		Fixed Delay	Repair Time
Onshore Converter	17532 (2 years)	-	3
Offshore Converter	17532 (2 years)	-	3
Onshore Transformer	876600 (100 years)	1440 (2 months)	48
Offshore Transformer	438300 (50 years)	1440 (2 months)	96
HVDC Transmission Cable	438300 (50 years)	1440 (2 months)	120
DC Circuit Breaker	525960 (60 years)	-	3

Table 3.9 - Worst case reliability scenario

Worst Case Reliability Scenario			
Components	MTTF (Hours*) <small>* Transmission cable - Hours/100km</small>	TTR (Hours)	
		Fixed Delay	Repair Time
Onshore Converter	2880 (4 months)	-	24
Offshore Converter	2880 (4 months)	-	24
Onshore Transformer	350640 (40 years)	2880 (4 months)	96
Offshore Transformer	262980 (30 years)	4320 (6 months)	144
HVDC Transmission Cable	109575 (12.5 years)	2880 (4 months)	168
HVDC Circuit Breaker	131490 (15 years)	-	24

It can be noted from Tables 3.7-3.9 that instead of using MTTR values as input to the reliability study, repairs are based on time to repair (TTR) values which are split into two separate categories. Each component has a specific repair time which relates to either the number of hours required to physically carry out a repair (onshore/offshore converters, onshore transformer and circuit breaker) or the size of the relevant weather window required to carry out a repair (offshore transformer and transmission cable). This reflects that different component types are subject to different repair modelling as described in detail in Section 3.4.3. Transformers and transmission cables are also subject to a fixed delay which relates to the time period required to acquire both a replacement component (assuming spares are not readily available) as

well as access to the specialist vessel required for the repair. The final TTR values and fixed delays used are arrived at through discussion with industry experts but are also broadly reflective of the MTTR values given in the literature.

Transmission cable MTTF values are given per 100km of cable section. This makes the assumption that cable failure rates are directly proportional to cable length. Although this is perhaps an oversimplification, given that cable faults can often be located at section joints or at platform connections [39], there is evidence to suggest that a large proportion of subsea cable faults are caused by external factors like anchor drags or by fishing nets [38, 40, 41]. The likelihood of these events does increase proportionally with cable length lending the assumption a degree of credence, although other localised and unique factors such as shipping activity around a particular project are also likely to be important. This thesis also makes the assumption that the main DC grid case studies utilise a symmetrical monopole grid configuration as outlined in Section 2.4.2 meaning that the transmission route consists of two separate cables. It is assumed that these are laid as a bundled unit meaning that the reliability figures for a single cable are still applicable. In this configuration all cable faults remove the entire transmission branch from service. Case studies involving the bipole grid configuration outlined in Section 2.4.3 are also examined whereby the transmission branch would consist of two main cables which would be laid a significant distance apart. In this scenario faults on each cable would be independent of one another so each cable is subject to its own failure rate.

3.4 Features of Main Sequential Monte Carlo Model

As Figure 3.2 shows the main functionality of the reliability software tool is delivered through a sequential Monte Carlo simulation methodology which draws upon a number of distinct Python developed modules which allow for modelling of system response to a lifetime of fault conditions. This section gives an explanation of the workings behind each of these functions in relation to a generalised example that is used to explain the simulation process.

3.4.1 Stop Criterion

A starting point for any Monte Carlo process is to define the criteria by which the process, once running, will be terminated. There are numerous methods which can be used to accomplish this including simply setting a fixed time period for the number of Monte Carlo years you want to simulate. It is more beneficial, however, to define the length of runtime by calculating a specific convergence criterion and terminating the simulation once a threshold target has been reached. The performance metric used as the stopping criterion in this study is the level of unsupplied energy as a percentage of total deliverable energy or the E_{und} as described in Eqn. 3.2. Under Central Limit Theorem as the number of trials, n , tends to infinity so the distribution of the trial means approximates a normal curve. Using procedure outlined in [42, 43] it is therefore possible to estimate the confidence limit, L , for the accuracy of the E_{und} calculation, that is, how close it is to the unknown true E_{und} value, μ , that would be derived from an infinitely long Monte Carlo simulation. If \bar{X} is the estimate of E_{und} from N Monte Carlo simulated years then the probability that the true E_{und} value lies between the interval $\bar{X} \pm L$ is calculated with the degree of confidence γ using the following:

$$\gamma = P(\bar{X} - L \leq \mu \leq \bar{X} + L) = 1 - \alpha \quad (3.6)$$

The confidence limit L is calculated from Eqn. 3.7 with $t_{\alpha/2}$ given by the t -distribution with $n-1$ degrees of freedom and S being the sample variance.

$$L = t_{\alpha/2} * \frac{S}{\sqrt{N}} \quad (3.7)$$

This study uses ω_r , the relative confidence interval as calculated in Eqn. 3.8, as the parameter on which to base the stop criterion.

$$\omega_r = \frac{2 * L}{\dot{X}} \quad (3.8)$$

To ensure a high degree of accuracy in the final calculated values for E_{und} the stop criterion placed on the Monte Carlo simulation is set at $\omega_r = 0.01$ (or 1%) with $\alpha = 0.05$ giving a 95% confidence that the calculated E_{und} value is accurate within $\pm 1\%$ of the true figure. This is a stricter value than the 2-5% figure suggested for use in [44]. This allows an extra degree of certainty to be given when comparing different grid options which give similar reliability performance but does mean several hundred thousand Monte Carlo simulation years are typically required to reach convergence on the networks investigated. As such, much of the modelling work looked to minimise the computational complexity of the reliability tool and so the runtime.

3.4.2 Time to Fail Calculation

At the beginning of the process all system components must be given a value for the expected time to fail (TTF), i.e. to change from the in service state to the out of service state due to a forced outage. This is also required each time an individual component fails and is then repaired so a new TTF value is assigned every time a component re-enters the in service state. A well-known model of the time variation of failure rates in electrical and mechanical components is represented by the ‘bathtub’ failure distribution as shown in Figure 3.5.

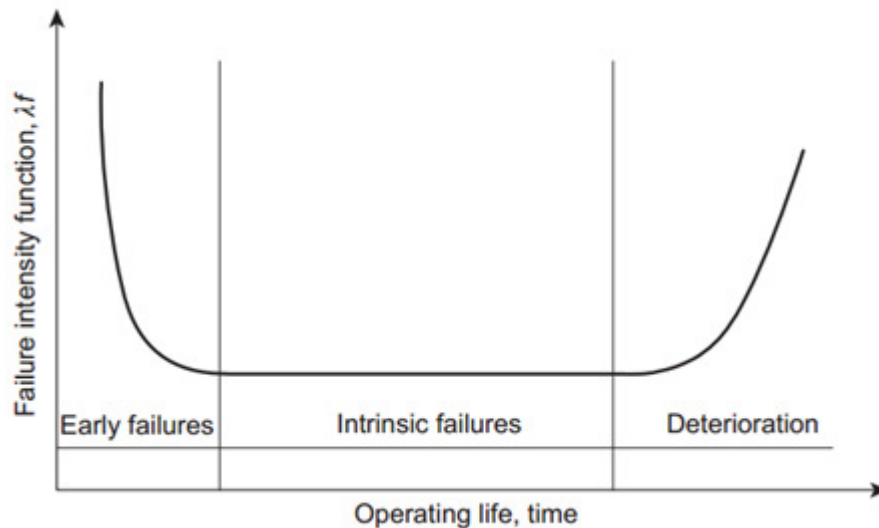


Figure 3.5 - ‘Bathtub’ curve showing failure intensity function (or failure rate) against time [45]

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The ‘bathtub’ curve represents three stages normally associated with repairable machinery. These are: a wear-in period that reflects an increased propensity for component failures in early life often due to unforeseen issues; a long normal operating period where failures are purely intrinsic and lead to a constant failure rate; and a wear-out period which represents an increase in failure rate as a fleet of components reach the end of their natural operating life. In reality the composition of this failure rate distribution will differ from component to component with, for example, mechanical components typically having a much shorter normal operating period and a much longer gradual wear-out period than electrical components which typically more closely follow the bathtub curve as illustrated in Figure 3.5 [43].

Without detailed knowledge of failure rate distributions it is typical in reliability studies to disregard the wear-in and wear-out periods and model only the constant failure rate normal operating life period. This study makes the same assumption as an attempt to model failure distribution in more detail requires more detailed data than is publicly available and also a more intensive computational, and therefore time consuming, analysis which is incompatible with the long Monte Carlo runtime required for convergence. This is considered a valid assumption in that the major mechanical component modelled in the system are cable failures which are mainly caused by random external faults and not often mechanical wear-out so all modelled components can be assumed to have a long normal operating life period. Further to this, if it is assumed an appropriate scheduled maintenance regime is in place then components can essentially be kept in the normal operating life state for the duration of their deployment and not allowed to enter a wear-out phase.

On top of these typical time related reliability factors there is some published evidence to suggest that faults relating to offshore wind turbines may be more likely to occur in extreme weather conditions, although the correlations found are relatively small and a matter of ongoing research [46, 47]. Given that there is little in the way of published evidence to corroborate that similar phenomena would apply to offshore transmission infrastructure this thesis does not attempt to model any seasonal variation in failure rates although the issue is highlighted as an area for future investigation if robust evidence were to become available. Seasonal impacts are

however modelled in terms of how they affect component repair times as explained in Section 3.4.3. The failure rate, λ , of a component is inversely proportional to the MTTF (Eqn. 3.9) so the input MTTF values are assumed to be independent of time and are utilised to generate new TTF values for each component when necessary via Eqn. 3.10.

$$MTTF = \frac{1}{\lambda} \quad (3.9)$$

$$TTF = -MTTF * \ln(R) \quad (3.10)$$

where, TTF is the component time to fail as calculated at the beginning of each simulation trial and each time you move from the out of service state to the in service state, MTTF is the given mean time to fail of the component in question and R is a randomly generated number. This results in the random generation of TTF values which, when taken as a whole for each component type, have a mean value equal to the MTTF and are exponentially distributed around the MTTF meaning they adhere to the constant failure rate assumption [48].

3.4.3 Time to Repair Calculation

When considering the operation and maintenance of offshore assets the ability, when necessary, to get to and carry out component repairs becomes a much more critical factor in terms of overall reliability than in traditional onshore systems. A number of additional practical barriers have to be negotiated and considered including physical distance from shore, increased likelihood of adverse weather conditions which limit access to assets and the potential need to acquire specialist vessels and equipment to carry out repairs. As such, the modelling of repair times for components is a central focus of the reliability study.

Instead of using a method similar to that used for the generation of failure times, as outlined in Section 3.4.2, repairs for offshore components are instead calculated with reference to the weather conditions encountered from the point of failure, as dictated by the input concurrent wind speed and wave height time series, as well as the time needed to actually carry out a repair and the weather constraints that impact the ability to work. Consideration is also given to the fact that the repair time associated with some serious fault conditions such as the need for cable repair or transformer

replacement are driven by delays relating to the time required to source new components and the need to obtain specialist vessel and equipment to arrange and carry out the repair. With this in mind repairs are split into a number of different categories relating to whether or not the component is onshore or offshore and also the main drivers behind repair time for each component. Each category has a repair process that is modelled separately as described in Sections 3.4.3.1-3.4.3.3.

One element of modelling that remains constant between each of the repair categories is the calculation of working hours. It is assumed that repairs are carried out during normal working hours with the onshore shift length set to 12 hours and the offshore shift length 15 hours with a 7 day working week. After any failure occurs the first calculation that is made is that of the number of hours until the beginning of the next available shift to begin the repair process. The working day starts at 6am so any repair will be delayed initially by at least the number of hours before the next 6am. Further to this the time required to travel to offshore sites is accounted for within each offshore repair strategy.

3.4.3.1 Minor Offshore Repair

This category relates to offshore component failures which require only minor repair and can therefore be managed by a small number of personnel travelling on a standard transport vessel. For relatively near shore operations a crew transport vessel (CTV) is likely to be used. For maintenance much further than 70km offshore it is likely that helicopter access would be required due to the length of transit time required using a standard CTV [45] or that a permanently manned offshore maintenance hub would be constructed to allow quicker access to offshore platforms. For this study offshore converter and DC circuit breaker faults fall into this category whereby it is assumed a relatively short and simple operation can be performed to replace power electronic sub-modules or otherwise and bring the converter or breaker back online. The ability to perform this operation is weather dependent and relies on the ability of personnel to safely transfer from the CTV to the offshore platform. The industry standard criteria for safe transfer states that the mean significant wave height should not exceed 1.5m [45]. For far offshore case studies as examined in this thesis it can be assumed that helicopters would be used for access or

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that CTV access is possible via a centralised offshore maintenance hub. If the former is assumed the access criteria would be based on visibility and wind speed as opposed to significant wave height. From discussions with industry experts it is found that there is anecdotal evidence of a high degree of crossover between periods of CTV and helicopter access restrictions. Visibility data for use in conjunction with wind speed and wave height data is lacking so modelling helicopter based repairs in detail is difficult. As such it is assumed that CTV wave height restrictions apply to all minor offshore repairs in this thesis regardless of mode of transport.

As the offshore converter is likely to be fully housed, any work that is carried out on the converter sub-system is assumed to be unaffected by further weather constraints and so is 'banked' and the repair is completed when the number of 'banked' hours is equal to the TTR value given in the reliability input data associated with the component in question. The repair methodology works by assuming perfect forecasting of wave conditions and thus looks forward into the wave height time series associated with the next available working day and determines the largest available weather window where wave heights are consecutively below the access threshold. If that weather window is larger than a minimum threshold then a certain number of hours are banked towards the component repair. This repeats through each working day until enough hours have been banked and the total time from point of failure to point of repair is calculated. The minimum threshold is defined as the total travel time to and from the repair site plus a minimum number of working hours which make the travel worthwhile. The minimum number of working hours is assumed to be 2 hours such that a repair that is located 1 hour from shore requires at least a 4 hour weather window for any maintenance to be carried out on that day. If two weather windows are available within a single shift then it is assumed that the maintenance team would make use of only the largest single weather window. Figure 3.6 shows an example scenario which yields two plausible weather windows within a single shift. The number of 'banked' hours in this scenario would be equal to the size of the largest window minus the travel time to and from site. If however the number of hours required to carry out the full repair is reached before the weather window is complete then the process is stopped and the final repair time reported.

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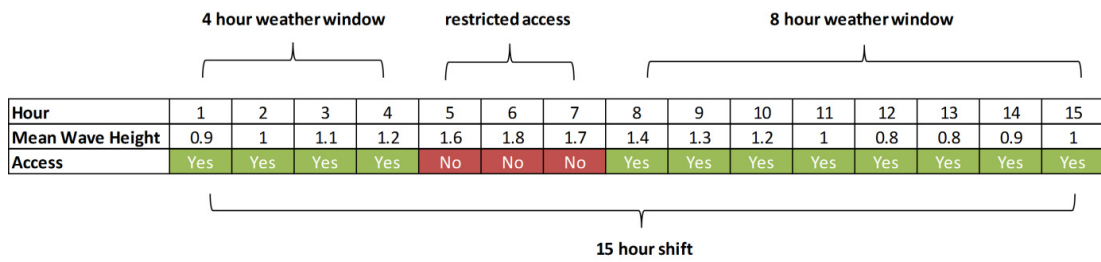


Figure 3.6 - Access example for minor offshore repairs

3.4.3.2 Major Offshore Repair

Major offshore repairs are taken to be repairs which require the procurement of a specialist vessel and or a replacement component. In this study replacement of offshore transformer units and the replacement of a section of damaged offshore transmission cable come under this category. Transformer replacement is likely to require use of a heavy lift vessel (HLV) [45] whereas cable repairs also require a specialist vessel or a vessel modified with the appropriate equipment to carry out the repair so long as it is capable of storing the replacement section of cable, typically 500m worth, and the associated jointing house, cranes and winches that are required [49]. It is considered that repair time for major offshore repairs are significantly driven by delays to procurement of the required vessels and replacement components as well as the weather constraints related to the actual repair process. Given this, a fixed time period is associated with each repair under this category which represents the minimum time required to carry out all preliminary work up to the point where you are ready to go and repair the component. As represented in Tables 3.7-3.9 this period is typically in the order of a few months. After that point it is determined that major repair operations require a fixed weather window under which to perform the entire operation which, again from Tables 3.7-3.9, is likely to be in the order of several days.

For cable repairs relatively calm seas are required to carry out the repair process which requires locating the two damaged ends of the original cable and jointing each end to a new cable section. Any periods of rough weather could lead to the loss of work already carried out so using expert opinion the same 1.5m wave height criteria is applied. For transformer repairs it is assumed that either an HLV or a large field support vessel (FSV) with suitable crane is used to carry out the repair. These vessels

also operate to maximum safe wave height criteria although this is less strict and is set at 2m [45].

As with the minor offshore repair category perfect forecasting is used to search out into the significant wave height time series from the beginning of the first shift after the fixed delay period. In this scenario, however, the repair is not completed until a single weather window is found that is suitably large to perform the entire repair based on the given reliability input figures. It is assumed that travel time to and from the repair site are included in the repair window. A degree of leeway is built into the process such that if 1 hour in the time series is only slightly above the threshold then it is not considered to have breached the criteria. This is realised through the use of a rolling three hour average to determine whether or not the wave height is below the allowed threshold. Both offshore repair categories are able to capture, by virtue of the weather modelling, the fact that repair times are likely to take significantly longer to carry out over the winter months than during the summer, as detailed in Section 4.3.2. This should give a more representative reflection of total E_{und} than a methodology which does not consider seasonal influences on repair times.

3.4.3.3 Onshore Repair

Onshore repairs relate to onshore converter and transformer failures and are not considered to be influenced by weather conditions. As such, the same process of ‘banking’ hours worked during each shift after the point of failure until the repair is complete, as described for minor offshore repairs, is used. There are no criteria to be met so onshore repairs are comparatively short compared with offshore repairs, although in the case of onshore transformer repairs a fixed delay period to account for procurement of the replacement component and appropriate equipment to facilitate the repair is applied. However, it should be noted that such a delay could be mitigated to an extent by the holding of spare components.

3.4.4 Fault Interruption

The reliability tool works by applying ‘active’ faults to the given offshore grid networks so it is necessary that fault interruption, isolation and grid reconfiguration are sufficiently modelled. Fault current interruption is assumed to be successfully achieved using the nearest available circuit breakers or, in the cases without DC

circuit breakers, through actions taken at the terminals of the DC grid either through use of AC side protection or the use of fault blocking VSCs such as those described in [50]. Initial network re-configuration is then assumed to occur such that the faulted component is isolated by the opening of appropriate isolators or circuit breakers, whichever succeed in minimising the number of components, other than the faulted one, that are also isolated. The objective of the fault handling algorithm is to identify the points of isolation and it is assumed that this occurs instantaneously in all network cases. In cases where circuit breakers are not present and there is the need for subsequent actions to re-configure and re-energise the network, this process is assumed to occur within the minimum one hour time resolution of the simulation.

A recursive algorithm is used which steps through the network from the component that has failed until the nearest circuit breakers on either side are reached and opened. In the case where the DC grid is protected via AC side circuit breakers or actions at the converter terminals, this action is assumed to occur on the fault inception such that fault current is blocked and the full grid section isolated. The recursive algorithm, in this case, instead searches for and opens the nearest isolators on either side of the fault to allow the remaining healthy network to be reconfigured as discussed in Section 3.4.5, if necessary, and re-energised, after a suitable delay. In both cases, the algorithm works by running through each branch that is adjacent to the fault. If that branch is a circuit breaker or an isolator, the function will open that element and continue searching along any remaining branches but if the branch is not a circuit breaker or isolator the function will continue on to the next bus and generate a new list of branches that are connected to this bus and will only stop once a circuit breaker or isolator are reached or the end of the line is reached. All buses that have been passed on the way are removed from service along with any connecting branches. To enable this functionality, when a fault or repair occurs the code is used to alter the component attributes such that the state of each component can be identified. Figure 3.7 shows the flowchart that is then implemented within the code to derive the list of buses that lie between the fault and the nearest circuit breakers, isolators or DC grid terminals and so require to be switched out in relation to any given fault.

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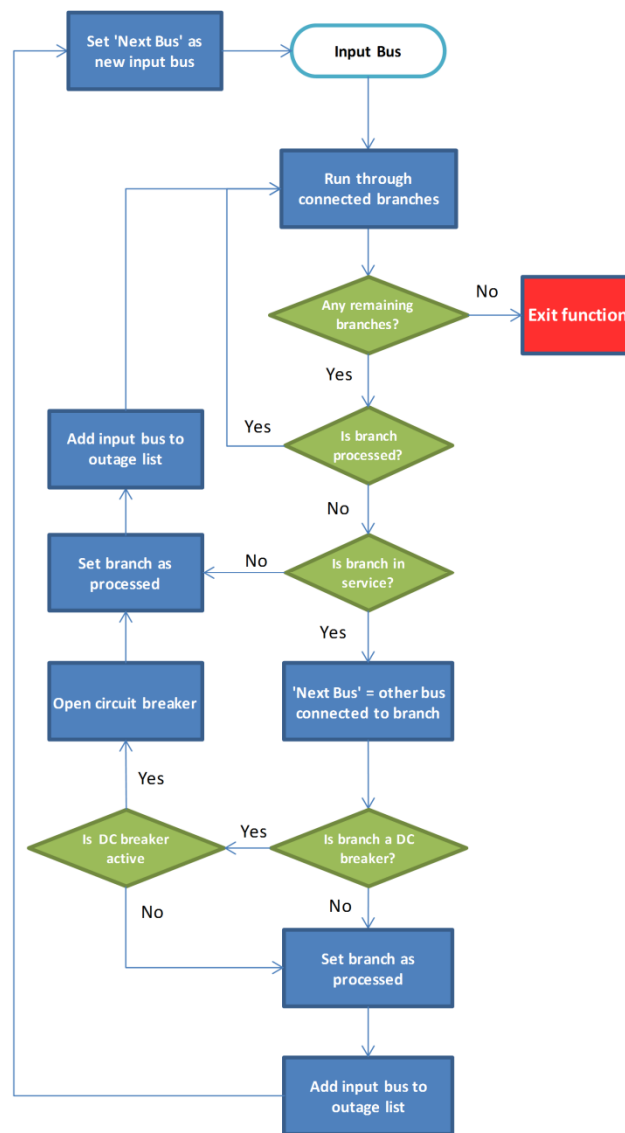


Figure 3.7 - Flowchart of fault propagation function

Given that minimising the program runtime is a key driver in the model design, the calculation of the buses to be removed for each individual fault is made offline and the results tabulated. This look-up table is then used within the Monte Carlo process when required as opposed to repeating the recursive process each time a component fails. When multiple faults are present any overlaps are handled such that components remain switched out until all faults that influence them are repaired.

With the exception of DCCBs the fault interruption code is initiated at the point of failure as dictated by the previous time to fail calculation made for that component. In the case of DCCBs, however, it is assumed that failures relate to instances when

the circuit breaker is called into operation to isolate another fault condition but fails to act for some reason. It is possible that ‘active’ faults could also occur at DCCBs during normal system operation but no data is available as to the nature of offshore faults and this work therefore follows the precedent set in [31] and assumes that DCCB failures are only made visible when they fail to respond to a separate fault condition. To allow this functionality circuit breakers are denoted as having been failed, like other components, when they reach their next calculated TTF. However, DCCB failures are considered to be ‘hidden failures’ which means that, at the time of failure, the network is assumed to be unaffected and the fault interruption code does not act. DCCB faults instead only become apparent at the point at which the breaker is next called upon to isolate a nearby fault whereby the recursive algorithm does not stop its search if the circuit breaker it reaches is in a failed state. The next available DCCB or grid terminal is thus called upon to take action to isolate the fault in question and so DCCB failures can be regarded as acting to increase the impact of other fault conditions. However, it is unrealistic to assume that DCCBs, especially in critical locations for backup, would sit in a non-operational state for several years without detection so it is assumed that the annual scheduled maintenance program, discussed in Section 3.8.2, acts to detect any ‘hidden’ circuit breaker failures and return them to an operational state each summer.

3.4.5 Grid Reconfiguration

Offshore grid designs that make use of circuit breakers throughout or rely solely on radial connections can be considered static in that they do not change structure under fault conditions but rather the fault is cleared and isolated and the remaining healthy sections of the grid are unaffected and continue to operate uninterrupted, with the only consideration being whether or not the remaining connected generation can be transmitted in full. For offshore network designs that do not employ circuit breakers and instead act as a series of sectionalised DC grids as described in Section 2.3.2 it is necessary to calculate the most appropriate grid re-configuration that should be applied for each fault scenario. This is achieved through an optimisation based method that tests every possible switching arrangement. To do this a number of criteria are set on which to judge the appropriateness of each configuration and so

choose the optimal solution. The factors used relate to the ability of each configuration to:

- Deliver wind power to shore
- Minimise the need for curtailment and,
- Allow for energy trading between regions, if available

Given that some faults in particular can be expected to take a long time to fix, the assumption is made that any grid re-configuration could be in place for a significant period of time. This allows the optimisation to be based on the expected earnings from each configuration option given the average yearly cumulative distribution of power output at the site in question. As such the objective function, f , for the optimisation process is set out in Eqn. 3.14 via Eqns. 3.11-3.13:

$$E_{del} = E_{gen} - E_{curtail} \quad (3.11)$$

$$p_{MWh} = p_{subsidy} + p_{market} \quad (3.12)$$

$$T_{cap} = T_{firm} + T_{flex} \quad (3.13)$$

$$f = Max (E_{del} * p_{MWh} + T_{cap} * p_{trade}) \quad (3.14)$$

where the delivered energy, E_{del} , is the amount of energy expected to be generated over the time period, E_{gen} , minus the expected energy curtailment over the period, $E_{curtail}$; the value of financial support available per unit of generated energy, e.g. in GB, via either the renewable obligation for offshore wind generation or the newly devised contracts for difference scheme [51], $p_{subsidy}$ and the wholesale electricity market price, p_{market} are combined to give the total value of generation per MWh, p_{MWh} ; the total trade capacity, T_{cap} , is the amount of trade capacity that can be utilised at any time, T_{firm} , plus the amount of trade capacity that can be utilised when wind output is not using the cable capacity, T_{flex} and p_{trade} is the average price difference between the two markets in question.

To allow the optimisation process to occur, the input details for the objective function first have to be calculated. For every conceivable switch arrangement the grid status algorithm set out in Section 3.4.6 is used to determine the state of the

entire system under each arrangement for a given fault scenario and thus allow the optimisation process to test for the most favourable re-configuration option. If more than one network configuration results in the same expected earnings the number of switching operations that are required to get to that configuration from the previous state is used as a further decision making factor. The contribution of all valid electrical sub-systems within the wider network is added together for each possible configuration scenario and the optimal solution identified. This is again a time consuming algorithm so calculations of the optimal grid re-configurations are made offline for each conceivable combination of component outages and stored in look up tables for use in the main Monte Carlo simulation.

3.4.6 Grid Status Identification

Once a fault has occurred and the fault handling algorithm and, if required, grid re-configuration algorithms have completed the task of switching out all affected components and re-configuring the grid if necessary, a further function is applied in order to understand the new state of the system. This function acts to locate any distinct and valid electrical grids that are functional within the wider network. It uses a very similar methodology to the fault interruption algorithm highlighted previously. The same recursive technique is used to step through the system, this time from each conceivable start point. There is, however, no stop criteria other than the fact that the function will not continue if it reaches a bus or branch that have been removed from service. The function is allowed to run through the entire system until all buses connected to the start point have been identified. If a wind farm converter bus and an onshore converter bus or two onshore converter buses are found to be part of a single connected grid then this is a valid electrical sub-system which allows either transmission of wind power or cross regional trading. The function is repeated starting from all conceivable DC grid entry points until all such sub-systems have been located. Buses which have not been identified must be part of electrical islands that are disconnected from a shore connection point and so cannot transfer power. These buses are removed from service and a count can be made of the number of wind farms that are no longer connected to active electrical sub-systems. Figure 3.8 shows the flowchart that is implemented to locate the electrical sub-systems.

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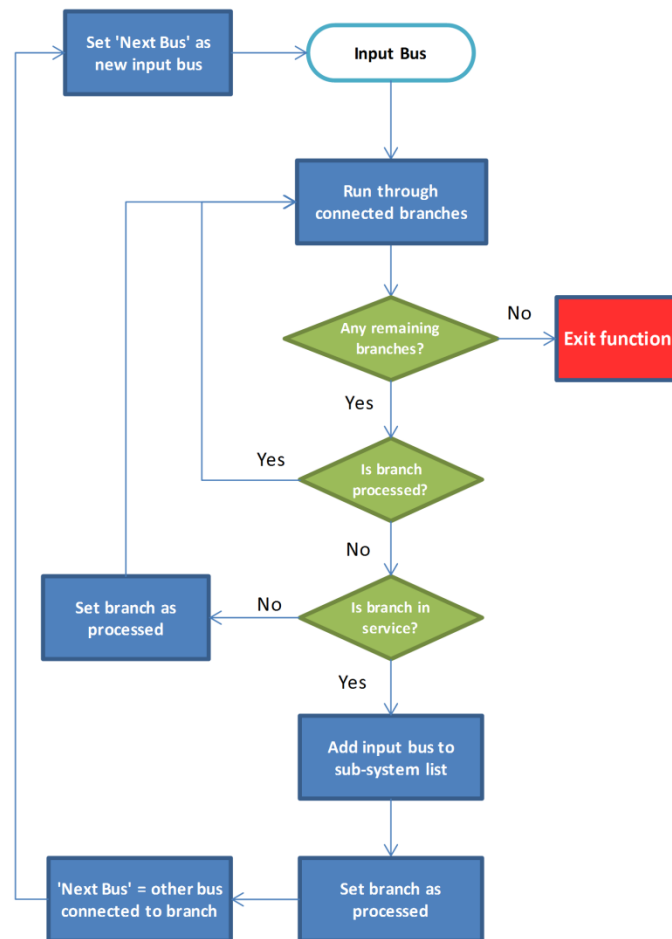


Figure 3.8 - Flowchart for grid status identification function

After the components connected to all valid electrical sub-systems have been identified it is possible to collate the relevant information, including the level of connected generation and the level of onshore transmission capacity, for each sub-system to determine the new status of the overall system and allow calculation of any potential undelivered energy.

3.5 System Outputs

3.5.1 Calculation of Undelivered Energy

As explained previously the leading metric which is used to evaluate the reliability of a given offshore network is the level of offshore generation not delivered to shore due to the impact of faults on the offshore transmission system. This level of E_{und} is calculated in the course of the Monte-Carlo simulation such that an evaluation of the reliability of the network and further estimations of the financial implications of that can be made. The total available generated energy, E_{avail} , for each network is calculated by multiplying the wind speed, taken from the input mean wind speed time series, with the appropriate conversion factor, derived from the input wind speed-wind power curve shown in Figure 3.4, and the total available capacity of the system for each time step as shown in Eqn. 3.15:

$$E_{avail} = \sum_{t=0}^n WF_{cap} * U_t * x_t \quad (3.15)$$

where n is the total time of the simulation in hours, WF_{cap} , is the total capacity of wind farms in the system, U_t is the wind speed at time t and x_t is the conversion factor for the wind speed, at time t , to wind power.

To determine the level of E_{und} a calculation is made at each change in system state during the simulation. If the previous system state includes any full wind farm disconnections the energy not transmitted due to these, E_{und_out} , is calculated using Eqn. 3.16 based on the capacity of any disconnected wind farm(s), WF_{out} , along with the hourly wind speeds, U_t , for the period between the point of calculation, T_{now} , and the point the system entered that state, T_{last} , and the conversion factor x_t . If the previous system state alternatively had a situation where any valid electrical sub-systems had more generation capacity than transmission capacity then a calculation of the level, if any, of energy lost due to requirement for curtailment of generation, E_{und_curt} , using Eqn. 3.18 is performed. Eqn 3.18 is only invoked when the power output at time t , P_t , of any valid electrical sub-system, as calculated from Eqn.3.17, exceeds the available transmission capacity of that sub-system, P_{lim} .

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$$E_{und_out} = \sum_{t=T_{last}}^{T_{now}} WF_{out} * U_t * x_t \quad (3.16)$$

$$P_t = WF_{cap} * U_t * x_t \quad (3.17)$$

$$\text{For } P_t > P_{lim}: \quad E_{und_curt} = \sum_{t=T_{last}}^{T_{now}} P_t - P_{lim} \quad (3.18)$$

A further calculation of undelivered energy is required for any network scenarios that require any grid sections to be temporarily shut down in the event of component faults. This relates to the time required to shut down the effected grid section, isolate the faulted region, re-configure the network if appropriate and re-energise the healthy parts of the system. Given that individual wind turbines can be restarted within a few minutes of being shut down and that switching sequences for re-configuration of onshore networks can be applied within a few minutes it seems reasonable to assume that this process can be undertaken in, at most, tens of minutes. As a conservative estimate this work assumes the process accounts for one time step in the simulation, i.e. 1 hour. As such the level of energy not delivered due to the process of grid re-configuration, E_{und_rcf} , can be calculated from Eqn. 3.19:

$$E_{und_rcf} = I_{cap} * U_t * x_t \quad (3.19)$$

where I_{cap} is the capacity of wind farms on the disconnected electrical sub-system, U_t is the average wind speed and x_t the conversion factor at the time, t , that the fault occurs. On completion of the Monte Carlo simulation the total level of undelivered energy is derived through the summation of all previous E_{und_out} , E_{und_curt} and E_{und_rcf} calculations and this can then be compared against the total level of available generation, E_{avail} , to give a final figure for the percentage of E_{und} for each network scenario as described in Eqn. 3.20.

$$E_{und\%} = \frac{\sum_{t=0}^n E_{und_out} + \sum_{t=0}^n E_{und_curt} + \sum_{t=0}^n E_{und_rcf}}{E_{avail}} * 100 \quad (3.20)$$

3.5.2 Assessment of Tradable Energy

For offshore networks that incorporate the ability for cross border trading between two or more regions it is necessary to calculate the level of trade capacity that is available over and above the energy that is generated at offshore wind farms connected to the grid. Tradable energy can be separated into two categories, the first of which is termed firm trade and relates to the amount of spare capacity that is always available on a grid or grid section that is always free to be used for cross border energy trading. The second category of tradable energy is termed flexible trade and relates to the amount of tradable energy that can be utilised when wind output is below maximum output meaning there is spare capacity on the cables. An illustration of the tradable energy is given in Figure 3.9 which looks at the annual cumulative power output from an offshore grid that has 800MW of wind farms connected to two separate shores each with 1000MW capacity.

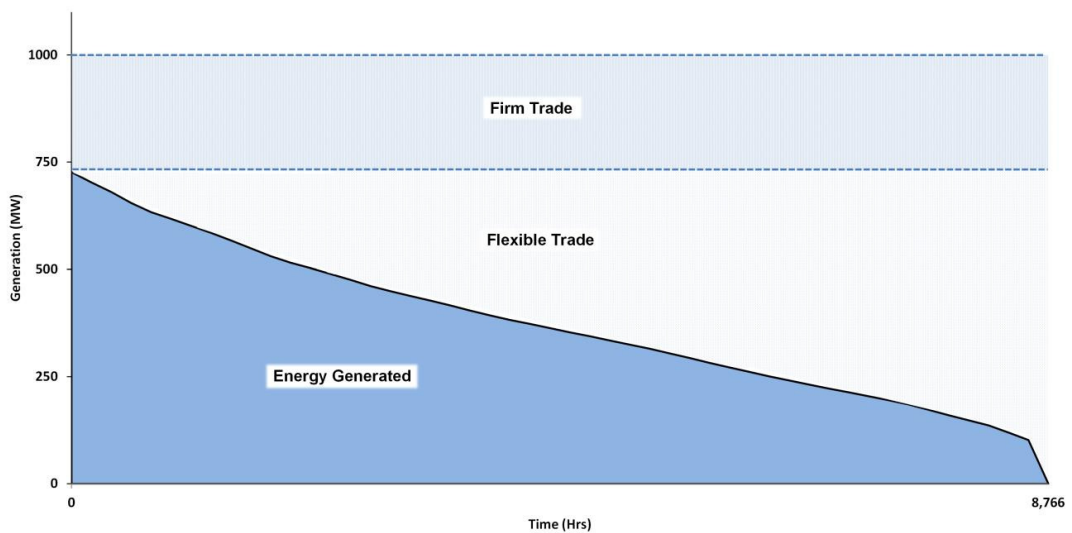


Figure 3.9 - Annual cumulative wind power output and tradable energy example

As is shown, the amount of firm trade energy is a fixed block between the maximum transmission capacity and the maximum wind power output. The amount of flexible trade at any one point in time is given by the difference between the maximum wind power output and the actual wind power output. The level of firm and flexible trade energy, like undelivered energy, is calculated at each change of system state for all viable electrical sub-systems. The grid status identification output of shore capacity and generation capacity are used to determine the level of firm trade capacity

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available on each sub-system connected in the previous system state and a calculation of the available firm trade over that period can be obtained by multiplying by the length of time spent in that state. For flexible trade energy a calculation is made for each hour the system was in its previous state which calculates the level of flexible energy as the difference between the maximum generation output and the real generation output. These values are summed over the full duration of the simulation to generate a total value and then divided by the number of years in the simulation to obtain an average annual value for the availability of both firm and flexible trade energy.

3.6 General Overview of Methodology

Figure 3.10 can be used to illustrate the overall procedure undertaken through the Monte Carlo analysis. In this example two components are shown from an example offshore grid for a 350 hour snapshot of time to highlight how the wind speed and wave height weather inputs are integrated into the reliability modelling. Component 1 is an offshore converter transformer associated with an offshore wind farm (WF1) that begins the example in a failed state meaning a portion of the fixed delay time associated with offshore transformer failures, as discussed in Section 3.3.4, has already elapsed. Component 2 is an offshore converter associated with another wind farm connected to the example grid and begins the example in functioning state with a time to fail that has been pre-determined by the method set out in Section 3.4.2.

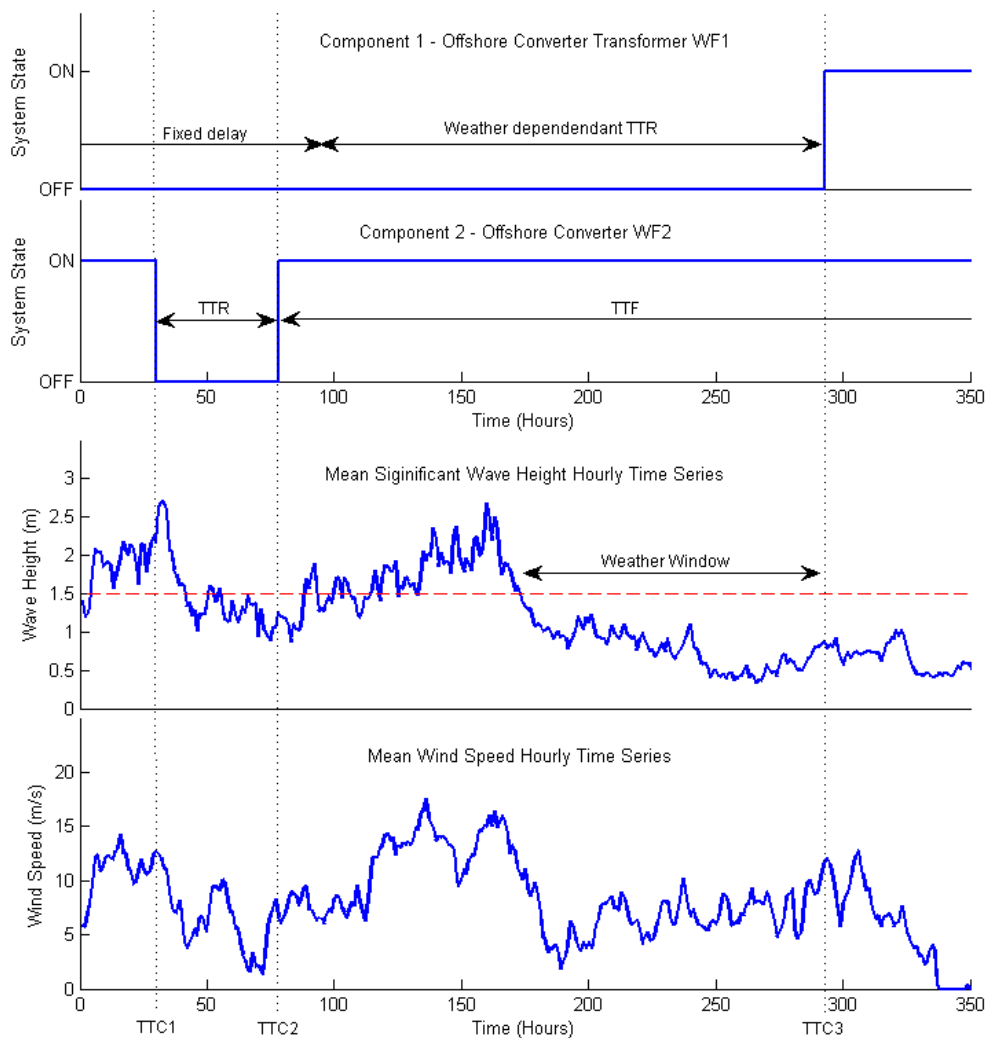


Figure 3.10 - Example illustrating methodology

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The model determines the next time to change (TTC) by comparing against the fail and repair times derived for all other components. Rather than stepping through time hour by hour and assessing all facets of the system state at each time step, the model makes substantial computational savings by stepping straight to the next TTC value, denoted TTC1 in the example. At TTC1 the model recognises that component 2 has reached a fail state so immediately invokes the fault interruption function to isolate the fault and switch out any necessary components, followed by the grid reconfiguration function to allow any alterations to the system configuration, if available. The grid status identification function can then be used to determine the new status of the system. Since component 2 is now in a failed state it is necessary to calculate a repair time so the time to repair methodology associated with offshore converter faults, as described in Section 3.4.3.1, is used. In this example around 50 hours elapse before conditions allow enough working hours within daytime shift periods to be carried out to repair the component using the access criteria of 1.5m significant wave height. This calculated TTR value is compared against all other system components and is confirmed to be the next TTC value, TTC2. Before moving to the next time to change it is necessary to assess any impact on reliability due to the previous system state. In this example we know that the previous system state had the failure of component 1 associated with it which would prohibit wind power export from WF1. The calculations described in Section 3.5.1 are thus applied to determine the level of undelivered energy associated with this fault given knowledge of the wind speed time series between TTC1 and the previous change in system state. If cross border trades are possible on the network then the level of traded energy will also be assessed as per Section 3.5.2.

At TTC2 the model recognises that component 2 has reached a repair state and acts to re-connect all the components that were switched out at TTC1. A new time to fail calculation is then made for component 2 and compared with all other component failure and repair times before determining the next TTC. The level of any cross border trade and undelivered energy is then calculated, as before, for the period between TTC1 and TTC2, noting that the output of two wind farms in the network were compromised during this period. This example also illustrates the methodology used to calculate the repair time of major offshore component failures such as the

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failure of an offshore transformer. Figure 3.10 shows that at a little before 100 hours the fixed delay period, required to procure the replacement component and appropriate repair vessel has elapsed and so the weather dependent portion of the repair time is calculated. The example shows a further 200 hours elapse before a sufficiently large calm weather period is obtained, as dictated by the reliability input criteria for offshore transformers and the component is repaired at TTC3 before the process of calculating the level of undelivered energy and any cross border trade potential between TTC2 and TTC3 is undertaken. The process continues on until the stop criterion is satisfied.

The methodology as described allows for failures and repairs of individual components to be implemented independently and means that overlapping fault conditions can be modelled. This means that potentially high impact conditions where two or more faults are present on the system simultaneously can be investigated to determine the importance of such scenarios to overall reliability performance. This is a feature that is not modelled in processes which restrict investigation to the impact of individual failure events. An extension of the ability to model multiple overlapping faults would be to include the possibility of single events leading to the outage of more than one component in the system. This would be more akin to traditional N-2 fault modelling whereby, for example, an extreme weather event might simultaneously lead to the loss of service of two system components. However, there is no data relating to such a phenomenon in the offshore transmission setting so this has not been considered in this thesis although it may be an issue that could be considered in any future work on the subject.

3.7 Electrical Loss Modelling

To precisely calculate electrical losses within HVDC grids accurate models could be produced and full load flow run within a program such as PSS[®]E for all possible fault scenarios and generation conditions. This would require modelling of the electrical networks to a greater degree of detail than has been undertaken in this project which instead focuses on modelling of aspects most important to overall reliability and response to fault conditions. To make a calculation of electrical losses at each time step within the Monte Carlo simulation would also add substantially to the system runtime so this approach is avoided. It is however possible to make offline estimates of the likely degree of electrical losses by applying published efficiency data for certain components and by calculating the copper losses in subsea cables and applying the results within the Monte Carlo simulation. Table 3.10 illustrates the assumptions that have been made in terms of electrical losses relating to the technologies most likely to be used in future offshore HVDC grids using published figures from [28, 31]. In reality the quoted figures for losses associated with VSC converters and DCCBs apply to operation at rated capacity and losses may well be lower for a substantial portion of the time. This is because some of the losses associated with the converter station, such as those associated with switching remain relatively fixed proportionally regardless of power throughput whereas conduction losses will be proportionally lower at lower levels of power transfer. However, without detailed understanding of the converters deployed and their loss mechanisms the modelling in this thesis makes the first pass assumption that the published converter station loss figures apply at all power ratings and therefore loss calculations can be assumed to be a conservative estimate.

Table 3.10 - Electrical loss parameters

Electrical Loss Parameters			
Component	Electrical Losses		Comments
	500MW	1000MW	Losses reduce with power rating
VSC Converter Station	1%	0.9%	Assumes MMC converters used
HVDC Circuit Breaker	0.01%	0.08%	Assumes hybrid concept used
HVDC Transmission Cable	0.02Ω	0.01Ω	Calculate from $P_{\text{loss}}=I^2R$

The level of electrical losses on a network, nevertheless, varies with the amount of current in the system due to copper losses, with proportionally higher losses as the grid approaches full utilisation. To estimate average losses, it is possible to use the wind power frequency distribution as shown in Figure 3.1 which gives the frequency of time spent in each of a range of power output bins. By considering how power flows are likely to be controlled in the system, for any given level of generation the expected level of electrical losses at each element in the network can be determined. Given knowledge of the amount of time spent at each generating level and the level of expected losses associated with each level a calculation of the average annual electrical losses you would expect to occur on an intact network, $E_{loss\ intact}$, over the range of expected operating conditions can then be made. This can be applied using, Eqn. 3.21, to the level of generated energy, E_{avail} , as calculated in Eqn. 3.15 within the Monte Carlo simulation to give an estimate of the level of deliverable energy, $E_{deliverable}$, associated with each network option. $E_{deliverable}$ is therefore a measure of the total generated energy minus the expected electrical losses associated with the offshore DC grid if it remained in an intact state.

$$E_{deliverable} = (100\% - E_{loss\ intact\ \%}) * E_{avail} \quad (3.21)$$

When included, electrical losses are also accounted for within the calculation of E_{und_out} , E_{und_curt} and E_{und_rcf} by calculating the average expected losses associated with each of the most common system states and applying as appropriate within the Monte Carlo simulation. For full wind farm outages this is achieved by reducing the calculated level of energy derived from Eqns. 3.16 and 3.19 respectively by the average intact losses of the system, $E_{loss\ intact}$. This accounts for the fact that the calculated E_{und} values would have been subject to these losses and ensures that the undelivered energy is not overestimated. For curtailed energy it is assumed that curtailment does not occur until the power output, P_t , minus electrical losses, $E_{loss\ curt}$, are more than the grid transmission limit, P_{lim} . The value of $E_{loss\ curt}$ is derived from the losses calculated only when generation is high enough to cause energy curtailment and so is greater than the intact system losses. The modelling of

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electrical losses therefore reduces the level of calculated energy curtailment by effectively increasing the threshold level of generation output before curtailment is required. To summarise, when system losses are included Eqns 3.16, 3.17 and 3.19 should be adjusted as shown in Eqns. 3.22-3.24 such that the final calculation of $E_{und\%}$ as shown in Eqn. 3.20 includes a consideration of losses at all stages.

$$E_{und_out} = \sum_{t=T_{last}}^{T_{now}} (100\% - E_{loss\ intact\ \%}) * WF_{out} * U_t * x_t \quad (3.22)$$

$$P_t = (100\% - E_{loss\ curt\ \%}) * WF_{cap} * U_t * x_t \quad (3.23)$$

$$E_{und_rcf} = (100\% - E_{loss\ intact\ \%}) * I_{cap} * U_t * x_t \quad (3.24)$$

Introducing faults into the network inherently alters the level of system losses experienced compared with the intact network so it is necessary to account for this. This change in system losses during periods when the network is in various faulted states can be thought of as influencing the level of energy actually delivered to shore. It is accounted for using the average system losses calculated for each of the possible system states to derive an adjustment that can be made to the level of deliverable energy as calculated in Eqn. 3.21. This is calculated as the difference between the losses that would have been present in the intact state, $E_{loss\ intact\ \%}$, and the losses that are present in the faulted state, $E_{loss\ y\ \%}$, multiplied by the level of generated energy during the outage period as shown in Eqn. 3.25.

$$E_{adjust} = (E_{loss\ intact\ \%} - E_{loss\ y\ \%}) * Grid_{con} * U_t * x_t \quad (3.25)$$

where $grid_{con}$ is the capacity of connected generation. The level of adjusted energy is calculated after each new outage state and summed to give a total value which can be used to evaluate the level of delivered energy, $E_{delivered}$, using Eqn. 3.26.

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$$E_{delivered} = E_{deliverable} + \sum_{t=0}^n E_{adjust} \quad (3.26)$$

As the size and complexity of the offshore grid design increases so does the number of possible system states. As such, it becomes increasingly time consuming to make the manual offline calculations used in this representation of system losses and the use of a more automated electrical loss model is desirable and would be considered as an area for future development.

3.8 Cost Modelling

To inform on the broader implications of the various reliability comparisons made in this project it is necessary to determine the overall financial consequences related to the reliability or unreliability of different grid options. To achieve this, a detailed cost model has been included which estimates the cost of undelivered energy due to faults and electrical losses as calculated within the Monte Carlo reliability model. In addition to this, included in the model is an estimation of the expected cost of the required operations and maintenance work undertaken to repair faults. The capital cost of each network design is also calculated and together with the other grid costs can be used to determine the total cost of generating electricity from each grid configuration. The details of the cost analysis are explained in the following section. It is assumed that all grid options to be investigated are designed such that onshore loss of infeed limits are not breached in any scenario and so there is no need to account for the cost of additional onshore system security of supply measures.

3.8.1 Cost of Energy

The Monte Carlo simulation is used to deliver values for the expected annual level of undelivered energy due to both fault conditions and system electrical losses for any given project. The monetary value of that lost energy can be assumed to be equivalent to the value of energy that is actually delivered to market. For offshore wind power the cost of energy for the consumer is given as the cost of subsidy plus the wholesale price of electricity. In previous years, the subsidy cost of offshore wind generation was derived from the renewable obligation system which awarded offshore wind two ROCs (renewable obligations certificates) on top of the wholesale price of electricity. Thus, assuming the price of both ROCs and wholesale electricity to be in the region of £50/MWh, the total value of offshore wind under this system is around £150/MWh. This system has recently been superseded in Great Britain by a CfD (contracts for difference) system which sets out a series of annual maximum available strike prices for the next five years beginning in 2014. This work assumes a value of £150/MWh for the price of energy which is the median maximum strike price over the 5 year period and is in line with the previously used ROC system [6, 52].

A straight application of the cost of energy to the expected annual undelivered energy values gives the expected annual cost. It is important however to assess those costs in the context of the overall project and so a discounted cash flow calculation is performed on annual costs over the estimated project lifespan to give the net present value (NPV) of the lifetime costs. This can then be added to the other system costs such as upfront capital expenditure required for the network option to give an estimate of the total investment costs associated with the project. The NPV calculation used is given in Eqn.3.27:

$$NPV = \sum_{t=1}^n \frac{P_{annual}}{(1+r)^{t-1}} \quad (3.27)$$

where n is equal to the project lifespan in years, r is the discount rate associated with the time value of money and P_{annual} , is the annual value of the undelivered energy being evaluated. This study assumes the project lifespan for offshore networks to be 25 years which is in line with the expected lifespan of individual offshore wind deployments and is equal to the figure used the OffshoreGrid study of future offshore electricity infrastructure [53]. The annual discount rate has an important influence on overall costs and a number of different studies into offshore transmission infrastructure have used figures ranging between 2% and 10% [6, 10, 19]. A central estimate of 6% is therefore used; however, as the discount rate can have a large impact on the calculated project costs, the impact of varying this value is studied within the sensitivity analysis in Section 5.5 as is the impact of varying the cost of energy.

3.8.2 Cost of Operations and Maintenance

The cost of offshore O&M is a major consideration when looking at the offshore wind farm development sector. The costs of vessel hire, procurement of replacement components and payment of maintenance crew to carry out the repair of components are significant to the overall financing of the project and this is an active area of research some examples of which are cited later in this section. When applied to offshore transmission systems the impact of individual faults is much higher than faults occurring on individual turbines because the transmission system faults often

lead to the curtailment of whole wind farms or grid sections. The costs associated with these large scale outages in terms of undelivered energy are likely to be significantly higher than the costs of repairing the fault. As such the costs of O&M are less likely to be a major driver behind overall project costs in relation to offshore transmission systems however the costs can still be significant and have been modelled for completeness.

3.8.2.1 Direct Repair Costs

O&M costs directly relating to component repairs are modelled within the Monte Carlo simulation alongside the calculation of component repair time. A number of details are required to estimate the cost of O&M for a particular fault such as the cost of any replacement components, the number and cost of personnel required to carry out the job and costs of the vessel required for the repair. A number of studies have addressed these costs in relation to offshore wind farm O&M [12, 45, 54] and offshore transmission component costs are addressed in [55]. By combining the data published in these sources it has been possible to derive a set of cost parameters that can be used to describe the various failure modes in offshore transmission networks. The values used are shown in Table 3.11.

Table 3.11 - O&M cost matrix

Operations and Maintenance Cost Parameters						
Failure Input	Offshore Platform	Offshore Transformer	Transmission Cable	DCCB	Onshore Converter	Onshore Transformer
Required Personnel	3	5	5	3	3	5
Personnel Cost	£100/hr	£100/hr	£100/hr	£100/hr	£100/hr	£100/hr
Vessel Type	CTV/ Helicopter	HLV	FSV	CTV/ Helicopter	-	-
Vessel Day rate	£1500/ £12500	£150000	£10000	£1500/ £12500	-	-
Mobilisation Cost	-	£500000	-	-	-	-
Fixed Cost of Repair	£1000	£2500000	£500000	£1000	£1000	£2500000

The total O&M cost for any repair is simply the addition of all the relevant costs as outlined. To further inform the decision the number of working days required to

complete the repair is calculated within the repair time function. This allows the total personnel costs to be calculated by multiplying the number of days worked by the appropriate shift length and the costs and number of personnel. The personnel costs are not meant to represent the actual individual payments but are rather inflated to represent the costs of keeping a substantially sized operations crew on standby to respond to faults as and when they occur. The total vessel costs can also be calculated by multiplying the day rate by the number of days worked and then adding the mobilisation cost of the vessel. The fixed cost of repair relates to the actual cost of replacement components and for converter and DCCB faults these are in line with the minor fault costs used in [54] whereas the costs of transformer and replacement cable sections are derived from [55] assuming that a 500m cable section is required for repair [38]. The total cost of all repairs can be summed for each Monte Carlo run and then divided by the number of Monte Carlo years to give an expected annual cost of O&M directly related to the repair of faulted components.

3.8.2.2 Scheduled Maintenance Costs

In addition to this it is also assumed that a scheduled annual maintenance regime is in place such that the previously stated assumption of constant failure rate remains valid over the full course of the assets' lifespan. The cost of this scheduled maintenance is calculated by applying a fixed cost to each of a number of maintenance categories and so varies with the number and type of components in each grid. The costs are taken as central estimates from [56] and are outlined in Table 3.12. Reference [56] is based on the expected O&M costs for a 500MW offshore wind farm so all costs calculated in this thesis are scaled to reflect the rating of the components in each of the grids investigated. Transmission cable O&M relates mainly to surveys of cable burial depth so costs are scaled on a per km basis assuming that the O&M cost quoted in [56] are true for a wind farm that is 50 km from shore. The annual scheduled maintenance costs related to DCCBs are taken to be $1/6^{\text{th}}$ of the O&M costs for a full offshore platform in line with the cost projections outlined in Section 3.8.3.

Table 3.12 - Scheduled O&M cost parameters

Scheduled Operations and Maintenance Cost Parameters			
	Cost/Unit/ Year	Unit Base	Comments
Offshore Station	£125000	500 MW	<ul style="list-style-type: none"> • Inspections of electrical and structural infrastructure • Paint and steelwork repairs
Onshore Station	£60000	500 MW	<ul style="list-style-type: none"> • Inspections of electrical infrastructure
Transmission Cable	£125000	50 km	<ul style="list-style-type: none"> • Surface or ROV based surveys of burial depth • Integrity testing
DCCB	£20833	500 MW	<ul style="list-style-type: none"> • Inspections of electrical infrastructure (1/6th cost of full offshore station applied)

After the total annual scheduled maintenance costs are determined an NPV calculation, as described in Section 3.8.1, can be performed to obtain a representation of the combined scheduled and unscheduled project lifetime O&M costs for direct comparison with the capital expenditure and lifetime costs of undelivered energy.

3.8.3 Capital Cost Modelling

Many of the technologies that are likely to be deployed as part of an offshore grid are both young in the context of offshore applications and subject to variability in cost. This makes cost estimation of different network options a difficult task although there is some literature to guide analysis. Major reports by National Grid and ENTSO-E [55, 57] have published projected cost data for offshore grid infrastructure based on the same findings whilst a number of Cigré Technical Brochures discuss potential costs of various offshore grid components [28, 58]. The data in [55, 57] has been garnered through purchase experience and historical costs where possible and otherwise through discussion with industry suppliers and the most up to date published figures can be used with reasonable confidence to form the basis of capital cost analysis within this project. Costs are given for a wide range of offshore equipment but those relating to the most likely technology options for offshore HVDC applications are summarised in Tables 3.13-3.17.

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Table 3.13 - Voltage source converter costs

VSC Converter		Notes
Specification	Unit Cost (£millions)	<ol style="list-style-type: none"> Price excludes platform cost Prices for larger rated stations are indicative projections of costs for 'next generation' technologies.
500 MW 300 kV	68 – 84	
850 MW 320 kV	89 – 110	
1250 MW 500 kV	108 – 136	
2000 MW 500 kV	131 – 178	

Table 3.14 - Transformer costs

Transformers		Notes
Specification	Unit Cost (£millions)	<ol style="list-style-type: none"> Price excludes civil works. Civil costs can approximately double the total installed bay cost. Material costs are subject to fluctuation based on relevant commodity indices.
240 MVA - 132/33/33 kV	1.26 - 2.09	
120 MVA - 275/33 kV	1.26- 1.68	
240 MVA - 275/33 kV	1.57 - 2.09	
240 MVA - 400/132 kV	1.88 - 2.3	

Table 3.15 - HVDC XLPE subsea cable costs

HVDC XLPE Cables		Notes
Cross Sectional Area (mm ²)	Unit Cost (£/m) 320kV	<ol style="list-style-type: none"> Prices can vary widely based upon market supply/demand and commodity fluctuations.
1200	314 – 471	
1500	346 – 471	
1800	314 – 524	
2000	366 – 576	

Table 3.16 - Subsea cable installation costs

Subsea Cable Installation		Notes
Installation Type	Total Cost per km (£millions)	<ol style="list-style-type: none"> Prices affected by many factors - seabed, route length, cable crossings, landing sites, natural environment etc.
Single cable, single trench	0.31 - 0.73	
Twin cable, single trench	0.52 - 0.94	
2 single cable, 2 trench (10m apart)	0.63 - 1.26	

Table 3.17 - Costs for different DC platform designs

800 MW or 1000 MW VSC DC Platform (±300 kV or ±500 kV - 8000 tonnes)		Notes
Structure	Unit Cost at 30 - 50 m (£millions)	1. Price not including electrical equipment costs.
Topside	60 - 80	
Jacket	20 - 25	
Install	27 – 35	
Self-installing	120 – 145	

A major proposed component of some offshore grid designs, as discussed, is the DC circuit breaker. Section 2.1.4 explains how this is a burgeoning technology that has yet to be delivered in a commercial sense. As such there is no cost data available for DCCBs meaning an estimate is required based on knowledge of the proposed design solutions. A hybrid option using a full power electronic branch as the means of current interruption, as proposed in [59] is one such design option. It is stated in [58] that for unidirectional breaking, power electronic DCCBs require only to break the pole to ground voltage of the VSC converter and so can be realised using the equivalent of one valve of the 6 pulse group that handles the pole to pole voltage of the converter. This suggests that for bi-directional interruption capability a DC circuit breaker would require one third of the power electronic capacity of a VSC converter. DC circuit breakers would not require the same level of additional components such as the filters and transformers that are associated with a VSC converter station. Cost estimates vary however with [60] estimating that the cost of a DCCB would be 20-30% of an equivalent sized converter station whereas the Twenties study set the cost of DC breakers to be €15m which is at the lower end of estimates compared to the projected costs of VSC converter stations [33]. Given that power capacity is shared in bipolar grids this study assumes that the cost of each DCCB is 1/6th of the cost of the VSC converter station it is associated with meaning that each breaker pair in the two cable system is 1/3rd the cost of its equivalent converter station. It is also assumed that this estimate factors in any additional expenditure that is required to accommodate DCCBs such as increased offshore platform space.

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The capital costs associated with case studies used in this thesis are based on mean values taken from the above input data with the exception of the ISLES case study, the costs of which were estimated within the original study [61]. Where components have ratings that do not match any of the quoted data a linear extrapolation is used to infer costs based on the two nearest quoted figures. The above costs are assumed to apply to all grid scenarios unless otherwise stated, whereby a justification for cost variation is given.

3.9 Conclusion

The chapter presents a novel methodology for assessing the reliability and associated cost of future potential offshore grid scenarios. A sequential Monte Carlo modelling process has been developed that takes in a number of input parameters, models failures and repairs on the network in question and calculates the level of undelivered energy as a measure of overall grid reliability.

The system inputs include the network design being assessed, which can be of varying grid topology and converter configuration as well as failure and repair data relating to each component in the grid. Three distinct reliability scenarios have been developed each with a unique set of component failure and repair rates based on the spread of available published data and a degree of expert opinion. Simulated mean hourly wind speed and wave height time series' which have been synthesised from existing data from an offshore wind farm site are also used as model inputs.

The Monte Carlo process chronologically applies faults randomly into the system based on the input failure rate data of the reliability scenario being investigated. A number of processes have been developed which are able to isolate the faulted grid component by following an appropriate protection strategy and if the grid has the ability to be re-configured to an improved system state then an optimisation process is implemented to determine and implement the required changes. After all network reconfigurations have been applied the new status of the network is determined and using knowledge of the time spent in the new system state and the wind speeds over that time a calculation can be made of any undelivered energy. The main novelty of the process is the treatment of component repair times which are modelled with reference to realistic constraints relating to procurement and logistics delays as well as weather, specifically wave height, based access restrictions following any faults.

Electrical losses, O&M costs and the capital costs of implementing each grid option are also modelled along with the potential for any cross border trade, if applicable, to allow a full cost-benefit analysis to be performed. Chapters 4 and 5 of the thesis will make use of the methodology that has been outlined to investigate a number of case studies and sensitivities.

3.10 References

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4. Evaluation of Grid Design Options

To evaluate and compare the reliability and thus overall cost effectiveness of different offshore grid design options, a number of case studies are investigated. The first set of case studies, outlined in Section 4.1, are developed from the ISLES project which suggested a means of connecting 2.1GW of wind energy between the islands of Ireland and Great Britain whilst also providing interconnection between the regions. The second set of case studies, discussed in Section 4.2, is developed from a generic offshore wind farm development connecting 2.4GW of wind capacity to shore and is akin to the expected early phase developments in UK Round 3 offshore sites such as Dogger Bank. This chapter presents the high level results and analysis from the reliability investigation and cost modelling performed and assesses the importance of the weather dependent reliability methodology.

4.1 Case Study 1 – Northern ISLES

4.1.1 Development of Grid Options

The ISLES study advanced proposals for the development of HVDC offshore grids between Great Britain and Ireland. One of those, the Northern ISLES concept, proposed a sectionalised multi-terminal HVDC network topology without the need for DCCBs that could incorporate 2.1GW of offshore wind generation as well as providing the opportunity for cross-border energy trading [1]. This proposal is used to derive the base case DC grid design option for this investigation, with two further design options proposed for comparison. The first of these represents a version of the ISLES network that incorporates DCCBs across the network and can thus be realised as a single DC grid rather than separate sectionalised grids. The final case study represents a semi co-ordinated design approach which clusters some wind farms but relies upon radial connections to shore and does not offer any interconnection between the sectionalised grid elements and thus has limited redundant transmission paths for re-routing power flows in the event of faults.

The base case grid option is shown in Figure 4.1 and utilises a sectionalised DC grid topology which negates the need for DCCBs in the clearance of DC side faults and avoids the breach of any onshore loss of infeed limits. The network is made up of three 500MW and two 300MW offshore wind farms with two 500MW connections to the Irish grid at Coolkeeragh and Coleraine and three connections, two 1000MW and one 500MW, to the GB grid at Hunterston. The offshore network is comprised of three distinct DC grid sections which are connected at a number of central switching hubs. In the normal pre-fault operating state the three grids operate independently of one another and the level of wind energy connected to each grid section is below the maximum infrequent loss of infeed limit for the GB and Irish networks. In the event of a fault an entire DC grid section will be temporarily shut down but the network can be re-configured to an appropriate new operating state via switching operations. The grid reconfiguration methodology outlined in Section 3.4.6 is used to determine the new operating state which is applied after an assumed delay of one hour, equal to the minimum time resolution of the Monte Carlo simulation, as outlined in Section 3.4.3.

4. Evaluation of Grid Design Options

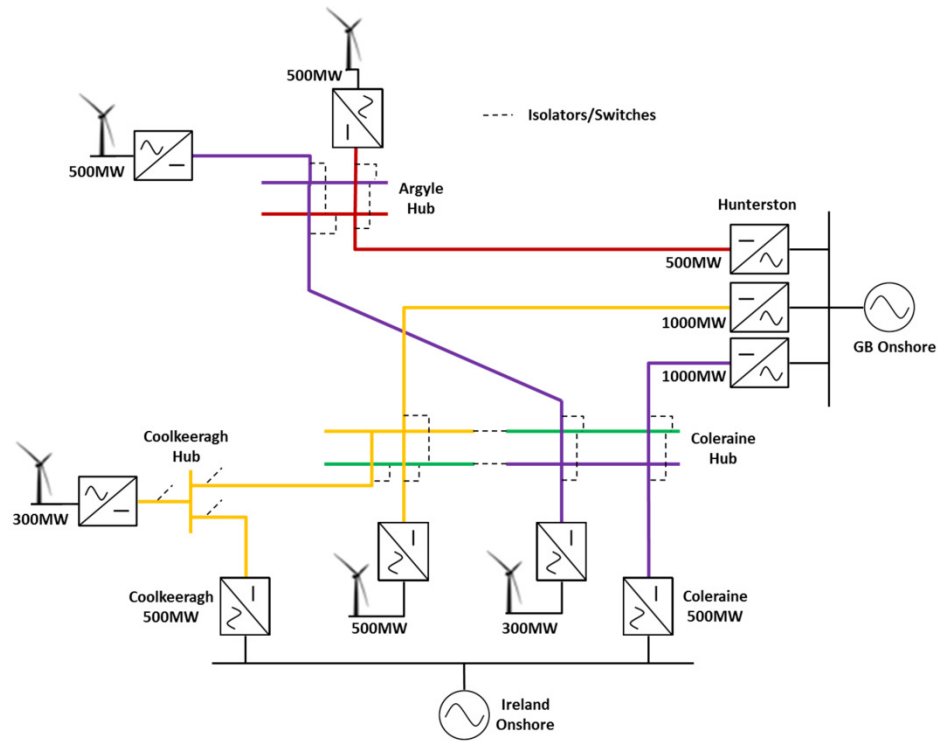


Figure 4.1 - Single line representation of ISLES base case DC grid scenario derived from [2]

Figure 4.2 shows the reconfiguration process that occurs after a fault has occurred on the transmission branch between Coleraine hub and Hunterston.

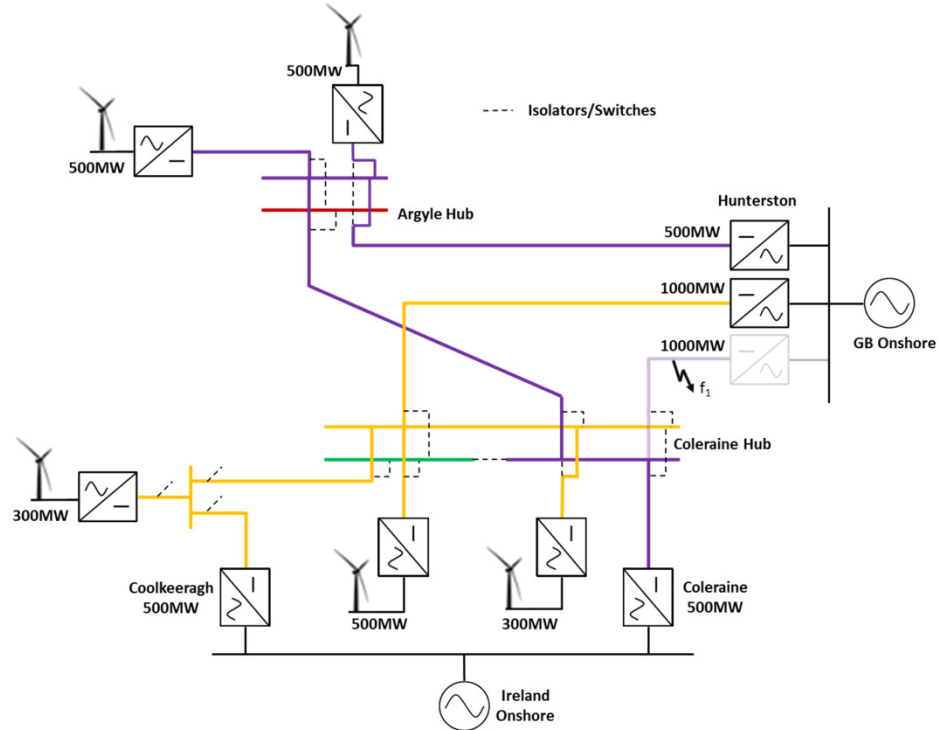


Figure 4.2 - Example post-fault grid reconfiguration for ISLES base case

4. Evaluation of Grid Design Options

The algorithm tests all possible solutions before settling on a new grid configuration which delivers two separate grids. Each of these has at least as much onshore transmission capacity as connected wind generation, such that there is no requirement for energy curtailment, and there is the ability to transfer power between the two regions when wind output is reduced.

To determine the level of impact on overall reliability of using the sectionalised DC grid topology, a second case study is investigated which utilises DCCBs. This topology, shown in Figure 4.3, is realised as a single contiguous DC grid as it is assumed fast acting DCCBs are available in conjunction with an appropriate protection strategy which allows individual faults to be isolated locally, without disruption to the wider grid.

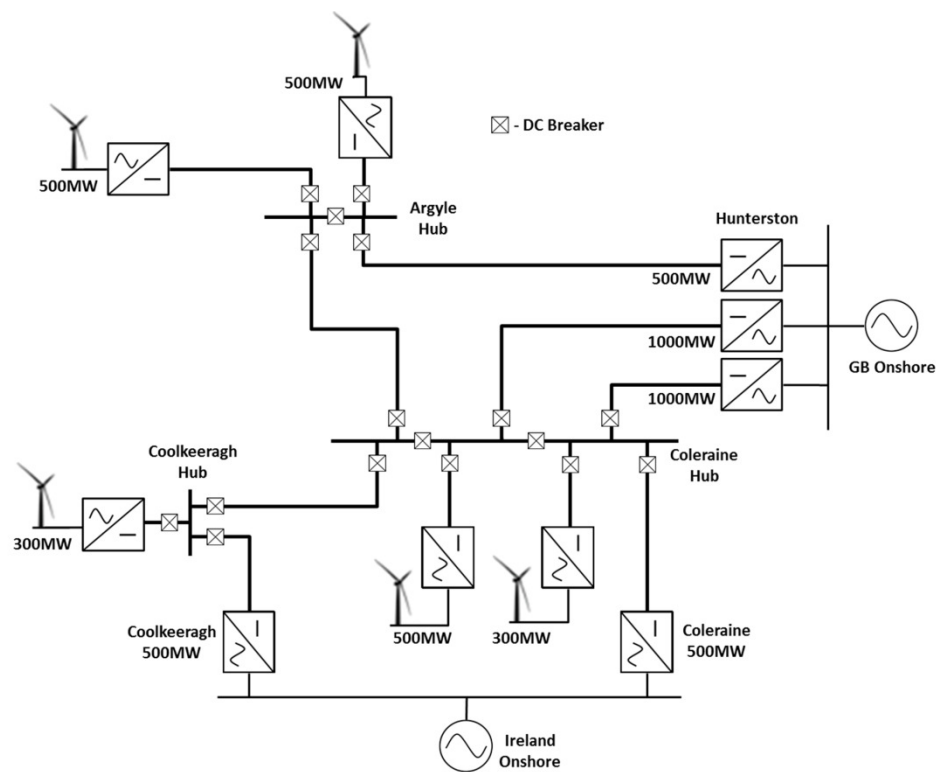


Figure 4.3 - Single line representation of ISLES DCCB grid scenario

It is assumed that DCCBs are not required at the end of transmission lines connecting into converter stations and that AC side protection is instead used. Additional DCCBs are however placed at the DC hubs to add a degree of backup protection such that the impact of a DCCB failing to operate is reduced. Although this adds to the cost of the network, discussion in [3] suggests that a degree of protection

4. Evaluation of Grid Design Options

redundancy is expected to be built into HVDC schemes with options including ‘breaker and a half’ switchyard schemes so this assumption is taken to be broadly representative of current thinking. In accordance with the methodology set out in Section 3.8.3 the cost of DCCBs is taken to be one sixth of the cost of the equivalent rated full converter station.

The final option investigated, shown in Figure 4.4, is that of a radial+ design which incorporates clustering of wind farms and a degree of shared infrastructure but does not include interconnection between DC grid sections and instead is realised as three completely independent DC grids with radial connections to shore.

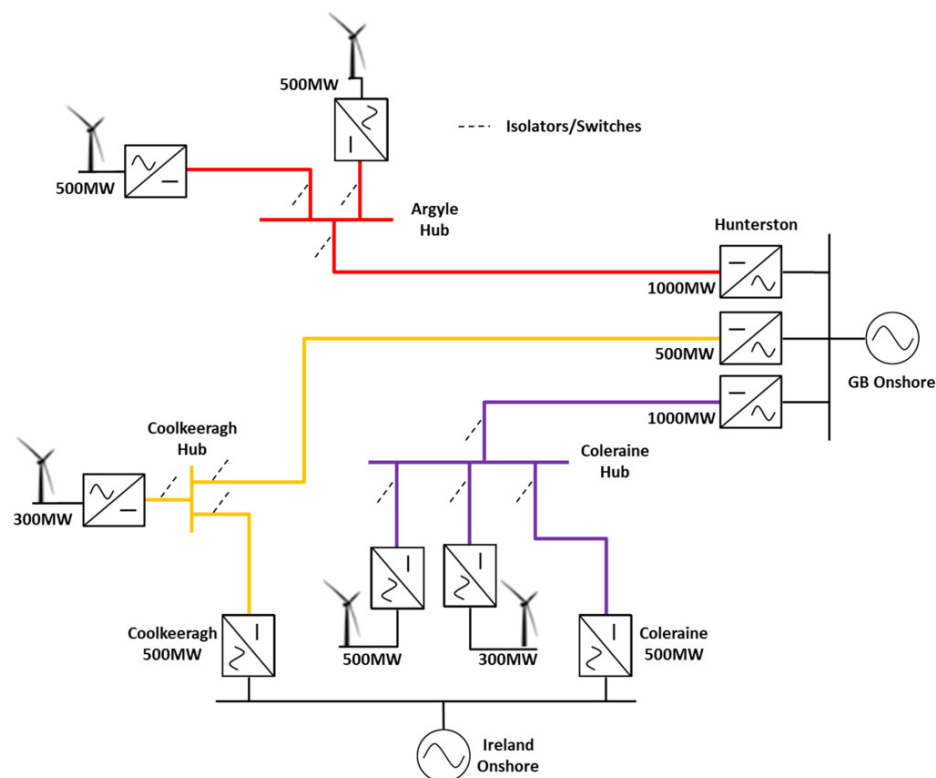


Figure 4.4 - Single line representation of ISLES Radial+ DC grid

The radial+ grid option operates with the same protection strategy as the base case grid option whereby AC side protection is used to shut down the entire DC grid section in the event of a DC side fault. DC isolators are available however, such that faulted grid components can be removed from service and healthy grid sections re-energised after a short time delay. This option reduces the total circuit length deployed but does so at the cost of redundant transmission paths for re-routing power

4. Evaluation of Grid Design Options

in the event of faults. This allows an investigation to be made of the trade-off between capital expenditure and reliability.

All the ISLES case studies are assumed to use a symmetrical monopole grid configuration with half-bridge MMC VSC converters, such that the impact of both redundant transmission paths and the choice of protection strategy on overall reliability can be compared. Figures 4.1-4.4 are therefore simplified representations of the investigated options meaning the number of cables and DCCBs/isolators is actually double the number shown. The DC grid voltage is set at ± 300 kV and the distances and ratings of transmission routes are outlined in Tables 4.1 and 4.2.

Table 4.1 - Distance and rating of transmission routes for Base case and DCCB grids as given in [2]

System Parameters - Base case and DCCB grids		
Transmission Route	Distance	Rating
WF1 – Argyle Hub	0.1 km	500 MW
WF2 – Argyle Hub	77 km	500 MW
Argyle Hub – Hunterston	256 km	500 MW
WF3 – Coolkeeragh Hub	0.1 km	300 MW
Coolkeeragh – Coolkeeragh Hub	53 km	500 MW
Coolkeeragh Hub – Coleraine Hub	53 km	600 MW
WF4 – Coleraine Hub	28 km	500 MW
WF5 – Coleraine Hub	0.1 km	300 MW
Coleraine – Coleraine Hub	41 km	500 MW
Coleraine Hub – Hunterston (1)	174 km	1000 MW
Coleraine Hub – Hunterston (2)	174 km	1000 MW
Argyle Hub – Coleraine Hub	101 km	1000 MW

Table 4.2 - Distance and rating of transmission routes for Radial+ grid as derived from [2]

System Parameters - Radial+ grid		
Transmission Route	Distance	Rating
WF1 – Argyle Hub	0.1 km	500 MW
WF2 – Argyle Hub	77 km	500 MW
Argyle Hub – Hunterston	256 km	1000 MW
WF3 – Coolkeeragh Hub	0.1 km	300 MW
Coolkeeragh – Coolkeeragh Hub	53 km	500 MW
Coolkeeragh Hub – Hunterston	227 km	500 MW
WF4 – Coleraine Hub	28 km	500 MW
WF5 – Coleraine Hub	0.1 km	300 MW
Coleraine – Coleraine Hub	41 km	500 MW
Coleraine Hub – Hunterston	174 km	1000 MW

4.1.2 Capital Costs

Component costs for the ISLES network options are taken directly from those given in the ISLES study which themselves are largely derived from the same resource as outlined in Section 3.8.3 as well as in-house databases [4]. The costs of DCCBs are set at one sixth the cost of a VSC converter station of equivalent rating and have thus been extrapolated from the VSC converter costs given in Table 3.13. The DCCB breaker costs and cable costs used for each power rating are given in Table 4.3 and the resulting overall capital expenditure required for each grid option is given in Table 4.4, including £60 million for the extension of onshore substations.

Table 4.3 - Unit cost input parameters for ISLES case studies

Cost Parameters for ISLES (£ millions)				
	300MW	500MW	600MW	1000MW
Cables (£m/km)	0.75	0.88	0.88	1.50
Offshore Converter Station	70.50	98.30	-	-
Onshore Converter Station	-	50.34	-	110.00
DCCB	10.43	12.67	13.79	17.99

Table 4.4 - Cost breakdown of ISLES grid options

Project Capital Expenditure (£ millions)			
	Base case	DCCB case	Radial+ case
Offshore Converter Stations	437.9	437.9	437.9
Onshore Converter Stations	431.0	431.0	431.0
Offshore cables	1081.2	1081.2	980.5
Onshore cables	56.7	56.7	56.7
DCCBs	-	500.7	-
Total	2006.8	2507.5	1906.1

The cost of implementing DCCBs across the entire ISLES DC grid is found to be some £500 million which makes it 25% more expensive than the base case option. This highlights the large impact that the use of DCCBs will have on the overall cost of grid options that implement a protection strategy that requires their use, if the

current best estimate for the cost of DCCBs holds valid. The radial+ option on the other hand comes in at almost exactly £100 million cheaper than the base case option which can be attributed to the removal of around 100 km of offshore DC cable from the design when compared to the two multi-terminal grid options.

4.1.3 Electrical Losses

Electrical losses are calculated using the parameters and methods defined in Section 3.7. The losses calculated are defined as the losses which are associated with wind energy generation only, so are distinct from losses attributable to traded energy between regions. To calculate losses for the pre-fault network configurations it is assumed that power would primarily flow into the GB network which allows the flow along each branch under the full spectrum of wind power output to be determined. A consideration is also made of the fact that the losses within the HVDC system will increase in the presence of additional regional power transfers. A steady transfer of 200 MW is therefore assumed to be injected from both the Irish shore connections, which together are equivalent to the maximum level of ‘firm’ inter-regional transfer that can be accommodated above the level of wind capacity in the base case and DCCB cases. It should be noted that this transfer is an illustrative attempt to consider the impact of energy trading on electrical losses and does not necessarily reflect a realistic interpretation of inter-regional power flows between the GB and Irish grids.

In reality electrical losses will fluctuate according to particular system state, for example re-routing of power along a longer transmission path in the event of faults would increase losses. It is considered however that the majority of time is spent in the normal pre-fault operating state and that the impact of these variations on the overall losses, compared to those calculated for the pre-fault operating state only, are negligible. This assumption is validated in the findings of Section 4.2.3 where losses in each system state are considered for a simpler network scenario.

The losses calculated for each network scenario are given in Table 4.5 and show that there is only a small difference in the level of losses that can be expected between the base case and DCCB case grid options. The difference can largely be attributed to losses in the DCCBs which are small but accumulate to give a total of 2.98%

4. Evaluation of Grid Design Options

expected annual electrical losses compared with the 2.95% expected for the base case grid option. The radial+ grid option on the other hand is a more straightforward design with fewer branches meaning that the overall losses are expected to be noticeably lower at 2.82%.

Table 4.5 - Expected annual electrical losses for ISLES case studies

Electrical Losses	
Base Case	2.95 %
DCCB Case	2.98 %
Radial+ Case	2.82 %

The impact of the level of traded energy on the overall losses is charted in Figure 4.5 which shows that losses would be noticeably lower if no traded energy is considered in the calculation. The losses as a percentage of the generated energy increases linearly with the level of traded energy considered to be present on the system for each of the grid options although the Radial+ option is influenced to a slightly lower extent than the base case and DCCB grid options.

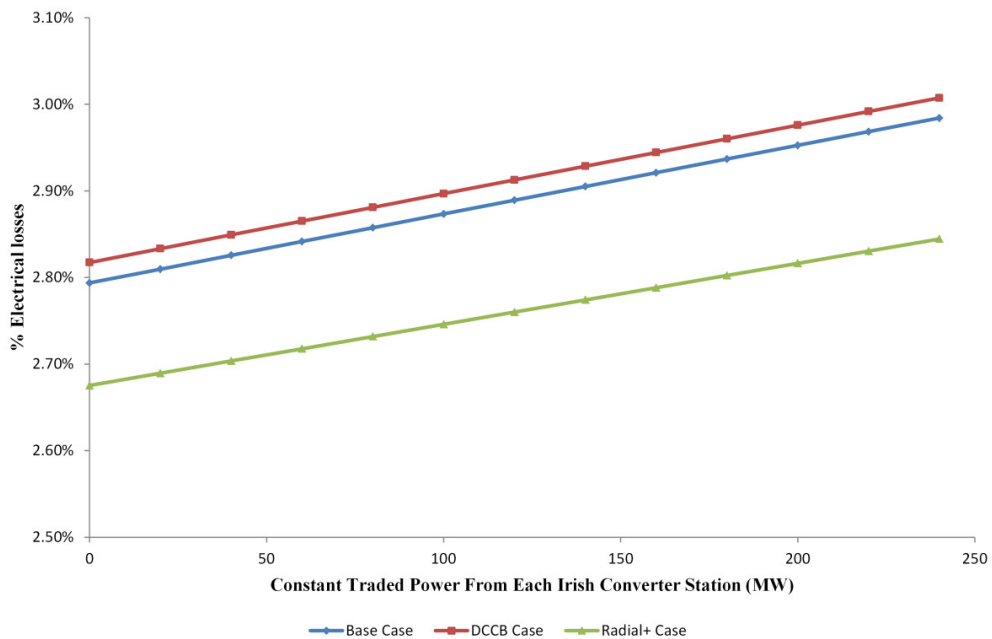


Figure 4.5 - Influence of traded energy on electrical losses

The financial implication of the difference in expected electrical losses between the grid options is investigated by applying a price to the level of generated energy from

4. Evaluation of Grid Design Options

the offshore wind farms in the system. This is set at £150/MWh which corresponds to the median maximum strike price that could be awarded to UK offshore wind farms in the period 2014-2019 [5]. This assumes that losses are valued at the same level as delivered energy although it should be noted that in reality the price attached to losses is dependent on where the metering point for wind energy is placed as is discussed further in Section 6.3 for future work. The average annual expected generation from the wind farms in the system is found to be 7.79 TWh based on the 100 years of wind input data and the wind speed to wind power curve used. The annual cost per year of electrical losses from each grid is found by applying the percentage loss estimates to this figure and multiplying by the value of wind energy, defined previously to be £150/MWh. The NPV of this over the project lifetime can then be determined using the methods set out in Section 3.8.1. Results are shown in Figure 4.6.

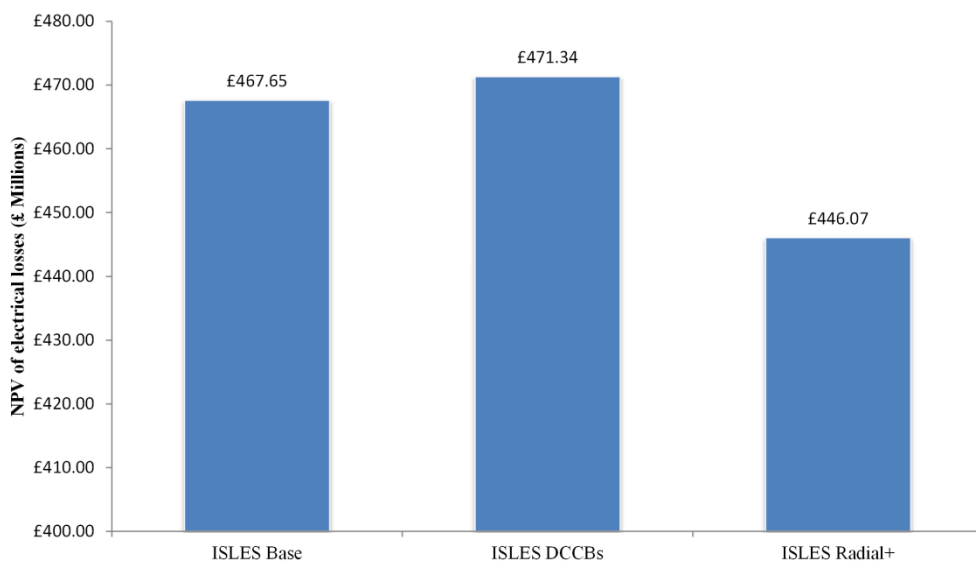


Figure 4.6 - NPV of electrical losses for ISLES case studies

Despite there being only a marginal difference in the losses between each of the designs, this equates to a £25 million difference in the value of expected losses over the project lifetime between the DCCB and Radial+ grid options showing that designs with low electrical losses have the potential to substantially increase the long term overall energy delivery and therefore project value.

4.1.4 Reliability Performance

The reliability performance of each grid option is determined by investigating the level of undelivered energy due to component outages under a number of reliability scenarios. The key results are shown in Figure 4.7 which gives the annual undelivered energy as a percentage of the annual deliverable energy, defined as the generated energy minus the electrical losses.

The results show that the reliability performance is highly sensitive to both the level of system redundancy and the input assumptions used. Under the best case reliability scenario the overall expected level of undelivered energy is small and ranges from 0.88% for the base case grid to 1.45% for the radial+ grid option. For the central case reliability scenario the level of undelivered energy increases to between 2.35% and 3.93% which although significant is still a manageable level. If however, the worst case reliability scenario is assumed undelivered energy rises to between 7.66% and 11.05% which represents a very significant portion of the deliverable energy and would have serious financial implications on the overall project.

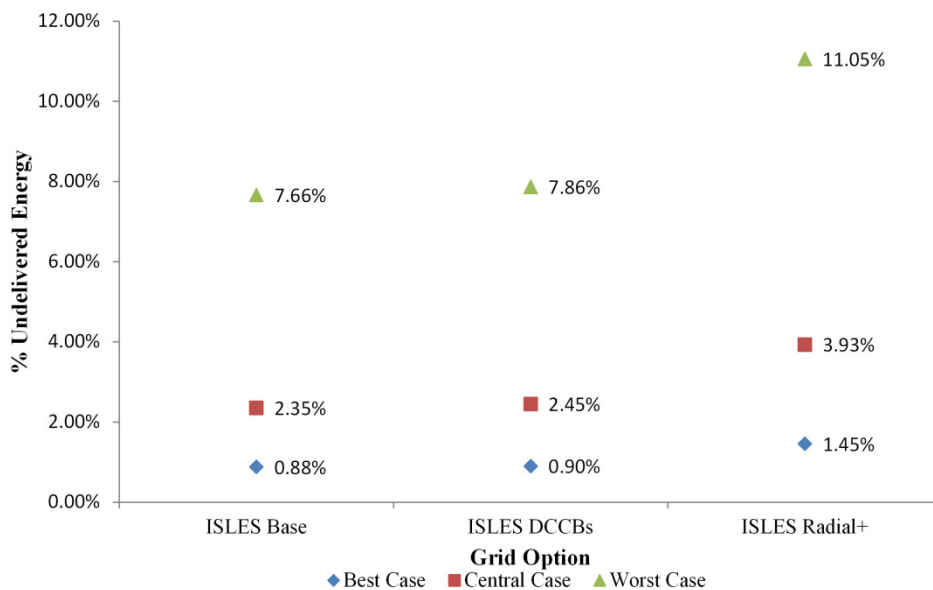


Figure 4.7 - Annual expected level of undelivered energy due to system faults

Comparing the three grid options against one another it can be shown that there is little difference between the performance of the base case grid and the DCCB grid option. The base case and radial+ grid options suffers from the need to temporarily shut down entire grid sections each time a fault occurs. The reconfiguration process

4. Evaluation of Grid Design Options

required to bring healthy grid sections back online is assumed to take one hour in the model and despite this being considered an upper limit it is found that the impact on overall undelivered energy is small. This is highlighted in Table 4.6 where the contribution to overall undelivered energy of using an AC side protection strategy is given for both the base case and radial+ grid options.

Table 4.6 - Contribution of grid shut down protection method to overall reliability

Contribution of Grid Shut Downs to Undelivered Energy				
Reliability Scenario	Base Case		Radial+	
	Total undelivered energy	Total from grid shut downs	Total undelivered energy	Total from grid shut downs
Best Case	0.88%	0.02%	1.45%	0.02%
Central Case	2.35%	0.05%	3.93%	0.05%
Worst Case	7.66%	0.13%	11.05%	0.11%

Despite the additional energy curtailment associated with using AC side protection the results actually show that the DCCB grid option has a poorer expected overall reliability performance. This can be accredited to the fact that the use of DCCBs adds another layer of components into the system which are susceptible to failure themselves. DCCB failures can lead to the shut-down of large grid sections as alternative DCCBs further away from the fault location would be required to open. The model found that the impact of DCCB failures and the associated periods of disruption add proportionally more to the level of total undelivered energy than utilising AC side protection does which explains why in each of the scenarios investigated the DCCB option has a marginally poorer reliability performance than the base case option. More complex breaker arrangements could be deployed, than those modelled, to mitigate this affect further. Breaker and a half arrangements [3] for example have been suggested. However, as the cost of DCCBs is relatively high the addition of enhanced redundancy in the protection system is likely to lead to a corresponding increase in capital expenditure that outweighs the small gains that could be made in terms of reliability.

The importance of having redundant transmission paths in an offshore grid scenario is clear from the results with the radial+ option having significantly higher levels of

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undelivered energy than the two multi-terminal grid options which both have the inherent ability to re-route power under certain fault conditions. This means that despite being the lowest capital cost option, the radial+ grid suffers from much larger levels of expected energy curtailment due to fault conditions and the corresponding value of energy delivered to shore will be significantly reduced over the project lifetime.

The financial implication of varying levels of undelivered energy are analysed by calculating the NPV of energy that each grid could be expected to successfully deliver to shore over its project lifetime and the results are shown in Figure 4.8. This can be defined as the total potential generated energy, calculated from the installed wind capacity, the wind speed time series and the wind speed to wind power curve, minus the electrical losses and energy curtailment due to component outages. An annual discount rate of 6% is again applied assuming a value for generated offshore wind energy of £150/MWh and a project lifetime of 25 years yielding a maximum value for generated energy for each grid option before curtailment and losses of £15.84 billion.

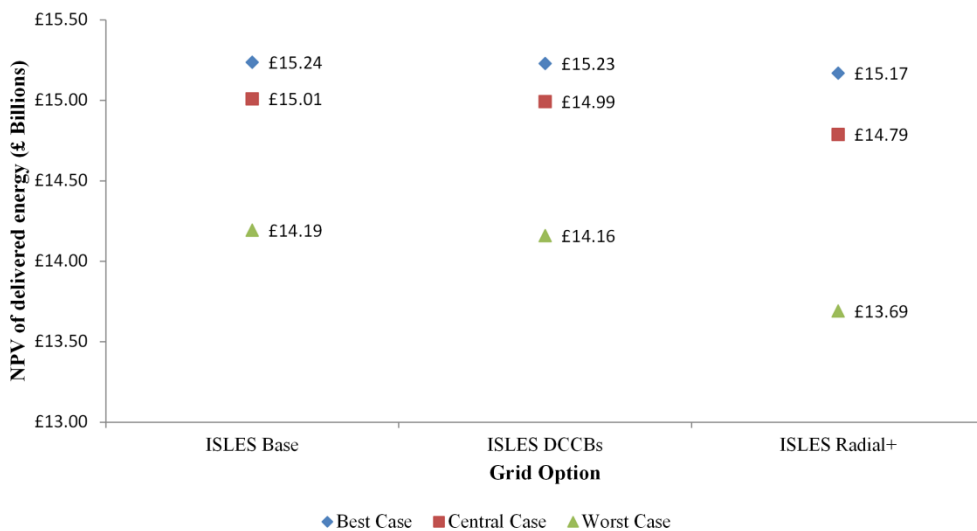


Figure 4.8 - NPV of delivered wind energy for each grid option over project lifetime

It was shown in Figure 4.6 that the value of energy lost to electrical losses was in the region of £450-£470 million over a project lifetime. The additional value of energy lost due to component outages can therefore be observed and is shown, for the best case reliability scenario, to add around an additional £135 million for the two multi-

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terminal grid options whereas the figure rises to £224 million for the radial+ grid option. Due to the lower E_{und} of the radial+ grid option, however, the increase in the value of lost energy overall for the radial+ grid option is only £60 million compared to the DCCB case and £67 million compared to the base case. For the central case reliability scenario the value of energy lost due to outages for the base case, DCCB and radial+ grid options respectively are £361 million, £376 million and £605 million. This brings total cost of lost energy to over £1 billion for the radial+ case which is around £204 million more than the DCCB case and £222 million more than the base case grid option. If the worst case reliability scenario were to be realised then the lifetime value of E_{und} associated with component outages rises to £1.18, £1.21 and £1.70 billion respectively for the three grid options discussed. This leads to a difference in the final value of delivered energy of £468 million or £502 million when comparing the radial+ option to the DCCB and base case grid options respectively.

4.1.5 Value of Trade Energy

For offshore grid scenarios which include the possibility of providing cross border or inter-regional energy transfer it is important to also consider the value of energy that can be traded on that grid when considering overall financial viability. To accurately model the amount of traded energy that would likely be utilised, a market based approach including knowledge of onshore energy demand and regional pricing at each time step is required. Such a model is complex in its own right and is deemed beyond the scope of this project. However, it is possible to calculate the spare grid capacity available for inter-regional transfers if it is assumed that delivery of wind generation is prioritised. As described in Section 3.5.2, two calculations are made to determine the level of trade capacity offered by each grid option. Firstly, the level of firm trade capacity which is available at all times for any given grid configuration based on the spare transmission capacity above the maximum level of wind farm output is determined. In addition to this the level of available flexible trade capacity is also calculated by determining at each hour the difference between the maximum level of wind output and the actual level. The addition of the calculated firm and flexible trade capacity yields a figure for the total available trade capacity that could theoretically be utilised if desired. The level of available trade capacity from each

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category is given in Table 4.7 and the associated maximum value of the theoretical combined trade capacity for each option is outlined in Figure 4.9. The values reached assume, as before, a 6% discount rate and a 25 year project lifespan with an average price differential between the two regions of £8/MWh which is derived from looking at typical spot market price differentials between the GB and Irish markets in 2014 [6]. The actual value of trade that would be realised would be scaled up or down by the actual price differentials experienced and would be scaled down by the level of utilisation of the available trade capacity.

Table 4.7 - Calculated annual average firm and flexible trade capacity of grid options

Annual Average Trade Capacity of Grid Options (TWh)						
Grid Option	Best Case		Central Case		Worst Case	
	Firm	Flexible	Firm	Flexible	Firm	Flexible
Base Case	3.55	4.26	3.57	4.02	3.63	3.40
DCCBs	3.51	4.28	3.47	4.07	3.41	3.53
Radial+	3.50	3.62	3.47	3.43	3.44	2.92

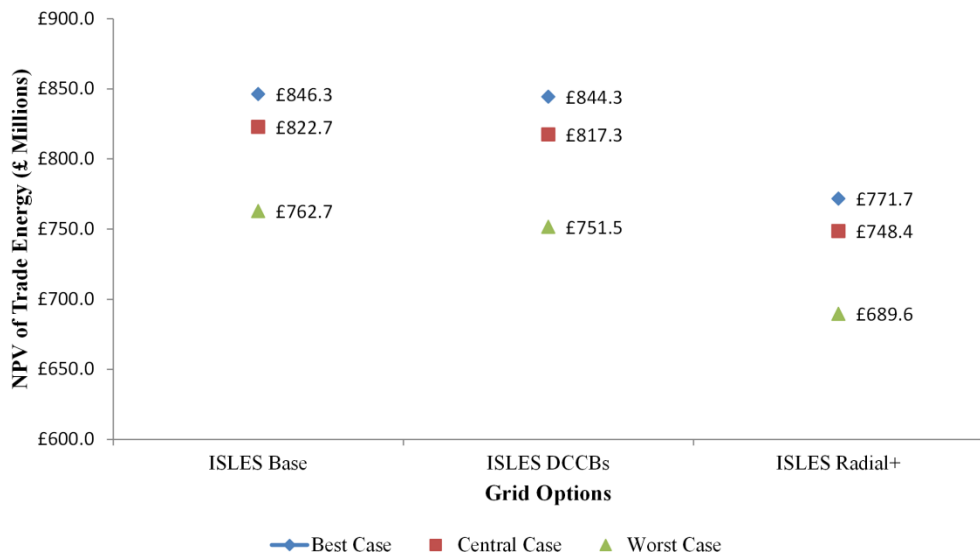


Figure 4.9 - Value of tradable energy between the GB and Irish markets over project lifetime

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Compared to the value of wind energy the value of traded energy is less important to overall project value but still has the potential to add a maximum value of almost £850 million over the lifetime of the project for the best performing grid option and best case reliability scenario. It is evident that in each of the reliability scenarios there is only a marginal difference between the trade value that could be utilised between the base case and DCCB grid options and this is in line with the difference in reliability performance they experience. In each case the radial+ grid option has less spare trade capacity available. It can be shown that this can almost entirely be accounted for by a reduction in the level of flexible trade energy that is available showing that the addition of redundant transmission paths not only minimises the impact of system faults by allowing wind power generation to be re-routed but also maximises the trade potential available on the grid. The difference in the value of transmission capacity between the radial+ and multi-terminal grid options is in the range of £60-75 million for the three reliability scenarios.

It is also observed that the difference in the overall trade value in each of the grid options between the best case and worst case scenarios is not as dramatic as the difference between, for example, the undelivered energy figures in each of these cases. The trade value calculated for each grid option for the worst case reliability scenario are around 90% of those calculated for the best case reliability scenario. This is perhaps reflective of the fact that, although some system faults conditions will inhibit the ability to trade energy, other fault conditions, such as the loss of connection of a wind farm will actually allow an increased level of trade energy to occur as it frees transmission capacity on the system.

4.1.6 Operations & Maintenance Costs

A final consideration to be made when assessing the overall project costs of different grid design options is the cost of O&M throughout their lifetime. As explained in Section 3.8.2 the costs associated with each repair action are calculated as part of the reliability analysis. In addition to this, scheduled maintenance costs are also applied annually based on the composition of the grid. The annual cost of scheduled O&M for each of the three grid options is shown in Table 4.8 taking into account the number and rating of components and costs outlined in Table 3.12. The NPV of this

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is again calculated by applying a 6% discount rate over a 25 year project lifetime. It is found that the DCCB based grid has the highest scheduled lifetime maintenance costs at £54.8 million due to the additional presence of the DCCBs themselves whereas the costs are £13 million lower for the radial+ grid option which has a lower circuit length that reduces the need for cable inspection.

Table 4.8 - Scheduled O&M costs for ISLES grid options

Scheduled O&M Costs (£ million)			
	Base case	DCCB case	Radial+ case
Offshore Substations	£0.525	£0.525	£0.525
Onshore Substations	£0.420	£0.420	£0.420
Offshore cables	£0.239	£0.239	£0.214
DCCBs	-	£0.708	-
Annual Total	£3.338	£4.047	£3.085
25 Year NPV	£45.234	£54.832	£41.813

The NPV of total O&M costs for each of the ISLES networks is derived by applying the same discounted cost calculation to the average annual expenditure directly related to repair works, calculated from the reliability studies, and adding to the results of Table 4.8. The total O&M costs under each reliability scenario are shown in Figure 4.10.

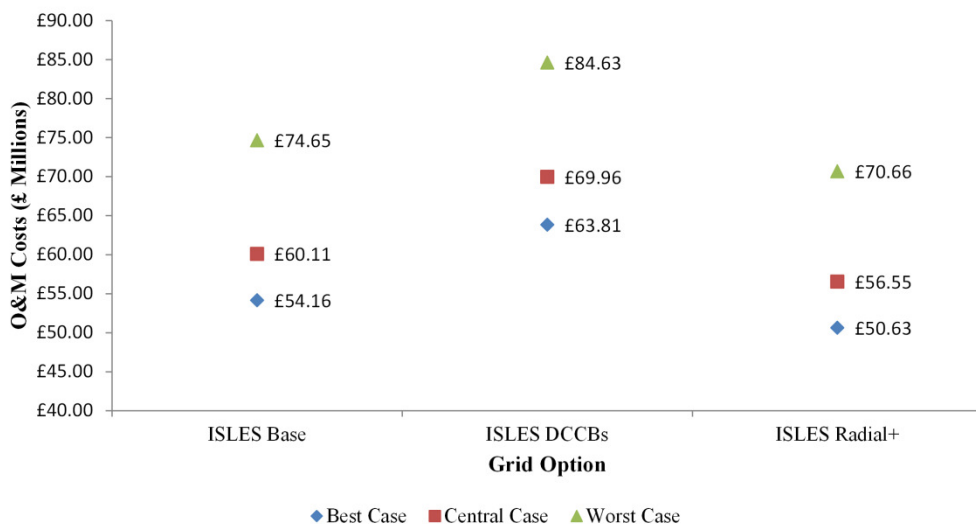


Figure 4.10 - NPV of O&M costs for ISLES grid options

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While the costs associated with scheduled maintenance remain constant in each of the reliability scenarios the costs associated directly with repairs vary significantly depending on the reliability scenario. The repair costs are largely similar between the grid options for each of the reliability scenario although again the DCCB grid option has slightly higher costs due to the increased number of components susceptible to failure and the radial+ grid option has lower costs due to the reduced length of installed transmission cable. In the best case reliability scenario the lifetime costs associated directly with component repairs are around £8 - 9 million whereas in the worst case scenario the figures are around £28 - 30 million.

The main point of note is that overall lifetime O&M costs are low in comparison to the project capital expenditure and the value of undelivered energy, at only around £56 - 64 million for the central reliability scenario which is around 3% of total grid capital expenditure. It is clear that O&M costs are likely then to play a much less significant role in overall project expenditure for offshore transmission grids than they do in, for example, an offshore wind farm where turbine O&M can account for upwards of 20% of the overall project costs [7]. This can be explained by the relatively low number of system components and low failure rates of the components in an HVDC grid compared with a fleet of turbines.

4.1.7 Overall Value of Grid Options

By combining the results highlighted in the previous sections it is possible to generate a final assessment of the overall value of each grid option investigated given each reliability scenario. The NPV of each grid option is determined by adding the value of energy that each is expected to deliver to shore in its project lifetime, after electrical losses and component outages are accounted for, to the maximum value of traded energy before subtracting the capital costs of building each grid and the operational costs associated with maintenance operations. The final results are given in Figure 4.11. It can be shown that when the full trade potential of the grid options is included the ranking of the grid options is the same under all three scenarios with the base case option giving the best value for money, followed by the radial+ option with the DCCB option being the least favourable.

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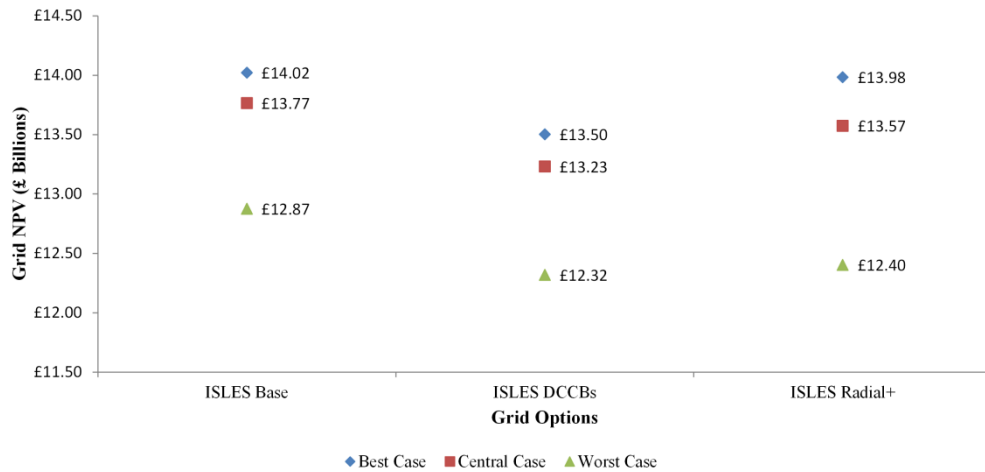


Figure 4.11 - Overall NPV of ISLES grid options

Under the best case reliability scenario with a low number of system faults and fast repair times, the lowest cost radial+ option gives almost the same overall value for money as the base case option, despite its poorer reliability performance. In fact, if a utilisation factor of 50% is applied to the trade potential then the two grid options have identical net worth, such that the savings made by not building redundancy into the radial+ option are exactly balanced by the extra costs associated with relatively poor reliability performance and reduced trade potential. The DCCB breaker option has an overall value which is £519 million less than the base case, a difference which is dominated by the additional cost of implementing the DCCBs across the system.

In the central case reliability scenario the base case is clearly the most cost-effective option with an NPV of £192 million more than the radial+ grid option and £534 million more than the DCCB option. This shows that the cost of implementing redundant transmission paths in the multi-terminal base case network is lower than the added value that can be expected to be achieved in terms of reducing undelivered energy. If the worst case reliability scenario is assumed then the value of the radial+ option drops further still, due to high the level of undelivered energy in this scenario, to just £85 million higher than the DCCB option despite a £600 million difference in capital expenditure between the two project options. The base case option is clearly the most favourable option in this scenario with a value £470 million above the radial+ option.

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In general the results show that under all the reliability scenarios there is significant value to be gained from building an offshore grid in the region under the price assumptions used. The way in which this value is distributed between the different market actors however is fundamental to gaining the required investment to make such a development a reality. Given that the difference in value between the best and worst case reliability scenarios is upwards of £1 billion over a 25 year project for any of the grid options it is clear that reliability is a hugely important factor in the overall profitability of an HVDC grid and there is a clear benefit to be had in minimising the impact of system faults. The value of system redundancy has been demonstrated with the reliability performance of the multi-terminal grid options far outstripping the lower cost radial+ option. It is found that for all but the very best case reliability scenarios the cost of implementing this redundancy through an additional transmission link is lower than the gains that can be expected through a reduction in undelivered energy. For this scenario a multi-terminal solution is therefore preferable to the radial+ option so long as the capital cost is not excessive. For the multi-terminal option using DCCBs the capital costs are found to be high and this can almost entirely be attributed to the costs of implementing the breakers themselves across the grid.

To avoid this issue it has been shown that an alternative protection strategy which uses multiple HVDC grids operating in parallel, protected via AC side equipment and with the ability for re-configuration in the event of faults is a financially preferable solution. Such a grid may bring with it additional issues which are not factored into this study. For example, it has been noted previously that full grid shut downs would lead to the need for the emergency stoppage of offshore wind turbines which could have a detrimental effect on long term internal wind farm reliability. It must also be considered if there would be any unwanted localised impacts in terms of stability issues or otherwise on the AC systems which connect to the DC grid through the sudden loss of potentially large sums of generation, even if this remained within loss of infeed limits. Table 4.9 investigates the number of full DC grid shut downs that could be expected to occur per year on average.

4. Evaluation of Grid Design Options

Table 4.9 - Number of DC grid shut downs per year for ISLES AC protected networks

Average Number of Grid Shut Downs per Year			
Grid Option	Reliability Scenario		
	Best Case	Central Case	Worst Case
Base Case	5.32	12.67	29.93
Radial+ Case	5.31	12.62	29.56

It can be shown that in the best case reliability scenario the frequency of faults and therefore grid shut downs is low at only around 5 per year on average. For the central case scenario the frequency of grid shut-downs rises to a little over 1 per month whereas in the worst case scenario the frequency of shut downs is higher still at close to 30 per year on average. The grid operator would need to make a decision as to what risks the expected level of shut down procedures might entail and whether or not this was acceptable.

4.2 Case Study 2 – Dogger Bank Scenario

4.2.1 Development of Grid Options

The second case study which has been investigated is based on options around the early phase development of UK Round 3 offshore development zones. Dogger Bank is the largest potential development zone and furthest from shore so has been used as a reference for the case studies examined in this section. Unlike the previous case study this scenario does not look at the possibility of cross border trade options but rather focuses on a number of different DC grid options which could be used to connect four separate but clustered 700 MW wind farm developments to shore. To evaluate the impact of added redundancy in a simple offshore grid scenario a number of different DC grid configurations are posed starting with the simplest solution of a fully radial option with four direct cable links to shore as shown in Figure 4.12.

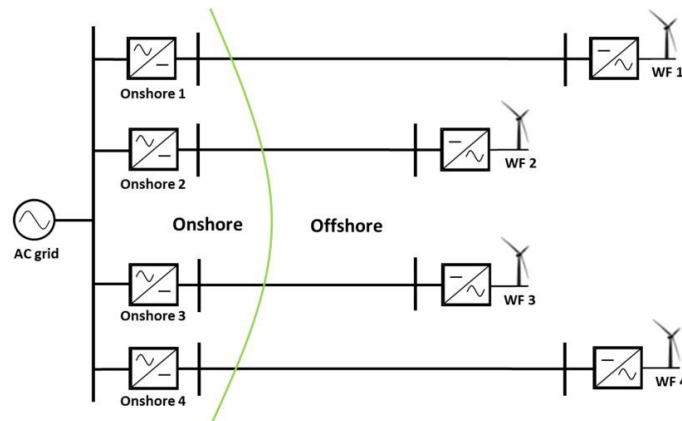


Figure 4.12 - Single line representation of fully radial grid option

The remaining scenarios consider options which make use of shared infrastructure to transmit power down two high power transmission routes with varying degrees of interconnection between the offshore wind farms. A radial+ option is considered which consists of two separate DC grids each with two wind farms transmitting power down a single transmission path. A multi-terminal DC grid scenario adds a link to the radial+ option, providing a redundant transmission path for power transfer in the event of fault conditions and creating a single offshore grid. A meshed system is considered next by adding a second link such that the wind farms are connected in a ring configuration with redundant transmission paths available from each wind farm. The control of a meshed DC grid is not trivial, as discussed in Section 2.3.5,

4. Evaluation of Grid Design Options

but for the purposes of this study it is assumed appropriate power flow controllers are available. The three grid options discussed are shown in Figure 4.13

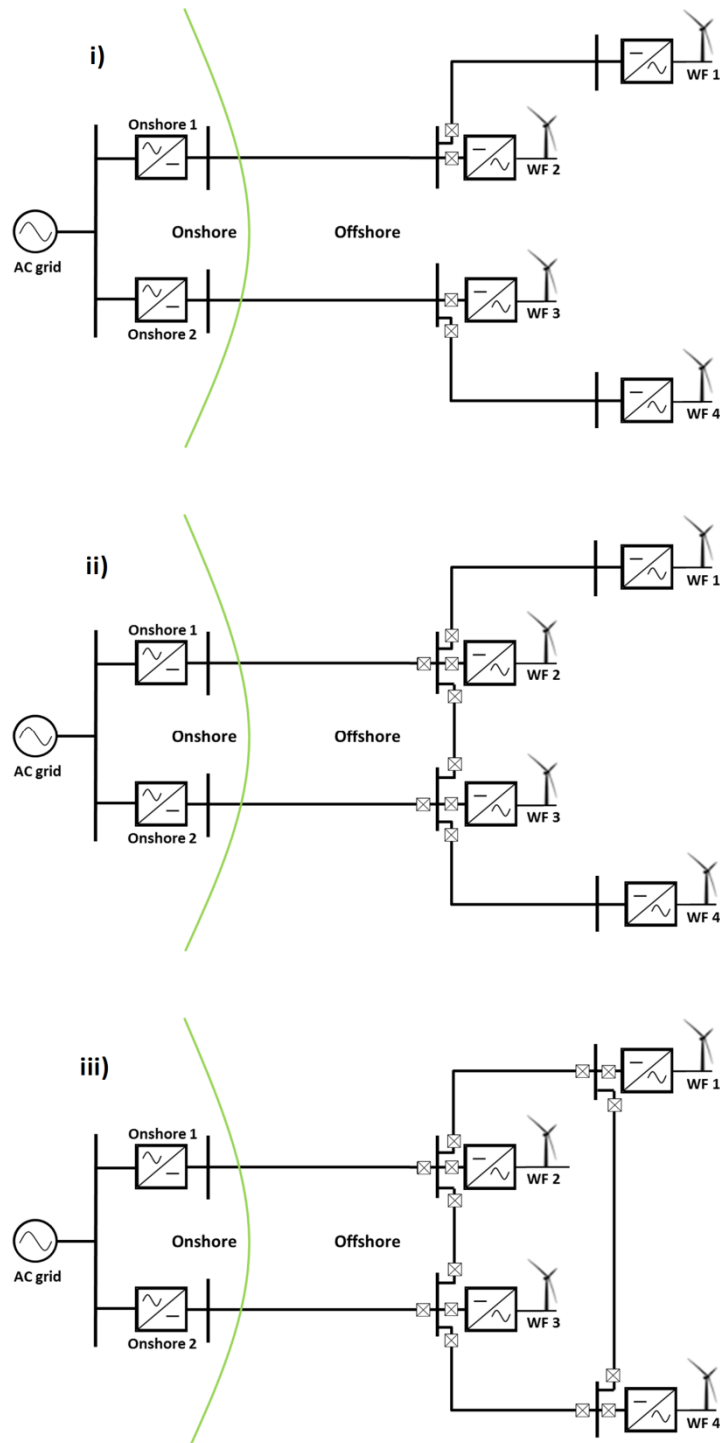


Figure 4.13 - DC Grid configurations: i) radial+; ii) multi-terminal and iii) meshed

Two variations of the multi-terminal grid option are also considered in Figure 4.14 to investigate the feasibility of different protection strategies. One option considers a

4. Evaluation of Grid Design Options

minimum breaker scenario as described in Section 2.3.3 which only deploys DCCBs on the link between the two transmission paths and makes use of AA-MMC full bridge converters, discussed in Section 2.1.2.2, with reverse current blocking capability. Another option considers a sectionalized DC grid protected on the AC side, whereby the link between the two main transmission paths is switched out under normal operation but can be connected in the event of a post-fault shut-down. This grid mimics the functionality of the ISLES base case grid option investigated previously and discussed in Section 2.3.2.

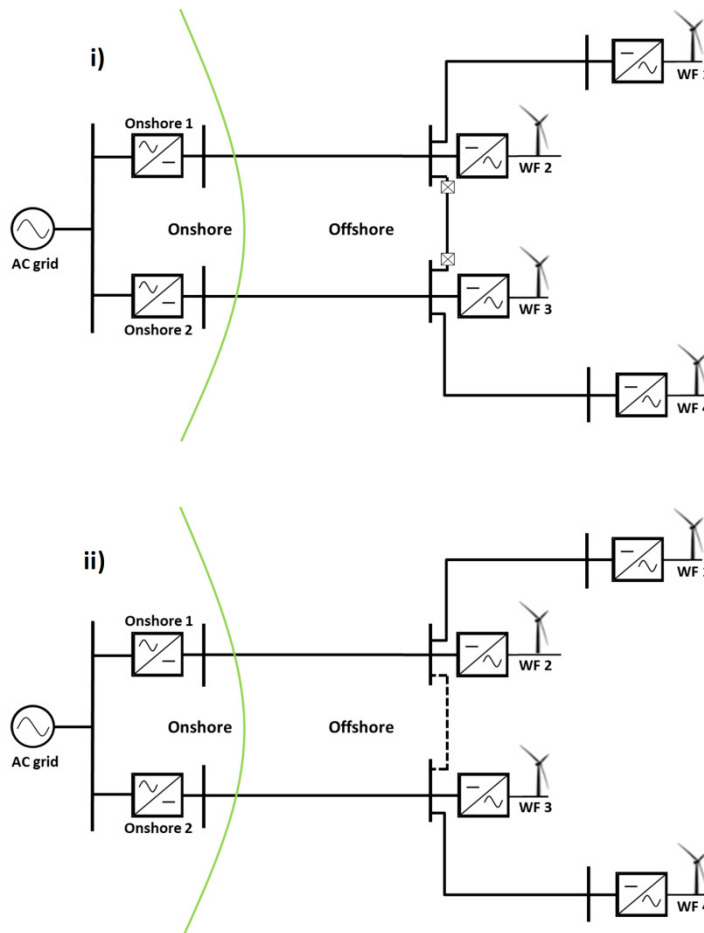


Figure 4.14 - Alternative DC grid protection methods: i) minimum breaker; ii) AC protected

Despite Figure 4.12-Figure 4.14 showing simplified single line representations of the grid options, all the networks are again assumed to be configured in a symmetrical monopole configuration with two bundled cables operating at opposite voltage polarity. This also means the actual number of DCCBs required is double that shown in the graphic. Although providing bipolar operation, symmetrical monopoles do not

4. Evaluation of Grid Design Options

provide the inherent redundancy of a true bipole configuration which utilises a metallic low voltage (LV) return conductor to provide partial transmission capability in the event of pole-earth cable faults and converter station faults. A final version of the multi-terminal grid is therefore explored, in Figure 4.15, which models bipole operation in the two main transmission paths and assumes 50% transmission capacity remains in the event of the fault conditions discussed.

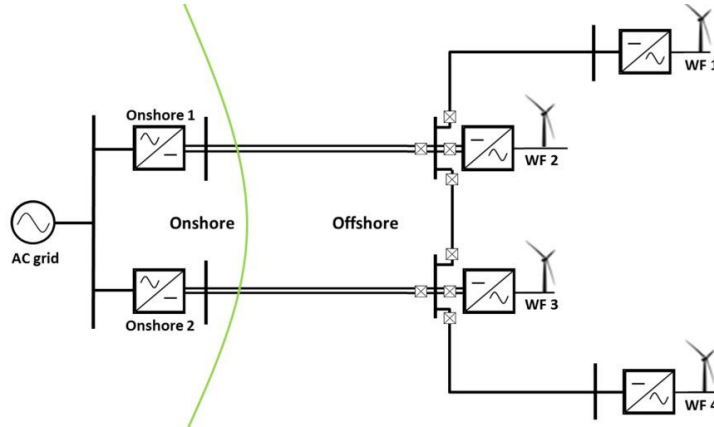


Figure 4.15 - Multi-terminal DC grid with bipole transmission links

A more accurate representation of how the bipole grid option is configured in reality is given in Figure 4.16 and shows how the two symmetrical monopole links from wind farms 1 and 4 could connect into the bipole configured connections to shore. Not shown is the ability to switch the power flow between the positive or negative pole and the LV return pole to allow monopole operation in certain fault conditions.

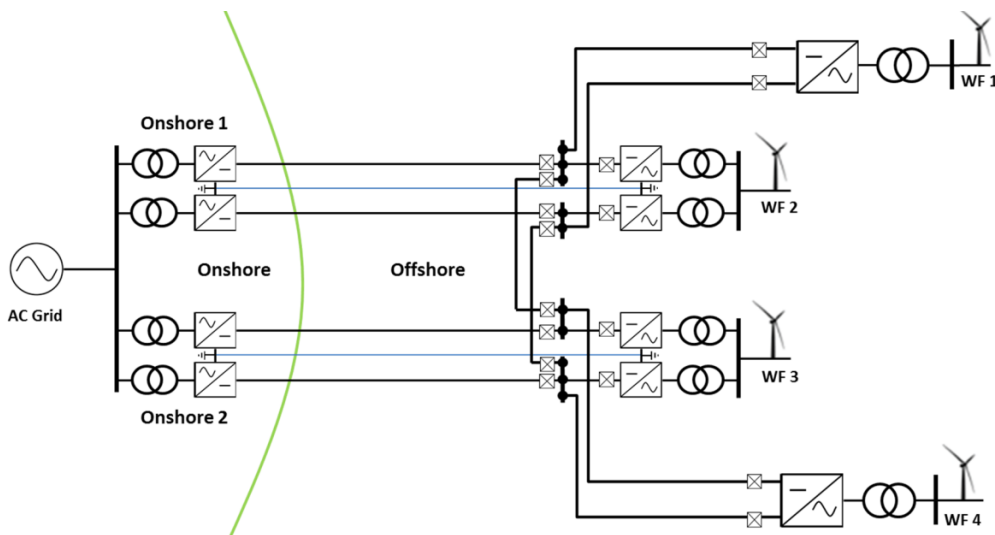


Figure 4.16 - Detailed representation of bipole grid option

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The diagram shows how the bipole transmission links are modelled with two converters and two transformers at each station. The voltage differential between the two poles is the same for both the bipole (wind farms 2 and 3) and symmetrical monopole configurations (wind farms 1 and 4) so an equal number of MMC modules are present in each of the wind farm converter stations. As such the failure rate applied to each of the single pole converters modelled at wind farms 2 and 3 is half that of the other offshore converters so that the reliability of the whole converter units are equal. The main reliability differences are therefore that the two pole cables on each bipole configured transmission path are assumed to be buried separately so fail independently as well as the presence of the LV return cable which allows operation at half capacity along the two bipole links for certain faults.

A number of key input parameters for the grid options are outlined in Table 4.10. The transmission parameters are taken with reference to a similar scenario investigated in [8] and the distances are realistic estimates based on the likely geography of early phase developments in the Dogger Bank zone as given in [9].

Table 4.10 - System parameters for Dogger Bank grid options

System Parameters	
DC Voltage Rating	± 320 kV
Transmission Limits	<u>Radial:</u> All routes: 700 MW <u>Radial+:</u> WF1-WF2 and WF4-WF3: 700 MW WF2-Shore and WF3-Shore: 1400 MW <u>Multi-terminal (all):</u> WF1-WF2 and WF4-WF3: 700 MW WF2-Shore, WF3-Shore and WF2-WF3: 1400 MW <u>Meshed:</u> All routes: 1400 MW
Distances	WF1-WF2: 15km WF1-WF4: 35km WF2-WF3: 20km WF3-WF4: 15km WF2-Shore: 200km WF3-Shore: 200km
Cables	350 MW and 700 MW XLPE
Expected Annual Wind Generation	7.79 TWh

4.2.2 Capital Costs

Unlike the ISLES network scenario there are no published capital cost estimates directly relating to Dogger Bank developments so the method outlined in Section 3.8.3 utilising the cost estimates made in [10] is used to determine an overall cost for each grid option. As estimates are not always given directly for the power ratings of the developed scenarios, linear interpolation has been used to extrapolate costs from the published data and the costs associated with each of the components are outlined in Figure 4.17 and explained in more detail in Table 4.11.

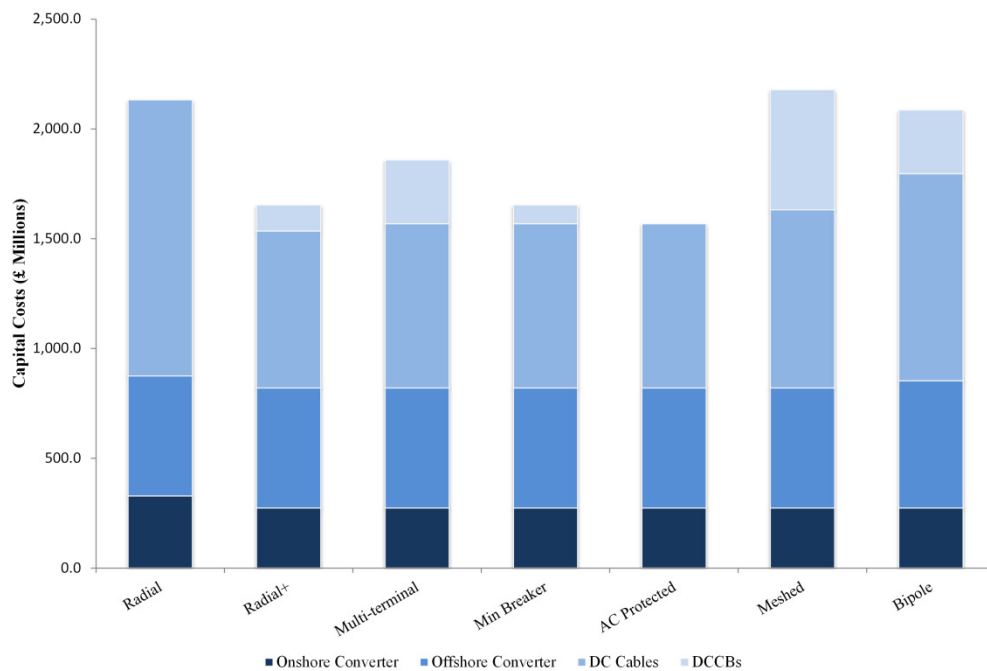


Figure 4.17 - Capital cost breakdown for Dogger Bank HVDC grid scenarios

The cost of onshore converter stations is constant throughout the grid options, apart from the radial option which has four 700 MW converters as opposed to the two 1400 MW converters deployed in all the other options. This equates to an increase in costs of £54.5 million for the radial case over the other options. All the offshore converter options have equal cost with four 700 MW converter stations and it is assumed that 8000 tonne jack-up platforms are deployed. The single exception to this is the bipole grid option which requires specialist transformers to be used which are capable of handling the DC voltage offset introduced by the bipole configuration [11]. Publicly available estimates of the cost implications of this are lacking so it is assumed that

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Table 4.11 - Capital cost breakdown of Case Study 2 grid options

Capital Cost Breakdown for Dogger Bank HVDC Grid Design Options															
Component \ Rating (MW)		Radial		Radial+		Multi-terminal		Meshed		Minimum Breaker		AC Protected		Bipole	
		700	1400	700	1400	700	1400	700	1400	700	1400	700	1400	700	1400
Offshore Converter Stations	No. Units	4	0	4	0	4	0	4	0	4	0	4	0	4	0
	£m / Platform	54.69	-	54.69	-	54.69	-	54.69	-	54.69	-	54.69	-	54.69	-
	£m / Converter	81.94	-	81.94	-	81.94	-	81.94	-	81.94	-	81.94	-	90.13	-
	Total (£m)	546.51	-	546.51	-	546.51	-	546.51	-	546.51	-	546.51	-	579.29	-
Onshore Converter Station	No. Units	4	0	0	2	0	2	0	2	0	2	0	2	0	2
	£m / Converter	81.94	-	-	136.64	-	136.64	-	136.64	-	136.64	-	136.64	-	136.64
	Total (£m)	327.76	-	-	273.28	-	273.28	-	273.28	-	273.28	-	273.28	-	273.28
DC Cables	Circuit km	830	0	30	400	30	420	0	485	30	420	30	420	30	420
	£m Install (/km)	0.73	-	0.73	0.73	0.73	0.73	-	0.73	0.73	0.73	0.73	0.73	0.73	0.95
	£m Cost (/km)	0.39	-	0.39	0.47	0.39	0.47	-	0.47	0.39	0.47	0.39	0.47	0.39	0.47
	Cables / Circuit	2	-	2	2	2	2	-	2	2	2	2	2	2.5	2.5
	Total (£m)	1257.5	-	45.45	668.80	45.45	702.24	-	810.92	45.45	702.24	45.45	702.24	51.34	880.7
DCCBs	No. Units	0	0	8	0	8	8	8	20	0	4	0	0	8	8
	£m / Unit	-	-	14.9	-	14.9	21.4	14.9	21.4	-	21.4	-	-	14.9	21.4
	Total (£m)	-	-	119.2	-	119.2	171.3	119.2	428.2	-	85.6	-	-	119.2	171.3
Total Cost		2131.7		1653.2		1857.9		2178.1		1653.1		1567.5		2075.1	

4. Evaluation of Grid Design Options

converter station costs are 10% higher than the other options considered. There is considered to be no variation in converter costs between networks using DCCBs and those reliant on AC side protection. Current AC protected systems often make use of oversized diodes to handle high fault currents induced into the DC network in the event of a fault before the AC breakers have time to open. If DCCBs are used it could be argued that this would reduce the requirement on the diodes within the system. It is likely however that some provision would still be made to protect the converter in the event of a DCCB failure therefore there is unlikely to be converter cost savings associated with using DCCBs.

The major differences in capital costs between the grid options can be attributed to the amount of DC cable required and the number of DCCBs deployed within the system. The radial grid option has by far the highest total circuit length and so cable costs, assuming symmetrical monopole configuration with two cables that are buried as a bundled unit, amount to a very large £1.26 billion. The radial+ grid option on the other hand has total cable costs of £714 million which is some £543 million lower. As the level of interconnection increases so too do the overall cable costs with all three standard multi-terminal options costing £748 million and the meshed grid option costing £811 million. The bipole multi-terminal grid option requires an additional dedicated low voltage return cable to be implemented to allow for continued monopolar operation in the event of certain fault conditions. Again, there are no published estimates of the cost of such a conductor however it is assumed that due to greatly reduced insulation requirements that the return conductors are 50% of the cost of the fully insulated high voltage cables. This along with increased costs to bury the two pole cables apart leads to comparatively high overall cable costs of £932 million.

As with the ISLES scenario the cost of DCCBs is again shown to have a major influence on the overall project capital expenditure. The AC protected network avoids the use of DCCBs and so has the lowest overall cost closely followed by the minimum breaker solution that greatly reduces the number of deployed DCCBs leading to a total additional cost of just £86 million. The radial+ option is also similarly low cost as it has relatively low breaker requirements with additional costs

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of £119 million but reduced cable costs. As the interconnection in the offshore grid increases however so too does the number of required DCCBs and this is reflected in the fact the breaker costs for the multi-terminal and bipole grid options come in at £291 million and for the meshed grid option the costs rise to some £547 million making it the most expensive option overall. The radial and Bipole grid options are both almost as expensive as the meshed grid whereas the overall costs reduce as the number of DCCBs and circuit length of cables in the systems reduce.

4.2.3 Electrical Losses

The same offline process is again used to calculate the losses that can be attributed to the various Dogger Bank network scenarios. It is assumed that the two onshore converter stations are co-located at the same onshore grid connection point so there is no inter-regional trade consideration. In light of direct information for component losses at the exact ratings used in this scenario the standard figures outlined in Section 3.7 are applied to the Dogger Bank scenarios as shown in Table 4.12.

Table 4.12 - Electrical loss parameters applied to Dogger Bank grid scenarios

Electrical Loss Parameters		
Component	Electrical Losses	
	700MW	1400MW
MMC Converter	1%	0.9%
AA-MMC Converter	1.15%	1.035%
DC Circuit Breaker	0.01%	0.08%
DC Transmission Cable	0.02Ω	0.01Ω

The losses applied to the AA-MMC converters of the AC protected grid option are 15% higher than those assumed for the standard MMC converters assumed for the other network options, which is in line with the findings of [12]. The annual expected, pre-fault operating state, system losses for each grid option are given in Table 4.13. The results show that there is little difference in the expected level of losses for each of the grid option in the pre-fault operating state with all grids apart from the radial and minimum breaker options having losses of around 2.80%. The small differences that are present are related the number of DCCBs in the system or

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the rating of transmission branches. The radial grid option has higher expected losses of 2.85% which reflects use of less efficient lower power transmission cables. The minimum breaker grid option utilises converters with 15% higher losses than other grid options which leads to overall losses which are around 10% higher than the standard multi-terminal grid option at 3.07%.

Table 4.13 - Expected annual electrical losses for Dogger Bank grid options

Electrical Losses	
Radial	2.85%
Radial+	2.80%
Multi-terminal	2.80%
Minimum Breaker	3.07%
AC Protected	2.79%
Meshed	2.79%
Bipole	2.80%

The expected lifetime project costs associated with electrical losses is calculated using the standard discount methodology discussed previously and the results are given in Figure 4.18.



Figure 4.18 - NPV of electrical losses for Dogger Bank case studies

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In reality the networks do not remain in the pre-fault operating state throughout their lifetime and as faults are introduced into the system the level of electrical losses associated with the remaining operational grid will fluctuate. To calculate the impact of this directly as part of the Monte Carlo simulation would add significantly to the already large computational demands of the program. For relatively small networks, like the Dogger Bank case studies, it is possible though to estimate the impact of this feature by determining what the average annual losses would be for each of the potential grid operating states and applying the results to the calculation of losses each time a new state is entered. The expected losses for each state are calculated offline using the same method that is applied to calculate the pre-fault operating state losses and the results are then applied within the Monte Carlo process as outlined in Section 3.7. The total energy adjustment that should be made to account for the system being in different operating states can then be estimated through Eqns. 3.25 and 3.26 which accounts for the difference between the expected loss figure of each new state and the figure for pre-fault operating state losses. The results are converted to costs through the usual NPV analysis and reported in Figure 4.19.

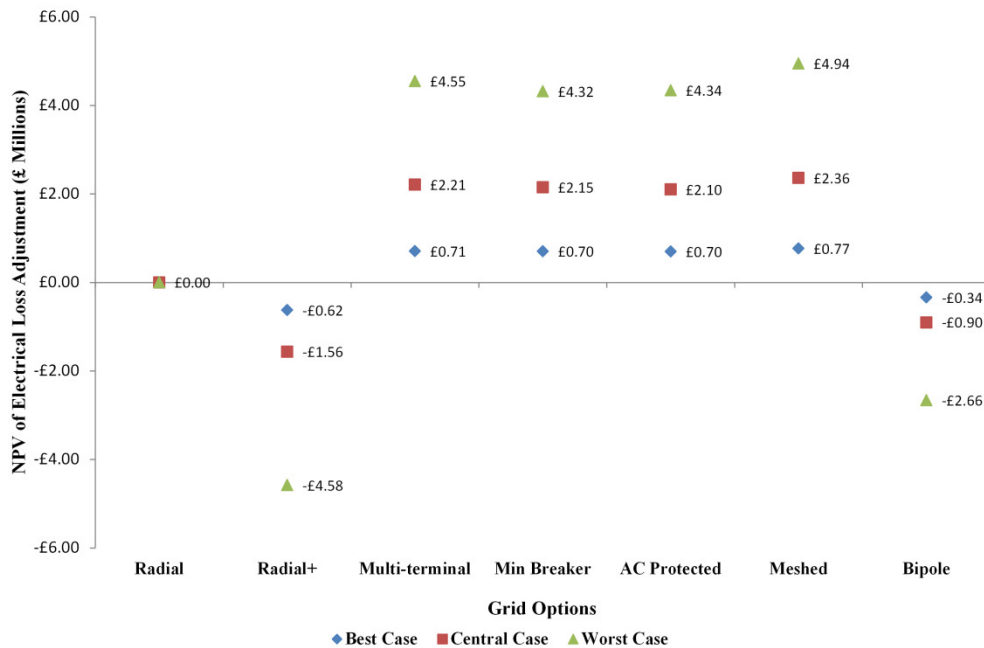


Figure 4.19 - NPV of electrical loss adjustment for Dogger Bank case studies

It is found that the overall deviation in electrical losses due to fault conditions is very small in value compared with those calculated for the pre-fault operating state only.

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For the Best case reliability scenario the deviations result in less than \pm £1 million worth of delivered energy depending on the grid option whereas for the central and worst case reliability scenarios the change in lifetime NPV increases to around \pm £2 million and \pm £5 million respectively. The radial grid option simply operates in functioning or non-functioning states so there are no deviations from the pre-fault operating state electrical losses. The other grid scenarios however have multiple possible operating states. The radial+ grid option is found to have a negative lifetime loss adjustment which means the real losses are lower than those calculated solely for the pre-fault network. This suggests that this grid option spends more time in states where the losses might be proportionally lower than normal. An example of this would occur if an entire wind farm is out of service. In this situation the proportional losses associated with the remaining connected wind farms on the network is lowered because the loading on the HVDC transmission cables is reduced meaning copper losses are lower. All the symmetrical monopole based multi-terminal and meshed grid options on the other hand give a positive loss adjustment value meaning losses are higher overall when compared to those calculated for the pre-fault operating state only. This suggests that more time is spent in states with comparatively high losses, an example of which would be if one of the long transmission links to shore is out of service. In such a scenario the remaining generation output on the grid is re-directed down the single remaining transmission route and the copper losses are pushed up as this link operates at or closer to full capacity. This result is validated by the findings of Section 5.2 which looks at the time spent in different system states and shows a high percentage for such a scenario in these grid options whereas the radial+ grid option has no ability to re-route power down other links. The bipole grid option shows negative losses but at a lower rate than the radial+ grid which tallies with the fact that this grid option is less likely to be effected by the removal of a full transmission link for long periods of time than the other multi-terminal grids meaning that the reduced losses associated with wind farm shut downs outweighs the increased losses associated with restricted transmission capability. Given that the final adjustment losses amount to less than 1% of the overall losses calculated for the pre-fault operating state even for the worst case reliability scenario, it suggests that this calculation can safely be regarded as

negligible and so can reasonably be ignored in other studies, as was the case for the ISLES case study investigated previously.

4.2.4 Reliability Performance

As with the previous ISLES case studies the reliability of each of the Dogger Bank grid options is evaluated through an assessment of the annual level of undelivered energy that can be expected under the three reliability scenarios outlined in Section 3.3.4. The headline results are shown in Figure 4.20 as a percentage of the annual deliverable energy for each grid option, defined as the generated energy minus the electrical losses.

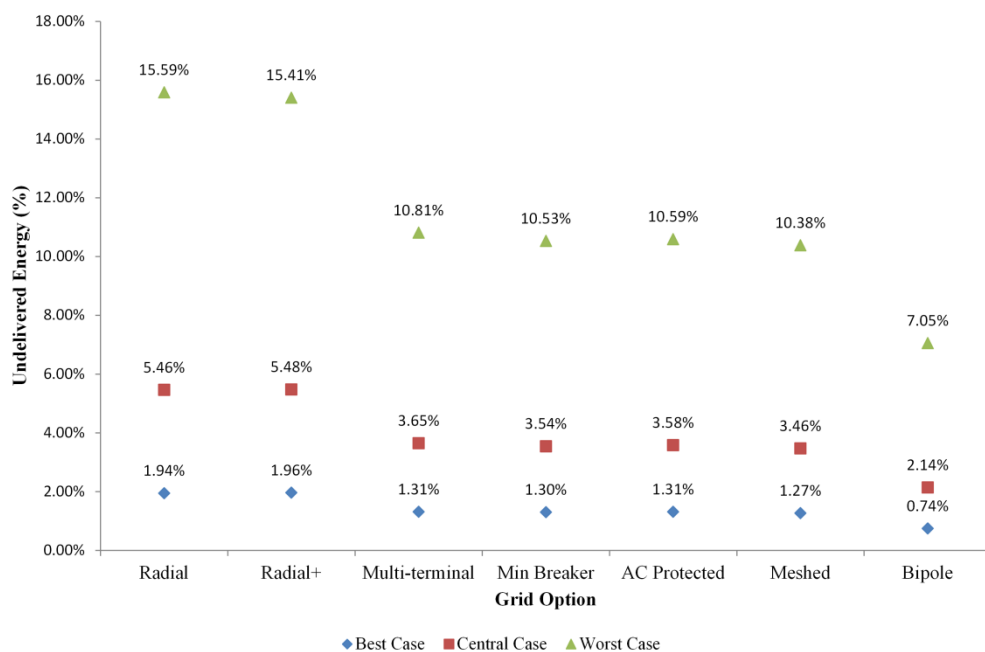


Figure 4.20 - Annual expected level of undelivered energy due to system faults

The sensitivity of the final reliability performance to input assumptions is even clearer for the Dogger Bank Case studies than for the ISLES case studies. The percentage of undelivered energy in the best case reliability scenario ranges from 0.74% to 1.94% depending on the grid option whereas in the worst case reliability scenario this increases to between 7.05% and a huge 15.59%. This is likely a function of the fact that there are fewer routes to shore in the Dogger Bank case studies and that the wind energy is concentrated in larger wind farms meaning the impact of certain system faults is likely to be proportionally higher. The central case

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reliability figures range from 2.14% to 5.46% with the multi-terminal and meshed options giving around 3.5% undelivered energy. This level is clearly much more acceptable than the worst case reliability figures which are upwards of 10% for all but the bipole grid options. The ability to deliver performance close to the best case or central case reliability estimates would therefore be very important to the project viability if any of the grid options were to be implemented in reality.

The value of having system redundancy in the form of alternative transmission paths to shore is also apparent in the results with the two radial solutions susceptible to significantly higher levels of energy curtailment than the multi-terminal and meshed options. For each of the reliability scenarios the level of undelivered energy is around 50% higher in the radial grid options than the symmetrical monopole based multi-terminal and meshed options, which highlights again the significant benefits of being able to re-route power transmission in the event of certain system faults.

A comparison can also be made of the three options which utilise a multi-terminal solution via different protection strategies and it is found that there are only small differences in their respective reliability performance. As was shown in the ISLES case study the introduction of an additional layer of components into the system actually negatively impacts the reliability meaning that the DCCB protected multi-terminal option has marginally higher expected levels of undelivered energy compared with the two alternative protection methods using the same grid configuration. The minimum breaker option which utilises full bridge AA-MMC converter technology and a reduced number of DCCB's reduces this burden and the AC protected option removes it completely. The AC protected option, however, is subject to temporary periods, after each system fault, in which an entire grid section is removed from service and the impact of this in terms of additional energy curtailment means that the minimum breakers option has the best reliability performance of the three multi-terminal grid options.

Adding the additional complexity of the meshed option further reduces the amount of curtailed energy. However, in this case study the impact is relatively small with only marginally better performance than the multi-terminal grid options. If the wind farms were more dispersed or the system more complex, the value of a meshed grid would

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likely be more apparent although the cost of implementing it would also increase, as is explored further in Section 5.4. The results for the Bipole grid option, however, show dramatically improved reliability performance compared with the symmetrical monopole grid solutions with undelivered energy reduced to around 60-70% of the best performing symmetrical monopole solutions. This highlights the vulnerability of the symmetrical monopole configuration to certain fault conditions even when an alternative transmission path is present in the system.

The financial impact of system reliability and system electrical losses is examined through an evaluation of the NPV of expected delivered energy over the lifetime of each of the grid options and the results are given in Figure 4.21. This is defined as the total potential generated energy, calculated from the installed wind capacity, the wind speed time series and the wind speed to wind power curve, minus the electrical losses and energy curtailment due to component outages. Applying an annual discount rate of 6%, a value for generated offshore wind energy of £150/MWh and assuming a project lifetime of 25 years yields a maximum value for generated energy for each of the Dogger Bank grid options, before losses, of £21.12 billion.



Figure 4.21 - NPV of delivered wind energy for each grid option over project lifetime

Figure 4.18 showed that electrical losses account for a reduction in NPV of between £588 and £647 million depending on the grid option so looking at Figure 4.21 it is

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possible to determine the additional impact of grid reliability on overall finances. It is found that the best performing grid under the best case reliability scenario accounts for a reduction in NPV of delivered energy of only £152 million over the project lifetime but that the worst performing grid option under the worst case reliability study would account for a reduction in NPV of some £3.20 billion. This not only shows there is a large gulf in the performance of the different grid options but that the monetary impact of reliability performance is highly dependent on the input scenarios assumed.

It is clear from all three reliability scenarios that the low curtailment levels of the bipole grid option mean it would be expected to deliver the greatest level of wind energy to shore over the project lifetime and given electrical losses are comparable with other grid options this option has the highest NPV of delivered energy in all cases. This financial advantage amounts to £106 million over the next best grid option for the best case reliability scenario but increases to £273 and £689 for the central and worst case reliability scenarios respectively. The meshed grid option is the next best in terms of value of expected delivered energy in all three scenarios but holds only a marginal advantage over the multi-terminal and AC protected grid options with which it shares similar electrical losses. The Minimum breaker grid option using higher loss full bridge converters, on the other hand, shows an NPV that is around £50 million less than the AC protected grid option for the central reliability case which shows that an increase in electrical losses can have important implications on the financial viability of the grid option.

The results also highlight the financial benefits of having redundant transmission paths with the two options that rely on purely radial shore connections having a significantly lower NPV for expected delivered energy over their project lifetime. Under the best case reliability scenario the significance of the added redundancy is relatively minor with a difference of around £130 million between the radial+ and multi-terminal grid options. However, if the same comparison is made for the central and worst case reliability scenarios then the difference in NPV values are much more apparent and are in the region of £370 million and £930 million respectively. There

is little difference in the value of delivered energy between the radial and radial+ grid options.

4.2.5 Operations & Maintenance Costs

A consideration is again made of the cost of operations and maintenance throughout the lifetime of each of the grid options. As explained in Section 3.8.2 the costs associated with each repair action are calculated as part of the reliability analysis with an additional scheduled maintenance cost calculated based on the composition of the grid. The scheduled maintenance costs for each grid option are calculated with reference to Table 3.12 and are given in Table 4.14 while the total NPV of scheduled and unscheduled O&M costs for each of the three reliability scenarios are presented in Figure 4.22 using the standard discount calculation.

Table 4.14 - Scheduled maintenance costs for Dogger Bank case studies

Scheduled O&M Costs (£ million)							
	Radial	Radial+	Multi-terminal	Meshed	Min. Breaker	AC Protected	Bipole
Offshore Substations	£0.70	£0.70	£0.70	£0.70	£0.70	£0.70	£0.70
Onshore Substations	£0.34	£0.34	£0.34	£0.34	£0.34	£0.34	£0.34
Offshore cables	£2.08	£1.08	£1.13	£1.21	£1.13	£1.13	£1.13
DCCBs	-	£0.23	£0.47	£0.82	£0.12	-	£0.46
Annual Total	£3.11	£2.34	£2.63	£3.07	£2.27	£2.16	£2.63
25 Year NPV	£42.16	£31.77	£35.61	£41.53	£30.86	£29.28	£35.61

It is found that the radial grid option has the highest lifetime scheduled maintenance costs at £42.16 million largely due to the extra transmission cable used in this design. The remaining grid option costs all vary depending on the circuit length of installed cable and the number of DCCBs required for the design. The meshed grid solution therefore has the highest number of breakers and an increased circuit length leading

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to high lifetime maintenance costs of £41.53 million compared with the AC protected design which avoids the need for DCCBs and has costs of just £29.28 million.

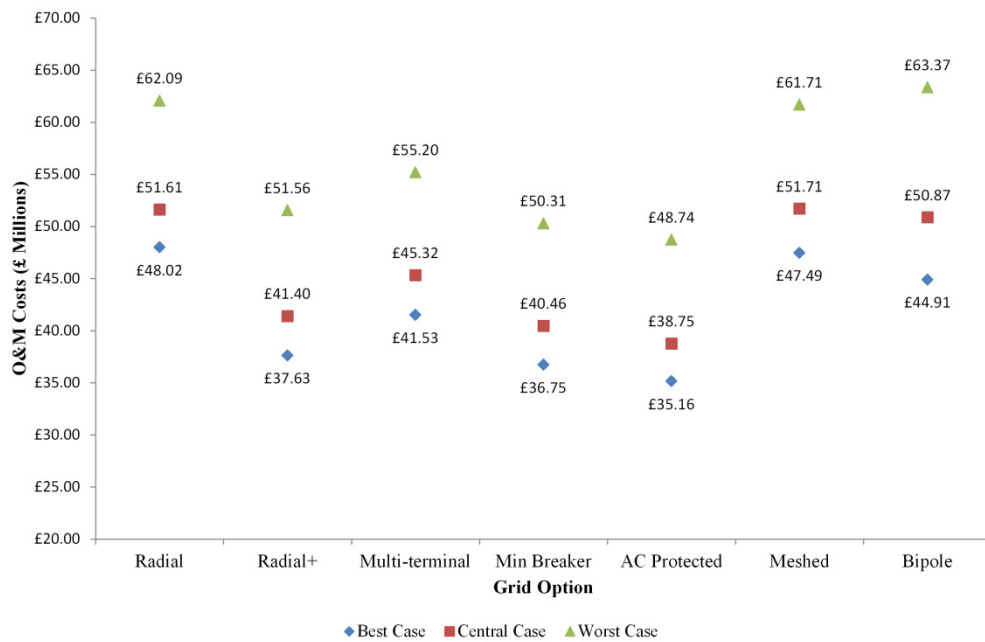


Figure 4.22 - NPV of O&M costs for Dogger Bank grid options

It is again found that lifetime O&M costs are very low in comparison to the project capital expenditure and the value of undelivered energy for each grid option. The Dogger Bank case studies contain fewer individual components and reduced total circuit length than the ISLES case studies so the additional maintenance costs, directly related to component repairs, are found to be lower adding around £9 - 10 million for the central case reliability scenario for each grid option with the exception of the bipole grid. This option shows O&M costs which are almost 50% higher than the other grid options. This is a function of both transmission cables and transformers being modelled separately for each pole in the bipole scenario whereas a single transformer and bundled cable system are assumed for the symmetrical monopole grid configurations. The overall O&M costs vary between grid options with the more complex meshed system with high number of DCCBs and the radial option with significantly higher circuit length showing the highest costs in each of the scenarios. The bipole grid option also has high costs, especially in the worst case reliability scenario where the direct repair costs are comparatively high. The relatively basic radial+ system and those with reduced DCCB requirements, such as the AC

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protected network show the lowest costs in each reliability scenario. For a far offshore development like the one investigated it is highly possible that an offshore maintenance base would be developed to serve the wind farms' O&M needs by housing personnel, transport vessels and equipment. It would make operational sense for the OFTO to also operate out of such a base and thus take on some of the cost burden but it is difficult to estimate the exact level of this. It can be considered that the cost would apply to all grid options investigated so such an additional cost is not included in this study.

4.2.6 Overall Value of Grid Options

By combining the results highlighted in the previous sections it is possible to generate a final assessment of the overall value of each grid option investigated given each reliability scenario. The NPV of each grid option is determined by subtracting the capital costs of building each grid option and the operational costs associated with maintenance operations from the value of lifetime energy that each is expected to deliver to shore after electrical losses and component outages are accounted for. The final results are given in Figure 4.23.

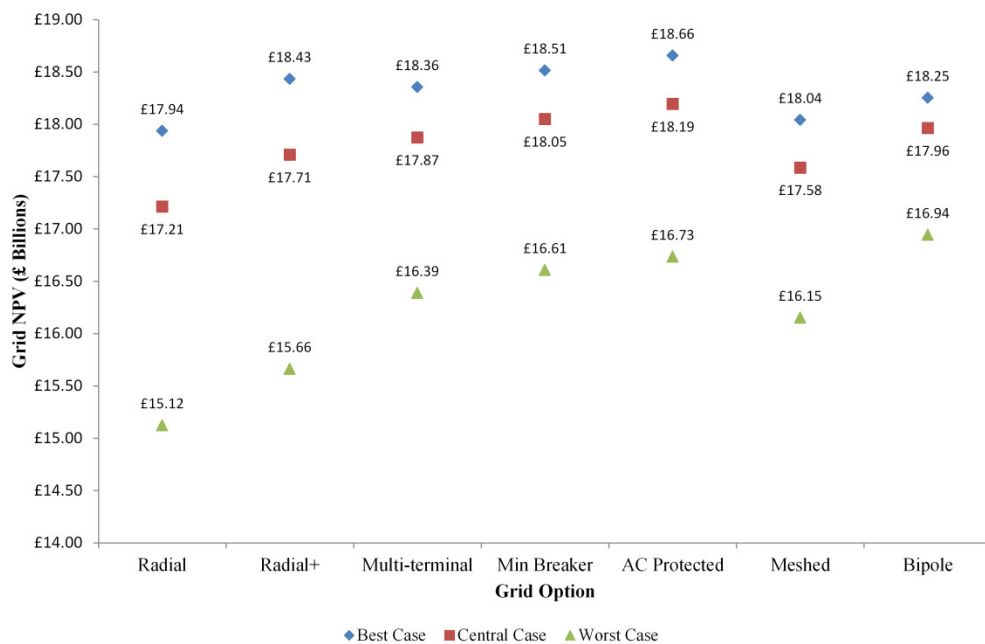


Figure 4.23 - Overall NPV of Dogger Bank grid options

It is clear from the results that capital expenditure and grid reliability are the two major influences which affect the overall ranking of the grid options in terms of total

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NPV. Under both the best case and central case reliability scenarios the lowest cost AC protected grid option is the most favourable in terms of overall NPV. Despite delivering the most value in terms of delivered energy by a clear margin, the increased costs associated with bipole grid option balance out this benefit to a varying degree depending on the input reliability scenario. In the best case reliability scenario the advantages of high reliability are less obvious and the high costs make the bipole grid only the fifth most favourable option out of seven with an NPV that is £403 million lower than the AC protected grid option. In the central case the importance of reliability increases and the bipole option is the third most favourable option but still has an NPV that is £231 million lower than the AC protected option. However, in the worst case reliability scenario the reliability offered by the bipole solution makes it the most favourable option with an NPV that is £209 million higher than the AC protected grid option. It should be noted that in this investigation the bipole grid option uses the relatively high cost DCCB based protection strategy which suggests the option would be even more favourable if it could be developed in conjunction with one of the lower cost protection methods.

The meshed grid option also shows good value in terms of delivered energy but the huge costs associated with implementing extra transmission capacity and DCCBs throughout the grid to facilitate a fast acting, low impact protection strategy severely reduces the favourability of this grid option. In both the best case and central case scenarios it is the second least favourable option and in the worst case scenario it is the third least favourable option. In all scenarios the meshed grid option is less favourable than the multi-terminal grid option which shows that in this case study the costs of delivering an additional layer of redundancy on top of that provided by the multi-terminal grid option are not balanced by the benefits.

The multi-terminal, minimum breaker and AC protected grid strategies all use the same general grid structure but deploy differing protection strategies and underlying technology. Despite the fact that the delivered energy under each of these options is found to be broadly similar in Figure 4.21 the large discrepancy in capital costs highlighted in Figure 4.17 means that the AC protected option ranks significantly better than the other two options. The highest cost multi-terminal grid option ranks

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the lowest of the three with an NPV that is between £301 million and £346 million lower than the AC protected grid option depending on the reliability scenario. The NPV of minimum breaker option on the other hand is only between £127 million and £143 million lower than the AC protected option and therefore ranks as the second most favourable option in the best and central case reliability scenarios and third most favourable in the worst case reliability scenario.

The radial+ grid option is delivered at a relatively low cost which means it compares well in the best case reliability scenario where its relatively poor performance is less important to overall costs. As such it is the third most favourable option under this scenario but as the level of component reliability drops the financial competitiveness of this option is heavily curtailed and it is only the fifth and sixth best option under the central and worst case reliability studies respectively. The radial grid on the other had suffers from both poor reliability performance and high capital expenditure meaning it is the least financially rewarding option under all scenarios.

Another important point that can be observed from the cost analysis is the spread of results under different reliability scenarios for each of the grid options. This again highlights the benefits of investing in grid reliability as the highly reliable bipole option shows the lowest level of difference in NPV between the best case and worst case scenarios at £1.31 billion. This compares with differences of £1.89 billion, £1.97 billion, and £2.77 billion, recorded for the meshed, multi-terminal and radial+ grid options respectively. This means that although in the best and central case scenarios the potential rewards of using the bipole grid option are lower than some of the other grid options there is also less risk associated with uncharacteristically poor reliability performance. This could be an important factor when deciding upon which grid to use as investors may prefer to finance an option that provides the ‘least regret’ over an option that may deliver good performance under central case conditions but poor performance if close to worst case reliability figures are realised.

The Dogger Bank scenario features two grid options which operate without DCCBs or full bridge converters such that DC side faults are protected using AC side circuit breakers alone. As was done for the ISLES case study, the frequency of temporary sub system grid shut downs is measured to give an indication as to the extent of

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potential issues that may arise through fatigue damage during turbine emergency stop procedures or otherwise. The results are given in Table 4.15 and for the radial grid option are similar to those found for the ISLES network whereby a temporary shutdown of one of the four radial grid links can be expected a little under once per month for the central case reliability estimate. This result changes to roughly once every three months in the best case reliability scenario or once every two weeks for the worst case. In contrast the AC protected grid shows much reduced propensity for grid shut downs with roughly a third fewer in all scenarios which can be attributed to the reduced circuit length and number of components in this system compared with the radial option.

Table 4.15 - Number of DC grid shut downs per year for Dogger Bank AC protected networks

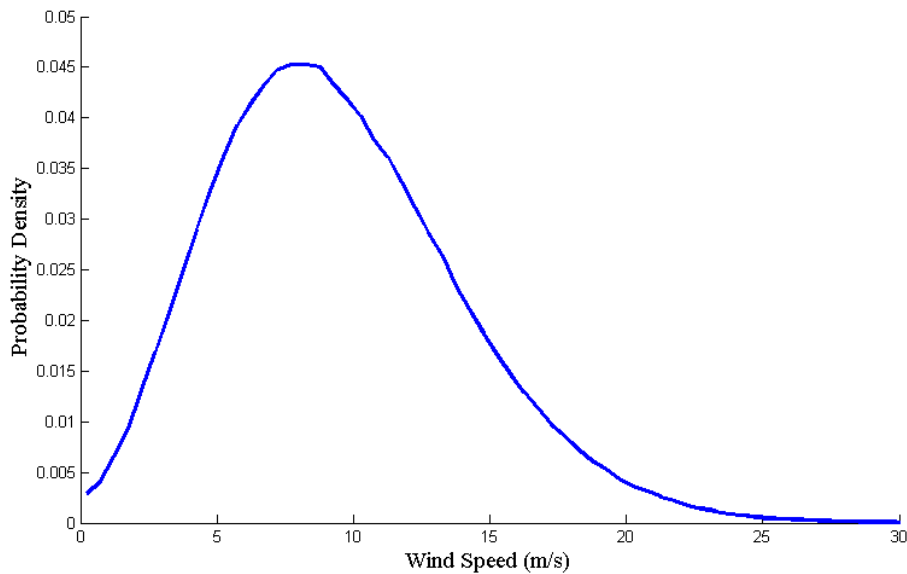
Number of Grid Shut Downs per year			
Grid Option	Reliability Scenario		
	Best Case	Central Case	Worst Case
Radial	4.27	11.12	22.98
AC Protected	3.18	7.55	17.80

4.3 Importance of Weather Dependant Reliability Analysis

One of the themes of this thesis is that the overall cost-benefit of different grid options depends on reliability performance, and that to quantify this accurately depends on modelling the effects of weather on curtailed wind energy and access to an offshore site to effect repairs. In this section, the sensitivity of the cost-benefit analysis results to the modelling of weather is explored. As explained in Section 3.4.3 the repair of offshore components is modelled to comply with access restrictions that are dependent on the input mean significant wave height time series. Section 4.3.1 analyses in detail the seasonal trends in the wind speed and significant wave height input time series used in this analysis, derived from the FINO offshore dataset. Section 4.3.2 then investigates the level of impact these seasonal trends have on the overall reliability and expected levels of undelivered energy for the network options in question by comparing against a case where seasonal influences are ignored.

4.3.1 Wind Speed and Wave Height output

This section outlines the characteristics of the mean wind speed and mean significant wave height time series, derived in Section 3.3.2 from the offshore FINO dataset and applied to the case studies examined in this chapter. The histogram for the offshore wind speed data is shown in Figure 4.24 and provides a mean wind speed of 9.87 m/s and an annual expected wind energy yield, before electrical losses or outages, of 7.79 TWh.



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Figure 4.24 - Histogram of wind speed input time series (Bin width: 0.5 m/s)

The histogram for the mean significant wave height time series is given in Figure 4.25. The average mean significant wave height is 1.49 m which is just below the 1.5 m safe access threshold deployed for many offshore repair operations.

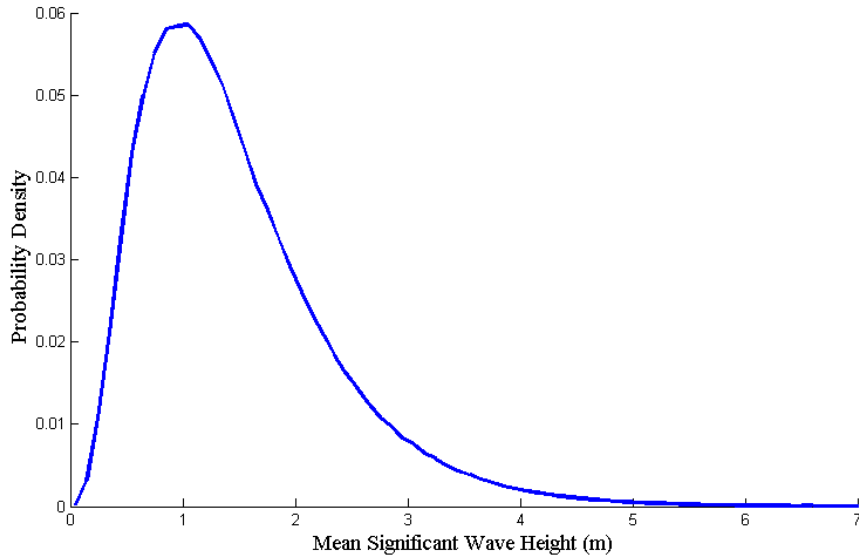


Figure 4.25 - Histogram of mean significant wave height input time series (Bin width: 0.1 m)

The seasonal variation in each of the time series are also calculated and shown in Figures 4.26 and 4.27. These represent the average wind speed or wave height for each of the months of the year using the 100 years' worth of simulated input data.

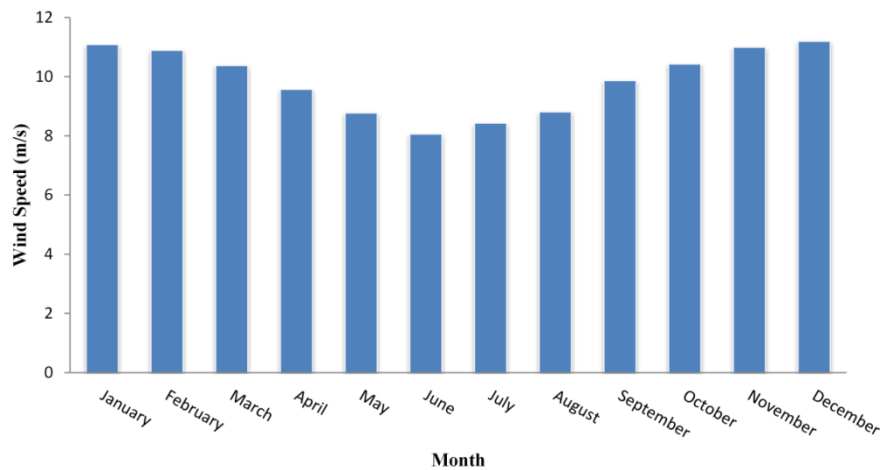


Figure 4.26 - Simulated mean hourly wind speed by month

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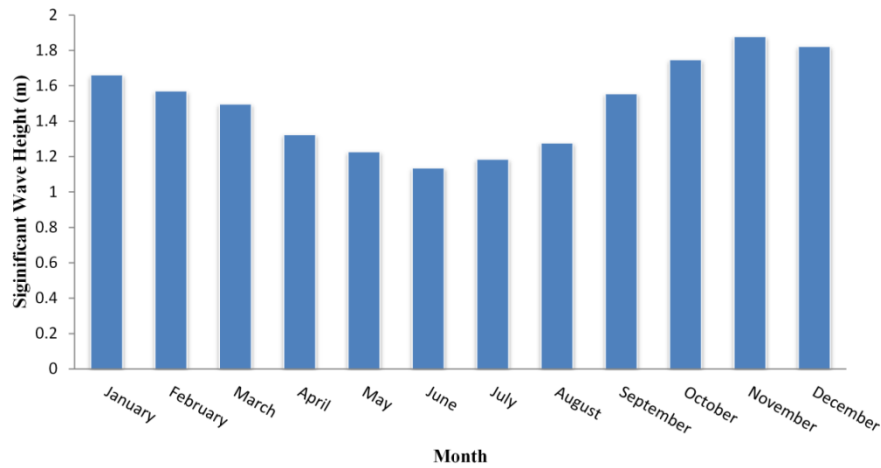


Figure 4.27 - Simulated mean hourly significant wave height by month

The results show a strong seasonal trend in both the wind speed and wave height time series with average monthly wind speeds in December and January reaching upwards of 11m/s compared with a low of around 8m/s in June. The wave height time series shows an equally strong seasonal trend which peaks at an average of close to 1.9m for November before falling as low as 1.1m for June.

These figures show that there is likely to be a large seasonal variation in the amount of time it takes to carry out repairs with delays likely in the winter months especially due to wave height access restrictions. As this also corresponds to the periods when wind speeds are highest the use of the sequential Monte Carlo methodology will inherently model the increased level of expected E_{und} that this suggests.

4.3.2 Influence of Seasonal Trends on Reliability Calculation

There are two main offshore repair categories and the features associated with each are summarised in Table 4.16. Major offshore repairs relate to cable and transformer faults whereby specialist vessel and calm sea states are required to carry out the repairs. A fixed length continuous weather window needs to be available before a repair is allowed on these components. For cable faults, a stringent weather window criterion is applied such that the hourly mean significant wave height must not be forecast to breach 1.5m for the duration of the weather window. For transformer faults the wave criterion is less stringent at 2m. Offshore converter and DC breaker repairs are based on offshore platforms and are not fully reliant on continuous good weather so a criterion is applied that allows work to be carried out on these

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components incrementally during shifts so long as there is an available weather window large enough to allow for transportation to and from the fault location and a set minimum number of hours work to be carried out. The number of hours worked on a repair is banked at the end of the working day until enough hours have been worked to carry out the repair.

Table 4.16 - Offshore repair category characteristics

Offshore Repair Category Characteristics		
	Major Offshore	Minor Offshore
Components	cables, transformers	converters, DC breakers
Weather Window	continuous	non - continuous
Weather Criteria	Hs<1.5m* Hs<2m**	Hs<1.5m

* cable faults ** transformer faults

Firstly, an analysis is carried out to determine the seasonal variation in component repair times using the two methods. Using the same repair windows as set in the best, central and worst case reliability scenarios for offshore cable, transformer and converter/DCCB failures, mock repairs are carried out assuming a failure occurs at 6 am each morning for the full input significant wave height time series. The results obtained in Figures 4.28-4.30 are grouped into monthly average failure times.

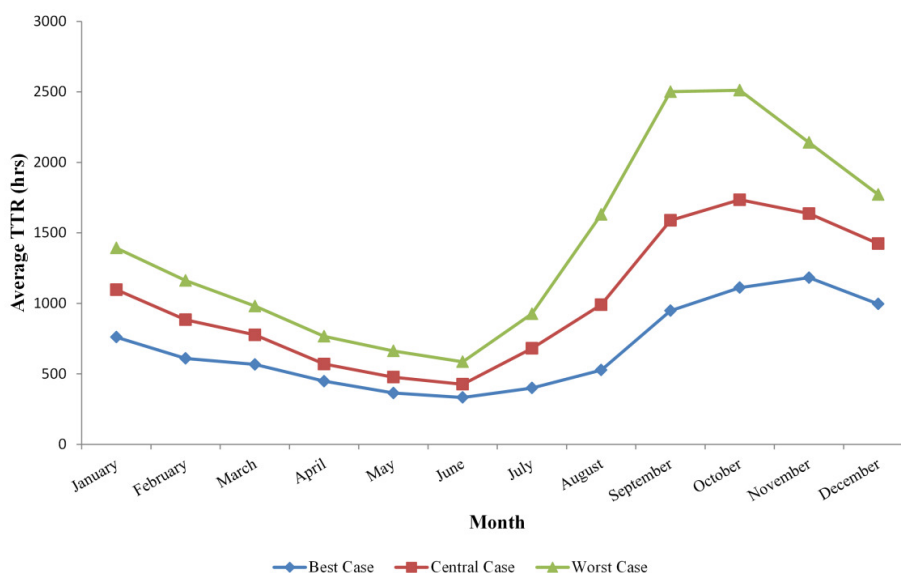


Figure 4.28 - Monthly average repair time for transmission cable faults

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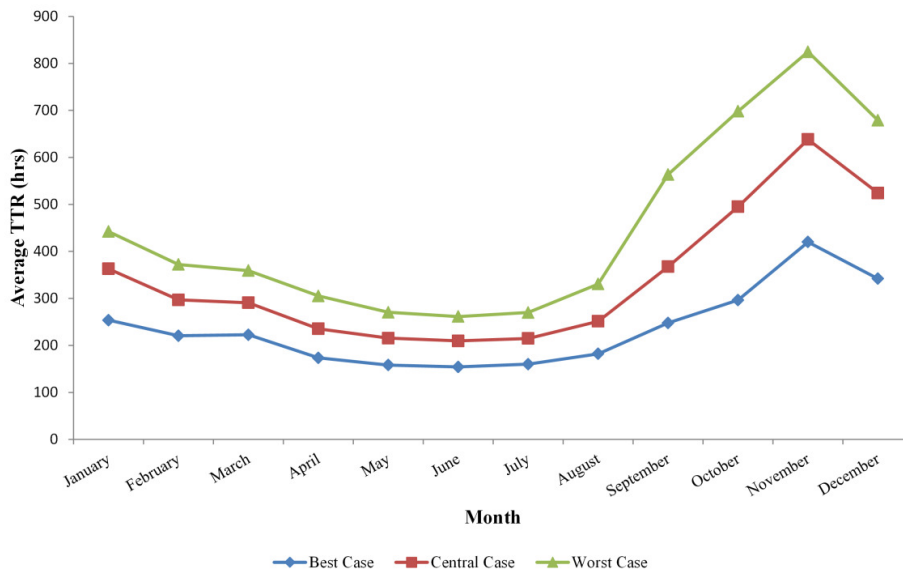


Figure 4.29 - Monthly average repair time for offshore transformer faults

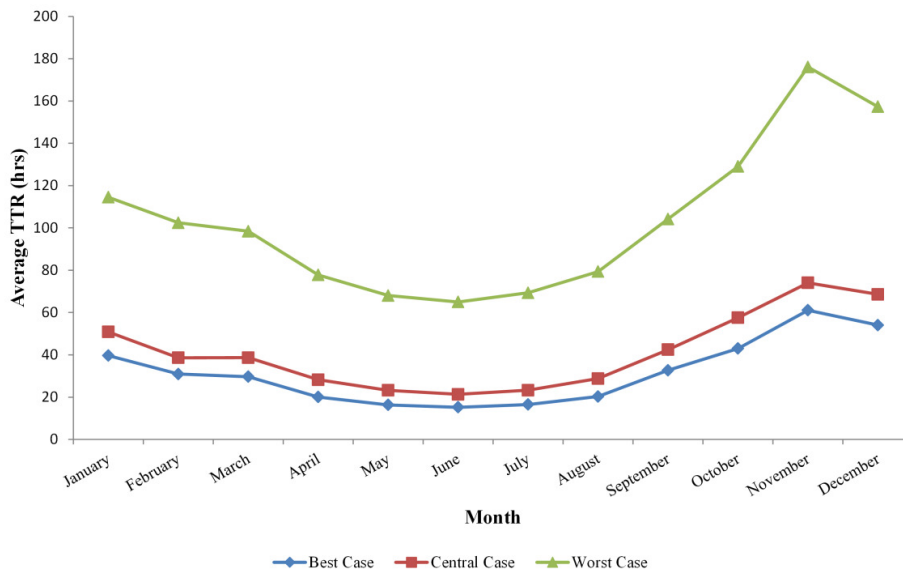


Figure 4.30 - Monthly average repair time for offshore converter and DCCB faults

The results show a distinct variation in the repair time of faults depending on the time of year in which the fault occurs. Cable faults are shown to have by far the longest repair times when not accounting for fixed procurement delays with faults occurring in September, October and November having the highest average repair time. For the central case scenario the average repair time for faults occurring in October is four times higher at 72 days than the average of 18 days for those

occurring in June. This reflects the fact that the months following these have the largest average significant wave height values and therefore are the least likely to have sufficiently long weather access windows to allow component repair.

A similar pattern can be found for offshore transformer failures which, like cable failures, require a fixed length weather window to allow repair. The threshold mean significant wave height for offshore transformer repairs is more relaxed however at 2m rather than 1.5m and this is reflected in significantly shorter average repair times. The highest average repair time for the central case scenario is for faults occurring in November at 27 days which is three times higher than the average repair time for faults occurring in June at almost 9 days. Offshore converter and DCCB faults are based on a different repair strategy and typically have much shorter repair times however a seasonal trend is still apparent in the results with a fault occurring in November likely to take a little over 3 days to repair compared with just 1 day for those occurring in June.

To determine the extent to which modelling this seasonal trend influences overall results a comparison is made between the chosen weather window based reliability methodology and a method which does not consider any seasonal influence. The alternative methodology simply operates by calculating a randomised repair time based on a fixed MTTR value using the same process that is used for the generation of failure times in the main methodology as outlined in Section 3.4.2. The MTTR values used are based on the average annual repair values generated using the weather window based methodology such that the failure rate and average repair times generated using each of the methodologies is equal. A comparison is made between the results obtained using both methodologies for a selection of grid options from both the ISLES and Dogger Bank based case studies and the results are shown in Table 4.17. The same stop criterion as described in Section 3.4.1 is used such that the results should be accurate to within $\pm 1\%$.

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Table 4.17 - Comparison of undelivered energy between weather window based and randomised repair methodologies for central case reliability scenario

Comparison of Undelivered Energy (Central case)				
Network Case Study	Repair Methodology		MWh/year Difference	25 Year NPV Difference
	Weather Window	Random		
ISLES Radial+	3.93%	3.82%	8412	£17,097,834
ISLES DCCB	2.45%	2.33%	9161	£18,620,699
DB Radial+	5.48%	5.38%	9480	£19,268,909
DB Multi-terminal	3.65%	3.52%	12945	£26,311,955
DB Meshed	3.46%	3.36%	10168	£20,666,332

The results show a clear difference between the two methodologies with randomised repairs generating undelivered energy estimates that are typically 2-5% less than those generated by the weather window based repair methodology. It can be shown that the impact is proportionately higher for multi-terminal and meshed grids compared with radial based options although in real terms the difference in the level of calculated undelivered energy is only marginally higher due the underlying difference in reliability performance. It is found that outages in the multi-terminal or meshed grid options tend to be more clustered around the winter months using the weather window based methodology which increases the likelihood of high impact overlapping faults occurring which acts to amplify the increase in undelivered energy when compared to the random methodology. In the radial+ grid options long outages on for example one of the transmission links can effectively take one whole grid section out of service. The modelling process effectively assumes that other component failures within that grid section that may have been due to occur during such a period are postponed until the grid section is operational again. In the weather window based methodology this assumption could have the effect of shifting some fault conditions outside the winter months and away from periods with highest wind conditions and thus reducing the difference between the two methodologies. A more thorough future investigation could look to determine the validity of this assumption and to ascertain whether the phenomena is an accurate representation of reality.

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Although the 2-5% difference is relatively small overall, it clearly shows that there is value in modelling and understanding the fact that faults occurring in winter not only take longer to repair but that they occur at periods when wind farm output is likely to be high and thus leads to proportionally higher E_{und} . To illustrate the impact of this a calculation is made of the difference in the expected level of undelivered energy in MWh/year and in turn the impact this has on the estimate of overall project value through a 25 year discounted NPV calculation. It can be shown that the difference typically equates to around 10 GWh in the expected level of undelivered energy and that over the lifetime of the projects the use of a purely randomised repair methodology will underestimate the projected value of undelivered energy by around £20 million compared with the weather window based methodology so the difference is significant in monetary terms. The fact that the computationally faster random method gives results that are only a few percent different does however mean that such an analysis method may be considered adequate if time constraints are a factor or if a high degree of accuracy is not required. In such a scenario it may be desirable for some form of correction to be applied to simpler and faster calculations based on the results of studies like this one to adjust results to more accurately account for seasonal impacts.

4.4 Discussion

In section 2.7 a number of questions are posed relating to the financial viability of different offshore grid development options. The results of the two case studies presented in this chapter help address several of these questions:

What is the value of implementing increasing levels of redundant transmission paths in offshore DC grids compared with more traditional radial solutions?

The first question looks at the value of added system redundancy in offshore networks through the implementation of alternative transmission paths. Both the case studies that were examined found that there is substantial added value in using multi-terminal or meshed grid topologies over radial solutions in terms of increasing the level of energy that the offshore grid can be expected to successfully deliver to shore. The financial value of this increased reliability is calculated for a range of offshore component reliability scenarios and it is found that the additional benefits of redundant transmission paths do outweigh the costs of implementing the additional infrastructure under certain scenarios. If the central projections for component reliability are realised then the additional reliability benefits are found to outweigh increased CAPEX in both case studies. In the ISLES case study the base case grid option essentially contains an extra 100 km of offshore DC cable when compared with the radial+ grid option which allows re-routing of power at a capital cost of roughly £100 million. The NPV of additional delivered energy that can be expected however equated to around double that figure. In the Dogger Bank scenario the cost of moving from two separate radial+ transmission grids to a single integrated multi-terminal grid using DCCBs is found to be £205 million but under the central case projections the added benefits in terms of reduced energy curtailment of doing this amounts to some £373 million so it is clear that in certain situations there is a strong case to be made for increased up front capital expenditure to allow for greater long term reliability. In contrast, however, it is found that the additional benefits of increasing reliability further through implementation of a meshed DC grid option only adds marginal financial benefits whilst adding substantial additional costs. If component reliability is found to be worse than the central case projection then the financial case for a highly reliable system increases further but if reliability figures

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approach the best case projections then the need case for a reliable but complex system design is much weaker. In fact under the best case reliability scenario the results of the Dogger Bank case study show that the radial+ option is preferable financially to the multi-terminal option whereas in the ISLES study there is very little NPV difference between the base case and radial+ grid design options.

Redundancy can also be introduced through other means such as the ability to operate at partial transmission capacity under certain fault conditions as is the case with the bipole grid option of Case Study 2. Similar results are found if the same analysis is applied to this scenario whereby investing the high costs associated with delivering the more reliable grid, only makes sense if the level of unreliability in offshore grid components is around or beyond the central case projections. If, instead, the best case component reliability is approached then the added CAPEX would not be redeemed over the project lifetime and the investment in the more complex grid system would not make financial sense.

Are multi-terminal or meshed offshore HVDC grids incorporating the widespread use of potentially costly DCCBs financially viable?

Given the expected cost estimates derived in Section 3.8.3 for DCCBs it is found that the widespread use of these devices is likely to add significantly to the capital cost of offshore grid projects. In the ISLES case study the breakers in the DCCB grid option account for 20% of the £2.5 billion capital cost. This means the grid that uses DCCBs to allow for a single large multi-terminal grid configuration is found to be 25% more expensive than the base case option that uses an almost identical grid topology but adopts a protection strategy that splits the grid into three separate sub systems which rely on AC side protection. Equally in the Dogger Bank case studies DCCBs account for 25% of the total cost of the meshed DC grid option which requires the highest number of DCCBs making it the most expensive grid overall despite other designs having significantly higher cable or converter costs.

In both case studies the NPV of all grid options are high and positive however these figures relate only to the value of saleable or tradable energy that is facilitated by the grid design in question and therefore does not represent the remuneration that would

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necessarily be returned to the project developers or owners. As discussed in [13] actual regulations for remuneration are non-standard across different countries and may or may not be linked to the physical delivery of energy to consumers. For example, offshore wind farm operators may not be exposed to the performance risk of the offshore transmission asset if their output is metered at the offshore rather than the onshore connection point. Offshore transmission owners may also be remunerated based on availability targets rather than delivered energy.

What the results do show is that DC grid options that incorporate large numbers of DCCBs are likely to be significantly more expensive when compared to other grid options that have been shown to deliver similar or in some cases even better reliability in terms of delivered energy. Although it is possible that such grid designs could be delivered in a profitable manner it is likely that the use of DCCBs to create offshore HVDC grids that can be operated and protected in a similar manner to onshore HVAC transmission systems would reduce the financial viability of a given offshore grid development.

What are the costs and penalties associated with alternative protection strategies that avoid the use of DCCBs?

Within the two case studies examined it has been made apparent that alternative protection methods to the use of DCCBs can be delivered at lower cost and even with marginally improved reliability. Sectionalised DC grids utilising AC protection in particular can be delivered at significantly lower cost than fully integrated DC grids with DCCBs, so long as the DC grid sections are kept within loss of infeed limits. The need to temporarily shut down entire grid sections each time a fault occurs does contribute to increased curtailment of energy in comparison to grids that can act to isolate faults instantaneously. However, the impact of this on reliability is found to be marginal and is in fact outweighed by the additional unreliability that DCCBs themselves contribute to the system. The grid shut-downs may, however, have other consequences that have not been accounted for such as increased fatigue of offshore wind farms through increased emergency stop procedures or potentially localised issues on the connected AC grid associated with the loss of potentially large power input. However, the frequency of grid shut down events are not considered to be

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unreasonably onerous for the grids investigated with one or fewer per month occurring in the central reliability scenarios, only some of which are likely to coincide with high wind output and therefore have increased potential to cause issues.

The other protection option which is investigated through the minimum breaker grid is the use of full bridge AA-MMC converters in conjunction with a greatly reduced number of DCCBs. This option is found to have higher electrical losses and upfront converter costs but delivers the best reliability performance of the three options and has lower overall costs than the multi-terminal optional due to the reduced DCCB burden. This means that overall, like the AC protected grid option, it is found to be financially favourable when compared with the DCCB based protection strategy. Although this grid option has a lower NPV than the AC protected option it potentially removes the need for offshore wind farm shut downs and the loss of whole grid sections so might be considered favourable from an operational perspective as it delivers functionality much closer to a fully DCCB protected grid.

Which grid design options provide the most value for money in terms of revenue potential against capital expenditure and running costs?

Although the two case studies looked at in this investigation reveal a number of key performance characteristics relating to each of the different proposed grid options it is not possible to definitively state which provide the best value for money as this depends on many variables. The ranking of DC grid options in terms of NPV is found to be highly dependent on the level of failure and repair rates achieved on an individual component level. By investigating best, central and worst case reliability scenarios it is possible to gain an understanding of how each grid compares under a range of conditions and gives a fuller idea of the risks and rewards associated with each design choice.

There is found to be clear value in utilising increasing levels of system redundancy with the meshed grid layout providing good reliability performance. Use of a bipole grid configuration as opposed to a symmetrical monopole solution has also been shown to bring significant benefits in terms of increased reliability and therefore

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revenue potential but there are higher costs associated with implementing these more complex designs so the business case depends on a number of factors and improves as the expected reliability performance of the system components gets worse.

The results to date also show that alternative protection strategies such as a sectionalised DC grid approach with AC side protection can be delivered at low cost with minimal impact on reliability although there may be a need to consider some operational side effects relating to this. Equally, it is found that a protection strategy utilising full-bridge reverse current blocking converters and a reduced number of DCCBs can be delivered at relatively low cost and with good reliability performance. Given the same grid topology, both of these alternative options are found to provide better value than a system utilising fast acting DCCBs throughout.

Project capital expenditure is found to be a main driver with high costs associated with both additional transmission circuit distance and implementation of DCCBs. Grid options with either of these features are likely to be significantly more costly than alternative options and so to remain cost competitive must provide significantly improved reliability to balance out the additional CAPEX. Long term O&M costs are found to be less influential as these are relatively low compared with the system CAPEX and the difference between different grid design options is also marginal.

What are the key drivers behind the reliability of electrical infrastructure in the offshore environment?

A closer interrogation of the results obtained and further investigations are required to determine what the main drivers behind offshore grid reliability are. The results of Section 4.3 do however show that the reliability of offshore grids is significantly impacted by a dependency on weather and that there is value in modelling accurately the seasonal variations in component repair times. The following chapter will look at a number of sensitivity studies, further specific case studies and provide a deeper investigation of the high level results presented in this chapter to provide an insight into the main drivers that dictate the final reliability performance of offshore DC grids and add additional understanding to the conclusions that have been made thus far.

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5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

This chapter looks to evaluate the key drivers behind offshore grid reliability and give further understanding of the results presented in Chapter 4 as to the value of different grid options. To do this a number of sensitivity studies are performed and further offshore grid scenarios investigated to determine how sensitive final results are to the variation of certain input parameters including:

- The failure and repair rate of individual offshore grid components
- Offshore wind speed and wave height time series
- The distance to shore and distance between offshore nodes
- Key component costs and accounting assumptions
- The temporal distribution of failures

A deeper analysis of the existing results is also undertaken to determine how different failure states impact on the overall reliability performance of different grid options.

5.1 Sensitivity to Individual Component Reliability

To better understand the key drivers behind the reliability of offshore grids a sensitivity study is performed to look at the impact of individual components on overall reliability. The analysis looks at what the impact would be on the overall undelivered energy metric if both the failure and repair rates of various components are varied from the central case reliability projection. Results are obtained for various network examples and show the impact on overall reliability of individual components' failure and repair rates varying between 50% and 200% of the central case estimates. For the repair rate calculation both the fixed delay time and the required length of weather window or repair time are altered, as applicable. A number of the Dogger Bank case studies are investigated to determine the different sensitivities associated with varying grid layouts and converter configurations followed by a comparison with two of the ISLES grid options to show how sensitivity varies under contrasting offshore grid scenarios.

5.1.1 Dogger Bank Case Study

The sensitivity to failure and repair rates for the Dogger Bank multi-terminal network is presented in Figures 5.1 and 5.2.

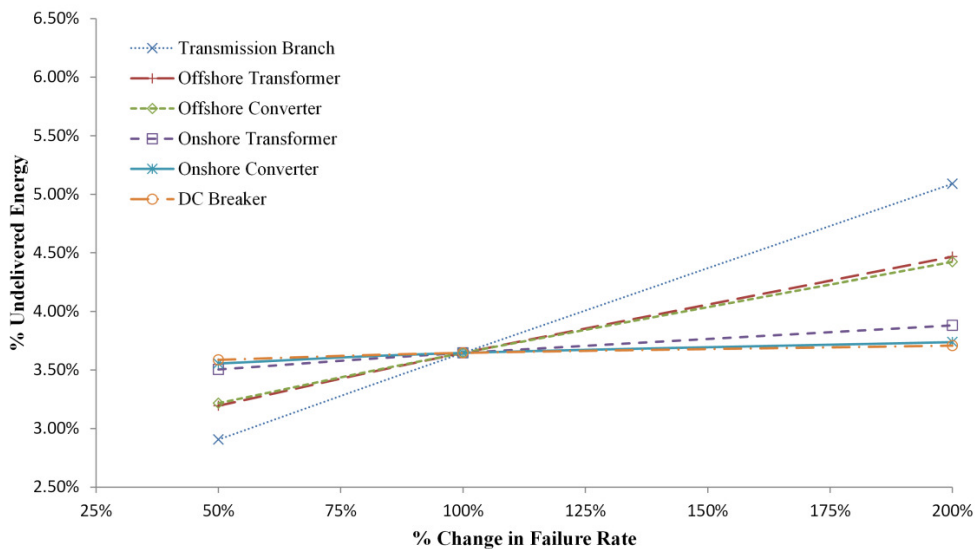


Figure 5.1 - Component sensitivity to failure rate for Dogger Bank multi-terminal grid scenario

Figure 5.1 shows that, in this scenario, the overall grid reliability is most sensitive to variations in the failure rate of transmission branches. A doubling of the failure rate leads to a 40% increase in the overall level of undelivered energy rising from a central case figure of 3.65% to 5.09%. Conversely, if the failure rate is halved the level of undelivered energy reduces by one fifth to 2.91%. The multi-terminal grid option is also found to be sensitive to the failure rate of both offshore transformers and converters. The impact of doubling the failure rate for each of these components is similar and leads to a 22.5% rise in the expected level of undelivered energy for offshore transformers and 21.3% for offshore converters at 4.47% and 4.42% respectively. Similarly a halving of the failure rate for offshore transformers and converters leads to 12.3% and 11.7% reductions in the overall undelivered energy respectively.

In the case of transmission branches and offshore transformers these results reflect the large repair times associated with these fault types and show that faults of these components account for much of the expected undelivered energy. For offshore converter faults the results reflect that the frequency of failures for these components is already high meaning that they too account for a large proportion of undelivered energy despite having relatively fast repair times. It must also be noted that failure of an offshore transformer or offshore converter automatically leads to a loss of power output from the wind farm in question. This is not necessarily the case for transmission branch faults due to the availability of an alternative transmission path for certain faults in the multi-terminal grid option. The results also show that variations in the failure rate of onshore components and DCCBs have a much lower impact on the level of undelivered energy. Onshore transformer faults do still have a relatively long repair time associated with them so a doubling of the failure rate leads to a small increase in the overall undelivered energy of around 6.5% whereas a halving of the failure rate reduces the level by almost 4%. For both onshore converters and DCCBs the influence of variations in the failure rate is smaller still showing that the overall results are not particularly sensitive to the input values used for these components. For all the components the undelivered energy can be broadly said to vary linearly with failure rate as would be expected with the repair parameters remaining fixed for each scenario.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

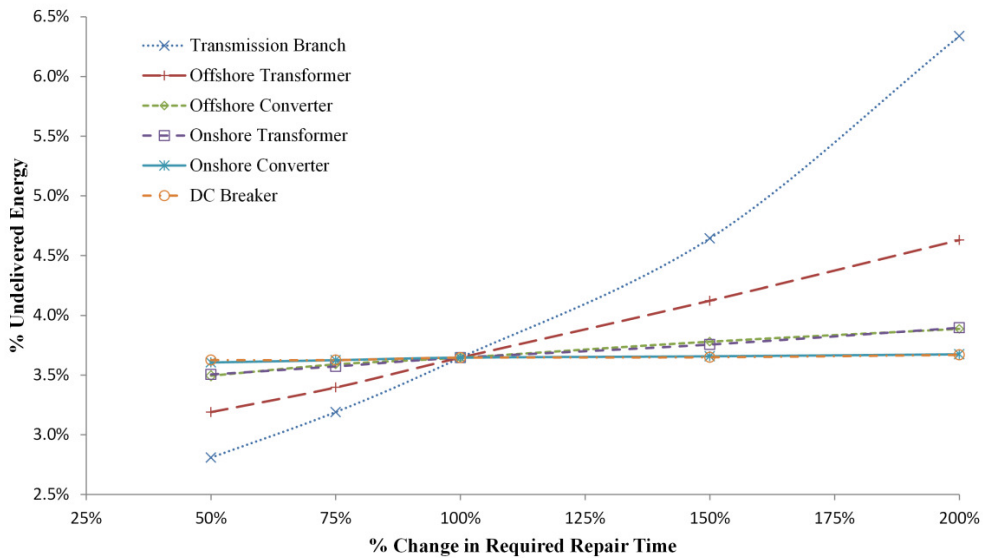


Figure 5.2 - Component sensitivity to repair rate for Dogger Bank multi-terminal grid scenario

Figure 5.2 shows the sensitivity of the grid reliability performance to individual component repair rates and again it is found that transmission branches are the most influential component followed by offshore transformers. Given the nature of major offshore component repairs, a strong non-linear trend is apparent in the results for these components which reflect the fact that as the size of the required weather window increases there is an exponential increase in the corresponding average calculated repair time for these components, as evidenced in Section 4.3.2. To illustrate this, results are taken for repair rate variations at 50%, 75%, 150% and 200% of the values used for the central case reliability study. For transmission branch failures an increase in repair calculation input values to 150% of the central case leads to an increase in the overall expected undelivered energy of 27%, up from 3.65% to 4.64%. If, however, the repair values are doubled in relation to the central case then the undelivered energy increases to 6.34% which is 74% higher than the central estimate. When repair values are halved there is a 23% reduction in expected undelivered energy which is significant although less severe than the increases observed at higher repair values due to the exponential component of the trend. For offshore transformer faults the trend is not as severe due to the less stringent mean significant wave height threshold applied for such faults. Nevertheless, a doubling of the repair requirements for offshore transformers leads to an extra 27% expected

undelivered energy whereas a halving of repair requirements reduces the undelivered energy by almost 13% for the multi-terminal grid option.

It was found that altering the frequency of offshore converter faults had a significant impact on overall reliability due to the fact this leads directly to the loss of all output from a single wind farm but this is not the case to the same extent for repairs whereby a doubling of the repair requirements leads to a less significant but still appreciable 6% increase in undelivered energy. This is due to the fact the central case average repair time for offshore converter faults is comparatively very small so repair times for these components are dominated by the time taken to safely gain access to the repair rather than the repair time itself. A much larger increase in the actual required repair time would therefore be required to have a meaningful impact on overall results. Onshore transformer faults are found to have a similarly low impact on overall reliability but the reasons for this are firstly due to the very low occurrence of such faults which means even large changes in the repair rates of such components have a relatively low impact overall and also that onshore converter faults do not necessarily lead to undelivered energy due to the availability of alternative transmission paths. The overall grid reliability is found to be particularly insensitive to both onshore converter and DCCB repair requirements with variations in both having negligible impact.

The results in Figure 5.2 are based on changes to both the TTR values relating to each component but also the fixed delay which is applied to transmission branch repairs as well as offshore and onshore transformer repairs. To assess what impact each of these separate repair time components has, the analysis is repeated such that the procurement delay associated with these three component repairs is fixed at the central case reliability estimate and only the TTR values are altered. The results are given in Figure 5.3. It is found that the actual length of time it takes to carry out a repair from the point at which all procurement delays are satisfied is the dominant feature for transmission branch faults but that for offshore and onshore transformer faults the procurement delay itself has a larger influence. This is evidenced in the results whereby a doubling of the required repair window only for transmission branch failures leads the expected level of undelivered energy to increase to 5.30%

from 3.65%. This accounts for 62% of the total increase that is found when the procurement delay is also doubled.

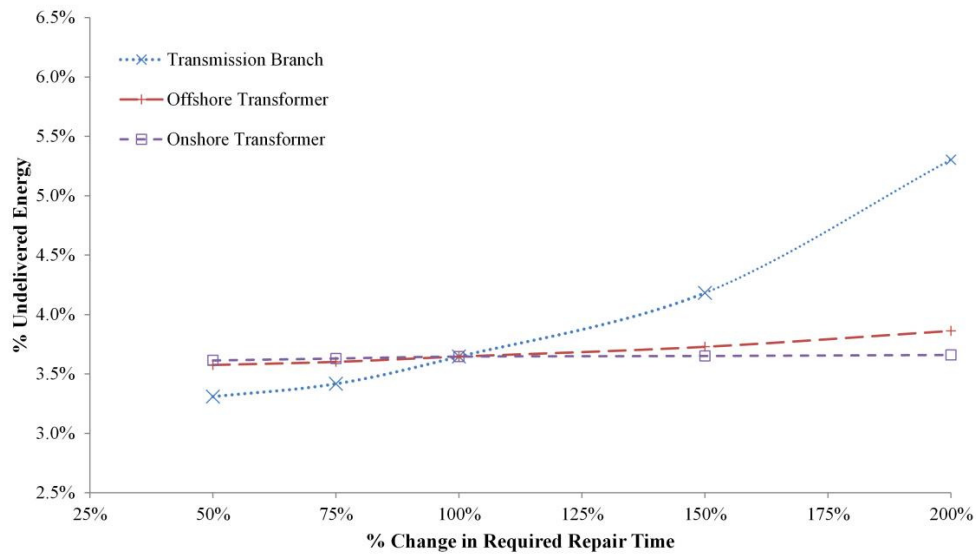


Figure 5.3 - Component sensitivity to repair time with fixed procurement delay

The influence of offshore transformer repair time is found to be less critical to overall results with a doubling of the required weather window leading to a more modest increase in overall undelivered energy to 3.86%. This change accounts for only 20% of the total increase found when both procurement delay and the repair weather window are doubled. The repair time of onshore transformers is found to have only a very small influence. These results are a reflection of the fact that the procurement delay is longer for transformer faults in the central case reliability scenario but also more importantly that the stringent mean significant wave height criteria associated with offshore transmission branch repairs has a large impact on repair time especially as the required weather window increases. This in turn has a major influence on the results that are produced from the modelling process.

To see how the sensitivity to different components' reliability performance varies depending on the chosen grid topology, the sensitivity study is also performed on a number of other grid options. The results for the Dogger Bank radial + grid option are shown in Figures 5.4 and 5.5.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

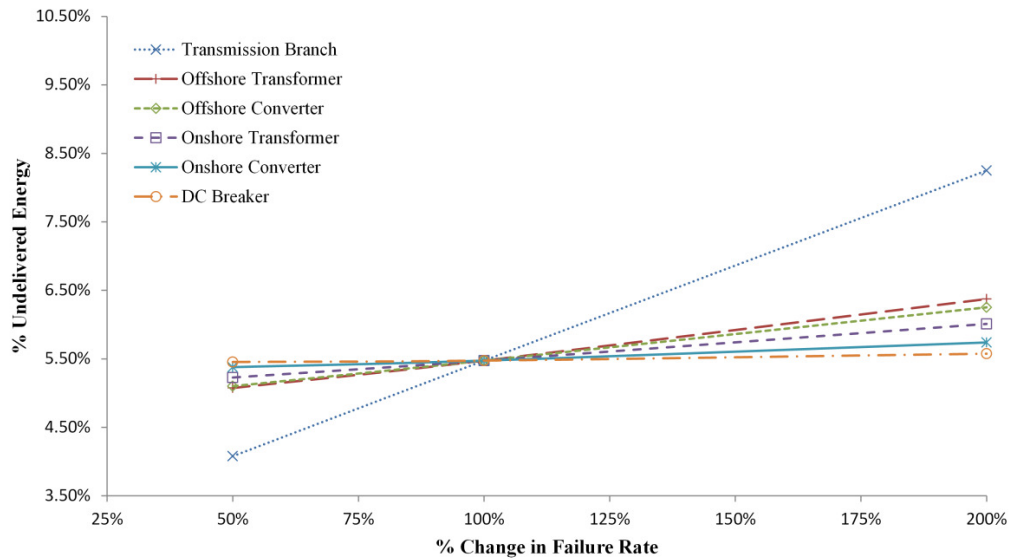


Figure 5.4 - Component sensitivity to failure rate for Dogger Bank radial+ grid scenario

Looking at the sensitivity to component failure rate for the radial+ grid options it can be shown that transmission branch faults are again a dominant factor in the overall undelivered energy and to an even greater extent than in the multi-terminal grid option. A doubling of the failure rate for transmission branches leads to a 50% increase in the undelivered energy up to 8.25% from 5.48%. In real terms this is almost double the increase in undelivered energy reported for the multi-terminal grid option. This reflects the inability of the radial+ grid to re-route power after a branch fault occurs which means all faults lead to energy curtailment and it highlights how the introduction of even a modest level of transmission path redundancy can help mitigate the impact of an increased level of unreliability.

In real terms the additional undelivered energy due to offshore transformers and offshore converter faults is roughly the same as for the multi-terminal grid option although compared with the central case result the changes are proportionally lower due to the high starting point of the radial+ grid option. This is to be expected as each of these fault types generally impacts on a single wind farm only, regardless of the grid design. Onshore transformers and onshore converters, like transmission branches, have the potential to impact the ability to deliver energy from multiple upstream wind farms so given the lack of redundant transmission paths in the radial+ grid option it is no surprise that the level of undelivered energy is more sensitive to

variations in the failure rate of these components than for the multi-terminal grid. Sensitivity to DCCB fault rates is also marginally higher in the radial+ case.

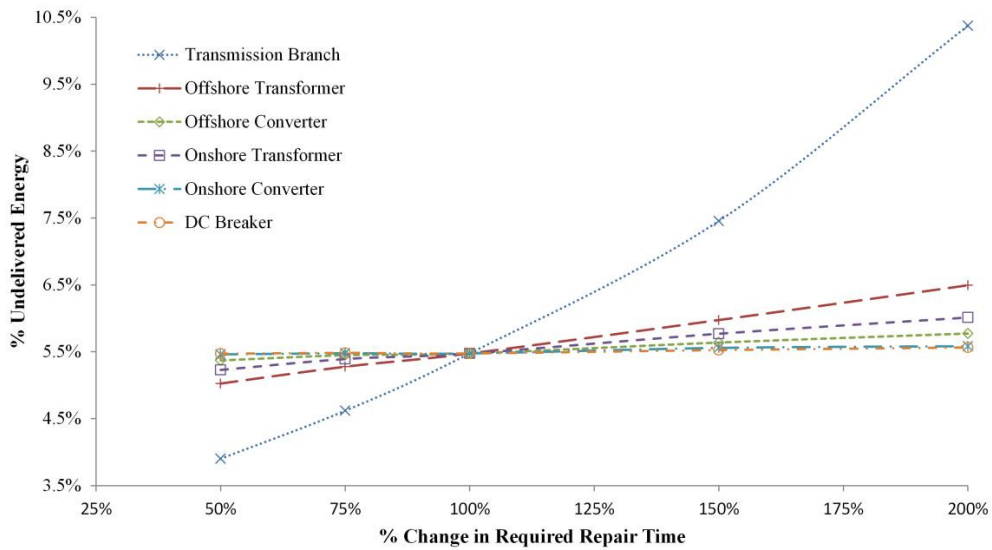


Figure 5.5 - Component sensitivity to repair rate for Dogger Bank radial+ grid scenario

The radial+ grid option is also found to be particularly sensitive to variations in the repair requirements for transmission branch faults as illustrated in Figure 5.5. A doubling of the repair requirements increases the overall undelivered energy by almost 90% up to 10.37% of the deliverable energy. As with the failure rate, the impact of varying the repair requirements of offshore transformer and offshore converter faults has a broadly similar impact on the overall undelivered energy in real terms compared with the multi-terminal grid option whereas variation in onshore transformer, onshore converter and DCCB faults have a comparatively higher impact than for the multi-terminal grid option. However, the overall sensitivity to onshore component and DCCB repair rates remains relatively small compared with offshore component repair rates, especially transmission branches.

The bipole Dogger Bank grid scenario is also investigated to determine how the additional level of redundancy introduced through this method impacts on the sensitivity of the grid to different component reliability performance. The results are given in Figures 5.6 and 5.7.

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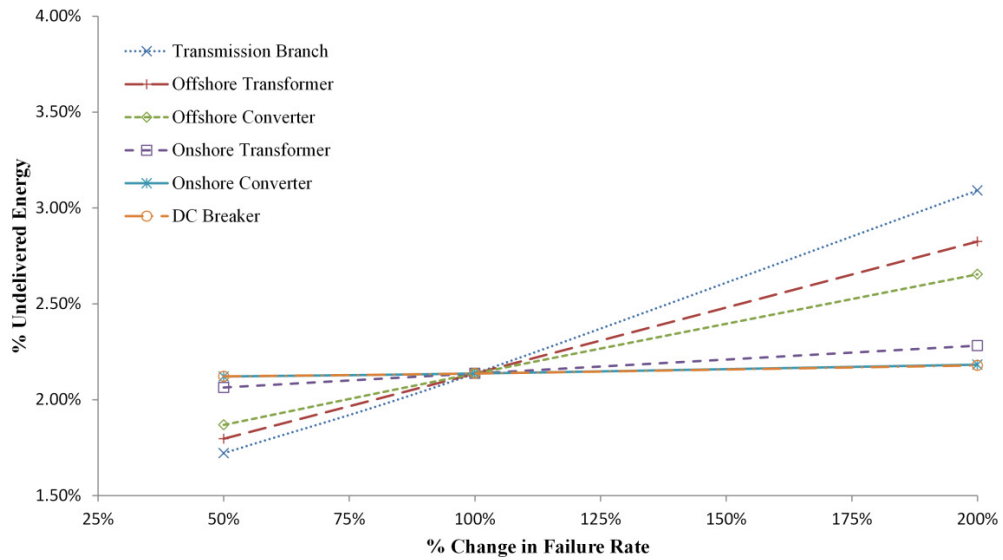


Figure 5.6 - Component sensitivity to failure rate for Dogger Bank bipole grid scenario

The bipole grid option is found to offer not only lower central case undelivered energy figures but a lower spread of results in real terms than the symmetrical monopole based multi-terminal grid option with the same high level topology. The proportional variation of results with failure rate for each component in comparison to respective central reliability predictions is found to be broadly similar for each grid option with, for example, a doubling of transmission branch failure rate increasing undelivered energy by 45% in the bipole option and 40% in the multi-terminal option. Offshore transformer faults are, however, found to have a noticeably larger proportional impact in the bipole scenario whereby a doubling in failure rate leads to a 32% increase in overall undelivered energy compared with the 22.5% increase found in the multi-terminal grid option. This can likely be attributed to their increased number in this grid option, although it should be noted that in real terms the increase is actually lower in the bipole scenario due to the inherent redundancy in the system design reducing the impact of individual faults.

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Figure 5.7 - Component sensitivity to repair rate for Dogger Bank bipole grid scenario

In terms of sensitivity to repair requirement these are again largely in line proportionally with the multi-terminal grid option but given the better central case reliability performance in real terms the changes in undelivered energy are smaller. Sensitivity to offshore transformer repair rate is also proportionally higher in the bipole grid option than in the multi-terminal grid configuration for the same reasons. This means that variations in transmission branch repair rate and offshore transformer repair rate have the highest impact on overall results and the remaining component repair times have relatively little impact on overall reliability so long as they remain reasonably close to central case predictions.

5.1.2 ISLES Case Study

To understand how sensitivity to individual component reliability impacts different offshore network designs the analysis is also performed on the ISLES DCCB grid option. The results are shown in Figures 5.8 and 5.9.

From Figure 5.8 it is clear that the sensitivity to variations in individual component failure rates is very different for the ISLES multi-terminal grid configuration than it is for the equivalent Dogger Bank grid option. It is found that transmission branch failures are not as important to the overall undelivered energy with a doubling of the failure rate increasing undelivered energy by 27% compared with 40% for the Dogger Bank multi-terminal grid. This is a reflection on the fact that there are more

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

available transmission paths to shore in the ISLES case and that these are also on average shorter than the two long distance links that connect the Dogger Bank case study meaning their initial failure rate is lower.

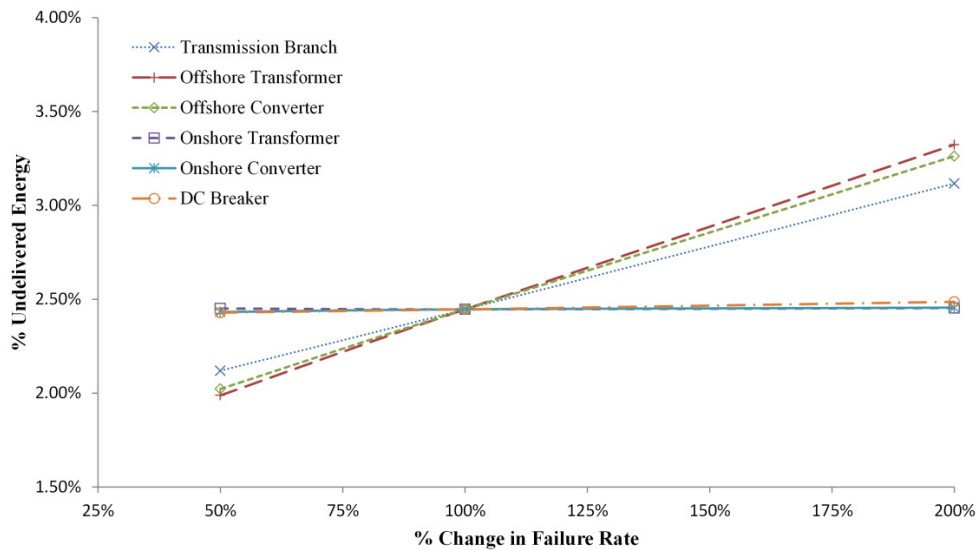


Figure 5.8 - Component sensitivity to failure rate for ISLES DCCB grid scenario

The relative importance of offshore transformer and offshore converter faults is also noticeably higher in the ISLES DCCB grid option with 35.8% and 33.3% rises in undelivered energy associated with a doubling of the failure rate for each of these components respectively. This is proportionally higher than for the Dogger Bank case study but in terms of actual GWh's undelivered energy the values are lower. This is to be expected given the lower generating capacity of the ISLES project and the lower central case percentage for undelivered energy. It is also found that there is very little sensitivity to variations in onshore component failure rates for the ISLES DCCB grid option which again can be explained by the fact that there are four alternative transmission paths to shore which can be utilised in the event that an outage occurs in any single transmission branch or associated onshore converter station. The impact of DCCB failure rate is also found to be negligible.

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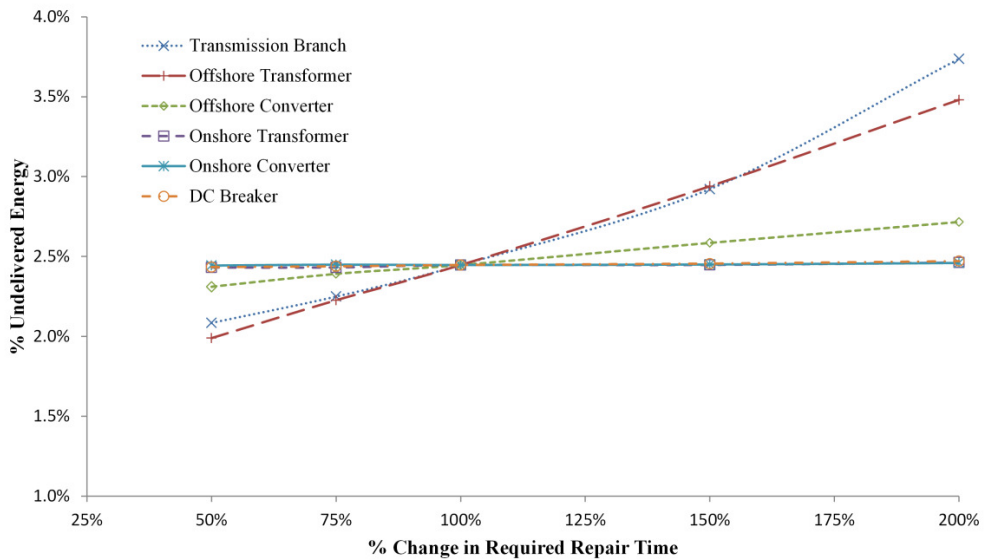


Figure 5.9 - Component sensitivity to repair rate for ISLES DCCB grid scenario

The sensitivity to the repair requirements for each of the components shows a similar pattern with results being most sensitive to variations in transmission branch and offshore transformer failure rates, as seen in Figure 5.9. The impact of each of these is almost equal for 50% reductions in repair requirements through to 50% increases, but if repair requirements are doubled then the strict weather window criteria associated with transmission branch repairs and the exponential growth in repair time dominates leading to a 52.7% increase in undelivered energy compared with a 42.2% increase when the transformer repair requirement is doubled. Offshore converter repair rates have less influence on overall results, as explained previously due the fact the physical repair time associated with them comprises only a small portion of the overall outage time such that a change in that portion has a relatively minor influence on overall average outage time. As with variations in their failure rate, the ISLES DCCB grid option has very low sensitivity to variations in the repair requirements of onshore components and DCCBs, again due to the ability to re-route power to other landing points.

Finally, the ISLES radial+ grid option is investigated through the sensitivity analysis and the results for sensitivity to failure and repair rates respectively are presented in Figures 5.10 and 5.11.

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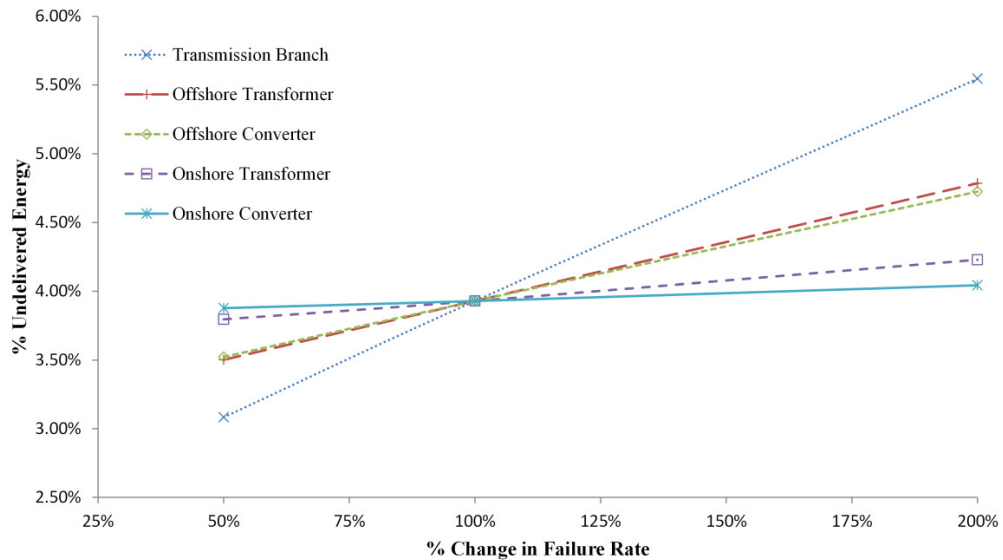


Figure 5.10 - Component sensitivity to failure rate for ISLES radial+ grid scenario

Once again it is found that a grid design that lacks alternative transmission routes to shore is highly sensitive to the propensity of high impact transmission branch failures. For the ISLES radial+ grid the transmission branch failure rate is shown to be a dominant factor in the overall reliability as a doubling of the failure rate leads to 5.55% undelivered energy up from a central estimate of 3.93%, which is a 41% rise.

Unsurprisingly the impact of offshore transformer and offshore converter failure rate variations, which impact primarily the output from individual wind farms, is comparable to the multi-terminal grid option in real terms. However, due to the poorer reliability performance of other aspects of the grid design, they make up a lower proportion of the overall curtailments for the ISLES radial+ grid design with a doubling of the failure rate leading to 22% and 20% increases in undelivered energy respectively. Whereas for the multi-terminal DCCB grid option, onshore converter and transformer failure rate variations have negligible impact on the overall grid reliability, in the radial + grid option the failure rate of these components does have a discernible impact. A doubling of onshore transformer failure rate leads to a 7.6% rise in undelivered energy whereas the rise is 2.9% if the onshore converter failure rate is doubled. This again emphasises that grids without inherent redundancy and therefore alternate transmission paths for delivering energy to shore are susceptible to variations in the failure rate of all component types, regardless of location within the grid.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

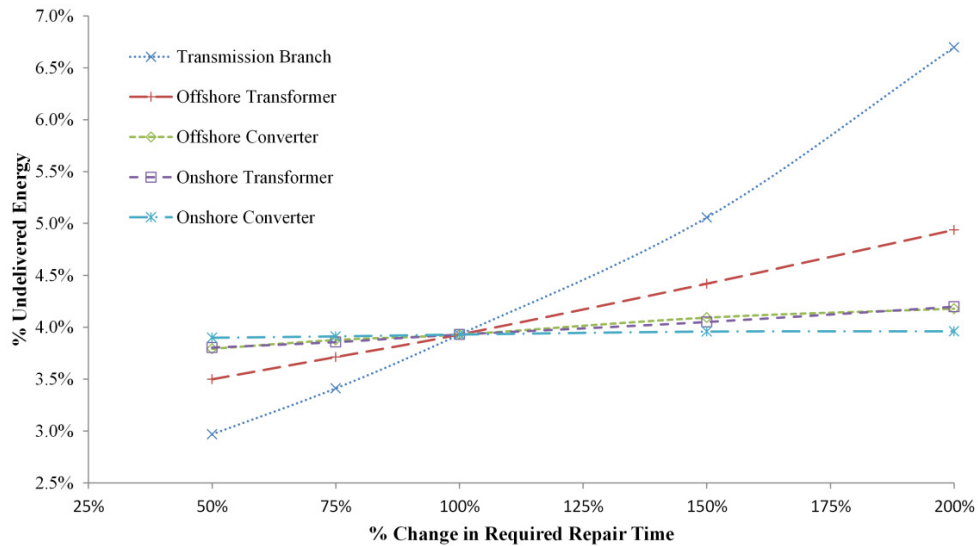


Figure 5.11 - Component sensitivity to repair rate for ISLES radial+ grid scenario

Figure 5.11 shows the sensitivity of the ISLES radial+ grid option to component repair requirements and, in contrast to the multi-terminal ISLES grid, overall results are most sensitive to transmission branch repair rates by a clear margin which reflects the inability to re-route power in the event of a long term cable outage. A doubling of the repair requirements for transmission branch failures increases overall undelivered energy by some 70% in the ISLES radial+ grid option showing once again that not only do grids that lack redundant transmission paths have poorer reliability performance overall but they are also more susceptible to large variations in the reliability performance depending on the repair rate of certain components. Sensitivity to the remaining components is largely in line with the multi-terminal DCCB grid option with variations in offshore transformer repair requirements contributing reasonably strongly to the overall results, offshore converter and onshore transformers contributing to a reduced extent and onshore converters having a negligible impact.

5.1.3 Conclusion

The results of the sensitivity studies on the various grid options help to gain an understanding of what the drivers are behind reliability in different offshore grid designs. It is found that in all grid options the reliability performance of transmission branches in terms of failure rate and repair times has the largest or close to the largest influence on the overall levels of undelivered energy. Given that there is also a large

degree of uncertainty as to the assumptions made regarding the failure rate of transmission branches this study allows an evaluation of what results alternative assumptions might yield. For example, given a lack of published data, it is assumed that two bundled cables will have identical failure rate to a single buried cable. However, if data were made available that challenged this assumption then the sensitivity analysis provides a means of identifying the implications of this.

Similarly the reliability of offshore transformers is found to play an important role in the final levels of energy curtailment. These are low probability but high impact fault events which explains why even a modest change in the frequency or duration of such events can have a significant influence on final results. This study has assumed no redundancy is incorporated into the design of transformer systems so future work might look to explore options that may include redundancy as the sensitivity analysis suggests this could have a significant impact on the final results. Discussion with industry experts also revealed how improvements in the design and installation of transformer systems could lead to shorter maintenance outages or even allow certain scheduled maintenance activities to be carried out without an outage of the component. Future work might also therefore look to investigate what impact this and other potential design improvements could have on the reliability assumptions used in this study.

Offshore converter and transformer components influence the ability to transmit power from one generation source but they do not influence the ability of the rest of the grid to transmit power unlike certain transmission branch failures or onshore faults within radial based grid options. This means that, regardless of the grid topology downstream of these assets, they have largely the same influence on undelivered energy in real terms. For grids with good reliability performance in general, variations in the reliability of these components has a proportionally higher influence on overall results than for grids with poorer overall reliability in which transmission branch failures tend to be the dominant influence on overall performance. It is also found that some component types have a relatively low impact on overall reliability, especially in multi-terminal or meshed grid options where variation in the reliability of, for example, onshore substation based

components has a negligible impact on the final results due to faster initial repair time estimates and the ability to re-route power to other onshore landing points.

When comparing results from the ISLES and Dogger Bank based grid options it is clear that the number of generation sources, transmission routes to shore and the level of interconnection within the grid all have a significant impact on which components dominate the overall reliability performance of the grid. The multi-terminal ISLES grid option with a larger number of transmission paths to shore and more dispersed generation, for example, is found to be less sensitive to transmission branch failures than the symmetrical monopole based Dogger Bank grid options investigated. The same is true of the Dogger Bank bipole grid option where the real terms variations in undelivered due to component reliability performance are reduced by the introduction of a grid configuration with inherent redundancy to allow partial power transmission under certain fault conditions. This backs up the findings in Chapter 4 which suggested that grid options with inherent redundancy in the available transmission routes for energy delivery are able to minimise the impact of variations in individual component reliability performance. This helps not only lower the central case reliability estimates but also lowers the level of uncertainty within results by limiting the likely spread of possible results between the best and worst case scenarios. The ability to minimise the risk associated with reliability performance, as discussed in Section 4.2.6, is likely to be an important consideration in the final design of any offshore grid.

The sensitivity study presented here also highlights areas in which industry could make targeted efforts to improve or optimise performance in terms of minimising both the number of component failures and the length of downtime when failures do occur. Failures could be minimised by ensuring best practice design and installation procedures but also potentially through information campaigns to minimise external faults like anchor drags or trawling in offshore transmission corridors. The holding of spare components and investment in appropriate offshore repair vessels could also significantly reduce the lead time on repair of certain components but as ever the potential benefits of such measures must be weighed against the level of required investment.

5.2 The Value of Redundancy and the Impact of Different System States on Overall Reliability

To gain a further understanding of the drivers behind the reliability of offshore grid options and to help understand the benefits of different features of a design (such as an extra route to shore or a bipole connection), an investigation is carried out which looks at the time spent in various failure states and the contribution that being in those states makes to the overall undelivered energy. The results will show that there is clear value in performing a full reliability analysis which considers multiple overlapping fault conditions rather than simply relying on a test of N-1 security. The investigation differentiates between system states based on the level of connected wind energy and the level of connected shore capacity. A failure state is taken to mean any fault or combination of faults which leads to a state where not all of the available offshore wind energy can be transmitted to shore while a full system outage is any combination of faults on the offshore grid which would mean none of the available wind power could be transmitted. Results focus on the most commonly occurring system states for a number of the previously investigated grid options. Once more the Dogger Bank multi-terminal grid option, shown for reference in Figure 5.12, is used as the basis of the investigation and results for the best, central and worst case reliability scenarios are presented in Figures 5.13-5.15.

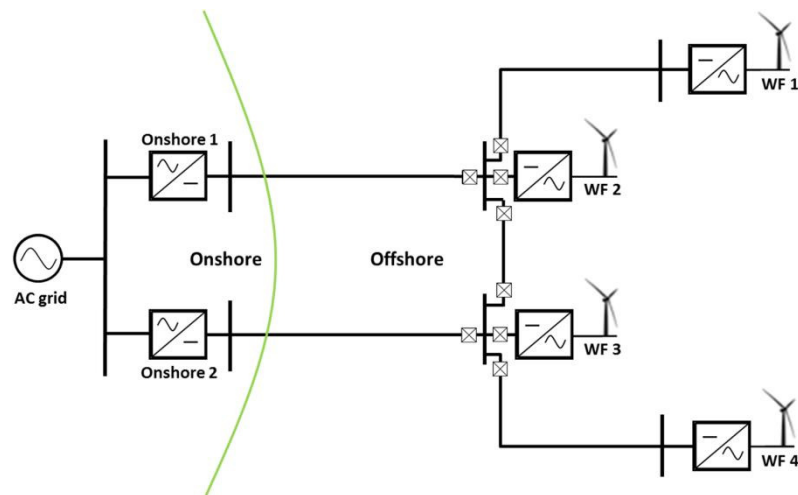


Figure 5.12 - Dogger Bank multi-terminal grid option

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

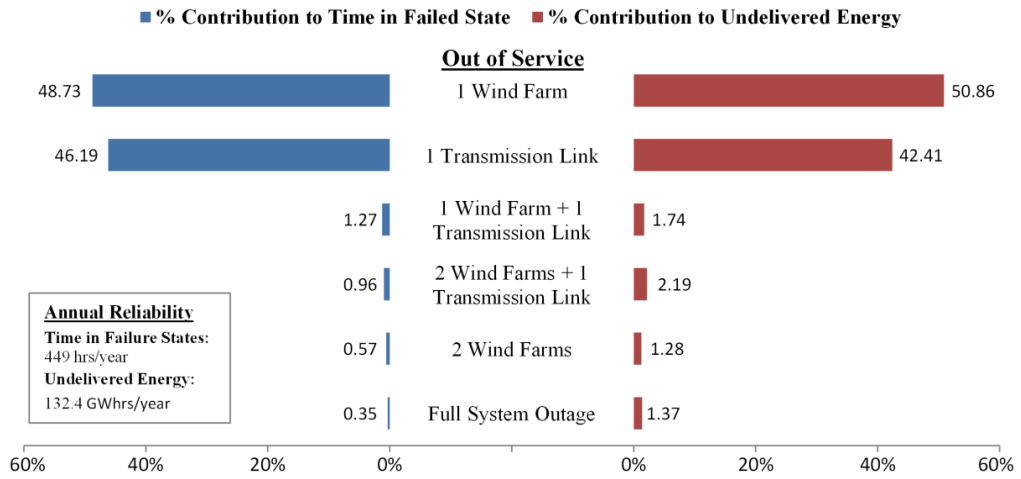


Figure 5.13 - Time spent in system state and contribution to undelivered energy for multi-terminal grid option with best case reliability scenario

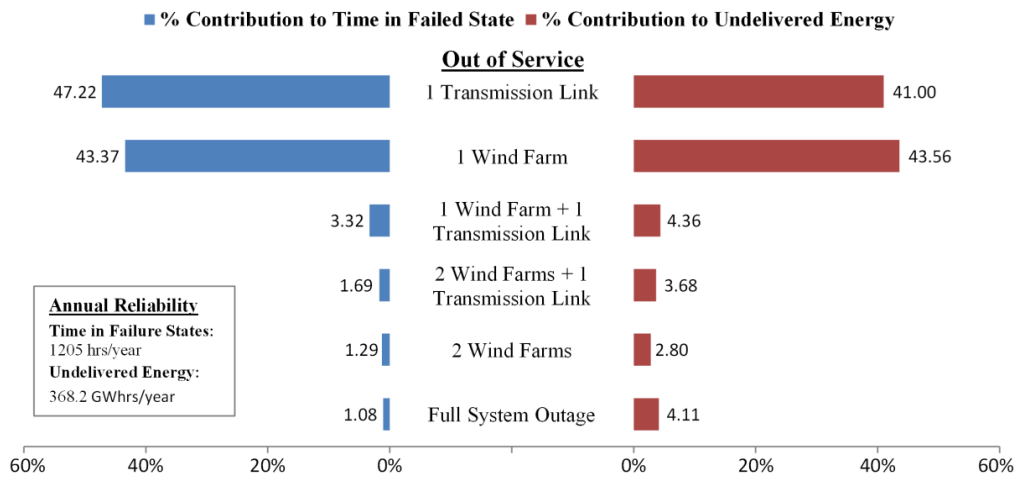


Figure 5.14 - Time spent in system state and contribution to undelivered energy for multi-terminal grid option with central case reliability scenario

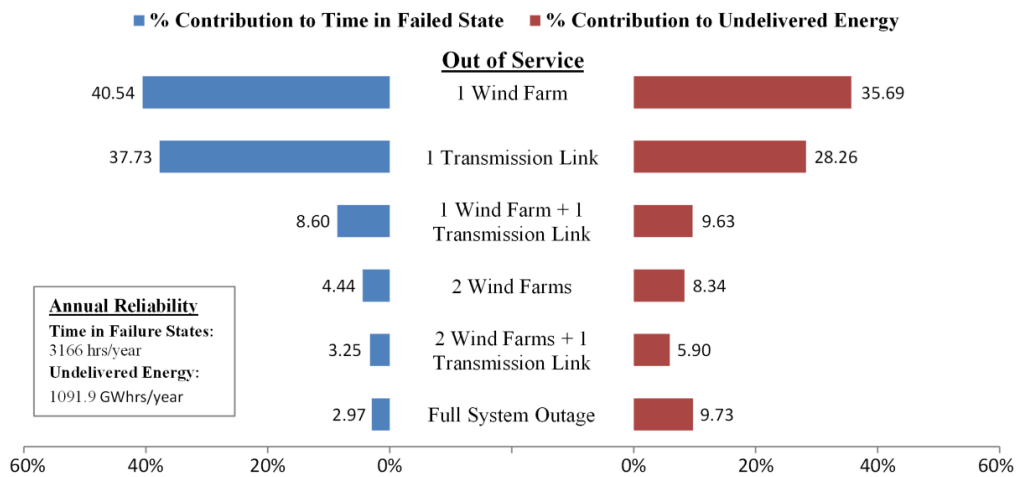


Figure 5.15 - Time spent in system state and contribution to undelivered energy for multi-terminal grid option with worst case reliability scenario

In each of the reliability scenarios it is found that the two most commonly occurring system failure states are for a single wind farm or a single transmission link to be out of service. Faults occurring at any offshore substation (converter or transformer) or on the transmission branches linking WF1 or WF4 to the main transmission routes to shore will lead to a single wind farm being out of service. Faults occurring at either of the onshore substations (converter or transformer) or on either of the two main transmission cable routes will result in a single transmission link being out of service. In the best case reliability scenario these two system states account for close to 96% of the 449 hrs/year on average that the system spends in some form of failed state. The time spent with 1 wind farm out of service accounts for 48.7% of the total time in failed states or 219 hours and the energy curtailment associated with this accounts on average for 50.9% of the 132.4 GWh undelivered energy per year. This compares to the 207 hours spent with 1 transmission link out of service which accounts for 42.4% of the undelivered energy. Despite the loss of a transmission link reducing the transfer capacity by a half, energy will only be curtailed if the combined power output of the four wind farms is above the remaining transmission capacity. This compares to the loss of a wind farm which only accounts for one quarter of the generation but the full potential output associated with that disconnected wind farm will be curtailed which results in the higher proportional energy curtailment. In the best case reliability scenario, situations with multiple overlapping faults account for only around 4% of the time spent in failed states but these in turn account for around 7% of the undelivered energy reflecting the higher impact associated with N-2 or beyond fault conditions. This is partly due to the simple fact that more of the system is affected when such conditions occur but perhaps also reflects that multiple overlapping fault states are more likely to occur in winter periods with poor sea state conditions making component repair difficult. As discussed previously winter periods also tend to coincide with the highest output wind conditions.

As individual components become less reliable and take longer to repair it is found not only that the amount of time spent in failed states increases, but also that the proportion of that time spent in N-2 or worse conditions increases. In the central case reliability scenario the same two failure states still dominate the results and account for just over 90% of the now 1206 hrs/year on average that are spent in failed states.

These states in turn account for around 85% of the total undelivered energy which is 368 GWh/year on average. However, N-2 or worse fault conditions now account for nearly 10% of the time spent in failed states and these account for the remaining 15% of undelivered energy. The results further demonstrate that certain low probability events can have a large impact on overall undelivered energy. This is shown in the central case results where a full system outage, which would require both transmission links to be out of service simultaneously or a larger number of overlapping faults is only expected to occur for 13 hrs/year on average, a little over 1% of the time spent in failed states, and yet has a total contribution to expected undelivered energy of over 4%. This is almost the same impact as the situation of a wind farm and a transmission branch being out of service simultaneously despite the expectation that three times as many hours will be spent in the latter scenario.

From the worst case reliability scenario it can be seen that as component reliability becomes poor, the time spent in states with multiple overlapping fault conditions increases significantly and adds to the increase in undelivered energy which jumps to 1092 GWh/year. In this scenario the two most common fault conditions now account for around 78% of the 3166 hrs/year spent in some form of failed state but these account for just 64% of the undelivered energy. This means that the remaining 22% of time spent in faulted states is made up of N-2 or worse fault conditions and these account for 36% of the 1092 GWh/year of expected undelivered energy.

Figures 5.17-5.19 show the results of the same investigation when applied to the meshed Dogger Bank grid option, which is depicted in Figure 5.16. In this scenario the additional transmission route between WF1 and WF4 acts to reduce the likelihood of a single wind farm being out of service by allowing an alternate transmission path in the event of faults on either of the two transmission paths linking WF1 and WF4 to WF2 and WF3 respectively. Although there are now more components in the system and therefore more chance of a component being out of service, the time spent in what are considered to be failed states actually reduces. This is because certain fault conditions in a meshed grid system do not, themselves, constitute the loss of ability to transmit power. In the Dogger Bank scenario the change is relatively minor. For example, in the central case reliability scenario the

number of hours spent in failed states is 1205 for the multi-terminal grid option but reduces slightly to 1145 hours for the meshed system.

It can also be shown that there is a greater reduction in time spent in failed states for certain states compared with others. For example, the amount of time spent with one wind farm failed or variations of overlapping faults involving the loss of single wind farms is significantly reduced in each of the reliability scenarios for the meshed grid compared with the multi-terminal grid. In total, for the central case reliability scenario, around 18 GWh/year of extra energy is delivered using the meshed network with the impact on undelivered energy associated with single wind farm outages reducing by 8 GWh/year. The impact of the condition of one transmission link and two wind farms being out of service is reduced by some 12 GWh/year. This shows that the meshed system guards against this extreme event, however in doing so it does increase the time spent in the less severe scenario of one transmission link and one wind farm disconnected.

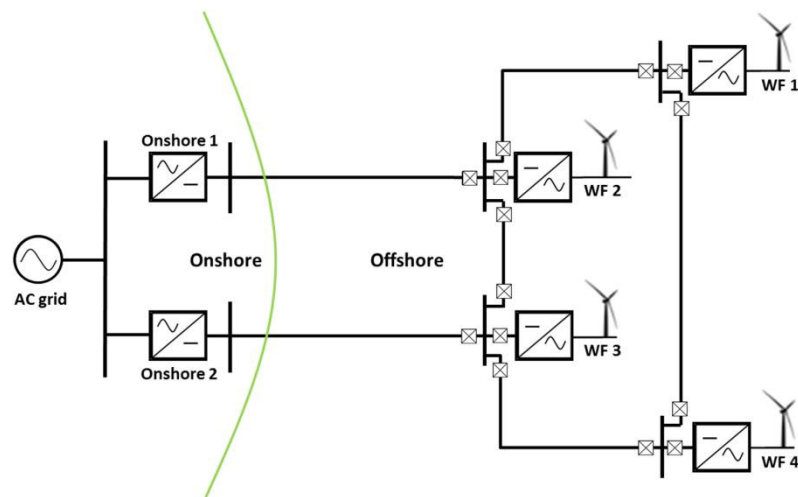


Figure 5.16 - Dogger Bank meshed grid option

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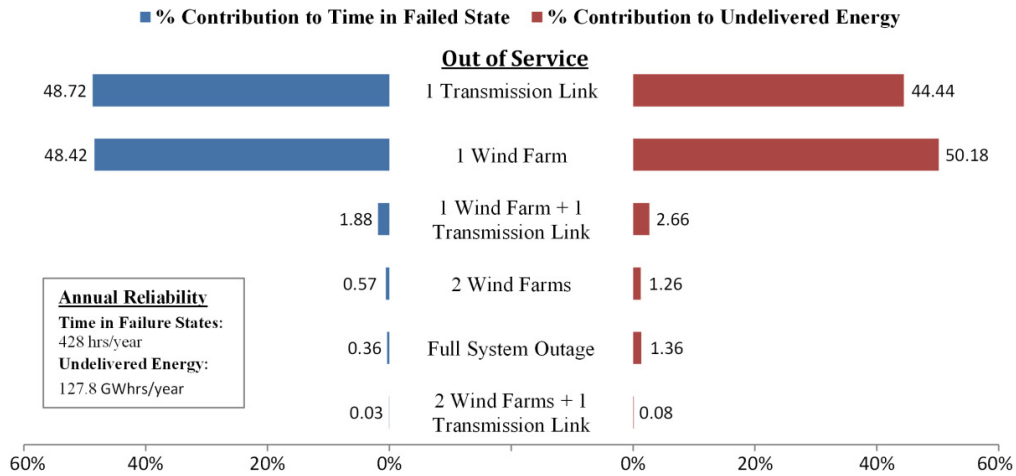


Figure 5.17 - Time spent in system state and contribution to undelivered energy for meshed grid option with best case reliability scenario

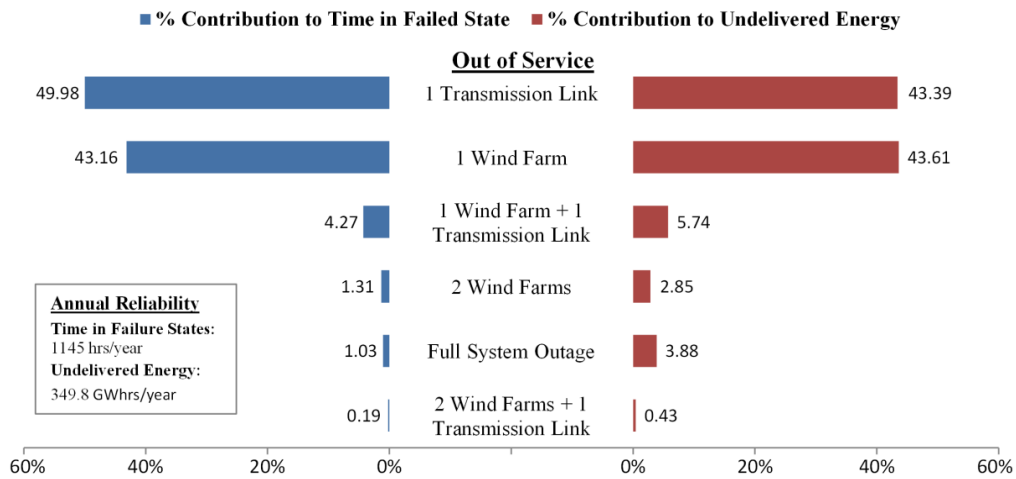


Figure 5.18 - Time spent in system state and contribution to undelivered energy for meshed grid option with central case reliability scenario

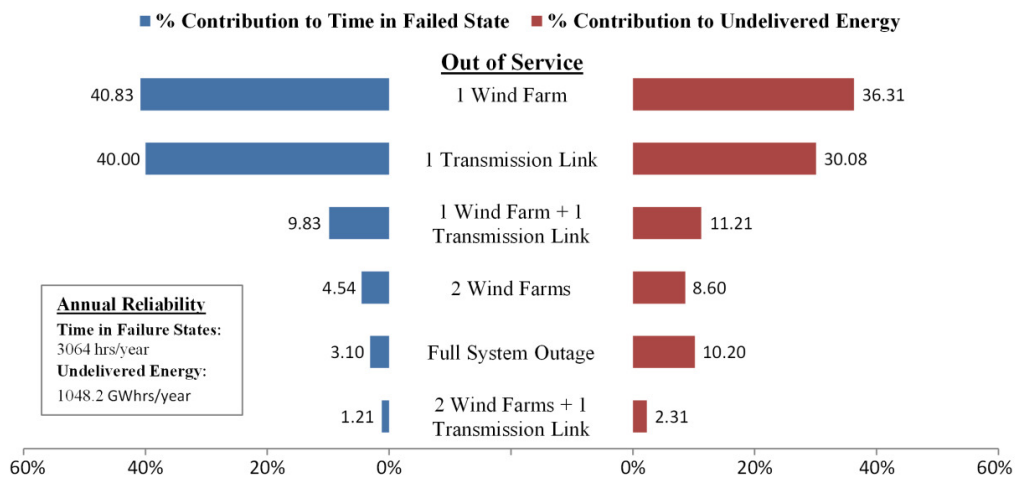


Figure 5.19 - Time spent in system state and contribution to undelivered energy for meshed grid option with worst case reliability scenario

The radial+ grid option, shown in Figure 5.20 is also investigated to determine the impact of reducing the level of redundant transmission paths in the system as opposed to increasing it. The results are given in Figures 5.21-5.23. The radial+ grid essentially operates as two autonomous three-terminal systems with no connection between them to re-route power. This inherently reduces the number of potential operating states and means that the two most common failure states dominate results even further than in the multi-terminal system. The loss of a transmission link in the radial+ grid option equates to the loss of the full grid section as does the loss of connection to both connected wind farms simultaneously.

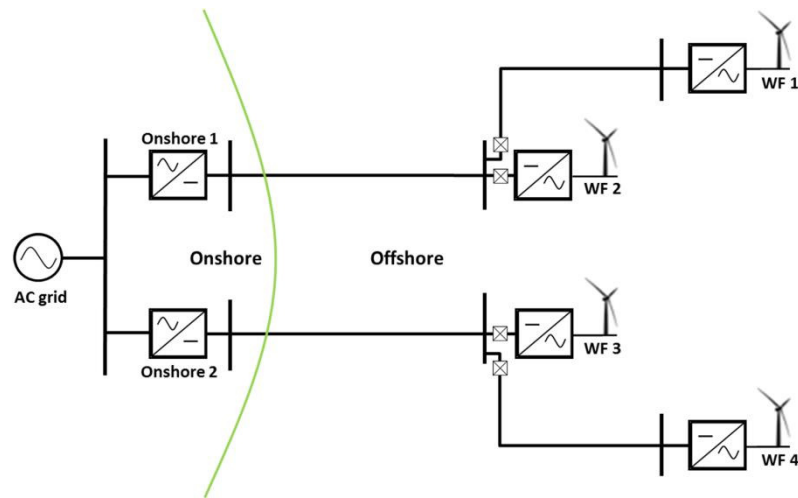


Figure 5.20 - Dogger Bank radial+ grid option

The main difference that can be observed between the radial+ and the more interconnected systems is that the absence of interconnection greatly increases the level of undelivered energy with an additional 200 GWh/year in the central case reliability study. This is almost entirely accounted for by the increase in undelivered energy associated with the lack of an interconnecting transmission link with grid section outages accounting for 63% of undelivered energy. This means that although the undelivered energy attributable to wind farm outages remains constant in real terms, a large drop is seen in the overall proportion due to single wind farm outages which account for just 29% of total undelivered energy. Multiple overlapping fault conditions are also less common and account for only 4% of the time in failed states and 8% of the undelivered energy.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

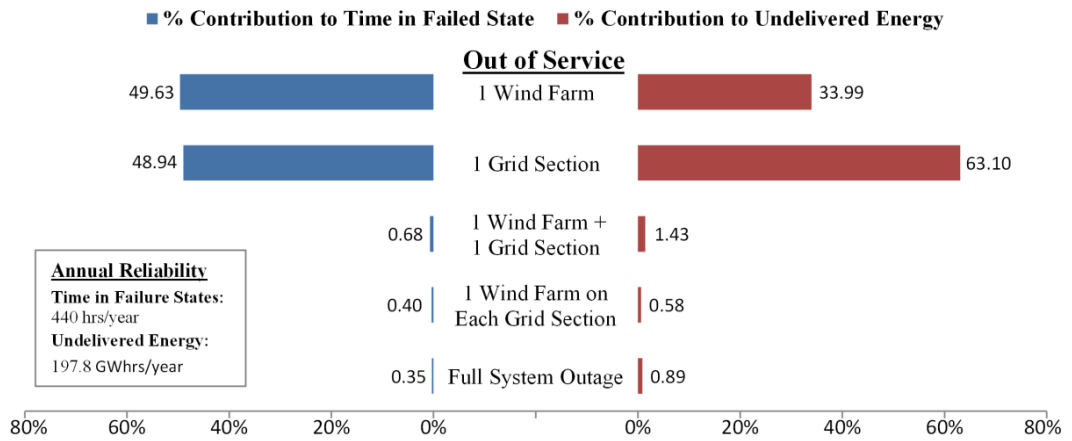


Figure 5.21 - Time spent in system state and contribution to undelivered energy for radial+ grid option with best case reliability scenario

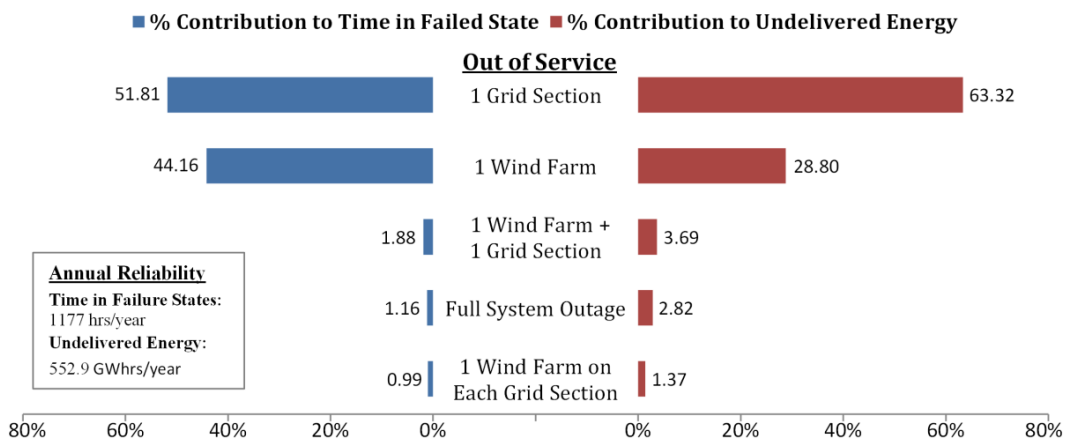


Figure 5.22 - Time spent in system state and contribution to undelivered energy for radial+ grid option with central case reliability scenario

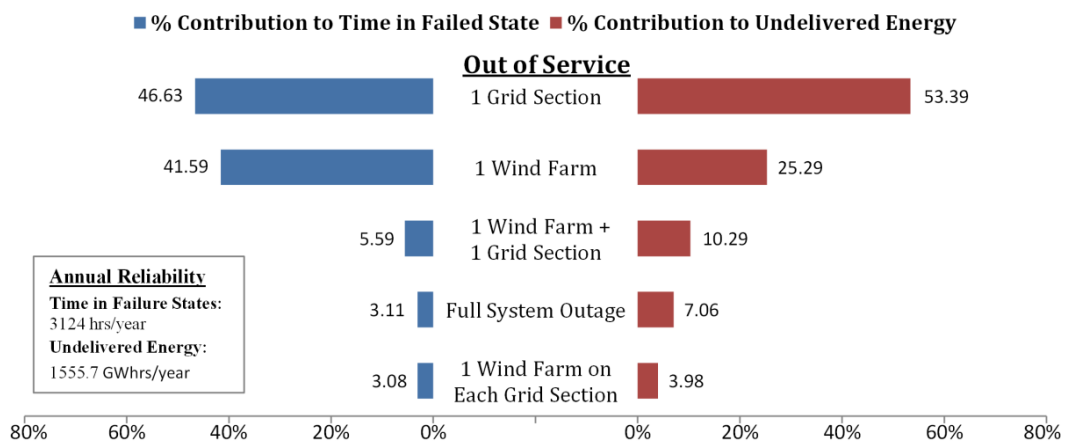


Figure 5.23 - Time spent in system state and contribution to undelivered energy for radial+ grid option with worst case reliability scenario

Finally, the Dogger Bank bipole grid option, shown in Figure 5.24, is investigated to help understand how a change in grid configuration can influence the driving factors behind offshore grid reliability. Again, results are presented for best, central and worst case reliability scenarios in Figures 5.25-5.27.

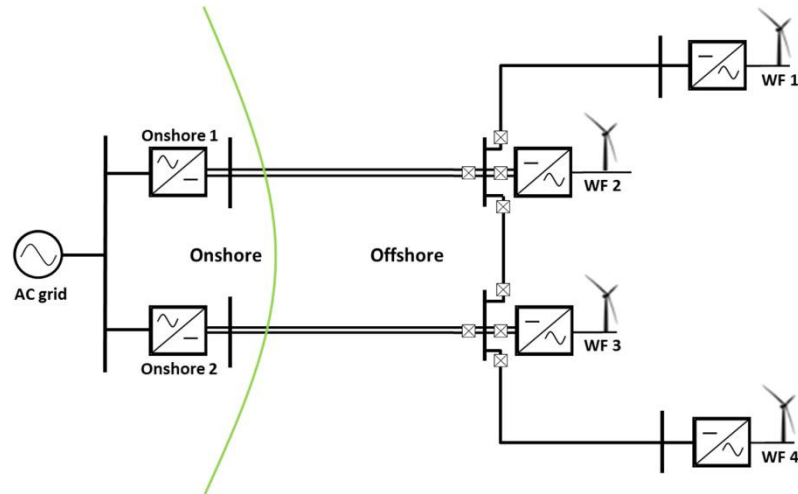


Figure 5.24 - Dogger Bank bipole grid option

The ability to make use of 50% transmission capacity in the event of transmission branch, converter and transformer failures means there are numerous possible system states but the six most influential are presented. It is found that in the bipole grid scenario the most common failure state is for one system pole to be out of service due to any one of the above component faults occurring on either of the two main transmission routes to shore. The total amount of time spent in failed states is actually significantly higher in the bipole grid option which can be accounted for by the underlying assumptions for this grid option. Firstly it is assumed that an additional transformer is required at each converter station and also that the two transmission cables associated with each pole of the bipole configuration in each transmission branch are buried apart such that single fault events cause only one cable to be lost from service. This is in contrast with the single bundled cable pair that is assumed for symmetrical monopole systems where certain cable failure modes would cause both to be lost.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

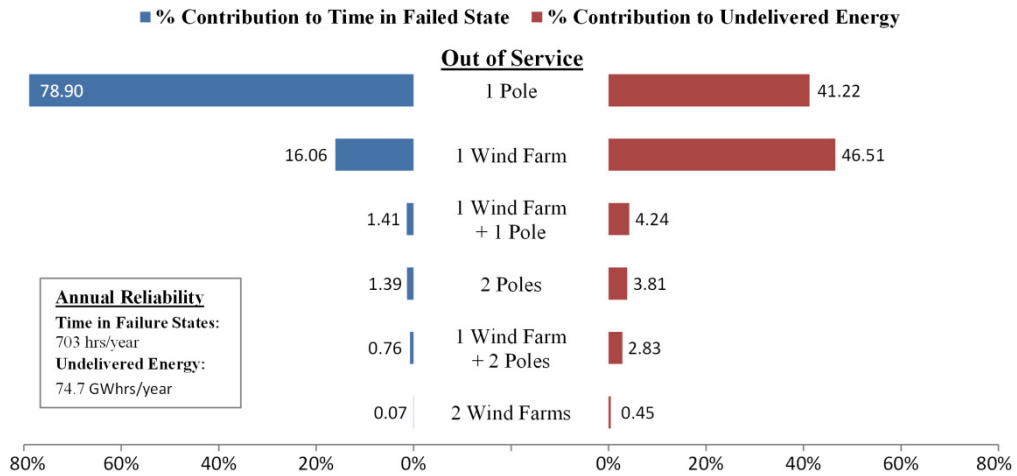


Figure 5.25 - Time spent in system state and contribution to undelivered energy for bipole grid option with best case reliability scenario

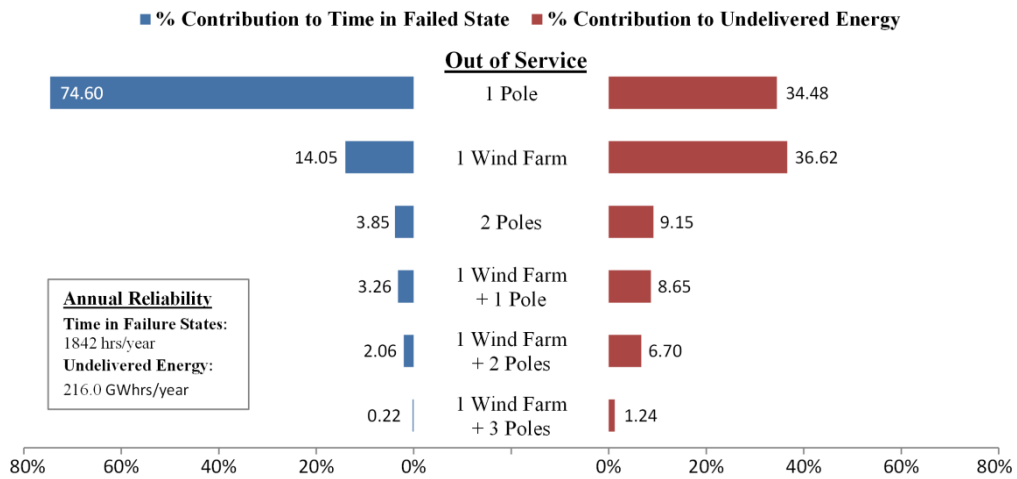


Figure 5.26 - Time spent in system state and contribution to undelivered energy for bipole grid option with central case reliability scenario

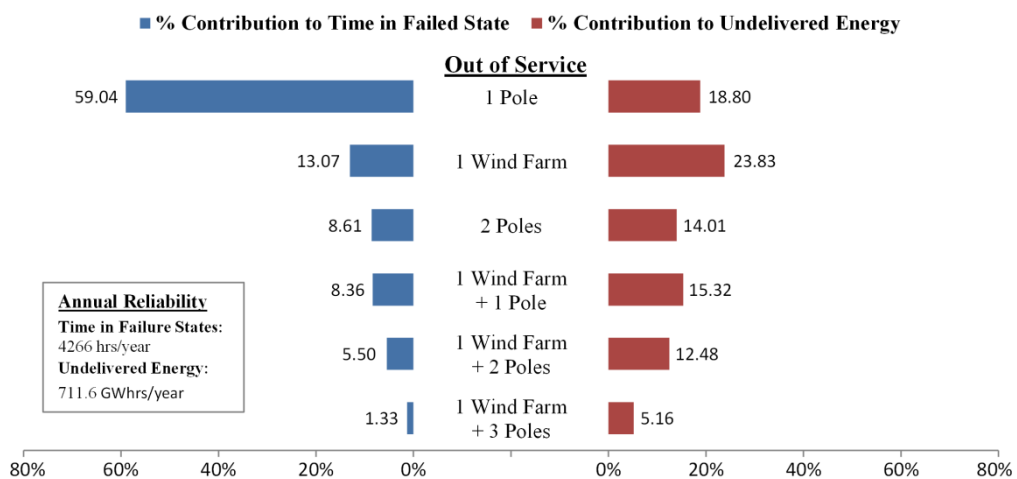


Figure 5.27 - Time spent in system state and contribution to undelivered energy for bipole grid option with worst case reliability scenario

It is found that the vast majority of the time spent in failure states is attributable to a single pole outage on the grid. For example, in the central reliability scenario this accounts for 75% of the 1842 outage hours. Despite the greatly increased time spent in this failed state the overall energy curtailment is greatly reduced for the bipole grid due to the inherent redundancy in the design. In the central case, despite the vast amount of time in all failed states being spent in the state of one pole outage, this accounts for less than 35% of the total undelivered energy. Only 14% of the time is spent with a full wind farm outage and yet these periods account for a further 37% of the total undelivered energy. The remaining time in failed states and undelivered energy is split across numerous different system states incurred through overlapping fault conditions with the third most frequent being the loss of two transmission poles, either a single pole from each transmission branch or one full transmission branch, which accounts for a further 4% of time and 9% of the undelivered energy.

5.2.1 Conclusion

This analysis sheds further light on the drivers behind offshore grid reliability by showing the time that can be expected to be spent in various system fail states and how much each of those states contributes to the overall undelivered energy for various grid design options and reliability scenarios. It is found that N-1 fault states are by far the most common occurrence and approximately the same amount of time is spent in the condition of one wind farm being disconnected from the grid as in the condition of a transmission link to shore being out of service. Unsurprisingly these states also contribute most to the total level of undelivered energy but the level of this contribution varies depending on the grid design.

It is found that overlapping fault conditions are relatively less common but, as expected, become more prominent as the reliability performance of components becomes worse. Such events are high impact compared to N-1 fault conditions so tend to have a proportionally larger contribution to the total level of undelivered energy. The ability to capture these overlapping events is therefore an important part of determining overall reliability performance that may be missed by more basic studies into offshore grid reliability that only look to capture the influence of individual fault situations in isolation. Finally, it is found that the grid design and

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

configuration has a large impact on the amount of time spent in different failure states which helps to explain the resulting variations in final calculated reliability performance between respective grid options.

5.3 Impact of Climate on Reliability

One of the benefits of modelling weather access windows to determine repair times as opposed to relying on estimates of MTTR values is that the model can differentiate between different offshore locations which might have significantly different wind speed and wave height profiles. The importance of this is investigated by carrying out reliability assessment of particular grid options assuming a number of different climate regimes. The results presented thus far have all relied upon input climate data derived from real data gathered from the FINO 1 offshore meteorological station, as described in Section 3.3.2. This is found to be the most suitable source for replicating the conditions that are likely to be found for far offshore grid installations such as at Dogger Bank or what can be termed as exposed North Sea sites. However, conditions could vary significantly based on location with near shore or more sheltered locations likely to experience a significantly calmer climate regime than described by FINO. Conversely, Atlantic sites off the West of the UK like the ISLES proposal could potentially experience an even harsher climate regime with both higher wind speeds and rougher sea states. The ISLES study reports estimated average wind speeds of 10.6 m/s for the North ISLES area [1].

Appropriate climate data was identified from three dispersed North Sea locations and processed using the same methods as outlined for the FINO data to produce 100 year time series for implementation within the reliability model. The three additional locations for climate data across the North Sea are shown in Figure 5.28 [2, 3]. Represented in addition to the exposed North Sea FINO site are North East and South East UK coastal sites and a Dutch Coastal site taken to represent standard North Sea conditions. Unfortunately, no locations with appropriate weather history are available to represent North Atlantic conditions likely to be present in the proposed ISLES project.



Figure 5.28 - Climate regime locations

The wind speed and wave height distributions are given in Figures 5.29 and 5.30 respectively. It is found that there is little difference in the wind regimes between the three new sites that are investigated but that the exposed North Sea site spends considerably more time at wind speed above 10 m/s than the other sites. There are, however, quite distinct variations in the wave height distributions between all the different sites. The exposed North Sea FINO site is found to have the harshest wave climate of those investigated, with a higher proportion of time spent at high wave heights, closely followed by the North East UK site. The North Sea site is found to experience high wave heights less frequently whereas the more sheltered South East UK site is found to be significantly calmer with the vast majority of time spent below the lower repair threshold of 1.5 m.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

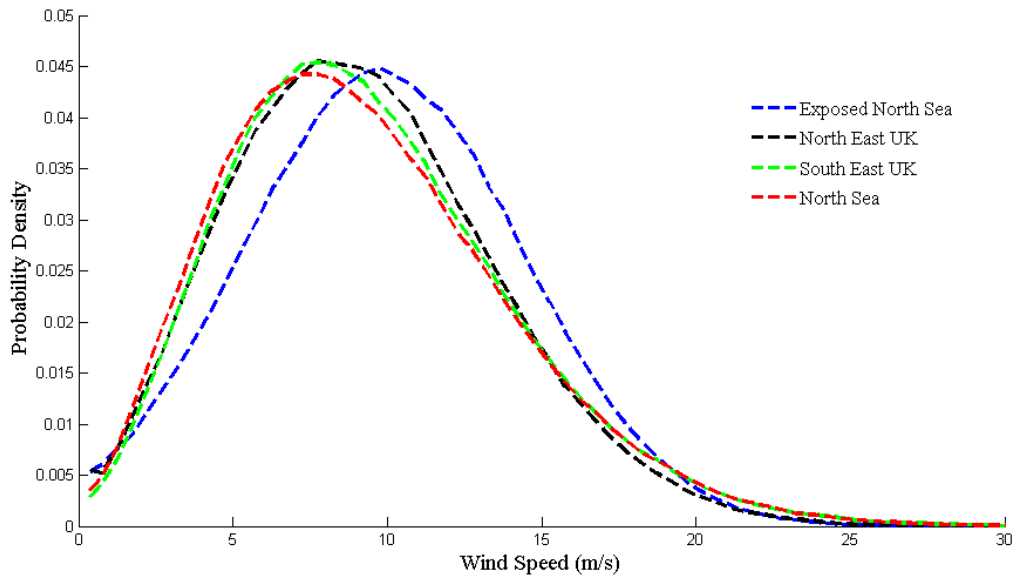


Figure 5.29 - Wind speed distributions for four North Sea sites (bin width: 0.5m/s)

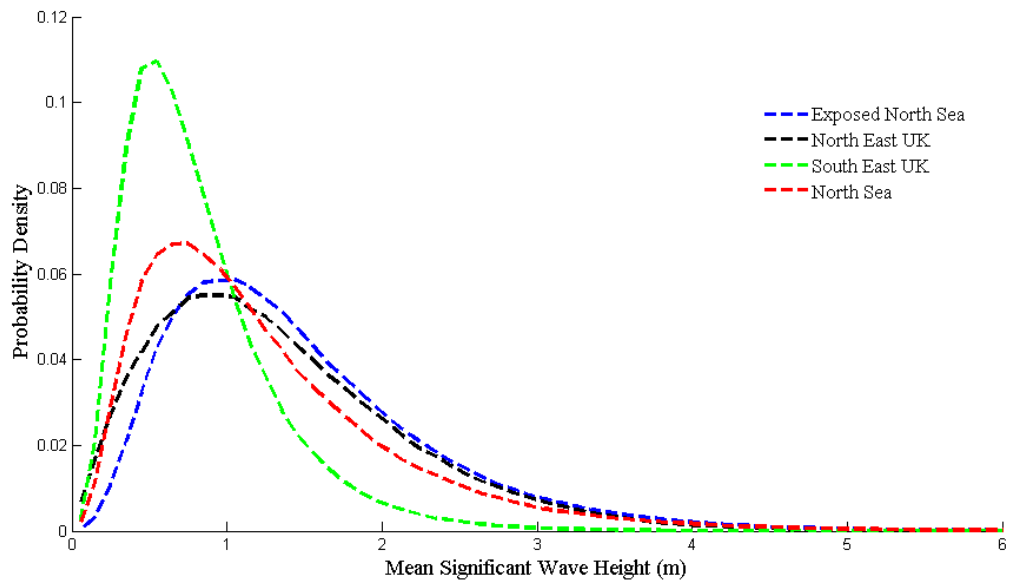


Figure 5.30 - Wave height distributions for four North Sea sites (bin width: 0.1m)

The Dogger Bank multi-terminal grid option is assessed with no other assumed changes other than the use of each of the alternative climate regimes in turn. This allows a direct comparison to be made between the different climate regimes as to their influence on both available and delivered energy with the wind profile influencing the capacity factor associated with the offshore wind farms and the wave profile influencing component repair times. The reliability performance under each scenario is presented in Figure 5.31 and overall grid performance is given in Table 5.1.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

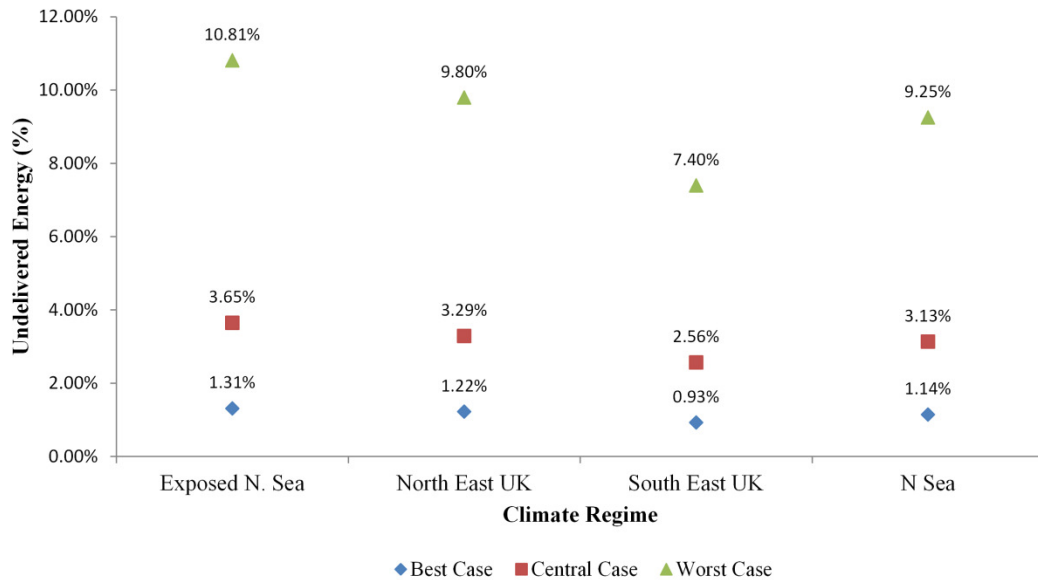


Figure 5.31 - Comparison of reliability under different climate regimes for multi-terminal grid option

Table 5.1 - Annual grid performance under varying wind and wave input profiles

Annual Performance Parameters Under Different Climate Profiles						
	Mean Wind Speed	Mean Wave Height	Capacity Factor	GWh Delivered		
				Best	Central	Worst
Exposed North Sea	9.87 m/s	1.49 m	41.14%	9966	9730	9007
North East UK	9.24 m/s	1.36 m	35.64%	8639	8459	7889
South East UK	9.45 m/s	0.82 m	35.80%	8705	8561	8137
North Sea	9.31 m/s	1.26 m	34.95%	8481	8311	7786

Altering the climate regime is found to have a significant impact on the reliability performance in terms of the expected percentage of available energy that is delivered to shore. The Exposed North Sea site is shown to have significantly poorer reliability performance than the other sites investigated. As expected the reliability results directly relate to the input wave height profile with the North East UK site having the closest reliability performance to the original FINO site with roughly a 10% drop undelivered energy in the central case reliability scenario, followed by the North Sea site which shows a 14% drop. The much calmer wave profile of the South East UK site however shows a large drop in the level of undelivered energy of some 30% for

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the central case. Table 5.2 shows that this change is driven by a change in the average time it takes to repair offshore components in each climate scenario. The most significant time differences are found for transmission branch repairs which see an average repair time of 46 days for the exposed North Sea site reduced to 12 days for the sheltered South East UK site. Offshore transformer repairs show a similar pattern with repair time dropping from a little under 15 days on average in the exposed North Sea site to less than half that for the South East UK site. Even for the North East UK site which retains a relatively harsh wave height profile the reductions in repair time are significant compared with the exposed North Sea site, especially for low probability, high impact transmission branch (36 days) and offshore transformer (12 days) fault types. Higher frequency offshore platform based repairs show comparatively smaller deviations in the expected repair time yet this will still have a serious impact on the final calculated reliability figures.

Table 5.2 - Offshore average component repair times under different climate profiles – central case

Average Component Repair Time Excluding Fixed Delays (Hours)				
Central Case				
	Component Type			
	Transmission Branch	Offshore Converter	Offshore Transformer	DCCB
Exposed North Sea	1103.2	52.5	351.1	52.3
North East UK	864.8	49.1	287.8	48.9
South East UK	285.2	22.2	158.0	22.2
North Sea	639.2	41.2	259.1	39.1

Despite having the poorest reliability performance the Exposed North Sea site also has the highest wind speeds meaning its expected capacity factor, after electrical losses are accounted for but before reliability is considered, is significantly higher than the other sites at 41.14%. This means it delivers significantly more energy each year on average in all the reliability scenarios despite the higher curtailment associated with slower repair times. Despite having quite different mean wind speeds, the North East and South East sites have very similar capacity factors due to the differing distribution of wind speeds. Despite this the South East site delivers significantly increased levels of energy on average due to a much better reliability

performance. Based on the capacity factor alone the output from the South East site would be 40 GWh/yr higher than the North East site yet when reliability is factored in, the final delivered energy is 102 GWh/yr higher in the central case. The North Sea site is found to have the lowest capacity factor and its wave climate is relatively challenging such that it has the lowest output overall of the four sites.

5.3.1 Conclusion

It is clear that the climate associated with a specific offshore grid development is a key factor in its final performance. The wind profile determines overall generation capacity and is therefore a key factor but it has been shown previously that reliability performance also has a significant bearing on the final performance of a grid option. This study suggests that reliability performance could vary greatly for offshore sites in different locations based on the ability to access and repair faulted components. Only closer to shore and potentially more sheltered sites are available for comparison with the exposed North Sea FINO site used in the main body of this research and it is shown that locations akin to these would on average have better reliability performance. It is therefore reasonable to conclude that sites with potentially harsher conditions than those found at the FINO site, such as the proposed ISLES project, would be subject to poorer reliability performance and that the reliability calculations made in Section 4.1 potentially underestimate the level of undelivered energy. If this is the case then even greater value could be placed in the design of a grid with strong reliability performance.

5.4 Sensitivity to Distance

Section 5.1 highlighted the importance of transmission branch failure and repair rates to overall grid reliability. Given the assumption that transmission branch failure rate varies linearly with distance, the distance between different nodes in an offshore grid is likely to have a significant impact on the overall calculated grid reliability. Cables are also one of the most expensive components in the grid so this section looks to investigate the trade-off between cost and reliability and the influence that varying the distance between HVDC converter stations on the offshore grid has on this.

5.4.1 Distance between Wind Farms

The radial+, multi-terminal and meshed symmetrical monopole Dogger Bank grid options are used in this analysis and the distance between the four offshore wind farms in each grid option is varied. Whereas in the original grid designs the distances between the wind farms varies between 15 km and 35 km based on realistic assumptions about the expected geography of the design proposal, this study looks at two alternative grid layouts with a larger spacing between the wind farms. For simplicity, each of these options assume that the four wind farms form the corner points of a square with firstly 50 km and then a 75 km distance between each adjacent wind farm. Figure 5.32 shows the relative positioning of wind farms in each of the grid layouts.

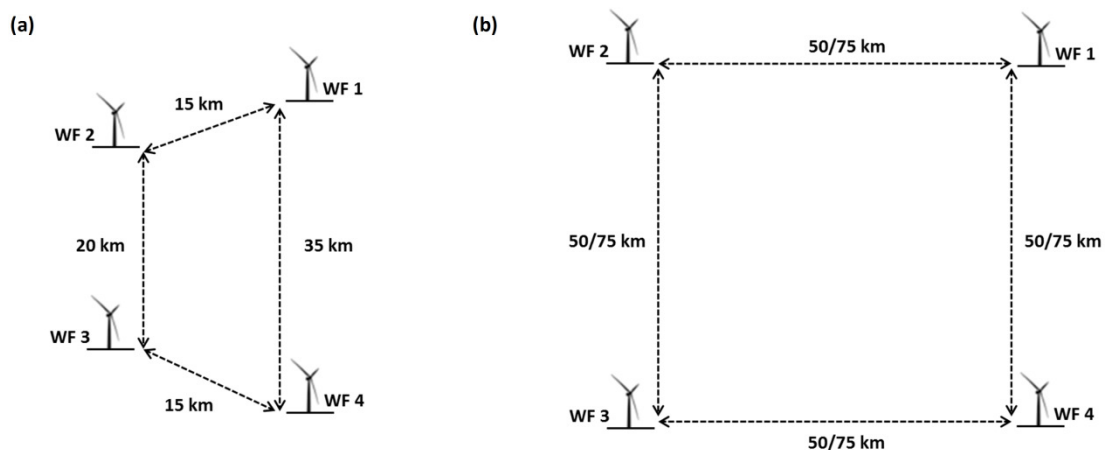


Figure 5.32 - Wind farm layout for a) original grid design b) 50 km and 75 km grid scenarios

The multi-terminal grid option provides a degree of redundancy by implementing a cable link on the relatively short 20 km stretch between the converter stations at WF2

and WF3. This is a cheaper option than implementing the cable link in the larger 35 km stretch between WF1 and WF4 although the latter option provides redundancy for a greater number of fault conditions and should therefore offer better reliability performance. This design would be akin to the ring network described in Section 2.2.3.3 and for the 50 km and 75 km scenarios would have equal cable costs to the original multi-terminal design but increased DCCB requirement. To provide a full investigation this fourth design option is also considered for comparison in the following analysis and an illustration of each grid option is provided in Figure 5.33.

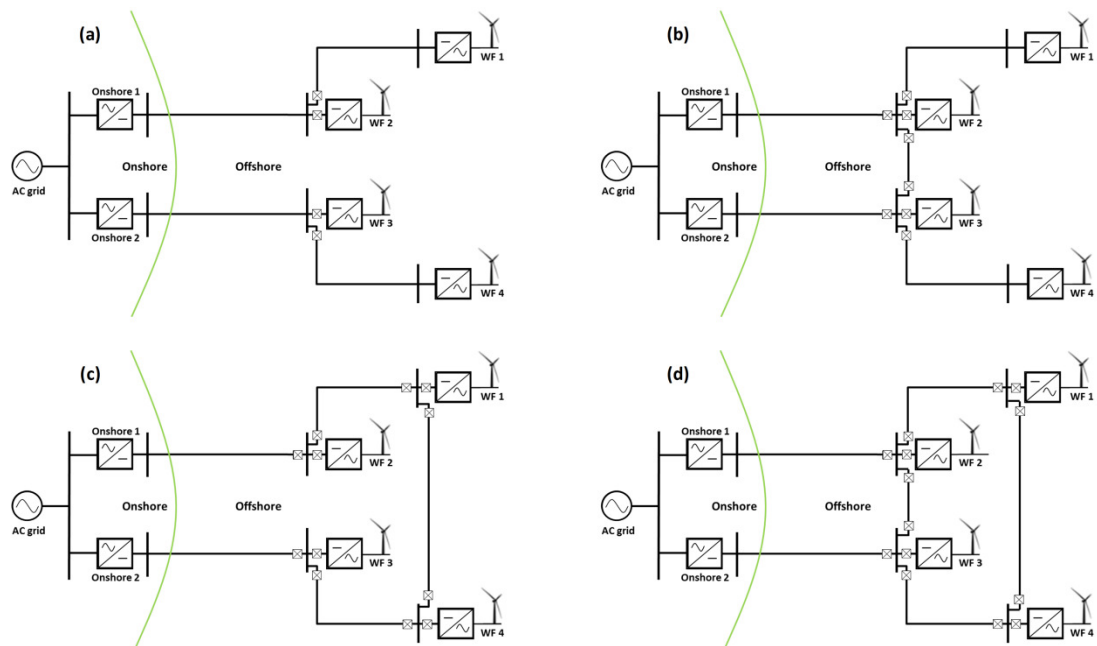


Figure 5.33 - Grid options used in analysis: a) radial+; b) multi-terminal; c) ring and d) meshed

The percentage of undelivered energy for each of the design options and grid layouts is given in Figure 5.34. As expected it is found that increasing the distance between the offshore wind farms increases the level of undelivered energy relating to each of the grid options. This is clear in the radial+ grid option where increasing the distance to 75 km spacing increases the curtailment to 5.95% annually compared with 5.48% in the more compact original grid layout for the central case reliability scenario. For the multi-terminal grid option the same pattern is found with a similar increase in undelivered energy between the standard grid layout and the 75 km option, increasing to 4.07% from 3.65%. This reflects the fact that the multi-terminal grid design only provides redundancy against faults affecting output from two of the four

wind farms (WF2 and WF3). The increased distance between the wind farms increases the likelihood of faults that affect WF1 and WF4, however, meaning the sensitivity to distance remains high in the multi-terminal grid option.

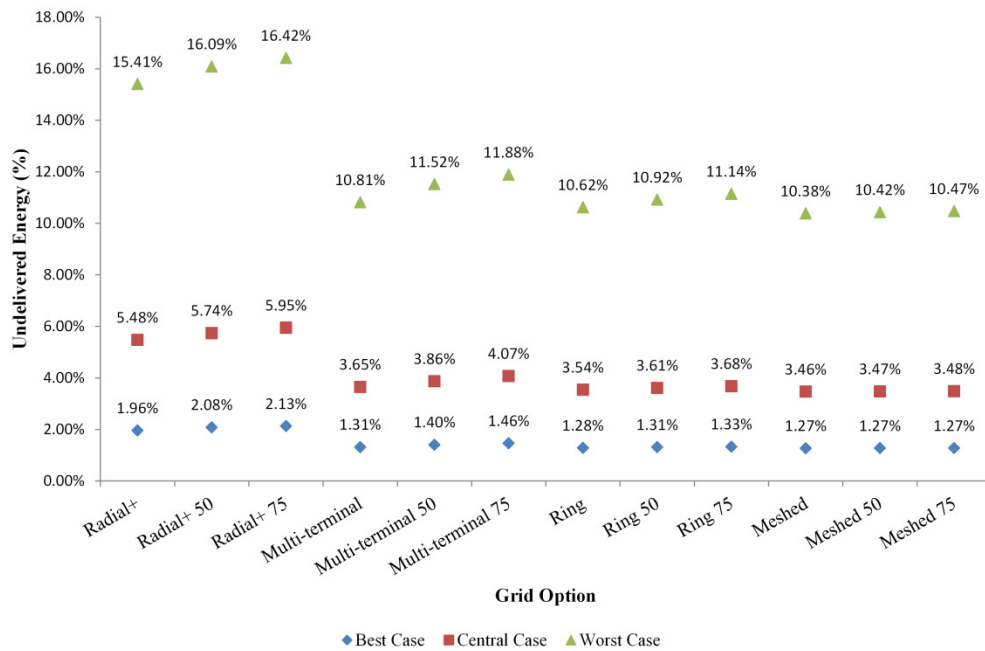


Figure 5.34 – Undelivered energy of grid options with increasingly separated wind farms

The ring topology on the other hand is capable of providing a redundant transmission path in the event of individual faults influencing any of the wind farms and this translates to a much lower sensitivity to increases in the distance between offshore nodes. For the ring network it is found that the difference in reliability performance between the original grid layout (3.54%) and the 75 km scenario (3.68%) is around three times lower than the difference with the multi-terminal grid option. The meshed grid option offers an additional layer of redundancy and shows an even stronger resilience to increased distance, and therefore cable failure rate, with reliability performance only fractionally worse under the longer distance grid layouts. This shows that in terms of reliability the more interconnected the system is the less important distance is to overall reliability performance. This means that in more geographically dispersed systems the reliability benefits of using a grid design with high levels of redundancy are even more pronounced. However, this is counterbalanced by the fact that greater transmission distances mean both higher capital costs and higher electrical losses. To understand how these different factors

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compare a full financial analysis of the different grid options is carried out, following the same approach as outlined in Chapter 4. Table 5.3 gives the capital cost and final value of delivered energy expected for each grid option and Figure 5.35 gives the resultant grid NPV under each scenario.

Table 5.3 - Capital cost and NPV of delivered energy for each grid option

Capital Cost and Value of Delivered Energy (£ billions)				
	CAPEX	NPV Delivered Energy		
		Best Case	Central Case	Worst Case
Radial+	1.65	20.12	19.40	17.37
Multi-terminal	1.86	20.26	19.78	18.30
Ring	2.06	20.26	19.80	18.34
Meshed	2.18	20.27	19.81	18.39
Radial+ 50	1.76	20.08	19.34	17.22
Multi-terminal 50	2.01	20.22	19.72	18.14
Ring 50	2.20	20.24	19.77	18.27
Meshed 50	2.37	20.26	19.81	18.38
Radial+ 75	1.84	20.06	19.28	17.14
Multi-terminal 75	2.13	20.20	19.66	18.06
Ring 75	2.33	20.23	19.74	18.21
Meshed 75	2.54	20.25	19.80	18.36

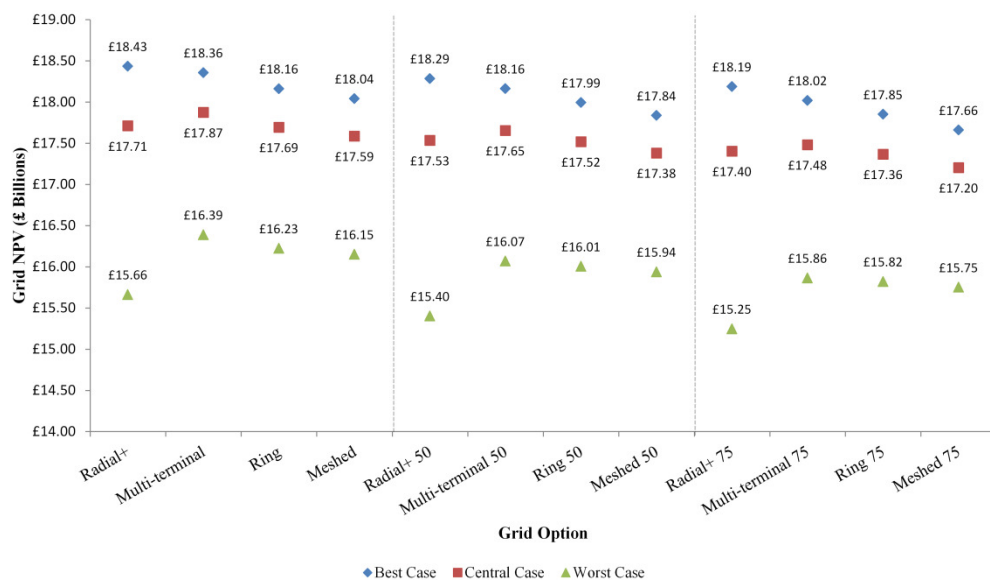


Figure 5.35 - NPV of grid options under various layouts

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Although the meshed grid designs have the best reliability performance and the importance of this becomes more prominent as the distance between offshore nodes increases, it is found that the additional capital costs associated with implementing a meshed system over these distances outweigh the benefits. For the 75 km grid layout the cost of implementing a meshed grid design is nearly £450 million higher than the multi-terminal design yet the increased reliability benefits amount to only £300 million for the worst case reliability scenario and only £140 million for the central case. The meshed grid option therefore does not rate favourably under any of the scenarios and in fact as the distance between nodes increases, the value of implementing the highest performance grid option reduces compared with alternative designs.

In the original grid layout it is found that the extra cost of implementing the ring network as opposed to the multi-terminal grid option outweighs the benefits incurred through greater reliability by a substantial £180 million in the central case. In the 50 km and 75 km grid layout scenarios however the extra cost of implementing the ring network over the multi-terminal network is proportionally smaller due to the equal cable costs in these scenarios. The extra cost associated with an increased number of DCCBs is, however, still a dominant factor and the improved reliability performance of the ring grid option over the multi-terminal option is not enough to recover the additional CAPEX. The most favourable option under central and worst case reliability scenarios for each of the grid layouts is therefore the multi-terminal grid option followed by the ring design. The gap between the two options does however reduce as distance increases at £135 million for the 50 km layout and £114 million for the 75 km layout. This highlights again that, alongside improving reliability performance, maintaining low capital cost is a main driver behind the overall value of a grid design and that the extensive deployment of DCCBs is likely to diminish this value in comparison to alternative systems with reduced protection costs.

For the best case reliability scenario the radial+ option is the best value for each set of distances considered. As the reliability performance of components gets worse, however, so too does the performance of the radial+ grid option and for each of the distances this option is of similar value to the ring grid option under the central case.

reliability scenario and is the least value option under the worst case reliability scenario. As distance increases so too does the risk associated with the radial+ grid option in terms of the spread of potential results across the three reliability scenarios. The increased costs associated with poor reliability performance do therefore outweigh the cost savings associated with building the simpler radial+ grid design for all distances examined unless individual component reliability performance is particularly good.

5.4.2 Transmission Link Distance

In addition to varying the distance between offshore nodes in the Dogger Bank based network a study has also been performed that investigates the impact of the distance to shore of the offshore wind farm cluster. In the original scenario the offshore transmission links to shore are 200 km in length so an additional study has considered the radial+, multi-terminal and meshed option at a 100 km distance from shore to explore the impact of altering the distance of the main transmission route from shore. Figure 5.36 shows a comparison of the reliability performance between the original grid designs and the closer to shore options.

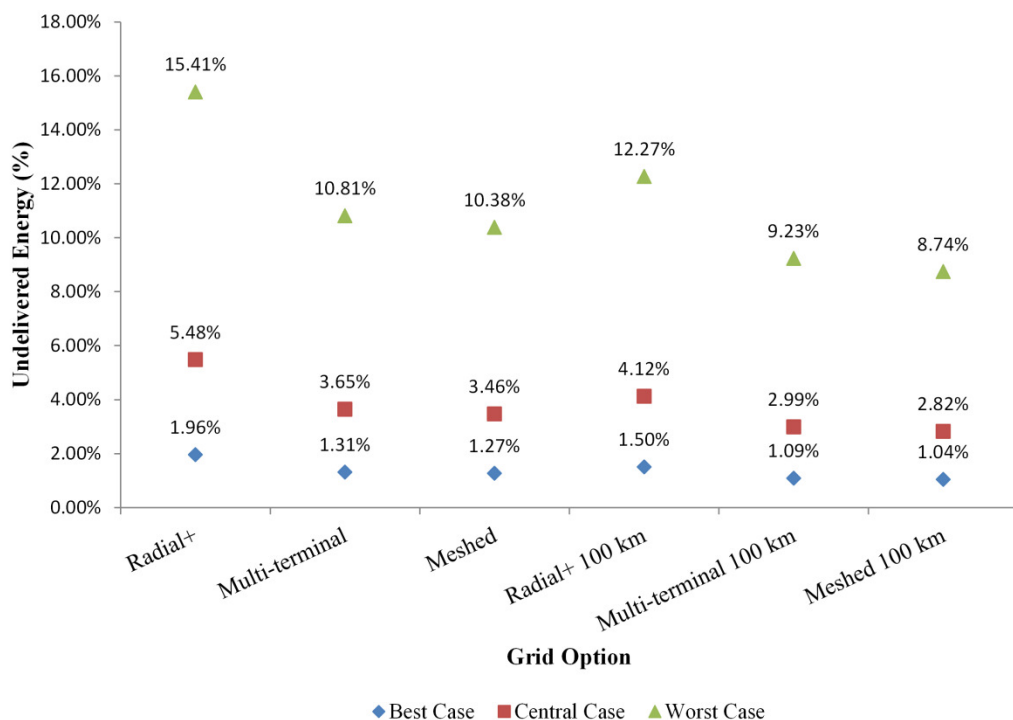


Figure 5.36 - Comparison of undelivered energy with reduced distance to shore

It is found that the long transmission links to shore in the original grid solutions understandably have a significant impact on the overall reliability of the grid and the reduced length grid options show significantly lower levels of undelivered energy. The distinction is most prominent in the comparison of the two radial+ grid options whereby the energy curtailment associated with the 100 km option is some 25% lower than the 200 km grid in the central case scenario. The equivalent reductions for the multi-terminal and meshed grid options are both around 18%. This once again highlights the significant role transmission branch failure rate plays in the overall results and that the introduction of redundant transmission paths in the grid can go some way to reducing the impact of this. It also implies that the further from shore an offshore wind farm cluster is, not only is the central estimate of undelivered energy higher but the range of probable outcomes is also wider.

The reduced distance to shore also has other obvious implications such as reduced CAPEX and lower electrical losses which impact on the overall financial merits of the grid. The capital cost reductions associated with each of the three grid options are the same and amount to £334 million in reduced cable costs. The electrical losses are also found to drop by almost 15% for each of the grid options. Taking these values into account along with the reliability performance a comparison of the final grid NPV values for each of the options is given in Figure 5.37.

The main implication of the shortened distance to shore is to increase the relative value of the lower capital cost radial+ grid option. In the 200 km from shore scenario the poorer reliability performance of the radial+ option makes the multi-terminal grid the clear preferable option in the central case reliability scenario. However, in the 100 km scenario the central case value of the radial+ and multi-terminal grid options is very similar. The radial+ grid option is also the best option by an increased margin if best case reliability performance is considered but remains the poorest option if worst case reliability performance is realised, although again by a reduced margin. This study therefore indicates that the use of more complex, but more reliable grid design options becomes more attractive as the distance from shore of the projects increases and for projects closer to shore there is increased value in considering lower capital cost options even if reliability is compromised.

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Figure 5.37 - Comparison of grid NPV with reduced distance to shore

5.4.3 Value of Linking Radial Connections

It has often been proposed that one method of delivering multi-terminal offshore networks might be through the connection of existing radial connections to shore. To investigate the merit of this a study has been performed involving a simple system with two 1 GW wind farms with radial connections to different shore points. The value of adding a connection between the two offshore installations is investigated considering a range of separation distances. As in the main results discussed in Section 4, a number of protection options are available and this study looks at the value of adding a link and protecting the system using firstly DCCBs throughout or by using a minimum breakers solution in conjunction with fault current blocking converters. The different grid options are illustrated in Figure 5.38 with the offshore wind farms again assumed to be situated 200 km offshore. Grid options with 20 km, 60 km and 100 km spacing between the offshore wind farm converter stations are investigated. The grid is assumed to be implemented with a symmetrical monopole configuration. A reliability analysis is performed using the methodology outlined previously, assuming central case conditions and the results, along with those of a financial analysis, are presented in Table 5.4. The cost analysis uses the available data outlined in Section 3.8.3 and scales values where appropriate to 1 GW and the value of curtailed energy is calculated over a 25 year project lifetime at a discount

rate of 6%. The initial results do not account for the potential benefits associated with interconnection but a consideration of these is discussed later in the section.

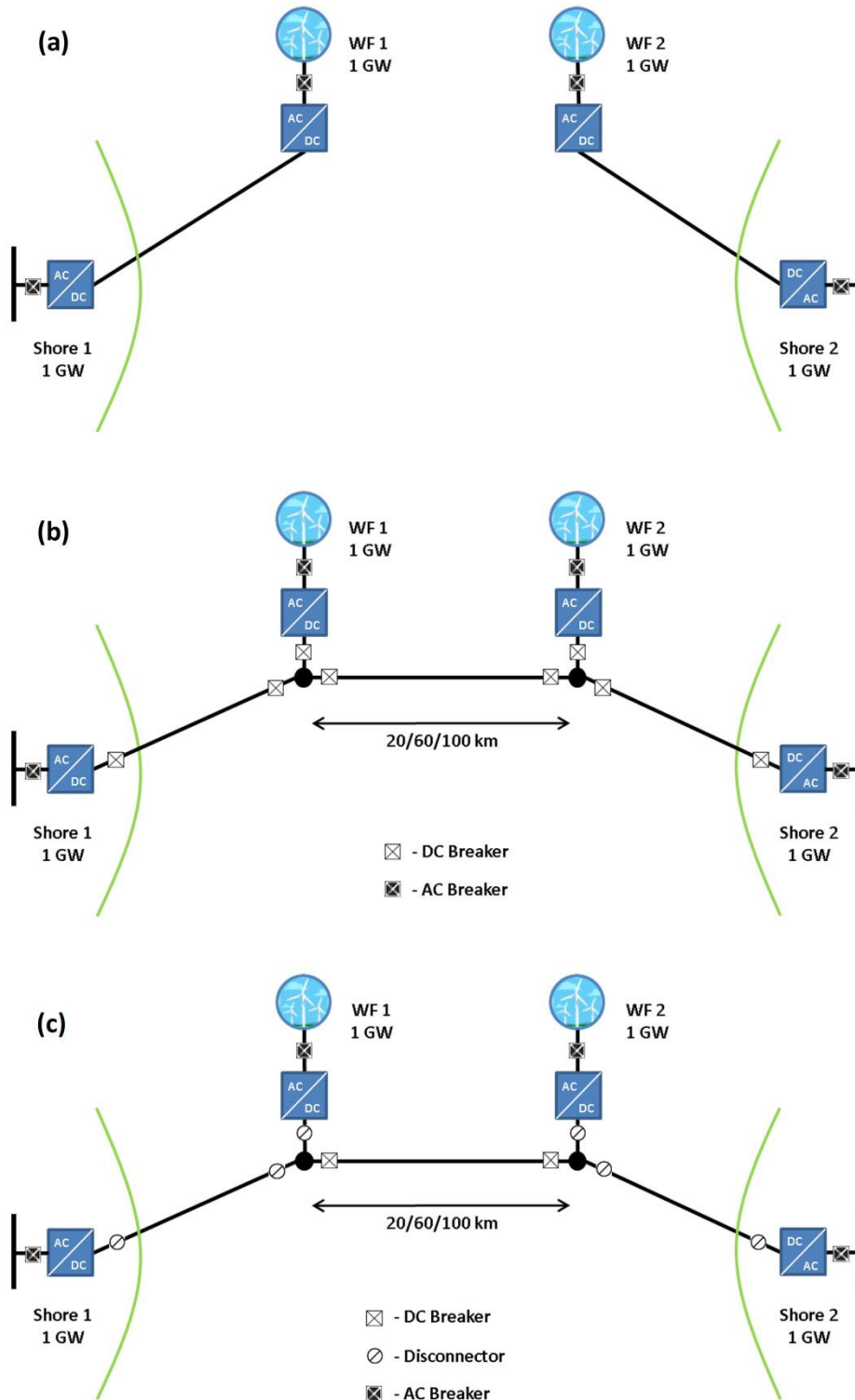


Figure 5.38 – Single line representation of Grid option configuration: a) Radial, b) Multi-terminal with DCCBs and c) Multi-terminal with minimum DCCBs

Table 5.4 - Comparison of radial and multi-terminal grid options for central case reliability scenario

Comparison of Radial and Multi-terminal Grid Options				
	CAPEX (£ millions)	Electrical Losses	Undelivered Energy	Grid NPV (£ millions)
2x Radial	1104	2.41%	5.50%	12779
MT DCCB 20 km	1353	2.61%	3.55%	12781
MT DCCB 60 km	1420	2.62%	3.56%	12709
MT DCCB 100 km	1487	2.62%	3.59%	12635
MT Min DCCB 20 km	1210	2.73%	3.46%	12923
MT Min DCCB 60 km	1276	2.74%	3.48%	12851
MT Min DCCB 100 km	1343	2.74%	3.50%	12779

For the cost assumptions used, the additional cost of linking the two radial connections is found to range from around £250 million to £380 million if DCCBs are utilised as the main protection method whereas the range drops to between £105 million and £240 million if fault current blocking converters are used in conjunction with a reduced number of DCCBs. The electrical losses associated with the use of these methods are also higher than the radial option due to the inclusion of both more equipment and also the assumption that power flows are directed to a single shore only when there is available spare capacity for trading energy between the two regions. The electrical losses associated with the minimum breaker grid designs are higher still due to the previously stated assumption that full bridge converter losses are 15% higher.

As was found in the radial design options previously studied, the reliability in terms of undelivered energy is poor and in this case the percentage of deliverable energy, after electrical losses are accounted for, that is curtailed due to system faults is expected to be 5.50% for the central case. The introduction of a link between the two offshore wind farms is found to significantly reduce the level of expected undelivered energy which drops as low as 3.46% in the 20 km gap minimum breaker grid scenario. As was found in the Dogger Bank case study, the introduction of

DCCBs introduces another level of components that are susceptible to failure and therefore the expected reliability performance of the DCCB protected options is slightly poorer in comparison at 3.55% for the 20 km grid design.

The additional value of the better reliability performance is found to slightly outweigh the extra costs of the link in the DCCB 20 km grid option when overall Grid NPV is considered. However, as the distance between the wind farms increases the additional cable costs outweigh the reliability benefits and the NPV of the two radial options is higher than the value of the combined multi-terminal grid solutions at both 60 km and 100 km separation if DCCB based protection alone is used.

The results, do not however, include the value of traded energy which can only be accounted for with knowledge of the utilisation of spare cable capacity and price differentials between the onshore locations. It is found that in each of the multi-terminal grid options there is approximately 3 TWh worth of available trade energy per year, the instantaneous value of which depends on the output of the wind farms. If the lower cost minimum breaker solution is implemented then it is found that the value of introducing the link outweighs the additional costs in the 20 km and 60 km cases and even at a link distance of 100 km the added reliability benefits are found to be almost exactly equal to the cost of the additional link. Including the potential value of traded energy, it can be assumed that there is overall value in introducing a link between two radially connected wind farms even if the distance between them is in excess of 100 km as long as a low cost protection method is utilised.

It must be noted that this study looks only at the value of delivered energy and physical costs of the grid and does not investigate the complex ways in which different participants in such a grid development would be remunerated. There are also a number of additional factors that could be explored through further analysis. For example, the capacity of the grid links could be increased which would have the dual impact of reducing curtailed energy further and increasing the available trade capacity however, such benefits would have to be weighed against the additional costs of implementing the higher rated equipment. This study also assumes central case reliability figures so deviations in the level of component reliability and repair rates would likely alter the conclusions of the analysis.

5.4.4 Repair Transfer Time

Another consequence of varying the distance from shore of projects is potential changes in the amount of time taken to reach offshore platforms to carry out repairs. Previous results all operate under the assumption of a 1 hour transfer time each way to and from an offshore platform based repair. For the far offshore case studies examined it is assumed that an offshore maintenance hub is in place but for closer to shore projects this would not necessarily be the case. It is also assumed that helicopters are used but for closer to shore projects it may be more economical or practical to use crew transfer vessels as discussed in Section 3.4.3. A comparison is made between the reliability results obtained for the 100 km multi-terminal case study using the standard 1 hour transfer time assumption and a second case that assumes a doubling of that transfer time to 2 hours each way to study the impact this has on overall reliability. The results are given in Table 5.5.

This change only impacts the repair time associated with minor offshore platform based faults yet the increase in the overall level of undelivered energy is around 5% for the central case and almost 7.5% in the worst case reliability scenario. This difference can be explained by the fact that repair of components is more likely to require multiple visits to the site than in the central and best case scenarios in which platform based repairs can be carried out in a single visit in most instances. The increased transfer time also means less time for actually carrying out the repair which means repairs are more likely to carry over to a subsequent shift. This short example illustrates that the transfer time is an important consideration for the reliability performance and a more detailed future investigation might look to quantify and include distinct transfer times for different locations on the offshore network.

Table 5.5 - Impact of transfer time on reliability

Impact of Repair Vessel or Helicopter Transfer Time on Undelivered Energy for 100 km Multi-terminal grid option			
Transfer Time	Reliability Scenario		
	Best case	Central case	Worst case
1 hour	1.09%	2.99%	9.23%
2 hours	1.14%	3.14%	9.92%

5.4.5 Conclusion

A number of studies have been carried out which have outlined that distance is an important factor in determining the likely benefits of various grid options due to the inherent influence it has on both reliability performance and capital expenditure. It is found that as the distance from shore of offshore wind farms increases so does the expected level of undelivered energy which increases the value of implementing grid designs with redundant transmissions paths. Equally, in terms of minimising curtailed energy, the benefits of more complex designs are proportionally higher as the offshore infrastructure becomes more geographically dispersed. Conversely, however, the price of implementing this complexity also increases if the grid is more geographically dispersed and this can outweigh the expected benefits of greater reliability performance in certain circumstances. A further study found that there is clear value in connecting two radial grid connections even if there is a reasonably large separation between them so long as a low cost protection methodology is implemented. It has also been shown that the transfer time required to access and repair faulted components is an important consideration which can influence the overall reliability performance.

None of the studies carried out in this section consider the spatial variation of wind output and as such future work on the subject could look to investigate what impact distance has on the correlation of power output between different wind farms' within the same offshore grid system and the resulting impact on reliability performance.

5.5 Cost Sensitivity

The results of the financial analyses in this thesis rely on a number of underlying assumptions relating to the cost of energy, annual discount rate and capital cost of components. This section looks to investigate the sensitivity of the overall results to changes in these underlying assumptions.

5.5.1 Cost of Energy

The assumption used in this study assumes the price paid for offshore wind energy, and therefore the cost of undelivered energy is equal to £150/MWh. As discussed in Section 3.8.1 this is based on the maximum strike price available to offshore wind farm developers connecting to the GB system. The real price paid to generators is based on an auction process and may well be lower than the maximum strike price. This study looks to determine the impact on the results produced from the methodology if lower prices are applied to the analysis. Figures of £125/MWh and £100/MWh are therefore applied to the Dogger Bank grid scenarios and the results are outlined in Figures 5.40 and 5.41 whilst the results of the original £150/MWh price are repeated for comparison in Figure 5.39.

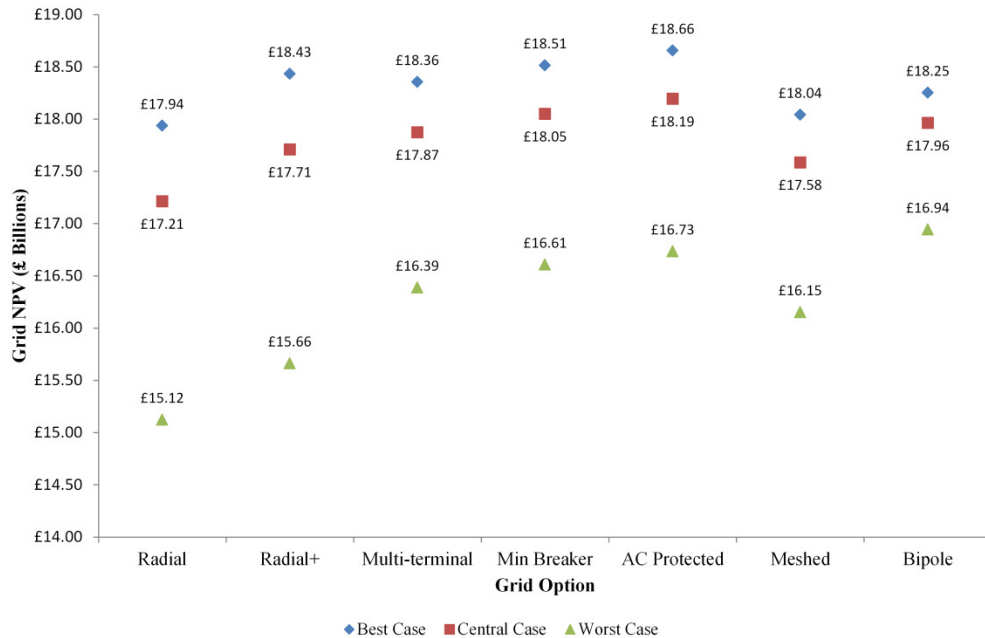


Figure 5.39 - Overall NPV of Dogger Bank grid options for £150/MWh cost of energy

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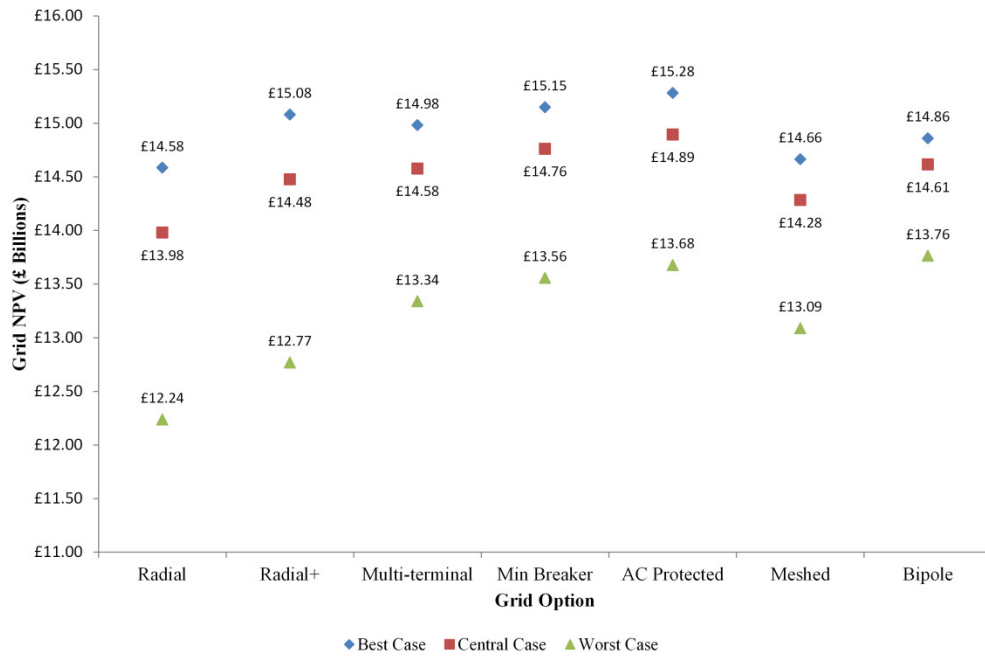


Figure 5.40 - Overall NPV of Dogger Bank grid options for £125/MWh cost of energy

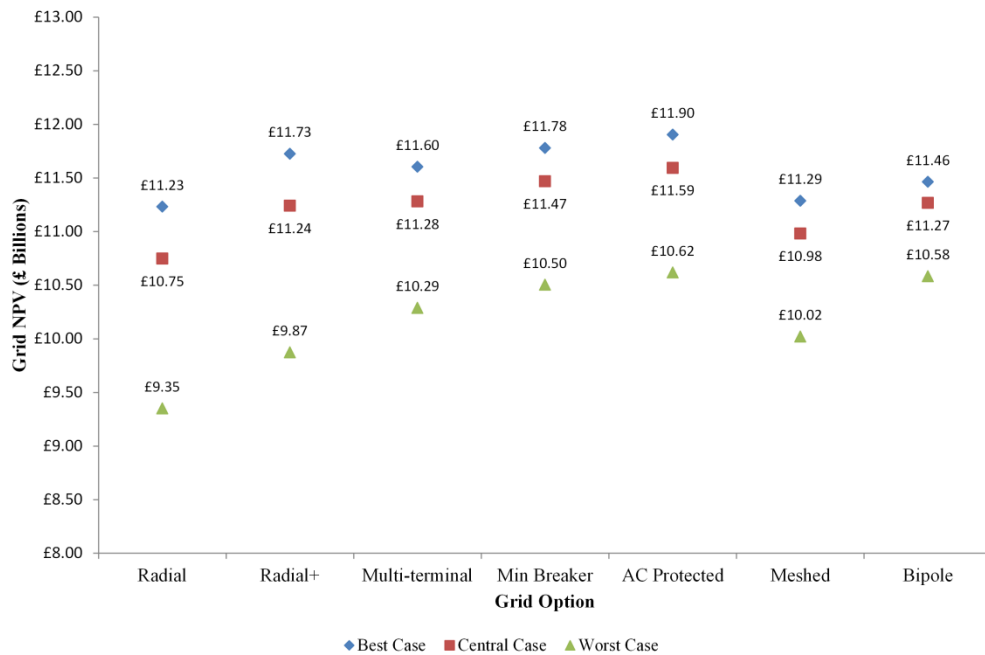


Figure 5.41 - Overall NPV of Dogger Bank grid options for £100/MWh cost of energy

Unsurprisingly, the results of this sensitivity study show that the assumption made regarding the value of offshore energy has a large impact on the overall NPV calculated for each grid option. The effect of reducing the cost of energy value is to reduce the value of delivered energy and thus increase the importance of capital and

operational expenditure in the results and reduce the importance of good reliability performance. The diminishing value of good reliability performance is highlighted by the fact that the favourability of the highly reliable bipole option reduces as the cost of energy reduces. At £150/MWh in the worst case reliability scenario the bipole grid option is clearly the most favourable option with an expected NPV some £210 million higher than the next most favourable AC protected grid option. At £100/MWh however the AC protected grid is deemed to give the best value in this scenario by some £35 million over the bipole grid option.

The additional importance of capital costs as the cost of energy reduces is demonstrated by the fact that the drop in NPV of the most expensive grid options is higher than the lower cost options between the £150/MWh and the £100/MWh cases. For example, the NPV of the high cost meshed system is over 60% higher in the £150/MWh case than in the £100/MWh case. This compares to a difference of less than 57% for the low cost AC protected option. In general then it can be said that reducing the cost of energy parameter has a high impact on the overall value of different grid options. It also has an impact on the relative importance of reliability performance but in the Dogger Bank scenarios investigated this impact is relatively small in that the ‘ranking’ of preferable grid options is largely similar regardless of the cost used. The exception to this is the bipole grid option which relies on exceptionally good reliability performance to outweigh an initial high capital expenditure and which therefore becomes relatively less favourable as the value of delivered energy reduces than other grid options.

5.5.2 Annual Discount Rate

It was stated in Section 3.8.1 that the annual discount rate applied to lifetime project finances in the NPV calculation is based upon a central estimate of 6% per annum. Although this is a standard figure applied in major offshore network studies previously, it is also noted that figures as low as 2% and as high as 10% have also been utilised in the literature [1, 4, 5]. This study investigates the impact of altering the annual discount rate applied to the calculation of NPV for delivered energy, electrical losses and O&M costs which contribute to the final calculation of Grid NPV. The Grid NPV also accounts for capital costs which are assumed to occur up

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front and therefore are not discounted over the project lifetime. The Dogger Bank case studies are again used as the basis of the sensitivity study to determine the impact of varying the annual discount rate from a low of 2%, Figure 5.42, a central scenario of 6%, Figure 5.43 and high of 10%, Figure 5.44.

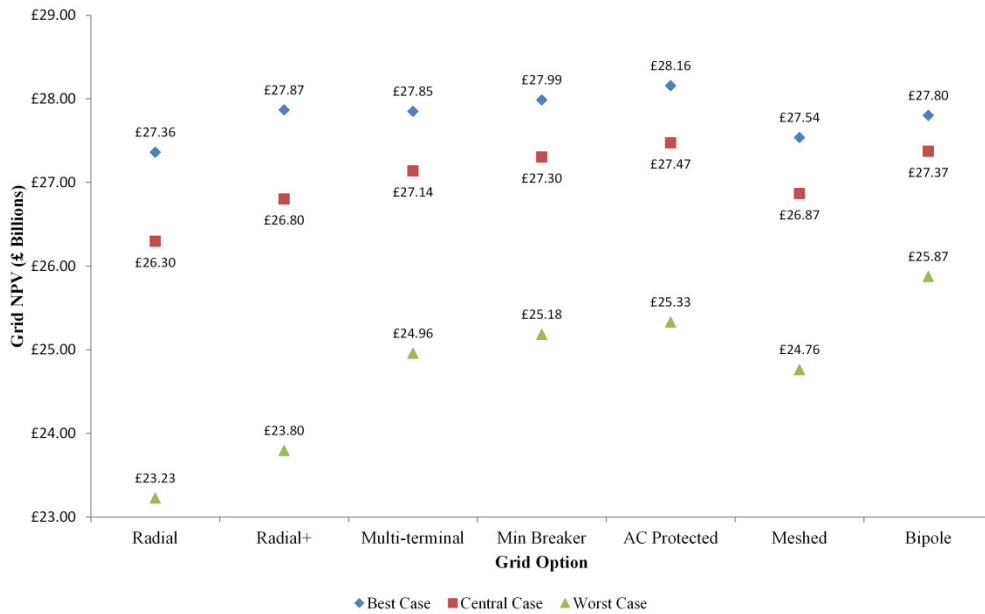


Figure 5.42 - Overall NPV of Dogger Bank grid options for 2% annual discount rate

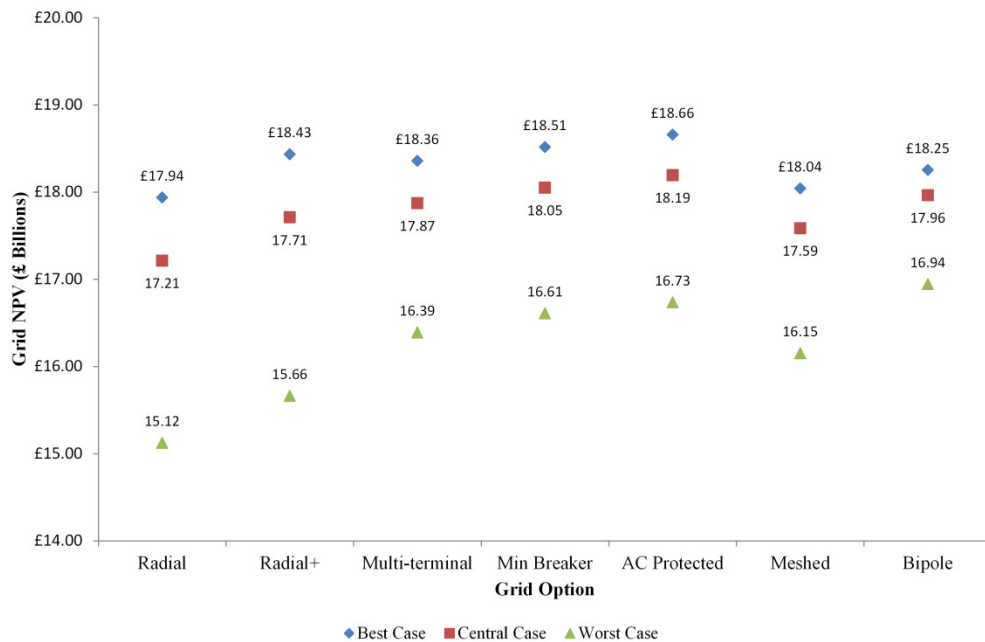


Figure 5.43 - Overall NPV of Dogger Bank grid options for 6% annual discount rate

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Figure 5.44 - Overall NPV of Dogger Bank grid options for 10% annual discount rate

The results show that there is a large variation in the final calculated Grid NPV value under each assumption with the 2% discount rate leading to a huge increase in the calculated present value of delivered energy and consequently overall grid NPV compared with the 6% and 10% discount rates. In the 2% case the final calculated NPV of each grid option is over 50% higher than in the 6% case which in turn has NPV results that are 40% higher than those of the 10% case. This has a similar effect as varying the cost of energy in that the higher the value given to the final expected delivered energy the more important reliability, in terms of maximising delivered energy, becomes when comparing the different grid options against one another financially. With the annual discount rate set at 2% the best performing grid options in terms of reliability, such as the bipole and meshed grids, compare better relative to the other grid options than when using either 6% or 10% discount rates. The bipole grid option for example is the second most favourable option under central case conditions in the 2% discount rate scenario and has a grid NPV that is just £101 million lower than the most favourable AC protected grid option. This difference changes to £231 million and £304 million in the 6% and 10% discount rate scenarios respectively and the bipole grid option drops to become the third most favourable option in each case. The ranking of grid options depending on their calculated NPV is, however, the same in both the 6% and 10% discount scenarios which again

emphasises that, although the results are sensitive to the discount rate used, in this case the changes are not so large as to drastically change the overall conclusions as to which grid options provide the best value from a design perspective.

5.5.3 Cost of DC Circuit Breakers

As discussed in Section 3.8.3 the cost of DCCBs is a large uncertainty and costs in this thesis are estimated based on an understanding of the most advanced proposed design concepts. These concepts, including hybrid DCCBs, utilise a power electronic solution and therefore contain many of the same components found in a VSC converter thus the assumption made in this study is that the cost of DCCBs is 1/6th of the cost of a full VSC converter station. This study will look at the sensitivity of the results to alterations in the assumed DCCB costs. To test the uncertainty associated with the original assumption, DCCB costs of 50% and 200% of the original estimate are used. In addition to this a DCCB cost that is 10% of the original estimate is applied which assumes that DCCBs could be realised using different, lower cost technology to the designs that have thus far been discussed. It has been suggested that much lower cost DCCBs could be realised if the strict requirement to break the DC fault current within a very short time frame of <5ms were relaxed. For example, it is suggested in [6] that slower acting DC side protection could be tolerated without incurring damage to VSC converters and with minimal disruption to the local AC system to which the DC grid connects. If true, this would mean low cost DCCBs could be implemented. The impact of the variation in DCCB cost on project CAPEX is given in Figure 5.45.

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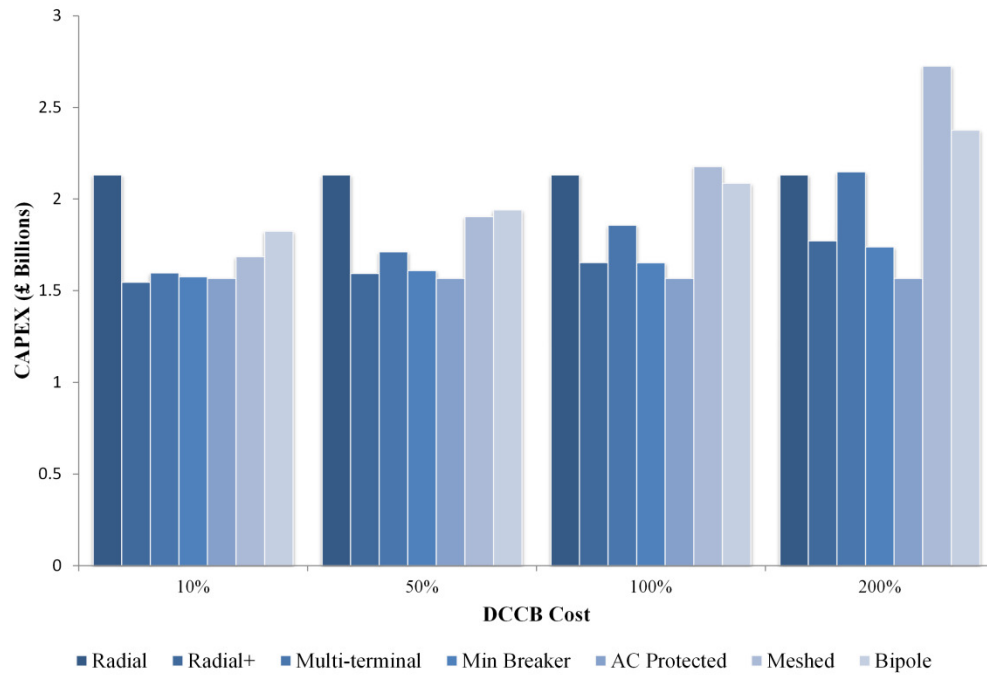


Figure 5.45 - Project CAPEX for each grid option under varying assumed DCCB costs

Figure 5.45 demonstrates clearly the impact the cost of DCCBs has on overall project capital expenditure. The cost of DCCBs, as assumed in this thesis, already constitutes a large component of the CAPEX of certain grid options. The meshed grid option, containing the most DCCBs, is marginally the most expensive option with the bipole and multi-terminal grid options which also contain a significant number of DCCBs also showing relatively high CAPEX. If DCCB costs are doubled it is found that the meshed grid options becomes most expensive option by a large margin and even the multi-terminal grid option becomes more expensive than the radial grid option despite its significantly lower cable costs. However, If DCCB costs are reduced then the difference in CAPEX between the grid options is increasingly driven by circuit length and therefore cable costs. If DCCB costs can be realised at 10% of the value assumed in the main results then the grid options that utilise DCCBs are realised at broadly comparable cost to grids using alternative protection strategies. The impact of this change in capital expenditure on overall grid NPV is outlined in Figures 5.46-5.49.

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

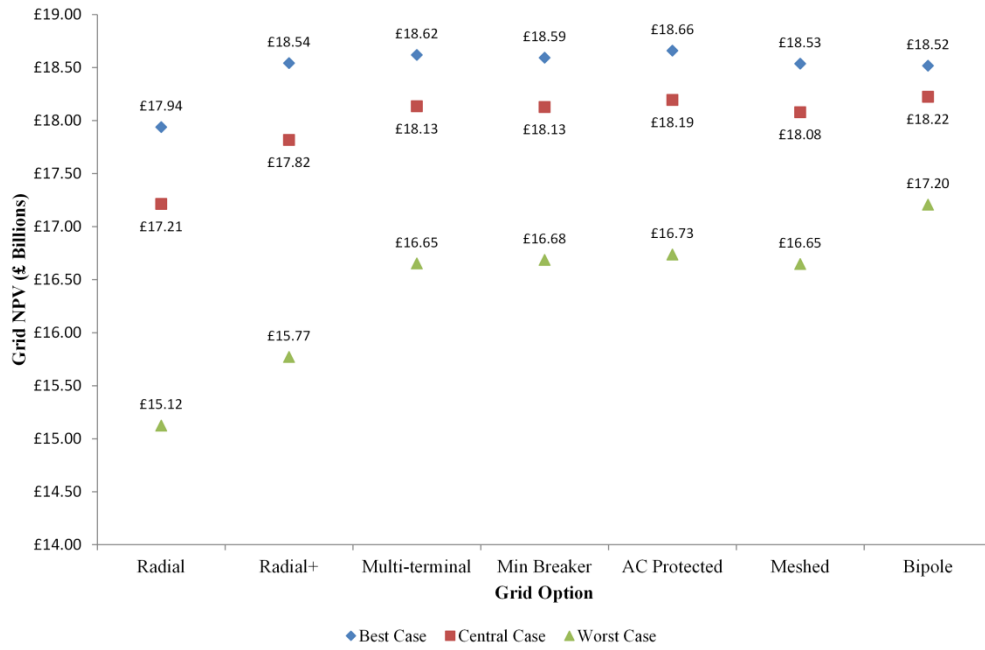


Figure 5.46 - Overall NPV of Dogger Bank grid options for DCCB costs at 10% of nominal value

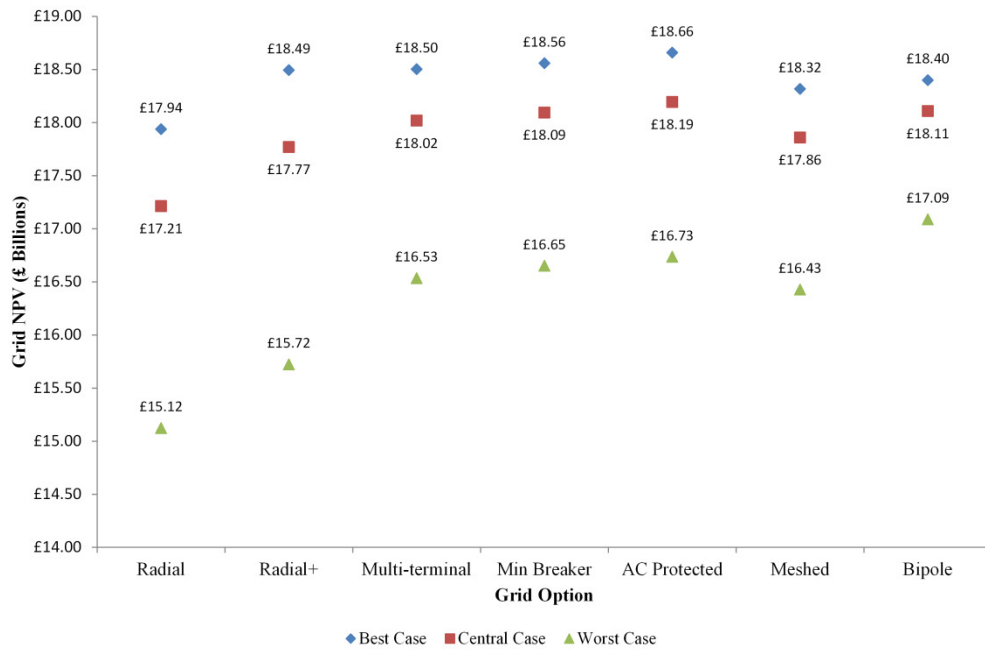


Figure 5.47 - Overall NPV of Dogger Bank grid options for DCCB costs at 50% of nominal value

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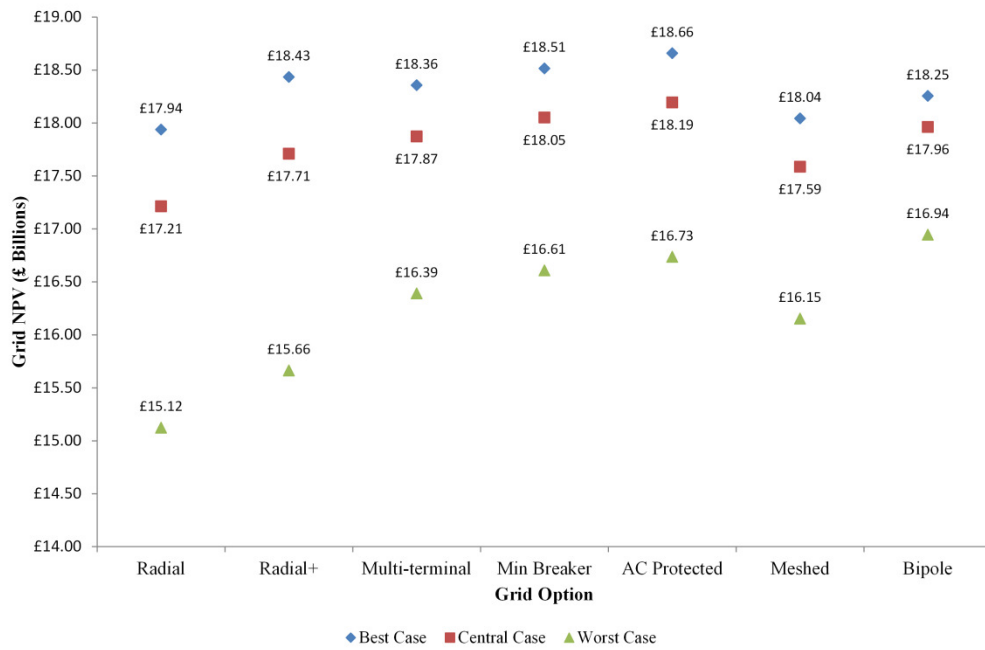


Figure 5.48 - Overall NPV of Dogger Bank grid options for DCCB costs at 100% of nominal value

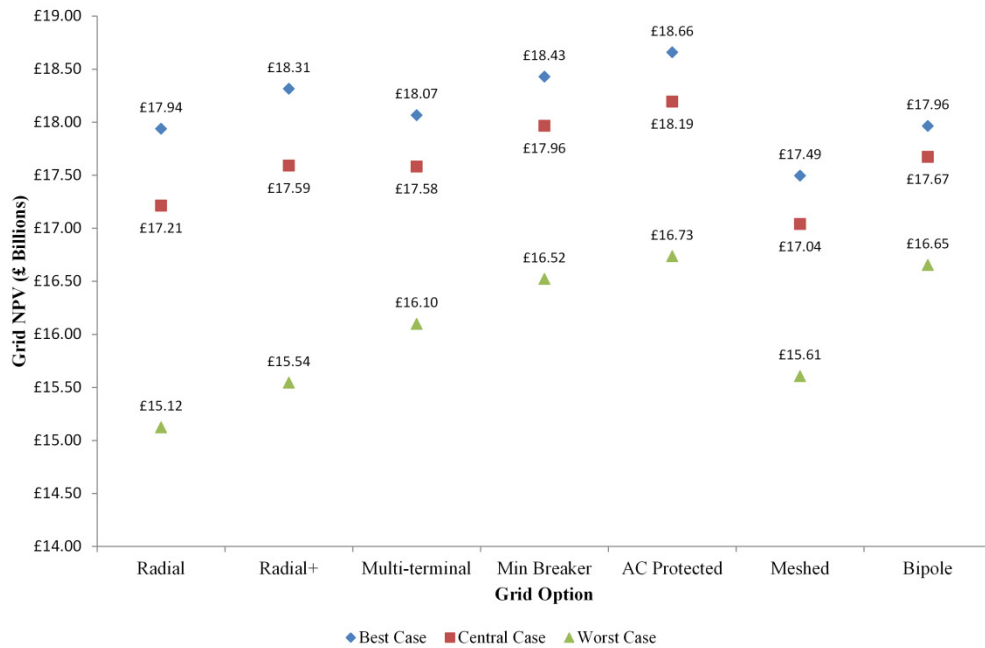


Figure 5.49 - Overall NPV of Dogger Bank grid options for DCCB costs at 200% of nominal value

The results show that the cost of DCCBs can have a large impact on the overall value of different grid options. In the extreme low case where the breaker cost is 10% of the nominal value the bipole grid option gives the highest NPV for the central case reliability scenario and the meshed grid option is only marginally poorer value than the multi-terminal grid options, all of which are of similar value to each other. In

contrast, in the high cost case where breaker costs are double the nominal value and assuming central case reliability scenario, the meshed grid option has the lowest NPV by a margin of £170 million compared with even the high cost, low reliability radial option. In this scenario the bipole grid option has only the third highest NPV and the difference between the multi-terminal grid options utilising full DCCB protection and alternative options using a reduced number or no DCCBs is substantial. The impact is summarised in Table 5.6 which examines the ranking of each grid option as determined by the calculated NPV for each grid option assuming central case reliability scenario and with varying DCCB costs.

Table 5.6 - Ranking of grid options by NPV for varying DCCB costs under central case reliability scenario

Ranking of Grid Options by NPV for varying DCCB costs Central Case Reliability Scenario				
	DCCB costs as % of nominal value			
	10%	50%	100%	200%
AC Protected	2	1	1	1
Minimum Breaker	4	3	2	2
Bipole	1	2	3	3
Multi-terminal	3	4	4	5
Radial+	6	6	5	4
Meshed	5	5	6	7
Radial	7	7	7	6

Unlike varying the cost of energy or the annual applied discount rate, which impact heavily on the level of calculated NPV but to a lesser extent on the way in which grid options compare to one another, it is found that the cost of DCCBs does have a substantial impact on how grid options rank in terms of the overall NPV calculation.

5.5.4 Conclusion

This section has considered the impact of altering various economic assumptions in determining the final comparison between grid options. These are found to have a significant impact on the final calculated value attributed to each grid option. It is found that varying both the cost of energy and the annual discount rate applied to the calculation of lifetime costs and revenues can heavily influence the final calculated

NPV of the grid options. This also inherently leads to a change in how the grid options compare financially against one another however it is found that the ranking of grid options in terms of the cost analysis applied does not alter greatly due to variations in either of these factors. This suggests that the methodology as applied can give a good indication of how network options compare against one another from a reliability design perspective but cannot necessarily be used as an accurate indication of the expected remuneration that would be derived from implementing the grid in reality, not least given the previously discussed regulatory complexities highlighted in Section 2.5. It is found that the cost applied to DCCBs is a variable that is both a relative unknown, given they have not yet been commercially realised, and has an important bearing on the merit of implementing DCCB based grid options when compared with options utilising alternative protection methods or that do not require extensive use of DCCBs. This variable is therefore an important element in assessing the financial viability of future offshore HVDC grid designs and the uncertainty will remain until there is a consensus delivered as to the exact requirement of DCCBs and the first examples are commercially delivered.

5.6 Sensitivity to Failure Rate Distribution

One aspect of the results that has been alluded to but not explored in detail is the extent to which the calculated reliability figures may vary within a given time period based on normal variations associated with the failure rate of components. Given that in general the expected MTTF of the main constituent components within offshore grids are relatively long with respect to the potential expected lifetime of the grid, the number of failures which occur within a specific time period could vary fairly significantly which in turn will have a large bearing on the overall calculated reliability. It is explained in Section 3.4.2 that this thesis derives the time to fail of each component based on an assumption that the failure rate remains constant regardless of time. This is a standard reliability assumption for a fleet of a particular component and leads to an exponential distribution of calculated individual time to fail values for each component type, the mean of which converges on the stated MTTF value used as input. This assumption allows for the calculation of the long term expected mean reliability performance of each grid option but does not necessarily provide information as to the spread of results that can be expected in a given time period. It is possible to change the distribution of the TTF calculations whilst maintaining the MTTF value and therefore without altering the final calculated reliability values. This does however influence the time varying characteristic of the results [7].

The impact of this is explored further in this section whereby, in light of any available data to indicate the real underlying distribution of component failure times, two alternative illustrative distributions are investigated. Along with the exponential distribution the reliability model is run for an example scenario using normally and then uniformly distributed failures. The distributions are derived such that the MTTF is preserved in each case and therefore the overall calculated expected undelivered energy figure is equal in each scenario. The normal distribution assumes that the standard deviation is $1/5^{\text{th}}$ of the MTTF value for each component while the uniform distribution assumes that the TTF values are uniformly distributed between 50% and 150% of the MTTF value. The resultant distributions are illustrated in Figure 5.50 for

converter failure times under the central case reliability scenario with a MTTF of 7200 hours in each case.

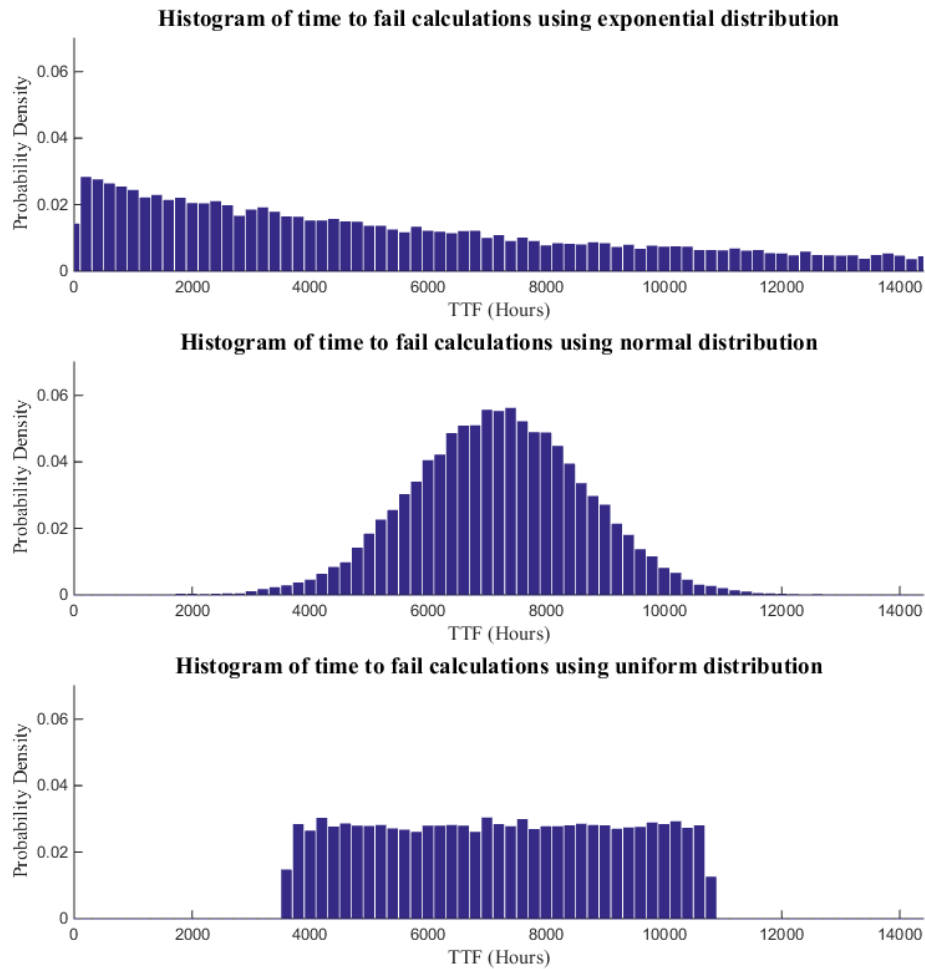


Figure 5.50 - Exponential, normal and uniform distribution of time to fail calculations for converter station faults in central case reliability scenario

It is clear from the diagram that there is a much larger spread of potential TTF values for individual components using the exponential distribution than for the normal or uniform distributions. The nature of the exponential distribution means that within a given time period there is a larger degree of uncertainty regarding the number of failures that occur for each component type than for the other distributions. When applied to individual components, use of the exponential distribution also increases the likelihood of a component failure being followed by another in a relatively short time frame. For key components, such as a long transmission link to shore, this could have a large influence on the calculated level of undelivered energy within in a given time period. The impact of this is investigated by examining the spread of calculated

5. Sensitivity Analysis and Drivers of Offshore Grid Reliability

grid reliability results over consecutive 50 year time periods using the Monte Carlo simulation. Simulation results are obtained for one thousand separate 50 year time periods for each failure rate distribution using the Dogger Bank multi-terminal grid option with the central case reliability scenario and the results are presented in Figure 5.51.

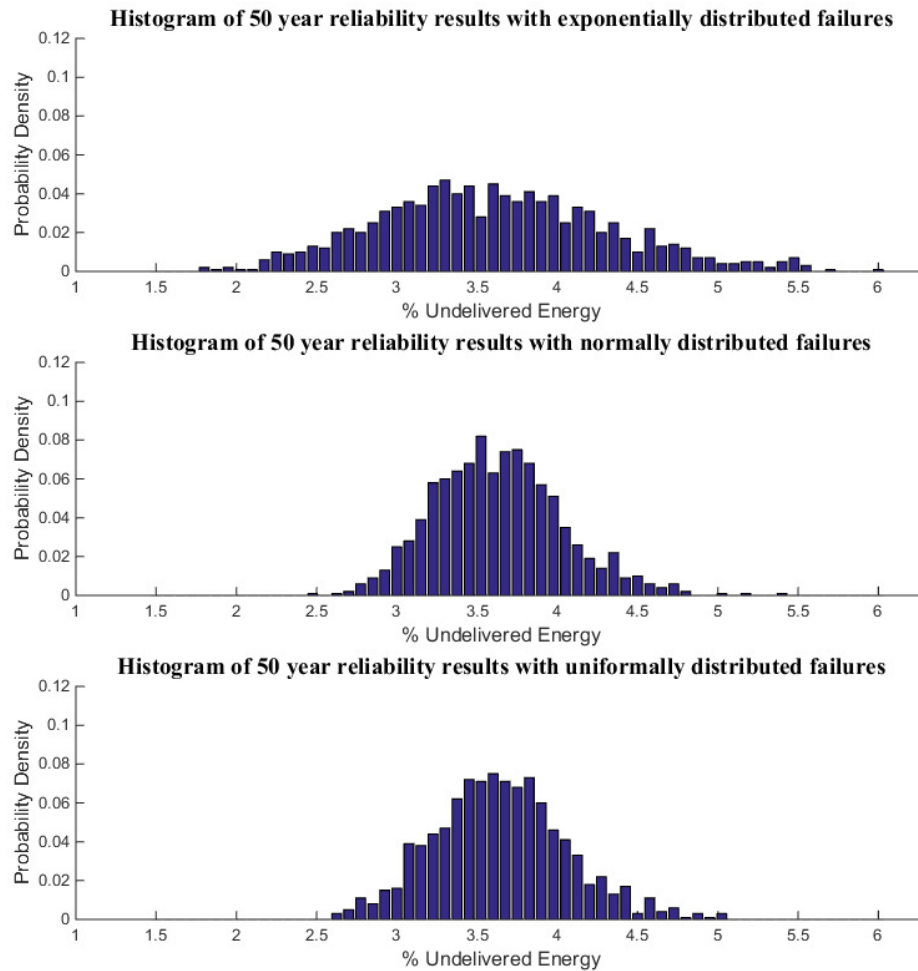


Figure 5.51 - Spread of 50 year reliability performance using Exponential, Normal and Uniform reliability failure rate distributions

It is clear from the results that the spread of expected results that may occur within a specific time period is heavily affected by the failure rate distribution with the exponentially distributed failure rates leading to a flattened normal distribution of 50 year reliability results compared with the other two distributions, for which the 50 year reliability results are more closely bunched around the expected mean. A further illustration of the variation within the results is given in Table 5.7 which looks at the

extreme values and standard deviation within the one thousand 50 year time periods for each scenario.

Table 5.7 - Variation in undelivered energy for exponential, normal and uniform failure rate distributions

Variation in Undelivered Energy for One Thousand 50 Year Time Periods				
Failure Rate Distribution	Mean	Minimum	Maximum	Standard Deviation
Exponential	3.61%	1.78%	6.44%	0.72%
Normal	3.63%	2.48%	5.43%	0.40%
Uniform	3.65%	2.63%	5.06%	0.42%

The standard deviation for the results is found to be around 80% higher in the exponential failure rate distribution scenario than in either of the normal and uniform failure rate distribution cases. The range of results is also much higher in the exponential case with the maximum recorded 50 year undelivered energy value being some 80% higher than the mean value compared with equivalent values of around 50% and 40% for the Normal and Uniform distributions respectively. The results also show that using the exponential distribution leads to a much longer convergence time to the mean expected undelivered energy value which in each case is 3.65%. After 50000 years' worth of simulation, the exponential distribution case is still some way from converging on this result whereas the Uniform distribution case with much lower variability has already reached convergence.

5.6.1 Conclusion

The results demonstrate that the distribution of failure rates has an important bearing on the uncertainty associated with the calculated reliability figures. In a similar manner to the previous sensitivity studies the results highlight that variations in the number of failures within a specified time period can have a large impact on the reliability of the grid within that time period. It is likely that low probability, high impact fault conditions such as transmission cable and offshore transformer faults, as identified in Section 5.1, contribute most to the variation in undelivered energy between different simulated time periods. An increase or decrease in the propensity of such events will likely lead to very different reliability performance than may be expected if considering only long term average outcomes. This study identifies the

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importance of modelling not just the long term mean failure rate but also the distribution of component failure times, but to fully understand the extent of this uncertainty more data is required to inform on what the underlying distribution of failure rates for offshore grid components might be. This is an area that could be developed in future additions to the model.

5.7 Discussion

This chapter has primarily looked to address what the key drivers are behind the reliability of offshore grid developments. In carrying out a number of sensitivity studies further light has also been shed on some of the other key questions laid out in Section 2.7 and partly addressed through discussion of the main results identified in Chapter 4. The findings are summarised below.

What are the key drivers behind the reliability of electrical infrastructure in the offshore environment?

Section 5.1 showed that, in terms of the constituent components within offshore DC grids, the biggest drivers influencing reliability performance are low probability, high impact component failures such as transmission branch or offshore transformer faults that tend to have long repair times. The sensitivity study showed that variations in either the failure or repair rate for such fault types can lead to large variations in the level of undelivered energy achieved. The level of sensitivity to component failure or repair rate is, however, dependent on the grid design and layout with increased redundancy or alternative transmission paths acting to reduce the real terms impact of altering component failure and repair rates. Given that transmission branch failure rates are assumed to vary proportionally with distance, the distance from shore and spacing of grids is also found, in Section 5.4, to have a significant impact on grid reliability. This is found to be further amplified if the time taken to reach faulted components is altered significantly.

Section 5.2 investigated the time spent in a number of different failure states and the contribution that they make to overall undelivered energy. It is found that the vast majority of time spent in failed states can be attributed to single, N-1 failures and so accordingly these also account for much of the undelivered energy. Multiple overlapping fault conditions, N-2 or worse, are much rarer but account for a disproportionately high level of the expected undelivered energy and thus are an important factor. The portion of time spent in such states increases with poorer component reliability. However, their impact can also be minimised through the introduction of system redundancy.

It was found in Section 5.3 that the localised climate around offshore grids has a significant impact on overall reliability. Sites with calmer wave conditions on average greatly reduce the expected repair times for faulted offshore components reliant on weather access windows for repair. This in turn increases the overall reliability of the modelled grid options and means proportionally more of the available generated energy is delivered. Calmer wave sites, however, are more likely to mean calmer wind conditions and therefore the total level of generated energy is likely to be lower. This means that proposed sites that potentially have a harsher climate than that modelled from the FINO offshore dataset in this study will likely produce more energy but also see a higher proportion of that energy go undelivered due to longer repair times associated with system faults.

What is the value of implementing increasing levels of redundant transmission paths in offshore DC grids compared with more traditional radial solutions?

It was found in Chapter 4 that there was significant value in implementing redundant transmission paths within DC grids. The sensitivity studies in Sections 5.1 and 5.2 help to illustrate why this is the case. Because transmission branches are found to be the single biggest factor influencing grid reliability performance it follows that introducing alternative transmission paths and so the ability to re-route power in the event of fault situations will have a substantial impact on the overall reliability performance. Grids with redundant transmission paths are therefore found to mitigate the impact of certain failure states and so reduce overall undelivered energy. The results of Section 5.4 show that the value, in terms of maximising delivered energy, of implementing such redundancy increases with the distance between nodes on an offshore network. The cost of implementing the redundancy also increases, however, and the results here suggest those additional costs potentially outweigh the benefits if a central case reliability scenario is assumed.

Are multi-terminal or meshed offshore HVDC grids incorporating the widespread use of potentially costly DCCBs financially viable?

Chapter 4 found that there are alternative protection methods that could offer better value than the implementation of potentially costly DCCBs. Section 5.5.3 performs a sensitivity analysis on the costs of DCCBs and finds that costs would need to go as

low as 10% of current projections before DCCB solutions close the gap or gain parity with alternative grid options in terms of NPV. Even at 50% of the current projections the cost of DCCB based grid solutions is high compared with other options, especially for a fully meshed system where the number of required DCCBs is high. Without large cost reductions on current projections, which may require a re-assessment of the required specification of DCCBs to allow for lower cost design solutions, then it seems likely that alternative protection methods, such as those outlined in this thesis involving either a reduced number of strategically placed DCCBs in conjunction with full bridge blocking converters or even more basic AC protected sectionalised grids, will provide better value for money for investors.

Which grid design options provide the most value for money in terms of revenue potential against capital expenditure and running costs?

The sensitivity studies carried out in this chapter show that the ranking of grid options in terms of overall value is dependent on a wide number of assumptions. It is clear that the value of implementing more complex grid designs that are more expensive but offer better reliability performance is dependent on the failure and repair rates achieved by individual component types. It has been found that a number of other factors can impact on the level of reliability performance, such as the wind and wave climate in the region of the grid development, the connection distance between offshore nodes and the transfer time required to reach failures. Further to this, it is found that the capital expenditure on different design options is sensitive to cost assumptions, especially surrounding DCCBs. The cost of energy and the annual discount applied in accounting for lifetime costs also influence the value that is placed on good reliability performance. The extent to which these factors influence the choice of grid option is varied with some factors, such as varying the distance between offshore nodes, having a discernible impact but not to the extent that the final ranking of the grid options in terms of NPV is altered, as demonstrated in Section 5.4.1. Conversely, it was found in Section 5.5.3 that varying the cost of DCCBs can have a large impact on the ranking of different grid options.

To decide upon a preferred grid option is therefore a complex decision that must be considered on a case by case basis and for accuracy requires a degree of certainty to

be had regarding a wide number of influencing factors. Using the assumptions made in this thesis it is possible to say that grid options utilising alternative protection strategies which either reduce or minimise the need for DCCBs are likely to be financially preferable given the same grid design. It is also clear that a degree of inherent system redundancy is preferable to simple radial solutions under most scenarios although the level of design complexity and additional redundancy that is optimal for any given scenario is likely to vary from case to case and is a matter that requires careful consideration.

5.8 References

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6. Discussion and Future Work

This chapter summarises the work that has been carried out in this research project and the major conclusions that can be drawn from it before discussing future work that could be carried out to advance the findings that have already been made.

6.1 Summary of Work Done

Chapter 2 of this thesis presented a thorough technical review on the state of knowledge in offshore networks. This assessed the current status of technology development within the industry and highlighted the range of options that are available to developers of future offshore HVDC networks. The technical review also identified a number of outstanding issues and questions that allowed the scope of work for the remainder of the thesis to be defined. A number of benefits associated with the installation of increasingly complex grid designs were identified through this investigation. However, it was found that few studies had sought to compare these benefits directly against the associated capital expenditure required for implementation. To quantify these factors it was determined that a bespoke reliability analysis software tool should be developed to compare the performance of the different available DC grid options through a cost-benefit analysis.

Chapter 3 of the thesis presents a novel methodology for assessing the reliability and associated cost of future potential offshore grid scenarios. A number of key criteria were set out in Section 2.7 and a sequential Monte Carlo modelling process has been developed and demonstrated which satisfies these as follows:

- The model is capable of comparing a range of different offshore network grid design options including various grid topologies, technology options, converter configurations and protection strategies.
- Fault conditions are randomly applied to the networks over time in line with best, central and worst case failure rate predictions for each of the main constituent components of the offshore grid.
- The model carries out the appropriate steps necessary to isolate the faulted component based on the deployed protection strategy. If the grid has the ability to re-configure to a new optimal set-up after a fault has occurred then an optimisation process is used to determine and implement this.
- Component repair times are separated into a number of categories and are calculated, where appropriate, based on realistic constraints including component and repair vessel procurement delays and the need for suitable weather dependent repair access windows.

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- Reliability performance is measured through the ability of each grid design to deliver available generated offshore wind energy to shore and, if applicable, provide inter-regional transmission capacity. A cost is applied to the value of this reliability based on the value of wind energy and differences in inter-regional electricity pricing.
- Detailed cost modelling based on available published data and informed estimates, is applied to each grid option to allow for an accurate representation of required capital expenditure.
- The operational costs associated with system electrical losses and continued O&M tasks are also calculated and together with the capital expenditure and reliability costs allow for a full cost analysis of each grid option to be applied.

The main novel contributions to knowledge offered by this thesis can be separated into two aspects. The first is the approach to determining the reliability of different grid options. No other published work into offshore network reliability has applied a methodology that intrinsically captures the seasonal variations associated with component repair times by directly basing the ability to carry out repairs on simulated time series of weather data and realistic access criteria as defined by industry. Secondly, the thesis quantifies the value of delivering good reliability in offshore networks and seeks to compare that against the costs of implementing this for each grid design option. No other published studies have compared to the same extent the array of different available network options or addressed this from a reliability and cost perspective.

6.2 Main Research Conclusions

Chapter 4 applied the developed reliability and cost modelling to various grid options over two specific offshore development case studies while Chapter 5 looked at a number of sensitivity studies and additional case studies to obtain answers to some of the key outstanding questions relating to the development of offshore HVDC grids. Both case studies looked at yet to be built, far offshore connection proposals with multiple large scale offshore wind farms, around which there is still some debate as to the preferred design choice. The ISLES case study looked at a project with five offshore wind farms totalling 2.1 GW capacity connecting between the GB and Irish grid systems whereas the Dogger Bank case study looked at a cluster of four wind farms with 2.8 GW capacity solely connecting into the GB system. The distances involved in both proposals suggest HVDC solutions are required but a number of scenarios were considered to compare and contrast different grid topology choices, configuration options, protection strategies and technology choices. A number of conclusions can be drawn from the results and are summarised in the remainder of this section.

The main results show that there is a large degree of uncertainty associated with the modelling and prediction of offshore grid reliability. In an attempt to define the degree of this uncertainty a range of feasible reliability scenarios have been investigated in each study and the results show that in the worst case scenarios, where individual component failure rates are high and repair times are long, reliability is a major issue with a large percentage of the generated offshore energy for a given grid option likely to remain undelivered due to faults on the DC grid. In this case the value of implementing grid options with inherent redundancy and therefore good reliability performance is high as the expected gains through increased energy delivery potentially outweigh the required capital expenditure. Under best case scenarios, however, the reliability performance of grid options are generally relatively high regardless of the grid design used so there is less value in implementing potentially costly measures to increase grid reliability as the returns in terms of increased energy delivery are relatively small. This means that in this scenario lower capital cost grid options are likely to offer the best value. Under

central case reliability predictions it is found that the trade-off between good reliability performance and high initial capital expenditure can be described as marginal and it is likely that compromises offering improved but not optimal reliability performance at relatively low cost may be the best option in terms of overall value.

Grid designs based on traditional radial connections to shore are found to offer poor reliability performance and in all the scenarios studied it is found that a grid option with some degree of co-ordinated design will offer better value than a grid that connects each individual offshore wind development directly to shore. Radial+ grid options with a degree of shared infrastructure can reduce capital expenditure but are still likely to display poor reliability performance. The introduction of multi-terminal HVDC systems introduces redundant transmission paths and offers a step change in reliability performance compared to radial solutions as evidenced by both case studies examined in Chapter 4. Unless the transmission distances and additional infrastructure costs associated with implementing the multi-terminal grid option are exceptionally high then it is likely that this is a preferable option to the use of unreliable radial design options. Moving from multi-terminal grid solutions to meshed DC grids is found to further improve reliability performance however the gains are less distinct than the jump from radial to multi-terminal grids and the costs of doing so are high, especially if a DCCB based protection strategy is assumed. The results of this thesis therefore question the value of pursuing highly reliable meshed grid designs when lower cost multi-terminal solutions may provide better value overall.

The technical review showed that it is widely assumed that DCCBs will be utilised in the protection of future offshore DC networks. However, the results of this study suggest that the expected costs associated with current design proposals make this option relatively expensive. Two alternative protection strategies are proposed and examined and it is found that both are likely to provide better value than the use of DCCBs. A strategy which uses sectionalised DC grids that are each limited in size to the loss of infeed limit of the AC system they connect to can be protected using existing AC side circuit breakers and cheap DC isolators only. In the event of a fault

the whole grid section is de-energized but even assuming a worst case time of one hour for isolation of the fault and recovery of healthy grid components it is found that there is only minimal impact on the overall delivered energy. It is found that the reduced complexity of this grid design can even improve reliability performance compared with a grid that utilises DCCBs. Given the assumed costs of DCCBs, avoiding the use of DCCBs has been shown to significantly reduce project capital expenditure. Another protection strategy is to make use of reverse current blocking full-bridge VSC converters and a reduced number of strategically placed DCCBs. It is envisaged that this option could provide near instant isolation and re-configuration to a new optimal system state which avoids the small penalty associated with temporary grid shutdown. This option, though, would incur higher electrical losses unless further technology advances are made. However, the cost savings related to the reduced number of DCCBs still make it a more favourable option than the assumed method of full DCCB protection.

As well as investigating different grid layouts an evaluation was made of two different converter configurations. The symmetrical monopole configuration is expected to be the standard approach to delivery of offshore DC networks. However, the use of a bipole grid configuration is also examined. This is found to offer a further step change in reliability performance compared against symmetrical monopole solutions although the costs of upgrading the converter station equipment and implementing the required additional earth return cable are found to be relatively high. The benefits of the bipole solution are therefore dependent on the transmission circuit length involved. As with other options that offer good reliability performance, the value of the bipole system increases as individual system component reliability becomes poorer. This means that although the bipole grid option may not offer the best value under central reliability predictions, unless DCCB costs are reduced or their use minimised, it does offer good value in terms of mitigating the risks associated with poor reliability performance so could be considered a least regret option for grid developers.

The value of implementing a reliability methodology which incorporates a measure of the seasonal influences relevant to the repair of offshore DC grid components has

been evaluated. It was highlighted in Section 4.3 that repairs can take significantly longer in winter months which is important because wind speeds are also generally higher in winter months. Reliability calculations based on simple mean time to repair estimates that do not include this seasonal impact may therefore underestimate the predicted level of undelivered energy for a given grid option by as much as 5% compared with the methodology proposed in this thesis. Although, in the context of various other uncertainties, this could be considered relatively small, the finding is appreciable and to deliver accurate estimates should be considered in future reliability studies involving offshore networks.

The main drivers behind offshore DC network reliability have also been investigated and it is found that the propensity of low probability but high impact fault conditions, especially transmission branch faults, are a key driver in determining the final reliability performance of an offshore DC network. These faults tend to strongly inhibit the ability to transfer power and also have long repair times associated with them such that even small variations in the number of such events or the length of events can have a significant impact on the overall level of undelivered energy associated with a grid design. Focusing on ways in which the number and impact of such fault conditions could be minimised is therefore a clear goal for the developers and operators of future offshore DC networks.

A number of other factors are found to have a strong influence on the reliability and therefore comparative value of different offshore grid options. The climate associated with the location of the offshore development is found to have a large bearing on the repair time of offshore components which in turn influences the reliability performance. Calmer sea states will lead to faster repair times and therefore reduce the value of expensive but reliable grid options whereas networks placed in areas with a harsher sea climate are likely to benefit proportionally more from having a highly reliable grid design. Distance between nodes in an offshore DC grid is also a key factor in determining which grid design should be used as the reliability benefits of more interconnected grid designs become more apparent as distance between nodes increases but so too does the cost of implementing expensive cable systems so the trade-offs should be investigated. Different cost assumptions can also have a

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strong influence on the final determination of the value of each grid option. Variations in the cost of energy, the annual discount rate and the cost assumed for different components, especially DCCBs, can all alter the conclusions that are drawn from the reliability studies. At current cost projections a DCCB based protection method is not cost competitive with alternative solutions and their cost would need to reduce significantly to achieve parity. Such a change would likely require a step change in the proposed requirements of DCCB breakers in offshore grids which assume a breaking time of less than 5ms is necessary.

6.3 Future Work

To build upon the work presented in this thesis and to improve the accuracy of future analyses there are a number of modelling areas which could be improved upon. Given the available published data this thesis has built a reliability model that focuses on the major constituent offshore grid components. If a more detailed breakdown of component failure data were to become available the model could be improved by separating failures into an increased number of categories, the repair of which could be modelled separately. For example, it is known that auxiliary systems are often a major source of the failures associated with the primary system components investigated in this study. The repair requirements for auxiliary systems are likely to be very different than for direct failure of the primary component and the ability to separate out failures in this manner would not only allow a more precise analysis of overall system reliability but would also be more informative as to what measures could be taken to improve reliability performance through easier identification of existing weak spots.

Improved reliability data might also address other issues raised throughout the analysis, for example whether or not there are distinct seasonal trends in the failure rate of offshore components or what the exact distribution of failure rates is. As discussed in Section 3.4.2 it has been reported in some quarters that failures are more likely to occur in winter months. However, without sufficient data available to corroborate this hypothesis the phenomena has not been modelled in this study. If such data were to become available then future studies could include this feature which would act to further enhance the seasonal variations in reliability performance that are already highlighted in this thesis. As discussed in Section 5.6, a detailed understanding of the true failure rate distribution of offshore grid components could also be used to gain a better understanding of the range of possible reliability outcomes and the probability of achieving close to the central estimates delivered by the model.

This thesis has looked in detail at the influence the level of redundancy built into offshore grid design in terms of number of transmission paths or the ability to maintain partial power flow under certain fault conditions. Further studies might also

seek to consider the influence of utilising further possibilities for system redundancy. For example, the use of a transformer system in offshore stations which incorporates a degree of redundancy against failures, as discussed in Section 5.1.3, may be a means of improving reliability performance that has not been considered in this study. To investigate this, more detail would be required as to the exact cost differences between different design options to allow for a cost benefit analysis.

Similarly, the level of spare components carried at any one time and the access to specialist vessels to allow access to failed components will both also have an impact on the overall level of reliability. This study makes specific assumptions regarding procurement delays. However, a more detailed study might compare the cost of reducing these delays, through investment in different levels of component spares or via different vessel ownership options, against the potential benefits of reducing repair times.

As discussed in Section 3.3.2, this thesis assumes that the input wind and wave time series are applied equally to all offshore wind farms in each scenario considered. This assumption is a valid approximation for wind farms clustered in relative proximity to one another. However for future studies, especially those that may consider more dispersed offshore network scenarios, it would be desirable to implement individual time series at each wind farm location which are cross correlated with one another. A means of maintaining the cross correlation between both wind speed and wave height time series is required to do this. Implementing this feature into the modelling process would allow a more accurate representation of the levels of generated energy that are available to the offshore grid at any one time. This would allow not only a more accurate representation of undelivered energy due to faults but, importantly, would allow an investigation to be carried out as to the optimal level of capacity that should be built into a given offshore grid design. This thesis has assumed that the transmission capacity built into each grid option is set at the full rated capacity of the system so that under normal operating conditions there is never the requirement for energy curtailment. However, it is rare that full generation output is achieved in an offshore grid with multiple generation sources so a study into the value of designing a system with reduced transmission capacity

would be an area worthy of future investigation. The expected utilisation of redundant transmission paths in multi-terminal or meshed grid options could also be examined to determine the optimal rating of transmission branches. If cross border energy trading is also considered the availability of interconnection capacity is another variable that would influence the optimisation of transmission branch rating.

Further improvements that could be made to the modelling process to include the calculation and cost of electrical losses and, where applicable, the level and value of traded energy. When considering more complex networks, to give a more detailed assessment of electrical losses a move away from the offline calculation used in this study is desirable. An automated loss calculation would be preferred either through bespoke modelling or through the implementation of the grid design options in an existing load flow simulation package. In either scenario this would require the accurate modelling of DC grid parameters and the control of power flows. Whereas this thesis assumes that the percentage converter losses are flat regardless of the level of power flow and only incorporates the dependency of power level into the calculation of transmission cable losses, for accuracy, future modelling should reflect the fact that converter losses may also vary proportionally with power output. This thesis also assumes that electrical losses are priced at the same value as delivered energy, whereas in reality if the metering point for wind energy is at the point of connection to the offshore transmission network then developers would actually be remunerated for their generation regardless of the electrical losses associated with the grid design. The cost applied to losses might therefore take on the average marginal wholesale price of electricity in the connecting market or markets to reflect the cost of producing additional generation from the remaining generation mix to replace the losses associated with the offshore network. Future work might therefore explore the different methods of costing electrical losses and the impact that may have on the overall cost analysis.

In terms of traded energy, this thesis has shown a means of determining the maximum available free transmission capacity that could be used for energy trading. To value traded energy, however, it is assumed that the interconnection itself has no influence on market prices at either end of the link which is not necessarily the case.

To determine an accurate representation of the value and level of traded energy a deeper consideration of the mechanisms and interactions of the energy market is required and one solution could be to merge the reliability methodology with a market simulation model which accounts for demand and energy prices on the onshore AC systems to which the offshore DC network connects. An example of a modelling method which incorporates these features but which does not include an assessment of reliability has recently been demonstrated in [1] and there would appear to be clear value in the future integration of reliability modelling, as demonstrated in this thesis, into existing platforms which offer more detailed modelling of other aspects of DC grid behaviour.

This thesis proposed an economic assessment methodology that allowed direct comparison of various grid options in terms of their overall suitability for carrying out the task of delivering offshore wind generation to shore and, if applicable, allowing cross border energy trading. Such a system does not, however, give a direct indication as to the costs and remuneration that would apply to each of the different actors who would be involved in the development and running of any future offshore grid developments. A more complete analysis might also consider the cost of energy to replace that which is curtailed, the impact on total social welfare or the direct remuneration that the offshore transmission owner receives in relation to the reliability performance their grid delivers. As discussed in Section 2.5 the wind farm developers, offshore transmission owners and the system operators will all have differing incentives with regards to the integration of reliability into the final delivered system. Further work is required to understand and model the means in which reliability performance might be incentivised in reality and thus translated into remuneration for the offshore transmission owner. A detailed knowledge of these matters would help determine the true value of building each of the different grid options discussed.

6.4 Summary

The topic of offshore HVDC network development remains one of great interest and there are still numerous areas in which further research is required to address the challenge of delivering infrastructure that can reliably connect to shore the anticipated increase in the levels of deployed offshore wind energy capacity at the best possible value. This thesis has shown that reliability can have a major influence on the overall value of different grid options and that the overall cost of delivering a grid design should always be weighed against its potential reliability performance. The case for implementing a degree of redundancy in terms of alternative transmission paths to shore in an offshore grid design has been made clear when compared to radial options. The optimal level of this redundancy, however, relies on a number of factors and minimising capital expenditure is a key aim. It has, therefore, been shown that to deliver DC grids at good value, alternative protection methods that avoid the widespread use of potentially high cost DCCBs should be considered.

6.5 References

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