MULBARTON PARISH COUNCIL

Norfolk Boreas - Deadline 18

7th October 2020

Introduction

This representation reviews the methodology by which past grid connection points seem to have been assigned, with reference to a report on the feasibility of offshore transmission recently issued by National Grid. In particular, aspects relating to the cost benefit analysis methodology that are relevant to the Norfolk Boreas project are discussed in Appendix 1.

A list of reference documents submitted under separate cover is included in Appendix 2.

Offshore Transmission review

A consultation report describing National Grid's approach to the government's review of offshore transmission was made available on 30th September 2020, together with several supporting documents. Whilst it has not been possible to review all of the documentation in detail, the table reproduced below appears in several places, and seems to summarise the approach that has been followed so far. The left hand column is described as the *status quo*, and has presumably been followed for the Norfolk Vanguard and Boreas projects.

Table 2-1 Comparison of project specific and integrated offshore network design approaches

Project Specific Design Approach	Integrated Offshore Network Design Approach
• Requirements for each project considered separately	• Takes account of possible future requirements
• Only considers point-to-point offshore network connections	• Considers a range of connection options including multi-terminal/meshed HVDC and HVAC options
• Individual project optimisation and transmission (HVAC or HVDC) decision	• Considers whole system optimisation and transmission technology decisions
• Onshore and offshore network designs are considered separately	• Considers effect on onshore system as part of offshore design development
• Interconnectors are designed and connected separately	• Possibility that interconnector/bootstrap capacity can be shared by an offshore wind farm
• Local community impacts are managed on a project by project basis	• Local community impacts considered on an overall impact basis

The left hand column seems to suggest that cumulative impacts, combined interactions with the onshore transmission grid, and impacts on local communities generally, have not been taken into account when assigning grid connection points. Furthermore, impacts on local communities seem to have been left to the applicant to 'manage' at a later stage. The cost benefit methodology used in the associated documentation seems to follow the same approach, and it is not clear whether the outcome is efficient, coordinated, or economical.

Conclusion

It would appear that the past assignment of grid connection points may not have taken full account of cumulative impacts, or the potential effects on local communities. Mulbarton Parish Council therefore maintains its objection to the onshore part of the Norfolk Boreas DCO application.

Appendix 1

Economic analysis

Following the methodology of the IOTP (East) feasibility study report, the baseline case is taken to be a simple radial connection scheme, in which each project has a direct link to the main centre of demand. The Bramford to Twinstead Tee upgrade is assumed to be in place, with Hornsea Three connected at Walpole, and Vanguard and Boreas at Bramford.

The purpose of the projects is to enable offshore wind energy to replace non-renewable energy supplies. This allows the substitution of one source of electricity supply by another at approximately the same price to the final consumer, and is not intended to increase the total supply. In economic terms, there is no net economic gain, and for the baseline case, the economic outcome is therefore assumed to be neutral. This is shown in Figure 1.

By providing offshore links between the projects, the capacity of the onshore grid is effectively increased. This reduces costs elsewhere, and leads to a net benefit for the final consumer. The net present value of an integrated scheme is then calculated by comparing this economic benefit, net of costs, against the baseline case of radial transmission only.

As demonstrated in the IOTP (East) study, all the integrated designs lead to a positive net present value. For the higher levels of East Coast Round 3 offshore wind deployment, this was found to lie between £7,469m and £8,017m. In the more limited case of Hornsea Three, Vanguard and Boreas only, the net present value may be estimated at around one third of the lower limit of the range, or £2,500m. This situation is illustrated in Figure 2.

In the case of a point-to-point connection scheme, the positive net present value arising from offshore integration is not applicable, leading to a loss of benefit for consumers. In addition, negative impacts are introduced within Norfolk. These unintended impacts, or ‘negative externalities’, are not necessary for the successful completion of the projects, but have significant adverse effects for local communities, for the natural environment, and in part, for the general public. This type of grid connection scheme is shown in Figure 3.

By way of example, the cumulative negative impacts can be estimated on a quantitative basis at a present value of about £2,500m. This nominal figure represents the real impact of the proposed connection scheme on homes, families, businesses, visitors, and the rural environment. These impacts have been described in full detail in other representations.[1]

Thus, in the case of an integrated scheme, the economic gain for the UK as a whole is estimated to be of a similar magnitude to the economic advantage for local communities and the rural environment. Unusually, these estimates can simply be combined, leading to a total overall advantage of a net present value of £5,000m in favour of integrated offshore transmission, as compared with point-to-point links. The national, local and environmental interests are all aligned in the same direction.

It would appear that this approach has not been followed in assigning a grid connection point for the Norfolk Boreas project.

1 Tourism is one of the largest sectors of the Norfolk economy, with an estimated annual value of £3,500m. A 2.8% reduction in revenue over 40 years, discounted at 2.5%, leads to an estimated present value of £2,500m. On a similar basis, the resident population of Norfolk is just under 900,000 people, occupying 400,000 households. A negative impact of £1,000 per year, experienced by 100,000 people, discounted at 2.5% per year over 40 years, also leads to an estimated present value of £2,500m. For simplicity, these two calculations can be merged into a single figure representing the overall negative economic impact.

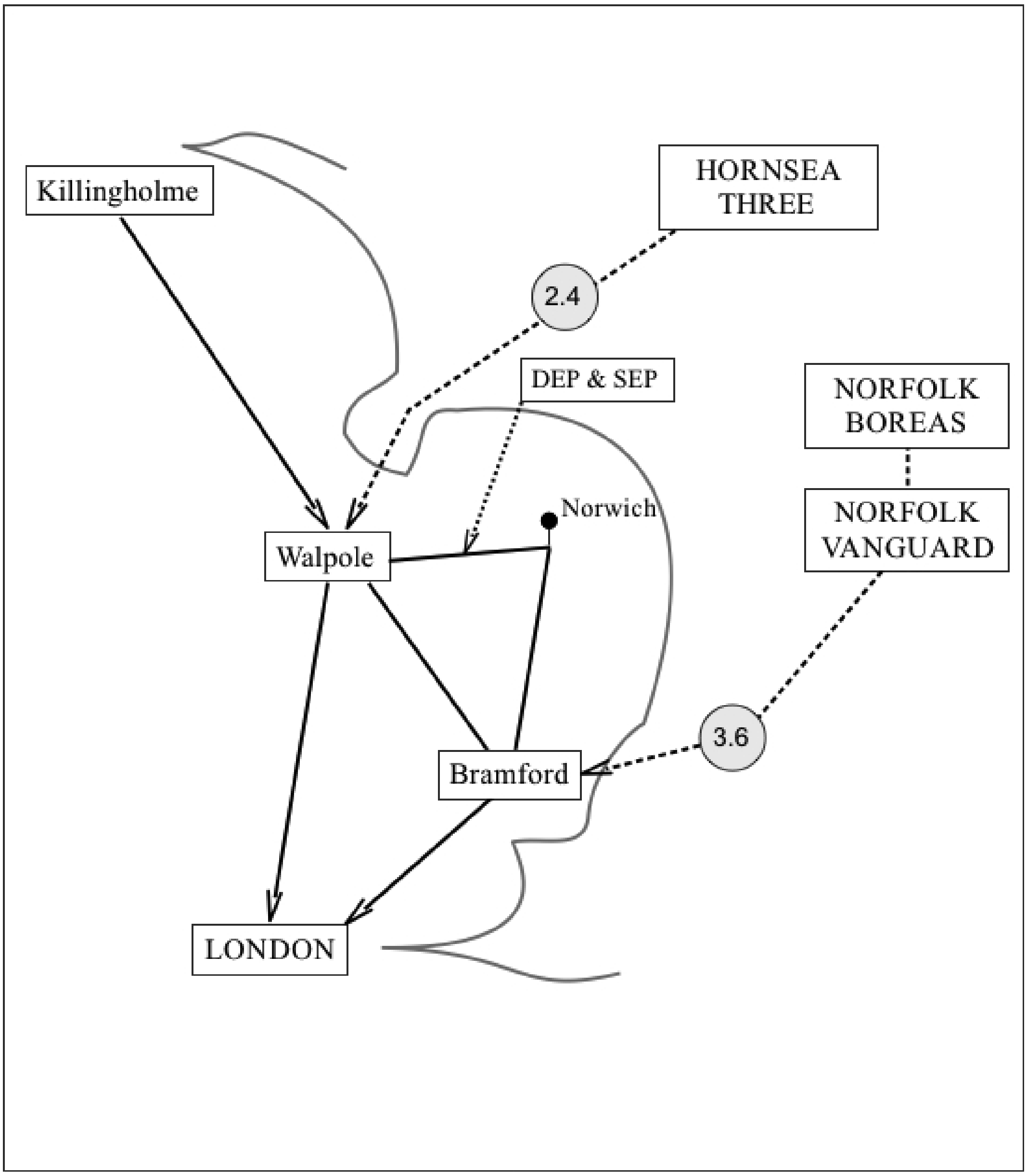


Figure 1: Neutral economic outcome

<u>Notes</u>:

For the baseline case, each project uses a radial connection leading directly to the main centre of demand. Assuming that there is sufficient out-of-region capacity available, this allows renewable wind energy to be substituted for other sources of power generation, at the same price to the final consumer, and in the same quantity. There is no increase in the overall supply of electricity, and in strict economic terms, there is no overall economic benefit arising from completion of the projects.

The export cables and onshore substations are sized for the maximum output of each project, at a total of 6.0GW. Due to the variability of wind energy, however, they are not fully utilised over time, and there is no alternative pathway in the event of temporary failure of an individual export cable.

Without an offshore link between the projects, the benefit to the final consumer from integration with the onshore grid is not possible. This is the baseline case against which the other scenarios are evaluated, and can be described as a neutral economic outcome.

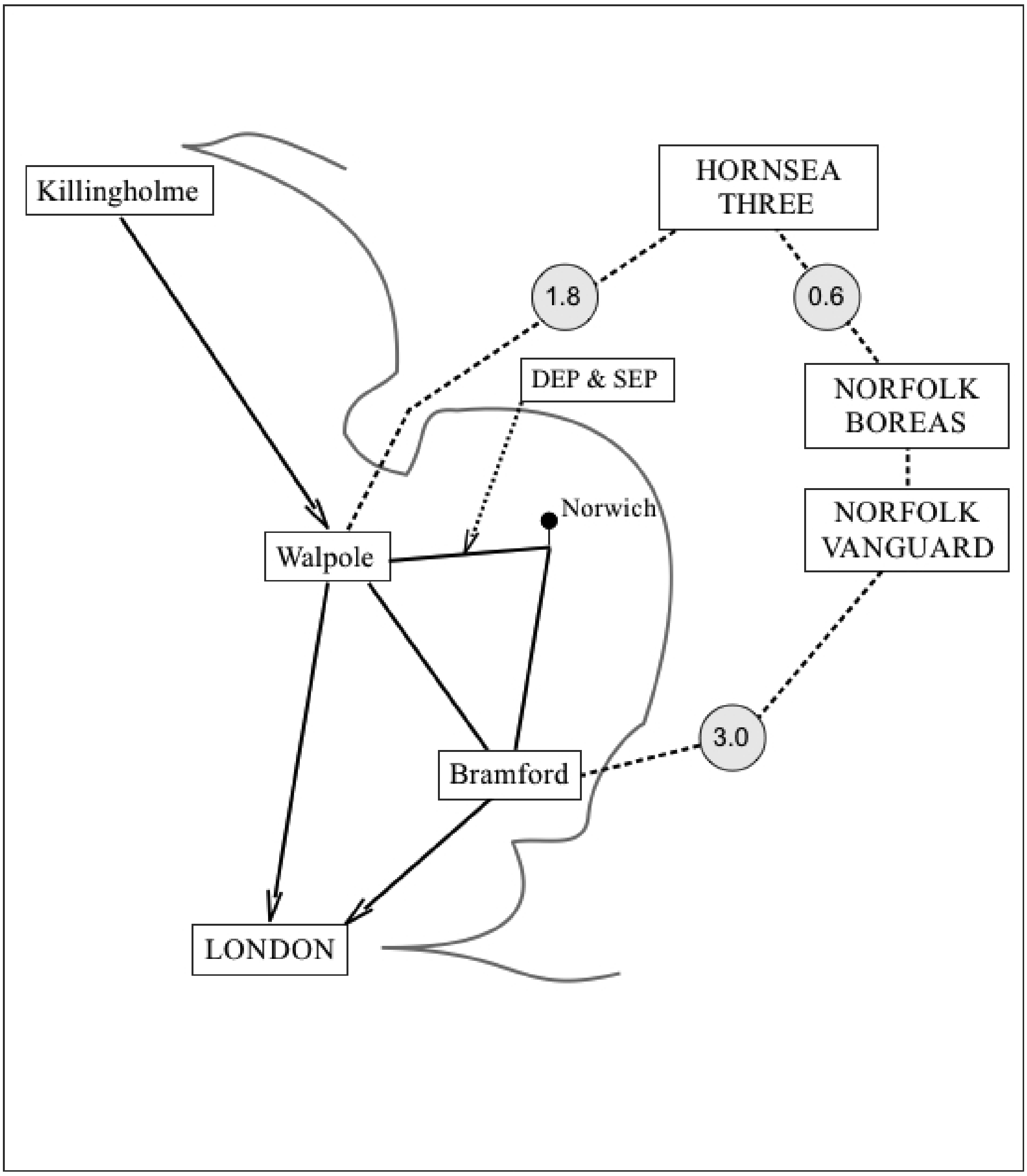


Figure 2: Positive economic outcome

Notes:

In comparison to the baseline case of one radial connection for each project, there are the same number of coastal landing points and grid connections, but the onshore substations are up to 20% smaller (4.8GW), and negative local impacts are reduced. The export cables can be fully utilised, and the availability of alternative pathways allows a greater amount of renewable energy to reach the main centres of demand.

The addition of an offshore link between the projects enables some integration with the onshore transmission grid, leading to savings for the final consumer estimated at approximately £2,500m. This is the net present value of the annual savings accrued over the life of the projects.

Compared to the baseline case, there is an overall economic benefit for the final consumer, for local communities, and for the environment, and the scheme has a positive economic outcome.

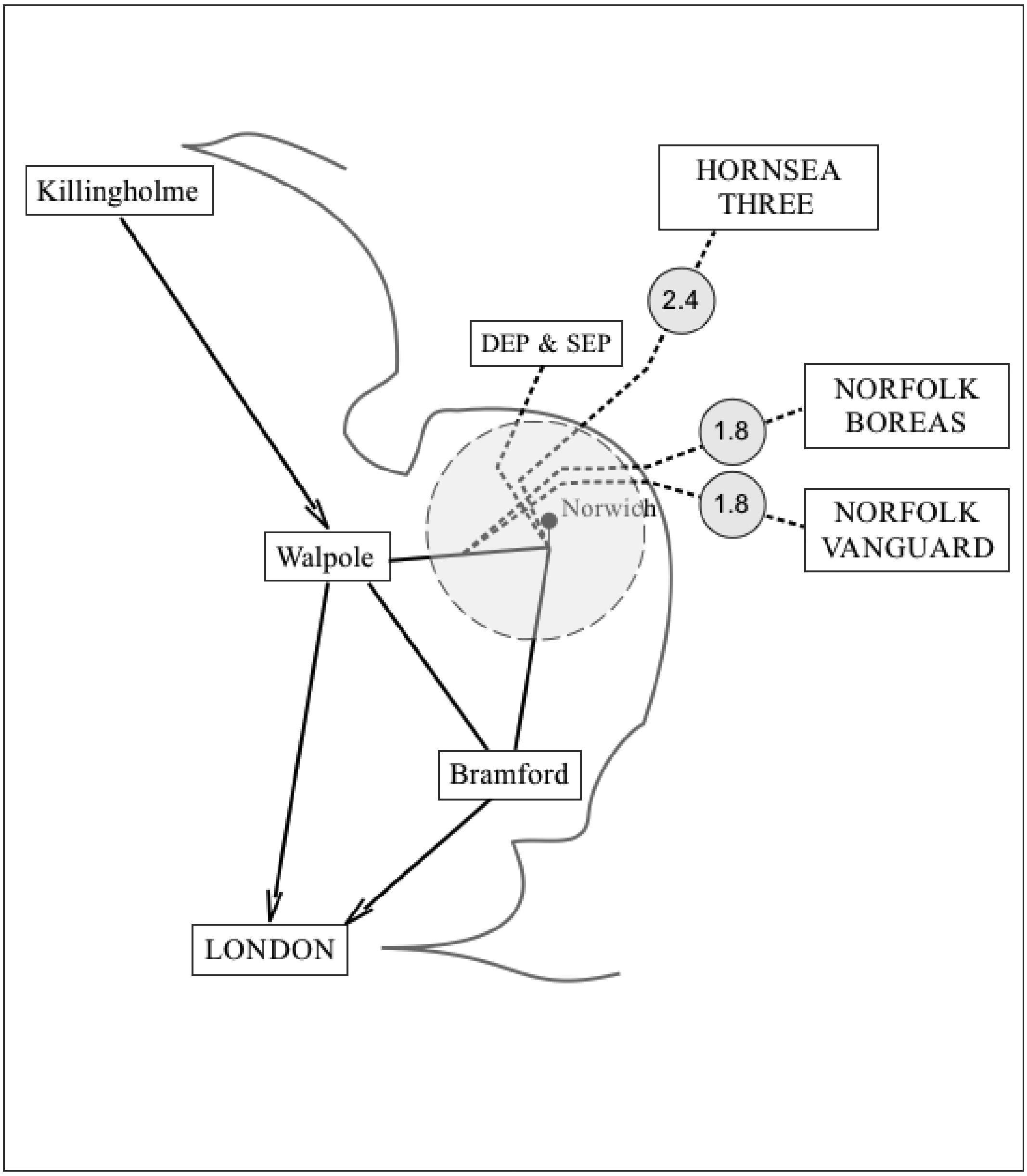


Figure 3: Negative economic outcome

Notes:

Compared to the baseline case of radial connections, each project has only a point-to-point link to the nearest onshore grid location point. The benefit to the final consumer of integration with the onshore grid is lost, and due to the location of the grid connection points, there may not be enough out-of-region transmission capacity for renewable energy to reach the main centre of demand.

As in the baseline case, onshore substations are sized for the maximum output of each project, even though they are not fully utilised over time, and in addition, further negative economic impacts are introduced within Norfolk. The cumulative impact of these economic losses, as experienced not only by local communities, but also by the general public, can be estimated at about £2,500m.

Compared to the baseline case, there is no significant overall benefit for the final consumer, or the environment, and economic losses arise for local communities. It does not seem to be possible to generate a positive overall economic outcome for the project from this scenario.

Appendix 2

Planning Inspectorate document references

Several documents cited or quoted in this and earlier representations can be found on the Planning Inspectorate's website under the appropriate project references:

Bramford to Twinstead Tee Overhead Line	EN020002
Norfolk Vanguard Offshore Wind Farm	EN010079
Hornsea Project Three Offshore Wind Farm	EN010080
Norfolk Boreas Offshore Wind Farm	EN010087
Dudgeon and Sheringham Shoal Extensions	EN010109

The Examining Authority is requested to accept these documents as being submitted.

Reference documents submitted under separate cover

IOTP (East) Feasibility Study	Summary Report and Appendices 1, 2 and 3 *

* The Summary Report has already been submitted by the applicant.

The Crown Estate	Offshore Wind Constraints Study

The Examining Authority is requested to accept these documents as being submitted.

Integrated Offshore Transmission Project (East)

Final Report

Conclusions and Recommendations

August 2015

Executive Summary

In 2011 the Crown Estate and National Grid published a report titled Offshore Transmission Network Feasibility Study[1] (OTNFS). This report detailed the initial consideration of using a coordinated design approach to provide connections for Round 3 offshore wind farms. This report concluded that savings for the GB consumer of between £2.4bn and £5.6bn could potentially be possible.

In order to ensure that the GB electricity transmission system continues to be developed in the most economic and efficient way possible, National Grid sought to build on the OTNFS findings to examine in more detail if an alternative approach to the development and connection of offshore generation could provide benefits.

The three large offshore wind zones located off the east coast of England – Dogger Bank, Hornsea, and East Anglia, were used as a basis to assess the potential benefits of alternative design approaches.

In 2012 a project team was formed made up of National Grid and the developers of these offshore wind zones: Forewind – Dogger Bank, SMart Wind and DONG Energy – Hornsea, and Scottish Power Renewables and Vattenfall – East Anglia.

Four individual work-streams (Technology, System Requirements, Commercial, and Cost Benefit Analysis) were formed to focus on each of these topics.

The Technology work-stream concluded that there are no major technical barriers that would definitely prohibit the development of integrated offshore networks to facilitate the connection of offshore wind generation.

The System Requirements work-stream identified a range of potential reinforcement strategies:

- A fully integrated design – offshore wind generation zones are inter-connected via offshore HVDC links to deliver both generation connections and wider system capacity.

- A hybrid design – offshore wind generation zones have some limited inter-connection but connections are generally direct to shore. Wider system capacity is provided by stand-alone offshore reinforcements i.e. an offshore link between two existing points on the onshore system.

- A standard radial design – offshore wind generation is connected directly to shore. There is no inter-connection between wind generation zones. Significant reinforcements are required on the onshore transmission system to provide wider system capacity. This approach is the one specified by the current regulatory and commercial frameworks.

The Commercial work-stream identified that, at the time the review of commercial issues was carried out, the existing regulatory and commercial arrangements would not adequately facilitate all aspects of the development and delivery of an integrated design solution for offshore wind generation. The project acknowledges that several of these concerns have since addressed by subsequent industry developments such as ITPR and the offshore

[1] http://www.thecrownestate.co.uk/media/5506/km-in-gt-grid-092011-offshore-transmission-network-feasibility-study.pdf

gateway process. The main report clearly identifies area where commercial concerns have been resolved.

The cost benefit analysis methodology sought to identify the least worst regret reinforcement strategy, i.e. across the range of generation scenarios assessed, which reinforcement strategy exposes the GB consumer to the minimum risk of over or under investment.

The cost benefit analysis showed that if the contracted levels of generation were delivered by 2030 then savings could be achieved by pursuing an integrated design.

However, since the OTNFS study there have been significant developments in the electricity industry and the wider economy, most notably Electricity Market Reform (EMR), which have impacted on the expected development rate of offshore wind generation.

It is now the view of the project members that offshore wind generation capacity is unlikely to reach the current contracted levels in the timescales required to make an integrated design approach beneficial.

The project now views the current contracted 17.2GW offshore wind generation scenarios as being unrealistic within the timeframe being considered. It therefore has set aside results based on 17.2GW being operational by 2030 from these the zones alone in the drawing final conclusions. A second scenario based around 10GW of offshore wind generation was also assessed. This 10GW scenario is considered to be a more likely top end scenario and the project acknowledges that there is a possibility that actual development may be lower even than this.

Under the Gone Green and Slow Progression variants of the 10GW scenario the CBA results show no clear least worst regret strategy. The differentials are well within the margin of error for this type of analysis.
The project acknowledges the possibility that the level of offshore wind generation delivered may be lower than the 10GW. Should this transpire then the non-integrated designs would perform better and would become the least worst regret reinforcement strategy.

By pursuing a non-integrated design both National Grid and the offshore generation developers can maintain closer control over the scope and programme of their individual works and hence minimise risks for consumers and investors alike.

As a result the project team does not believe it would be economic and efficient to progress with the development of an integrated design philosophy or delivery of anticipatory assets at this time.

Contents

1. Introduction and Background

In 2009 the Crown Estate concluded its tendering process for Round 3 offshore wind farm development zones. The potential generation capacity of these zones represented a step change in the scale of offshore wind farms compared with the Round 1 and 2 developments.

All previous offshore wind farm connections in Great Britain have been radial in design, i.e. a single direct link is provided between the wind farm and the point of connection on the onshore transmission system (using either alternating current – a.c. or direct current – d.c. technology). This radial connection is owned by a separate Offshore Transmission Owner. Although the current industry codes and frameworks do not exclude the possibility of an alternative design approach they were developed primarily to best facilitate the prevailing radial approach.

This radial design approach, when applied to the potential Round 3 developments, would mean significant volumes of generation connecting at single points on the onshore transmission system, in many cases these points of connection would be in close proximity to each other. Additional capacity on the onshore transmission system is likely to be required to accommodate these new generation connections and the resulting increased power flows.

A study was undertaken by National Grid and the Crown Estates (Offshore Transmission Network Feasibility Study – OTNFS), which identified that developing a coordinated approach to the development of offshore transmission infrastructure, focusing on the Round 3 and Scottish Territorial Waters projects, together with possible interconnection, could potentially save around £3.5bn in capital costs compared with a purely radial solution

The three Round 3 development zones located off the east coast of England, Dogger Bank, Hornsea, and East Anglia, are amongst the largest (in terms of potential generation capacity) proposed. These three zones are in relatively close proximity to each other and could drive the need for significant reinforcement of the onshore system.

In order to ensure the development of the most economic and efficient transmission system, National Grid sought to examine the potential for offsetting the need for new onshore infrastructure by establishing an integrated design approach to the connection of these generation zones. This approach would include the use of inter-connection between offshore zones (via offshore transmission assets) and optimising connections to the onshore transmission system.

In order to achieve this National Grid formed a project team including the developers of these offshore wind zones: Forewind – Dogger Bank, SMart Wind and DONG Energy – Hornsea, and Scottish Power Renewables and Vattenfall – East Anglia.

The Integrated Offshore Transmission Project - East (IOTP-E) team would examine different design philosophies for the connection of the three Round 3 offshore wind farms located of the east coast of England.

This summary report gives an overview of the work carried out, the main conclusions reached, and the recommended next steps.

2. Project Scope and Approach

In order to assess the viability of integrated connection designs the project team focused on four key areas: Technology, System Requirements, Cost Benefit Analysis, and Commercial. A dedicated work-stream was set up to study each area.

1. Technology – This work-stream would assess the current state, and expected future development, of technology required to deliver integrated offshore networks (primarily Voltage Source Converter High Voltage Direct Current – VSC HVDC equipment). The work-stream would provide a view as to whether the required technology would be available in the same timescales as the wind farm developments and also provide a forecast estimate of potential costs.

2. System Requirements – This work-stream would assess the impact of the new offshore wind generation connections on the existing onshore transmission system and identify the additional capacity that would be required. The work-stream would also propose connection options ranging from a radial design (in line with the current arrangements) to a fully integrated approach, including intermediate hybrid designs. The work-stream would also determine the additional system capacity provided by each design proposal and, using the information from the technology work-stream, determine a capital cost estimate.

3. Cost Benefit Analysis – This work-stream would use National Grid's established methodology and modelling techniques to carry out an economic analysis of the different design options proposed. This would primarily involve comparing the system operation costs that would result from each option. Operational costs in this context refer to conditions where the power flows across a network boundary exceed the maximum capacity of that boundary and hence generation must be paid not to generate and replaced with generation located elsewhere on the system. These costs are referred to as constraint costs. Using this method the work-stream would make a recommendation on the preferred design options and the optimal delivery time for reinforcements.

4. Commercial – This work-stream would examine the current commercial and regulatory frameworks that govern offshore wind development and recommend the additions or modifications required to facilitate an integrated design approach. This work-stream would consider the requirements of generation developer, offshore transmission owners, and onshore transmission owners.

Each work-stream has prepared a stand-alone report detailing the work carried out and the conclusions reached. Those reports are included here as appendices to this overall summary report.

This summary report describes the main conclusions reached by each work-stream, the overall conclusions reached by the project team, and the recommended next steps.

3. Technology Work-Stream

The work-stream aimed to establish the present state of development of the technologies required for an integrated offshore transmission system and to identify developments required in order for an integrated offshore transmission system to be built.

Due to the location and volume of the offshore generation being considered, HVDC technology would be required to deliver an effective integrated design. The costs of providing equivalent capacities with a.c. cable technology prohibit the use of that technology and hence it was not considered further by this work-stream.

A fully integrated offshore transmission system would require multi-terminal HVDC designs. To date the vast majority of worldwide HVDC applications have been point to point developments where only two converter stations are connected together. A multi-terminal approach would consist of several converters connected together as a meshed network where power could be transferred to several different converters at once. A multi-terminal HVDC design of type required for this project would represent a significant step change in this technology.

HVDC Technology

There are two main HVDC technology types, Line Commutated Converter (LCC – also known as current sourced converter or 'classic' HVDC) and Voltage Source Converter (VSC).

The majority of HVDC schemes currently in service use LCC technology, which has been commercially available since 1954. VSC technology is a newer development, it was first applied commercially in 1997 and significant growth in application and development in the technology have occurred since then. VSC technology offers certain performance advantages over LCC but is yet to achieve the same power ratings. However, significant developments are being made with respect to VSC ratings.

LCC HVDC Technology

The main characteristics of LCC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

- Based on thyristor valves to control the commutation.
- LCC HVDC technology is able to achieve high power ratings, an example being an HVDC link connecting Jinping and Sunan in China with a power rating of 7200 MW operating at ± 800 kV d.c. which was commissioned in 2013.
- Typical losses for a LCC HVDC converter are around 0.8% of the transmitted power.
- Operation is dependent on an a.c. voltage source (i.e. a connection to the a.c. system).
- Requires high short circuit ratio to ensure stable operation – i.e. the a.c. grid at either end of the HVDC link must be strong.
- Converter operation is accompanied by reactive power absorption, typically in the range 50 to 60% of the transmitted power. Hence reactive compensation plant is required.
- Converters of this type cause harmonic distortion. Therefore additional equipment is required to provide a.c. harmonic filtering in order to keep the harmonic distortion on the a.c. system within permitted levels.

- The space required for reactive compensation plant and a.c. harmonic filters in a LCC HVDC converter station may typically account for 50% or more of the station footprint.
- LCC HVDC converters are susceptible to faults and disturbances in the a.c. system which may cause commutation failure. A commutation failure results in temporary interruption to the power transmission.
- When more than one HVDC converters are in electrical proximity, a single fault or disturbance in the a.c. system may cause simultaneous commutation failures and loss of transmission in all links.
- Power reversal is accompanied by a change in the polarity of the d.c. voltage, which precludes use of LCC HVDC technology with extruded cables.

VSC HVDC Technology

The main characteristics of VSC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

- Based on semi-conductor technology, VSCs use Insulated Gate Bipolar Transistors
- The highest rated VSC HVDC system in service at present is the 500 MW East–West Interconnector between Ireland and Wales. A number of VSC HVDC systems with higher power transmission capacities are under construction at present, including some at 1000 MW.
- Active and reactive power are controlled independently and both may be controlled rapidly and continuously within the limits of the converter’s rating.
- VSC is not dependent on a strong a.c. network. It can be used with weak and passive systems making it ideal for offshore applications.
- VSC HVDC converters are self-commutated, meaning there is no requirement to install additional reactive compensation equipment.
- VSC HVDC converters require little or no a.c. harmonic filtering.
- Since a VSC HVDC converter requires little or no reactive compensation and a.c. harmonic filters, the station footprint is less than that of an equivalent LCC HVDC converter.
- A VSC HVDC converter may continue to transmit power in the event of a fault on the a.c. system. VSC HVDC converters do not suffer commutation failures.
- Losses for the present generation of VSC HVDC converters are less than 1% of the transmitted power per converter.
- Continuous operation at any level of power within its rating is possible.
- Power reversal is achieved by a reversal of the d.c. current, with the d.c. voltage polarity remaining unchanged. Since no reversal of the d.c. voltage polarity occurs, VSC HVDC converters may be used with extruded cables.

LCC vs VSC Comparison

The differences between VSC and LCC HVDC technology may lead to one or the other being better suited to the functional requirements of a given project. VSC HVDC technology tends to be advantageous in the following situations:

- where short circuit levels are low or where a black start capability is required
- where rapid control of power or rapid power reversal is required
- where the use of extruded cables is required
- where limited space is available

VSC HVDC converters are well suited to connection of offshore wind generation and to multi-terminal applications as required for the integrated offshore transmission project. The use of LCC technology for wind generation and offshore applications would generally require additional investment and would present some additional engineering challenges.

It is the conclusion of the Technology work-stream that the performance characteristics of VSC HVDC technology would be better suited to the integrated connection of offshore wind generation than LCC HVDC technology.

Technology Development

Many of the technologies required for an integrated offshore transmission network are new and developing rapidly.

At the moment the ratings available from VSC HVDC technology are lower than those of LCC alternatives. However, it is expected that by 2016, LCC HVDC systems with cables will no longer offer a greater power transfer capability than VSC HVDC systems.

VSC HVDC converters for offshore application are under construction. Several projects with offshore converters are currently in progress and valuable experience will be gained from these.
There is a clear requirement for reducing the costs of platforms for offshore HVDC converters. It is thought that developments in offshore platform technology would allow a 2000 MW offshore converter to be in service by 2021.

However, the development of offshore platforms required to accommodate 2GW converter stations is considered to represent the largest single technology risk to the delivery of integrated offshore networks.

The first two multi-terminal VSC HVDC systems have recently been commissioned. Both were designed and built as multi-terminal systems in a single stage of construction. To facilitate the wider implementation of multi-terminal HVDC systems, the development of standards to ensure compatibility of the equipment of different suppliers on a common HVDC system is highly desirable. Working Bodies within CIGRE and CENELEC are currently active in this area.

In order to secure integrated HVDC networks against faults to the same standard as an a.c. network, HVDC circuit breakers would be required. An HVDC circuit-breaker has been demonstrated in the laboratory. It is expected that such a device could be in service by 2019. Ongoing developments are envisaged in HVDC circuit-breaker technology in pursuit of increased operating speeds, higher ratings, reduced losses and reduced costs. Integrated HVDC networks can be delivered without this technology but would require different security and design standards.

Unit Cost Estimates

Unit costs have been obtained for each of the technologies required for an integrated offshore transmission network for use in cost benefit analyses.

Costs are influenced by many factors, including the specific requirements of a given project, exchange rates, commodity prices and the balance of supply and demand in the market at the time of tender. Due to a scarcity of current data, the costs were generally obtained by inflating those published in National Grid’s 2011 Offshore Development Information statement in line with the Harmonised Index of Consumer Prices (HCIP).

The full details of the unit cost estimates produced by the Technology work-stream are shown in Appendix A.

Protection of HVDC Multi-terminal Networks

Multi-terminal HVDC networks are more vulnerable to faults than an a.c. equivalent. This is due to the fact that there is currently no commercially available d.c. circuit breaker technology. As a result a fault within a d.c. network will result in the loss of the complete d.c. network rather than just the faulty section.

While an integrated offshore network could be delivered without this technology it would potentially be less flexible and robust than an a.c. equivalent.

Staged Delivery of HVDC Assets

VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the potential requirement for a higher transmission capacity it some point in the future is anticipated. Staged construction is described fully in Appendix A.

Technology Work-Stream Conclusion

The review carried out by the technology work-stream has concluded that there are no major technical barriers that would definitely prohibit the development of integrated offshore networks to facilitate the connection of offshore wind generation.

VSC HVDC technology is considered to be best suited to the application of integrated generation connections.

While the ratings currently available for this technology are lower than the LCC equivalent, it is considered that VSC converters and cables at 2GW ratings will be available prior to 2020 and hence would not limit the application of VSC technology.

The Technology work-stream acknowledges that there remains a significant amount of work to develop common VSC HVDC specifications and control philosophies, however indications are that manufacturers are seeking to address this. It is expected that if real demand for integrated VSC HVDC projects was to materialise that manufacturers would facilitate development in this area.

The development of protection equipment for integrated HVDC networks is currently behind that of the a.c. equivalent, particularly with respect to d.c. circuit breakers. While an integrated offshore network could be delivered without this technology, greater flexibility and efficiency could be achieved should they be developed. Indications are that manufacturers would seek to invest in this area if consumer demand materialises.

Estimated capital costs have been developed. While the work-stream acknowledges the degree of uncertainty inherent in these estimates, it concludes that, should integrated offshore HVDC networks be required, costs are unlikely to present a prohibitive factor compared with other design solutions.

The full Technology work-stream report can be found in Appendix A.

4. System Requirements Work-Stream

Assessing Transmission System Capability and Requirements

In order to allow National Grid to assess the capability and requirements of the onshore transmission system the network is divided into series of areas by notional boundaries.

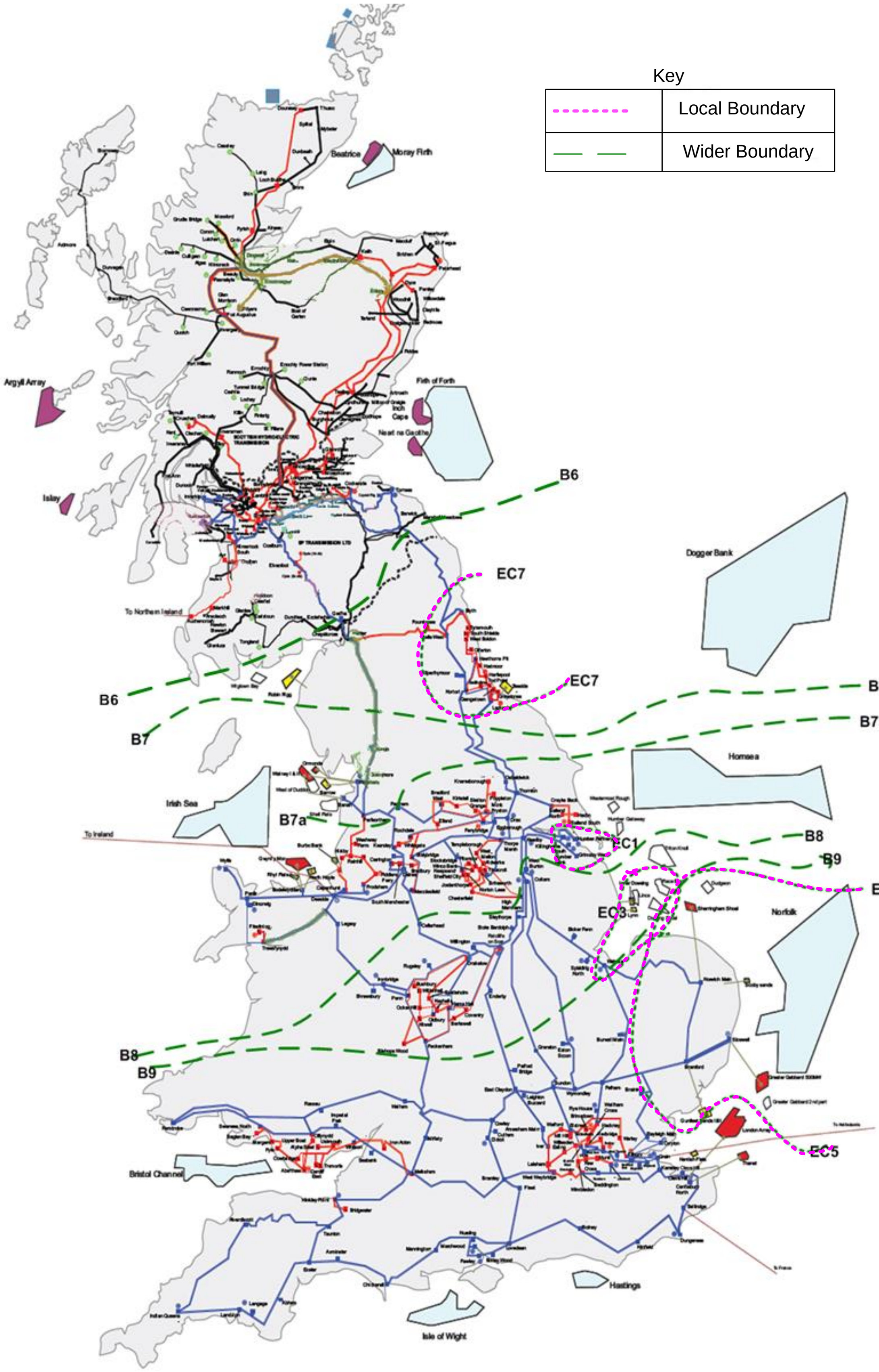
These boundaries define key parts of the network from which power is either exported or imported.

The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) defines the method for calculating the minimum power transfer a boundary must be capable of. Where boundaries are unable to meet this transfer, National Grid may have to constrain generation in that area to reduce power flows, over time this can result in significant costs.

Therefore National Grid seeks to ensure that, where it is economic and efficient to do so, all boundaries have sufficient capacity to meet the requirements of the NETS SQSS.

The main system boundaries that will be affected by the connection the east coast Round 3 offshore wind farms are titled B6, B7, B7a, B8, and B9; these boundaries are concerned primarily with the transfer of power from Scotland and the north of England to demand centres located further south. Some smaller local boundaries were also studied.

The geographic location of the key boundaries considered in this project is shown in the following diagram.


Key
Local Boundary
Wider Boundary
Moray Firth
Beatrice
Argyll Array
Islay
Firth of Forth
B6
EC7
Dogger Bank
To Northern Ireland
B7
B7a
Hornsea
Irish Sea
To Ireland
EC1
B8
B9
EC3
EC5
Norfolk
Bristol Channel
Hastings
Isle of Wight

Future Generation Scenarios and Boundary Requirements

New generation connections can increase the transfer requirements across boundaries in that area. If this additional capacity requirement exceeds the maximum limit boundary limit then the boundary will need to be reinforced through either upgrading the existing circuits or by delivery new circuits.

As there is uncertainty around the exact volumes of offshore wind generation that will be delivered, the System Requirements work-stream has used a number of different future generation scenarios to determine a range of possible future requirements.

The 2013 versions of the National Grid Future Energy Scenarios (FES) were used as the basis of the more specific scenarios developed for this project.

The 2013 FES comprised of two core scenarios: Gone Green (GG) and Slow Progression (SP). The GG scenario is design to represent a case where the GB 2020 carbon and renewable energy targets are met. The SP scenario illustrates the case where the 2020 targets are missed and not achieved until around 2025.

In addition to these wider scenarios the work-stream considered two main sensitivities specific to the development of the offshore wind generation in the Dogger Bank, Hornsea, and East Anglia zones. These were:

Sensitivity	Description	Total Volume of Offshore Wind Generation
Contracted Position	The contracted volume of offshore wind generation across the three zones is delivered.	17.2GW
Central View	Wind generation across the three zones is lower than the currently contracted position.	10GW

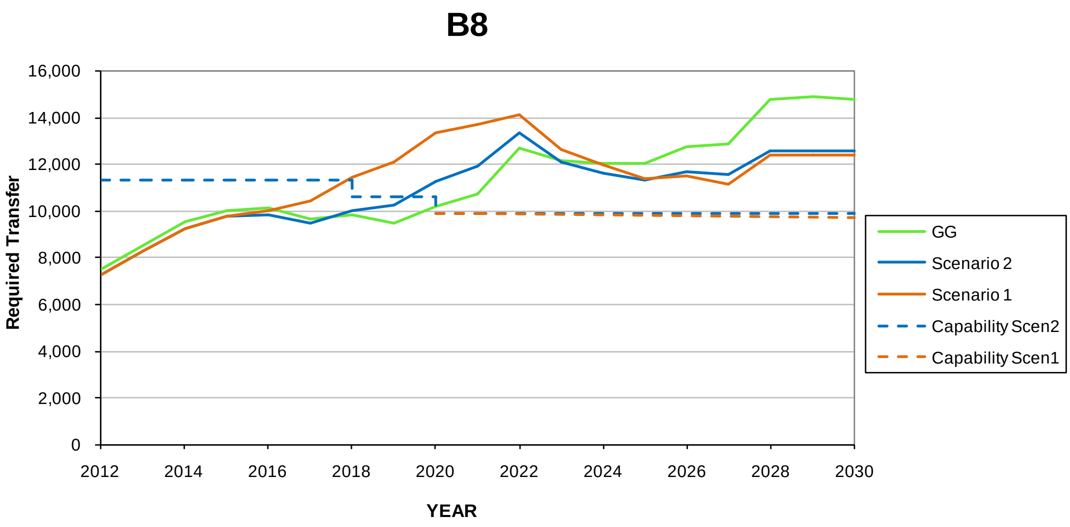
The central view was intended to represent a case where, for any given reason, the offshore generation developers chose to deliver a level of generation lower than the maximum capacity of the zone. Changes to the originally agreed contracted position are not uncommon in generation development project (onshore or offshore).

Each of these local sensitivities was then coupled with the both the core GG and SP scenarios, giving four overall background scenarios.

Core Scenario	Local Sensitivity
Gone Green	Contracted Position
Gone Green	Central View
Slow Progression	Contracted Position
Slow Progression	Central View

The System Requirements work-stream has assessed the future boundary requirements that will be driven by the connection of the three Round 3 wind farms off the east coast of England.

An example of the boundary transfer requirements calculated is shown below. The graph shows that, against all variants of the core GG scenario, the power transfer requirements for the B8 boundary will exceed the existing capability of the boundary sometime between 2016 and 2020.



The full details of the boundary analysis carried out and the future transfer requirements calculated are given in Appendix B.

The boundary analysis has shown that there will be a need to deliver additional capacity across the boundaries assessed under all combinations of scenarios considered. The requirement is greater and materialises earlier under the GG based scenarios.

Proposed Design Options

The Systems Requirements work-stream developed a range of different design options that could be used to provide both a connection for the offshore wind generation and additional boundary capacity across the key B6, B7, B7a, and B8 boundaries.

In order to determine the merits of an integrated offshore solution the work-stream also developed options that focused on standard radial offshore connections with additional boundary capacity being provided by reinforcements to the existing onshore system.

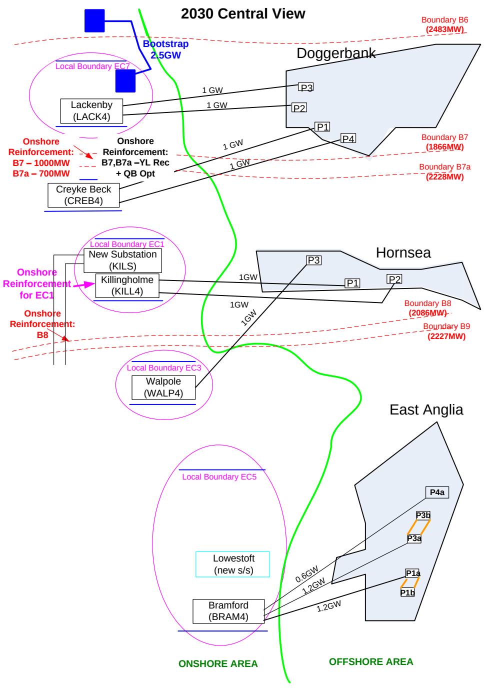
The work-stream also considered hybrid solutions that combined elements of offshore integration with stand-alone boundary reinforcements.

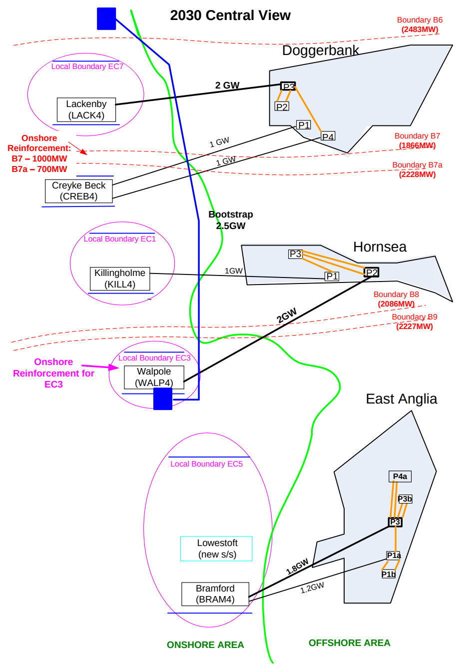
The technology types used to develop these design options was governed by the findings of the Technology work-stream and hence are based around VSC HVDC links with ratings up to 2GW.

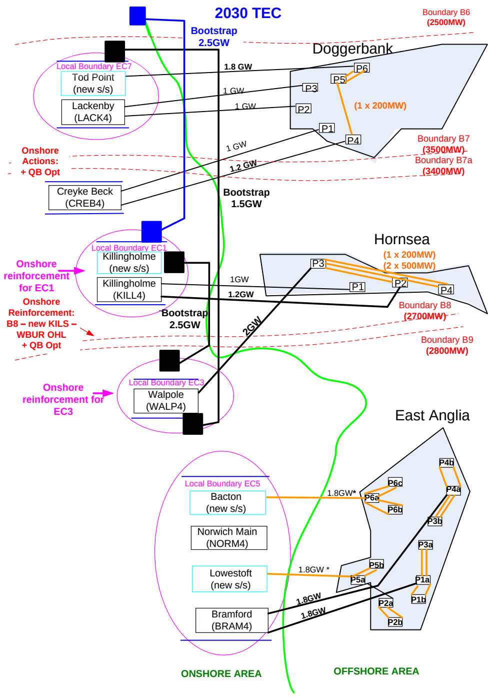
The System Requirements work-stream assessed the additional boundary capacity that would be delivered by each design option proposed.

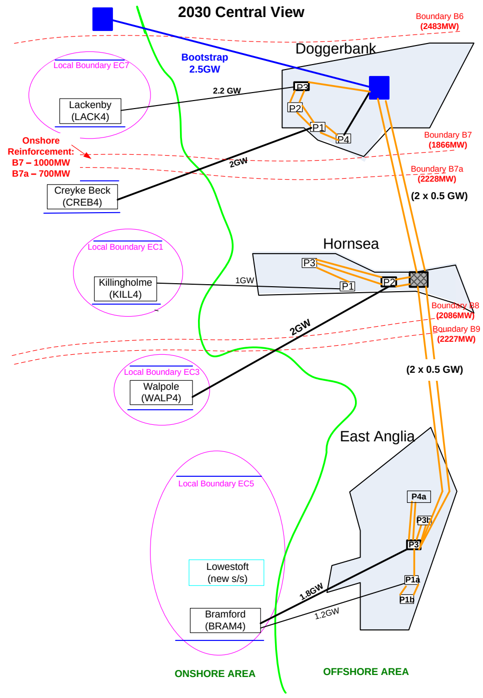
Cost estimates for the design options were also calculated using the unit cost assumptions prepared by the Technology work-stream.

Over 15 design options (and variants thereof) were developed by the System Requirements work-stream, examples of these are shown below.









The full details of the complete range of designs proposed, the capital cost estimates, and the boundary capacity delivered can be found in Appendix B.

5. Commercial Work-Steam

Note for the Reader

Much of the analysis work carried out as part of this project took place prior to and then in parallel with Ofgem's Integrated Transmission Planning Review (ITPR) project. As such some of the key concerns raised by the Commercial work-stream have now been addressed, particularly with regards to the process through which anticipatory investments would be identified and assessed by Ofgem. Instances where an issue raised by the work-stream has now been resolved will be specifically highlighted in this report.

Existing Frameworks

The current commercial and regulatory frameworks in place were primarily designed and developed to support the delivery of the Round 1 and 2 offshore wind farms. Due to the size and location of these developments, all were connected using a radial approach.

Prior to the announcement of the proposed Round 3 developments there was not considered to be any driver to examine an integrated design approach. Therefore, while the existing commercial and regulatory arrangements did not exclude the potential of an integrated design approach they had been designed and developed to best facilitate radial connections.

As a result, the pre-ITPR arrangements introduced a number of risks and uncertainties to the development of integrated connections that could cause significant barriers, particularly around the ability of offshore wind farm developers to plan and finance projects.

An essential element of any approach to enhance co-ordination is the ability to drive through the identified design solution. All parties will need to be clear as to their accountabilities and those of others, particularly the role of the National Electricity Transmission System Operator (NETSO) need case. Effective collaboration will be an important mainstay of the process of co-ordinating investment.

In order to address this risk, the Commercial work-stream has explored five key areas to determine if changes would be required to allow development of an integrated approach.

- Regulation
- Financing
- Charging
- Consenting
- User Commitment

Regulation

The regulatory issues associated with developing and delivering integrated offshore generation connections are primarily related to the ownership of assets and the relationships and obligations between these different parties – generators, offshore transmission owners (OFTOs), and onshore transmission owners.

An integrated design (especially one delivered through the staged build of anticipatory investments) would introduce uncertainty over the definition of generator connection assets and those assets that are providing wider network benefits. For example, the subsequent delivery of additional assets to provide integrated benefits could interact with the control system configuration of the initial generator connection assets. This could lead to the need to redesign or reconfigure these assets. Clarification would also be needed on how individual generators could demonstrate ongoing compliance with their Grid Code requirements whilst also delivering wider network benefits. For example, in an integrated system where would the interface points be specified? If the requirement was to remain at the point of connection to the onshore network how would the Grid Code requirements be aggregated and allocated between all connected generators?

Uncertainty around the initial scope or future requirements of any offshore transmission assets could potentially limit the number of parties providing tenders to deliver these works. The scope of work to be delivered could change in response to generators changing their TEC, delivery dates or terminating altogether. This could result in significant changes being made to the specification against which a supplier has tendered and hence require re-design / re-tendering. The work-stream considers it possible that suppliers could favour non-integrated projects in order to increase certainty over their deliverables. This could result in higher costs and hence a poorer outcome for the GB consumer. The work-stream acknowledges that this issue also applies to onshore developments but to a lesser extent. Onshore projects are generally driven by one developer and the design of connection assets dependent almost entirely on their plans. In an integrated offshore environment it is possible that multi-parties could impact on each other design requirements and the potential for significant changes are projects develop is considered to be higher than for “standard” onshore projects.

An integrated offshore design would likely result in a large degree of interdependency between different OFTOs, which has implications for the availability incentive and the co-ordination of outages. While this is not a barrier to progressing integration it must be acknowledged that it would add an additional layer of complexity to the existing arrangements and hence would need a robust process put in place to ensure these relationships would be managed.

The availability incentive mechanism should be enhanced to ensure that the incentives are appropriately weighted, and that an OFTO that is dependent on another OFTO’s assets to route power to shore is not penalised for an inability to export if the fault occurs on the other OFTO’s assets. There should further be a requirement for all interconnected OFTOs to coordinate outages in the best possible way to ensure that the disruption to generators is minimised.

Financing

The Commercial work-stream has concluded that any regulatory arrangement that increases the risk profile currently carried by offshore wind developers is likely to dissuade investment in this area.

If greater certainty cannot be achieved as to how the risks around potential asset stranding would be managed then it is the view of the Commercial work-stream that offshore wind farm developers will focus on project where the risk profile can be minimised, e.g. smaller scale, radially connected developments.

Due to the timescales and stranding risk it seems more likely that anticipatory investments that are relatively cheap have a chance of being made. Even with these investments it will be important to analyse the benefits to ensure that the party contemplating making the investment and taking the risk is the party getting the reward. This is by no means a given in the current regulatory environment. Furthermore, the party making the anticipatory investment and taking the risk should be the decision maker as to whether the investment is made. If another party seeks to influence the investment decision or direct that it is made there would need to be a clear transfer of risk to that other party.

Some of the anticipatory investments with the potential to save the biggest amounts of capital require high up front anticipatory investment and are risky. They probably only be managed by making bigger financial investment decisions. A 2GW wind farm FID to match with a 2GW HVDC transmission link is an example of what may be needed. While such 2GW wind farm FID decisions have not yet been ruled out for the later phases of the development of the southern North Sea Round 3 wind farm zones, no developer is currently developing projects greater than 1.2GW for the projects that are in active development at the moment. One of the developers has put some thought into larger links for the later stages of zone development, but deployment would be well into the future.

The concerns raised in this section accurately represent the concerns of the project work-stream at the time of writing. However, the Offshore Gateway process was developed and implemented in a parallel with this work and addresses the key areas of these concerns, particularly around anticipatory assets and potential stranding risks. The work-stream acknowledges that these risks should be adequately managed through the offshore gateway process.

Charging

If an integrated design approach were to be applied to the east coast Round 3 development is it possible that some anticipatory investments (e.g. oversizing of platforms and HVDC links) would have to be put in place well before the period 2025 – 2030 when the bulk of the gernation capacity would be delivered.
Charging arrangements for offshore generators had been introduced into the charging methodology by modification GB-ECM08. These arrangements did not consider the possibility of an integrated, coordinated or interconnected offshore network, but rather offshore generators connected radially to the main onshore network.

Under this arrangement offshore assets were assumed to be dedicated investments for specific projects, and the cost would be carried mainly by those projects.

In 2012, National Grid initiated an industry workgroup to look at the issues around charging for an integrated offshore transmission system, and identify potential developments to the charging methodology that could be taken forward. The group concluded in summer 2013 and a report was published on National Grid's website. The report noted three main areas where change was required:

1. The link between offshore tariffs and OFTO revenue could result in the cost of integrated offshore transmission assets being reflected disproportionately on offshore users, as their tariff would be calculated on the assumption that the assets were sole use.
2. The attribution of flows on offshore transmission networks does not reflect the different standards used to design those networks, which could result in wider system reinforcements being unduly assigned to offshore generators.
3. The impact of sequential co-ordination could have a significant impact on the volatility of charges (and implications for certainty under Contracts for Difference strike prices), and act as a first mover deterrent.

The group identified a number of potential solutions which could be developed through a Connection and Use of System Code (CUSC) modification proposal to address these issues.

Any Transmission Charging Methodology modifications should be progressed through the normal forum to eliminate the identified unacceptable level of tariff volatility that can be seen with integration.

Consenting

It is likely that the different elements of an integrated offshore network would require individual consents which would be obtained through separate existing processes.

The commercial work-stream does not expect that it will be possible to obtain consent for the complete scope of an integrated offshore network through a single planning application.

Certain works may be more difficult or take longer to obtain consent than other works. Broad assumptions can be made, for example obtaining consent for a Nationally Significant Infrastructure Project (NSIP) under the Planning Act 2008 is likely to take considerably longer than only seeking a marine licence for an electricity cable.

However, it can reasonably be assumed that if new onshore transmission circuits were required, then gaining consent for these would represent the most challenging element of any project in terms of risk, cost and time.

Despite this the Commercial work-stream does not believe that there are any barriers in the consenting process over and above those already faced by large scale electricity infrastructure projects.

User Commitment

There are two main types of integrated offshore investments that on which user commitment could impact.

The first is when additional interconnection is provided between wind farms to provide wider system boundary capacity. In this case, the Gateway process to allow Ofgem the opportunity to approve the rationale behind the project has to provide full confidence for whoever is progressing the investment.

There is currently no obvious financial incentive on an offshore developer to undertake a project with such a limited direct benefit. Indeed, the additional financing costs that would be required to construct a project of this type could be a barrier to a developer agreeing to undertake such work. An OFTO build approach would mitigate the developer carrying the additional financing requirement. However, there have yet to be any examples of the OFTO build approach being adopted for any Round 1 or 2 wind farms and the work-stream does not see any indication of why this would change for Round 3 developments.

The second case is where additional anticipatory capacity is provided to facilitate the connection of future offshore wind developments. In this case the work-stream finds that the existing industry framework for user commitment could be applied.

Commercial Work-Stream Conclusions

The Commercial work-stream concluded that, at the time of project commencement, the existing regulatory and commercial arrangements would not adequately facilitate the development and delivery of an integrated design solution for offshore wind generation. This was due to there being a perception that there was too a great a level of uncertainty around roles and responsibilities in the development process and also with regards to who would deliver and own certain assets.

It was considered that the current arrangements resulted in too great a level of uncertainty around project scope and cost when applied to integrated designs. In particular the arrangements around funding and charging would need to be clarified to ensure that offshore wind developers can successfully secure investments.

If those levels of uncertainty were not addressed, there was a risk that offshore developers will be discouraged from progressing large scale far shore projects that may be subject to integration requirements and hence focus on smaller, less complex developments.

The Commercial work-stream acknowledges that several of the key concerns identified during this project have now been addressed by the offshore gateway process and ITPR, particularly with regards to the process with which anticipatory investments would be identified and assessed by Ofgem.

There remain a number of uncertainties regarding specific issues around allocation of charging and treatment of asset unavailability. However these are not considered to present material barriers to the progression of integrated designs.

6. Cost Benefit Analysis Work-Stream

Study Objectives and Scope

The work undertaken by the Cost Benefit Analysis (CBA) work-stream was designed to compare the scale of forecast network constraint cost savings versus the investment cost of more sophisticated network designs.

The current transmission network capabilities coupled with the range of generation projected to connect/disconnect over the next 20 years will impact on operational costs. These operational costs will increase in the absence of any further network reinforcements.

The CBA work-stream had the following key objectives:

- To present economic justification for the preferred designs and an explanation of how they compare with the alternative counterfactual case.
- To present evidence on expected long-term value for money for consumers considering a range of sensitivities, and
- To present evidence on optimal timing of the preferred reinforcement option.

To meet these objectives, the CBA work-stream agreed the following scope of work:

- To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across two generation background scenarios.
- To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.
- To undertake a CBA by:
    - Appraising the economic case of the options by adopting the Spackman approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
    - Establishing worst regrets associated with each design/technology appraised.
    - Identifying the Least Worst Regret option overall.
    - Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
- Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

Future Generation Scenarios

As described in the System Requirements section, the project assessed the requirements of the two core Future Energy Scenarios (as were available in 2013): Gone Green and Slow Progression.

In addition to these two core scenarios the work-stream also considered two sensitivities related specifically to the development of wind generation in the three zones (Dogger Bank, Hornsea, East Anglia). These sensitivities were the contracted position – giving a total wind generation capacity of 17.2 GW, and the central view – which gave a total installed capacity of 10 GW across the three zones.

In addition to these overall scenarios, the work-stream also made assumptions around the load factor of the three offshore wind generation zones and the output correlation between these zones. The load factor information was based on information from the Metrological Office.

Methodology and Modelling

Constraint costs are incurred when the desired power transfer across a transmission system boundary exceeds the maximum operational capability of that boundary. When this occurs, it is necessary to pay generation behind that boundary to reduce production (constrain their output) and replace this energy with generation located in an unconstrained area of the network to balance the system.

Under current arrangements, constraint payments are made to onshore Generators, but not to offshore generators. Renewable Obligation Certificates (ROCs) / Contracts for Difference (cfd) are not paid when Generators are not delivering energy. Consequently the consumer will pay less when offshore wind generation is constrained, as the reduced ROC / cfd payments outweigh the cost of bringing on onshore generation. However, established practice in cost benefit assessment of offshore wind is to assume that higher availability brings consumer benefit through its contribution to meeting renewable energy targets, and its potential to offset the need to develop further offshore generation to ensure that targets are met. In the analysis described in this report this benefit is represented by applying constraint costs to offshore generation. The applied constraint cost includes the value of ROCs / cfds that would be paid if the energy was provided.

The Electricity Scenario Illustrator (ELSI) is National Grid's in-house model used to prepare medium to long term constraint forecasts on the transmission network. The model is our preferred tool to inform long term investment decisions.

ELSI is a Microsoft Excel based model which utilises Visual Basic linear programming to perform optimisations. Additionally, unlike most tools, ELSI adopts a transparent modelling approach, where all input assumptions and algorithms are accessible to the user.

ELSI represents the GB electricity market, in which the energy market is assumed to be perfectly competitive; i.e. there is perfect information for all parties, sufficient competition so that suppliers contract with the cheapest generation first, and that there are no barriers to entry and exit.

The electricity transmission system is represented in ELSI by a series of zones separated by boundaries. The total level of generation and demand is modelled such that each zone contains specific generation capacity by fuel type (CCGT, Coal, Nuclear etc.) and a percentage of overall demand.

Zonal interconnectivity is defined in ELSI to reflect existing and future boundary capabilities. The boundaries, which represent the transmission circuits facilitating this connectivity, have a maximum capability that restricts the amount of power which can be securely transferred across them.

ELSI models the electricity market in two main steps:

- The first step looks at the short run marginal cost (SRMC) of each fuel type and dispatches available generation from the cheapest through to the most expensive, until the total level of GB demand is met. This is referred to as the 'unconstrained dispatch'. The network is assumed to have infinite capacity and so does not impinge on the unconstrained dispatch.

- The second step takes the unconstrained dispatch of generation and looks at the resulting power transfers across the boundaries. ELSI compares the power transfers with the actual boundary capabilities and re-dispatches generation where necessary to relieve any instances where power transfer exceeds capability (i.e. a constraint has occurred). This re-dispatch is referred to as the 'constrained dispatch' of generation.

The algorithm within ELSI will relieve the constraints in the most economic and cost effective way by using the SRMC of each fuel type. The cost associated with moving away from the most economic dispatch of generation (unconstrained dispatch), to one which ensures the transmission network remains within its limits (constrained dispatch) is known as the operational constraint cost and is calculated using the bid and offer price associated with each action.

Like industry benchmark tools for constraint cost forecasts, ELSI includes various input data including:

- Transmission Network
    - Boundary capability assumptions
    - Seasonal ratings
    - Annual outage plan for each boundary
- Economic Assumptions
    - Fuel costs and price of carbon forecasts
    - Thermal efficiency assumptions by fuel type
    - Bid and Offer price assumptions by fuel type based on historical data
    - Seasonal plant availability by fuel type based on historical data
    - Renewable subsidies
    - Forecasts for base load energy price in Europe and Ireland
    - Forecast SRMCs by fuel type, which defines the merit order
    - Zonal SRMC adjuster
- Generation scenarios and sensitivities
- Demand
    - Demand profile or load duration curve
    - Zonal distribution of peak demand
    - Forecast annual peak demand based on two energy scenarios
- Wind generation
    - Represented by sampling ten years of historical daily wind speed data. Each day studied is defined by season and is divided up into four periods within the day.
    - ELSI model disaggregates the wind data into fifteen zones, with Dogger Bank, Hornsea and East Anglia separately represented. This allows for temporal and locational wind diversity in ELSI
- Reinforcements
    - Onshore reinforcements anticipated in ETYS for both generation backgrounds that are delivered by 2030/31.
    - The offshore integrated capability across each boundary provided by each design from 2030/31.

The full details of the modelling assumptions and methodology used can be found in Appendix D.

Least Worst Regret Analysis

Best practice when undertaking economic appraisals requires a clear definition of the counterfactual for comparison purposes. The counterfactual represents the basis against which the effectiveness of any additional reinforcements will be measured.

For the purpose of this CBA, the counterfactual network state is:

- Radial HVDC links from offshore hubs to onshore connection points utilising 1GW cable technology for the Dogger Bank and Hornsea zones. East Anglia zone utilises a range of cable technologies and includes some within zone links. This offers some redundancy within the zone.
- Limited onshore reinforcements necessary to ensure NETS SQSS compliance. This is based on the wider GB network investment projections identified in the ETYS 2013 out until 2030, and reflects each generation background.

i.e. the counterfactual case represents the current radial design philosophy.

Once constraint costs for the counterfactual and each alternative design option have been calculated by the ELSI model these can then be assessed against the capital costs. If there is an overall net saving in constraint costs then an option can be said to provide a cost benefit. If an option provides a higher net saving than the counterfactual then there would be benefit in delivering this option in preference to the counterfactual.

As the CBA work-stream has considered a range of generation scenarios it is necessary to assess the benefits that an option delivers across all possible outcomes, it may be the case that an option performs well against one possible generation scenario but very poorly against others.

Therefore the work-stream applied a process known as Least Worst Regret (LWR). A “regret” cost is incurred when the costs of the assets delivered outweigh the savings in constraint costs returned and hence there has been an over-investment in the network from which the consumer will receive no benefit.

Under LWR we seek to identify the design option that would result in the lowest worst outcome across the range of scenarios. If this option was selected then the project (and in this case the GB electricity consumer) would be exposed to the minimum level of risk regardless of which generation scenario should materialise.

Under a given scenario the option that delivers the highest net constraint saving is said to have zero regret.

Under LWR it is possible that the preferred solution may be one that does not return the highest cost benefit across any of the given individual scenarios.

CBA Results

The CBA work-stream has assessed the constraint costs incurred for each design option proposed and carried out a least worst regret analysis.

A summary of the results are shown below:

Design & Technology by Scenarios: Regrets in (£m)	Gone Green		Slow Progression		
	10GW	17.2GW	10GW	17.2GW	Worst Regret
Base Case plus onshore	1947	2911	1833	1966	2911
Bootstrap 1 GW	25	7289	619	4166	7289
Hybrid bootstrap 2 GW	1102	1268	81	615	1268
Hybrid offshore 1 GW	999	1003	1381	3444	3444
Hybrid offshore 2 GW	N/A	353	N/A	1581	1581
Integrated 1 GW	**0**	**0**	1180	448	1180
Integrated 2 GW	741	134	0	0	741

The work-stream assessed the performance of reinforcement strategies against the two agreed levels of offshore wind generation (10GW and 17.2GW) and also against two wider generation development scenarios, giving four scenarios in total.

The cost benefit analysis methodology sought to identify the least worst regret reinforcement strategy, i.e. across the range of generation scenarios assessed, which reinforcement strategy exposes the GB consumer to the minimum risk of over or under investment?

It can be seen that an integrated design (either 1GW or 2GW) offers the least worst regret reinforcement strategy across all generation scenarios considered.

Interpretation of Results

Since the IOTP project was commenced in 2012 there have been significant developments in the electricity industry and the wider economy, most notably Electricity Market Reform (EMR), that have impacted on the expected development rate of offshore wind generation.

It is now the view of the project members that offshore wind generation capacity is unlikely to reach the current contracted levels in the timescales required to make an integrated design approach beneficial. It is expected that offshore wind development will likely consist of smaller projects being delivered separately over a longer period of time.

As such the project views the 17.2GW offshore wind generation scenario as now being unrealistic and has discounted these results in drawing final conclusions. The 10GW scenario is considered to be more likely but the project acknowledges that there is a possibility that actual development may be lower even than this.

Under the Gone Green + 10GW scenario the CBA results show that a 1GW integrated design offered the least worst regret strategy. However, the 1GW bootstrap (a hybrid type design) showed a regret cost of only £25m. This is well within the margin of error for this type of analysis.

By pursuing a non-integrated design, e.g. the 1GW bootstrap, both National Grid and the offshore generation developers can maintain closer control over the scope and programme of their individual works and hence minimise risks for consumers and investors alike.

Under the Slow Progression + 10GW scenario the 2GW integrated design performed best. However, the gap between that and the nearest non-integrated design (hybrid bootstrap 2GW) was small, only £81m. Again this is not a sufficient margin to consider the result a clear indictor to pursue an integrated approach.

The project acknowledges the possibility that the level of offshore wind generation delivered may be lower than the 10GW. Should this transpire then the non-integrated designs would perform better and would become the least worst regret reinforcement strategy.

7. Overall Conclusions and Next Steps

Conclusions and Recommendations

The Integrated Offshore Transmission Project team make the following conclusions:

- The technology required to deliver integrated offshore networks is in development and can reasonably be expected to be available, at the ratings required, by around 2020.

- The commercial and regulatory frameworks in place at the time of project commencement did not properly support the development of integrated design solutions. Modifications would be required, particularly to clarify the roles and responsibilities of the parties involved and also to reduce the risk around financing for offshore generation developers. The most material of these concerns have now been addressed by the Offshore Gateway process and ITPR.

- Technically feasible integrated design solutions can be developed if required and it is possible for these networks to operate in a safe and secure way with the existing onshore a.c. transmission system.

- Integrated design solutions could offer benefits for the GB consumer but only when the installed capacity of offshore wind generation is very high.

- Current market indicators show that development of offshore wind generation in the zones considered will not reach the required levels of capacity in near term timescales that would be required to make the implementation of an integrated design economic and efficient.

- As a result the project team does not believe it would be economic and efficient to progress with the development of an integrated design philosophy or delivery of anticipatory assets at this time.

The Integrated Offshore Transmission Project team make the following recommendations:

- Although the project team does not believe integration is required at this stage it believes that consideration of the development of the codes, frameworks and charging arrangements required to facilitate such an approach is vital to maintaining integration as a viable design option. The project team acknowledges that many of the key concerns identified during this work have been addressed by the Offshore Gateway process and ITRP.
- Responsibility for assessing the growth in offshore wind generation developments and hence the potential need for integration should sit with a single body – the GB system operator.

- No further material work is required is required at this time and the Integrated Offshore Transmission Project team should now be stood down.

8. Lessons Learned

The Integrated Offshore Transmission Project (IOTP) brought together National Grid and offshore wind farm developers, in both their roles as generator and offshore TO, to assess the most economic and efficient way of progressing connections.

A project team with this membership and scope of responsibility has not previously been formed, and many important learning points were recorded throughout the course of this work.

This section records the areas of success that the project members would propose as representing best practice for future projects, and also the lessons learned where improvements could be made.

Successes

- The project team membership included the appropriate range of industry stakeholders.
    - The inclusion of offshore wind farm developers complemented the Knowledge already held by National Grid and allowed the project to consider issues from all perspectives. The involvement of the developers was particularly important to the success of the commercial work-stream.
- The project benefited from including the regulator, Ofgem, throughout the process.
    - Working closely with the regulator allowed the project team to discuss and agree key assumptions and to move forward with confidence that we were meeting the needs of this key stakeholder.
- The structure of the project team was based around four independent work-streams who reported into a single Project Management Committee.
    - This structure allowed the most appropriate expertise to be assigned to each work-stream and allowed them to focus on a specific area. This structure made best use of the resources available.

Lessons Learned

- Due to the wide scope of the project and the number of project team members it is important that a clear programme, milestones, and outputs are agreed up front.
    - The detailed nature of the analysis, and debates over approach (see next point), resulted in the timescales for the work extending beyond the originally expected deadlines. Clear deliverables and timescales should be agreed prior to analysis commencing to ensure that project momentum is maintained.
- The key assumptions and methodology to be used in the course of the project must be agreed up front by all parties.
    - Although specific terms of reference were prepared and agreed for all work-streams the key assumptions and methodology of analysis was not. This lead to some confusion and debate over the approach taken, particularly with respect to the designs proposed and the cost benefit analysis. This resulted in delays and

re-working. In future any project team made up of several separate industry parties should ensure that agreement is reached on the specific nature of the analysis being carried out prior to work commencing.

- Multi-party projects of this nature should be co-ordinated through a single party.

    - In this case National Grid acted as project co-ordinator in its role as combined transmission owner / system operator. For future projects that include multiple TOs and / or generator developers co-ordination should be the responsibility of the GB system operator with the roles of the contributing parties clearly defined at the outset.

Integrated Offshore Transmission Project (East)

Appendix 1

Technology Work-Stream Report

Appendix 1 – Technology Work-Stream

1. Introduction

This appendix reports on currently available technologies and technologies which may become available within project timescales to enable an integrated offshore transmission system be built. It reports on the limitations of current technology development and identifies where technology development needs to be focussed in the future to allow the successful delivery of an integrated network.

The technologies considered in the report are those relevant to the potential system design options for the integrated offshore transmission network, including HVDC converters and their protection and control systems, switchgear, d.c. and a.c. cables and offshore platforms.

The report is structured into a number of separate chapters:

Chapter 2 provides an introduction to the technologies that might be used in an integrated offshore transmission network and highlights issues related to their application.

Chapter 3 considers the commercial availability of the key technologies. It establishes the present state of development and forecasts future developments. It aims to provide an indication of whether technology will be available for application within the timescales of a given project.

Chapter 4 provides high level unit costs for each of the technology areas to inform cost benefit analyses and optioneering. In each case, a range of costs is given to reflect the complexity factors associated with different projects. The sources of information and the assumptions made in deriving the unit costs are stated.

Chapter 5 describes how VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the need for a higher transmission capacity at some point in the future is anticipated. The chapter introduces VSC HVDC transmission configurations and describes how a scheme may be constructed in stages.

Chapter 6 provides information on reliability and availability for key technology areas to further support cost benefit analyses.

Chapter 7 is concerned with protection strategies for an integrated offshore transmission network. Possible protection strategies are illustrated using a set of generic scenarios, representing the different basic types of connection that might be used in an integrated network.

Chapter 8 is concerned with strategies for the control of power flows in an integrated offshore transmission network. Potential control strategies are illustrated using the same set of generic scenarios as in the previous chapter. The particular nature of the offshore a.c. 'islands' is taken into account. The characteristics of offshore windfarms relevant to their connection to an integrated network are described in Annex A to the chapter.

Chapter 9 draws conclusions from the previous chapters and highlights areas where technology development is required in order to allow an integrated offshore transmission network to be delivered.

2. Technology areas

2.1 Introduction

This chapter introduces the technologies that might be used in an integrated offshore transmission network and highlights issues related to their application. The material presented provides the necessary background for the chapters that follow.

2.2 Technologies for integrated offshore transmission

For the purposes of the present chapter, the technologies for integrated offshore transmission have been grouped under the headings 'HVDC converters, 'switchgear', 'cables' and 'offshore platforms'.

2.2.1 HVDC converters

The majority of HVDC schemes currently in service use line commutated converter (LCC) technology (also know as current sourced converter or 'classic' HVDC), which has been commercially available since 1954. LCC HVDC transmission has been described in detail by a number of authors, examples being works by Arrillaga [1] and Kundur [2]. The main characteristics of LCC HVDC technology that are relevant to its application in an integrated offshore transmission system are summarised below.

LCC HVDC technology uses thyristor valves to control the commutation of current between the converter and the three phases of the a.c. system in turn. A thyristor is switched on by the application of a pulse to its gate terminal and will switch off when the current attempts to change direction. It cannot be switched off by control action. As a consequence, the converter is dependent on an a.c. voltage source for its operation. Furthermore, the strength of the a.c. system, as characterised by the ratio of a.c. short circuit level relative to the d.c. power, is important for stable operation. Guidance on the interaction phenomena that may occur between a.c. and d.c. systems where the a.c. system is weak is given in [3], while guidance on planning and design to take the interaction phenomena into account is considered in [4].

Since the thyristor valves of an LCC HVDC converter can be switched on by control action but not switched off, commutation of the current between the phases of the a.c. system can be delayed with respect to the a.c. system voltage but cannot be advanced. LCC HVDC converter operation is therefore accompanied by reactive power absorption, typically in the range 50 to 60% of the transmitted power. The converter is provided with reactive compensation plant in the form of switched capacitor banks. The capacitor banks are switched in or out to maintain the reactive power exchange within specified limits as the transmitted power is varied. Dynamic reactive compensation and shunt reactors are also required in some applications.

The commutation of an essentially d.c. current between the phases of the a.c. system gives rise to harmonic distortion. Some or all of the capacitor banks provided for reactive compensation are therefore configured to also provide a.c. harmonic filtering in order to keep the harmonic distortion on the a.c. system within permitted levels.

The space required for reactive compensation plant and a.c. harmonic filters in a LCC HVDC converter station may typically account for 50% or more of the station footprint.

A LCC HVDC converter operating as an inverter is susceptible to faults and disturbances in the a.c. system which may cause commutation failure. A commutation failure acts as a short-circuit of the converter bridge on which it occurs, resulting in temporary interruption to the power transmission. The causes and consequences of commutation failure are discussed in [5]. When the inverters of more than one HVDC system are in electrical proximity, a single fault or disturbance in the a.c. system may cause simultaneous commutation failures and loss of transmission in all links. Furthermore, commutation failure at one inverter might itself cause an a.c. system disturbance that induces commutation failure at other inverters that would otherwise not have been affected. Guidance on systems with multiple inverters in electrical proximity is given in [6].

LCC HVDC technology is able to achieve high power ratings, an example being an HVDC link connecting Jinping and Sunan in China with a power rating of 7200 MW operating at ± 800 kV d.c. which was commissioned in 2013. The d.c. current corresponding to the power rating and operating voltage is approximately 4.5 kA. Typical losses for a LCC HVDC converter are around 0.8% of the transmitted power. LCC HVDC converters are not able to operate continuously at low levels of power, typically less than 5 to 10% of the rated power transmission capacity. Power reversal is accompanied by a change in the polarity of the d.c. voltage, which precludes use of LCC HVDC technology with extruded cables.

Data on the reliability of HVDC systems throughout the world is collected annually by CIGRE Advisory Group B4.04 [7]. The data is reported in accordance with a reporting protocol developed by the Advisory Group [8]. A standardised reporting protocol for operational performance data for LCC HVDC systems is defined in PD IEC/TS 62672-1 [9].

Voltage sourced converter (VSC) HVDC transmission is a relatively new technology. It was first applied commercially in 1997 [10] and significant growth in application and development in the technology have occurred since then. Guidance on VSC HVDC power transmission is given in BSI PD IEC TR 62543 [11]. The characteristics of VSC HVDC transmission that are relevant to its application in an integrated offshore transmission network are summarised below.

The valves of a VSC HVDC converter are self-commutated, that is they use semiconductor devices that can be switched both on and off, as required, by control action. The usual semiconductor device is the insulated gate bipolar transistor (IGBT). The valves generate a power frequency a.c. voltage at the a.c. terminals of the converter. Since it acts as a voltage source, the VSC is not dependent on a strong a.c. network. It can be used with weak and passive systems and, where required, provide black start capability.

The a.c. terminal voltage is controlled in phase angle and amplitude to give the required exchange of active and reactive power, respectively, between the converter and the a.c. system. Active and reactive power are controlled independently and both may be controlled rapidly and continuously within the limits of the converter's rating. The present generation of VSC HVDC converters requires little or no a.c. harmonic filtering.

Since a VSC HVDC converter requires little or no reactive compensation and a.c. harmonic filters, the station footprint is less than that of an equivalent LCC HVDC converter. A comparison of the site area required for VSC HVDC and LCC HVDC converter stations both of 500 MW rating was reported in [12]. A VSC HVDC solution required a site area of 58% of that of the LCC solution. The building footprint, however, was larger on account of the larger size of the valves.

A VSC HVDC converter may continue to transmit power in the event of a fault on the a.c. system, albeit at a reduced level depending on the reduction of a.c. system voltage. VSC HVDC converters do not suffer commutation failures.

Although the earlier VSC HVDC systems were of quite modest power transfer capacity, developments in converter technology have resulted in continuously increasing capabilities. The highest rated VSC HVDC system in service at present is the 500 MW East–West Interconnector between Ireland and Wales [13]. A number of VSC HVDC systems with higher power transmission capacities are under construction at present, including some at 1000 MW [14, 15].

Much development has been aimed at reducing VSC HVDC converter losses. Losses for the present generation of VSC HVDC converters are less than 1% of the transmitted power per converter.

Power reversal is accompanied by a reversal of the d.c. current, with the d.c. voltage polarity remaining unchanged. Continuous operation at any level of power within its rating is possible. Since no reversal of the d.c. voltage polarity occurs, VSC HVDC converters may be used with extruded cables.

Little information on reliability and availability of VSC HVDC converters has been published, reflecting the still comparatively limited service experience. However, there is no reason to expect that the reliability of VSC HVDC systems will be found to be any lower than that of LCC HVDC systems.

Published values for VSC HVDC converter stations tend to show costs in the range 100 – 120% of the equivalent LCC HVDC converter station. National Grid's 2013 Electricity Ten Year Statement (ETYS) states the cost of a 1250 MW VSC HVDC converter to be in the range £108–136 M [16]. The economic aspects relating to the application of VSC links within a transmission system are discussed in CIGRE Ref. 492 [17].

The differences between VSC and LCC HVDC technology may lead to one or the other being better suited to the functional requirements of a given project. VSC HVDC technology tends to be advantageous in the following situations:

- where short circuit levels are low or where a black start capability is required
- where rapid control of power or rapid power reversal is required
- where the use of extruded cables is required
- where limited space is available

LCC HVDC technology tends to be advantageous where a power transfer capability is required that exceeds that achievable with VSC technology. For cabled applications, however, this advantage is becoming less relevant as increasing VSC ratings approach the power transfer capability of the cables. In applications where none of the factors that favour the use of VSC technology are important to a project, LCC technology may provide a more economic solution.

The application of HVDC links in the Integrated Offshore Transmission Project is primarily for connection of wind generation located offshore, together with reinforcement of the onshore transmission network. Some of the HVDC links are likely to be multi-terminal.

The use of HVDC transmission for connection of wind generation is described in CIGRE Ref. 370 [18]. VSC technology is well suited to such connections. Since the converter does not require a commutating voltage from the a.c. system and since it is able to operate at any level of power flow within its rating, the VSC HVDC system can be used to start up the wind farm and provide auxiliary power to the wind farm during periods of no wind generation. An LCC HVDC connection would require a synchronous condenser or Statcom to provide a commutating voltage and a generator to provide auxiliary power during periods of no wind generation. The inability of the LCC HVDC system to operate continuously at levels of power less than 5 to 10% of its rated level would be a disadvantage for energisation of the wind farm and operation at low wind speeds. The VSC HVDC converter is more compact than an equivalent LCC converter and can be accommodated on an offshore platform with less difficulty. In consequence, the use of LCC technology for wind generation and offshore applications would generally require significant additional investment compared to a VSC solution and would present some additional engineering challenges.

While most of the HVDC schemes in service comprise a d.c. connection between two terminals, in some applications, a multi-terminal link is found to represent a cost-effective and efficient solution. For example, a multi-terminal HVDC link could be used to combine offshore wind generation connection with onshore reinforcement such that spare capacity on the link could be used for cross-boundary power transfer during periods when the wind generation is less than 100%.

LCC technology can be used for multi-terminal HVDC systems. However, since reversal of the power flow direction requires a change in the polarity of the d.c. voltage, reversal of power flow at individual terminals requires switching to reconfigure the d.c. circuit. In addition, commutation failures can occur, resulting in collapse of the d.c. voltage and interrupting operation of the whole multi-terminal HVDC system.

At present, two multi-terminal LCC HVDC systems are in service: The SACOI (Sardinia – Corsica – Italy) project, commissioned in 1989, and the Quebec – New England HVDC transmission system which was commissioned in phases between 1990 and 1992. Both of these are LCC HVDC systems.

The SACOI HVDC system was originally commissioned as a two-terminal system connecting Sardinia and the Italian mainland. A third converter station, at Lucciana on the island of Corsica, was connected as a tap in 1988. The original two-terminal system was designed for unidirectional power flow from Sardinia to Italy. The Lucciana Converter station was provided with d.c. switchgear to allow a bidirectional flow of power to and from Corsica.

The first phase of the Quebec – New England HVDC project was a two-terminal system between Des Cantons, in Quebec, and Comerford in New Hampshire. It was originally planned to extend the existing system north to Radisson in Quebec and south to Sandy Pond in Massachusetts and to adapt the controls at Des Cantons and Comerford for multi-terminal operation. Finally, a converter station was to be commissioned at Nicolet, in Quebec, to form a five-terminal system. In the course of the project the scope was changed resulting in a system that can be operated as a three-terminal system (Radisson – Nicolet - Sandy Pond) or as two separate two-terminal systems (Radisson – Nicolet and Des Cantons - Comerford). A description of the HVDC transmission system is given in [19].

A third multi-terminal LCC HVDC system, the North East Agra HVDC project, is planned [20]. The HVDC link will comprise rectifiers at Bishwanath Chariali and Alipurduar and two parallel inverters at Agra. The power flow will be unidirectional and no reversal of d.c. voltage polarity will be necessary.

In principle, VSC technology is better suited to multi-terminal HVDC links than LCC technology. Since power flow reversal does not involve a change in the polarity of the d.c. voltage, the power flow can be reversed at individual terminals without reconfiguring the d.c. circuit. Also, VSC HVDC converters do not suffer commutation failures.

The first two multi-terminal VSC HVDC schemes have recently entered service. A three-terminal VSC HVDC system was commissioned at Nan’ao in China in December 2013 [21]. The system connects wind generation located on Nan’ao island to the transmission system in Guangdong. A five-terminal system was commissioned in Zhoushan in China in June 2014 [22]. The system reinforces the connection between the islands of Zhoushan and the mainland transmission system.

A disadvantage of multi-terminal HVDC systems is that, until the advent of a HVDC circuit-breaker, a d.c. fault will result in loss of transmission at all terminals of the HVDC system while the faulted part is isolated and the system restarted. This disadvantage would limit the quantity of generation that can be connected to the HVDC system to that permitted by infeed loss risk limits of the planning standards unless some form of partial redundancy is provided. A further disadvantage is the lack of standards for control and protection that would ensure that the equipment of different suppliers could operate on a common HVDC system. Progress is being made in this area by working bodies within CIGRE and CENELEC.

International standards have been developed against which HVDC equipment and systems may be procured. HVDC schemes in general tend to be of bespoke design in order to achieve an optimum solution for a particular application. The design of the system is strongly influenced by the a.c. system characteristics at each terminal, with factors such system strength and harmonic impedances being important considerations. The requirements for component equipment items are determined from design calculations.

General guidance on performance requirements for two-terminal LCC HVDC systems is provided in BS EN 60919 [23, 24, 25]. The report comprises three parts: BS EN 60919-1 concerns the steady state performance, BS EN 60919-2 concerns the transient performance related to faults and switching and BS EN 60919-3 concerns the dynamic performance. Guidance on VSC for HVDC power transmission is given in BSI PD IEC TR 62543 [11]. The report aims to provide a guide for specifying a VSC transmission scheme.

Guidance on procedures for insulation coordination of HVDC converter stations, where they differ from a.c. system practice, is provided in IEC TS 60071-5 [26]. The guide is primarily concerned with LCC HVDC systems.

Electrical type and production tests for converter valves are specified in BS EN 60700-1 [27] for LCC and in BS EN 62501 [28] for VSC HVDC transmission.

Tests for VSC converter components including valves, interface transformer, d.c. capacitor, sub-module capacitors, reactors and radio frequency interference filters are proposed in CIGRE technical brochure 447 [29].

Standard procedures for determining power losses for LCC HVDC converter stations are presented in BS EN 61803 [30]. The procedures cover all components of the converter station but do not include any dynamic reactive compensation plant that may be used. General principles for calculating power losses for VSC HVDC converter valves are set out in IEC 62751-1 [31]. IEC 62751-2 [32] provides the detailed method to be used for calculating power losses in VSC HVDC converter valves based on the modular multilevel converter (MMC) topology.

Guidance on system tests for two-terminal LCC HVDC installations is given in BS EN 61975 [33]. The standard provides guidance on planning of commissioning activities. Guidelines for commissioning of VSC HVDC schemes are being developed by CIGRE WG B4.63.

Guidance on technical specifications for and design evaluation of a.c. harmonic filters for HVDC systems is given in PD IEC TR 62001-1 [34]. Part 1 constitutes an overview. Part 4, which will address equipment, is being developed within IEC SC 22F.

Specification and evaluation of outdoor audible noise from HVDC substations is specified in PD IEC/TS 61973 [35]. The specification is primarily intended for LCC HVDC projects. Part of it may be used for VSC HVDC projects.

A number of projects are in progress within IEC TC 115, including control and protection equipment in HVDC systems, guidelines for HVDC system operation procedures, guidelines on asset management of HVDC installations, planning of HVDC systems and guidelines for the system design of HVDC projects.

The requirements for converter transformers for HVDC applications are specified in BS EN 61378-2 [36]. Requirements for bushings used on d.c. systems are specified in BS EN 62199 [37].

2.2.2. Switchgear

AC switchgear for transmission applications is a mature and widely used technology. The requirements are well covered in international standards. Common specifications for a.c. switchgear are specified in BS EN 62271-1 [38], requirements for a.c. circuit-breakers are specified in BS EN 62271-100 [39] and requirements for a.c. disconnectors and earthing switches are specified in BS EN 62271-102 [40]. The requirements for synthetic testing of circuit-breakers are specified in BS EN 62271-101 [41] and requirements for inductive load switching in BS EN 62271-110 [42].

In a HVDC system, switching operations that differ from those specified in the standards are encountered. BS EN 60919-2 classifies switching operations without faults as follows:

a) energization and de-energization of a.c. side equipment such as converter transformers, a.c. filters, shunt reactors, capacitor banks, a.c. lines, static var compensators (SVC) and synchronous compensators;

b) load rejection;

c) starting and removal from service of converter units;

d) operation of d.c. breakers and d.c. switches for paralleling of poles and lines; connection or disconnection of d.c. lines (poles), earth electrode lines, metallic return paths, d.c. filters, etc.

Switchgear requirements corresponding to the above switching operations in addition to the various fault switching duties for the HVDC system are determined from the design calculations.

Gas-insulated metal enclosed switchgear (GIS) is used in a.c. systems as an alternative to conventional air-insulated switchgear in certain applications, often on account of its compact size or greater immunity to airborne pollution. GIS is therefore widely used for a.c. switchgear in offshore applications. Requirements for GIS are specified in BS EN 62271-203 [43]. The standard completes and amends, if necessary, the standards applying to the component switchgear items of the GIS.

DC switchgear is not covered by its own specific standards. Many of the requirements of the a.c. switchgear standards will be applicable to d.c. switchgear. In contrast, switching duties will generally be different for d.c. equipment and the equipment will need to withstand a continuous d.c. voltage. The functions and operation of switching devices, other than circuit-breakers, that are used in d.c. applications have been described in a report by CIGRE WG 13/14.08 [44, 45]. The report was published in two parts, with Part 1 covering current commutation switches and Part 2 covering disconnectors and earthing switches. An earlier report, by WG 13.03, deals with the metallic return transfer breaker (MRTB), which is used for reconfiguring a bi-polar system for mono-polar operation [46]. Guidance on the specification of d.c. switchgear is given in BS EN 60919-2.

GIS is not widely used for d.c. applications. Under the influence of a d.c. electric field, charge may accumulate on the surfaces of solid insulators within the gaseous insulation system. Accumulation of charge distorts the electric field profile and may reduce the performance of the insulation. However, should a solution to the issue be found, GIS would offer an attractive solution for HVDC converters located offshore. Gas insulated systems for HVDC are summarised in [47].

So far, circuit-breakers have not been applied in HVDC systems. The availability of a HVDC circuit-breaker would allow a d.c. network to develop beyond a single protection zone for earth faults. This in turn would enable the volume of generation connected to a d.c. network to exceed the maximum loss of power infeed permitted by planning standards.

The performance requirements of a circuit-breaker for d.c. application are significantly more onerous than for a.c. application. The circuit-breaker must interrupt a current that has no natural current zero. Furthermore, since a d.c. fault will cause a voltage collapse that propagates rapidly throughout the d.c. network, the circuit-breaker must operate within a few ms. In principle, these requirements could be fulfilled using a semiconductor circuit-breaker, but the associated losses have prevented such a device from being developed.

A hybrid HVDC circuit-breaker has been demonstrated in the laboratory [48]. The device uses a small auxiliary circuit-breaker to bypass the main semiconductor circuit-breaker during normal operation and hence reduce the losses. In the event of a fault, the auxiliary circuit-breaker trips to commutate the fault current into the path of the main circuit-breaker. A high speed mechanical switch protects the auxiliary breaker from exposure to high recovery voltages as the main circuit-breaker interrupts the fault.

Due to the fast operating time, novel protection concepts are required. In the case of the device described above, operation is initiated by built-in overcurrent protection. The device may then operate in a current limiting mode, delaying operation of the main circuit-breaker, until a trip signal from selective protection is received.

2.2.3. Cables

Two main types of cable technology have been developed for use in HVDC applications. These are distinguished by the type of insulation, mass impregnated (MI) and extruded. Both types of cable consist of a copper or aluminium conductor surrounded by the insulation, a metallic sheath to protect the cable and prevent moisture ingress and a plastic outer coating. Cables for subsea installation are additionally provided with armouring in the form of helically wound galvanised steel wires to increase the tensile strength of the cable and protect it from the stresses associated with subsea installation. For installation in deeper waters, a double layer of armouring is provided. The armouring may be covered with a serving of bitumen-impregnated polypropylene yarn for corrosion protection.

Extruded d.c. cable systems have been in service since 1999. The insulation is cross-linked polyethylene (XLPE), which is extruded over the cable core. The ratings of extruded cables have continued to increase since their introduction. At present, a number of projects using extruded cables with a d.c. voltage of 320 kV and power transfer capabilities of up to 1000 MW are under construction and a 525 kV d.c. extruded cable system has been qualified. Extruded cables have not been used with LCC HVDC systems due to the need to withstand the d.c. voltage polarity reversal that occurs when the power flow direction is changed.

MI cables have been in service since the 1950s and have demonstrated high reliability. The insulation consists of lapped layers of kraft paper which are impregnated with viscous oil. A recent development from MI insulation is polypropylene laminated (PPL) insulation, in which the kraft paper is laminated with thin layers of plastic. PPL insulation permits a higher operating temperature and hence allows a higher current rating for the cable to be achieved. MI cables generally have higher ratings than extruded cables. The highest d.c. voltage for MI cables currently on order is 600 kV, providing a continuous power transfer capability of 2250 MW. MI cables can be used with both VSC and LCC HVDC systems.

Recommendations for testing of d.c. cables with rated voltages of up to 800 kV have been published in [49] and an addendum published in [50]. Recommendations for testing of d.c. extruded cable systems with rated voltages of up to 500 kV have been published in [51].

Three-core a.c. subsea cables have been widely used for connection of offshore wind generation. The cable consists of three copper conductor cores, each surrounded by XLPE insulation and a lead sheath, laid up into a single cable with oversheath and helically-wound steel wire armouring. Constructing the cable with the three cores in close proximity significantly reduces the external magnetic field and consequent losses due to induced currents. Three-core a.c. submarine cables are available for rated voltages of 245 kV.

Single-core a.c. cables have not been widely used for subsea application. On land, special sheath bonding may be used to balance the voltages induced along the sheaths of single core cables and thereby reduce circulating currents and their associated losses. Since special bonding is not practical for subsea cables, low resistance copper armouring has been used as an alternative. The cable cost, however, is significantly increased due to the larger quantity of copper used.

Nominal cross sectional areas for conductors in electric power cables are specified in BS EN 60228 [52]. Test methods and requirements for power cables with extruded insulation and their accessories for rated voltages 30 kV to 150 kV are specified in IEC 60840 [53]. The requirements apply to single-core and individually screened three-core cables. Test methods and requirements for power cables with extruded insulation and their accessories for rated voltages from 150 kV to 500 kV are specified in IEC 62067 [54]. The requirements apply to single core cables and their accessories. The requirements of the latter two standards do not apply to submarine cables, for which modifications to the standard tests may need to be devised.

A critical differentiating factor between the use of a.c. and d.c. cables is the influence of capacitive charging current. At power frequency, for lengths of more than a few km, the charging current may account for a significant proportion of the cable current rating. The active power that can be transmitted decreases sharply with cable length. The impact of the charging current is greater at higher voltages. The charging current can be compensated for by the provision of shunt reactors. However, for subsea cables, it will only be practical to install shunt reactors at the ends of the circuit and the use of cables for a.c. transmission over long distances remains impractical. Many of the wind generation areas in the Crown Estate Round 3 zones are located such that HVDC cables are the only practical option for connection to the onshore transmission system.

Installation of submarine cables is a challenging operation which may represent a significant part of the cost of an offshore project. The cost is strongly influenced by sea bed conditions and the presence of obstacles. A detailed sea bed survey and selection of an appropriate route are essential.

Cables are installed from a dedicated cable laying vessel or, in shallow waters, from a barge. The maximum length of cable that can be laid and hence the number of cable joints to be made along the cable route is determined by the capacity of the laying vessel. Making the cable joints is a skilled operation requiring a period of around three days of good weather so that the vessel may remain stationary while the joint is made.

The stresses imposed on a submarine cable during installation are a significant factor in the cable design. Recommendations for mechanical tests on submarine cables have been published in [55]. Detailed stress analyses using computer models are also performed.

Submarine cables are buried in the sea bed to protect them from damage from ships anchors and fishing equipment. For this purpose, a trench is cut by water jet or cable plough depending on the sea bed conditions. In difficult sea bed conditions burial may not be possible and the cable is instead protected using concrete mattresses, rock placement or other means. Guidance on protection of cables from third-party damage is given in [56].

The cables of a circuit may be bundled and buried in a single trench or spaced apart and buried in separate trenches. Burial of the cables in a single trench will reduce the costs of installation but will also limit the achievable rating due to mutual heating. It will also be more difficult to carry out a repair, should one be required, once the cables are in service. In the case of d.c. cables, restrictions on the allowable compass deviation may restrict the possible spacing of the cables. The optimum solution for a given project must be determined by detailed study.

On land, cables may be directly buried or installed in troughs. In some circumstances cables may be installed in a cable tunnel, but this is an expensive option and is reserved for applications such as installation in urban areas where other methods are impractical. As with submarine cables, detailed surveys and an appropriate choice of route are essential. Recommendations for laying and installation techniques are given in [57].

For directly buried installation, the cables are laid on a bed of sand in a trench which is back filled with cement bound sand to provide a controlled thermal resistance. Concrete covers are placed above the cables to provide protection against third party damage. The depth of burial is dependent on land use and is typically around 1 m.

For trough installation, a trench is excavated and a concrete trough is constructed. The cables are laid within the trough and the trough closed with reinforced concrete covers. As for directly buried cables, the trough may be back filled with cement bound sand to provide a controlled thermal resistance. Trough installation is used where limited space is available for the cable route.

Obstacles such as roads, railways and rivers may be crossed using techniques such as horizontal directional drilling (HDD). In HDD, a pilot hole is drilled which is then reamed to the required diameter and a conduit installed before the cables are pulled through. HDD may also be used in bringing submarine cables onshore.

The distance between cable joints is determined by the maximum size of cable drum that can be transported. The transport restrictions will be dependent on the particular project. The maximum length of cable is typically a few hundred metres. Joint bays will need to be provided at intervals along the cable route to accommodate the cable joints. For a.c. cables, link boxes will also be required for bonding and earthing of the cable sheaths.

Methods for calculating cable ratings are specified in BSI BS IEC 60287 [58, 59, 60, 61,62]. The standard is divided into three parts: Part 1 deals with current rating equations (100% load factor) and calculation of losses; Part 2 is concerned with calculation of thermal resistance and Part 3 is concerned with operating conditions. Calculation of cable ratings is generally simpler for HVDC cables than a.c. cables since skin and proximity effects do not need to be taken into account.

2.2.4. Offshore platforms

Although introducing a range of challenges not encountered in onshore locations, offshore platforms for a.c. substations and HVDC converter stations have been able to build on years of experience gained in the offshore oil and gas sectors.

Guidance on the design and construction of offshore a.c. substations for wind power plants is provided in CIGRE Ref. 483 [63]. The document addresses a range of considerations including risk management, maintenance, certification, definition of the single line diagram, specification of primary plant, physical layout and secondary equipment requirements.

An offshore platform for an a.c. substation consists of a topside, which houses the electrical equipment, and a supporting substructure. The substructure may be of monopole, jacket, gravity based or self-elevation type.

A monopole is a single steel pile, driven into the seabed. A jacket consists of four or more legs, with interconnecting bracing, attached to the seabed by piles. A gravity based foundation consists of a reinforced concrete or steel structure, filled with ballast and located directly on the sea bed. For each of these, the topside is transported to site by barge and installed on the substructure by a heavy lifting vessel.

The self-elevation platform is not dependent on heavy lifting vessels for its installation. It is designed as a floating structure, with four legs and a jacking system connected to the topside. It is towed to site and positioned, following which the legs are lowered by the jacking system. The choice of platform is dependent on many factors, including topside weight, water depth and seabed conditions.

Many of the considerations for offshore a.c. substations are applicable to offshore HVDC converter stations. At present, very few have been built and they are considerably larger than offshore a.c. substations. In comparison with offshore a.c. substations, they are a developing technology.

The first offshore HVDC converter stations, BorWin Alpha and DolWin Alpha, have been of jacket and topside construction [64, 65]. The jacket and topside construction is a flexible solution but dependent on heavy lifting vessels. Few lifting vessels with sufficient capacity to lift the topside of an offshore HVDC converter station exist and there is competition for their availability. The largest heavy lifting vessels, the Thialf and the Saipem 7000, have lifting capacities of 14 200 t and 14 000 t respectively [63]. A new heavy lifting vessel, the Pieter Schelte, with a topsides lifting capacity of 48,000 t is expected to be delivered in 2014 [66]. Shallow water and the width of the load have the effect of restricting the capacity. The lifting operation is dependent on a window of suitable weather.

Other platform designs are being pursued. The HelWin Alpha and BorWin Beta platforms are of a floating and self-installing type [67, 68]. A description of the BorWin Beta and HelWin Alpha platforms is given in [68]. The DolWin Beta platform is of a gravity base type with topside attached and will be self-installing [70].

2.3. Conclusions

An introduction has been provided to the technologies that might be used in an integrated offshore transmission network and issues relevant to their application have been highlighted. These issues will be of importance in the following chapters.

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3. Technology availability

3.1. Introduction

Many of the technologies required for integrated offshore transmission are new and developing rapidly. Voltage Sourced Converter (VSC) HVDC technology was introduced in 1997 and since then has been characterised by continuously increasing power transfer capabilities. Significant developments have taken place in the area of d.c. cables including the introduction of extruded and mass impregnated polypropylene paper laminate (MI PPL) insulation technologies. New devices are emerging, such as the HVDC circuit-breaker. The present chapter aims to anticipate how the capability of the key technology areas might develop in coming years and provide an indication of technology availability by year in order to inform planning decisions.

Figures are presented for each of the key technology areas, in which technology capability is tabulated against year. The availability of technology with a given capability in a given year is indicated by means of a colour-coded cell. The key is shown in Figure 1. Red indicates that the technology is not expected to be available in that year. It is important to distinguish between the time at which a technology becomes commercially available and the time by which it might be in service; amber indicates that the technology is expected to have been developed and to be commercially available but not yet in service. It has been assumed that project timescales for HVDC schemes are such that a period of typically four years would elapse between technology becoming available and being in service. It is clear that for technology to be in service, a contract will have to have been placed at the appropriate time. Consequently, a hatched green cell is used to indicate that it would be possible in principle for the technology to be in service in a given year provided a contract has been placed. A solid green cell indicates that the technology is in service or scheduled to be in service on the basis of contracts which are known to have been placed.

R	**Technology not available**
A	**Technology available but not in service**
G	**Technology potentially in service subject to contract**
G	**Technology in service or scheduled to be in service**

Figure 1: Key to figures

In this way, the time at which a technology is fully developed and ready to be offered to the market is identifiable by a change in cell colour from red to amber; the time at which a technology may first enter service is identifiable by a change in cell colour from amber to green or hatched green (depending on whether a specific contract has been placed).

Where the availability of a technology is indicated by an amber cell, its introduction will require an appropriate risk-managed approach that takes account of the lack of service experience. Where the availability is indicated by a green cell, a greater level of experience will be available but appropriate risk management will still be required particularly in the earlier years.

In deriving the forecast availabilities, published information has been used wherever possible. The sources of information are referenced in the text. Where no published information is available, forecasts have been based on a best estimate. The forecasts have not been confirmed or endorsed by the manufacturers. For technologies that are not yet available, the rate of development will depend on the level of demand and is therefore subject to change with market conditions.

3.2. Technology availability

3.2.1 HVDC technology

In the following sections, the component technologies that comprise an HVDC system are considered initially in isolation. Subsequently, the forecast capabilities of HVDC systems are determined by taking into account the forecast capabilities of the component technologies.

3.2.1.1 HVDC converters

The expected development in the capability of voltage sourced converter (VSC) HVDC technology is illustrated in Figure 2.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1563 A	G	G	G	G	G	G	G	G	G	G	G	G	G
1800 A	A	A	A	A	G	G	G	G	G	G	G	G	G
2000 A	R	R	A	A	A	A	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 2: Voltage sourced converters

Where used with a d.c. cable circuit, the achievable power transfer capability for the converters will be dependent on the level of d.c. voltage permitted by the cable. The present generation of modular-multi-level converters are scalable by voltage and could reach the d.c. voltage level of any foreseeable cable with little development effort. The highest d.c. voltage for a VSC HVDC system presently on order is 500 kV pole-to-earth for the Skagerrak 4 project [1], which uses mass impregnated cables and is due to be operational in 2014. It is assumed that converters will continue to reach the level of d.c. voltage permitted by the cables as the technology develops.

The level of d.c. current achievable at present is determined by the IGBT modules used in the converter valves. A d.c. current of around 1600 A could be achieved with present technology. The interconnection between France and Spain [2], due to commission in 2014, comprises two HVDC links with a power transfer capacity of 1000 MW each and operating at ± 320 kV, representing a d.c. current of 1563 A.

VSC HVDC converters with d.c. current in excess of 1800 A are available [3], although no orders are known for this level of current at present. IGBT modules permitting d.c. currents of 2000 A are expected to be available for contracts placed in 2016 [4]. Achievement of higher d.c. currents may be possible in future years with further development of semiconductor devices and materials but would be dependent on the availability of cables able to carry such levels of current.

Line commutated converter (LCC) technology has developed to a stage where it could match the voltage and current ratings of any cable or overhead line with which it might be used on the GB transmission system. For example, the HVDC link connecting Jinping and Sunan in China operating at ± 800 kV d.c. and with a power transfer capability of 7200 MW went into service in 2013 [5]. No figure is given in the present document to illustrate the future development of LCC HVDC converter technology since it is unlikely to represent the limit on the capability of the system in which it is used within the GB transmission system.

3.2.1.2 HVDC cables

The expected availability of HVDC cables with extruded insulation is illustrated in Figure 3.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
320 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
525 kV	A	A	A	A	G	G	G	G	G	G	G	G	G
600 kV	R	R	R	R	R	A	A	A	A	G	G	G	G
650 kV	R	R	R	R	R	R	R	R	R	R	A	A	A
700 kV	R	R	R	R	R	R	R	R	R	R	R	R	A

Key

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A	Technology available but not in service
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Figure 3: Extruded d.c. cables at 70 to 90 ºC

Extruded cables with a d.c. voltage of 200 kV are in service [6] and several projects using extruded cables with d.c. voltages of 300 kV and 320 kV are due to be commissioned in the next few years [7]. A 525 kV extruded d.c. cable system has been qualified [8].

With regard to cable development, CIGRE Ref. 533 published in April 2013 included the results of a questionnaire that had been sent to cable manufacturers [9]. One respondent indicated that extruded cables for a d.c. voltage of 600 kV would be available within the next five years and 750 kV within ten to fifteen years. Other manufacturers were also pursuing developments but tended to be less specific and more cautious with regard to their plans.

Figure 3 takes into consideration the range of forecasts for development of extruded cables together with a judgement of the likely timescales for development and testing.

The expected availability of HVDC cables with mass impregnated (MI) and mass impregnated paper polypropylene laminated (MI PPL) insulation is illustrated in Figure 4.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
500 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
600 kV	A	A	G	G	G	G	G	G	G	G	G	G	G
650 kV	R	R	A	A	A	A	G	G	G	G	G	G	G
700 kV	R	R	R	R	R	R	A	A	A	A	G	G	G
750 kV	R	R	R	R	R	R	R	R	R	R	A	G	G

Key

R	Technology not available
A	Technology available but not in service
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G	Technology in service or scheduled to be in service

Figure 4: Mass impregnated d.c. cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC - voltage

MI cables are longer established than extruded cables and can achieve higher voltages at present. MI cables at 500 kV are in service on the SAPEI HVDC link between Sardinia and Italy [10]. The highest d.c. voltage for cables currently on order is 600 kV for the Western HVDC Link, scheduled to enter service in 2016 [11]. The questionnaire reported in the April 2013 CIGRE Ref. 533 also addressed the forecast development of MI cables [9]. In his response, one respondent indicated that MI cables for a d.c. voltage of 750 kV would be available within ten to fifteen years. Another expected to achieve a voltage level of 800 kV 'in the next few years'.

Figure 4 takes into consideration the range of forecasts for development of MI and MI PPL cables together with a judgement of likely timescales for development and testing.

MI cables may be used with LCC converters, which will be able to match the current carrying capability of the cable. The expected availability of MI cables according to current carrying capability is illustrated in Figure 5.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1876A	A	A	G	G	G	G	G	G	G	G	G	G	G
2000 A	R	R	A	A	A	A	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 5: Mass impregnated cables at 55 ºC and mass impregnated polypropylene paper laminate cables at 80 ºC - current

The cables of the Western HVDC Link, scheduled to enter service in 2016, will achieve a current carrying capability in excess of 1800 A [10]. It has been assumed that, with some development, an increase in current carrying capability to 2000 A in the early years would be challenging but possible. This is consistent with the results of CIGRE Ref. 533 survey [9]. This does not represent a fundamental limit since the conductor cross section could be increased at the cost of more difficult cable installation.

3.2.1.3 Offshore platforms for HVDC converters

The forecast availability of offshore platforms for HVDC converters is illustrated in Figure 6.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
320 kV	G	G	G	G	G	G	G	G	G	G	G	G	G
400 kV	A	A	A	A	A	G	G	G	G	G	G	G	G
500 kV	A	A	A	A	A	A	G	G	G	G	G	G	G
600 kV	R	R	R	A	A	A	A	A	G	GG	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 6: Offshore platforms for HVDC converters

The achievable transmission capacity of offshore converters is dependent on the size and weight of the platforms which can be constructed and installed. The d.c. voltage, in particular, is subject to the limitations of platform physical dimensions due to the clearances in air required for insulation of the valves and d.c. equipment.

The highest d.c. voltage for offshore converters under construction at present is ± 320 kV, for which a number of examples exist [12, 13, 14]. Based on installation vessel lifting capability and fabrication yard size, a ± 400 kV offshore converter is thought to be deliverable. A new or upgraded installation vessel would allow an increase in d.c. voltage to around ± 500 kV. The lifting vessel Allseas Pieter Schelte, expected to be delivered in the second half of 2014, will increase the largest available lifting capacity significantly (topsides lift capacity 48,000 t) [15]. However, an increase in fabrication yard size would be required to exploit the full capacity of the vessel. Higher d.c. voltages could also be achieved, in principle, by adopting a modular converter design for installation in two or more lifts. Further design work would need to be carried out to establish the feasibility of such a solution.

3.2.2 HVDC systems

The forecast capability of systems comprising HVDC converters and d.c. cables is determined from the forecast capability of the component technologies illustrated in the previous figures. The achievable MVA rating in a given year is determined from the d.c. current and d.c. voltage permitted by the component technologies.

The availability of a given MVA rating in a given year is determined by whichever of the component technologies has the lowest availability. Many combinations of component d.c. current and d.c. voltage are possible; results are shown in the figures where an increase in d.c. current, d.c. voltage or both allows a higher MVA rating for the system to be achieved. If a given MVA rating is available in a given year, it follows that any lower value of MVA rating will also be available. The combination of d.c. current and d.c. voltage permitting the increase in MVA rating is indicated in the figures.

The maximum real power transmissible by the system may be less than the MVA rating, depending on requirements for converters to provide reactive power. For line commutated converters, reactive compensation plant is always provided as part of the scheme.

3.2.2.1 HVDC systems with converters located onshore

The availability of HVDC systems where VSC converters located onshore are used with extruded cables is illustrated in Figure 7.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1000 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	320 kV 1563 A
1890 MVA	A	A	A	A	G	G	G	G	G	G	G	G	G	525 kV 1800 A
2100 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	525 kV 2000 A
2400 MVA	R	R	R	R	R	A	A	A	A	G	G	G	G	600 kV 2000 A
2600 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	650 kV 2000 A
2800 MVA	R	R	R	R	R	R	R	R	R	R	R	R	A	700 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 7: HVDC systems comprising voltage sourced converters and extruded cables

The France-Spain Interconnector, which combines VSC converters and extruded cables, will achieve a power transfer capability of 1000 MW following commissioning in 2014 [2]. The forecast increases in d.c. current and voltage levels of the converters and cables allow a continuing increase in the achievable MVA rating. The figure indicates that a 2000 MVA solution would be commercially available by 2017 and might potentially be in service by 2021.

The availability of HVDC systems where VSC converters located onshore are used with mass impregnated cables is illustrated in Figure 8.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1400 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	500 kV 1400 A
2160 MVA	A	A	A	A	G	G	G	G	G	G	G	G	G	600 kV 1800 A
2600 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	650 kV 2000 A
2800 MVA	R	R	R	R	R	R	A	A	A	A	G	G	G	700 kV 2000 A
3000 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	750 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 8: HVDC systems comprising voltage sourced converters and mass impregnated cables

The greater d.c. voltage permitted by mass impregnated cables compared with extruded cables allows greater MVA ratings to be achieved in a given year. The Skagerrak 4 project [1] combines VSC converters with MI cables to achieve a power transfer capability of 700 MW with a single pole operating at 500 kV d.c. Consequently, although Skagerrak 4 is a monopole, the technology would allow 1400 MVA to be achieved with two poles operating at ± 500 kV. Skagerrak 4 is due to be commissioned in 2014. However, the d.c. current of around 1400 A is within present limits and, in principle, 1563 MVA or more could be achieved with existing technology. The expected developments in converter current and cable voltage indicate that a 2000 MVA solution might potentially be in service by 2019.

The availability of systems where line commutated converters located onshore are used with mass impregnated cables is illustrated in Figure 9.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
2250 MVA	A	A	G	G	G	G	G	G	G	G	G	G	G	600 kV, 1875 A
2600 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	650 kV, 2000 A
2800 MVA	R	R	R	R	R	R	A	A	A	A	G	G	G	700 kV, 2000 A
3000 MVA	R	R	R	R	R	R	R	R	R	R	A	A	A	750 kV, 2000 A

Key	
R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 9: HVDC systems comprising line commutated converters and mass impregnated cables

In contrast to systems using voltage sourced converters, the d.c. current will not be limited by the capability of the converter but by that of the cables. A solution with a power transfer capability of 2250 MW will be in service in 2016 on commissioning of the Western HVDC Link [11]. Further increases will be possible, largely enabled by increases in cable d.c. voltage. Beyond 2016, however, the d.c. current capability of the voltage sourced converter is expected to have converged with that of the cables. From this point on, the power transfer capability of HVDC systems using line commutated converters will no longer be greater than that achievable with voltage sourced converters.

3.2.2.2 HVDC systems with converters located offshore

Where HVDC converters are located offshore, the size of the available platform may impose a limit on the d.c. voltage of the system. The achievable MVA rating in a given year is therefore determined by the lower of the d.c. voltages permitted by the cable and platform.

The availability of HVDC systems comprising VSC converters and extruded cables where one converter or more is located offshore is shown in Figure 10.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
800 MVA	G	G	G	G	G	G	G	G	G	G	G	G	G	320 kV 1250 A
1440 MVA	A	A	A	A	A	G	G	G	G	G	G	G	G	400 kV 1800 A
1800 MVA	R	A	A	A	A	A	G	G	G	G	G	G	G	500 kV 1800 A
2000 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	500 kV 2000 A
2400 MVA	R	R	R	R	R	A	A	A	A	G	G	G	G	600 kV 2000 A

Key	
R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 10: HVDC systems comprising voltage sourced converters and extruded cables (offshore)

The DolWin Alpha offshore converter station, installed in 2013, has achieved a d.c. voltage of ±320 kV [7]. However, the d.c. current of the link, at around 1250 A, is well within present limits. In principle, an offshore converter with a rating of 1000 MVA or more could be achieved with existing technology, but allowance needs to be made for the project delivery time.

Comparison of Figure 10 with Figure 7 shows that offshore platform size does not impose a significant restriction on the capability of HVDC systems with extruded cables over the range of voltage considered (up to 600 kV d.c.).

The availability of HVDC systems comprising VSC converters and mass impregnated cables where one converter or more is located offshore is shown in Figure 11.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
1440 MVA	A	A	A	A	A	G	G	G	G	G	G	G	G	400 kV 1800 A
1800 MVA	A	A	A	A	A	A	G	G	G	G	G	G	G	500 kV 1800 A
2000 MVA	R	R	A	A	A	A	G	G	G	G	G	G	G	500 kV 2000 A
2400 MVA	R	R	R	A	A	A	A	A	G	G	G	G	G	600 kV 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 11: HVDC systems comprising voltage sourced converters and mass impregnated cables (offshore)

Comparison of Figure 11 with Figure 8 shows that the offshore platform imposes a restriction on d..c voltage such that the capability of MI cables cannot be exploited fully. The use of mass impregnated cables in such applications offers little or no increase in rating beyond that which can be achieved with extruded cables.

3.2.3 HVDC protection and control

The availability of control and protection for VSC HVDC systems is illustrated in Figure 12. The figure shows the expected availability of protection and control VSC HVDC systems of increasing complexity, i.e. two-terminal systems, multi-terminal systems and multi-terminal systems with multi-vendor interoperability.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
Control (two-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Protection (two-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Control (multi-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Protection (multi-terminal)	G	G	G	G	G	G	G	G	G	G	G	G	G
Control (multi-terminal, multi-vendor)	A	A	A	A	G	G	G	G	G	G	G	G	G
Protection (multi-terminal, multi-vendor)	A	A	A	A	G	G	G	G	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 12: HVDC protection and control

For two-terminal ('point-to-point') VSC HVDC schemes, including connections to wind generation, both protection and control are well established and the technology has been in service since 1997 [16, 17].

Protection and control for multi-terminal VSC HVDC schemes are less well established. The world's first multi-terminal VSC HVDC systems have recently been commissioned.

The first three-terminal VSC HVDC system was commissioned at Nan'ao in China in December 2013 [18]. SEPRI (Electric Power Research Institute, China Southern Power Grid), had technical responsibility for the project, in which three different control and protection suppliers were involved.

The first five-terminal VSC HVDC system was commissioned in Zhoushan in China in June 2014 [19]. The control and protection systems were provided by a single supplier.

A further development in protection and control technology for VSC HVDC systems is the achievement of multi-vendor interoperability, such that a VSC HVDC system may be extended in the future by the connection of further terminals without being restricted to the original supplier.

A contract was awarded for a VSC HVDC connection forming the first phase of the South West Link, in Sweden, in January 2012 [20]. The scheme has been designed to permit future extension by the connection of additional terminals to form a multi-terminal link [21].

A greater level of complexity is represented by the Atlantic Wind Connection in the US. The project is planned to be built in stages to form an offshore multi-terminal VSC HVDC network spanning the east coast from New Jersey to Virginia. When complete, it will facilitate the connection of more than 7000 MW of offshore wind generation while reinforcing the onshore transmission system [18]. Suppliers have been announced for the first phase of the New Jersey Energy Link, which will form the initial segment of the project. The first phase comprises a multi-terminal VSC HVDC link with two onshore converter stations and one offshore converter station and is due to be in service in 2019 [23].

At present, no standards exist for the control and protection of multi-terminal VSC HVDC systems. Working Bodies within both CIGRE and CENELEC are addressing the issues of control and protection for multi-terminal HVDC systems and it seems likely that standard solutions will be developed within the next few years.

With regard to protection and control technology, therefore, it is concluded that for two-terminal VSC HVDC systems, service experience exists. For multi-terminal applications, the technology is commercially available and recently put into service. It would be possible for a solution with multi-vendor interoperability to be in service by 2018, but no contracts are known to have been placed at present.

It should be emphasised that the interaction of any HVDC link with the a.c. system or systems to which it is connected may raise issues related to its protection and control that are not covered by any of the above and further guidance is needed. The requirements for each scheme will need to be assessed and the risks evaluated.

3.2.4 HVDC circuit-breakers

The expected availability of the HVDC circuit-breaker is illustrated in Figure 13.

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	
A	A	A	A	G	G	G	G	G	G	G	G	G	320 kV, 2000 A
R	R	A	A	A	A	G	G	G	G	G	G	G	550 kV, 2000 A

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 13: HVDC circuit-breaker

A hybrid HVDC circuit-breaker has been demonstrated in the laboratory [24]. The device is designed for a rated voltage of 320 kV, a rated current of 2 kA and a current breaking capability of 9 kA. Allowing for project timescales, it might potentially be in service by 2019. The manufacturer envisages that the next generation of semiconductor devices will allow an increase in the breaking current to 16 kA [24]. The increase in rated voltage that this would facilitate is dependent on the current limiting reactor that is used with the HVDC breaker which may itself be subject to limitation in size. For the purposes of Figure 13, it has been estimated that a rated voltage in excess of 550 kV would be achievable and that such a device might potentially be in service by 2021.

The above is consistent with the results of a questionnaire sent to prospective HVDC breaker manufacturers and published in CIGRE Ref. 533 in April 2013 [8], where one respondent indicated that HVDC breakers operating at > 500 kV with a breaking capacity of 16 kA would be available within five years. Another indicated that a > 500 kV device would be available within 10 years.

3.2.5 HVDC gas-insulated switchgear (GIS)

Gas-insulated switchgear (GIS) is a compact alternative to conventional air-insulated switchgear. It has been widely used in a.c. systems for a number of years in applications where space is limited, such as substations located in urban areas. At present, however, GIS has not been widely applied to HVDC systems. Under the influence of a d.c. electric field, charge tends to accumulate on solid insulation [25]. The accumulated charge distorts the electric field and may reduce the performance of the insulation system. The need for compact HVDC switchgear for offshore application might drive the development of HVDC GIS. At present, however, no HVDC GIS is known to be commercially available.

3.2.6 Offshore platforms for a.c. substations

Offshore a.c. substations are of significantly smaller size and weight than those required for HVDC converter stations and the required power transfer capacity can usually be achieved without great difficulty.

3.2.7 AC cables

With the proliferation of offshore wind farms globally, a.c. submarine technology has seen rapid development lately. Both single (1c) and three core (3c) solutions have been in service for decades using fluid filled (1c) and paper and oil individual lead sheaths (3c) at a wide range of power and voltage applications. Extruded cross linked polyethylene (XLPE) cable types have formed the bulk of the a.c. submarine cable market for the last five years [26].

3.2.7.1 Three core a.c. submarine cables

Three core cable designs offer a good solution to the problems of losses in the armour as the three differently phased magnetic fields in trefoil formation largely leads to the cancellation of magnetic fields which reduces circulating currents in the armour allowing the use of more conventional (lower cost) steel wire armouring (SWA).

The trefoil formation does have some thermal disadvantages, but this is helped to some extent by the generally lower ambient temperatures in water (compared to land).

The consolidation of three cores into a single cable means that just a single installation run is required, although the material costs are generally greater than the costs of three individual cables, so for shorter distances, single core solutions may prove more cost effective.

Single cables with three cores of up to 230 mm diameter and weights of nearly 100 kg / m have been built at voltages up to 245 kV [27], with a 420 kV cable rated at 500 MW on order [28].

Conductor sizes of more than 1000 mm^2 are believed to be possible [29]. A cable length of just over 100 km has been achieved at a voltage of 132 kV [30]. Unfortunately the physics (increasing capacitive effects) disadvantages higher voltage cables with the economic range of 400 kV and higher voltage cables reducing to not much more than 20 km. 220kV is a useful voltage allowing a good compromise between power delivery and transmission distance, but there is no voltage standardisation within the offshore industry yet and 245 kV and 275 kV solutions are also possible.

The technology is likely to be limited by the capability of factory extrusion lines to manufacture the larger sized common over sheaths and armouring required for increasing conductor sizes. Handling difficulties both on and offshore will also play a role as weights beyond 100 kg / m could prove challenging. Lighter “filler” materials with better thermal properties could bring benefits as the technology matures.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
500 MW	G	G	G	G	G	G	G	G	G	G	G	G	G
600 MW	A	A	A	A	G	G	G	G	G	G	G	G	G
700 MW	R	R	R	R	A	A	A	A	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 14: Three core a.c. submarine cables

3.2.7.2 Single core a.c. submarine cables

Single core solutions benefit from the improved thermal characteristics associated with flat configurations and increased spacing between cores (as well as the differential between sea and land temperatures), but suffer from the consequences of unbalanced magnetic fields normally resolved by the use of cross bonding on land. This requires the use of conductive armours (to reduce circulating currents and armour losses). As these can often be of almost the same cross section as the conductors, material costs can be high compared to the equivalent land cables and three installation runs are likely to be required.

The single core designs are however free to use much larger conductor sizes than 3c cables (theoretically up to 3000 mm^2) and so very large power transfers are possible [31].

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
1000 MW	G	G	G	G	G	G	G	G	G	G	G	G	G
1200 MW	A	A	A	A	G	G	G	G	G	G	G	G	G
1300 MW	A	A	A	A	A	A	A	A	G	G	G	G	G

Key

R	Technology not available
A	Technology available but not in service
G	Technology potentially in service subject to contract
G	Technology in service or scheduled to be in service

Figure 15: Single core a.c. submarine cables

3.3. Conclusions

The likely availability of key technologies for integrated offshore transmission has been forecast, based on current state-of-the art and, wherever possible, on known developments. Overall, increasing trends are seen in power transfer capability and in the functionality of VSC HVDC links that are likely to play an increasingly important role as the GB transmission system accommodates increasing volumes of renewable generation in the coming years. Key developments that are expected include:

- an increase in d.c. current of VSC HVDC converters as higher power semiconductor devices become available
- a continuing increase in the d.c. voltage of both extruded and mass impregnated d.c. cables
- developments in the technology of offshore platforms for HVDC converters allowing higher power transfer capabilities

- the application of multi-terminal VSC HVDC systems
- the achievement of interoperability between HVDC equipment of different suppliers
- the introduction of the HVDC circuit-breaker

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4. Unit Costs

4.1 Introduction

The main goal of the IOTP (E) project is to determine the scope and viability of integrated solutions between the various Round Three Wind Farm regions.

The Technology workstream was tasked with obtaining and agreeing a set of unit costs for each technology. A range of costs was to be provided to allow complexity factors to be taken into account.

These costs were then to be used by the Systems Requirements Workstream to complete the Cost Benefit Analysis across multiple options.

4.2 Methodology

A Strategy for obtaining unit costs was developed and agreed within the workstream. See Appendix N (Technology Workstream Strategy for obtaining unit costs Rev 1)

In practice the programming of the IOTP(E) project provided the opportunity to utilise the costs developed for National Grid's Electricity Ten Year statement (ETYS) 2013 [2] and so these have formed the basis of the IOTP(E) unit costs.

4.2.1 Methodology for obtaining costs for ETYS 2013

It has proved almost impossible to get indicative costs directly from the marketplace and very difficult to get engagement with suppliers without a definite project with clear commissioning dates.

In practice, the round of canvassing suppliers to inform the unit costs in 2013 brought little additional unit cost information. Questionnaires were sent out to the same set of suppliers as for the ODIS cost exercise in 2011.

Unfortunately, very few suppliers responded in 2013. Where comments from submissions could be kept anonymous these have been incorporated, but for the most part the ETYS 2013 results are the same as the 2011 results, but inflated to 2013 values.

The exceptions to this are a.c. and d.c. Platforms where the original emphasis on water depths have been replaced with topside weights and new Tables have been derived. The derivation of the new platform tables will be described later.

4.2.2 Choice of Indices

Consideration was given to a number of inflation indicators. Because most of the project cost information available in the media was being quoted in Euros, it was felt that a consolidated Harmonised Index of Consumer Prices (HICP) value for the European Union would be the most appropriate.

The 2011 ODIS values were therefore inflated by:-

2011/12	3.1 %
2012/13	2.6 %

In comparison, the equivalent UK values were:-

2011/12	4.5 %
2012/13	2.8 %

(UK inflation over the 2 year period was 1.6 % higher overall).

4.2.3 Commodity Prices

The commodity prices of interest to the electricity industry have steadied since December 2010 and Copper, Aluminium and Lead prices have all been decreasing at roughly similar rates.

The exception to this trend being the Steel price which dropped sharply during 2012 while the other three metals levelled. This could be because it is a 3 month futures price, rather than a spot price. The Steel price rallied in 2013.

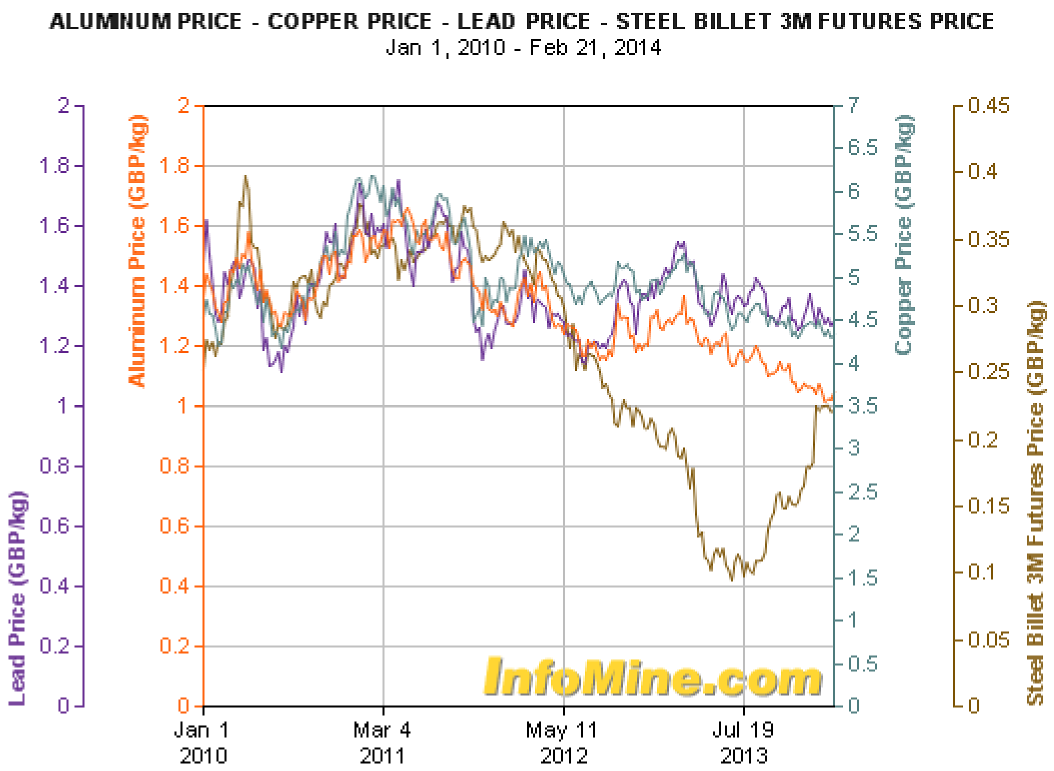


Figure N		Graphs showing commodity price changes in the last four years for Copper, Aluminium, Lead and Steel.

Note that all metal prices have been quoted in GBP whilst most offshore transmission projects will be bought in Euros and the Pound / Euro exchange rate which has favoured the Euro in this period has had a large influence on the unit costs of UK offshore transmission equipment.

The impact of metal prices and exchange rates on unit costs will depend very much on the constituent components and the proportions affected by these factors. [10] Unfortunately whereas the exchange rate costs of wind turbines might be displaced with domestic manufacturing, it is unlikely that there will be any domestic manufacturing of converters, platforms or submarine cables.

In order to make optimum use of commodity pricing it is necessary to have a good feel for the relative quantities of these and other materials in each of the units. This is straightforward for the more familiar equipment types of onshore equipment, where there are six decades of cost history, but this information is not readily available for all technologies and is particularly scarce for the newer technologies, especially VSC converters and HVDC converter platforms.

Most options being compared in the various scenarios use similar equipment using similar baskets of materials, but at differing scales.

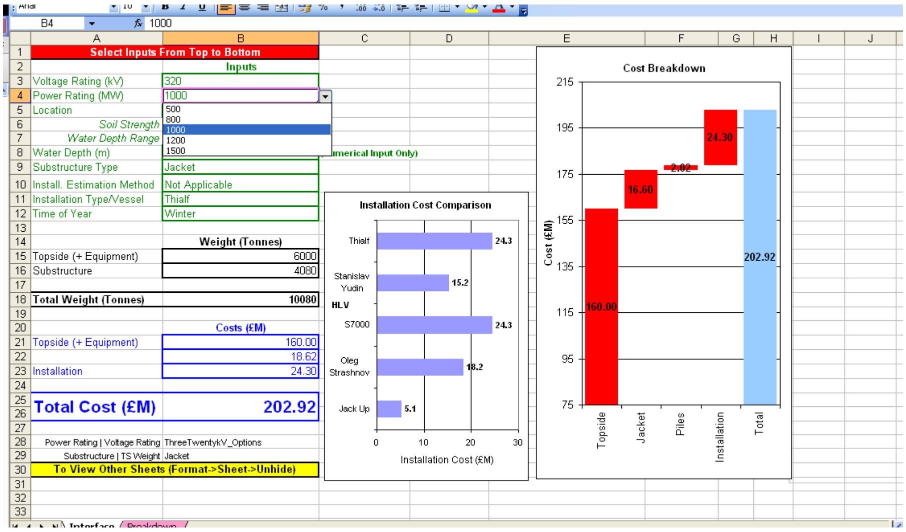
In the light of this it was felt that further work is required to get value from the use of commodity prices for unit costing and it is a recommendation that research work in this area be initiated now to inform the unit costs used in the next phase of this project.

4.2.4 Derivation of Platform costs.

In 2011 National Grid initiated a study from an established consultancy in the Petro-chemical industry to derive a costing tool for offshore platforms. This included insight into the installation and auxiliary plant requirements of offshore platforms and the necessary ancillary facilities for supporting High Voltage electrical transmission in the North Sea.

NG have used this work to derive weights and dimensions for our cost models for a.c. and d.c. Platforms.

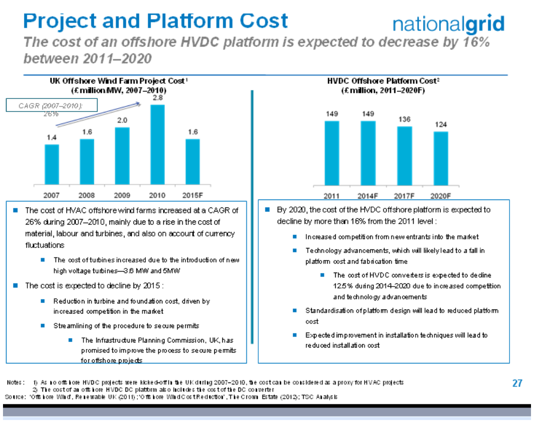
This resulted in a change of focus in the platform unit cost tables from a water depth centric method to one in which the lift related requirements of platforms (amongst others) were considered.

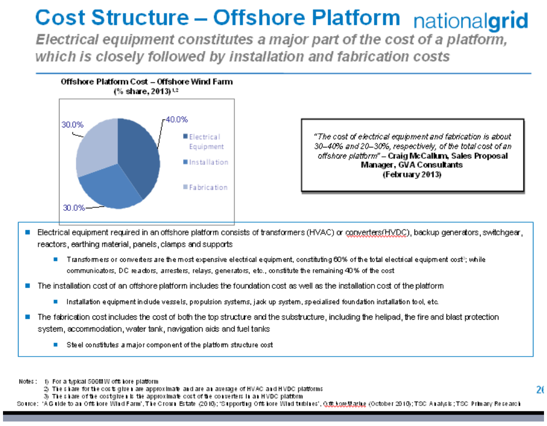


This work was augmented by a desktop market research study done in January 2013 on a.c. and d.c. platforms. This gave assumed growth figures from the platform industry including both suppliers and fabricators. Also included were cost breakdowns for eight previous/ current projects.

The headline findings were that a cumulative annual growth rate of 16.5% was expected for the HVDC platform industry. This growth rate would provide a level of certainty of development in the sector allowing the suppliers to invest in more capability and capacity, allowing for more competition in offshore projects. This would bring about standardisation with increasing offshore project experience and potentially reduce the unit cost for assets.

The growth rate is consistent with other studies that have been done looking at HVDC transmission from 2013-2018 by Marketsandmarkets. Supplier analysis showed trends towards partnerships at work in a number of projects.





A set of estimated total platform costs were produced. Electrical equipment costs are said to contribute to 35% of the total HVDC platform installed cost.

(For HVDC it is EE x (1/0.35)) = 2.8).

(For HVAC it is EE x (1/2.6 = 3.8)).

We checked our figures against costs provided by manufacturers and also against project costs in the public domain and found that they were within tolerances of +/- 10% of our estimates.

New figures suggested increases of 40 % on 2011 figures were in order. Even taking this large increase into account these costs still fell within the calculated cost range.

4.2.5 Use of ETYS 2013 costs for IOTP(E)

Once the ETYS costs were derived they went through a further set of internal governance and were then passed to the IOTP(E) Technology Workstream and to the System Requirements Workstream for comments.

As a result of these comments a number of units which would inform the CBA were introduced. These include 320 kV 1000 MW and 500 kV 1800 MW VSC Converters; 220/ 33 kV Transformers; 120 and 200 MVAr 220 kV Reactors and also a 150 MVAr Static Var Compensator. Changes were made to the voltage and power ranges of some units where power ratings outside the area of interest were removed.

VSC converter upper range cost scaling was derived using a method described in CIGRE brochure 388 (For LCC), less 10% and with dollars converted to pounds.

4.3 Comparisons with other sources.

4.3.1 Comments from workstream

Contributions to the unit cost exercise from the workstream members have generally been commensurate with project experience. Unfortunately nobody in the workstream has any tendered costs for HVDC projects, although everybody has contributed some budget numbers received from manufacturers.

Note that the Basslink, Britned and Nemo projects are part of National Grid Business Development and the regulated National Grid businesses do not have access to cost or technical information from these projects. Also these projects are designed to a very different business model to the likes of Western Link which is designed for Transmission between two parts of the same network, and operation over a 40 year life. This is different again to the Integrated Offshore models, where most assets are designed to a life matching the leases on the Windfarm sites.

National Grid's technical experience with submarine a.c. cables was pioneering with the Isle of Mann cable, but there is little recent submarine a.c. experience to derive costs from.

There was an initial reticence to contribute in open sessions, and a strong awareness that the developers are in competition with each other. But useful comments on costs have now been given individually although these have had to be anonymised.

A review of the Round 3 project ratings and distances from shore mean that many of the Round one and two units may not be relevant for Round three solutions. For example most developers were considering 220 kV and not 132 kV three phase cables between collector stations. 220 kV is also preferred for most IOTP(E) integration options to provide the higher ratings required and to reduce the number of cables.

The most contentious area is that of HVDC platform costs where some developers feel that the costs are too low by about £100 – 150 m. An exercise to clarify public domain information for one of the current German offshore projects (which is a key reference) by asking those directly involved has unfortunately not been successful.

It is therefore recommended that further research work be commissioned to explore the composition and costs associated with HVDC Platforms – an exercise to determine the makeup and costs of a 2GW VSC platform would be extremely valuable.

The other area of contention are the costs of the a.c. switchgear and other platform based equipment necessary for the actual integration between converter platforms. Whilst these are generally thought to have second order effects as they can be incorporated directly into platform designs at an early stage at which time they should not greatly contribute to the overall project costs.

The a.c. switchgear costs in ETYS are higher than recent NG quotes for comparable unlicensed work and therefore probably contain some allowance for additional infrastructure.

There is however, some small risk, and larger concerns that these relatively compact components might push the platform design into needing significant additional infrastructure at considerable extra cost, especially if retrofitted.

4.3.2 Costs associated with Energy Absorption

Whilst the review of the a.c. islanding question is still ongoing and it is not clear how much of a problem this is, it is possible that some energy absorbing equipment will be required.

There is a view that this functionality may best be introduced in a distributed way at medium voltage and that in this way the need for significant additional deep sea platform space will be assuaged. Certainly it is likely to be more cost effectively located on a.c. platforms or within the turbine structures than on d.c. platforms. The £50 m proposed as a budget figure to cover against this risk, being nearly half the cost of a converter station, might then be significantly reduced.

Unfortunately while we are very interested in exploring this technology in more detail, our brief for this project is to identify areas requiring further development and where possible to set the research work in motion, but not necessarily to completely close out the issues.

We would need closer understanding of the potential specifications of the devices before we could usefully engage with the suppliers for costs.

It is recommended that further work is done to establish the system needs, equipment specifications and unit costs at the earliest opportunity.

4.3.3 Comparisons to TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

This report has broadly based costs on NG ODIS 2010 figures with a comment that actual platform costs are thought to be 25 – 30 % lower than those quoted (this prior to recent German Experience) and actual cable costs were thought to be 10 – 15% less than those quoted.

4.3.4 Comparison to ENTSO-E Costs.

The unit cost information contained in the ENTSO-E Report (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011 was derived from the ODIS 2011 Report. This is confirmed on the very bottom of page 35 of the ENTSO-E report (as reference 7).

4.3.5 Comparisons to OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

The document has a table showing the cost differences between nations but no unit cost information.

4.4 Unit Cost Tables

4.4.1 Voltage Source Converters

Specifications	Cost (£M)
500MW 300kV	68 - 84
850MW 320kV	89 - 110
1000MW 320 kV	98 - 124
1200MW 400kV	108 - 136
1800MW 500kV	116 - 168
2000MW 500kV	131 - 178

Includes Civils / Building

4.4.2 Current Source Converters

Specifications	Cost (£M)
1000MW 400kV	73 - 94
2000MW 500kV	136 - 168
3000MW 600kV	178 - 209

Includes Civils / Building

4.4.3 Transformers

Specifications	Cost (£M)
180MVA 132/33/33 or 132/11/11kV	1.05 - 1.9
240MVA 132/33/33kV	1.26 - 2.09
250 MVA 220/33/33kV	1.85 - 2.15
120MVA 275/33kV	1.26 - 1.68
240MVA 275/132kV	1.57 - 2.09
240MVA 400/132kV	1.88 - 2.30

Excludes civil works

4.4.4 HVAC Swichgear

Specifications	Cost (£M)
132kV	1.15 - 1.47
220kV	2.85 - 3.15
275kV	3.04 - 3.46
400kV	3.98 - 4.29

Includes protection and Infrastructure

4.4.5 Shunt Reactors – supplied cost

Specifications	Cost (£M)
60MVAr/13kV	0.52 - 0.84
120MVAr/220 kV	2.25 - 2.75
200MVAr/220 kV	2.75 - 3.25
100MVAr/275kV	2.30 - 2.51
200MVAr/400kV	2.51 - 2.72

Excludes civil works

4.4.6 HVAC Shunt capacitors – Installed cost

MVAr of capacitive reactive compensation	Cost (£M)
100	3.14 - 5.24
200	4.19 - 7.33

Includes civil works – (land)

4.4.7 Static VAR compensators- Installed cost

MVAr of reactive compensation	Cost (£M)
100	3.14 - 5.24
150	9 - 13.5
200	10.47 -15.71

Includes civil works – (land)

4.4.8 STATCOMs – Installed Cost

MVAr of reactive compensation	Cost (£M)
50	3.14 - 5.24
100	10.47 - 15.71
200	15.71 - 20.94

Includes civil works – (land)

4.4.9 Extruded HVDC Cables – Supply only

GBP per metre	Cost (£/m)	Rating (MW)
Cross Sectional Area	**320 kV**	**320 kV**
1200mm2	314 - 471	560
1500mm2	346 - 471	636.8
1800mm2	314 - 524	704
2000mm2	366 - 576	752

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.10 HVDC Mass impregnated (excluding PPLL)

a) 400 kV

GBP per metre	Cost (£/m)	Rating (MW)
Cross Sectional Area	**400 kV**	**400 kV**
1500mm2	366 - 576	892
1800mm2	418 - 576	1200
2000mm2	418 - 628	1400
2500mm2	627 - 733	1500

b) 500 kV

GBP per metre	Cost (£/m)	Rating (MW)
Cross Sectional Area	**500 kV**	**500 kV**
1500mm2	418 - 576	1115
1800mm2	428 - 628	1500
2000mm2	418 - 681	1750
2500mm2	524 - 785	1880

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.11 HVAC 3Core Cables

MVA Rating	Voltage	Cost (£/m)
180	132kV	471 - 733
300	220kV	524 - 785
400	245kV	681 - 1047

Use Sub-sea cable installation costs per kilometre in 4.3.5.13 below

4.4.12 HVAC 3 phase OHL

Description	Cost (£M)
Cost per route km 400kV, double circuit	1.57 - 1.99
Cost per route km 132kV, double circuit	0.73 - 0.94
Cost per route km 132kV, single circuit	0.52 - 0.63

Installed

4.4.13 Subsea Cable Installation

Installation Type	Cost (£M/km)
Single cable, single trench	0.31 - 0.73
Twin cable, single trench	0.52 - 0.94
2 single cables; 2 trenches, at least 10M apart	0.63 - 1.26

These are generalised as seabed conditions will strongly influence costs, as will length (mobilisation); crossings and environmental factors.

4.4.14 DC Platforms

Ratings	Weight	Cost (£M)
1000 MW @ 320-400 kV	8000-10250	260 - 329
1250 MW @ 320-400 kV	9500-14000	281 - 385
1500 MW @ 450-500 kV *	17000-27500	352 - 496
1750 MW @ 450 550 kV *	20000-30000	414 - 530
2000 MW @ 500-600 kV *	24500-33000	419 - 534
2250 MW @ 600-700 kV *	29500-39250	480 - 588
2500 MW @ 650-750 kV *	32000-43000	506 - 638

4.4.15 AC Platforms

Ratings	Cost (£M)
200-400 MW 33 kV arrays @ 132-150 kV *	30 - 55
200- 400 MW 33 kV arrays @ 220 -275 kV	36-44
400-700 MW 66 kV arrays @ 220 - 275 kV	45 - 81
700 -1000 MW 66 kV arrays @ 220 - 275 kV	70 - 134

4.5 Extract from Technology Working Group Terms of Reference Issue 4, 31 May 2013

2. Unit costs

Unit costs will be identified for each technology area for optioneering purposes. A range of costs will be obtained to reflecting the complexity factors associated with different locations.

4.6 Strategy for Obtaining Costs

INTEGRATED OFFSHORE TRANSMISSION PROJECT (EAST)

TECHNOLOGY WORKSTREAM STRATEGY FOR OBTAINING UNIT COSTS

4.7 PURPOSE AND SCOPE

One of the four main deliverables of the Technology Workstream is to obtain unit costs for the components of an integrated offshore transmission network for use in cost benefit analysis. The report on unit costs is required by 27 September 2013. The present paper sets out the strategy by which it is intended to obtain the unit costs.

4.7.1 BACKGROUND

Unit costs are required for the components of an integrated offshore transmission network as follows:

HVDC converters, including transformers and switchgear, located onshore

HVDC converters, including transformers and switchgear, located offshore

AC collector substations, located offshore

DC cables, land and submarine

AC cables, land and submarine

DC circuit-breakers

The unit costs are required to reflect a range of system transmission capacities from 1000 to 2 500 MW.

Few contracts have been placed for projects using technology applicable to offshore transmission and cost information is scarce. Costs will differ between projects due to project complexity, changes in commodity prices, variation in exchange rates, the required ratings, market elasticity and other factors.

4.7.2 STRATEGY

Unit costs for the applicable technologies have been published in National Grid's Offshore Development Information Statement (ODIS) [1]. The unit costs were based on information received from equipment suppliers in response to a questionnaire. ODIS was last published in 2011 and has since been superseded by the Electricity Ten Year Statement (ETYS). The 2012 ETYS [2] did not include unit costs, but unit costs are being sought for the 2013 publication. Timescales, however, will probably preclude the use of 2013 ETYS information for IOTP(E).

It is proposed to use costs from ODIS 2011 costs increased to account for inflation and changes in commodity costs. Comparison will be made with information from other sources where costs have been published [3, 4, 5] to ensure consistency. Additionally, comparison will be made with contract prices published in press releases for appropriate projects.

CIGRE JWG B2/B4/C1.17 [6] published an empirical formula which may be used to scale converter costs as a function of power and d.c. voltage. It will therefore be possible to obtain indicative costs for converters for which no published costs exist. Guidance will also be taken from CIGRE B4.46 [7] and B4.52 [8].

The indicative costs obtained for offshore platforms will be circulated to the developers with a request to advise suitable complexity factors to account for sea bed conditions, water depth, and so forth so that a range of costs reflecting different project conditions may be obtained.

4.8 REFERENCES

1. 2011 Offshore Development Information Statement, September 2011, www.nationalgrid.com

2. 2012 Electricity Ten Year Statement, November 2012, www.nationalgrid.com

3. TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

4. ENTSO-E (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011

5. OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

6. CIGRE JWG B2/B4/C1.17, 'Impacts of HVDC lines on the economics of HVDC projects', CIGRE Ref. 388, August 2009

7. CIGRE B4.46, 'Voltage source converter (VSC) HVDC for power transmission – Economic aspects and comparison with other a.c. and d.c. technologies', CIGRE Ref. 492, April 2012

8. CIGRE B4.52, 'HVDC grid feasibility study', CIGRE Ref. 533, April 2013

4.8.1 Unit Cost Report References

1. 2013 Electricity Ten Year Statement Technology Appendix p 52

2. 2011 Offshore Development Information Statement, September 2011, www.nationalgrid.com

3. 2012 Electricity Ten Year Statement, November 2012, www.nationalgrid.com

4. TNEI/PPA Energy, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', December 2011

5. ENTSO-E (European Network of Transmission System Operators for Electricity) 'Offshore transmission technology', November 2011

6. OffshoreGrid, 'Offshore electricity infrastructure in Europe – A techno-economic assessment', Final Report, October 2011

7. CIGRE JWG B2/B4/C1.17, 'Impacts of HVDC lines on the economics of HVDC projects', CIGRE Ref. 388, August 2009

8. CIGRE B4.46, 'Voltage source converter (VSC) HVDC for power transmission – Economic aspects and comparison with other a.c. and d.c. technologies', CIGRE Ref. 492, April 2012

9. CIGRE B4.52, 'HVDC grid feasibility study', CIGRE Ref. 533, April 2013

10. RenewablesUK, Offshore Wind: Forecasts of future costs and benefits, June 2011

    http://www.ppaenergy.co.uk/web-resources/resources/710645de357.pdf

11. Marketsandmarkets, HVDC Transmission Market - By Technology (LCC/VSC), Configuration (Back To Back, Monopolar, Bipolar, Multi-Terminal), Power Rating (Below 500 MW, 501 MW - 999 MW, 1000 MW - 2000 MW & Above 2000 MW), Application, Component & Geography (2013 - 2018)http://www.marketsandmarkets.com/Market-Reports/hvdc-grid-market-1225.html

5 Staged Construction of HVDC Transmission Systems

5.1 Introduction

HVDC transmission lends itself to construction in discrete stages. Staged construction allows investment to be better phased in accordance with the system requirements at the time of investment. The staged construction of HVDC transmission systems is described in CIGRE Ref. 186 [1]. The present chapter introduces transmission configurations for VSC HVDC schemes and describes how the scheme may be constructed in stages.

5.2 HVDC Transmission Configurations

The choice of transmission configuration is a key factor in enabling an HVDC transmission system to be constructed in stages. The transmission configuration also has major impacts on the loss of power transmission during outages of converters and d.c. circuit conductors and on the capital and operating costs of the scheme. Possible configurations for VSC HVDC transmission are described in PD IEC/TR 62543 [2]. Configurations for HVDC grids are discussed in CIGRE Ref. 533 [3].

5.2.1 Monopolar configurations

A monopolar configuration uses a single converter unit at each end of the HVDC system. Symmetrical and asymmetrical monopolar configurations exist.

The symmetrical monopole configuration is shown in Figure 1. The voltages at the d.c. terminals are equal magnitude and opposite polarity. The mid-point of the d.c. circuit is earthed. No current flows through earth under normal operating conditions. Most VSC HVDC schemes installed to date are of symmetrical monopolar configuration.

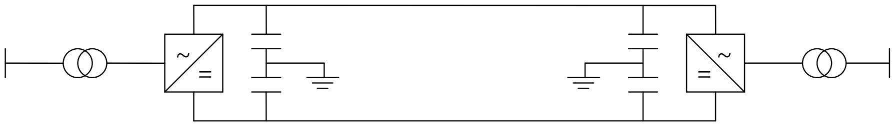


Figure 1: Symmetrical monopole

The asymmetrical monopole configuration is shown in Figures 2 and 3. One side of the d.c. circuit is at high voltage and the other side is earthed. The return circuit may either be a metallic return, as shown in Figure 2, or an earth or sea return, as shown in Figure 3. The use of an earth or sea return may yield savings on cable costs, but is unacceptable in many parts of the world due to environmental concerns.

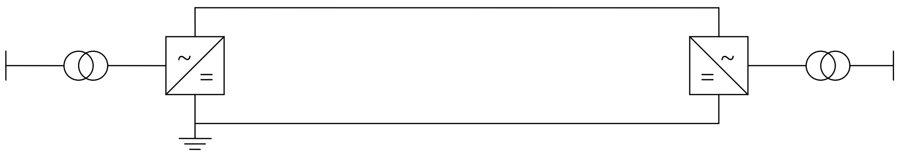


Figure 2: Asymmetrical monopole with metallic return

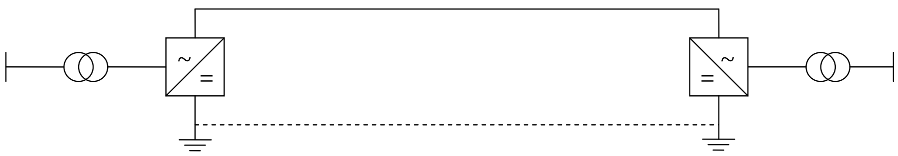


Figure 3: Asymmetrical monopole with earth or sea return

Where a monopolar configuration is used, an outage of either a converter or a d.c. circuit conductor will cause the loss of all power transmission for the duration of the outage.

5.2.2 Bipolar configurations

The basic bipolar configuration is shown in Figure 4. The bipolar configuration consists of two asymmetrical monopoles of opposite polarity with respect to earth. In normal operation, the pole voltages and currents are maintained in balance by the control system.

Switchgear is usually provided to allow the HVDC system to be reconfigured as a monopole, allowing power transmission to continue at a reduced level during an outage of a converter. Following reconfiguration, the healthy pole operates as an asymmetrical monopole using the circuit of the pole that is on outage as the return conductor. Switching for reconfiguration is performed with the d.c. circuit de-energised and all power transmission is interrupted temporarily while re-configuration takes place.

In the event of an outage of a d.c. circuit conductor, all power transmission is lost.

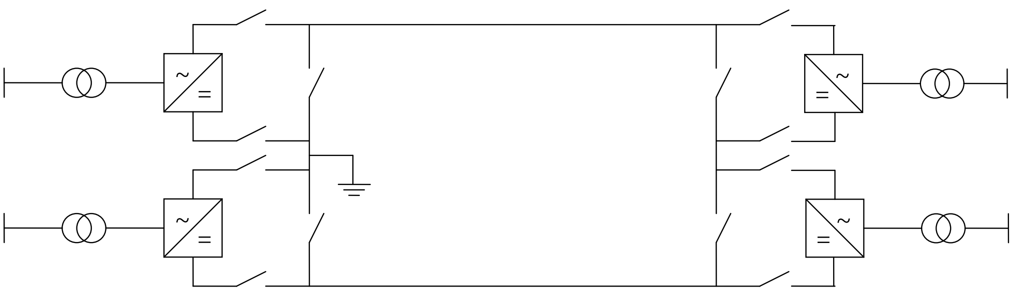


Figure 4: Bipole configuration

A metallic return, as shown in Figure 5, may be provided. The return circuit allows the HVDC system to be reconfigured for monopole operation without interrupting power transmission through the healthy pole. Power transmission may continue at a reduced level during an outage of either a converter or a d.c. circuit conductor.

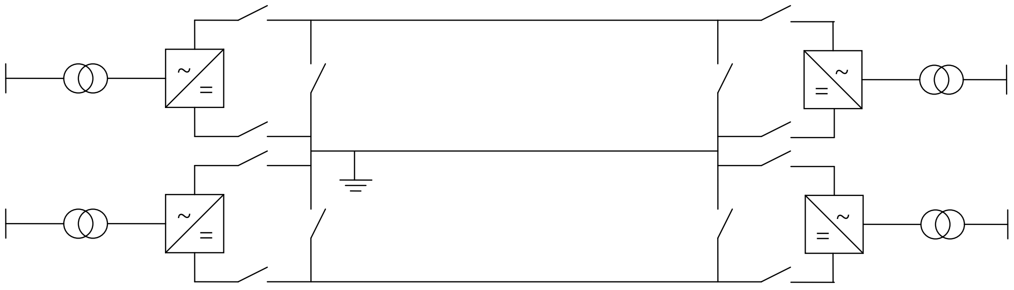


Figure 5: Bipole with metallic return

In some circumstances, the provision of a metallic return will be advantageous in allowing the limits on loss of infeed permitted by the planning standards to be complied with.

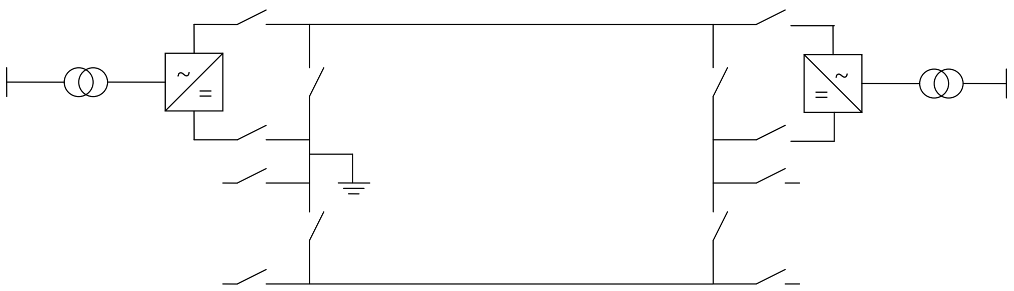
Although only carrying a current while the system is operating as a monopole, the metallic return requires a current rating equal to that of the pole conductors. As in the case of the asymmetrical monopole, an earth or sea return might, in principle, be used as an alternative to the metallic return, but this is unacceptable in many parts of the world. Where an earth return is used, a metallic return transfer breaker may be provided to transfer the d.c. current from the earth return to the conductor of the pole that is on outage following reconfiguration of the d.c. circuit.

The bipolar configuration may be used with VSC HVDC systems and is a common configuration for LCC systems.

5.3 Staged construction

The most common staging in d.c. transmission is the initial construction of a monopole and subsequent extension to a bipole [1]. The staged construction of a bipole is illustrated in Figure 6. The system is initially constructed as an asymmetrical monopole using the conductor of the future pole as metallic return.

Stage 1



Stage 2

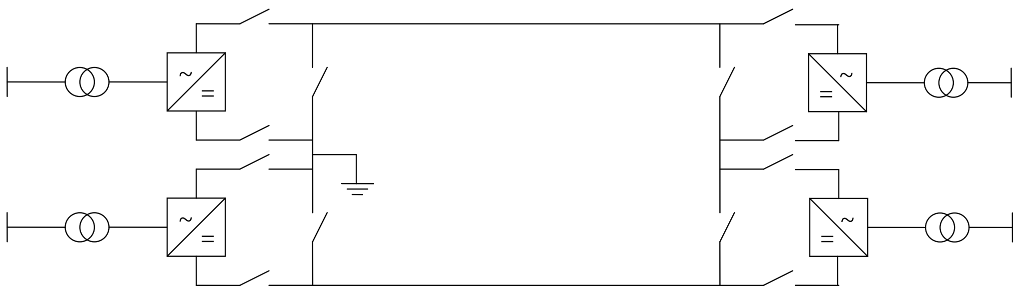
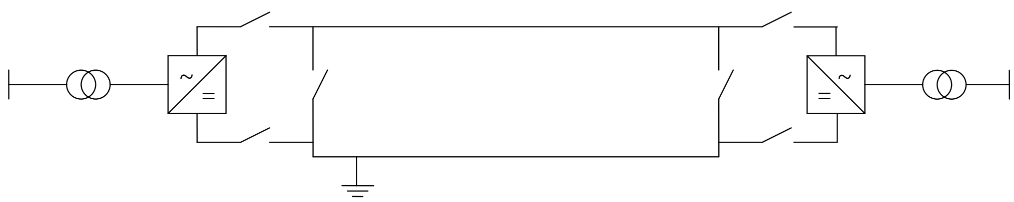


Figure 6: Staged construction of bipole

The staged construction of a bipole with metallic return is illustrated in Figure 8. The metallic return is installed during the initial stage and the conductor of the future pole is installed during the second stage of construction.

Stage 1



Stage 2

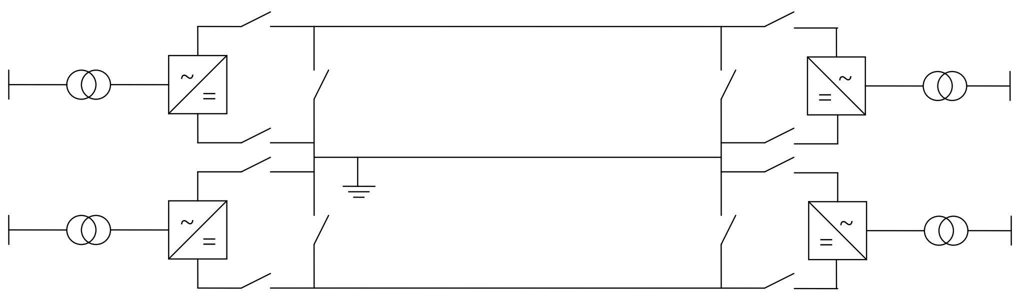


Figure 8: Staged construction of a bipole with metallic return

The potential requirement to extend an HVDC link to form a bipole in a future second stage of construction must be taken into account when the original scheme is designed. If insufficient provision is made, connection of the second stage may be difficult or even impossible. Space must be available for the future converters and, depending on the configuration, for a future cable. For offshore installation, it may be beneficial if infrastructure such as additional J-tubes and switchgear bays are provided when the initial installation is constructed. Consideration will need to be given to the outages of the system that is in service for connection and commissioning of the second stage.

Where the potential requirement for future bipolar extension exists, the initial scheme must be of asymmetrical (rather than symmetrical) monopole configuration. For a given power transfer capability, the d.c. pole to earth voltage will be higher than it would have been for a symmetrical monopole configuration. The higher d.c. voltage will tend to increase the cost of the initial scheme. The overall cost of the final bipolar scheme, however, may be less than that of constructing two symmetrical monopoles in succession.

The provision of a third cable, as required by the bipole with metallic return, will significantly increase the capital cost of the second stage. It will, however, increase the reliability and availability of the final scheme, particularly in the event of a d.c. cable fault. Installation of the third cable in proximity to the two cables already in service may present difficulty.

When extending a monopole to form a bipole, the protection and control systems will need to be upgraded for bipolar operation. This may present challenges with regard to equipment compatibility and factory testing unless the contract for the extension is placed with the original supplier.

To date, few VSC HVDC schemes have been constructed in stages. Some information has, however, been reported. The first stage of the Caprivi Link Interconnector in Africa has been constructed as a 300 MW HVDC transmission line with asymmetrical monopolar converter stations [4]. The scheme has been designed for extension to a 600 MW bipolar system in a future second stage.

Skagerrak 4, a VSC link currently under construction, will constitute the fourth HVDC link between Denmark and Norway. Skagerrak 4 will operate together with the existing Skagerrak 3, which uses line commutated converters, to form a bipole [5]. The extension includes an upgrade of the control system for bipolar operation.

5.4 Conclusions

HVDC schemes may be constructed in stages to allow investment to be better matched with system requirements where the need for a higher transmission capacity at some time in the future is anticipated. The scheme may be constructed initially as an asymmetrical monopole and extended to a bipole as and when the need for a higher transmission capacity arises. The bipole may be provided with a metallic return if required, which, while increasing the cost of the second stage of construction, will increase availability particularly in the event of an outage of a d.c. circuit conductor and will restrict the loss of transmission occurring in the event of a fault or converter trip.

VSC HVDC schemes may be constructed in stages although few such schemes have been constructed so far. Examples of VSC HVDC schemes designed for staged construction are the Caprivi Link Interconnector in Africa and Skagerrak 4 in Scandinavia. Staged construction might be found to be an attractive approach in the construction of an integrated offshore transmission system.

5.5 References

1. CIGRE WG 14.20, ‘Economic assessment of HVDC links’, CIGRE Ref. 186, June 2001

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6. Technology Reliability and Availability

6.1 Introduction

The aim of this chapter is to present published information on the reliability and availability of HVDC technology. This information will be used in cost benefit analysis for an integrated offshore transmission system.

Meaningful information on reliability and availability requires a sufficient level of service experience to have been accrued. Most of the data that has been collected for HVDC systems corresponds to line commutated converters (LCC) and mass impregnated (MI) cables. Less experience exists with voltage sourced converters (VSC) and extruded cables and little data for these is available in the literature.

Generally, the user specifies the reliability and availability requirements for a given HVDC system in his specification and the supplier designs the solution in order to achieve the specified performance [1]. The information presented in this chapter concerns the reliability and availability that has been achieved in service.

The figures presented in this chapter are based on the HVDC system reliability surveys carried out annually by CIGRE B4 AG 4 and reported every two years at the CIGRE Paris session. The data is reported in accordance with a protocol [2] developed by AG 4. Energy Unavailability (EU) is defined in the protocol as 'a measure of the energy which could not have been transmitted due to outages'. Energy Unavailability includes Forced Energy Unavailability (FEU) and Scheduled Energy Unavailability (SEU). In the present chapter, greater emphasis is given to FEU than SEU since scheduled outages may be planned for periods when unavailability of the HVDC system is acceptable. The protocol also defines the concept of Equivalent Outage Hours (EOH) as 'the sum of equivalent outage durations within the reporting period'.

The tables presented in this chapter provide the reliability and availability data of various HVDC components. The data presented includes energy unavailability, failure rate and mean time to repair.

6.2 HVDC Converter

Table 1 shows the average FEU for HVDC converters from the last four CIGRE reliability survey reports [3, 4, 5, 6]. The data has been classified according to the major equipment category as follows:

AC and auxiliary equipment	AC-E
Converter transformer	Conv Tx
Valves	V
Control and protection	C&P
DC equipment	DC-E
Other	O

Data on transmission lines or cables reported in the CIGRE surveys has been excluded from the data presented in Table 1.

Table 1 Average FEU for HVDC converters

	2003-04[3]	**2005-06**[4]	**2007-08**[5]	**2009-10**[6]	**Overall 1983 – 2008**[**Error! Bookmark not defined.**]
Average of System FEU Hours / Station / year	177.3	266.3	170.2	271.7	169.4
AC – E	10.7%	3.0%	4.1%	4.1%	64.2%
Conv.Tx	82.7%	80.9%	82.5%	79.0%	
Valves	0.6%	11.2%	1.8%	3.3%	11.5%
C&P	3.7%	2.2%	3.3%	8.9%	8.0%
DC – E	2.1%	2.1%	8.0%	4.7%	15.4%
Others	0.3%	0.5%	0.3%	0.9%	0.9%

From Table 1, it can be seen that converter transformer failures account for a large proportion of FEU for a.c. Equipment. Table 2 gives values of average system FEU and system EOH with converter transformer failures both included and excluded from the analysis.

Table 2 Average FEU for HVDC converters with and without converter transformer data

	2005-06	**2007-08**	**2009-10**
System FEU Including Transformer %	3.04%	1.94%	3.1%
System FEU Excluding Transformer %	0.58%	0.34%	0.65%
System EOH Including Transformer (hours)	266.3	170.2	271.7
System EOH Excluding Transformer (hours)	50.8	29.8	57.1

The data reported in the surveys is for HVDC systems which are either back-to-back or point-to-point and hence comprise two HVDC converter stations. The FEU for a single HVDC converter may be obtained by assuming that it accounts for 50% of the system FEU. Values of HVDC converter FEU excluding converter transformers are given in Table 3.

Table 3 HVDC Converter FEU

		HVDC LCC System	**Single Converter Station**
2005-06[**Error! Bookmark not defined.**]	FEU %	0.58%	0.29%
	MTTR (hrs)	50.8	25.4
2007-08[**Error! Bookmark not defined.**]	FEU %	0.34%	0.17%
	MTTR (hrs)	29.8	14.9
2009-10[**Error! Bookmark not defined.**]	FEU %	0.65%	0.325%
	MTTR (hrs)	57.1	28.55

VSC HVDC systems have not reported reliability performance data to CIGRE Advisory Group B4.04 to date and published data on the performance of these systems is limited. However, some data on the operation of the Cross Sound Cable project and the Murraylink project have been published [7]. Table 4 shows the reported average FEU for the two systems for seven years operation from 2003 through to 2009.

Table 4 Reliability Performance of two VSC-HVDC Systems

	Average FEU %
Cross Sound Cable (330MW, ±150kV)	1.16
Murraylink (220MW, ±150kV)	2.35

The development in the capability of VSC HVDC technology have increased since the installation of these two VSC HVDC systems, but these developments have yet to provide service experience.

6.2.1 Converter Transformer

Given that converter transformer failures account for a large portion of converter FEU, CIGRE set up a Joint Task Force [8], [9] to report on converter transformer failures. The report [9**Error! Bookmark not defined.**] addresses converter transformer failures in the period 1972 to 2008. It classifies the converter transformer failure areas into bushings, valve winding, a.c. winding, static shields, load tap changers, core and magnetic shields and internal connections.

The report [9] also categorised failures as actual failures or preventive failures. An actual failure was defined as a failure where removal of a unit from service was required due to the damage of the active part. A preventive failure was defined as a failure where the unit did not actually fail but was taken out of service to repair active parts following diagnostic testing such as dissolved gas-in-oil analysis (DGA), high insulation power factor, or failure of similar unit(s). [9]

Converter Transformer failure rate is based on the ratio between the total number of units failed and the total number of units in service in a number of years. Figure 1, taken from [9**Error! Bookmark not defined.**], shows the converter transformer failure rate against year of commissioning. The figure shows an increase in failure rate for preventive failures while the total failure rate reduces. This trend is due to:

a) Modern transformers are now more closely monitored
b) Most of the systems are designed with spare transformers being readily available: statistics in the reports shows that converter transformer failure rate has improved
c) Implementation of the modified IEC Standard (61378-2) issued in 2001

These developments have improved the failure rate of the converter transformers to about 0.02 per year in the period of 2006 - 2008

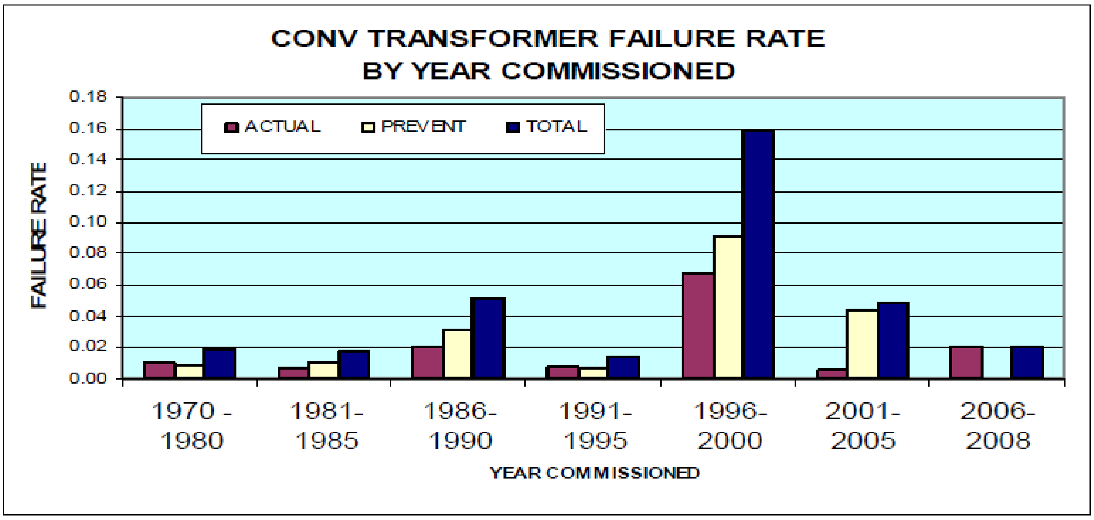

Figure 1 Converter Transformer failure rate by year of commissioning

Reported converter transformer reliability mainly focuses on LCC HVDC schemes. It is assumed that VSC HVDC schemes will utilise conventional HVAC transformers, therefore the availability and reliability of VSC transformers will be the same as HVAC transformers.

Converter Transformer replacement with Spare

The provision of spare transformer at site minimises the outage time in the event of a converter transformer failure. Table 4 shows the reported [**Error! Bookmark not defined.**] outage hours for transformer replacement when a spare transformer was available on site.

Table 4: Average transformer replacement time

Projects	No of Units Replaced with Spare	Outage Time (h)
Gui-Guang 2	1	177
Rihand-Dadri	2	39
Tian-Guang	1	49
3G-Changzhou	1	72
3G-Guangdong (	1	72
Nelson River (2006)	1	67
3G-Guang (2007)	1	72
Total	**8**	**548**
Average Transformer replacement time		**68.5**

In an offshore environment, transformer replacement times are subject to a number of factors that can lead to a significant increase in replacement time. These include the availability of a spare transformer at the platform, tools, availability of vessel (if spare transformer is not at site) and weather conditions.

6.3 HVDC Cable

The primary source of cable reliability data is a survey reported in CIGRE brochure 379 [10]. The data presented in the brochure is related to the installed quantities of underground and submarine cable systems rated at 60kV and above together with the service experience and performance of existing underground and submarine cable systems rated at 60kV above. The survey is based on responses received from utilities and cable suppliers.

The survey considers a 5 year period ending December 2005 for land cables and a 15 year period ending December 2005 for submarine cables.

The survey identified more than 33,000 circuit km of underground cables and approximately 7,000 circuit km of submarine cable system in service at the end of December 2005.

49 faults were reported on submarine cables in which 4 of it were related to a.c. XLPE cable and 18 were related to d.c. MI. The faults reported are mainly external faults, with immediate breakdown or an unplanned outage of the cable system.

Tables 5 and 6 provide a summary of failure rates for submarine d.c. MI and submarine a.c XLPE cables. The causes of failure were classified as ‘internal’ and ‘external or unknown’. For both types of cable, all reported failures were attributed to external or unknown causes. Reported a.c. XLPE cables faults occurred on voltages below 220kV as there were cables beyond this range.

Table 5: DC Submarine cable failure rates (fail/year cct.km)

	DC - MI Cables		
	60 – 219 kV	**220 – 500 kV**	**All Voltages**
Internal	0.00000	0.00000	0.00000
External or Unknown	0.001336	0.000998	0.001114
Total	0.001336	0.000998	0.001114

Table 6: AC Submarine cable failure rates (fail/year cct.km)

	AC - XLPE cables		
	60 – 219 kV	**220 – 500 kV**	**All Voltages kV**
Internal	0.00000	N/A	0.00000
External or Unknown	0.000705	N/A	0.000705
Total	0.000705	N/A	0.000705

Since all causes of failure were external or unknown, it is suggested that the failure rates reported for d.c MI cables could be used for d.c extruded cables. This is based on the following:

- External faults are not generally related to insulation type since the reported d.c. MI cable external cable faults were caused by activities such as trawling, anchoring and excavation
- No internal faults were reported on either the a.c. extruded or d.c. MI hence we can assume the same for d.c. extruded
- Installed capacity of submarine d.c. MI in the reported period is greater than installed submarine a.c. extruded
- Lack of published data for extruded submarine a.c. cables
- Reported a.c. extruded cable failure rated 220kV and below.

Excluding the extremes and unknown faults, the average reported repair time of submarine cables is approximately 60 days**.** However, repair times for submarine cables are subject to a number of factors which can lead to significant increase in repair time. These factors include weather conditions, vessel availability and spares availability. Long outage times were related more to location of cable installation and type of cable than voltage level.

6.4 CONCLUSIONS

Reliability and availability data based on published information have been collected for use in cost benefit analysis for an integrated offshore transmission system. The recommended data are summarised in Table 7 for converter stations, in Table 8 for converter transformers and in Table 9 and for cables.

The data presented in Table 7 for converter reliability is based on the CIGRE survey for the years 2009 – 2010 [6**Error! Bookmark not defined.**] since it is the most recent survey and therefore most representative of present technology.

Table 7 Summary of Converter Reliability

	FEU (%)	Mean time to repair (hours)
Converter	0.325	28.55

Operational experience has only been reported for two VSC HVDC projects. The reported data is not considered sufficient to provide reliability and availability figures that are representative of VSC HVDC systems in general.

The converter transformer reliability data in Table 8 is based on results reported by the CIGRE JWG A2/B4.28 [9]. Reliability data of converter transformers commissioned after 2006 has been selected since this is most representative of present technology.

Table 8 Summary of Converter Transformer Reliability

	Failure Rate (per year)	Mean time to repair (hours)
Converter Transformer	0.02	68.5

The d.c. cable data in Table 9 is based on the survey reported by CIGRE WG B1.10 [10]. In the present work, it is assumed that d.c. extruded cable will have same failure rate as a.c. extruded cable given that the reported a.c. extruded cable failures were all external failures.

Table 9 Summary of HVDC Cable Reliability

	Failure Rate (per circuit km year)	Mean time to repair (days)
DC MI Cable	0.001114	60
DC XLPE Cable	0.000705	60

In recent years, experience with both VSC HVDC converters and d.c. extruded cables has increased, although the service experience with these technologies has yet to be published. In the absence of published data, assumptions on reliability and availability can be made based on experience with LCC HVDC converters and MI d.c. cable. Meanwhile, there is a pressing need for published data for VSC HVDC converters and d.c. extruded cables.

6.5 References

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[2] 346 Protocol for Reporting the Operational Performance of HVDC Transmission Systems

[3] B4_202_2006 Survey of the reliability of HVDC systems throughout the world during 2003 – 2004

[4] B4_119_2008 A survey of the reliability of HVDC systems throughout the world during 2005 – 2006

[5] B4_209_2010 A survey of the reliability of HVDC systems throughout the world during 2007 – 2008

[6] B4_113_2012 A survey of the reliability of HVDC systems throughout the world during 2009 – 2010

[7] Dodds, S; Railing, B; Akman, K.; Jacobson, B.; Worzyk, T.; Nisson, B.; HVDC VSC (HVDC Light) Transmission - Operating Experiences, B4-203, CIGRE 2010

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[9] Joint Working Group A2/B4.28 “HVDC Converter Transformers” CIGRE Publication 406, February 2010

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7 PROTECTION STRATEGY

7.1 Introduction

Suitable protection strategies for point-to-point offshore wind farm connections have been well established in the course of a number of projects around the world [1]. Such projects have utilised standard practices for both a.c. (Alternating current) and d.c. (Direct current) applications respectively. The present chapter considers the challenge of devising a suitable protection system for such a network within the scope of the integrated offshore transmission project.

Firstly, a brief introduction to the functional and performance requirements of a protection system is described. This is followed by a description of possible protection strategies using a.c. and d.c. circuit breakers respectively.

Five Generic scenarios, one using d.c. circuit breakers, are analysed in turn for faults at different locations. The sequence of protection actions following the detection of the fault are explained.

For a.c. protection systems the total duration of a fault can have a significant affect on the stability and security of the power system. If the fault is not cleared within a specific time, otherwise known as the critical fault clearing time, the power system will lose the angular stability

For d.c. protection systems the clearance of a fault on the d.c. side may be much faster compared to that on the a.c. side. Limiting the fast rise in d.c. current, as well as preventing d.c. voltage collapse is the key drivers for the d.c. protection systems [2].

The ability of a converter station to control fault currents is an area still under study [2]. Line Commutated Converter (LCC) as well as Voltage Source Converter (VSC) Full Bridge (FB) stations can have ability to control or block fault currents, while a VSC Half Bridge (HB) combined with fast a.c. or d.c. side circuit breakers can behave similar to the VSC Full bridge [2].

The earthing of the HVDC system plays a key role in the formation and distribution of short-circuit currents, and therefore can have a large influence on the protection system to successfully detect and clear earth faults [2].

7.1.1 Key Functional and Performance Requirements

Each HVDC converter station should be equipped with a protection system which must operate correctly under both normal and abnormal conditions. The HVDC system should remain stable in all situations and the system must be self-protecting with and without inter-station communications in service. The protection systems for all converter stations of a HVDC system should be interoperable.

The protection system should have full redundancy in all vital parts. The protection for an HVDC converter station should comprise protection functions related to Harmonic Filter(s), Converter Transformers(s), Poles(s)/Converter(s), d.c. busbar(s)/line(s) and a.c. busbar(s).

The HVDC protection system should be divided into a number of separately protected and overlapping zones. A protection function should only operate upon a specific fault within a designated zone and must remain stable to any faults external to the relevant zone.

Protection and control systems should be as independent as possible. Each of the protection systems should always remain active and be powered by separate, independent supplies to ensure satisfactory operation in the event of the loss of one supply.

Each protective zone should be protected by two main protection functions and one back-up protection function, preferably using different protection principles. Where it is not possible to use different protection principles, duplicated protections should be used.

The protection functions of the HVDC system should be coordinated with those of the connected a.c. network.

The protection system should be designed to ensure that no single credible malfunction shall cause the total failure of the HVDC system.

A typical protection arrangement for a HVDC converter station is shown in the figure below.

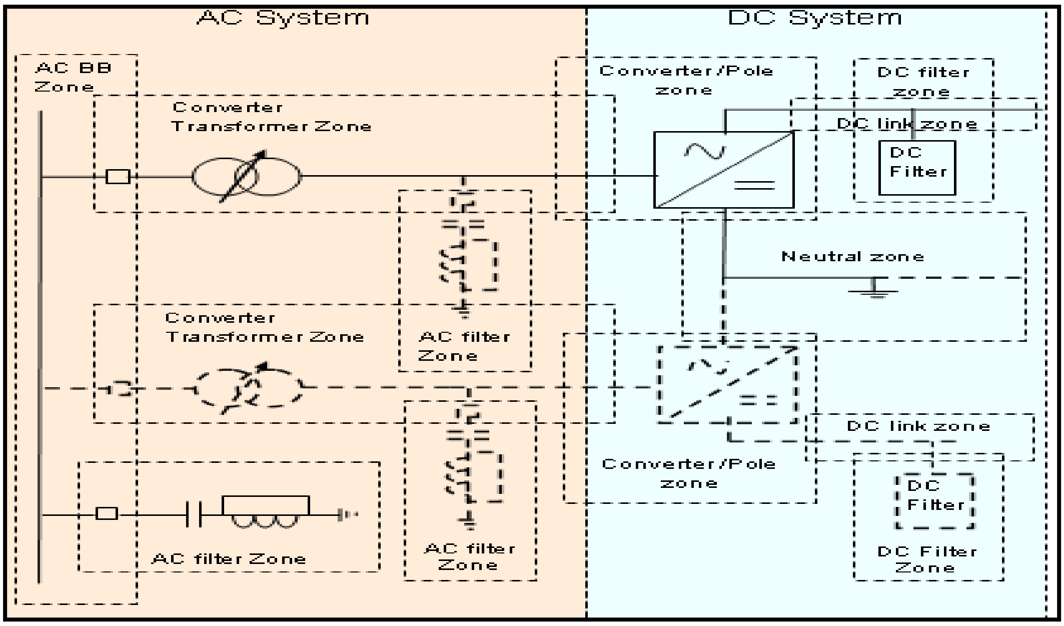

Figure 2*:* Example of HVDC Protection zones

Generally-speaking there are two protection strategies for managing faults within a DC network or a Line: Using a.c. Circuit Breakers and using d.c. Circuit Breakers.

7.2 Protection Strategy Using AC Circuit Breakers

In a.c. systems, it is standard practice to clear a fault by sending trip commands to the relevant a.c. circuit-breakers.

LCC HVDC converters and some types of VSC HVDC converters have the ability to block the infeed of fault current from a d.c. fault, allowing the fault to be cleared by appropriate control or switching actions [3].

For the HVDC converters that do not have the ability to block the infeed of fault current, the opening of the a.c. circuit breaker at each d.c converter to clear a d.c. fault is one of the strategies for a d.c. protection system.

The faults on the offshore a.c. network and windfarm generators are expected to be detected and cleared by the dedicated offshore windfarm protection systems, hence not within the scope of discussion in this report.

7.2.1 Scenario 1

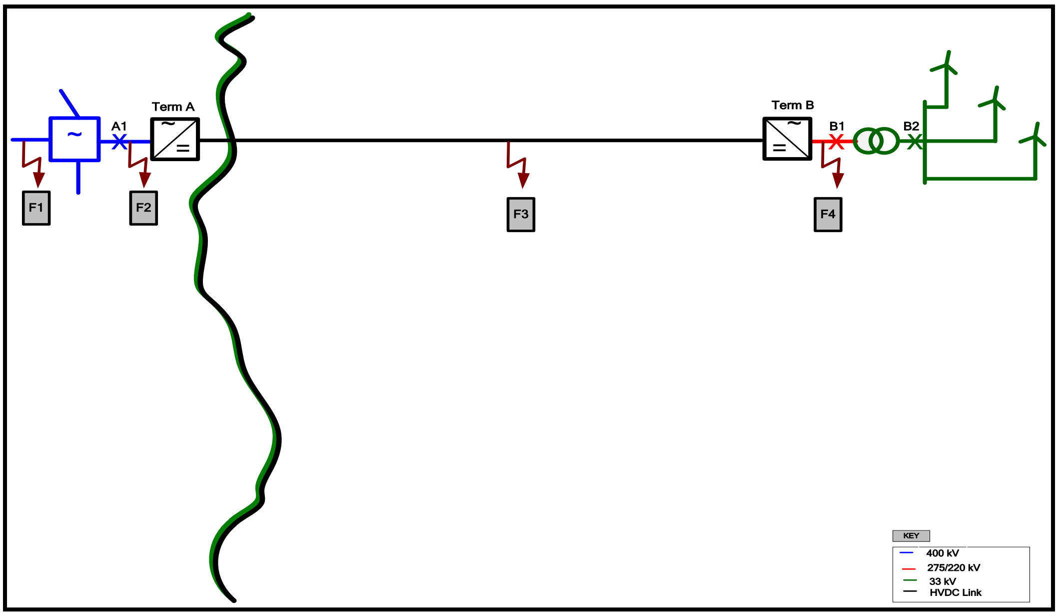

Figure 3: Basic point to point HVDC link

<u>Protection Strategy for Scenario 1</u>

For scenario 1 above, the protection strategy for a point-to-point wind farm connection has already been well established in practice [4],[5]. For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection systems.

For a fault at other position F2, F3 and F4 has to be cleared by tripping the a.c. CBs at both end of the d.c. link, and will result in the removal of both the d.c. link and wind farm from the system.

Fault Analysis for Scenario 1

Faults (Onshore)

For a fault on the a.c. network, such as that at F1, the local a.c. protection system will trip associated circuits on shore to clear the fault.

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the HVDC converter station protection system at Terminal A will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A
3. Trip both the onshore a.c. circuit breaker A1 and offshore a.c. circuit breaker B1 to clear the fault.

Fault (DC Cable)

For a fault at F3 on the grid side of the converter, the HVDC protection system will be required to:

1. detect the fault,
2. Issue blocking commands to both the onshore d.c. Converter at terminal A and offshore d.c. converter at terminal B.
3. Trip both the a.c. Circuit Breakers A1 and B1 to clear the fault

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the protection system at converter station Terminal B will be required to

1. Detect the fault.
2. Issue a blocking command to the d.c. converter at terminal B
3. Trip the a.c. circuit breaker B1 to clear the fault.

7.2.2 Scenario 2

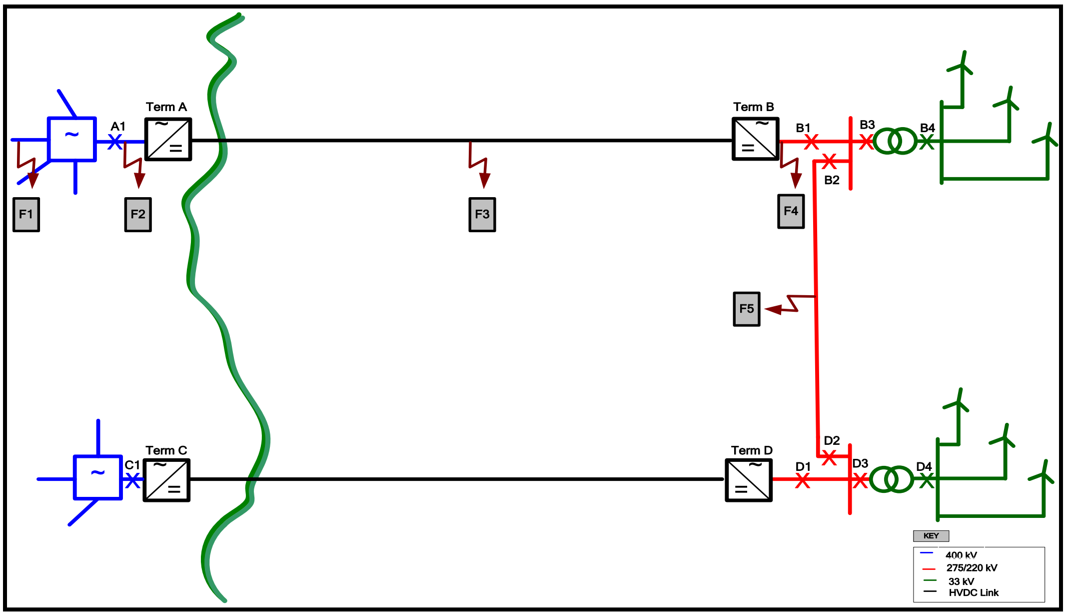

Figure 4: Radial d.c. links with a.c. Interconnection

<u>Protection Strategy for Scenario 2</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, F3 and F4 has to be cleared by tripping a.c. CB A1, B1 which will result in the removal of the d.c. link between terminals A and B from the system. With the addition of the a.c. interconnection between the two offshore wind farms it will be possible to keep the offshore wind farm located at terminal B in-service.

For a fault at F5, due to a cable connection, only the a.c. interconnection between the two wind farms needs to be tripped by opening a.c. CB B2 and D2. This strategy will result in both the wind farms and d.c. links operating as separate radial connections to the onshore system.

<u>Fault Analysis for Scenario 2</u>

Faults (Onshore)

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the protection system at converter station term A will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A

3. Trip both the onshore a.c. circuit breaker A1 and offshore a.c. circuit breaker B1 to clear the fault.

Fault (DC Cable)

For a fault at F3 on the grid side of the converter, the HVDC protection system will be required to:

1. Detect the fault,

2. Issue blocking commands to both the onshore d.c. Converter at terminal A and offshore d.c. converter at terminal B.

3. Trip both a.c. Circuit Breakers A1 and B1 to clear the fault

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the protection system at converter station Term B will be required to

1. Detect the fault.

2. Issue a blocking command to the d.c. converter at terminal B

3. Trip the a.c. circuit breaker B1 and A1 to clear the fault.

Faults (AC interconnection)

For a fault at position F5 on the a.c. interconnection between the two offshore wind farms the a.c. cable protection system will be required to:

1. Detect the fault.

2. Trip both a.c. circuit breakers B2 and D2 to clear the fault

7.2.3 Scenario 3

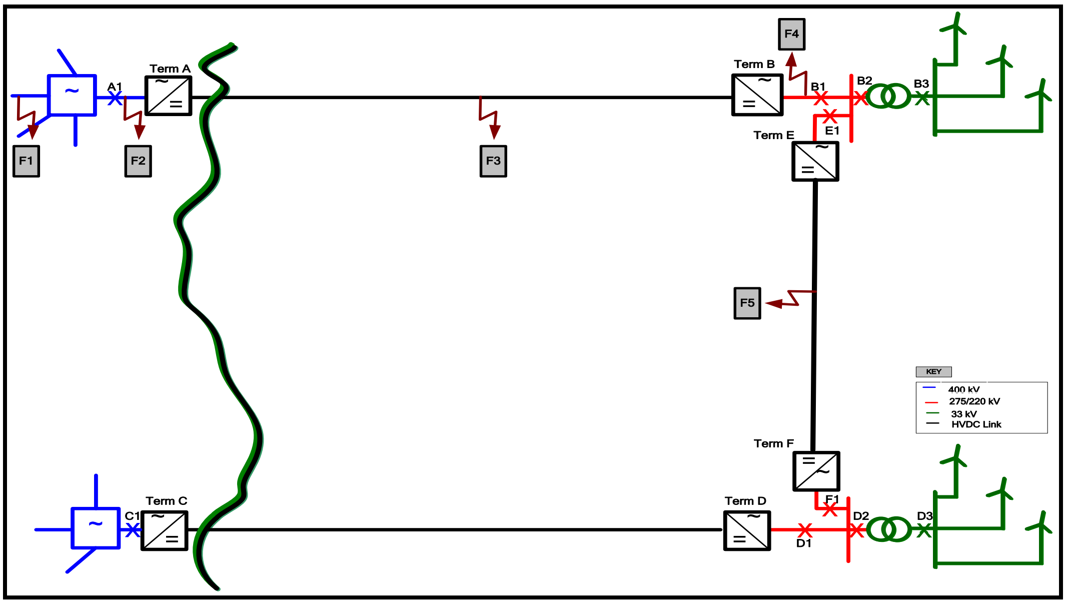

Figure 5: Interconnection via Point-to-point HVDC Link

<u>Protection Strategy for Scenario 3</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, F3 and F4 has to be cleared by tripping a.c. CB A1 and B1, which will result in the removal of the d.c. link between terminals A and B from the system. With the addition of the d.c. interconnection between the two offshore wind farms it will be possible to keep the offshore wind farm located at terminal B in-service.

For a fault at F5, due to a cable connection, only the d.c. interconnection between the two wind farms will need to tripped to clear the fault. This strategy will result in both the wind farms and d.c. links operating as separate radial connections to the onshore system, as was the case with scenario 2.

<u>Fault Analysis for Scenario 3</u>

The protection operation sequence for the faults on the location at F1 – F5 are the same as Scenario 2.

7.2.4 Scenario 4

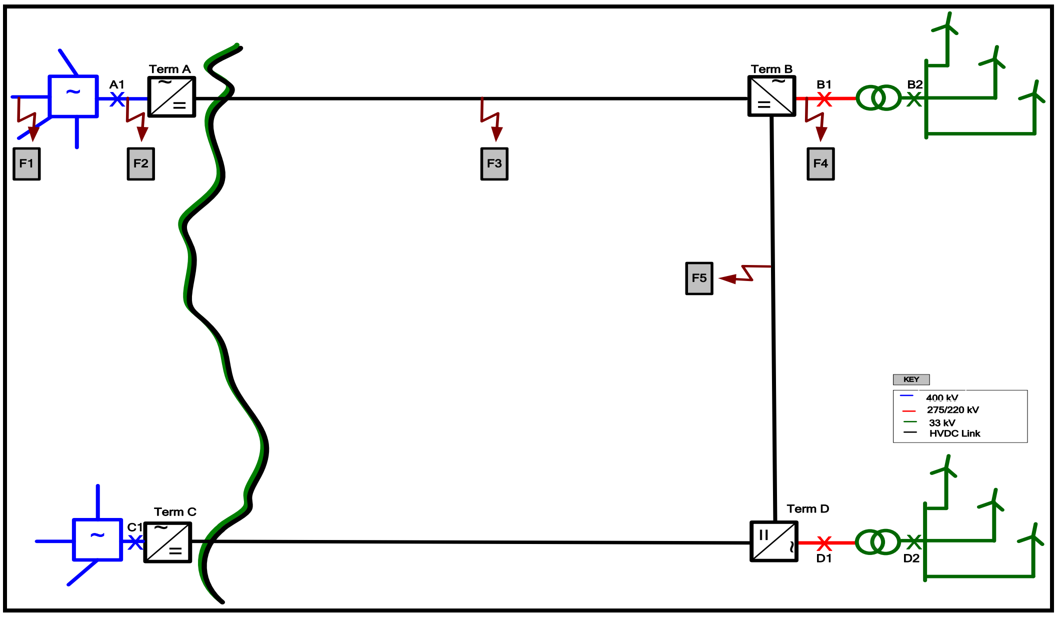

Figure 6: Interconnection with Multi-terminal HVDC Grid

<u>Protection Strategy for Scenario 4</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2 – F5 has to be cleared by tripping all the a.c. CB A1,B1, C1 and D1, will result in the removal of the whole d.c. system and power transfer will be stopped. Once the fault has been successfully cleared and the faulty section isolated, the system may be restarted and power transfer can recommence.

<u>Fault Analysis for Scenario 4</u>

Faults (Onshore)

For a fault at F2 – F5 the HVDC protection system will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A
3. Trip all the a.c. circuit breakers

7.3 Protection Strategy Using d.c. Circuit Breakers

With the inclusion of d.c. circuit breakers in a power system, the protection strategy will be different from that when conventional a.c. circuit breakers are utilised for fault clearing purposes. Due to the much quicker operating time of the d.c. circuit breaker [6], clearance of the fault can be achieved much faster compared to the fault clearing strategy of the a.c. circuit breaker. This also ensures that under the occurrence of a d.c. fault, only the faulty section is isolated and does not result in the loss of the whole power system.

One of main aims of the protection strategy is to stop the fault current from rising too high to prevent the maximum rating of the d.c. circuit breaker from being exceeded [7]. If this is not achieved then this can result in physical damage to the circuit breaker. The design of the series reactor to help limit the fault current plays a crucial role in this particular protection strategy [7].

The other aim is to help prevent the d.c. network from possible voltage collapse under a d.c. fault condition. The speed of operation of the d.c. protection is critical to prevent the above situations from occurring and requires further investigation [7]

One advantage of employing d.c. Circuit Breakers is that in the event of a one end of a d.c. link being tripped, the ‘STATCOM’ functionality can still be utilised on the Converters due to no blocking signal or a.c. Circuit Breaker tripping being required. Hence the voltage of either the onshore a.c. network or offshore a.c. island point of common coupling maybe supported during the fault isolation process.

7.3.1 Scenario 5

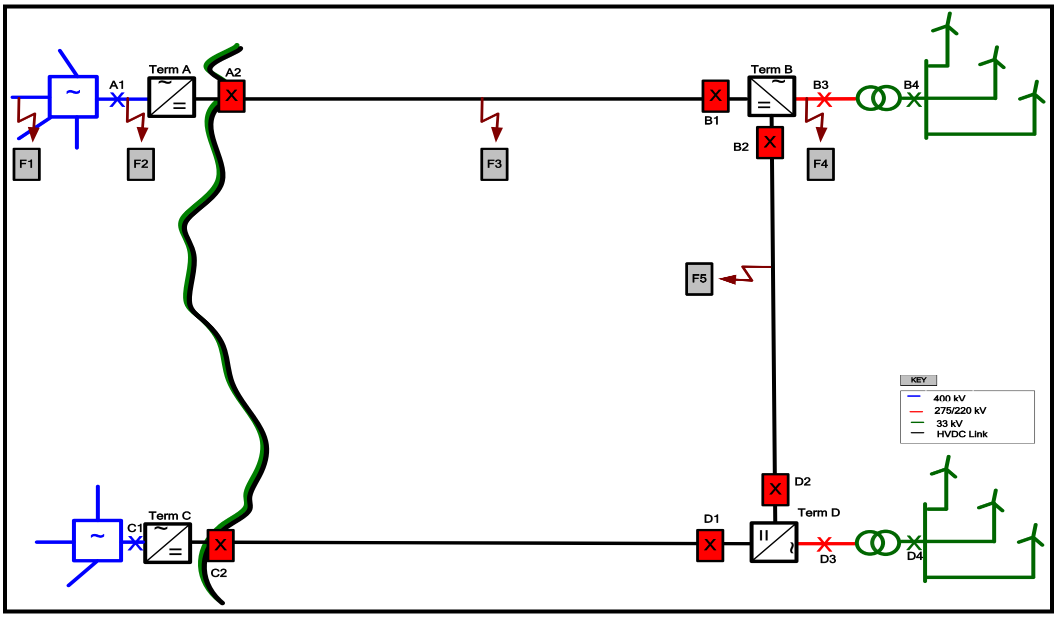

Figure 7: Interconnection with Multi-terminal Grid Utilising d.c. Circuit Breakers

<u>Protection Strategy for Scenario 5</u>

For any fault at location F1, the wind farm must stay connected to the offshore system for the total duration of the fault (fault ride through), until it has been successfully detected and cleared by the onshore a.c. protection system.

For a fault at position F2, it will be cleared by tripping a.c. CB A1 and d.c. CB A2, which will result in the removal of the onshore d.c. converter at terminal A from the system.

To clear a fault on the d.c. cable at F3 and F5, it only needs to trip the associated d.c. link by opening the two d.c. CBs at each end of the link. Other healthy part of d.c. network will remain in service.

The protection strategy to clear a fault at F4 will be very similar to that previously described for a fault at F2 and will result in the removal of the d.c. converter at terminal B from the system.

<u>Fault Analysis for Scenario 5</u>

Faults (Onshore)

For a fault at F2 between the onshore a.c. circuit breaker A1 and d.c. converter at terminal A, the a.c. protection system will be required to:

1. Detect the fault.
2. Send a blocking signal to the onshore converter at terminal A
3. Trip the onshore a.c. circuit breaker A1 and d.c. circuit breaker A2

Fault (DC Cable)

For a fault at either F3 on the grid side of the onshore converter, or F5 on d.c. cable between terminals B and D the HVDC protection system will be required to:

1. Detect the fault.
2. Trip both d.c. circuit breakers A2 and B1 to clear the fault at F3
3. Trip both d.c. circuit breakers B2 and D2 to clear the fault at F5.

Faults (Offshore Converter)

For a fault at position F4 between the offshore a.c. circuit breaker B1 and the d.c. converter at terminal B, the a.c. protection system will be required to:

1. Detect the fault.
2. Issue a blocking command to the d.c. converter at terminal B.
3. Trip the a.c. circuit breaker B1
4. trip both d.c. Circuit Breakers B2 and D2

7.4 Conclusion

Both the functional and performance requirements expected of a protection system, suitable for such an application as the IOTP(E) has been covered. Faults occurring at different locations on five generic network scenarios have been analysed to explain the sequence of events required from both the a.c. and HVDC protection systems to clear the faults concerned.

Faults positioned between the onshore a.c. circuit breaker and d.c. converter within an HVDC Multi-terminal system may require additional protective actions to enable the fault to be cleared and requires further detailed investigation. This also applies to faults between the offshore d.c. converter and offshore a.c. circuit breaker respectively.

The speed of operation of the HVDC protection system is crucial to prevent the rate of rise of the d.c. fault current from being too excessive and exceeding the rating of the HVDC circuit breaker and other d.c. equipment [7]. Fast operation of the HVDC protection system is also required to prevent the collapse of the d.c. voltage for a d.c. side fault causing system instability. Hence further detailed investigations into these areas is also required.

The coordination between the a.c. protection and HVDC protection systems is fundamental to the correct detection and clearing of faults within an integrated offshore transmission network and also required further detailed analysis.

The ability of the d.c. converters to participate in the management of d.c. fault current depends on both the topologies employed, together with the earthing of the power system and will require additional examination, in addition to those currently already under study [9].

Study into wind farm protection system and coordination between this and the HVDC protection system also requires detailed analysis [8], [9].

7.4 References

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2. Oahu Wind integration and Transmission Study(OWITS) – Hawaiian Islands Interconnection Project (Electranix corporation Winnipeg, Manitoba Canada, February 2011.
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8. POWER FLOW CONTROL

8.1 Introduction

HVDC technology based on self-commutated voltage sourced converter has the capability of independent control of active and reactive power which makes integration of offshore wind farms and multi-terminal operation easier than for conventional a.c. and LCC HVDC. In this chapter, the functional requirements of primary and secondary control for VSC HVDC systems are introduced and the primary control methods and their characteristics are described. Application of power flow control is illustrated using a number of generic scenarios representing the basic types of connection that would be used in an integrated offshore transmission network. For each scenario, it is demonstrated how converter control characteristics can be coordinated to achieve the desired steady state power flows. It is also shown how a new operating point can be achieved following the loss of a transmission connection. An annex is included in which the characteristics of variable speed wind turbines relevant to their application in an integrated offshore transmission network are described.

8.2 Functional Requirements for Power Flow Control

8.2.1 Primary Control

The requirements for primary control in VSC-based d.c. systems have been summarised as follows [1]:

- Well-defined operating points that are easy to schedule
- Stable operating point after a large disturbance
- Possible to schedule for optimal power flow
- Possible to handle restrictions and limitations in both a.c. and d.c. networks
- Prevention of overload
- Voltage control
- Dynamic control division between several converter stations, to ease the influence on the a.c. system
- Automatic control, i.e. work without communication

Active and reactive power are controlled locally at a converter by means of pre-programmed control characteristics. In this way, the converter is able to respond to changing system conditions in the short term without dependence on communications.

8.2.2 Secondary Control

The functions of secondary control are described in [1] as follows:

- The secondary control actions in a d.c. grid comprise of a change in set points which dictate the overall steady state power flows in the grid, prevent overload of branches, minimize losses, re-establish regulator range and reschedule according to planned operation
- A central dispatch centre can use power flow tools to determine the desired grid state and use the results to alter the converter set-points in a slow manner through secondary control.
- The secondary control coordinates the power orders and d.c. voltage references to all stations in the d.c. grid.

The primary control characteristics of the converters in a d.c. system are coordinated so that the desired load flow is achieved and so that the overall response of the d.c. system to an event is acceptable and a new steady state operating condition is reached. Following such a change, new control parameters may be sent to the converter controllers by secondary control so that an optimised power flow is again achieved.

8.3 Primary Control Methods in VSC-HVDC

The most important feature of VSC-based systems is independent control of active and reactive power, *P* and *Q*, so that the four-quadrant operation capability can be achieved. The typical *P*-*Q* operating range for a VSC HVDC converter is shown in Figure 1[2].

The objectives for the power flow control in a VSC-based system, whether a point-to-point d.c. link or a multi-terminal d.c. grid, are to control the voltage and power through the converters and branches to meet the operation requirements of the a.c. and d.c. systems.

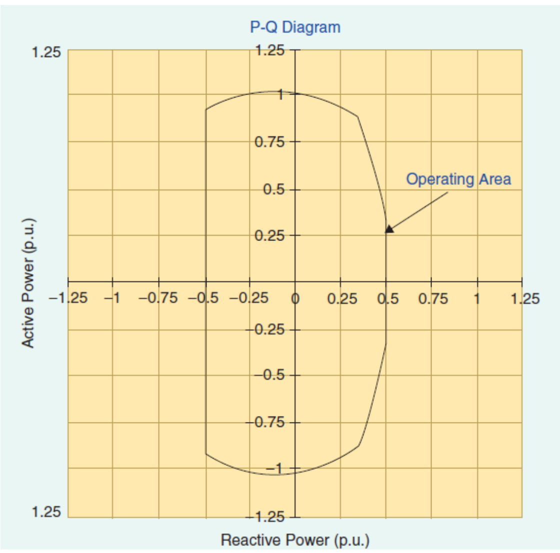

Figure 1: Typical P-Q Characteristics within a VSC-based Station [2]

8.3.1 Inner Current Controller of VSC

The vector control methods are widely applied in the controller design of the VSC-based systems to achieve the independent or so-called decoupled control of active and reactive power [3]. In Figure , the measured voltages and currents at the point of common coupling (PCC) in the three-phase *a-b-c* coordinate system are transformed into their own direct and quadrature *d*- and *q*-axis components in the rotational *d-q* coordinate system via the Park transformation [4]. The *d-q* coordinate system rotates in synchronism with the power frequency voltage and the phase angle is usually selected such that quantities related to active power are aligned with the *d*-axis and quantities related to reactive power with the *q*-axis.

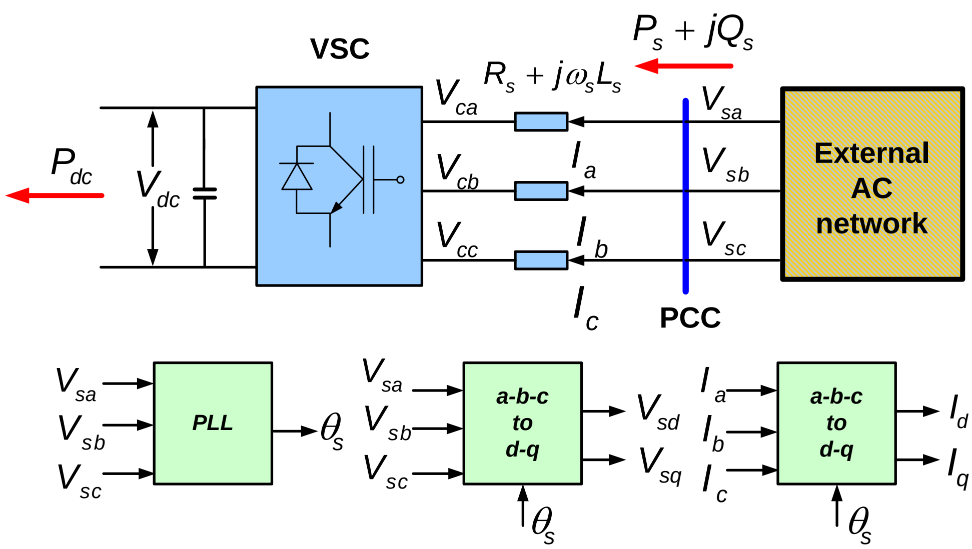

Figure 2: Park Transformation for a-b-c to d-q Coordinate System

A VSC controller is usually designed based on the cascaded two-stage controller structure. In the inner current controller shown in Figure , the *d*- and *q*-axis components I_d and I_q are compared with their own references and the errors are sent to the proportional integral (PI) regulators to provide the required modulation index (voltage) for generating the firing signals to turn on or off the VSC [4]. With this design structure of the inner current controller, the control of *d*- and *q*-axis currents can be decoupled [5].

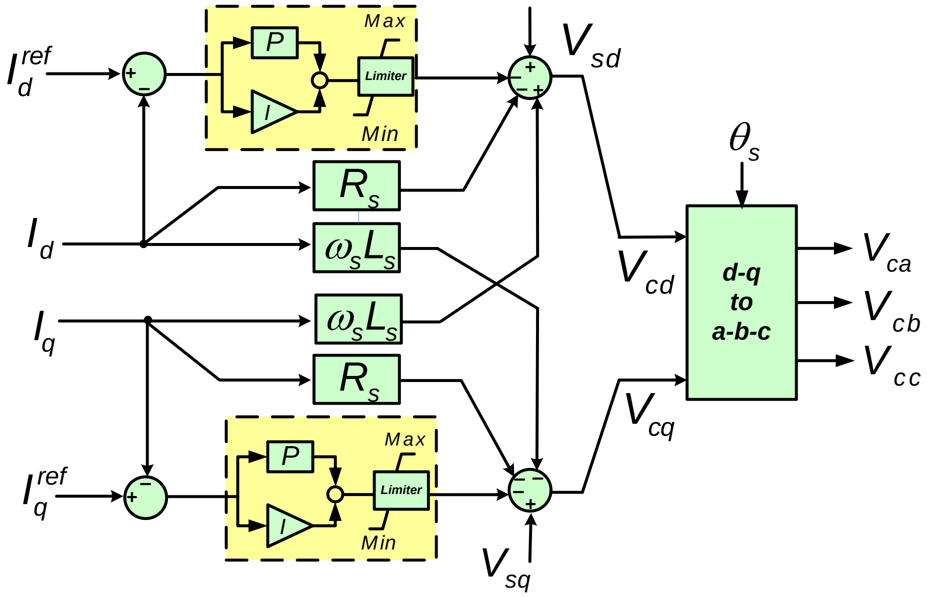

Figure 3: Control Schematic of Inner Current Controller

8.3.2 Outer Controller of VSC

For the outer controller, the measured variable is compared with its reference and their error is then sent to the PI regulator to provide the *d*- or *q*-axis current reference for inner-stage current controller mentioned above [3]. In different operation conditions, different control objectives e.g. constant active power or voltage can be achieved via the *d*- or *q*-axis outer controller to maintain the normal operation of VSC-based systems.

8.3.2.1 Power Controller

8.3.2.1.1 Constant Active Power Controller

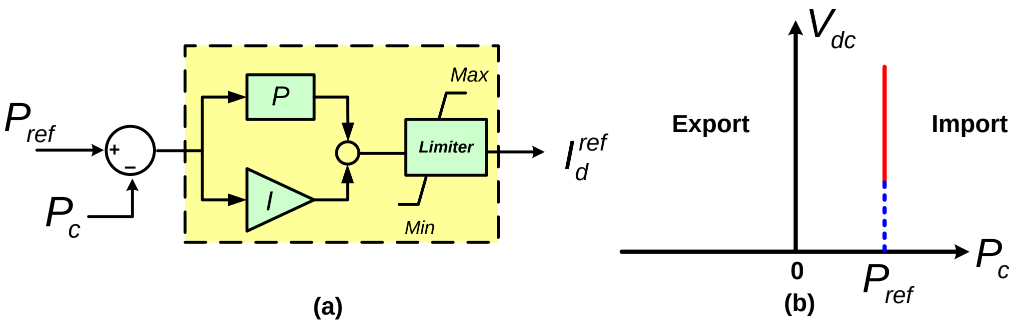

Figure 4: The Constant Active Power Controller

The control schematic of a constant active power controller is shown in Figure 4 (a) [3, 4]. The active power P_c measured at the a.c. terminal of the VSC is compared with the preset reference P_{ref}. The error is sent to the PI regulator to provide the *d*-axis current reference. In order to limit the magnitude of current to within the allowable range, the output of the active power is followed by a limiter function. At steady state, with the constant active power controller, P_c equals P_{ref}.

The characteristic of this controller represented by the "d.c. voltage vs active power" curve is illustrated in Figure 4 (b) [6]. P_{ref} is set regardless of the level of the d.c. voltage V_{dc}, hence the vertical line shows the characteristics of constant active power controller. For the purposes of this report, 'import' refers to the import of power to the HVDC system and 'export' refers the export of power from the HVDC system.

8.3.2.1.2 Constant Reactive Power Controller

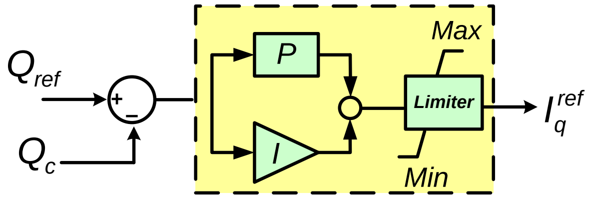

Figure 5: Control Schematic of Constant Reactive Power Controller

The control schematic of constant reactive power controller is shown in Figure 5 [3, 4]. The q-axis current reference can be obtained by regulating the error between the reactive power Q_c measured at the a.c. terminal of the VSC and the preset reference Q_{ref}, similar to the constant active power controller. At steady state, with this controller, Q_c equals Q_{ref}.

8.3.2.2 Voltage Controller

8.3.2.2.1 Constant DC Voltage Controller

By controlling the d.c. voltage to a constant value, the balance between active power imported onto the d.c. system and exported from the d.c. system is maintained. The control schematic of constant d.c. voltage controller is shown in Figure 6 (a) [3]. In a similar way to the constant active power controller, the d-axis current reference can be obtained by regulating the error between the measured d.c. voltage V_{dc} at the d.c.-side of the VSC and its preset reference V_{dc}^{ref}. At steady state, V_{dc} equals V_{dc}^{ref} and the characteristics of the constant d.c. voltage controller are as illustrated in Figure 6 (b) [6]. The d.c. voltage reference is set regardless of the level of active power, so that the horizontal line shows the characteristics for the d.c. voltage controller. Note that, should I_d reach one of its limits, it will no longer be possible to balance the power flows and the d.c. voltage will either fall (if the converter is importing power to the d.c. system) or rise (if the converter is exporting power from the d.c. system).

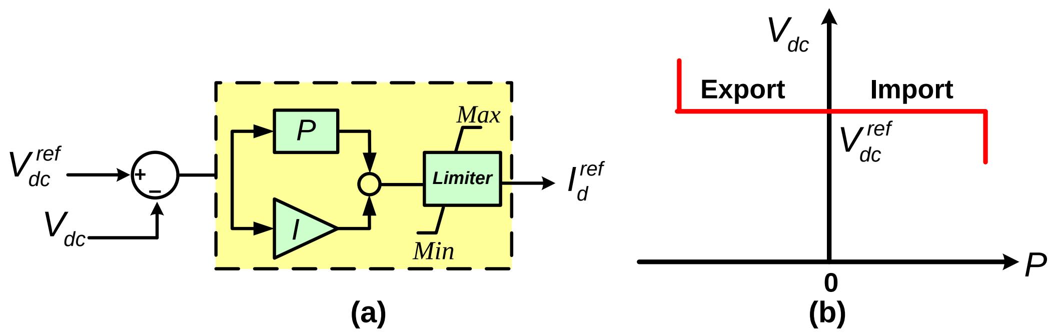

Figure 6: The Constant d.c. Voltage Controller

8.3.2.2.2 Constant AC Voltage Controller

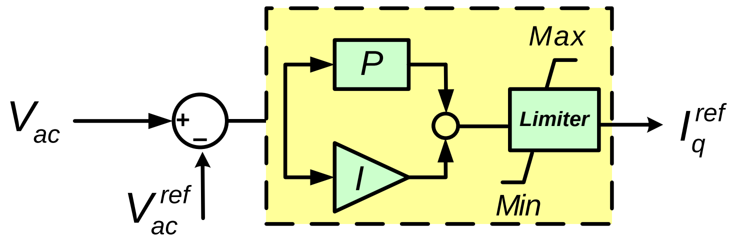

Figure 7: The a.c. Voltage Controller

The control schematic of a.c. voltage controller is shown in Figure 7[3]. In a similar way to the constant reactive power controller, the *q*-axis current reference can be obtained by regulating the error between the measured a.c. voltage V_{ac} at the a.c. terminal of a VSC and its preset reference V_{ac}^{ref}. At steady state, V_{ac} equals V_{ac}^{ref}.

8.3.2.3 DC Voltage Droop Controller

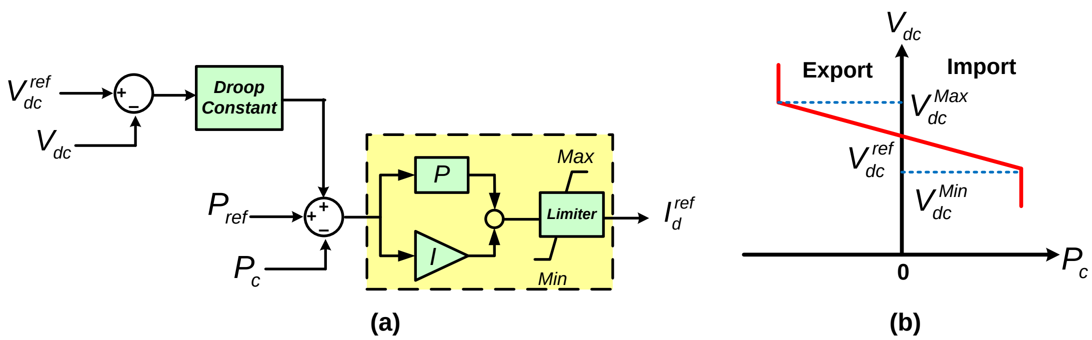

Figure 8: d.c. Voltage Droop Controller

The d.c. voltage droop controller uses the error between the measured d.c. voltage V_{dc} and the reference voltage V_{dc}^{ref} to generate an additional proportional offset in the power reference P_{ref} within the original active power controller. The principle is shown schematically in Figure 8 (a). The d.c. voltage droop controller characteristic is shown in Figure 8 (b) [1, 6]. The droop constant is defined as: $\frac{\Delta V_{dc}}{\Delta P_c} = K_{droop}$

Such control characteristics are usually applied in the MTDC systems to share the role of "slack bus" between several terminals instead of only one terminal [7].

8.3.2.4 Frequency Control

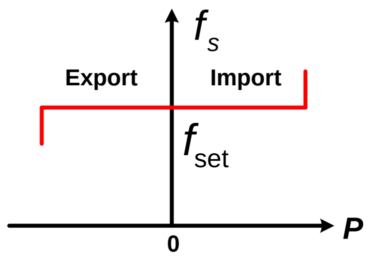

Figure 9: Constant Frequency Characteristic

The constant frequency controller usually works together with constant a.c. voltage controller in the VSC-based systems to provide the frequency and voltage references for weak a.c. systems e.g. islands and offshore wind farms [1, 2, 4]. The characteristics of the constant frequency controller are illustrated in Figure 9 [8]. The frequency reference is set regardless of the level of active power, so that the horizontal line shows the characteristics for constant frequency controller. Where limits are set, should I_d reach one of its limits, the frequency will either rise (if the converter is importing power to the d.c. system) or fall (if the converter is exporting power from the d.c. system).

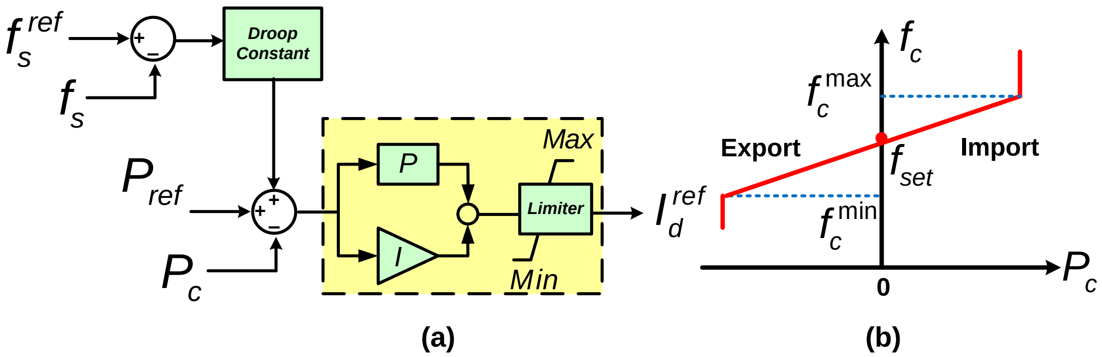

Figure 8: Frequency Droop Controller

With the frequency droop controller shown in Figure 10 (a), the functionality of frequency droop characteristics in a conventional synchronous generator can be achieved in the VSC-based systems [4, 6]. In a similar way to the d.c. voltage droop controller in Section 0, the error between the measured frequency f_s and the reference frequency f_s^{ref} is used to generate an additional proportional offset in the power reference P_{ref} within the original active power controller. The characteristics of the frequency droop controller are shown in Figure 10 (b) [4, 6, 8]. The droop constant is defined as:

$$\frac{\Delta f_c}{\Delta P_c} = K_{droop}$$

In order to optimise the network for the varied power dispatch, the master control adjusts the droop constants power and frequency references in the VSC-based system.

8.4 Variable Speed Wind Turbine Generators

The wind turbine generators connected to an integrated offshore transmission network are likely to be of the variable speed type. One of the key differences between MW-level variable-speed wind turbine generators and conventional generators is the use of back-to-back a.c./d.c./a.c. frequency converters. The frequency converters, typically IGBT-based voltage-sourced converters, are able to control their active and reactive power independently for four-quadrant operation [9, 10]. Consequently, these wind turbine generators can capture wind energy over a wide range of wind speed and their efficiency can be improved compared with fixed-speed wind turbine generators without frequency converters [11].

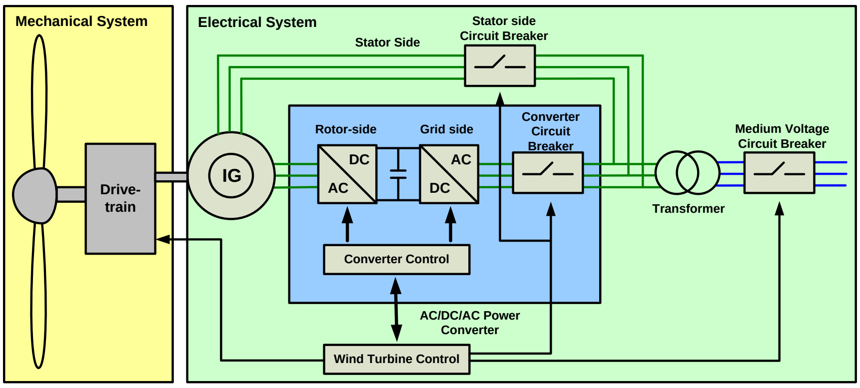

Figure 11: General schematic of DFIG

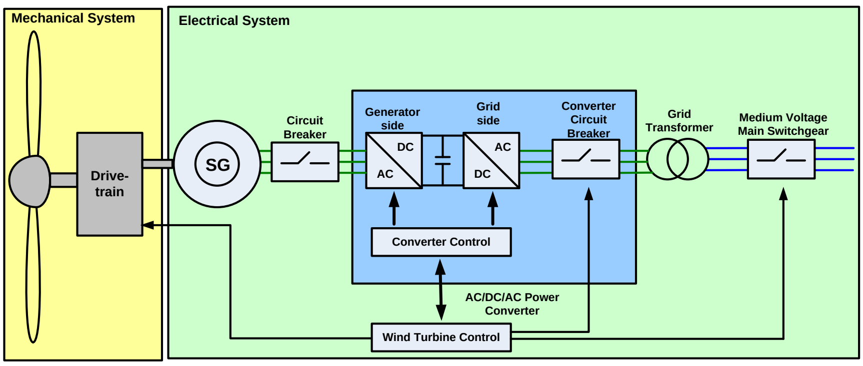

Figure 12: General schematic of FSC

Variable-speed WTGs are typically divided into two types according to the general configurations of their electrical system [9 - 12]:

1) Wind turbine with doubly-fed induction generator (DFIG)

2) Wind turbine with full-scale frequency converter (FSC)

The electrical system of a DFIG is shown in Figure 11 [10]. The stator of an induction generator is connected directly to the external grid. However, a frequency converter is inserted between the rotor of the induction generator and the external grid. With this layout, a portion of power from the generator's rotor (typically 25-30% of generator capacity) can be controlled by the frequency converter and the DFIG can operate over the variable-speed range of ±30% around the synchronous speed [12].

The electrical system of a FSC is shown in Figure 12 [10]. The frequency converter is connected in series with the stator of the synchronous generator so that the generator's power can be fully controlled by the frequency converter to perform smooth grid connection over the entire speed range [12]. However, for the same generator capacity, the power rating of the frequency converter in a FSC will be larger than that of a DFIG and the power losses and equipment costs will be higher.

The characteristics of variable speed wind turbine generators relevant to their connection to an integrated offshore transmission network are described in the annex to this chapter.

8.5 Application of Load Flow Control in Generic Scenarios

In this section, the application of load flow control is illustrated using a number of generic scenarios representing the basic types of connection which would be used in an integrated offshore transmission system. In each case, converter control strategies are chosen such that the desired steady state load flow is achieved. The response to the loss of a connection, such as might be caused by a fault or a converter trip, is considered for each possible case and the subsequent achievement of new operating points demonstrated.

8.5.1 Scenario 1: Point-to-Point VSC-HVDC Link

In Scenario 1, an offshore wind farm *WF* is connected to the onshore a.c. network via a point-to-point VSC-HVDC link L_1 as illustrated in Figure 13. The HVDC link has converters located onshore at T1 and offshore at T2. The frequencies of the onshore and offshore a.c. networks are f_{on} and f_{off}, respectively. The power imported by the offshore converter at T2 is P_{ofc}.

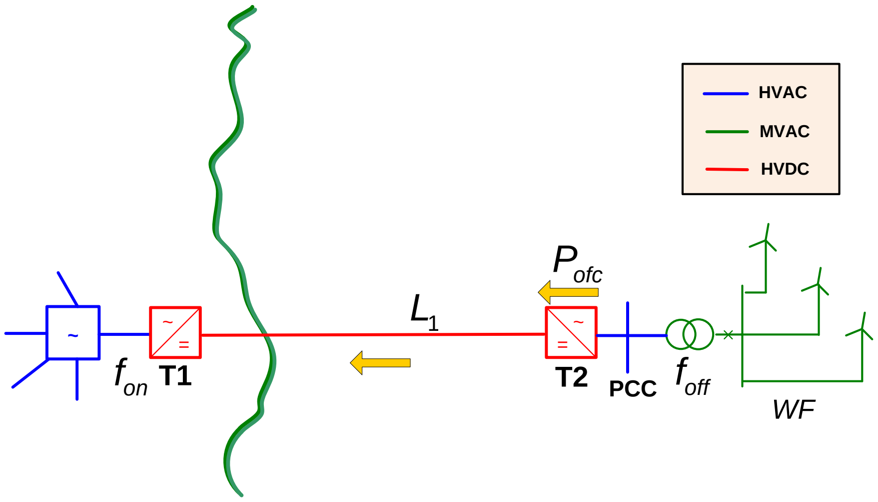

Figure 13: Point-to-Point HVDC Link

8.5.1.1 Control Strategies for Converters

The offshore wind farm is a weak a.c. network which is not easily able to provide the voltage and frequency references by itself. In this way, the offshore converter T2 needs to play the role as the reference machine for setting references of frequency and voltage at the point of common coupling (PCC) of the offshore a.c. network. The offshore converter at T2 maintains the frequency of the offshore a.c. network at a constant value so that the power imported into the d.c. link is maintained in balance with the power generated by the offshore wind farm. The onshore converter at T1, maintains a constant d.c. voltage on the d.c. link so that the power exported from the d.c. link to the onshore a.c. network is maintained in balance with the power imported to the d.c. link from the wind farm. The control strategies for the two terminals are summarised in Table 1.

Table 1: Control Strategies Proposed for Converters in Scenario 1

	Active Power	Reactive Power
T1	Constant V_{dc}	Constant Q
T2	Constant f	Constant V_{ac}

8.5.1.2 Loss of Connection

In the event that the HVDC link L_1 is tripped, all power transmission from the offshore wind farm to the onshore a.c. network will be lost. Consequently, the volume of generation connected by such a d.c. link may not exceed the limits on loss of infeed permitted by planning standards [13, 14].

Following loss of the d.c. link, the power generated by the wind turbines will cause the turbines' rotational speed to accelerate. Curtailment of the generated power is required to prevent over-speed of the turbines, rotor overcurrent in the generators and overvoltage/overcurrent in the d.c. link of the generators' frequency converters, particularly under high wind generation conditions. The protection strategies proposed to manage such risks are discussed in the annex to this chapter.

Grid codes typically require a fault ride through capability for the offshore wind turbines in the event of faults on the onshore a.c. network [15, 16]. For the VSC-HVDC link, a thyristor-switched resistor bank at the onshore end of the d.c. system may be used for isolating the offshore wind farm from a.c. faults on the onshore a.c. network [9]. This solution has been used in the BorWin 1 project.

8.5.2 Scenario 2: Offshore AC connection

In Scenario 2, two offshore wind farms, WF_1 and WF_2, are each connected to the onshore a.c. network by point-to-point HVDC links L_1 and L_2. The wind farms are connected on the a.c. side by a connection L_3. The arrangement is shown in Figure 14.

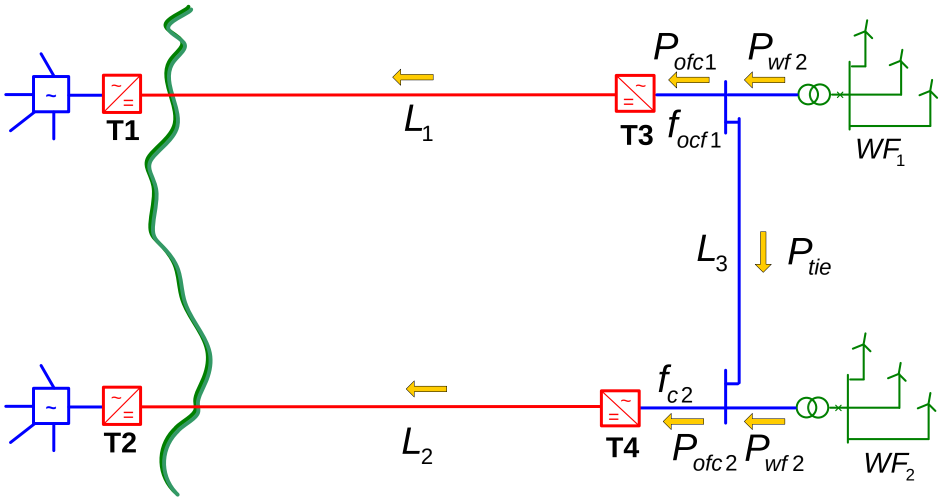

Figure 14: Offshore a.c. Interconnector for Two Parallel HVDC Links

In this arrangement, spare capacity on the HVDC links can be used for cross boundary power transfer for the onshore a.c. network when the wind generation is less than maximum. Referring to Figure 14, the power generated by WF_1 is P_{WF1} and the power imported by the offshore converter at T3 is P_{ofc1}. The power generated by WF_2 is P_{WF2} and the power imported by the offshore converter at T4 is P_{ofc2}. The direction of the power flow P_{tie} through the a.c. connection is from WF_1 to WF_2. The power flow of two offshore a.c. converters can be represented:

$$\begin{cases} P_{ofc1} = P_{WF1} - P_{tie} \\ P_{ofc2} = P_{WF2} + P_{tie} \end{cases}$$

8.5.2.1 Control Strategies for Converters

A similar scenario to Scenario 2 was studied in [17]. Constant d.c. voltage control and constant *Q* control were proposed for both of the onshore converters (corresponding to T1 and T2 in Scenario 2), while frequency droop control and constant a.c. voltage control is proposed for the offshore converters (corresponding to T3 and T4). A similar scenario to Scenario 2 was studied in [8], except that the offshore a.c. network was connected to the onshore network by three HVDC links. Applying the principles used in [8], a further two strategies for the present scenario may be proposed. The three proposed strategies are summarised in Table 2.

Table 2: Possible Control Strategies for Converters in Scenario 2

	T3	T4
Strategy 1	*f* Droop	*f* Droop
Strategy 2	Constant *f*	*f* Droop
Strategy 3	Constant *f*	Constant *P*

In [8], there are two key conclusions with regard to the control strategies:

- For Strategy 1, the use of frequency droop control allows load sharing between the HVDC links to be achieved. However, unexpected large load unbalances can occur under some conditions.

- For Strategy 2 and 3, the frequency will be constant. Load sharing can be achieved by smart power dispatch. However, Strategies 2 and 3 impose high requirements on communication between the central control and the individual converter controls.

Due to the fast response required of the d.c. system, it is not recommended to rely on communication for primary control of the power flow at disturbances [1]. As a result, the Strategy 1 may be more practical than Strategy 2 and 3 in terms of requirements for automatic control.

Based on [8, 17], the control strategies for converters T1 to T4 are proposed in Table 3.

Table 3: Proposed Control Strategies for Converters in Scenario 2

	Active Power	Reactive Power
T1	Constant V_{dc}	Constant Q
T2	Constant V_{dc}	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}

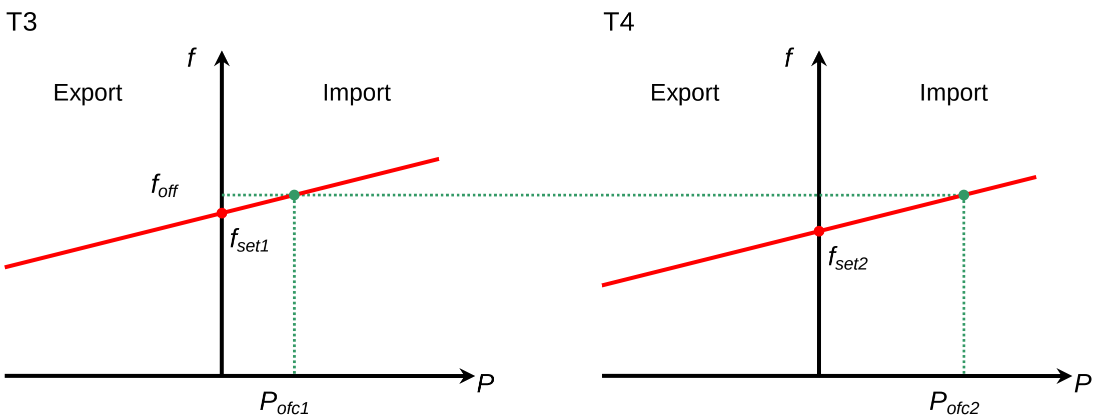

Figure 15: Power Dispatch between T3 and T4

The use of frequency droop control to achieve sharing of power between terminals T3 and T4 is illustrated in Figure 15. The two offshore a.c. networks are coupled via the HVAC interconnector and share a common frequency f_{off}. The power import at each converter is determined by its control characteristic. The power share can be changed by shifting the control characteristic of either converter up or down the frequency axis.

8.5.2.2 Loss of Connection

a) Loss of HVDC Link L_1

In the event that the HVDC link L_1 is tripped, the frequency of the offshore a.c. network comprising WF_1 and WF_2 will increase and the converter at T4 will adjust its operating point to increase its power import in accordance with its frequency droop characteristic. This is represented by the move from Operating Point 1 to Operating Point 2 in Figure 16. If the total power generation of the two wind farms is within the capacity of the converter at T4, a new, stable operating point will be reached. New reference points will subsequently be sent to the controller of T4, as represented by the move from Operating Point 2 to Operating Point 3 in Figure 16 as the frequency is restored.

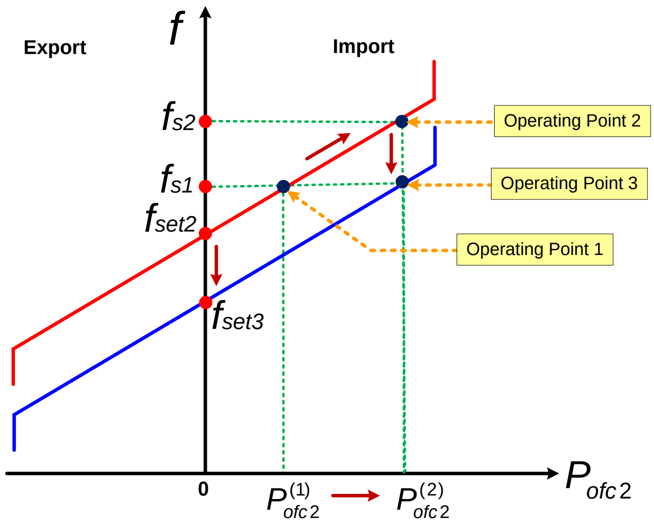

Figure 16: Change in Operating Points for Converter at T4

If the total power generation of the two wind farms exceeds the capacity of the converter at T4, urgent action will be required to manage the excess power. The IGBTs in the valves of a VSC HVDC converter cannot support overload conditions for more than a few milliseconds. In the event of an overload, the converter at T4 will rapidly be tripped with the loss of all connected generation. It is possible to prevent the converter at T4 from overload by using its control system to limit the current, but some means must still be found to manage the excess generated power.

In principle, it would be possible to reduce power generation by control action, possibly using the frequency of the offshore network as a trigger. A power reduction controller has been proposed in [17]. It was stated that due to the fast response of the wind turbine converters, the output power is reduced quickly.

Strategies to manage excess power generation in a similar scenario to the present one have also been described in [8]. The scenario considered connection of an offshore a.c. network to the onshore network by multiple HVDC links, where the loss of one might result in overload of the remaining links and cascade tripping of all of them.

- A partial solution is to design the system such that the total generated power can be accommodated with the loss of the largest link.

- A semi-conductor controlled resistor bank (or ‘chopper’) connected to the offshore a.c. side would be a feasible solution, but would require significant additional investment in primary plant and platform infrastructure.

- Tripping excess generation might be a solution provided the level of overload on the remaining converters is sufficiently low that they can withstand the time required for decision plus circuit-breaker operation before tripping. In order to ensure that the level of overload be sufficiently low, the total generation connected under normal conditions would have to be restricted.

In [8], the longer time constant for reduction of power from the wind turbine generators was contrasted against the short overload time limits of VSC HVDC converters. Changing the turbine blade pitch angles may provide a reduction of around 25% of nominal power per second. The implication is that, by itself, power reduction by blade pitch control is too slow to be a solution.

Once the excess generation has been managed, new reference points will be sent to the controller of T4 to optimise the power flow under the new conditions.

The risk of the converter at T4 overloading and tripping following a trip of HVDC link L_1 could be eliminated by operating with the offshore a.c. connection L_3 normally open. The system would operate as two independent point-to-point HVDC links as described in Section 5.1. Thus, in the event that HVDC link L_1 tripped, power transmission from WF_1 to the onshore a.c. system would be lost but transmission from WF_2 would be unaffected. Should L_1 be out of service for a sufficient length of time, the offshore a.c. connection L_3 would be closed to allow generation from WF_1 to make use of any spare transmission capacity existing on HVDC link L_2. This arrangement would increase the availability for WF_1 compared with the point-to-point connection of Section 5.1, but would not contribute to cross boundary power transfer for the onshore a.c. network.

b) Loss of HVDC Link L_2

In the event that the HVDC link L_2 is tripped, the frequency of the offshore network will rise and the converter at T3 will attempt to adjust its operating point until all power generated by the two wind farms is transmitted by the remaining link L_1. Should the total power generation of the two wind farms exceed the capacity of the converter at T3, urgent action will be required to prevent overload and tripping as described above for the loss of L_1. The considerations related to managing excess generation are similar. Finally, new reference points will be sent to the controller of T3 to optimise the power flow under the new conditions.

The risk of the converter at T3 overloading and tripping following a trip of HVDC link L_2 could be eliminated by operating with the offshore a.c. connection L_3 normally open, as described above for the loss of L_1. This arrangement would increase the availability for WF_2 compared with the point-to-point connection of Section 5.1, but would not contribute to cross boundary power transfer for the onshore a.c. network.

c) Loss of offshore a.c. connection L_3

Where offshore wind farms are connected by means of an offshore a.c. connection, as represented by L_3 in Figure 14, it becomes increasingly important that the generators be able to remain transiently stable and connected for the fault clearance time in the event of a short circuit fault on the offshore a.c. network. Given the exclusive use of wind turbine generators and cable connections, the fault ride through requirements of existing grid codes may not be sufficiently onerous for the offshore a.c. network.

In the event that the offshore a.c. connection L_3 is tripped, and assuming that all generation has remained connected, the offshore frequencies at terminals T3 and T4 will be decoupled and, clearly, the power flow P_{tie} through the a.c. connection will equal zero.

In the milliseconds following the loss, the frequency of T3 moves up with its droop controller as the power previously transmitted by the a.c. connection flows into T3. T3 will increase its import of power to the HVDC link according to its f vs P droop characteristic shown in Figure 17(a). Meanwhile, the frequency of T4 moves down with its droop controller as the power previously imported from the a.c. connection is no longer imported by T4. T4 will reduce its power import according to its f vs P droop characteristic shown in Figure 18(a).

There is no risk of overload for T3 and T4 and the whole system will survive and enter new operating conditions. After surviving the emergency state, the original system becomes two independent point-to-point HVDC links as described in Section 0. The central dispatch may change the controllers of T3 and T4 from frequency droop control to constant frequency control with new reference points as shown in Figure 17(b) and Figure 18(b).

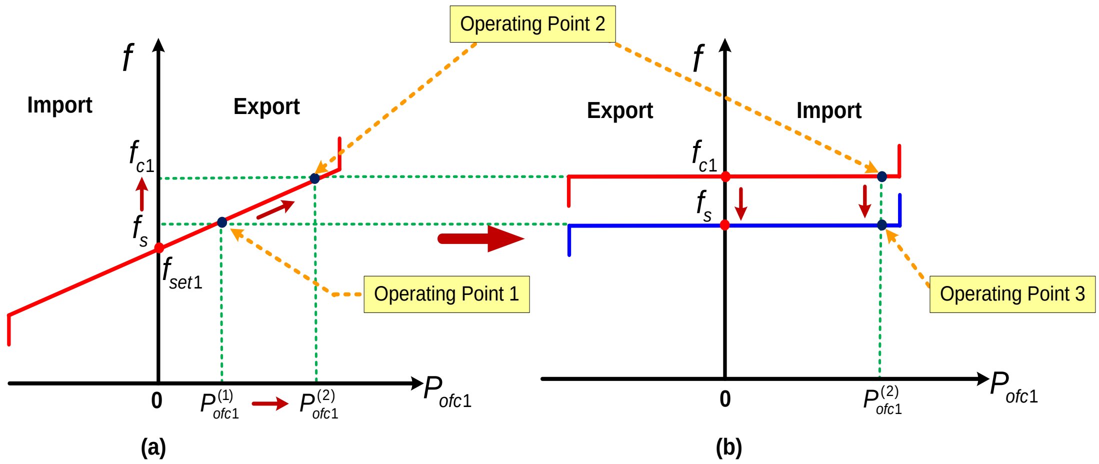

Figure 17: New Reference Point for T3 after System Restoration

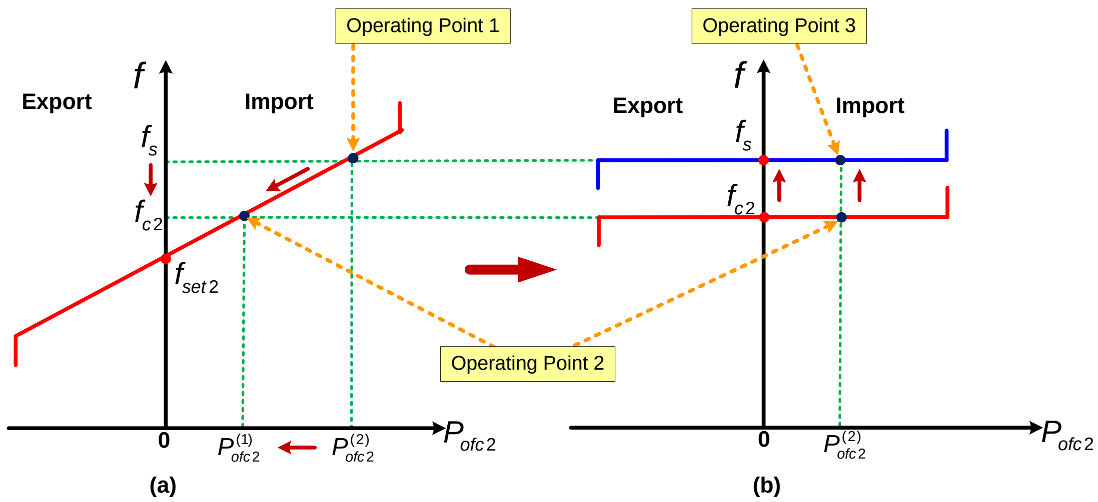

Figure 18: New Reference Point for T4 after System Restoration

8.5.3 Scenario 3: Offshore point-to-point HVDC connection

In Scenario 3, two offshore wind farms, WF_1 and WF_2, are each connected to the onshore a.c. network by point-to-point HVDC links L_1 and L_2. The wind farms are connected on the a.c. side by a point-to-point HVDC link L_3. The arrangement is shown in Figure 19.

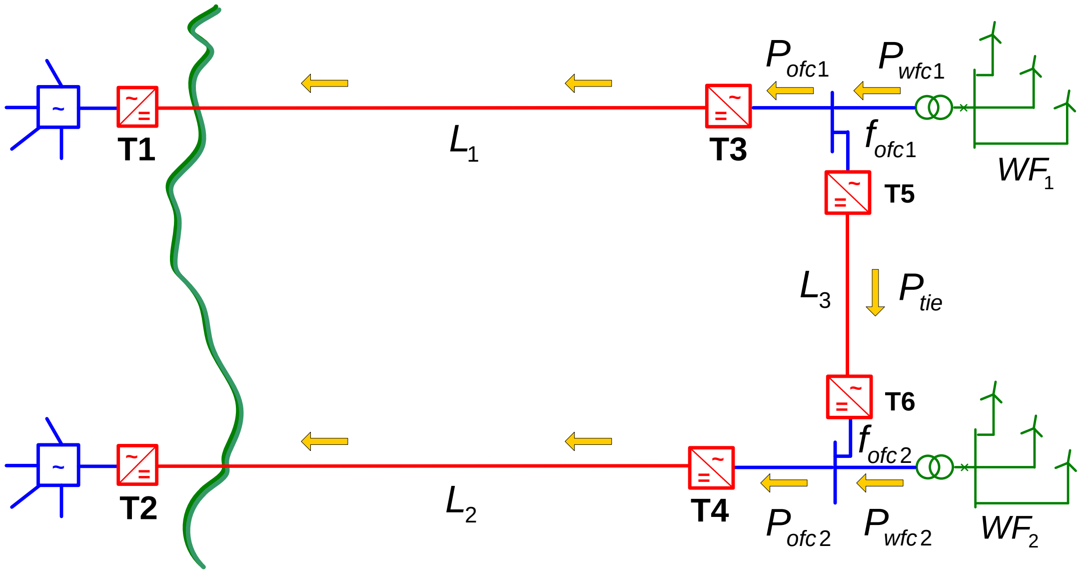

Figure 19: Offshore point-to-point HVDC connection for two parallel VSC-HVDC links

In this arrangement, the frequencies f_{ofc1} and f_{ofc2} of the two offshore a.c. networks are independent. It is assumed that the power rating of the converters at T5 and T6 is equal to that of the other converters. As in the case of Scenario 2, this arrangement allows spare capacity on the HVDC links to be used for cross boundary power transfer when the wind generation is less than maximum.

8.5.3.1 Control Strategies for Converters

For the converters at T1 and T2, the constant d.c. voltage controller and constant reactive power controller are used. For the converters at T3 and T4, the frequency droop controller is used. The converters at T3 and T5 share a common frequency, so the frequency droop controller is also proposed for T5. Since at least one converter of a HVDC link must participate in d.c. voltage control, the constant d.c. voltage controller is used for T6. For reactive power control, the constant reactive power controller is used for T5 and T6. The proposed control strategies are summarised in Table 4.

Table 4: Proposed Control Strategies for Converters in Scenario 3

	Active power	Reactive power
T1	Constant V_{dc}	Constant Q
T2	Constant V_{dc}	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}
T5	f Droop	Constant Q
T6	Constant V_{dc}	Constant Q

8.5.3.2 Loss of Connection

a) Loss of d.c. Link L_1

In the event that the HVDC link L_1 is tripped, the frequency of the wind farm *WF1* will change and T5 will adjust its operating point until the power previously transmitted through L_1 is transmitted through L_3. In turn, the frequency of the wind farm *WF2* will change due to the change in power transmitted through L_3 and the converter at T4 will change its operating point to import the total generation of the two wind farms.

If the total power generation of the two wind farms is within the capacity of the converter at T4, a new, stable operating point will be reached. Should the total power generated by the wind farms exceed the rating of T4, action will need to be taken to manage the excess power as in the previous scenario.

Finally, the central dispatch will send new reference points to the controllers of the remaining converters to optimise load flow under the new conditions.

b) Loss of d.c. Link L_2

The loss of L_2 in this scenario would present a greater challenge. In the event of L_2 being tripped, wind farm WF_2 would lose its frequency reference. Furthermore, T6 is in d.c. voltage control mode and would not adjust its operating point in response to the loss of L_2. It might be possible to change the control mode of T6 to frequency or frequency droop control and that of T5 to d.c. voltage control, but it is not clear whether this could be achieved sufficiently quickly. It would also impose a dependence on telecommunications which might be better avoided. Possible solutions require further investigation.

An alternative strategy would be to avoid the use of a converter in d.c. voltage control mode at the wind farm end of a connection. In the present scenario, if L_1 and L_3 were combined to form a multi-terminal HVDC link connecting T1, T3 and T6, then T6 could be in frequency droop control mode. In the event that L_2 was tripped, T6 would adjust its operating point until all power generated by the wind farm WF_2 is transmitted through L_3.

Finally, new reference points will be sent to the converter controllers to optimise the load flow under the new conditions.

c) Loss of offshore d.c. connection L_3

In the event of the offshore HVDC link L_3 being tripped, the frequencies of the offshore networks would change and the operating points of T3 and T4 would adjust as the power generated by *WF1* is transmitted by L_1 and the power generated by *WF2* transmitted by L_2. The system would operate as two separate point-to-point HVDC links as described in 4.1.

Following the disturbance, new reference points will be sent to the controllers of the converters at T3 and T4.

8.5.4 Scenario 4: Offshore Multi-terminal HVDC Grid

In Scenario 4, two offshore wind farms WF_1 and WF_2 are connected to the onshore network by a multi-terminal DC grid as shown in Figure 20.

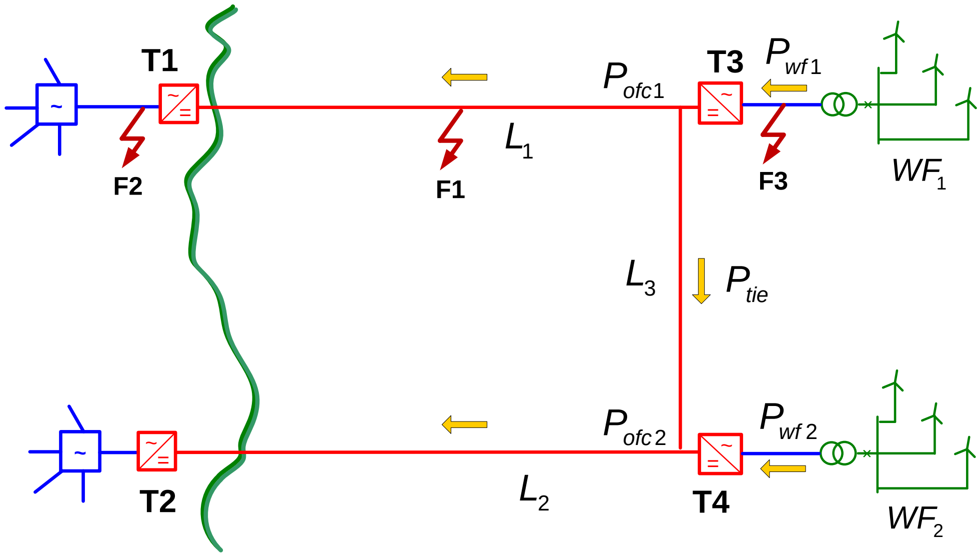

Figure 20: Multi-Terminal d.c. Grid for Integration of Two Offshore Wind Farms

8.5.4.1 Control Strategies

The onshore converters T1 and T2 share the role of maintaining the d.c. voltage in the HVDC system using their d.c. voltage droop controllers [4, 7]. The frequency droop controller is used for the converters at T3 and T4. The proposed control strategies are summarised in Table 5.

Table 5: Proposed Control Strategies for Converters in Scenario 4

	Active Power	Reactive Power
T1	V_{dc} Droop	Constant Q
T2	V_{dc} Droop	Constant Q
T3	f Droop	Constant V_{ac}
T4	f Droop	Constant V_{ac}

8.5.4.2 Loss of converter

If any single converter on the multi-terminal HVDC system was tripped, a new stable operating point could be reached. If T1 was tripped, T2 would take sole control of the d.c. voltage. The d.c. voltage would rise or fall (depending on whether T1 was exporting or importing immediately before the trip) and the operating point of T2 would change as all power imported at T3 and T4 is transmitted through T2. If the total power generation of the two wind farms is within the capacity of the converter at T2, a new, stable operating point will be reached.

Should the total power generation exceed the capacity of T2, the excess generation would need to be managed. In contrast to the previous scenarios, the frequency of the wind farms *WF1* and *WF2* would not change. It is likely, however, that current limits would be implemented in the control system of the converter at T2 as shown in Figure 8. Consequently, when the power export limit for T2 is reached, the d.c. voltage of the HVDC system will rise. In [17], such a rise in d.c. voltage was used to trigger a transient frequency adjustment which in turn triggered the power reduction control of the wind turbine generators. The excess power generation will need to be reduced sufficiently quickly to prevent the d.c. system from tripping due to d.c. overvoltage.

The situation where T2 trips would be similar to the above, with T1 taking sole control of the d.c. voltage and exporting the total generated power.

If T3 or T4 was tripped, the d.c. voltage would fall and the sharing of power through T1 and T2 would be adjusted in accordance with their droop characteristics. There would be no risk of overload.

Following the disturbance, new reference points will be sent to the controllers of the remaining converters to optimise the load flow under the new conditions.

8.5.4.3 Loss of HVDC link (fault clearance with AC circuit-breakers)

Currently, there is no commercial application of an HVDC circuit-breaker in the protection of VSC-based systems [1]. In the absence of an HVDC circuit-breaker, a fault on the d.c. side of the multi-terminal HVDC system would be cleared by tripping the a.c. circuit-breakers of all converters. All generation infeed would be lost. Consequently, the total generation connected to the system may not exceed the limits on loss of infeed permitted by planning standards.

8.5.4.4 Loss of HVDC link (fault clearance with HVDC circuit-breakers)

If the branches L_1, L_2 and L_3 were protected using HVDC circuit-breakers, the unaffected branches of the multi-terminal system could continue operation in the event of a d.c. fault. If L_1 was tripped, the converter at T2 would take sole control of the d.c. voltage. The d.c. voltage would rise or fall, depending on whether L_1 was exporting or importing power prior to the trip, and the operating point of the converter at T4 would adjust to export all generated power from the wind farms WF_1 and WF_2. Should the total power generation exceed the capacity of the converter at T2, the excess power would need to be managed as discussed previously. The situation where L_2 trips would be similar, with the converter at T1 taking sole control of the d.c. voltage and exporting all generated power.

If L_3 was tripped, the converter at T1 would take control of the d.c. voltage of L_1 and adjust its operating point to export the power imported at T3. The converter at T2 would take control of the d.c. voltage of L_2 and adjust its operating point to export the power imported at T4.

Following any HVDC circuit-breaker trip, new reference points will be sent to the converter controllers to optimise the load flow under the new conditions.

8.6 Conclusions

The primary control methods and characteristics for VSC HVDC converters have been introduced and their application for power flow control in VSC-based HVDC systems has been described. Primary control strategies have been illustrated using a set of four generic scenarios, which represent the different basic types of connection that might be used in an integrated offshore transmission network.

In general, it is possible to propose control characteristics such that the desired load flow is achieved and an acceptable steady state operating point is reached following a major disturbance such as a fault or converter trip. However, challenges may arise where a converter connected to an offshore a.c. network is in d.c. voltage control mode, since it will not automatically adjust its operating point in response to changes in the offshore a.c. network. It remains to be established whether a rapid change in converter control mode is feasible.

Where offshore wind farms are connected by means of an a.c. connection, it becomes increasingly important that the generators be able to remain transiently stable and connected in the event of a short circuit fault in the offshore a.c. network, particularly where the combined generation volume exceeds the limits on loss of infeed permitted by planning standards. Due to the use of wind turbine generators and cable connections, it is possible that the fault ride through requirements of existing grid codes are not sufficiently onerous for application to an offshore a.c. network. The range of conditions in the a.c. offshore network that might occur in the event of a short circuit fault requires to be established and, if necessary, appropriate fault ride through requirements developed.

In an integrated system, when a connection to the offshore a.c. network is lost and the total generated power exceeds the capacity of the remaining connections, the excess power must be managed in order to prevent overload and cascade tripping of the remaining connections. Where connection is made by VSC HVDC links, rapid action is essential since the converters cannot support overload conditions for more than a few ms.

A number of methods for managing the excess power generation have been proposed. These range from power reduction by control action to the provision of semi-conductor controlled resistor banks (or ‘AC choppers’). Design of the system such that the total generation can still be accommodated with the loss of the largest connection would provide a partial solution. Tripping of generation might be a solution provided that the overload is sufficiently low that the converters can support the overload conditions for the time taken to trip the generation.

Reduction of power generation by changing the blade pitch angle of the wind turbine generators is relatively slow and is, in itself, unlikely to provide a solution. It may, however, be used to reduce the duty on alternative methods of managing excess power generation.

The scenarios discussed in this chapter have been concerned with steady state power flows. It will be necessary to perform studies to investigate the dynamic response of the a.c. and d.c. systems for the events studied in each scenario.

Studies are required to establish the effectiveness and the cost associated with each of the proposed solutions for managing excess power generation, including costs associated with restricting or tripping generation. It would be also worth exploring additional solutions. The potential of using synthetic inertia control to reduce the rate of change of frequency of the offshore a.c. network and thereby increase the time available to reduce power generation merits investigation. The development of new converter topologies with greater overload capability would alleviate the problem.

8.7 References

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Appendix A: Offshore wind farm characteristics

A.1. Variable-speed wind turbine generators

One of the key differences between MW-level variable-speed wind turbine generators and conventional generators is the introduction of back-to-back AC/DC/AC frequency converters. The frequency converters, typically IGBT-based self-commutated voltage-sourced converters, are able to control their active and reactive power independently for four-quadrant operation [1, 2]. Consequently, these wind turbine generators can capture wind energy over a wide range of wind speed and their efficiency can be improved compared with fixed-speed wind turbine generators without frequency converters [3].

Variable-speed wind turbine generators are typically divided into two types according to the general configurations of their electrical system [1-4]:

3) Wind turbine with doubly-fed induction generator (DFIG)

4) Wind turbine with full-scale frequency converter (FSC)

The electrical system of a DFIG is shown in Figure A1 [1]. The stator of an induction generator is connected directly to the external grid. However, a frequency converter is connected between the rotor of the induction generator and the external grid. With this layout, a portion of power from the generator's rotor (typically 25-30% of generator capacity) can be controlled by the frequency converter and the DFIG can operate over the variable-speed range of ±30% around the synchronous speed [3].

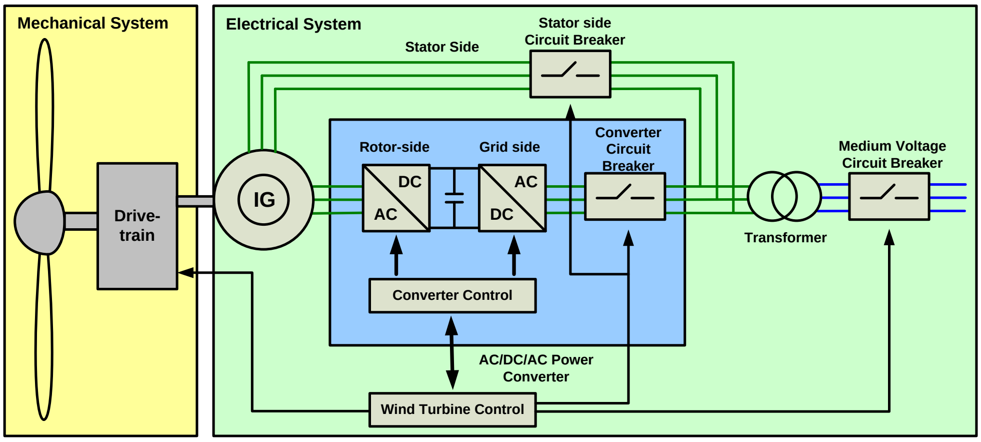

Figure A1: General schematic of DFIG

The electrical system of a WT-FSC is shown in Figure A2 [1]. The frequency converter is connected in series with the stator of the synchronous generator so that the generator's power can be fully controlled by the frequency converter to perform smooth grid connection over the entire speed range [3]. However, for the same generator capacity, the power rating of the frequency converter in a FSC will be larger than that of a DFIG and the power losses and equipment costs will be higher.

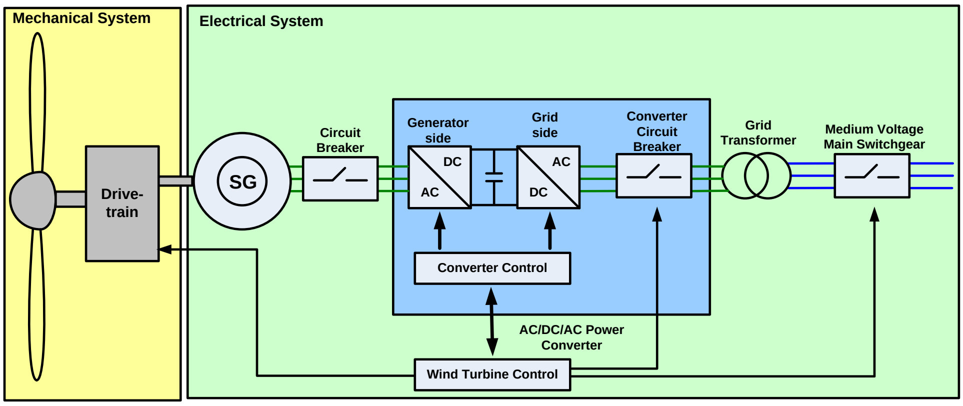

Figure A2: General schematic of WT-FSC

A.2. Primary frequency response

With the introduction of the frequency converters, the rotational speed of the WTG is decoupled from the system frequency. Consequently, the wind turbine generators in an offshore wind farm offer little or no natural response, unlike conventional generators. As a result, the increasing integration of these wind farms will lead to continuous reduction of system inertia which may bring issues of rate of change of frequency (ROCOF) when a severe generator-demand power imbalance occurs.

A.2.1. Primary frequency response requirements

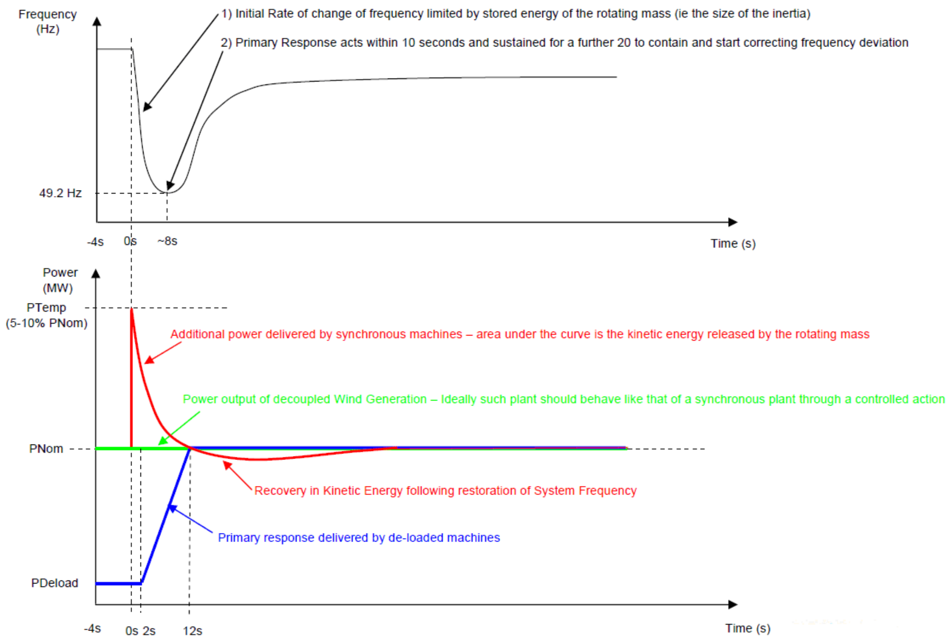

Figure A3: Primary frequency response requirements proposed by National Grid [5]

The impacts of ROCOF due to low-inertia wind farms lead to continuous demands for primary frequency response. For National Grid, an investigation into primary frequency response proposed that a power increase of 5-10% during an event where grid frequency drops to 49.2 Hz in approximately 8 seconds would be sufficient for the GB transmission system. The system frequency and the power increase during such an event are illustrated in A3 [5]. In order to meet these requirements, different methods have been proposed with the aim of releasing the stored or reserve energy of the variable-speed wind turbine generators to provide ancillary services similar to conventional generators for primary frequency response support to onshore a.c. networks using the strategies shown in Figure A4.

A.2.2. Solutions

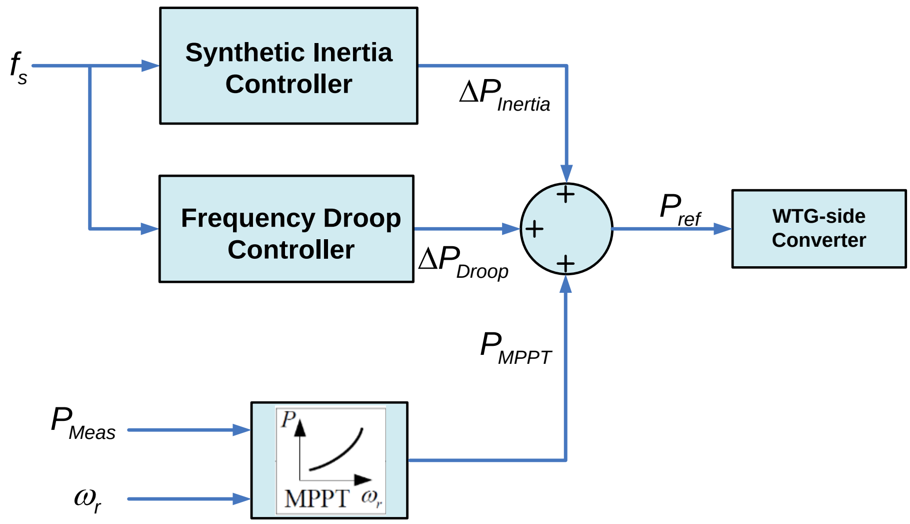

Figure A4: Strategies for primary frequency response enhancements for variable-speed wind turbine generators

A.2.2.1. Synthetic inertia

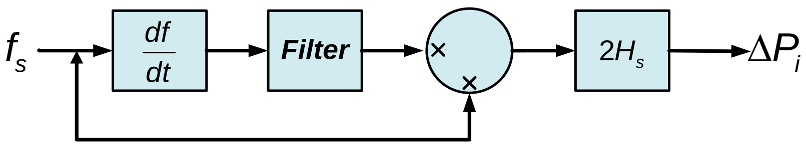

Figure A5: Synthetic inertia controller

Synthetic inertia controllers, as illustrated in Figure A5 [6], are being developed by some manufacturers to enable a variable-speed wind turbine generator to provide synthetic inertia response similar to the response of conventional generators by releasing a large amount of kinetic energy stored in its rotating mass [6-8]. The synthetic inertia response can last for several minutes, following which the wind turbine generator's rotor needs to be accelerated by absorbing power from the grid.

A.2.2.2. Frequency droop control

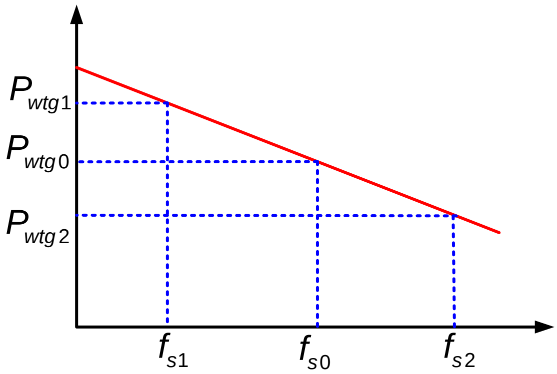

Figure A6: Frequency droop controller

Moreover, more and more wind turbine generators have been or will be upgraded with frequency droop control similar to conventional generators with a power-frequency characteristic as shown in Figure A6 [9]. The capability of frequency droop control is heavily dependent on the selected droop gain value *Kdroop* where:

$$K_{droop} = -\frac{\Delta P_{WTG}}{\Delta f_s}$$

By virtue of the capabilities of frequency droop control with a suitable K_{droop} and synthetic inertia response, the frequency performance in low-inertia systems may be significantly improved.

A.3. Fault ride through

In order to ensure system stability, grid codes usually require generation to be able to remain connected when the system voltage is reduced due to a fault [10, 11]. The protection and control schemes of the frequency converters need to be configured to meet the requirements of fault ride through (or low voltage ride-through) specified in grid codes.

A.3.1. Solutions

For a DFIG [1, 2, 4] , the partial-scale frequency converter is connected between the induction generator's rotor and the external grid. Operation of a DFIG during a voltage dip caused by a fault requires coordinated operation of the rotor- and grid-side converters as well as the induction generator. Additionally, due to two sudden changes in terminal voltage directly at the time of fault and fault removal, the induction generator undergoes two significant changes in output current, resulting in rotor-side overcurrents to sustain the flux linkages. To protect the rotor-side converter from these overcurrents, a DFIG is normally equipped with an additional crowbar circuit. During a voltage dip, the additional crowbar resistor will be connected into the DFIG's rotor circuit to limit the overcurrents and the rotor-side converter will be temporarily blocked for the fault duration. Although the crowbar solution can guarantee successful fault ride through, it will involve additional investment and particularly loss of control to active and reactive power outputs. Moreover, when the crowbar is activated, the DFIG will absorb a large amount of reactive power which is not allowed in some grid codes.

In contrast to a DFIG, the FSC is equipped with a full-scale frequency converter so that the operation during a voltage dip is easier to manage. The fault ride through performance is entirely determined by the characteristics of the grid-side converter, which simply adjusts its active and reactive power to comply with the fault ride through requirements. Other components, such as the generator and generator-side converter are effectively removed from service temporarily to maintain the wind turbine generator in a safe state [1, 2, 4, 12-16]. During normal operation a FSC produces active power and regulates a.c. terminal voltage [1, 2, 4, 17]. When a voltage dip occurs, the input wind power remains effectively constant, since it is determined by the wind conditions and the pitch angle, both of which change slowly relative to the fault condition. For a three-phase fault at the a.c. terminals of the FSC, the power output drops to zero. The generator-side converter adjusts its frequency to stop collecting power from the generator, causing an acceleration of the shaft that is limited by the rotor and shaft inertia. As the shaft speed increases, the rotor's pitch control adjusts to temporarily reject additional power input from the rotor. This is done very quickly (in approximately 2 seconds) by the wind turbine generator's pitch-angle controllers. When the FSC detects a voltage dip, the converter transfers to another operation mode where the priority is voltage support rather than power production. This allows the converter to provide voltage support during the fault by injecting reactive current as a function of retained voltage. As a result, compared with a DFIG, the control design of the FSC provides an effective method for providing fault ride through capability, with minimal risk to components of FSC and maximal support for the external grid.

A.4. Protection of wind turbines against loss of connection

Provision must be made to manage excess power in the event that the power generated cannot be transmitted, due to loss of a transmission connection or otherwise. Excess power will cause rotor a.c. overcurrent in the generators, over-speed of the wind turbines and d.c. overvoltages or currents in their frequency converters. Protection strategies for the wind turbine generators against such risks are required.

A.4.1. Protection strategies of DFIG

A protection scheme which has been proposed for the DFIG is shown in Figure A7 [12]. The protection scheme is a combination of four functional blocks:

- Crowbar protection
- AC series dynamic resistor

- DC chopper
- Pitch-angle control

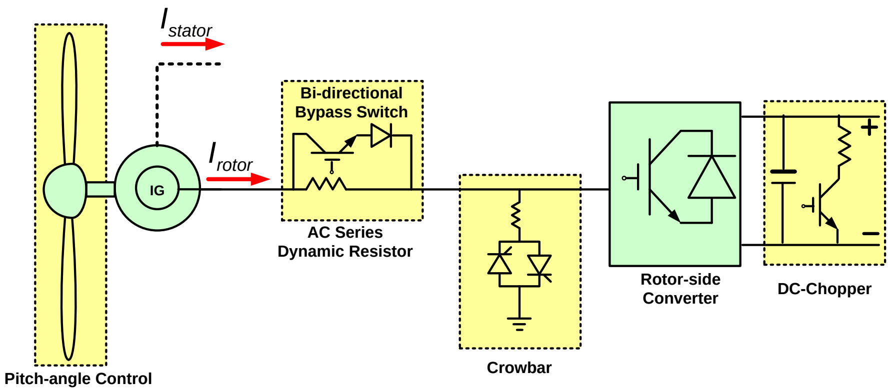

Figure A7: Protection schemes of WT-DFIG rotor-side converter

A.4.1.1. Crowbar

The crowbar protection is a prevalent protection scheme for DFIGs [1, 12, 13]. A crowbar is a set of resistors which are connected in parallel with the rotor winding in the event of an interruption, bypassing the rotor-side converter. The active crowbar control scheme connects the crowbar resistance when necessary and disconnects it to resume DFIG control. For active crowbar control schemes, the control signals are activated by the rotor-side converter. The DC-link bus voltage may increase rapidly under these conditions, so it is also used as a monitored variable for crowbar triggering. Power electronics elements e.g. bi-directional thyristors, GTOs or IGBTs are typically used for crowbar switching.

A.4.1.2. DC chopper

In [12], a DC-chopper is connected in parallel with the DC-link capacitor to limit the overcharge during low grid voltage. It protects the rotor-side converter from overvoltage and can dissipate surplus wind energy, but this has no effect on the rotor overcurrent.

A.4.1.3. AC series dynamic resistor

In [12], a new protection scheme based on a a.c. series dynamic resistor is proposed which also combines and coordinates the existing crowbar and d.c. chopper protection to absorb the surplus wind energy together. A series dynamic resistor is used as the primary protection. When the series dynamic resistor cannot protect because of a deteriorating situation, the crowbar circuit will be activated. The crowbar is engaged only at the beginning or the end of the fault, if required. The d.c. chopper is used for DC-link overvoltage limitation.

A.4.1.4. Pitch-angle control

The surplus wind energy will cause the acceleration of rotor rotational speed. To avoid over-speed, the pitch-angle control is activated. The pitch angle control reduces the rotor speed by increasing the pitch-angle of the blades to reduce the aerodynamic torque. Mechanical braking is usually used to hold the turbine still and will be used as a backup for the pitch-angle control. Since the pitch-angle of the blades is mechanically controlled, its response time is much slower than other methods based on power electronics (25% of power reduction per second or less). It is usually used as the backup method if electrical damping is not adequate in some severe fault conditions.

A.4.2. Protection strategies of FSC

A protection which has been proposed for the FSC is shown in Figure A8 [12]. The protection scheme is a combination of five functional blocks:

- AC series dynamic resistor
- AC damping load
- DC chopper
- DC series dynamic resistor
- Pitch-angle control

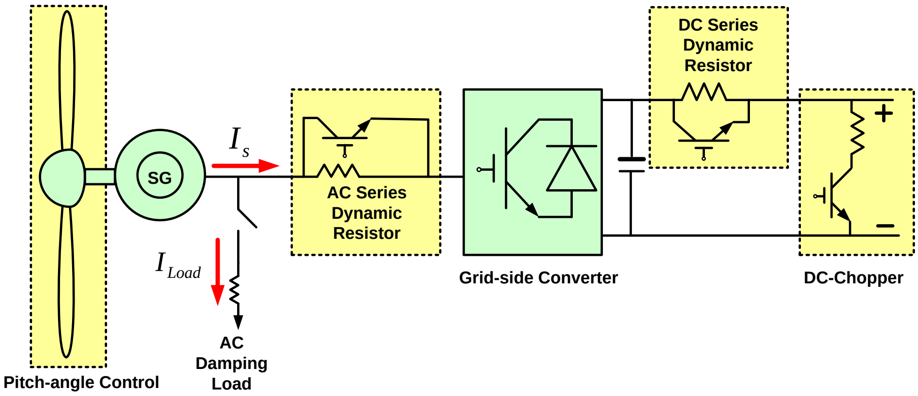

Figure A8: Protection schemes of WT-FSC grid-side converter

A.4.2.1. AC Series Dynamic Resistor

A power-electronic-controlled external resistor, which is connected to the stator windings of the generator, is used to limit the rotor overcurrent during a fault. This is a three-phase series resistor. The purpose of the a.c. series resistor is to balance the active power then improve generator stability during a fault.

A.4.2.2. AC damping load

A three-phase a.c. damping load is connected at the generator terminal to help absorb the surplus power generated by the wind turbine generator as an electrical braking system [12].

A.4.2.3. DC series dynamic resistor

A d.c. series dynamic resistor can also be used as an overcurrent limiter in the DC-link circuit. A fast solid-state switch is used to bypass or engage the resistor during normal operation and fault conditions.

A.4.2.4. DC-chopper and pitch-angle control

Application of the d.c. chopper and the pitch angle control are similar to that described in Section A.4.1.2 and A.4.1.4.

A.5. Voltage and reactive power support

Variable-speed wind turbine generators have extended capabilities to supply ancillary services including power factor regulation, dynamic voltage control and reactive power support. As a result, requirements for ancillary services for wind farms may be specified in the same way as for conventional generators [18].

A.5.1. Solutions

The voltage and reactive power capabilities of a wind farm depends on the combination of WTGs and additional reactive power compensation devices such as passive reactors/ capacitors or state-of-the-art FACTS-based SVC or STATCOM [18].

A.5.1.1. Reactive capability of wind turbines

The VSC-based frequency converter of the variable-speed wind turbine generators can achieve independent control of active and reactive power (four-quadrant operation) [1, 3]. The maximum reactive power (generation or absorption) is dependent on the power rating of frequency converter. Consequently, the reactive power capability of DFIGs is limited compared with FSCs.

DFIGs with a crowbar protection scheme have to absorb reactive power during fault ride through. However FSCs can inject reactive power into the grid with voltage support.

A.5.1.2. Passive reactive compensation devices

Mechanically-switched shunt capacitor banks typically consist of a group of individual capacitor units. The bank may either be fixed or switched using appropriately rated devices. It is only possible to control slow variations in reactive power. The capacitive reactive power output is a function of the system voltage. By using a number of capacitor banks of different size, the reactive power exchange can be kept within a range. Capacitor banks typically require a 5 minute discharge time before they can be re-energised, but there are also designs that allow for shorter durations on a limited basis.

Reactors are typically mechanically switched devices so that it is only possible to control slow variations in reactive power as well. The inductive reactive power output is a function of the system voltage. Regulated shunt reactors are shunt reactors equipped with a tap-changer as used for voltage control [18].

A.5.1.3. FACTS-based dynamic compensators

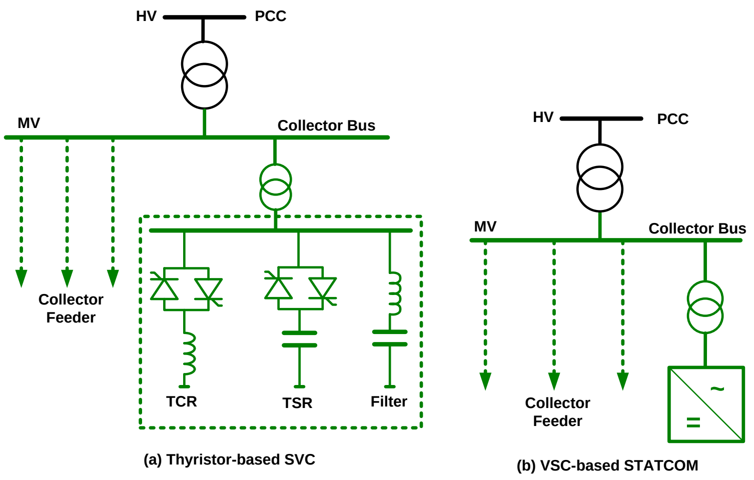

Figure A9: FACTS-based dynamic reactive compensation devices

A static VAr compensator (SVC) is typically a fixed shunt capacitance in parallel with reactance that is controlled by thyristors as shown in Figure A9(a) [18]. With dynamic control of the thyristors, reactive power may be controlled at time scales down to the order of a 100 milliseconds. Additional filters must be used to control harmonics generated by the distorted current waveshape caused by the thyristor switching. A static synchronous compensator (STATCOM), shown in Figure A9(b) [18], uses an IGBT or GTO-based voltage-source converter to generate or absorb reactive power via a fast-response control system. Some STATCOM units may have short-time overload capabilities for 2 to 4 seconds. The reactive power output is a linear function of the voltage [19].

A.6. Harmonic resonance of offshore wind farms

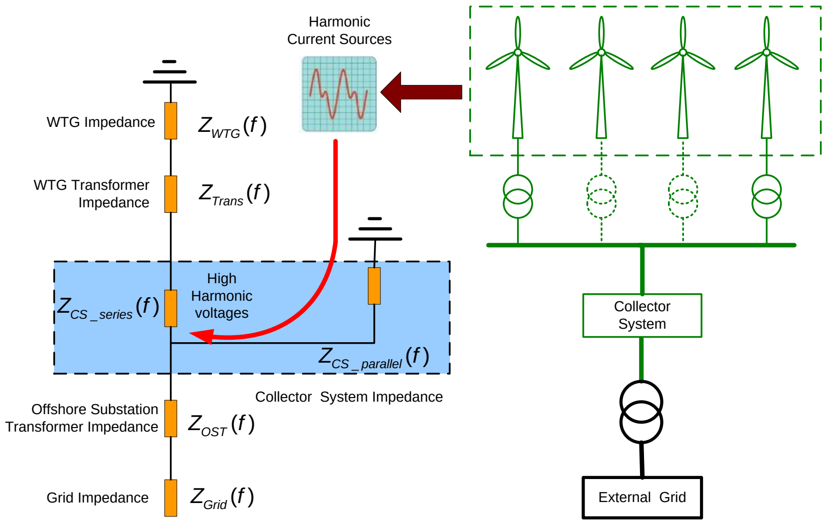

Figure A10: Harmonic generation by offshore wind farms

Harmonic resonance issues arise in offshore wind farms because they contain both inductive source and capacitive elements. The offshore wind farms typically have extensive cable systems, which can result in many series and parallel resonance points. Harmonic sources may include wind turbine generators with VSC-based frequency converters. Parallel resonance occurs when harmonic current sources excite resonant points (relatively high impedances) resulting in harmonic voltages [20-22].

A.6.1. Requirements

The offshore wind farms and interconnection facilities for the offshore wind farms e.g. HVDC links should be designed to avoid introducing detrimental harmonic resonance into the transmission system. The design of the wind farm protection and control schemes shall ensure that any issues related to resonance are addressed.

A.6.2. Solutions

There are two primary methods for controlling harmonic impact in wind power plants [20]: Harmonics may be controlled during the design of the wind plant collector system by careful consideration of equipment to avoid resonance problems; alternatively, harmonic filters may be designed based on measurements and simulation results in order to reduce or control series resonance conditions of the wind plant. The latter method is the most common mitigation approach when capacitive compensation is required.

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9. CONCLUSIONS

The report has aimed to establish the present state of development of the technologies required for an integrated offshore transmission system and to identify developments required in order for an integrated offshore transmission system to be built. A brief introduction to the technologies, including HVDC converters, switchgear, cables and offshore platforms, has been provided and the application issues highlighted.

Differences in the characteristics of line commutated converter (LCC) and voltage sourced converter (VSC) HVDC technologies may lead to one or the other being better suited to the functional requirements of a project. VSC HVDC converters are well suited to connection of offshore wind generation and to multi-terminal applications as required for the integrated offshore transmission project. The use of LCC technology for wind generation and offshore applications would generally require additional investment and would present some additional engineering challenges. The possibility of commutation failures affecting more than one inverter on the onshore transmission system would need to be excluded.

LCC HVDC converters are a mature technology and comprehensively covered by international standards. Standards have been developed for many aspects of VSC HVDC converters. CIGRE is currently preparing guidance on commissioning. At present, there is no standard for insulation coordination for VSC HVDC converters.

Many of the technologies required for an integrated offshore transmission network are new and developing rapidly. The report has attempted to anticipate how these technologies might continue to develop and provide an indication of technology availability by year.

VSC HVDC systems with extruded cable are under construction with power transfer capabilities of 1000 MW. The technology exists to allow 1400 MW to be achieved. It is envisaged that 2000 MW VSC HVDC systems could be in service by 2019 with mass impregnated cables and, with some development in converter valve technology to increase d.c. current, by 2021 with extruded cables.

VSC HVDC converters for offshore application are under construction at +/- 320 kV, allowing power transfer capabilities of around 1000 MW to be achieved. Several projects with offshore converters are currently in progress and valuable experience will be gained from these. There is a clear requirement for reducing the costs of platforms for offshore HVDC converters. It is thought that developments in offshore platform technology would allow a 2000 MW offshore converter to be in service by 2021.

An LCC HVDC system with mass impregnated cables with a power transfer capability of 2250 MW is due to be in service during 2016. The power transfer capability of LCC HVDC systems is governed by the d.c. voltage and current of the cable. Beyond 2016, the capability of VSC HVDC converters is foreseen to have also reached that of the cable. From then on, LCC HVDC systems with cables will no longer offer a greater power transfer capability than VSC HVDC systems.

The first two multi-terminal VSC HVDC systems have recently been commissioned. Both were designed and built as multi-terminal systems in a single stage of construction. To facilitate the wider implementation of multi-terminal HVDC systems, the development of standards to ensure compatibility of the equipment of different suppliers on a common HVDC system is highly desirable. Working Bodies within CIGRE and CENELEC are currently active in this area.

An HVDC circuit-breaker has been demonstrated in the laboratory. It is expected that such a device could be in service by 2019. Ongoing developments are envisaged in HVDC circuit-breaker technology in pursuit of increased operating speeds, higher ratings, reduced losses and reduced costs.

Unit costs have been obtained for each of the technologies required for an integrated offshore transmission network for use in cost benefit analyses. Obtaining the costs has proved difficult. Costs are influenced by many factors, including the specific requirements of a given project, exchange rates, commodity prices and the balance of supply and demand in the market at the time of tender. Due to a scarcity of current data, the costs were generally obtained by inflating those published in National Grid's 2011 Offshore Development Information statement in line with the Harmonised Index of Consumer Prices (HCIP).

In order to be able to make use of commodity prices in unit costing, research is needed into the relative quantities of materials in each of the units, particularly for VSC HVDC converters and offshore HVDC converter platforms. Research is also required into the construction and costs associated with offshore HVDC converter platforms.

Information on reliability and availability of HVDC technology has been collected for use in cost benefit analyses. Data for HVDC converters has been obtained from annual surveys reported by CIGRE AG B4.04. All of the reported data was for LCC HVDC schemes, since experience with VSC HVDC schemes is still limited. In the absence of data for VSC HVDC converters, it is assumed that the values reported for LCC HVDC schemes could be used given the similarities in the technologies.

Reliability and availability data for d.c. cables has been obtained from a survey performed by CIGRE WG B1.10. The survey included data for d.c. mass impregnated cables but not d.c. extruded cables. In the absence of data for d.c. extruded cables, it is assumed that the values reported for d.c. mass impregnated cables could be used since none of the reported failures were attributed to internal causes and are therefore unlikely to be related to the type of insulation.

There is a clear need to collect and publish data on the reliability and availability of VSC HVDC converters and extruded d.c. cables.

Established specifications exist for the protection systems of converter stations connected to the onshore a.c. network. In this report, protection strategies have been illustrated for a number of generic scenarios representing the basic types of connection of which an integrated offshore network is formed.

In an integrated network where HVDC links are interconnected by offshore a.c. networks, a d.c. fault may be cleared by the a.c. circuit-breaker at each terminal of the affected HVDC link. This represents a viable solution to the design of an integrated offshore transmission network. The network may be designed such that the limits on loss of infeed permitted by planning standards are not exceeded.

In a multi-terminal HVDC system, the disadvantage of clearing a d.c. fault by a.c. circuit-breakers is that the whole multi-terminal system will be tripped. The commercial availability of the HVDC circuit-breaker will allow a d.c. fault in a multi-terminal HVDC system to be cleared while the unaffected branches of the system remain in operation. The HVDC circuit-breaker will therefore facilitate the application of larger multi-terminal HVDC systems.

CIGRE WG B4/B5.59 has been developing guidelines for control and protection of HVDC grids, with emphasis on protection of the grid and the elements in it. Their report is expected to be published shortly.

The report has illustrated the principles of primary and secondary control in an integrated offshore transmission network. Primary control is reasonably well understood and strategies can be proposed for achieving the required steady state power flows through HVDC links and the offshore network. A converter can respond to changes in the a.c. or d.c. networks by means of its pre-programmed control characteristics. The control characteristics of the converters in a system can be coordinated such that the system can respond to events such as loss of a transmission connection and reach a new steady state operating condition without dependence on telecommunications. Secondary control can than be used to change converter control characteristics to establish a new optimum power flow.

Coordination of control to achieve the required power flows has been illustrated using the same generic scenarios as previously. In general, a feasible solution can be proposed for each scenario. At least one converter of each HVDC link must control the link d.c. voltage. The frequency of the a.c. offshore network may be used to control the power through the HVDC links and the offshore network. Challenges may be encountered, however, where a converter connected to an offshore a.c. network is used to control the d.c. voltage of a d.c. link since it will not automatically respond to changes in the a.c. network.

The discussion in the report has concentrated on steady state power flow. Studies are required to simulate the dynamic response of an integrated offshore network in order to investigate issues including the stability of the a.c. and HVDC systems and any transient overloads. It also needs to be established whether it is feasible to change the control mode of a converter so that it can take over frequency control of an offshore a.c. network in the event that another converter trips.

Where offshore wind farms are connected by a.c. connections, it becomes increasingly important that the generators remain transiently stable and connected in the event of a short circuit fault in the offshore a.c. network. Due to the exclusive use of wind turbine generators and cable connections, the conditions in the offshore a.c. network in the event of a fault may be more onerous than those covered by the fault ride through requirements of existing grid codes. The range of conditions existing in the event of a short circuit fault in the offshore a.c. network requires to be established and, if necessary, appropriate fault ride through requirements developed to address the more onerous conditions.

In an integrated network, provision must be made to manage the situation where the total generation in an offshore a.c. network exceeds the capacity of the remaining transmission connections when one of the connections is lost. Urgent action is required to prevent the remaining connections from overloading and tripping in cascade. The effectiveness of any method used to prevent overloading and cascade tripping is dependent on its ability to operate within the short timescales involved.

In principle, it would be possible to reduce power generation by control action, possibly using the frequency of the offshore network as a trigger. The use of a power reduction controller has been proposed in the literature. It was stated that, due to the fast response of the wind turbine converters, the output power is reduced quickly.

A semiconductor-controlled resistor bank (‘ac chopper’) connected to the offshore network could be provided to dissipate the excess power. Such a device would be able to operate sufficiently rapidly but would represent a significant additional investment.

Excess power generation may be reduced by tripping generators, but the time required for decision plus circuit-breaker operation may be too long.

Wind turbine blade pitch control reduces power generation typically over a period of seconds and is therefore not fast enough to be effective in preventing overload and cascade tripping. It may, however, reduce the period of time for which an alternative method of managing excess power generation is required to be active.

Detailed studies are required to simulate the sequence of events occurring when a connection is lost and to evaluate potential solutions to prevent overloading and cascade tripping. It will be necessary to understand the rate of change of frequency and voltage in the offshore a.c. network following loss of a connection and the timescales for control- and protection-initiated actions. If the need for a.c. resistor banks to dissipate excess generated energy is confirmed, the functional requirements and cost of such equipment will need to be determined. The development of new converter topologies having greater overload capability would alleviate the problem.

The risk of overloading and cascade tripping does not arise if the total generation is within the capacity of the remaining connections when the largest connection is lost.

The extensive cable systems of the offshore a.c. networks will potentially present a large range of harmonic resonant frequencies. It may be possible to manage harmonic generation through careful equipment design or through the provision of a.c. harmonic filters. It must be ensured that there is no adverse interaction with the control systems of converters. A generic understanding of the potential issues would be helpful but it will be essential to demonstrate satisfactory operation of the converter and a.c. network for any given project. This may best be achieved by simulation during factory testing.

VSC HVDC schemes may be constructed in stages to better match investment with system requirements where the potential requirement for a higher transmission capacity it some point in the future is anticipated. Staged construction has been described in the report. The initial scheme is constructed as an asymmetrical monopole, which is extended to form a bipole in a second stage of construction. The installation of a third d.c. circuit conductor will allow one of the original d.c. circuit conductors to be used as a metallic return. The provision of a metallic return, while increasing the cost of the second stage of construction, will improve availability, particularly in the event of an outage of a d.c. circuit conductor, and will limit the loss of transmission in the event of a fault or converter trip. Staged construction might be a viable approach in the construction of an integrated offshore transmission system.

Integrated Offshore Transmission Project (East)

Appendix 2

System Requirements Work-Stream Report

1. Introduction

1.1 Purpose and Scope of the Integrated Offshore Transmission Project (East)

The System Requirements workstream was responsible for establishing whether or not there is a system needs case for coordinated network designs for the three wind farms connecting to the East Coast of the National Electricity Transmission System (NETS).

This appendix is structured into the following sections:

2. Planning of the Transmission System for Offshore Wind Generation

3. Methodology and Generation Background Assumptions

4. Study Results – Slow Progression Background

5. Proposed Design Solutions – Slow Progression Background

6. Study Results – Gone Green Background

7. Design Template

8. Proposed Design Solutions – Updated Boundary Capability

9. Capital Costing of Proposed Design Solutions

10.

Operability of Offshore Integrated Designs

2. Planning the Onshore Transmission System for Offshore Wind Generation

This study investigates the connection of three large Round 3 developments, namely Dogger Bank, Hornsea and East Anglia off the East Coast of England.

National Grid has a statutory duty under the Electricity Act 1989 to develop and maintain an efficient, co-ordinated and economical system of electricity transmission. National Grid Electricity Transmission also has a duty to facilitate competition in the supply and generation of electricity and must offer a connection to any proposed generator. The NETS is designed in accordance with the requirements of the Security and Quality of Supply Standard (SQSS). The standard sets out the minimum requirements for both planning and operating the NETS so that a satisfactory level of reliability and power quality is maintained. Thus any modification to the transmission system, for example, new offshore generation connections, external connections and/or changes to demand must satisfy the requirements of the NETS SQSS. The NETS SQSS is applicable to all GB transmission licensees including National Grid, Offshore Transmission Owners (OFTOs) and the Scottish Transmission Owners.

3. Methodology and Generation Background Assumptions

The methodology used to model the generation background was based on principles of balancing the generation with the demand; in the case where we have increased the generation levels of all three wind farms, the overall generation in the rest of the network (England, Wales and Scotland) was reduced; and, in the case where we have decreased the generation, the overall generation will be balanced by the rest of the network.

As part of the study two representative years, or transmission network snapshots, were taken into consideration. 2021 – as the year when half of the excepted wind farm generation is planned to be connected, and 2030 when the all of the generation from the three wind farms is planned to be connected to the system.

The calculation of boundary capability and required transfers are based on winter peak studies.

A major assumption is that interconnectors are not modelled into the network design. All interconnectors (e.g. Anglo – French link) are assumed to be at zero import / export (referred to as “float” position) and do not contribute to the flow into the network. More information on the treatment of interconnectors is given in section 3.8.

3.1. General Methodology

The overall methodology is summarised in Figure 1 below. The first stage involves the selection and agreement of the Generation Backgrounds and Scenarios to be used.

Following this, the Required Transfer and Boundary Capabilities for the selected System Boundaries were determined. Boundaries with a shortfall in network capability (with a shortfall being the difference between the Required Transfer and the Boundary Capability) were identified. This analysis formed the basis for a range of network design options to provide the required additional capacity across the relevant Boundaries.

Reinforcement solutions were identified for boundaries B7/B7a, B8 and B9, however the need for reinforcement on B6 was also analysed as the B6 reinforcement directly affected the network solution on the other boundaries. Design solutions take into account conclusions reached by the Technology workstream in the form of the Technology Availability Matrix with design operability also investigated. Estimate costs have been prepared for all reinforcement options.

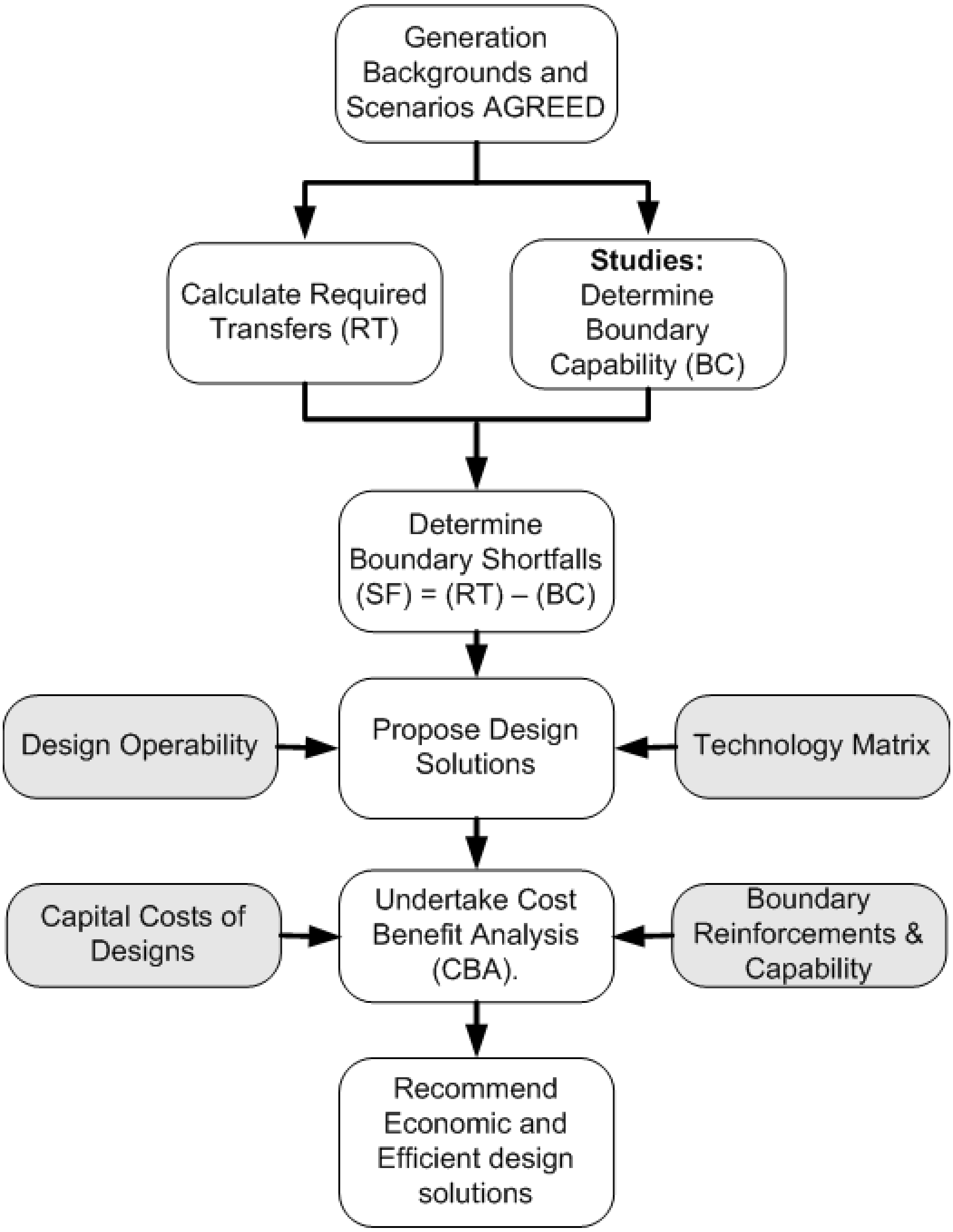


Figure 1: Methodology Flow Chart

3.2 Generation Background and Scenario Assumptions

In line with the Future Energy Scenarios published by National Grid[1], two Generation backgrounds have been considered as part of this study; the Gone Green 2012 background (GG) and the Slow Progression 2012 Background[2] (SP).

[1] At the time analysis was undertaken the 2013 version of the FES was the latest available.
[2] http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

Gone Green Background

Gone Green has been designed to meet the nation's environmental targets; 15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting the carbon budgets out to 2027, and an 80% reduction in greenhouse gas emissions by 2050. There are two case studies to test uncertainty in the Gone Green generation background: one with high offshore wind; and the other with high onshore wind.

Slow Progression Background

Slow Progression is for where developments in renewable and low carbon energy are comparatively slow and the renewable energy target for 2020 is not met. The carbon reduction target for 2020 is achieved but not the indicative target for 2030. Again, there are two case studies to explore some of the uncertainty seen in fuel prices. At the moment coal is significantly cheaper to burn than gas, so one case study is based on high coal generation and the other flips the fuel price dynamic and examines a high gas generation case.

For each of the backgrounds, two scenarios of possible cumulative connection of the wind farms have been determined and agreed in collaboration with the developers of the three proposed wind farms, the assumed build-ups are shown in Figure 2 below;

- The contracted capacity as per the Transmission Entry Capacity Register as at August 2013 - **Scenario 1**
- Developer build-up wind farm generation proposed collectively in August 2013 - **Scenario 2**
- *The Graph also represents the GG and SP dates, where the assumptions of wind farm generation is per GG and SP scenario*

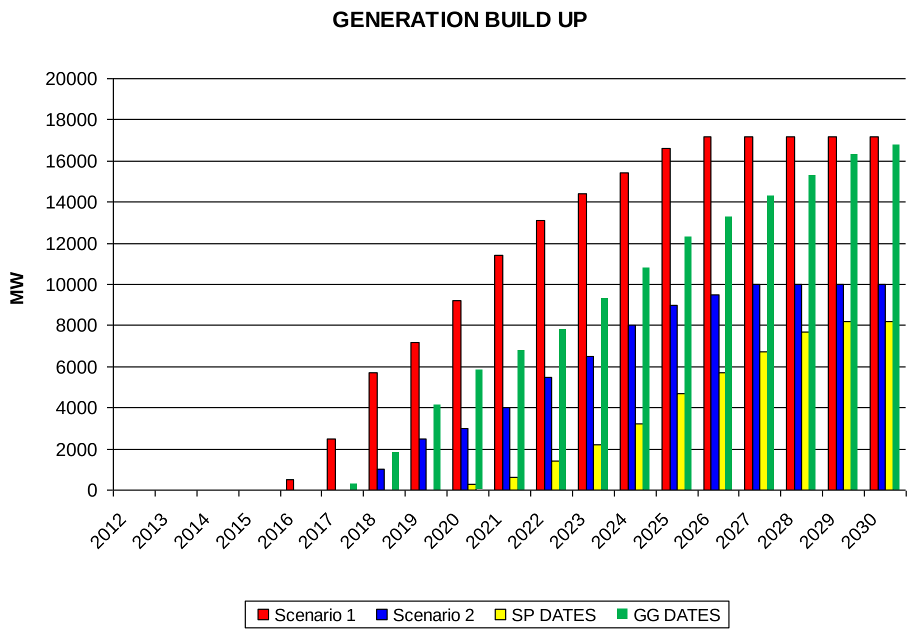


Figure 2: Generation Build Up for the Different Scenarios

For the calculation of Boundary Capabilities the same generation backgrounds were taken into consideration.

The transmission network reinforcements which are developed through detailed network modelling and design were explained in the Electricity Ten Year Statement (ETYS) 2012 which was also taken as a basis for our network assumptions.

The potential ranges of network reinforcement in years 2020 and 2030 for GG and SP, based on ETYS 2012[3] that will be needed, are presented in Figures 3 and 4 below.

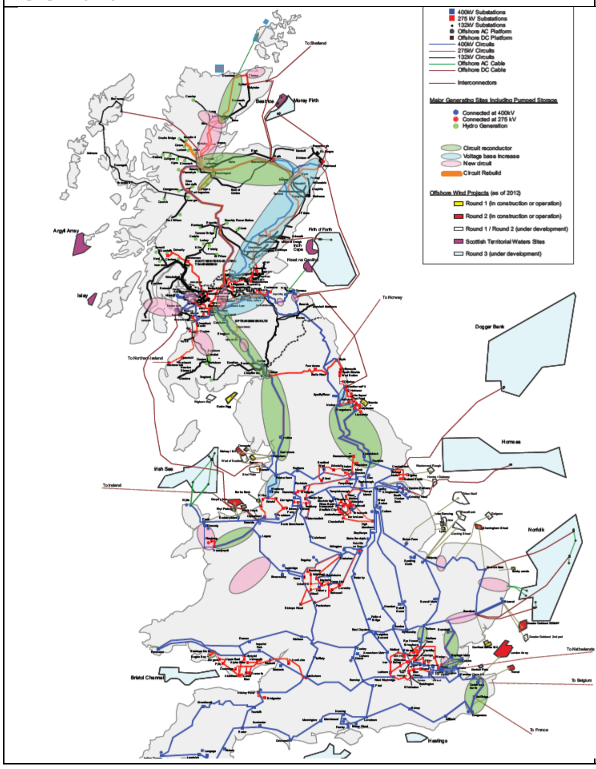
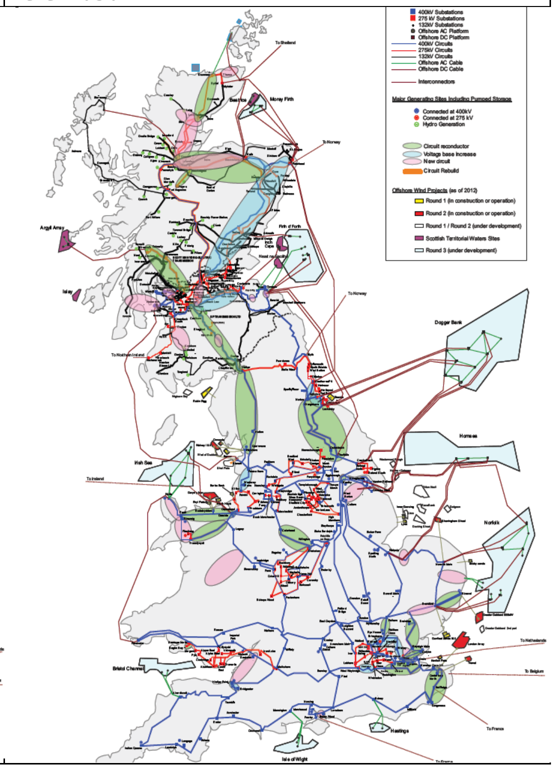
DIAGRAMS OF BASE NETWORKS **ETYS 2012** **GG 2020**	**DIAGRAMS OF BASE NETWORKS** **ETYS 2012** **GG 2030**
	

Figure 3: Diagrams of Base networks GG 2020 and 2030

[3] Latest version available at time of analysis

DIAGRAMS OF BASE NETWORKS ETYS 2012 SP 2020	DIAGRAMS OF BASE NETWORKS ETYS 2012 SP 2030

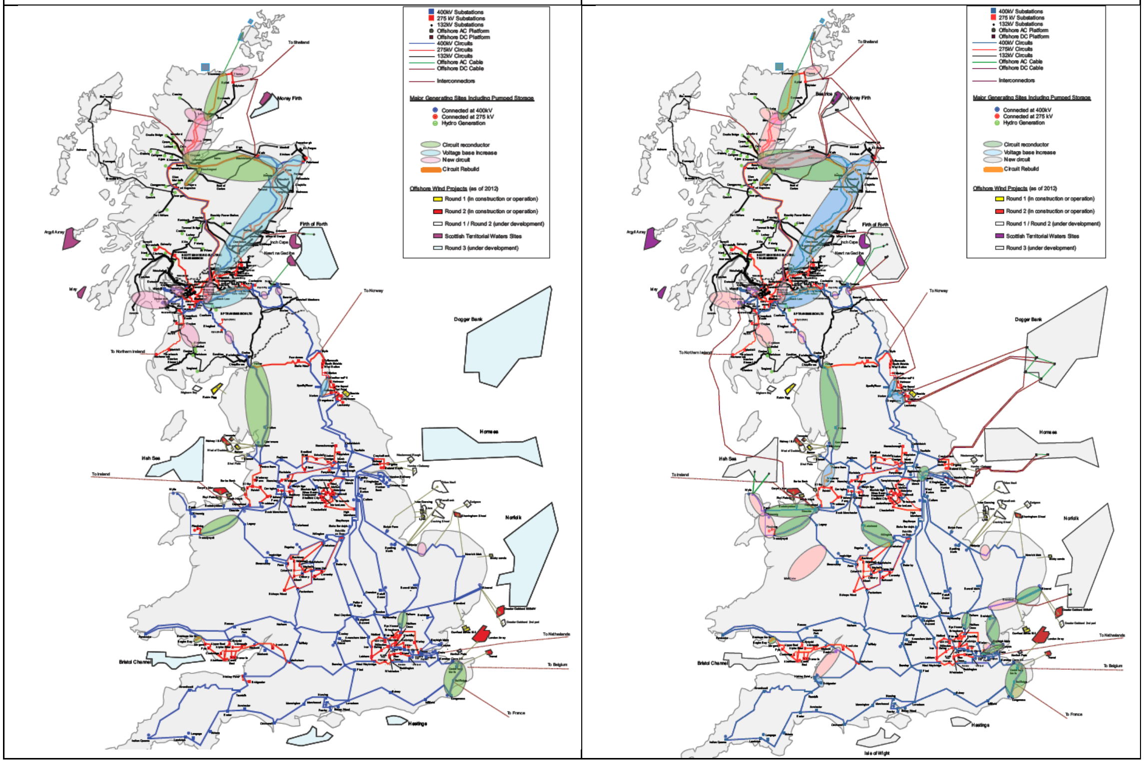


Figure 4: Diagrams of Base networks SP 2020 and 2030

A range of background generation scenarios was created by overlaying the local offshore wind generation assumptions onto the wider SP and GG generation backgrounds.

Combining GG with offshore wind generation Scenario 1 results in the highest power flows and hence the greatest requirement for additional capacity.

The lowest requirement for reinforcement is seen when the SP background is combined with the local Scenario 2.

The condition where the SP background is combined with the local Scenario 1 has been included in the analysis but is considered as a very low probability.

3.3 Boundary Assessment in Transmission Planning

The transmission network is designed to ensure that there is sufficient transmission capacity to send power from areas of generation to those of demand. To provide an overview of existing and future transmission requirements, and report the restrictions, the concept of boundaries has been developed. Boundaries split the system into contiguous parts, crossing critical circuit paths which carry power between the areas along which power flow limitations may be encountered.

The limiting factor on transmission capacity may be one or more of several different restrictions including thermal circuit rating, voltage constraints and/or dynamic stability, each of which is assessed to determine the network capability.

Boundary Capability – The ability of a transmission network to transfer energy from generation to supply can be described in terms of boundary capability. Each boundary within the transmission network is required to securely enable the maximum expected power transfer. It is important to note that many of the solutions to increase boundary capability can affect more than one boundary.

Required Transfer - In the case of wider system boundaries the overall generation is selected and scaled according to the Economic criteria. The demand level is set at national peak, which results in a ‘Planned Transfer’ level. Furthermore for each system boundary an extra interconnection or boundary allowance is calculated and added to the Planned Transfer level to give a Required Transfer level. In this way the standard seeks to ensure that peak demand will be met, allowing for generator unavailability and system variations

The NETS SQSS specifies separate methodologies for local boundaries and wider boundary analysis. The differences between both are in the level of generation and demand modelled, which in turn directly affect the level of boundary transfer to be accommodated.

Local Boundaries: The generation is assumed at its registered capacity and the local demand is assumed to be that which may reasonably be expected to arise during the course of a year of operation. Local boundaries must be able to accommodate any generation to be connected without being constrained by the local network in the year of operation.

Wider Boundaries: In the case of wider system boundaries the overall generation is selected and scaled according to the Security and Economic criteria described below and assessed against peak demand, which result is a ‘Planned Transfer’ level. For each system boundary an interconnection or boundary allowance is calculated and added to the ‘Planned Transfer’ level to give a ‘Required Transfer’ level. In this way the standard seeks to ensure that peak demand will be met, allowing for variation in both generator location and demand forecast.

3.4 Wider Boundaries: Security and Economic Criteria

The ‘Planned Transfer’ of a boundary, as defined by the NETS SQSS, is based on the balance of generation and demand on each side of the boundary and represents the natural flow on the Transmission System for a given demand and generation background. The ‘Required Transfer’ of a boundary is the Planned Transfer value with the addition of an interconnection or boundary allowance based on an empirical calculation defined in the SQSS.

The full interconnection allowance is applied for single circuit losses and half the allowance is applied for two circuit losses. A shortfall in Boundary Capability compared with the Required Transfer indicates a need for reinforcement of that boundary. The SQSS specifies two separate criteria upon which transmission capability should be determined. These are described below and are based on Security and Economic factors respectively.

The Security Criterion:

The object of this criterion is to ensure that demand can be supplied securely, without dependence on intermittent generators or imports from interconnectors. The generation background is then set by ranking the conventional generation in order to meet 120% of peak demand, based on the generation capacity and then scaling the output of these generators uniformly to meet demand (this means a scaling factor of 83%).

This selection and scaling of surplus generation takes into account generation availability. The Planned and Required Transfer values are then calculated. This criterion determines the minimum transmission capability required, ensuring security of supply. This is then further assessed against the economic implications of a wide range of issues such as safety, reliability and the value of loss of load.

The Economic Criterion:

As increasing volumes of intermittent generation connect to the GB system, the Security Criterion will become increasingly unrepresentative of year-round operating conditions. The Economic Criterion provides an initial indication of the amount of transmission capability to be built, so that the combined overall cost of transmission investment and year-round system operation is minimised. It specifies a set of deterministic criteria and background conditions from which the determined level of infrastructure investment approximates to that which would be justified from year-round cost benefit analysis. In this approach scaling factors are applied to all classes of generation such that the generation meets peak demand.

Based on this the Planned and Required Transfer values are calculated in the way explained above. If a comparison with the Economic Criterion identifies additional reinforcements, a further cost benefit analysis should be performed in order to refine the timing of a given investment. In networks where there is a significant volume of renewable generation it is expected that the application of the Economic Criteria will require more transmission capacity than the Security Criteria to ensure there is sufficient transmission capacity.

3.5 Wider System Boundaries - East Coast

The application of the Main Interconnected Transmission System (MITS) planning criteria involves the assessment of Wider System boundaries. Wider System boundaries are those that separate large areas of the GB transmission system containing significant quantities of demand and generation. With a predominant power flow toward the demand centre of London and the South East, connection of all three wind power plants could impact directly on boundaries B7, B7a and B8 and indirectly on boundaries B6 and B9, presented in 5. These wider System Boundaries are analysed to ensure the NETS SQSS requirements are maintained.

Boundary B6

Boundary B6 is the boundary between SP Transmission and the National Grid Electricity Transmission systems. The existing transmission network across the boundary primarily consists of two double circuit 400kV routes. There are also some smaller 132kV circuits across the boundary which is of limited capacity. Scotland typically contains an excess of generation leading to mostly Scottish export conditions, so north-south power flows are considered as the most likely operating and boundary stressing condition. The boundary capability of B6 is currently limited by voltage and stability to around 3.3 GW.

Boundary B7

Boundary B7 bisects England south of Teesside. It is characterised by three 400kV double circuits, two in the east and one in the west. The area between B6 and B7 is traditionally an exporting area, and constrained by the power flowing through the region from Scotland towards the South with the generation surplus from this area added.

Boundary B7a

Boundary B7a runs parallel with boundary B7, sharing the same path in the east, but encompassing Heysham, Hutton and Penwortham in the west. The region between Boundary B7 and B7a includes more generation than demand, further increasing the transfers from north to south. The boundary capability is currently 4.8 GW, limited by thermal ratings

Boundary B8

The North to Midlands boundary B8 is one of the wider boundaries that intersects the centre of Great Britain, separating the northern generation zones from the Midlands and Southern demand centres. The east of B8 is a congested area due to the large amount of existing generation. The current boundary capability of 11.3 GW is limited by voltage restrictions.

Boundary B9

Boundary B9 separates the northern generation zones and the Midlands from the Southern demand centres. The boundary crosses five major 400kV double circuits, transporting power from the north over a long distance to the Southern demand hubs including London. The current boundary capability is 12.6 GW, limited by thermal and voltage restrictions.

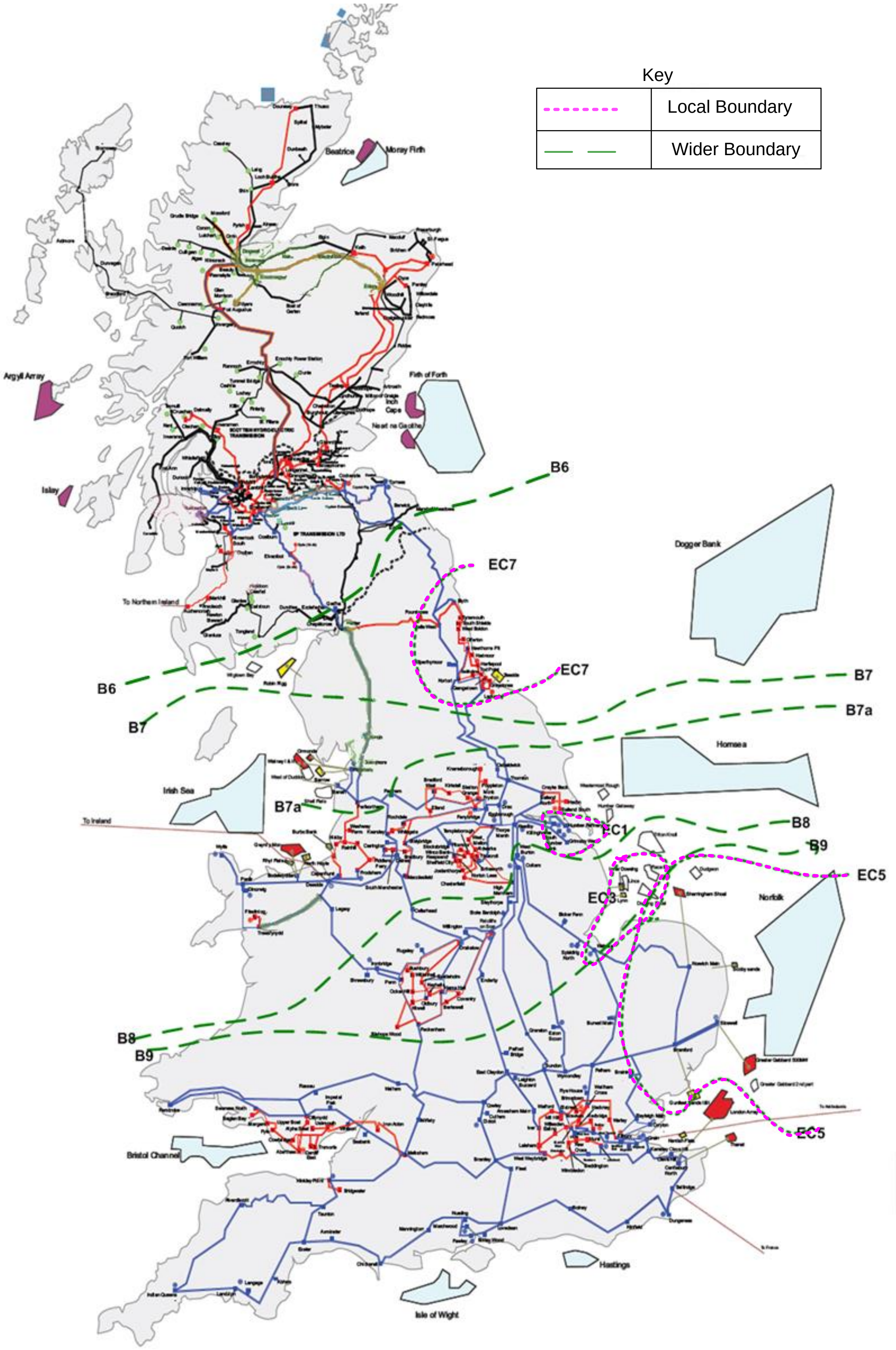


Figure 5: Graphical Representation of the Local and Wider System Boundaries

3.5 Local System Boundaries - East Coast

Connection of the East Coast projects to the wider transmission network involves multiple transmission connections all along the East coast from Teesside to the Thames Estuary including areas around Humberside, Lincolnshire and the Wash.

The Local Boundaries are smaller areas of the NETS, which typically contain a large imbalance of generation and demand leading to heavy loading of the circuits crossing the boundary. As demand is not predicted to change significantly over the period, the local boundaries see significant growth in Generation resulting in high boundary transfers.

The local boundaries for the three large East Coast offshore wind power plants are shown above in Figure 5 and summarised below:

- Dogger Bank connecting to local boundary EC1, EC3 and EC7
- Hornsea connecting to local boundary EC1 and EC3
- East Anglia connecting to local boundary EC5

Boundary EC1

Boundary EC1 is an enclosed local boundary in the Humber group, consisting of four circuits that export power to Keadby substation. The maximum power transfer out of this boundary is currently 5.5 GW which is limited by thermal overloads on the boundary circuit. The boundary is at its local limit and any further generation injections would require onshore reinforcement.

Boundary EC3

Boundary EC3 is a local boundary surrounding the Walpole substation and includes the six 400kV circuits out of Walpole. Walpole is a critical substation in supporting significant offshore generation connections and high North- South network power flows along the East Coast network. The maximum boundary transfer capability is currently limited to 3.2GW by thermal overloads on the boundary circuits. Following the Walpole re-build, Walpole will be able to accommodate up to a further 2GW before reaching its limit.

Boundary EC5

The local boundary EC5 covers the Eastern part of East Anglia including the substations of Norwich, Bramford and Sizewell. Significant generation is enclosed by the boundary so that power is typically exported out of the zone, predominantly along the southern circuits. The maximum boundary transfer capability is currently limited to 3.4 GW due to thermal overload. Onshore reinforcements are planned to facilitate the rapid build-up expected from East Anglia.

Boundary EC7

Boundary EC7 is a local boundary that encompasses the north east of England, predominately a 275kV ring serving local demand but crossed by one of the two 400kV export routes from Scotland. This area is constrained by North-South power flows with the 400kV circuits at the southern end of the boundary. This boundary is already at its limit for further generation and would require onshore reinforcement to facilitate additional generation.

3.6 Integrated Offshore Design Philosophy

Design Philosophy Assumptions

Proposing offshore integrated designs took into the consideration the following assumptions:

- We are not considering onshore reinforcement other than AC options - HVDC LCC is not considered as an alternative to bootstraps options
- The Cost Benefit Analysis will take into consideration all the possible construction delays related with the export of power from landing point on the shore
- Under Operability framework the System Inertia impact on system are taken into consideration
- Designs consider the Technology Availability matrix and take into consideration when a particular Technology is available.

In developing integrated offshore designs two major design criteria were taken into consideration: network capacity availability of local boundaries and the shortfall of the wider system boundaries.

According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary. This means that for a 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.

In planning the MITS however, under Economic Criterion, different scaling factors are applied to different types of generating plant i.e Nuclear Power – 85%, Pumped Storage – 50%, Interconnectors – 100%, Wind, Wave and Tidal – 70% while conventional generation is scaled variably[4]. In the case of wind, this implies that the assets are assumed to be 70% utilized by the Wind generated, allowing some spare capacity in the assets of about 30%. It is this ‘spare’ capacity that provides the opportunity for offshore integration to be utilised as one of the options to provide boundary capability across a non-compliant boundary.

[4] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode

Figure 6 below demonstrates two offshore design options; the first option shows a link between two wind farms which provides boundary reinforcement of 30% of the capacity of the radial links. It is important to emphasize that the link should cross the boundary in order to contribute to the reinforcement of the network boundary. The second option is the case where wider system boundaries are reinforced by a HVDC link which also crosses the boundary as is shown in Figure 6.

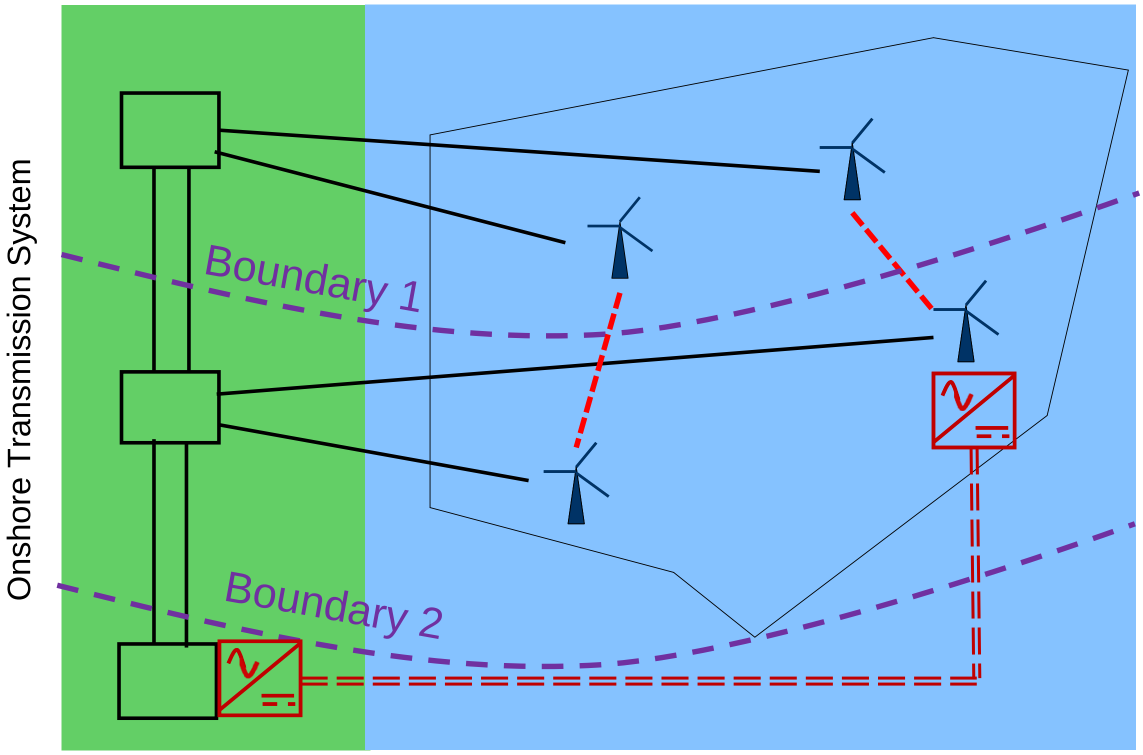


Figure 6: Design Methodology

Bootstrap design philosophy

We have also considered point-to-point offshore HVDC bootstraps as alternative design options to reinforce the boundaries. Both LCC and VSC technologies have been considered.

Updated Boundary Capabilities based on results in document ETYS 2013

The boundary capabilities used in the initial base design were updated to reflect the updated boundary contingency sets used for Boundary capabilities from the ETYS 2013. Based on the updated boundary capabilities, the new optimal designs were produced.

Updated Capacity of radial links (1GW vs. 2GW)

In order to reduce the capital cost investments the over-sizing of connection link cables, from a rating of 1GW to 2GW, was analysed. The technology availability as specified in the Technology Availability matrix was utilised in determining cases where larger sized assets could be used.

Optimal Offshore Design Philosophy

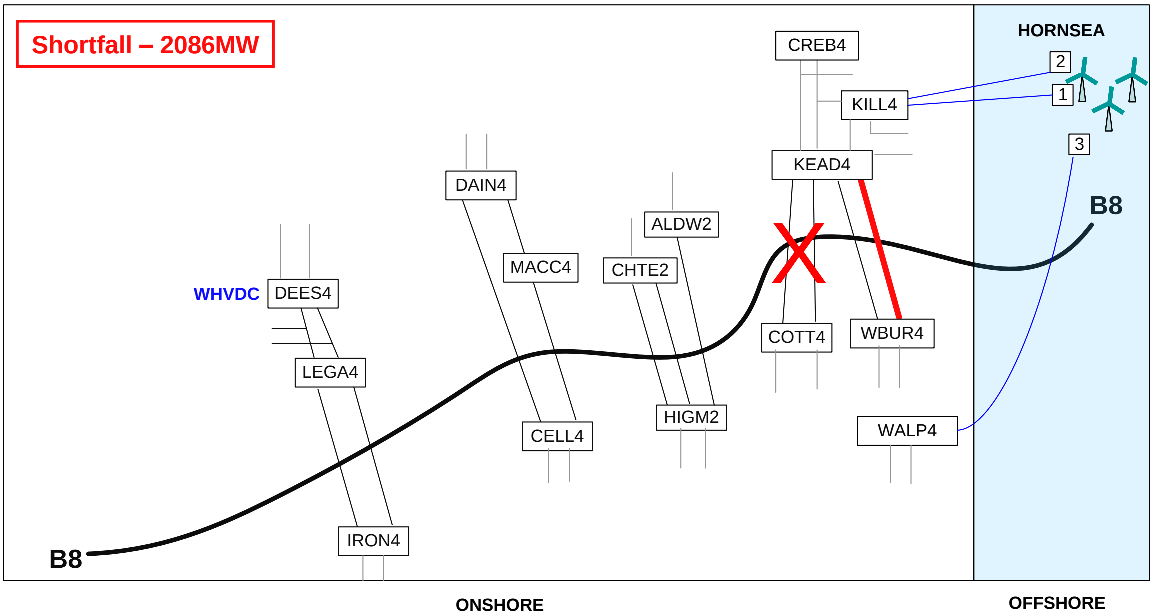
The benefits of the integrated designs were assessed by utilising a combination of actions to maximize the capability across the boundaries, actions included QB optimisation, redirection of flows in HVDC links as explained by a generic example below;

Offshore integration has the effect of changing the loading of the boundary circuits and this provides an opportunity to couple additional onshore actions to achieve additional capability across the boundary.

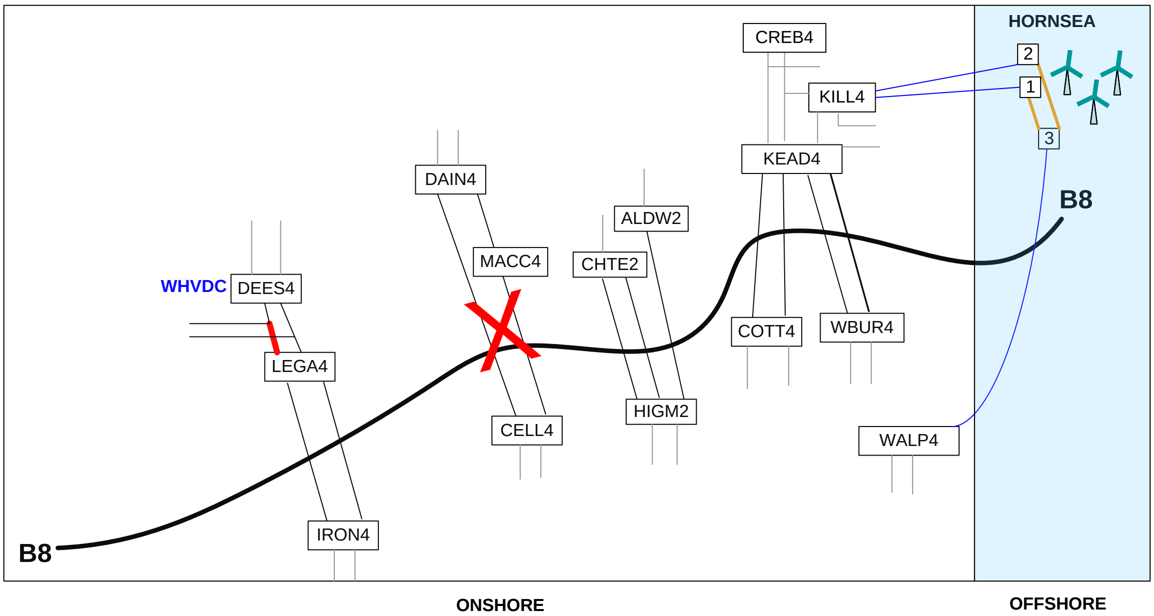
Boundary B8 Example:

In the case below, the base case shortfall across B8 is ~ 2GW, with the limiting condition being a thermal overload of the Keadby-West Burton OHL Circuit.

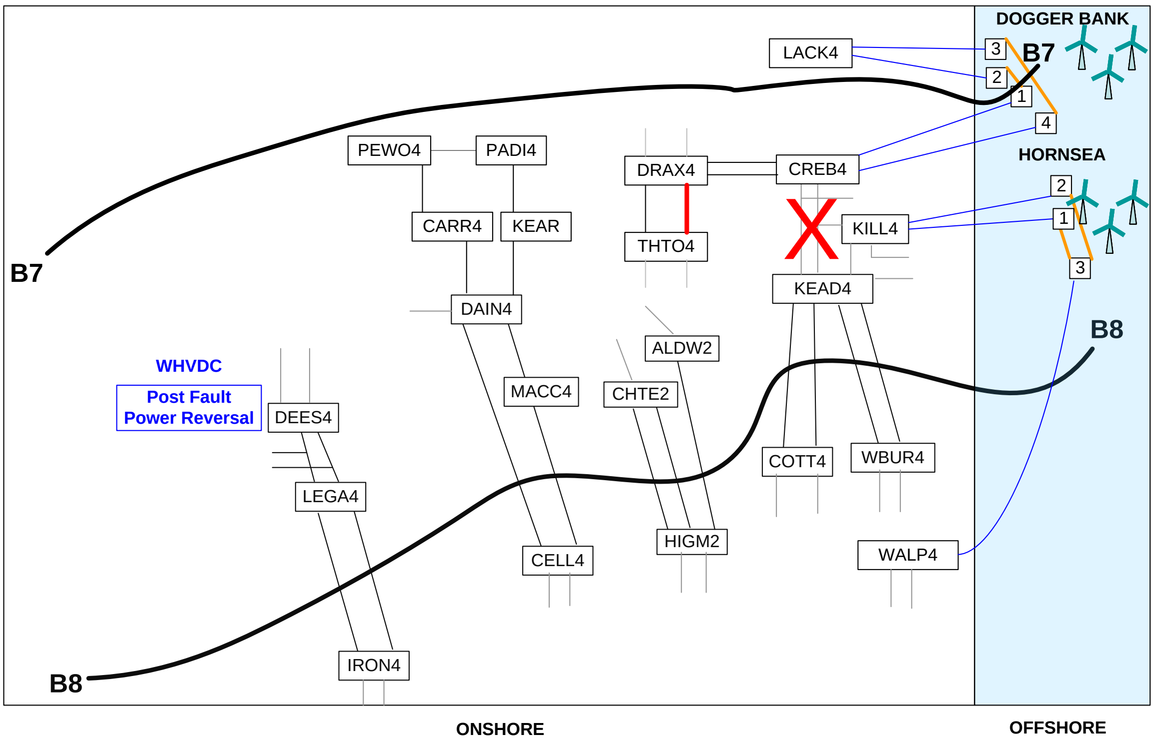
Action 1: By tapping some QBs post-fault, the boundary capability was improved by ~ 0.5GW however, the limiting condition remained the same.



Action 2: By providing integrated links of total ~ 0.3GW capability between the Hornsea projects e.g. project 2 & 3, the boundary capability was improved by ~ 0.58GW due to changes in load sharing across the boundary. In this instance however, the limiting circuit moves to the west coast to a thermal overload of Deeside-Legacy circuits.



Action 3: The overload on the west coast is relieved by pushing back power across the link to Scotland. Following this, the next limiting circuit is on the east coast at the Drax – Thornton OHL circuit



Action 4: The overload on the Drax – Thornton OHL circuit can be relieved by utilising integrated links between Dogger Bank projects across B7 to redirect upto ~ 0.6GW towards Lackenby. This, together with QB actions at Keadby and Legacy, results in an additional capability of ~ 2GW across B8.

This example shows how integrated offshore links can be utilised to provide boundary capability. By undertaking subsequent onshore actions such as QB optimisation, redirection of flows through existing HVDC links, some cumulative boundary capability is attainable. It is important to note however that the onshore actions available do strongly depend on the location of the overloads.

3.8 Impact of Interconnections on Offshore Integrated designs

The core scenario view of the Gone Green and Slow Progression scenarios mostly hold the interconnectors at low to no power flow at winter peak, so the boundary requirements do not change much. With new generation and interconnectors connecting within the boundary the sensitivities for this boundary can become the driving force for future requirements.

Treatment of Interconnectors in IOTP(E) studies

For the purpose of the IOTP(E) study the proposed offshore integrated design were derived without the interconnectors being included into the model. In ETYS 2013 the interconnectors are treated in exporting mode if the GB system price is below the market price, i.e the receiving country takes advantage of low power prices in GB. Between the lower and upper price, there is assumed to be no power flow (i.e the interconnectors are at float). If the GB system price is above the market price, the interconnectors are importing power.

In IOTP(E) the “float” mode of interconnectors has been taken as an approach, which means that interconnectors do not affect the required transfer.

In reality, modelling of interconnectors is a complex task, and was beyond the scope of this project. Interaction between interconnectors and offshore integrated designs could be significant and future work is required to identify the coordination and impact of interconnectors on offshore integrated designs.

3.9 Application of NETS SQSS and Grid Code

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS), sets out a coordinated set of criteria and methodologies that transmission licensees shall use in the planning, development and operation of the National Electricity Transmission System (NETS).

Current versions of the NETS SQSS and Grid Code do not explicitly cover the offshore integrated approach; Chapter 4 for designing the Main Interconnected Transmission System is used as a reference. However, further update and development of the NETS SQSS and Grid Code is required.

4. Study Results – Slow Progression Background

The following section presents boundary transfer requirements and capabilities for the Slow Progression background combined with local Scenario 1 and Scenario 2.

4.1. Required Transfer

The following graphs indicate the required transfer across boundaries B6 to B8 for the selected sensitivities of the Slow Progression scenario. All are calculated using the generation ranking order and demand values as published in the 2012 Future Energy Scenarios. Sensitivities have been created by the project to evaluate how the build-up of wind generation at Dogger Bank, Hornsea and East Anglia affects the required transfers. It is important to note that the capability shown is from the ETYS 2012 studies under a Gone Green background. Deviations from this capability were found when the various boundaries were studied due to the large changes in the generation and demand backgrounds and location of generation for the studies. Table 1 gives a description of the sensitivities.

Table 1: Comparison and Explanation of Slow Progression Sensitivities

Scenario/ Sensitivity	Description
SP 2012	Slow Progression as per the ETYS 2012
SP 2012 + Scenario 1	Slow Progression sensitivity using the contracted SCENARIO 1 values for the East Coast generation units.
SP 2012 + Scenario 2	Slow Progression sensitivity using the developers Best-View values for the East Coast generation as proposed in August.

Boundary B6

Figure 7 indicates that there is a greater required transfer under Slow Progression than any of the sensitivities studied for B6. This is due to the increase in wind generation found in the various sensitivities displacing plant in Scotland, therefore reducing the required transfer across the border.

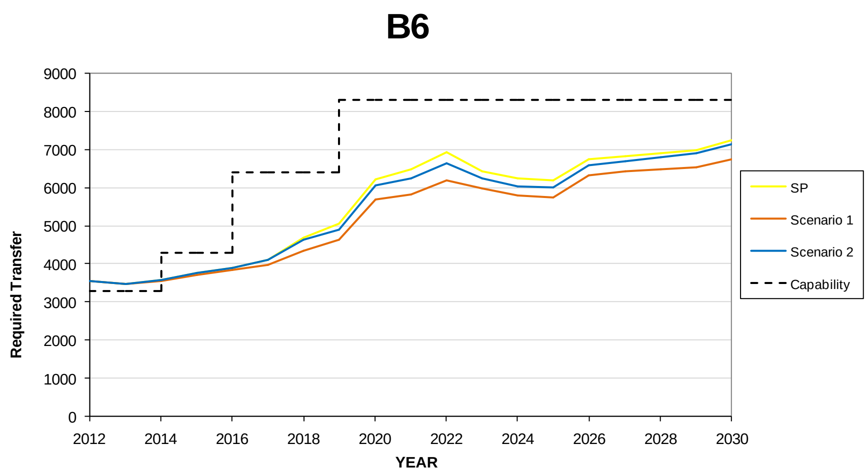


Figure 7: B6 Required Transfer (Slow Progression)

Boundary B7

Figure shows that for all sensitivities Boundary B7 is compliant under slow progression. The required transfer is greater for the majority of sensitivities than the slow progression scenario. The differences in required transfer are closely linked to the value of generation applied inside the B7 boundary for each sensitivity. Only the

Slow Progression + Scenario 1 required transfer trace exceeds the capability for any year. Studies performed in 2021 and 2030 were undertaken to inspect the capability more closely, showcasing that with the Slow Progression + Scenario 1 sensitivity, a greater capability will be expected in 2021 and 2030, which will not require any further works to complete.

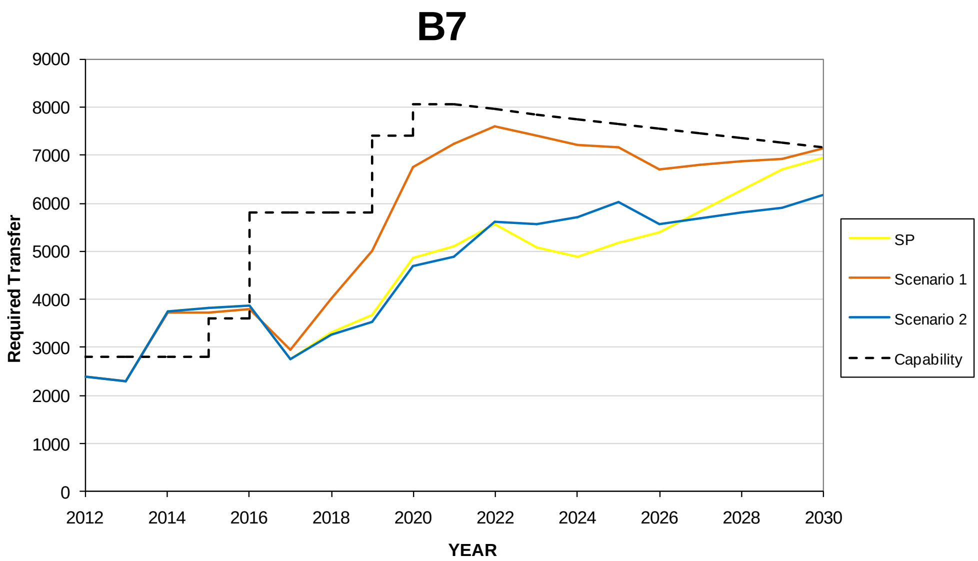


Figure 8: B7 Required Transfer (Slow Progression)

Boundary B7a

Figure 9 shows the required transfer for boundary B7a under the various sensitivities. This boundary is compliant for all scenarios out to 2030.

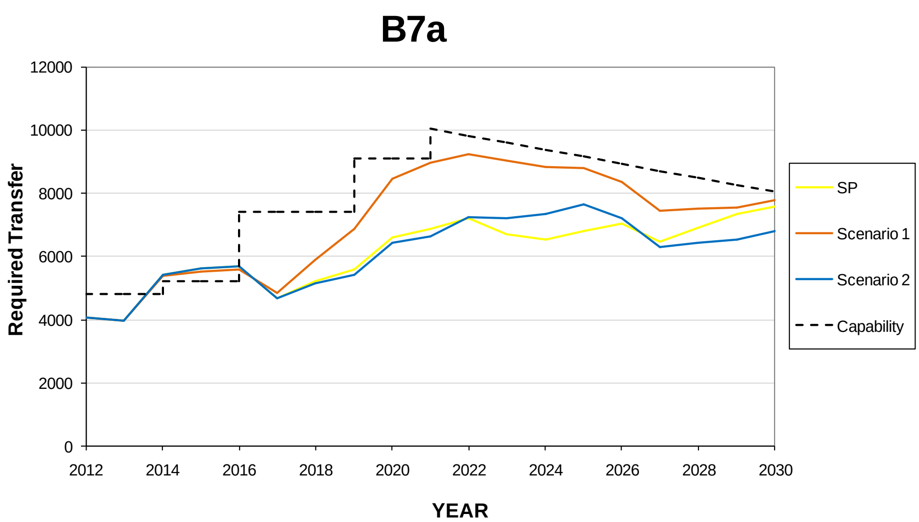


Figure 9: B7a Required Transfer (Slow Progression)

Boundary B8

Figure 10 indicates that Boundary B8 will be non-compliant under the Slow Progression + Scenario 1 sensitivity for 2021. It was also found that, due to the changes in generation background, the capability in 2030 was below the required transfer for the Scenario 1 sensitivity.

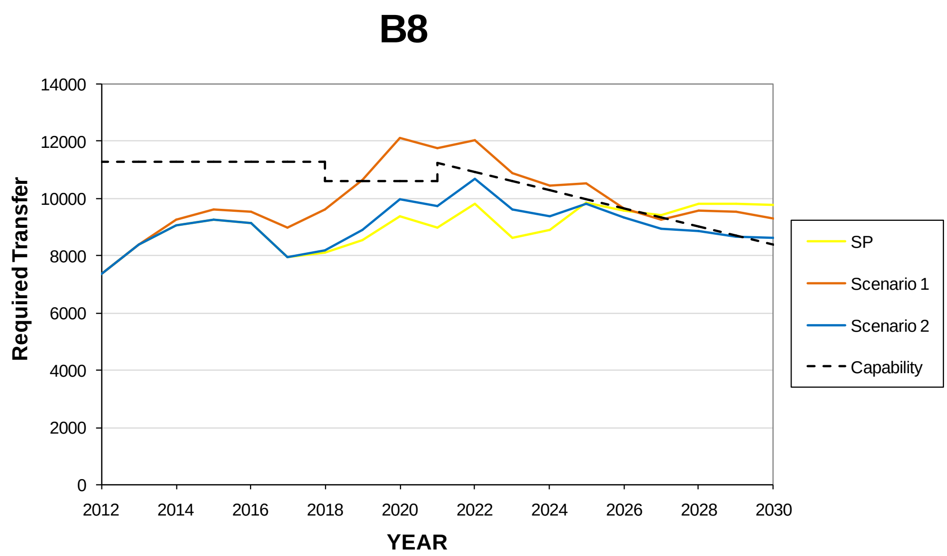


Figure 10: B8 Required Transfer (Slow Progression)

4.2 Boundary Capability: Scenario 1 (2021)

This scenario assumes that the three East Coast projects build up to a total generation capacity of 11.4GW. In 2021/22 the demand is forecast at 57,106MW. The results for the thermal boundary studies are summarised in **Error! Reference source not found.** below;

Table 2: SCENARIO 1 2021 DC Thermal Boundary Result (Slow Progression)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B7	7237	8048	- 811	LACK4-THTO4-2-LACK4-THTO4-1	LACK4-NORT4-1	99%
B7a	8964	10,041	- 1077	PEWO2-WASF2A-PEWO2-WASF2B	CARR4-DAIN4-2	99%
B8	11,766	11,230	**536**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	109%

The study shows that B7 and B7a are compliant. However, the transmission network has the capacity to transfer a maximum power of 11.2GW across the B8 boundary. The required power transfer across this boundary is 11.8GW. Therefore, there is a 600MW shortfall which makes the boundary non-compliant under the SQSS requirements.

The B8 boundary capability is limited by the thermal rating of the A394 circuit between Keadby and West Burton 400kV substations. The boundary capability study shows that this circuit gets 116.8 % overloaded under Keadby - Cottam (A492 – A493) double circuit outage. The matching results suggests that the A394 circuit would be stressed to its maximum and running at its thermal limit if this post fault condition or circuit outage were to occur, and therefore there is not enough transmission capacity to accommodate any additional surplus generation on the north side of this boundary, no more than what this generation scenario planned transfer already imposes.

4.3 Boundary Capability: Scenario 1 (2030)

This scenario assumes that the three East Coast projects build up to a total generation capacity of **17.2GW**. In 2030/31 forecast demand is 56,149MW. The results for the thermal boundary studies are summarised in Table 3 below;

Table 3: SCENARIO 1 2030 DC Thermal Boundary Result (Slow Progression)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B7	7130	7155	-25	HEYS4-QUER4A-HEYS4-QUER4B-HUTT4	DRAX4-EGGB4-1	84 %
B7a	7764	8041	-277	HEYS4-QUER4A-HEYS4-QUER4B-HUTT4	DRAX4-EGGB4-1	84 %
B8	9279	8400	**879**	COTT4-KEAD4-COTT4-KEAD	KEAD-WBUR (105%)	105%

The study shows that B7 and B7a are compliant. The study shows that the transmission network has the capacity to transfer a maximum power of 8.40GW across the B8 boundary. The required power transfer across this boundary is 9.28GW. There is a significant shortfall of 879MW which makes the boundary non-compliant under SQSS requirements.

5 Proposed Design Solutions – Slow Progression Background

5.1 Onshore Solutions

Creyke Beck - Drax - Keadby Ring

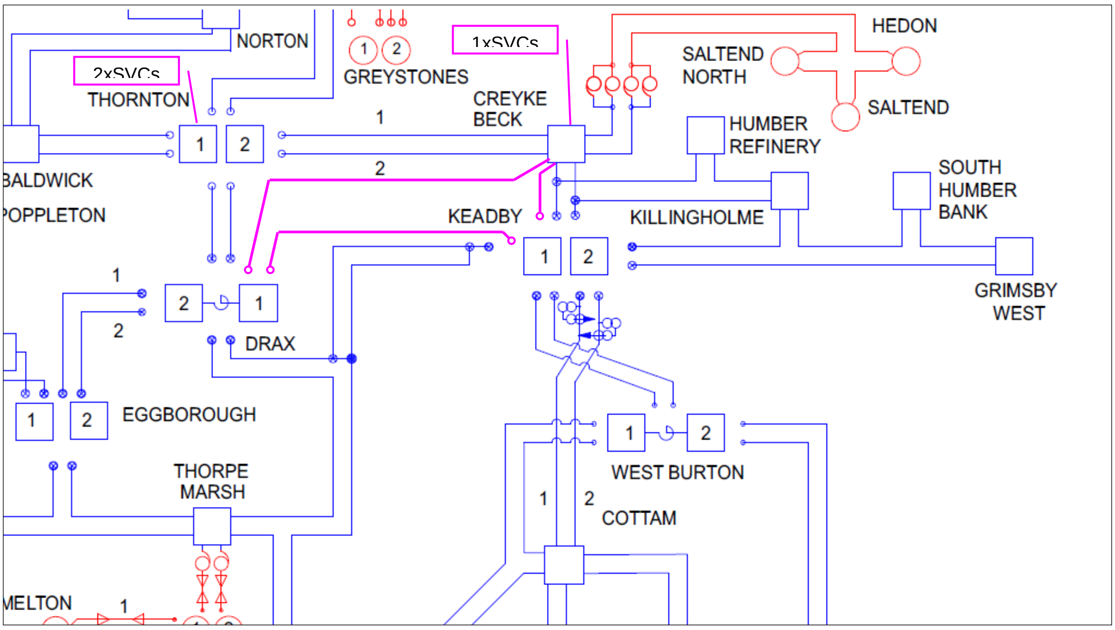


Figure 11: Creyke Beck - Drax - Keadby 400kV New OHL

This reinforcement is included in the base case for B8 in 2030 for the "SP+SCENARIO 1" sensitivity.

THTO-DRAX is the critical contingency seen in studies on boundary B8. In order to alleviate the overloading of the surrounding circuits under this contingency, the following package of works should be undertaken:

- Creyke Beck-Drax Single Circuit *(Approximately 25 km in length)*
- Creyke Beck-Keadby Single Circuit *(Approximately 40 km in length)*
- Drax-Keadby Single Circuit *(Approximately 35 km in length)*
- 2 SVC's at Thornton
- 1 at Creyke Beck *(This requirement may be satisfied if the HVDC link from Doggerbank has voltage control)*.

This option provides an increase in the thermal capacity of the Creyke Beck/Drax/Keadby area, reducing the impact of the THTO-DRAX contingency. A diagram with the new assets is shown in Figure 11.

Effectiveness:

Sensitivity	Increase on B8 boundary
2030 Slow Progression ("Clean")	+2250MW
2030 Slow Progression + SCENARIO 1	Base case reinforcement

West Burton - Killingholme new Substation

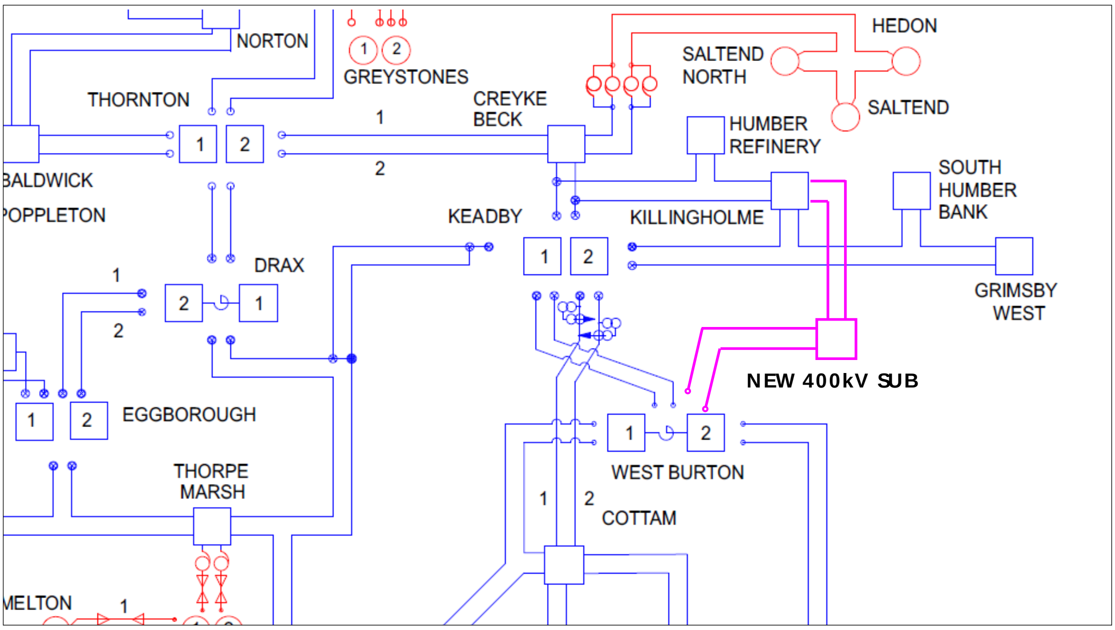


Figure 12: New 400kV Substation between West Burton and Killingholme

This reinforcement provides approximately 2500MW of boundary uplift for B8 in 2030 for the "SP plus SCENARIO 1" sensitivity. Under Slow Progression "Clean", the capability provided is marginally smaller at approximately 2140MW.

This option entails a new 400kV substation between West Burton/Killingholme including a new double circuit OHL. Reconductoring of the Keadby-Cottam circuits is required, alongside the operational removal of the Cottam-West Burton circuit. The Cottam-West-Burton circuit is the limiting component of the B8 boundary studies in B8, but when removed from service has no effect on boundary capability. A diagram with the new assets is shown in Figure 12.

- Double Circuit OHL from Killingholme to proposed Substation ≈ 35 km.
- Double Circuit OHL from West Burton to proposed Substation ≈ 35 km.
- Operational removal of the Cottam-West Burton circuit.
- Reconductoring of the Keadby-Cottam circuits to GAP rating (for n-2).

Effectiveness:

Sensitivity	Increase on B8 boundary
2030 Slow Progression ("Clean")	**+2140MW** *(Creyke Beck-Drax-Keadby in base case)*
2030 Slow Progression + SCENARIO 1	**+2500MW** *(Creyke Beck-Drax-Keadby in base case)*

Coordinated Quadrature Boosters

A possible operational solution to relieve the overloading on the limiting component of B8, circuits A394 and A39E between Keadby and West-Burton, is the installation of co-ordinated Quadrature Boosters (QB). These would be located on the 400kV double circuit between Keadby and West Burton substation (A394 – A39E). The new QBs are shown in red in Figure 13. The coordinated scheme would need to communicate with the local QBs at Keadby and West Burton, and also with the geographically more distant QBs at Penworhtam to balance the power flows across the entirety of B8.

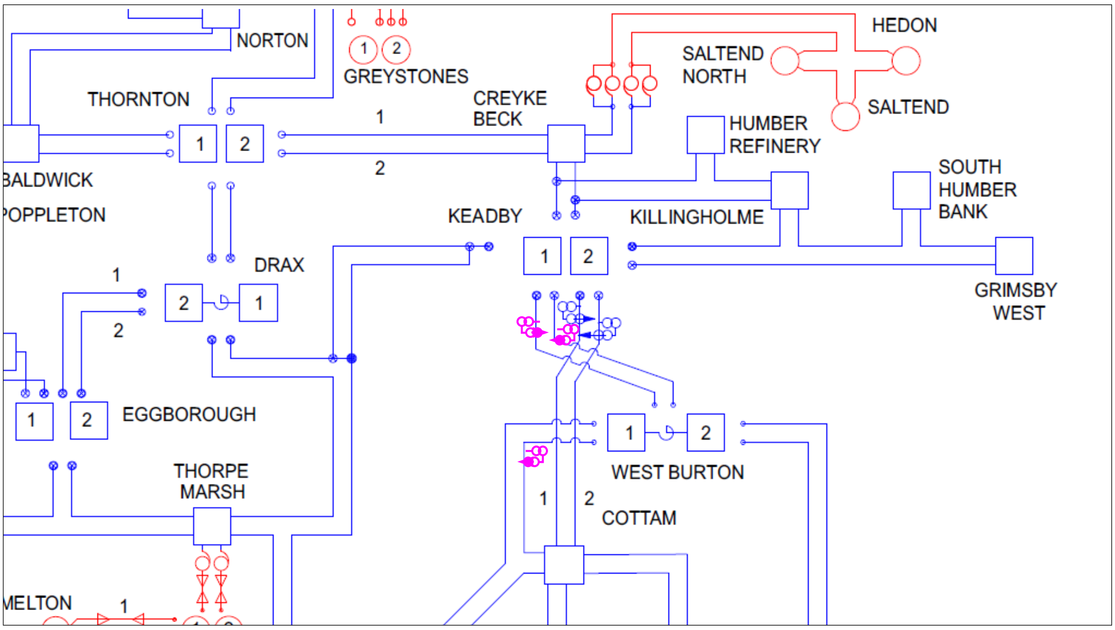


Figure 13: Coordinated Quadrature Booster Option

The QB solution provides some degree of control over the distribution of the power flows through the A394 & A39E lines under the critical N-D contingency between Keadby and Cottam substations (A492 – A493). The study shows that the power flows re-distribution obtained by optimising the relevant Quadrature Boosters post fault tap settings is enough to increase the boundary capability to make the boundaries compliant.

The study shows that the power flows re-distribution obtained by optimising the relevant Quadrature Boosters post fault tap settings is approximately 900MW under all sensitivities. In 2021 this is enough to increase the boundary capability beyond the requirement, in 2030, this reinforcement would have to be partnered with one of the other solutions to make B8 compliant.

The tap settings required to achieve this boundary capability are shown in **Table 4**.

Effectiveness:

Sensitivity	Increase on B8 boundary
2021 Slow Progression + SCENARIO 1	+900MW
2030 Slow Progression ("Clean")	+900MW
2030 Slow Progression + SCENARIO 1	+800MW (Total Boundary Capability of)

It can be seen from Table 4 and Table 5 that significant tapping is required for this solution to be most effective. Operational standards do not currently allow such significant changes to tap positions in planning timescales. The standards would have to be challenged for a QB optimisation Scenario 1hnique to be implemented.

Table 4: QB Tap settings under coordinated QB Tapping Scheme 2030

QB>	West Burton QB1		West Burton QB2 (A413)		Keadby QB1		Keadby QB2 (A394)		Penwortham QB2	
Year	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
2030	20		20	15	20		20	25	20	29

Table 5: QB Tap settings under coordinated QB Tapping Scheme 2021

Contingency	Kead4 QB1		Kead4 QB2		Kead4 QB3		Kead4 QB4		Stay4 QB		Wisd2Q724		Wisd2Q724		Higm4 QB2	
	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
Kead4-Wbur4-1/Kead4-Wbur4-2	20	34	20	34	20	-	20	-	20	39	10	19	10	19	20	-
Cott4-Kead4-1/Cott4-Kead4-2	20	-	20	-	20	25	20	25	20	-	10	-	10	-	20	-
Creb4-Kead4-Kill4/Creb4-Kead4-Humr4	20	-	20	-	20	-	20	-	20	-	10	-	10	-	20	35

5.2 Comparison of Possible Reinforcements

Table 6 gives an indication of the possible combinations of reinforcements on the network. The colour coding gives an indication of the boundary compliance under the given generation sensitivity and onshore option applied.

Table 6: Slow Progression Results with reinforcements

		2021 SP+ Scenario 1 (MW)	2030 SP + Scenario 1 (MW)	2030 SP (MW)
	Required Transfer	**11766**	**9279**	**9789**
	Capability	11230	8400*	7024
	BC + CB-D-K	-	8400*	9292
	BC + CB-D-K + WB-K	-	10900	11432
B8	BC + QB	12130	9200	9200

CB-D-K Reinforcement included in base case

The onshore options proposed deliver significant reinforcement across the B8 boundary, which is found to be non-compliant under the Slow Progression plus SCENARIO 1 sensitivity in both 2021 and 2030. B8 is also found to be non-compliant in 2030 for Slow Progression.

Under the developer sensitivity of Slow Progression plus Scenario 2, required transfers across B7, B7a and B8 are approximately 1000MW less than in the sensitivities studied. This would drive no reinforcement in 2021 and a marginal case for reinforcement across the B8 boundary in 2030. Further analysis would need to be undertaken as more certainty is gained in the generation background in 2030. These studies were undertaken with the Slow Progression 2012 background as the base case, early high-level analysis of the 2013 Slow Progression background shows significantly less required transfer across B7, B7a and B8, further reducing the need for reinforcement under slow progression sensitivities.

6 Study Results – Gone Green Background

6.1 Required Transfer

Local Boundaries

The Required Transfer for the local boundaries is presented in the figures below. The local boundaries considered are the East Coast boundaries EC7 (North East), EC1 (Humber), EC3 (Walpole) and EC5 (East Anglia).

EC7 – North East

The
Figure below shows that boundary EC7 has sufficient capability for all scenarios except Scenario 1 which requires the Yorkshire Line reconductoring.

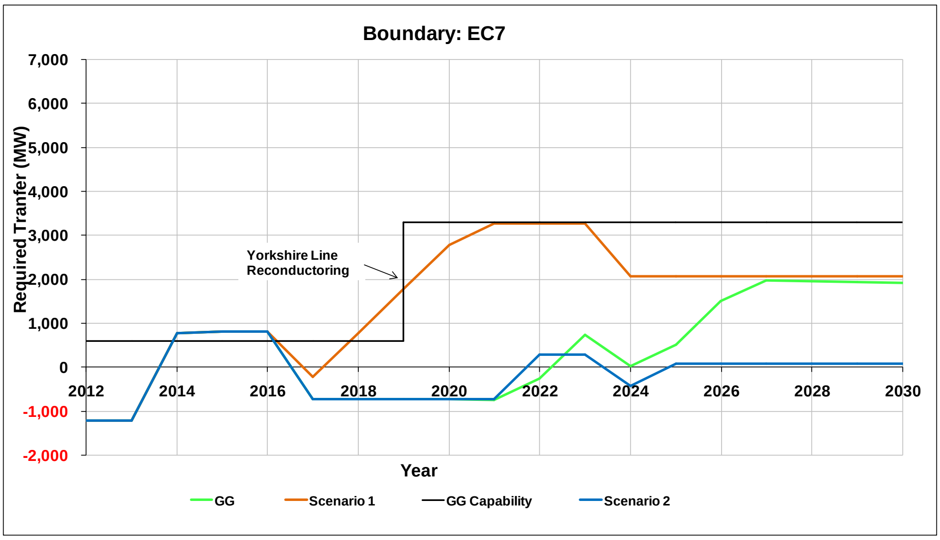


Figure 14: EC7 Required Transfer (Gone Green Scenario)

The local boundary EC7 is the proposed landing for the first Eastern HVDC link from Scotland. Figure 15 indicates that with the EHVDC in the background, additional reinforcements will be required in EC7 to facilitate additional injections into this boundary.

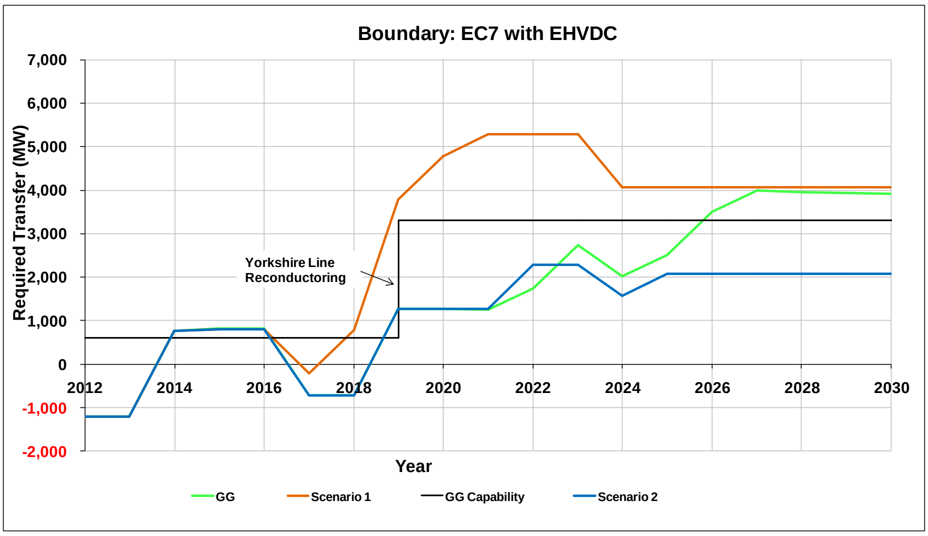


Figure 15: EC7 with EHVDC Required Transfer (Gone Green Scenario)

EC1 – Humber

The EC1 boundary currently has a capability of approximately 5.5GW and has limited capacity for further generation injections in the region. Any further injections will trigger reinforcements out of this boundary as seen for the Gone Green case in about 2027 in Figure 16 below;

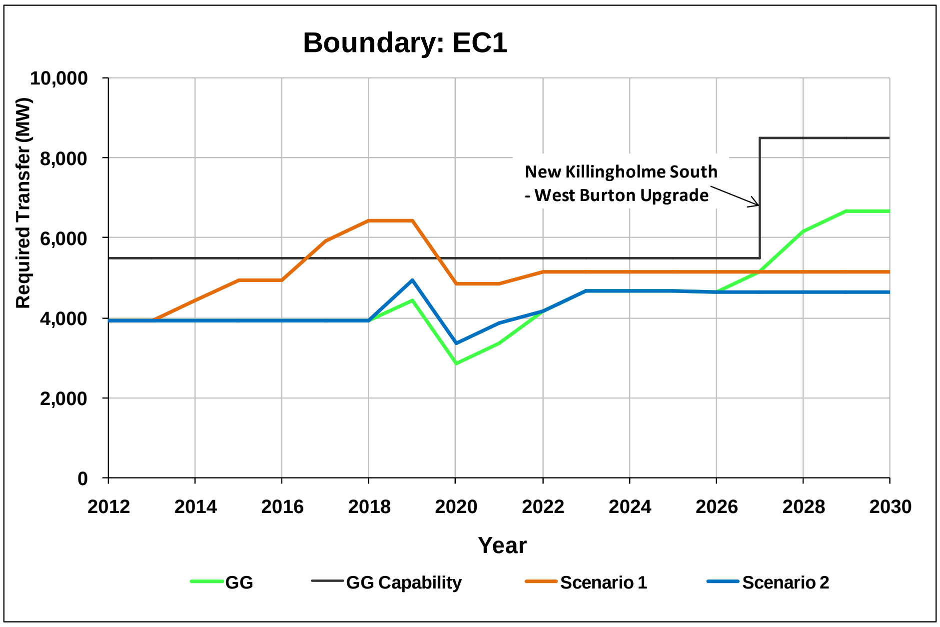


Figure 16: EC1 Required Transfer (Gone Green Scenario)

EC3 - Walpole

Boundary EC3 has some spare capability which is significantly reduced as generation connects in this region. By 2023, Scenario depletes all spare capability in the region and any additional generation injections would trigger the need for reinforcements in this local boundary. In the base Gone Green (GG) and Scenario 2 however, EC3 can accommodate just under 1.5GW extra generation injection before triggering the need for boundary reinforcement.

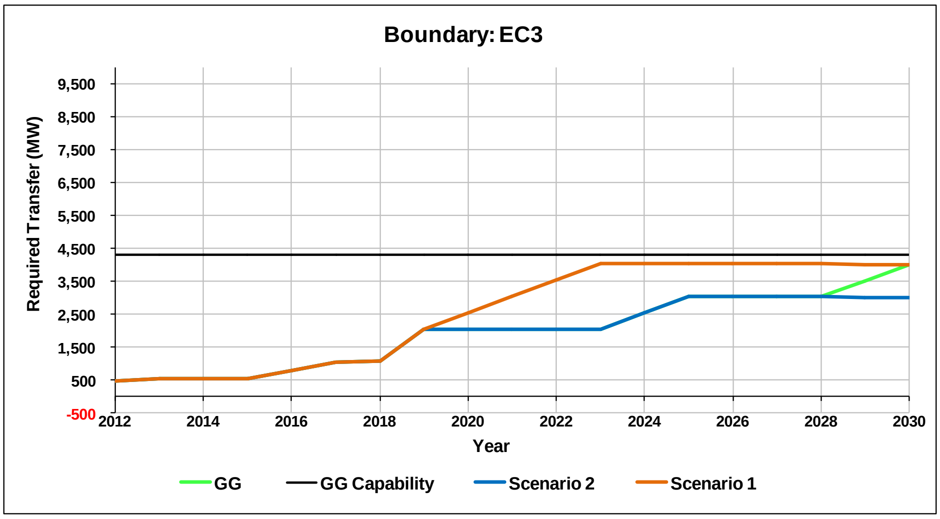


Figure 17: EC3 Required Transfer (Gone Green Scenario)

EC5 – East Anglia

Boundary EC5 has limited capability and will require a range of reinforcements to accommodate the levels of generation planned in the region as shown in Figure below:

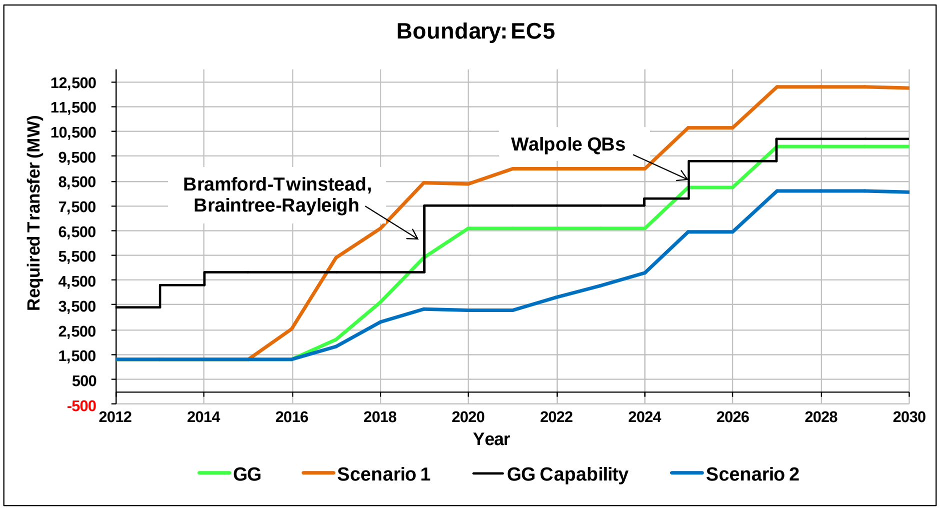


Figure 18: EC5 Required Transfer (Gone Green Scenario)

Gone Green Required Transfer for Wider System Boundaries

The figures below summarise the required transfer for the different boundaries over the range of scenarios considered. It can be generally seen that required transfer exceeds boundary capability, indicating the need for reinforcements.

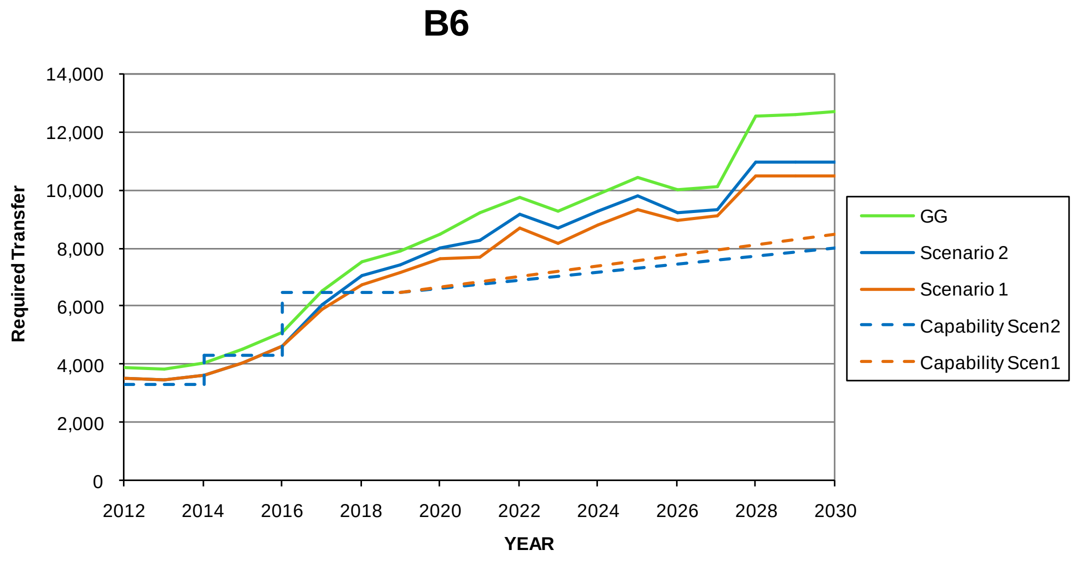


Figure 19: B6 Required Transfer (Gone Green Scenario)

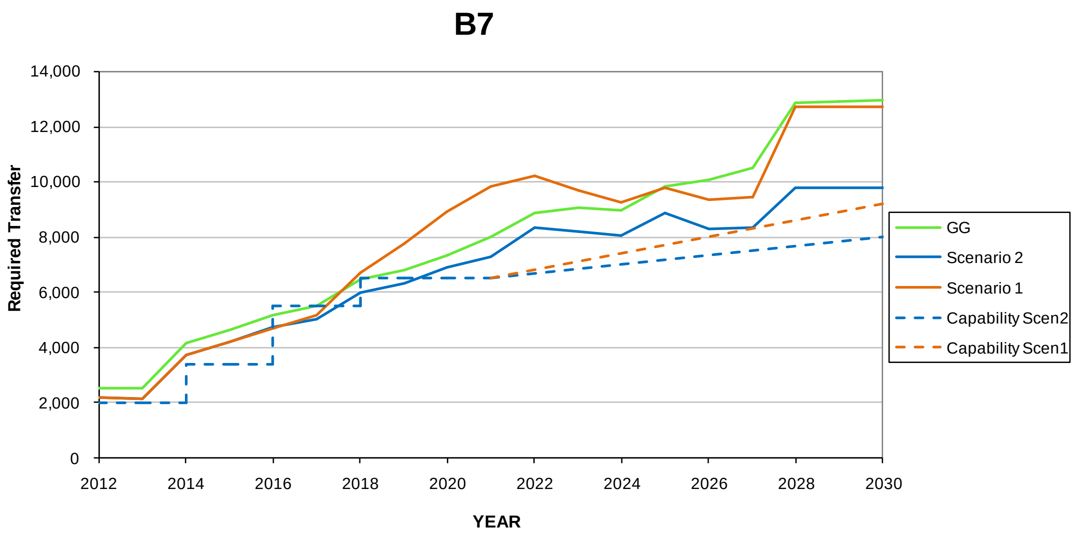


Figure 20: B7 Required Transfer (Gone Green Scenario)

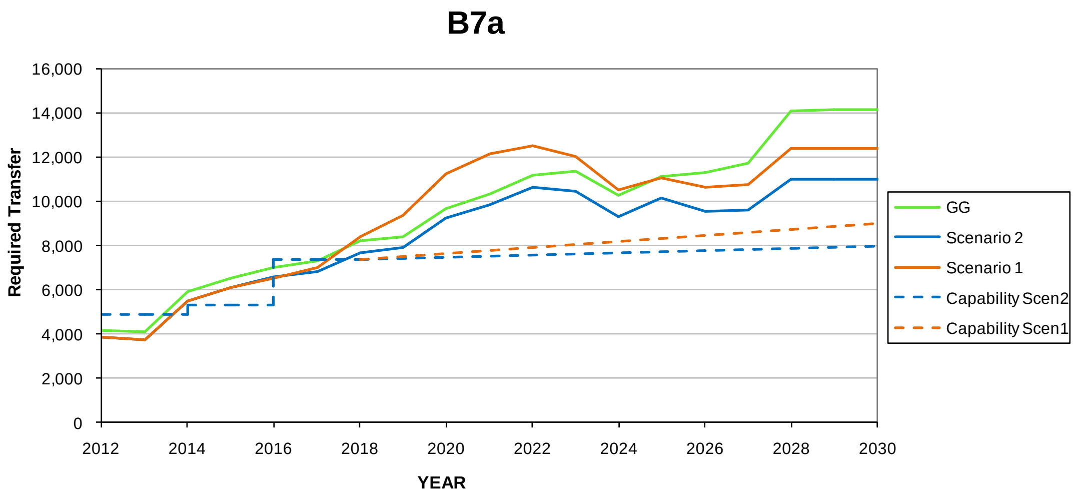


Figure 21: B7a Required Transfer (Gone Green Scenario)

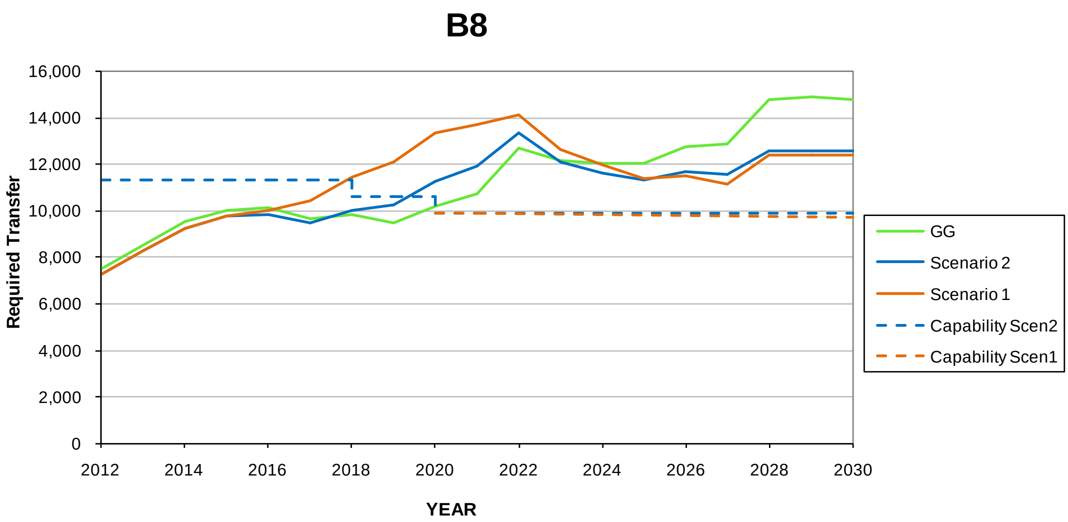


Figure 22: B8 Required Transfer (Gone Green Scenario)

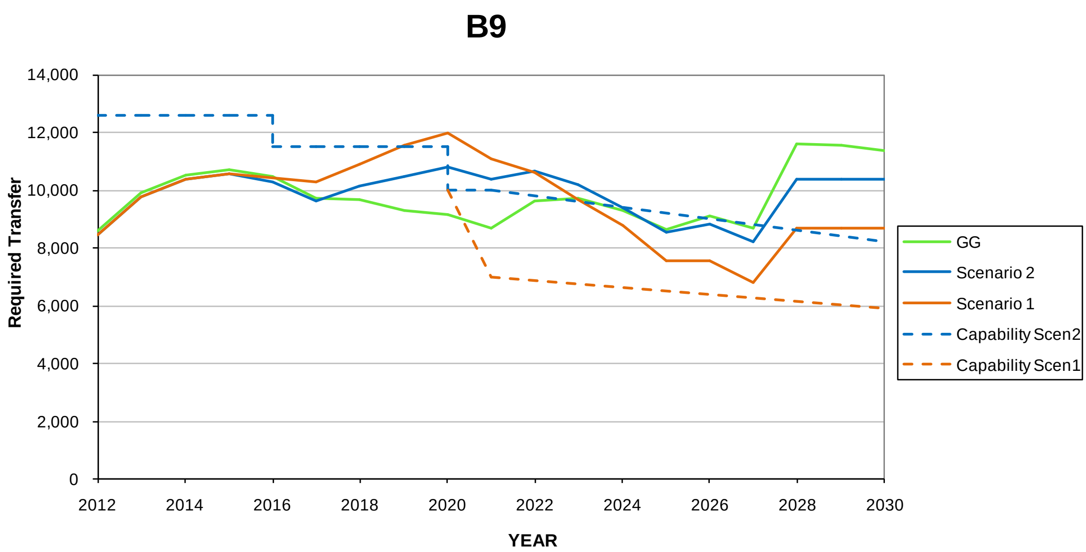


Figure 23: B9 Required Transfer (Gone Green Scenario)

6.2 Boundary Capability – Generation Scenario 2 (2021)

This scenario assumes that the three East Coast projects at Dogger Bank, Hornsea and East Anglia, build up to a total generation capacity of 4GW. It is also assumed that the Western HVDC link (WHVDC) and proposed Eastern HVDC link (EHVDC) are developed as currently proposed (in 2016 and 2019) to facilitate the level of flows experienced from Scotland in this scenario. The results for the DC thermal boundary studies are summarised in Table 7 below:

Table 7: Scenario 2 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	8392	10239	-1847	HARK4-ELVA4-1-GRNA4-HARK4-1	HEDD4B-STWB4B	99%
B7	7311	6614	**697**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	99%
B7a	9627	8858	**769**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	99%
B8	11876	11350	**526**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	99%
B9	10450	15264	-4814	GREN4-STAY4-1-COTT4-GREN4-1	CARR4-DAIN4-1	99%

Results for this scenario show that Boundaries B6 and B9 are compliant; however, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B7 and B7a boundaries have shortfalls of 697MW and 769MW respectively, both limited by the N-2 contingency of Padiham-Penwortham and Carrington-Pewortham circuits which overloads the Birkenhead-Lister Drive circuit which is part of the Mersey Ring 275kV circuits.

B8 has a shortfall of 526MW and is limited by the overload of Keadby to WestBurton circuit due to the double circuit outage of Cottam to Keadby circuits.

6.3 Boundary Capability – Generation Scenario 2 (2030)

This scenario assumes that the three East Coast projects build up to a total generation capacity of 10GW. Similar to the 2021 case, the Western HVDC link (WHVDC) and proposed Eastern HVDC link (EHVDC) are assumed to be developed as currently planned in 2016 and 2019 respectively. The results for the DC thermal boundary studies are summarised in Table 8 below;

Table 8: Scenario 2 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	11526	10202	**1324**	HARK4-ELVA4-1-GRNA4-HARK4-1	HEDD4B-STWB4B	99%
B7	10456	7469	**2987**	GRNA4-HARK4-1-HEDD4A-STWB4A	HARK4-ELVA4-1	95%
B7a	11021	8033	**2988**	GRNA4-HARK4-1-HEDD4A-STWB4A	HARK4-ELVA4-1	95%
B8	12652	9830	**2822**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	91%
B9	10669	11848	-1179	FECK4-IRON4-1-BISW2-FECK2-1	PELH4-RYEH4A-2	97%

Results for this scenario show that Boundary B9 is compliant; however, B6, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B6 has a shortfall of 1.3GW and is limited by the double circuit outage of Harker-Elvanfoot and Harker-Grenta circuits which overloads the Stella West-Eccles circuit.

B7 and B7a boundaries both have a shortfall of about 2.9GW, both limited by the N-2 contingency of Harker–Grenta and Stella West-Eccles circuits which overloads the Harker–Elvanfoot circuits.

B8 has a shortfall of 2.8GW and is limited by the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

6.4 Boundary Capability – Scenario 1 (2021)

The total East Coast generation under this scenario is 11.4 GW. This consists of Dogger Bank (6GW), Hornsea (3GW) and East Anglia (2.4GW). The East Coast generations are at about 66.3% anticipated full generation capacity. The background includes the proposed Western HVDC and Eastern HVDC 1 links connecting in 2016 and 2019 respectively which will provide capability across B6, B7 and B7a. The results in Table 9 below show that there is need for boundary reinforcement across B7, B7a and B8 boundaries.

Table 9: Scenario 1 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	**7,795**	8995	-1199	HARK4-HUTT4-1-HARK4-HUTT4-2	NORT4-OSBA4-1	102%
B7	**9,471**	8429	**1043**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	100%
B7a	**11,760**	10726	**1035**	PADI4-PEWO4-1-CARR4-PEWO4-1	BIRK2 - LISD2A-1	100%
B8	**13,198**	9639	**3559**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	105%
B9	**10,665**	15059	-4394	GREN4-STAY4-1-COTT4-GREN4-1	CARR4-DAIN4-1	100%

Results for this scenario show that Boundary B6 and B9 are compliant; however, B7, B7a and B8 are not compliant and will require Boundary reinforcement to achieve compliance;

B7 and B7a boundaries have a shortfall of about 1GW. They are both limited by the N-2 contingency of Padiham-Penwortham and Carrington-Pewortham circuits which overloads the Birkenhead-Lister Drive circuit which is part of the Mersey Ring 275kV circuits.

B8 boundary has a shortfall of 2.2GW where the limiting contingency on East Coast is the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

6.5 Boundary Capability – Scenarios 1 (2030)

The total East Coast generation under Scenario 1 is 17.2GW. The background includes the proposed Western HVDC and Eastern HVDC 1 links as connecting in 2016 and 2019 respectively to provide capability across B6, B7 and B7a. The results in Table 10 below show that there is need for boundary reinforcement across all the relevant boundaries.

Table 10: Scenario 1 DC Thermal Boundary Result (Gone Green)

Boundary	Required Transfer (MW)	Boundary Capability (MW)	Short Fall (MW)	Limiting Contingency	Overloaded Element	Loading
B6	**11,644**	9144	**2500**	HARK4-HUTT4-1-HARK4-HUTT4-2	DRAX4-EGGB4-1	105%
B7	**11,860**	8289	**3571**	HEDD4B-STWB4B-HEDD4A-STWB4A	HARK4-ELVA4-1	100%
B7a	**13,117**	8790	**4327**	HEDD4B-STWB4B-HEDD4A-STWB4A	HARK4-ELVA4-1	100%
B8	**13,301**	9975	**3326**	COTT4-KEAD4-2-COTT4-KEAD4-1	KEAD4-WBUR4-1	94%
B9	**9,567**	7481	**2086**	FECK4-MITY4-1-FECK4-WALH4-1	LEGA4 QB3	97%

Results for this scenario show that all Boundaries are not compliant and will require Boundary reinforcement to achieve compliance;

B6 has a shortfall of 2.5GW and is limited by the double circuit outage of Harker-Hutton overhead lines which overloads the Drax-Eggborough circuit.

B7 and B7a boundaries both have a shortfall of about 3.6GW and 4.3GW respectively. They are both limited by the N-2 contingency of Harker–Grenta and Stella West-Eccles circuits which overloads the Harker–Elvanfoot circuits. This shows that for boundary B7 and B7a to be reinforced requires the reinforcement of the Scotland-England border circuit of Harker-Elvanfoot.

B8 has a shortfall of 3.3GW and is limited by the double circuit outage of Cottam to Keadby circuits which overloads the Keadby to West Burton circuit.

B9 has a shortfall of 2GW and is limited by the double circuit outage of Feckenham-Minety and Feckenham-Walham circuits which overloads the QB at Legacy substation.

6.6 Updated Boundary Capability- Scenario 2 (2021 & 2030)

The Scenario 2 assumes a total East Coast generation capacity of 4GW in 2021 building up to 10GW in 2030. The results for DC thermal boundary studies are summarised in table below;

In 2021, B7 is compliant however, for boundaries B7a, B8 and B9, the shortfall is small and can be addressed by a combination of post-fault QB tapping and post-fault reversal of existing HVDC links. For B6, constraint payments might be required to relieve the boundary as the 200MW shortfall does not warrant the delivery a significant reinforcement across this boundary. In 2030 however, the boundary shortfalls increase significantly, indicating increased power flows across all boundaries. In 2030, the boundaries will need to be reinforced to achieve compliance. This can be achieved by onshore reinforcements, Offshore HVDC links, Offshore integration or combinations of these as later presented in the design section.

	2021			**2030**		
Boundary	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**
B6	8300	8100	**200**	11000	8500	**2500**
B7	7300	7800	-500	9800	8000	**1800**
B7a	9600	8800	**800**	11000	8800	**2200**
B8	11900	11300	**600**	12600	10500	**2100**

B9	10400	10000	**400**	10400	8200	**2200**

In process determining the boundary capabilities the initial designs were created. Those designs were later updated to create the final results. The initial designs boundary results are located in the Appendix. The results were updated with ETYS 2013 contingencies.

6.7 Updated Boundary Capability – Scenario 1 (2021 & 2030)

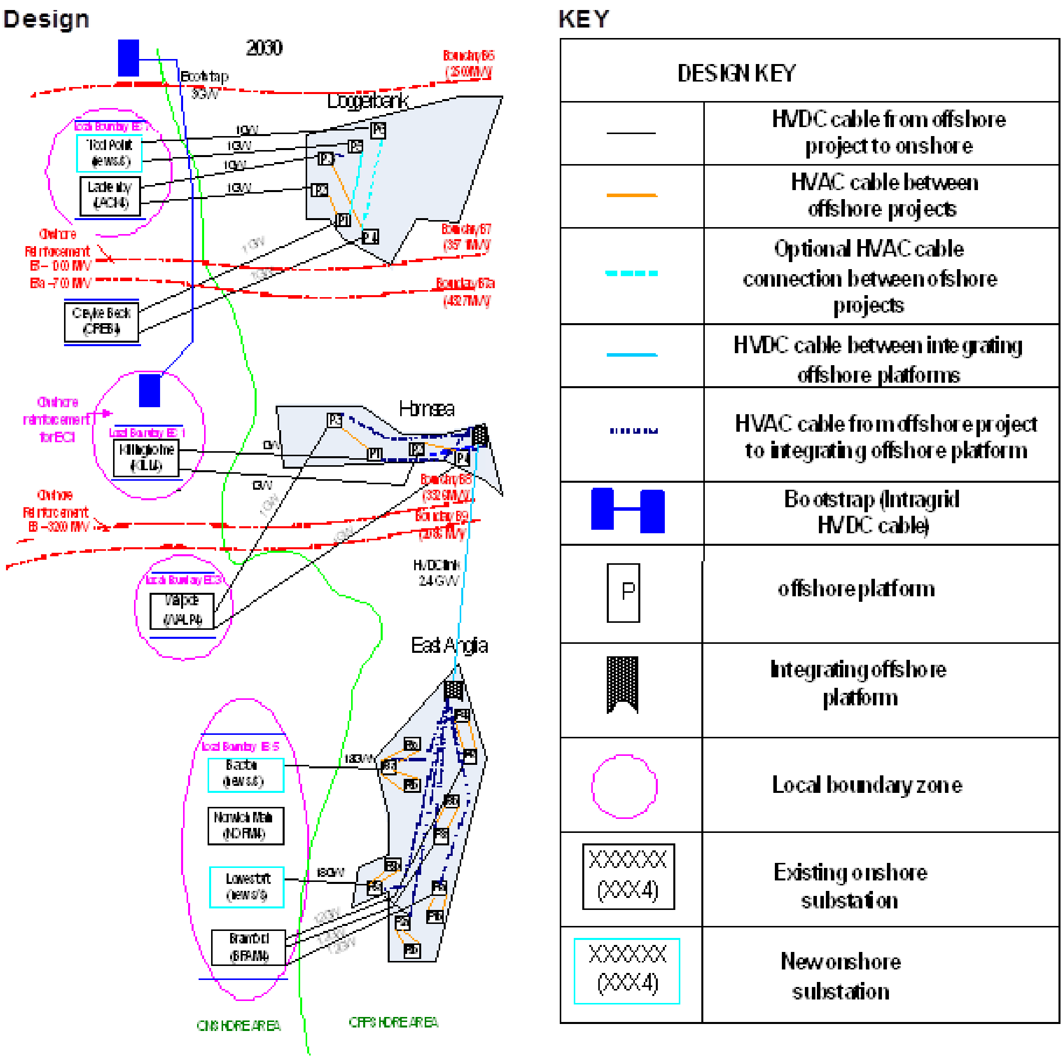
The Scenario 1 assumes a total East Coast generation capacity of 11.4GW in 2021 building up to 17.2GW in 2030. The results for DC thermal boundary studies are summarised in table below;

In 2021, Boundary B6 is complaint however; boundaries B7, B7a, B8 & B9 are all non-compliant and will require reinforcement. In 2030, all boundaries are not compliant and a combination of onshore and offshore reinforcements will be required to make these boundaries compliant as presented in the design section.

	2021			**2030**		
Boundary	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**	**Required Transfer (MW)**	**Boundary Capability (MW)**	**Short Fall (MW)**
B6	7700	8000	-300	10500	8000	**2500**
B7	11200	8800	**2400**	12700	9200	**3500**
B7a	13500	10900	**2600**	12400	9000	**3400**
B8	13700	9900	**3800**	12400	9700	**2700**
B9	11100	7000	**4100**	8700	5900	**2800**

7 Design Template

The picture below presents the design template.



8 Proposed Design Solutions – Updated Boundary Capability

8.1 Scenario 2 (2030)

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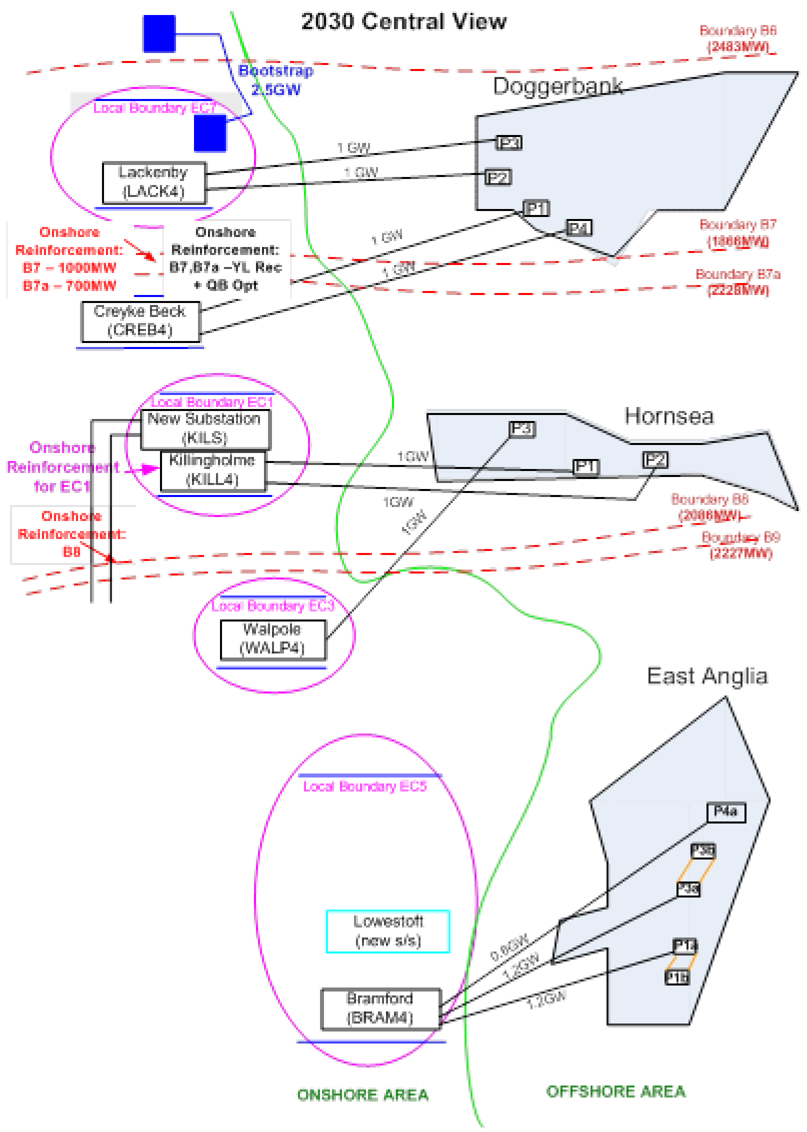
<td>
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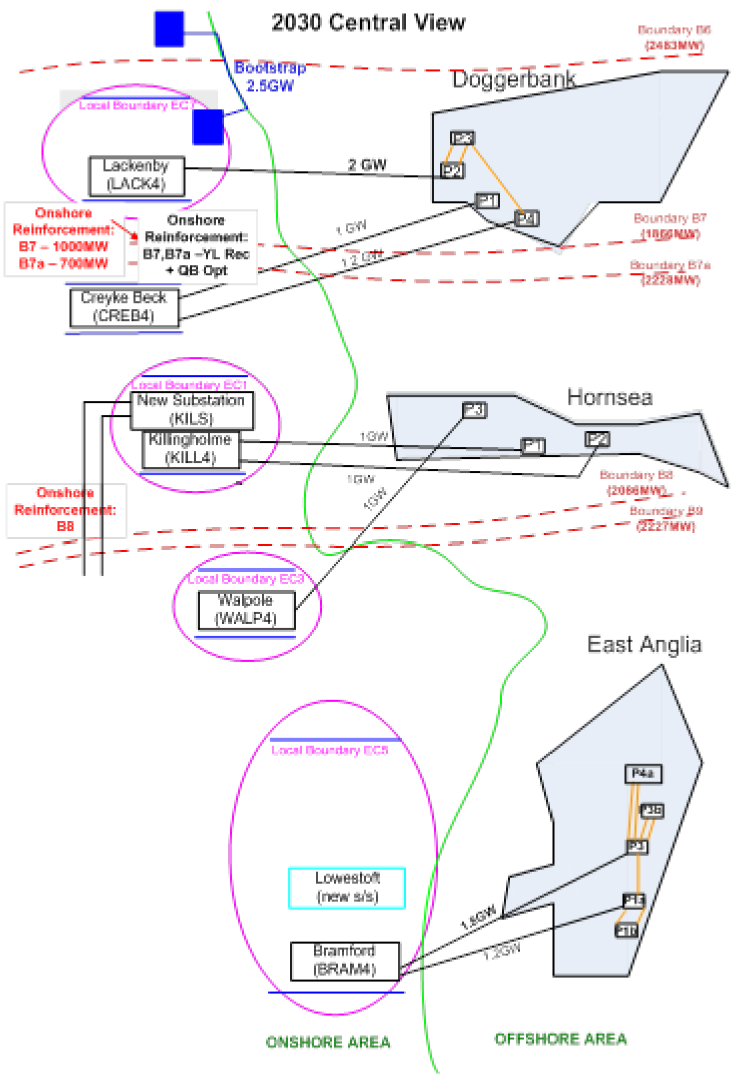
<td>
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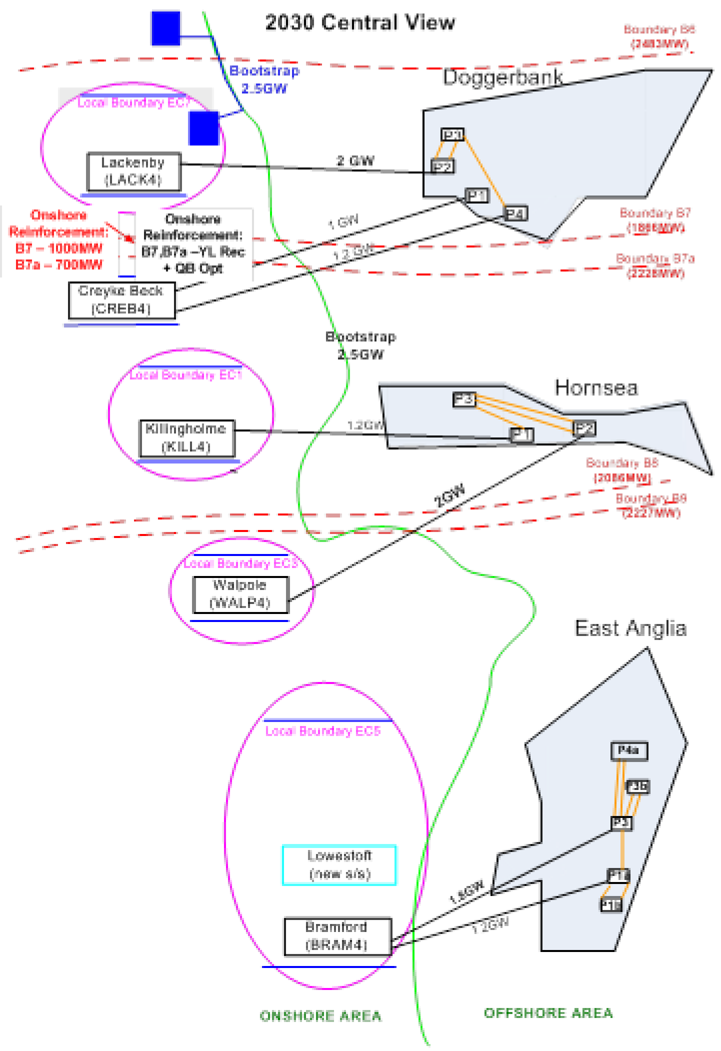
<td>
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Scenario 2 (2030)

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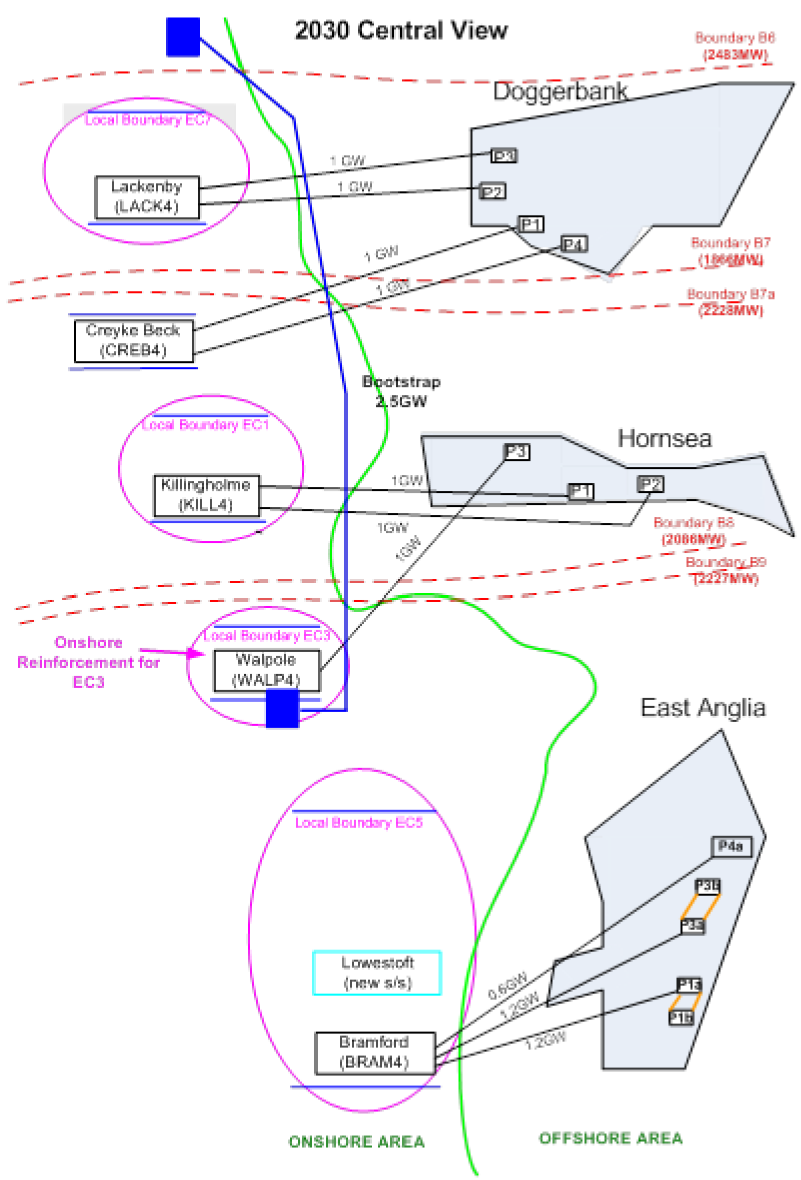
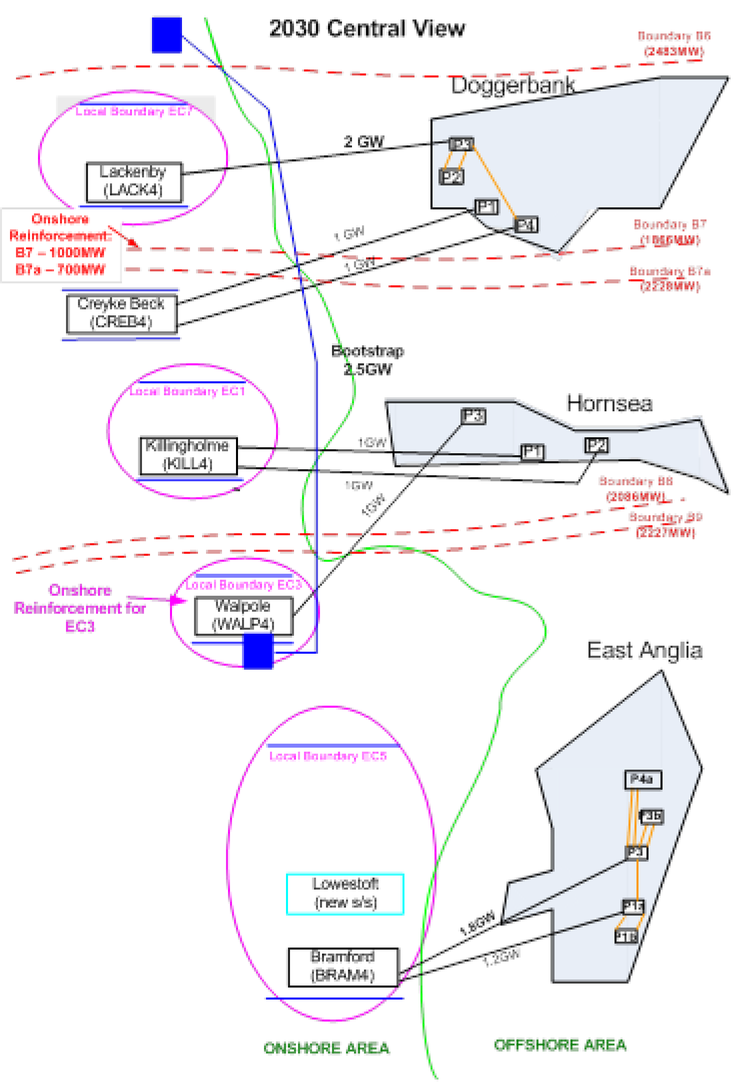
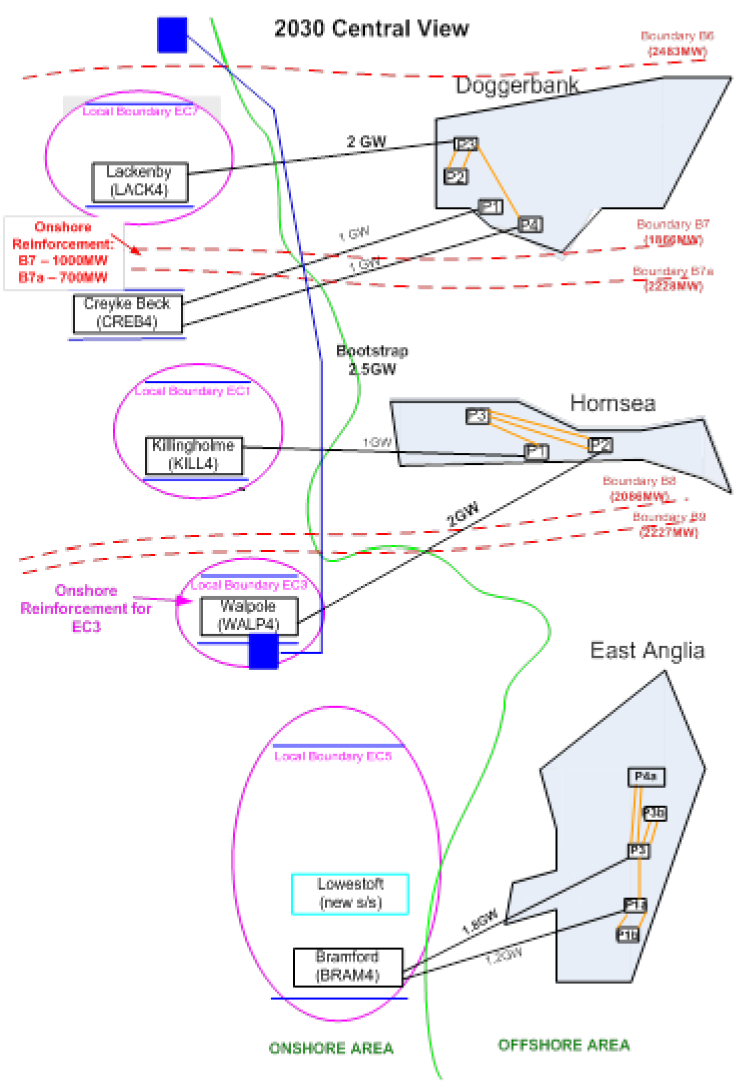
<tr><td>
</td><td>
</td><td>
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Scenario 2 (2030)

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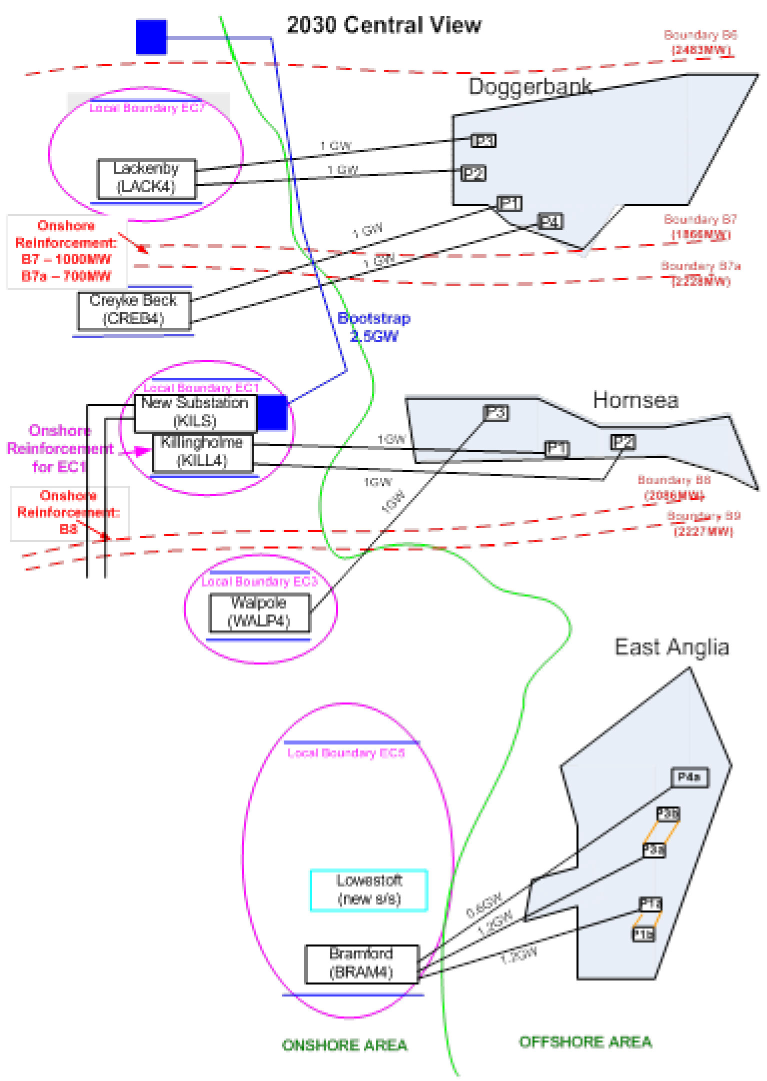
<tr><td>
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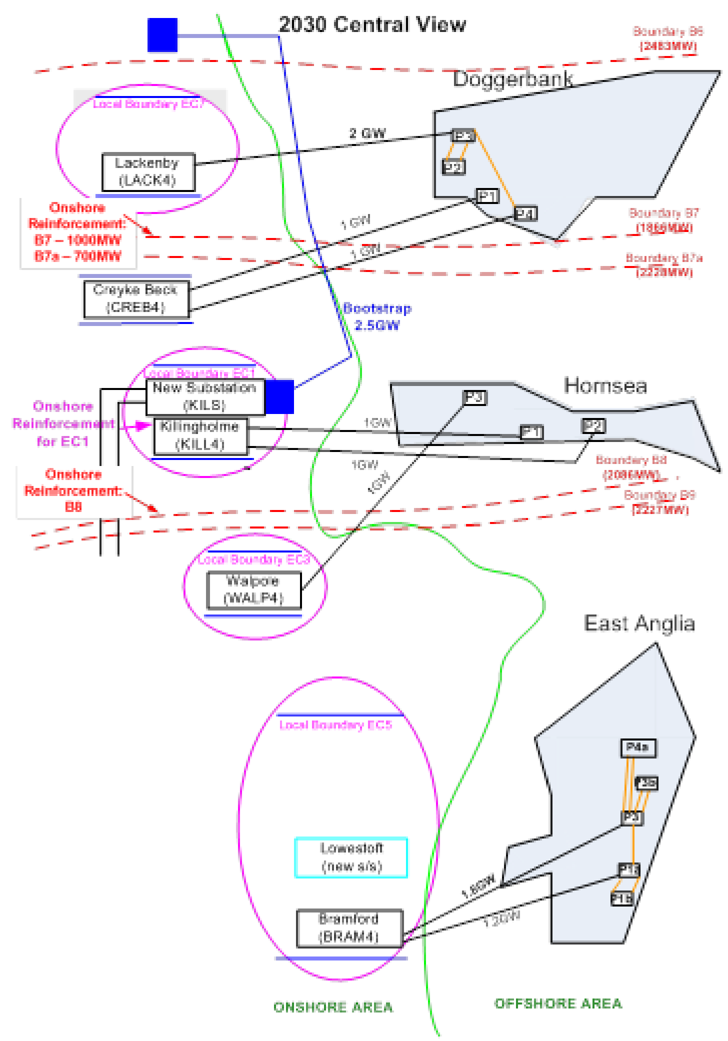
<td>
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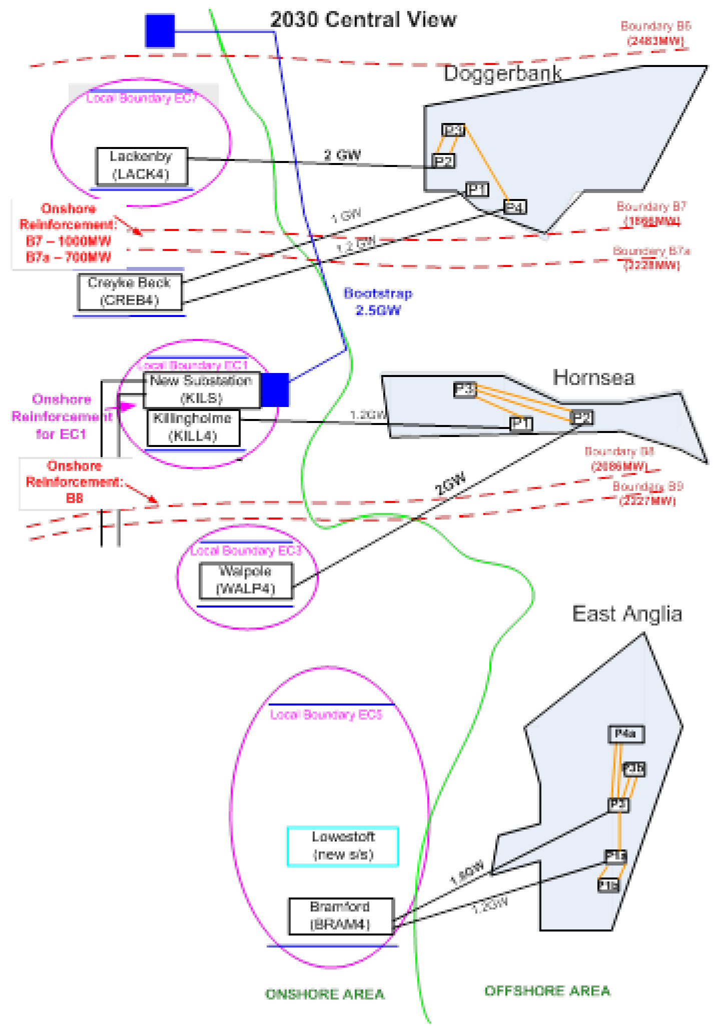
<td>
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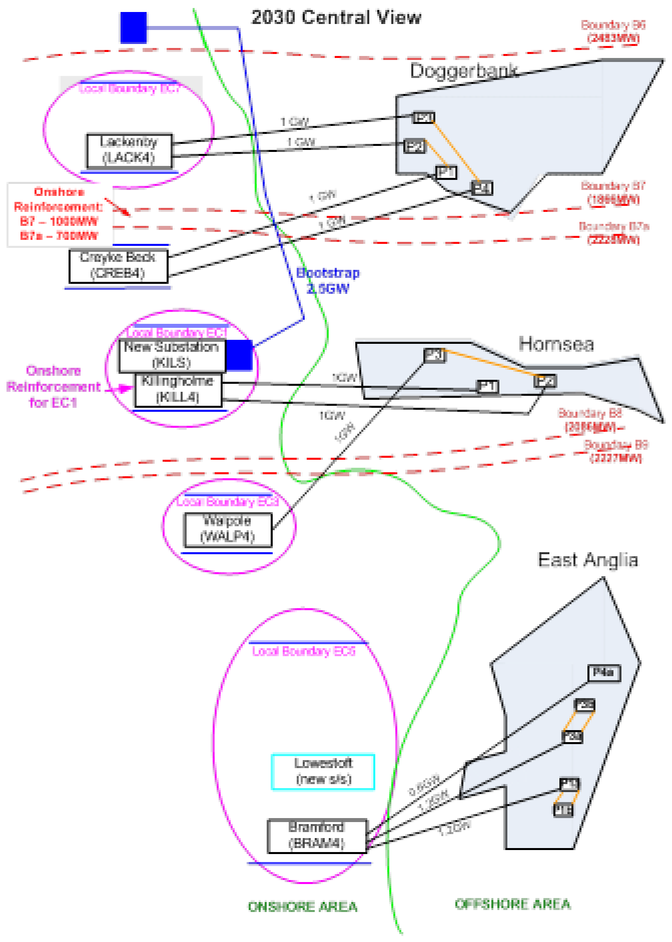
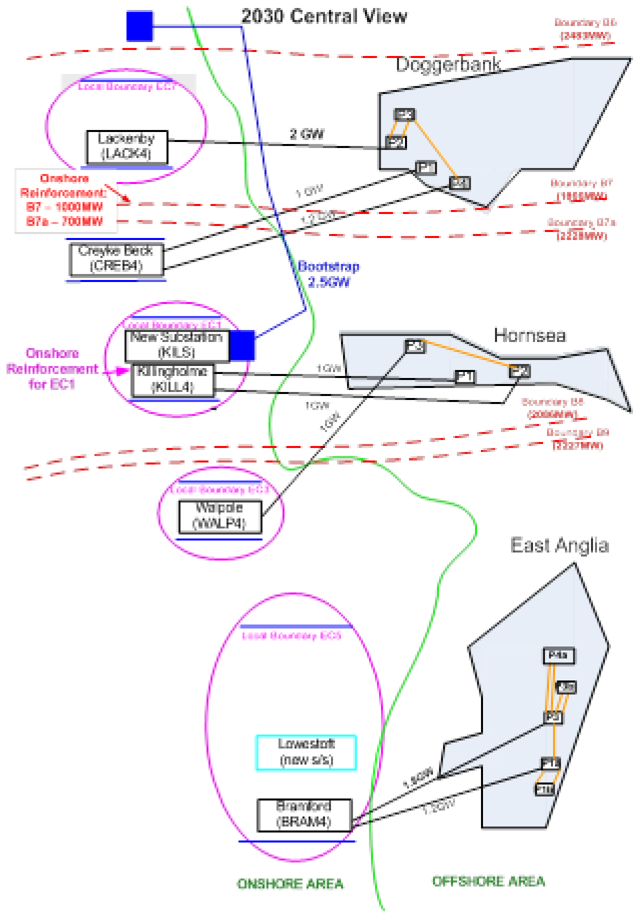
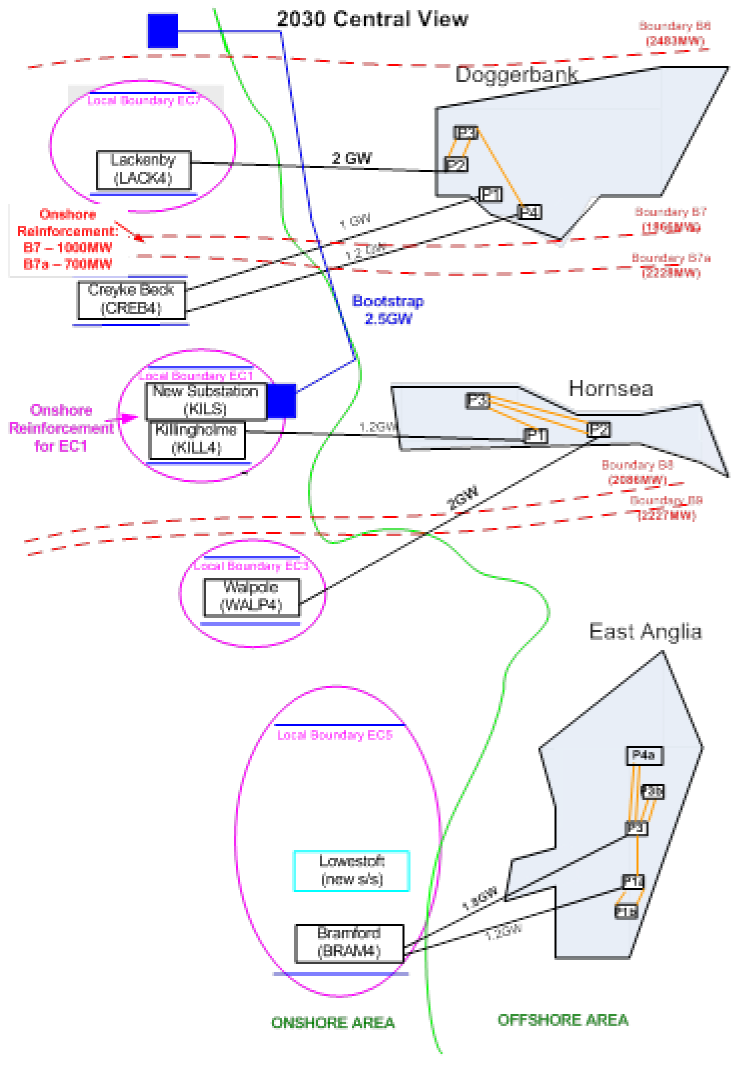
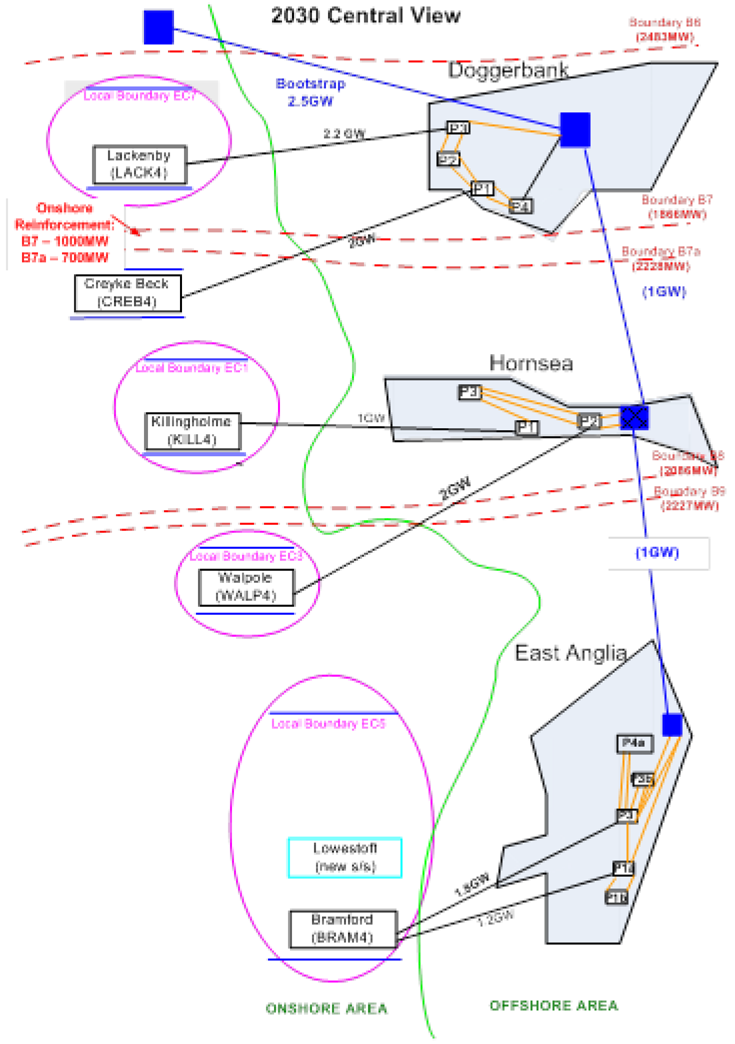
Scenario 2 (2030)

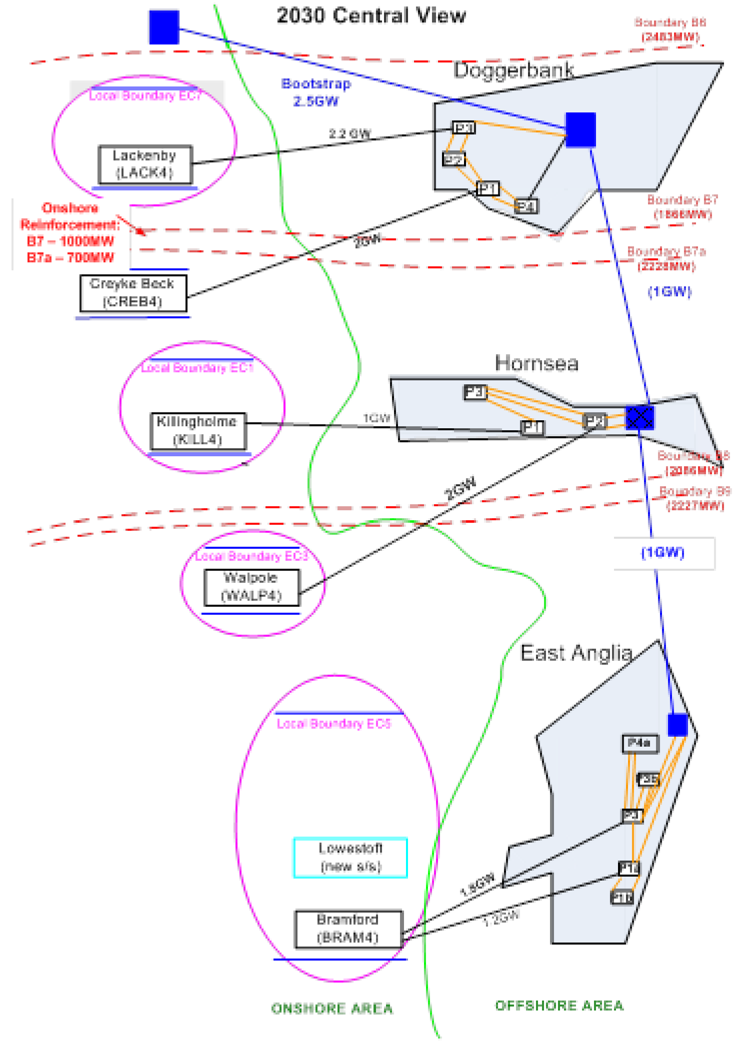
4A Hybrid Off 1GW	**4B Hybrid OFF 2GW**	**4C Hybrid OFF 2GW Opt**
		

Scenario 2 (2030)

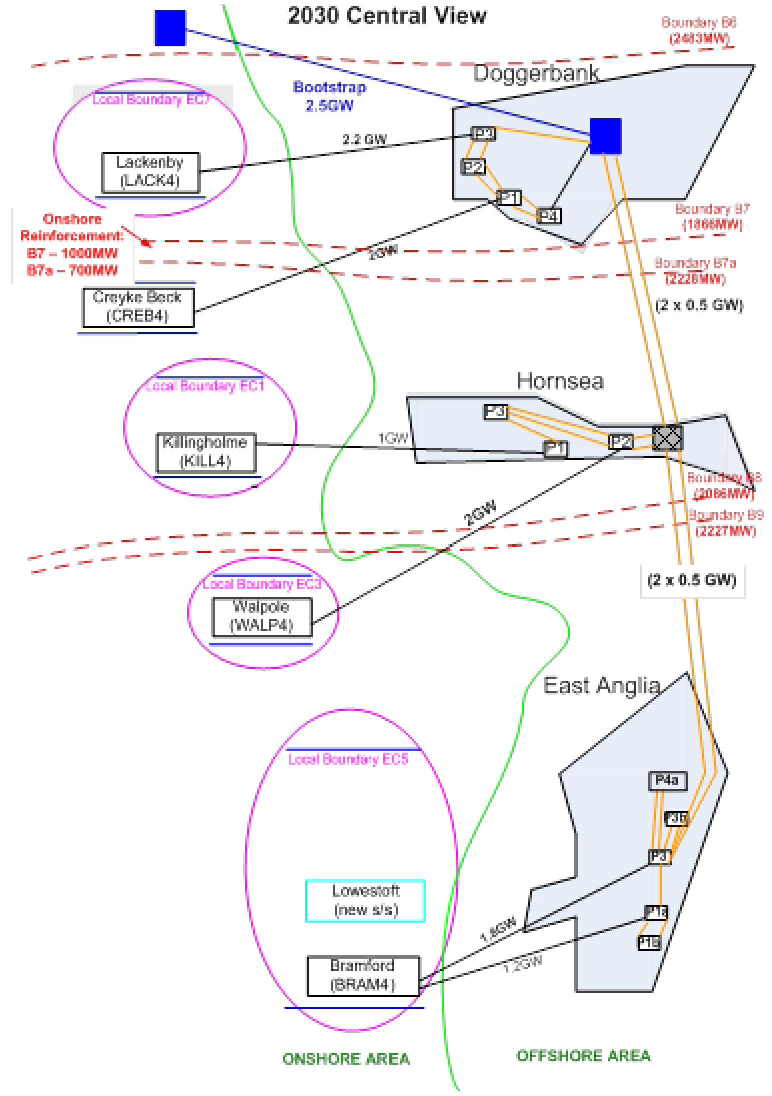
5A – Offshore 2GW HVDC



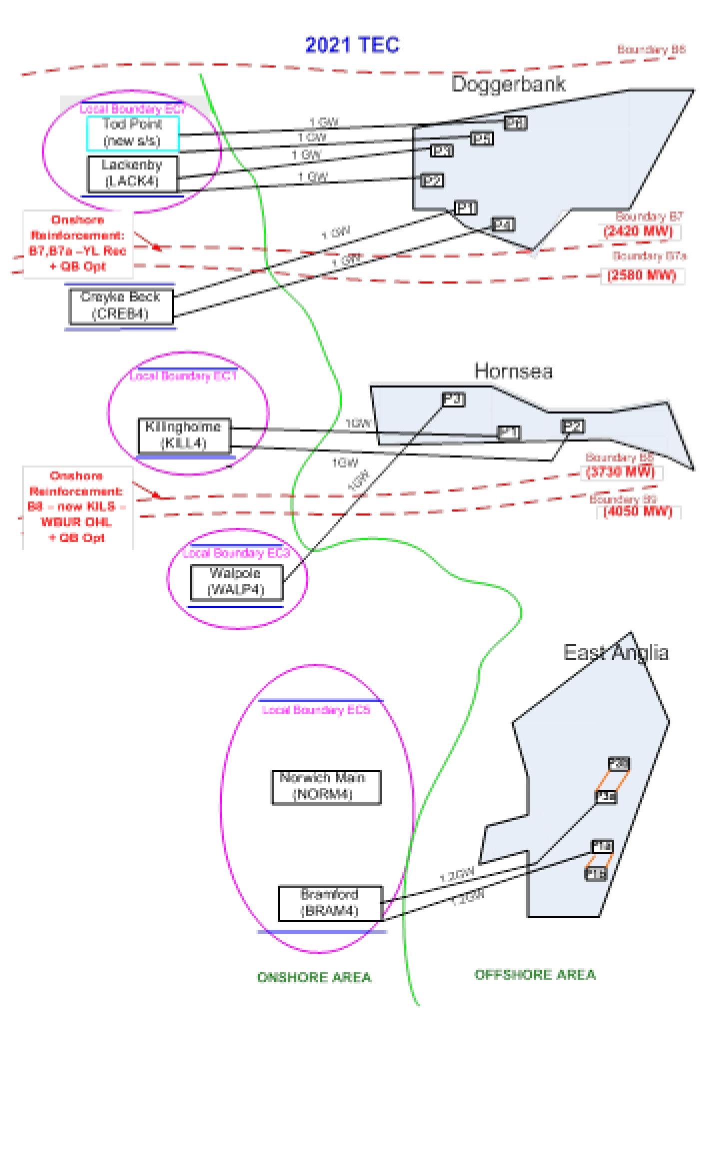
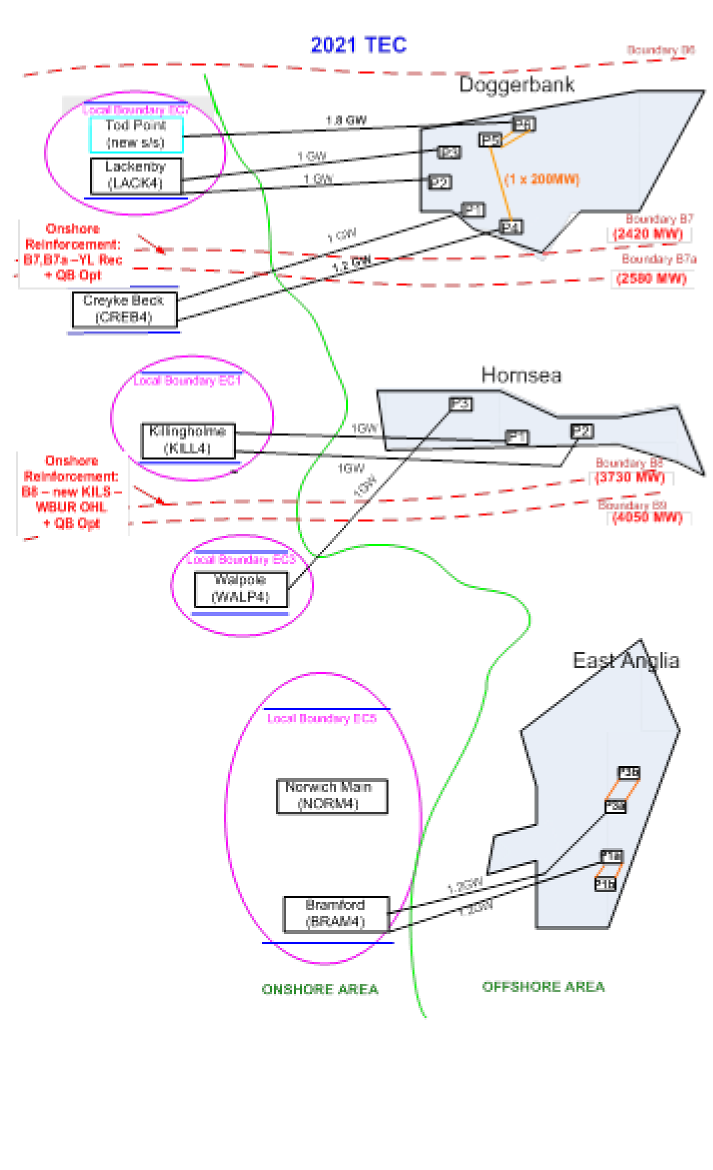
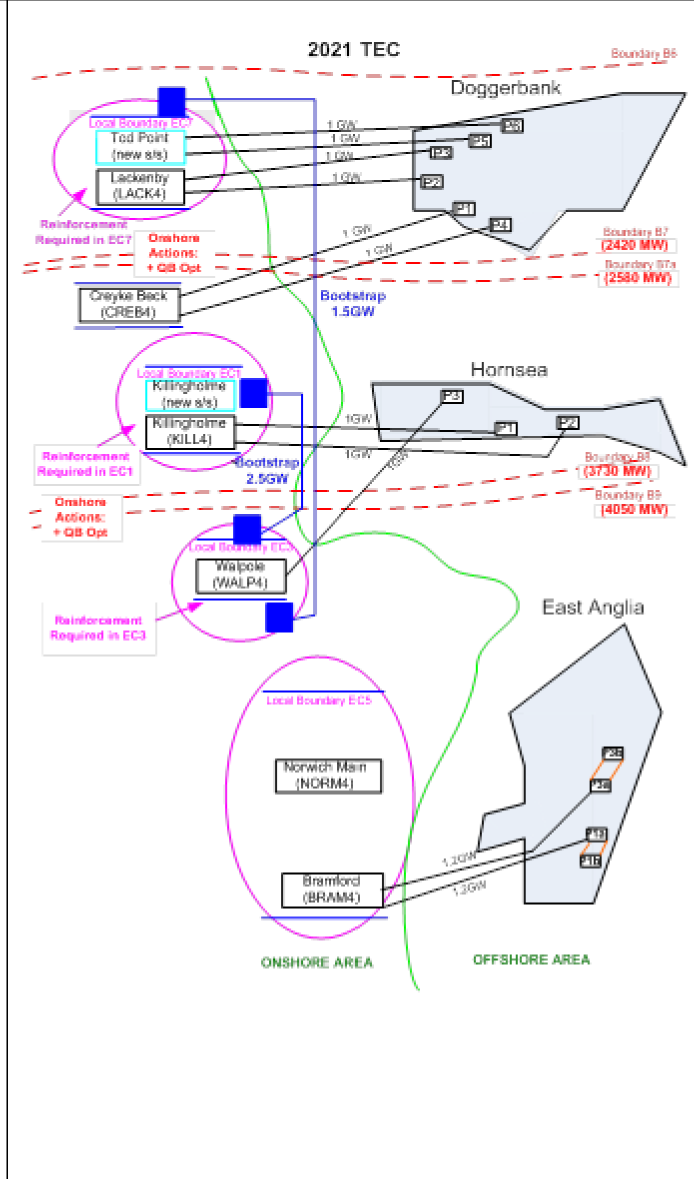
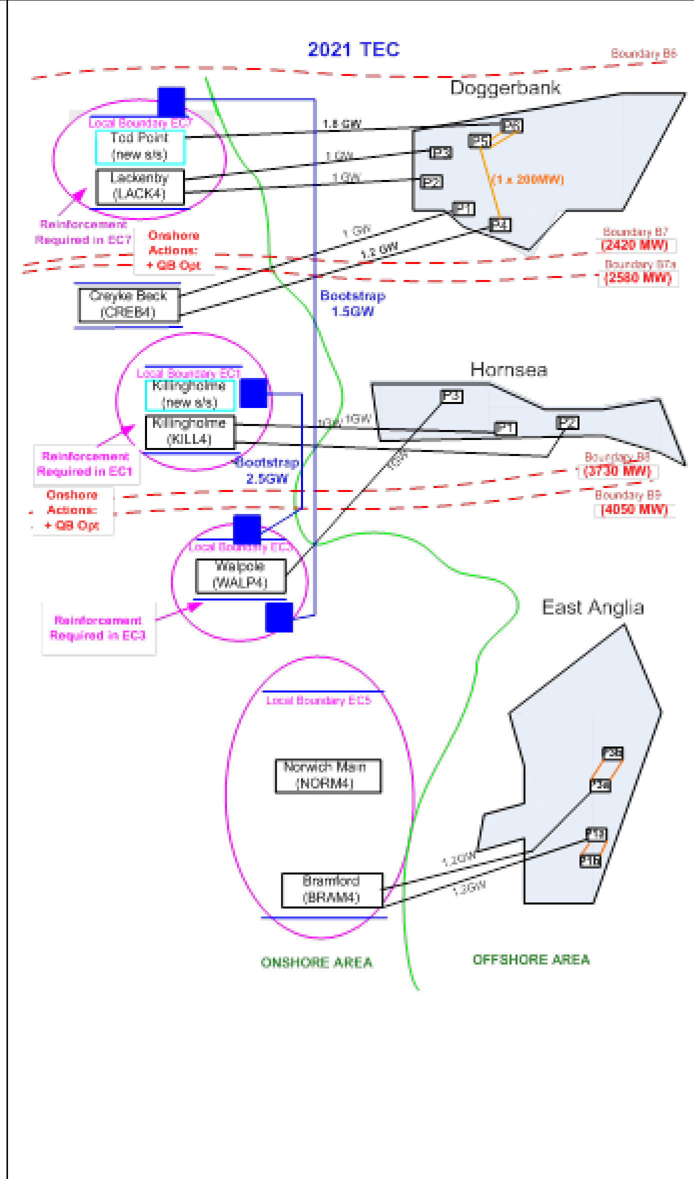
5B – Offshore 2GW HVDC



5C – Offshore 2GW HVAC

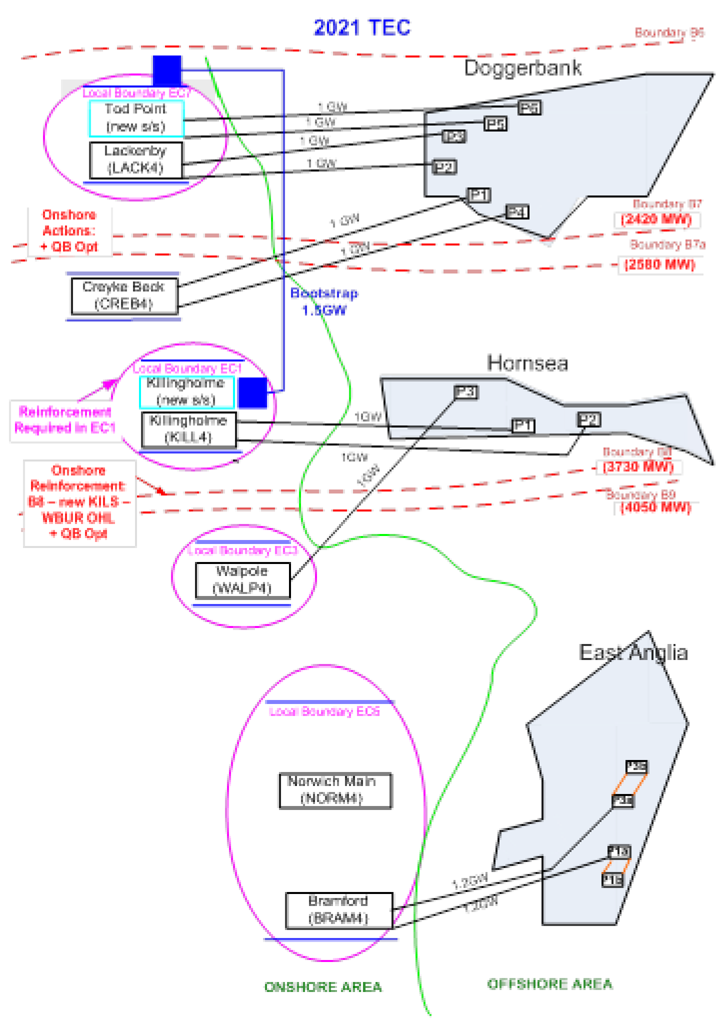


8.2 Scenario 1 (2021)

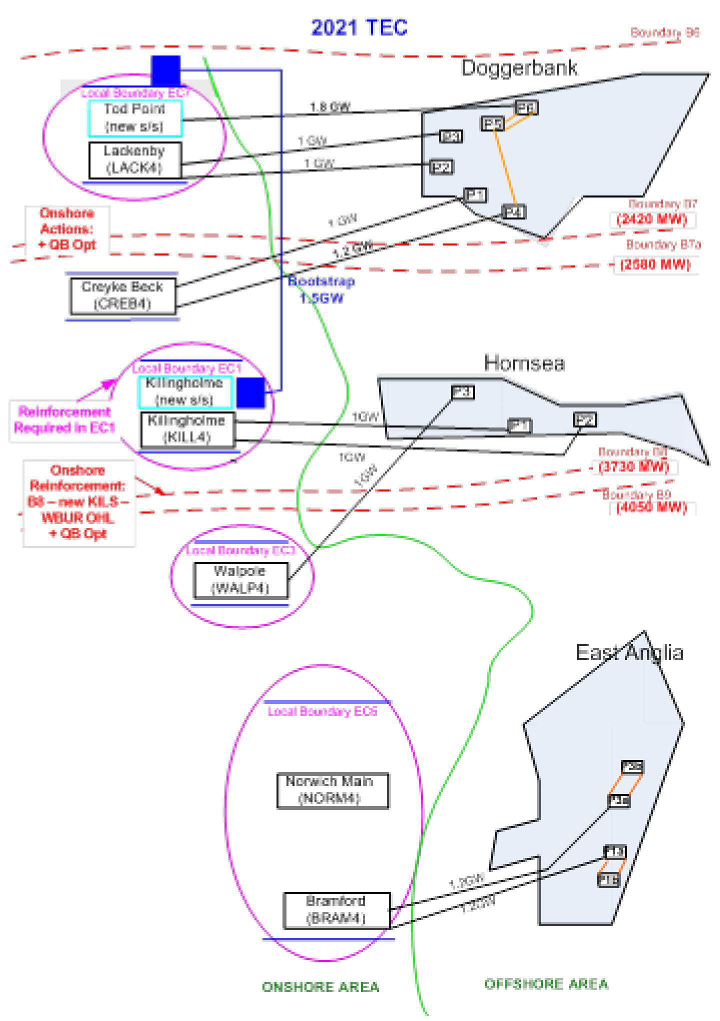
6A- Onshore Design Option 1GW	6B - Onshore Design Option 1.8GW	7A - Bootstrap Design 1GW	7B - Bootstrap Design 1.8GW
			

Scenario 1 (2021)

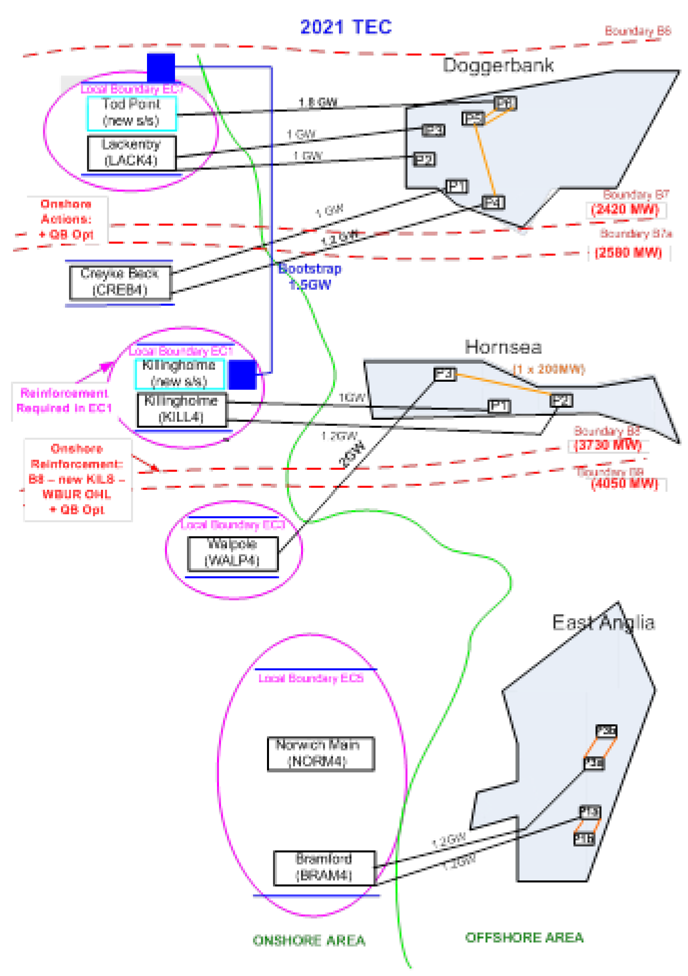
8A – Hybrid Onshore & Bootstrap 1GW



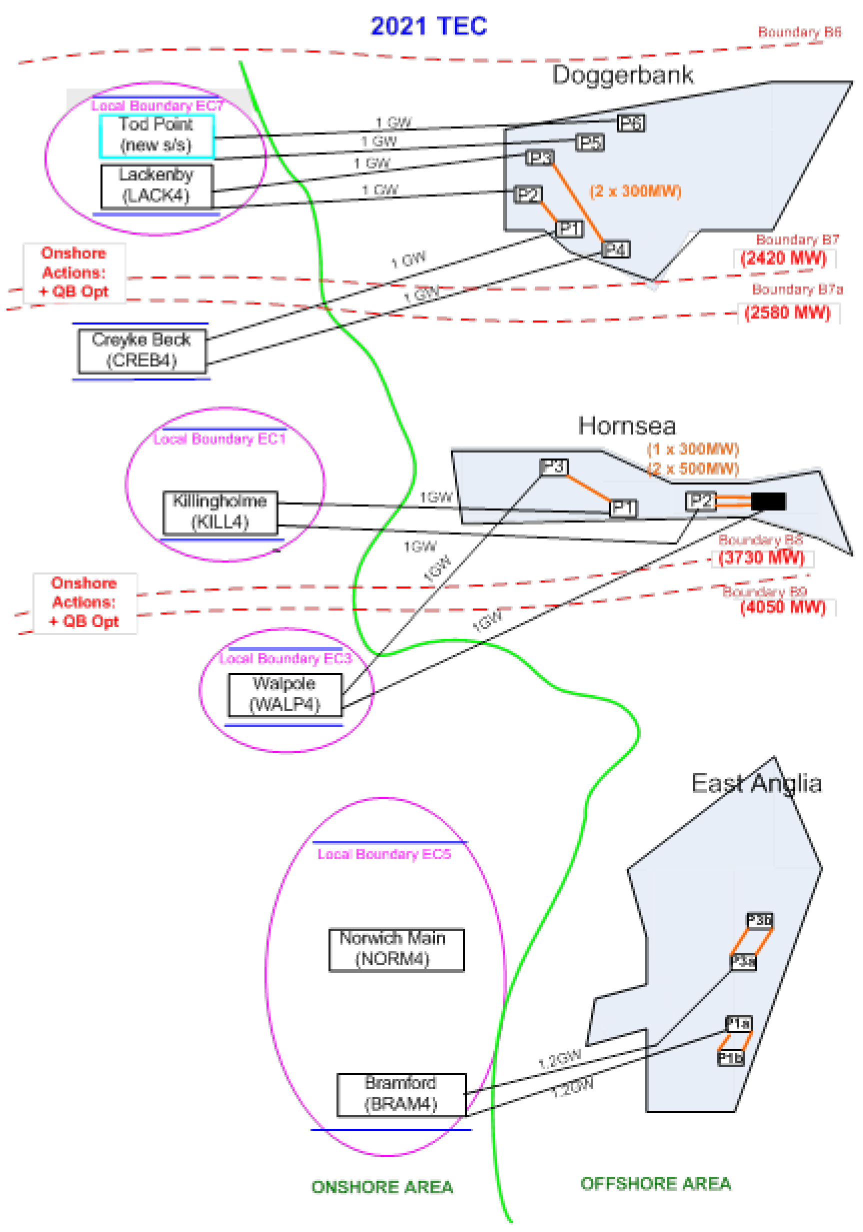
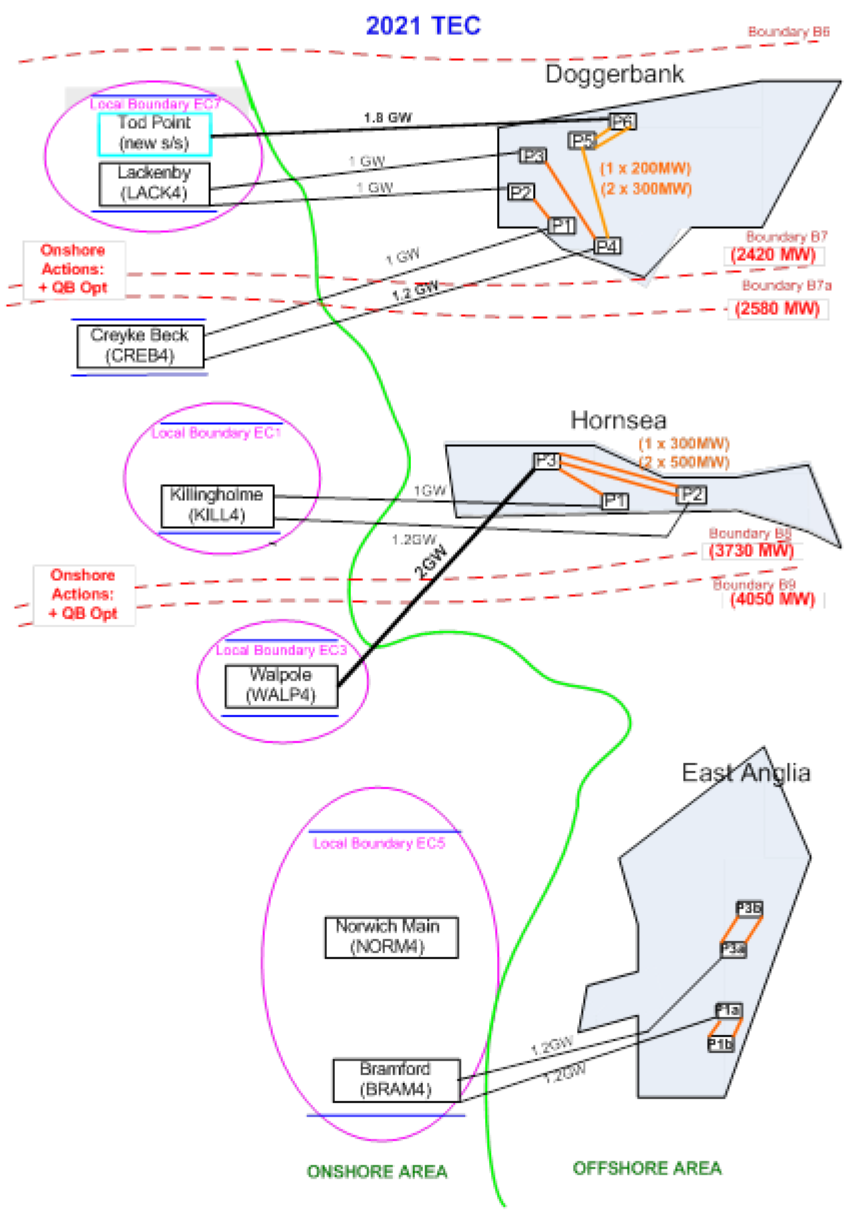
8B – Hybrid Onshore & Bootstrap 1.8GW



8C – Hybrid Onshore & Bootstrap Oversized 2GW



Scenario 1 (2021)

9A – Offshore 1GW	9B – Offshore 2GW
	

8.3 *Scenario 1 (2030)*

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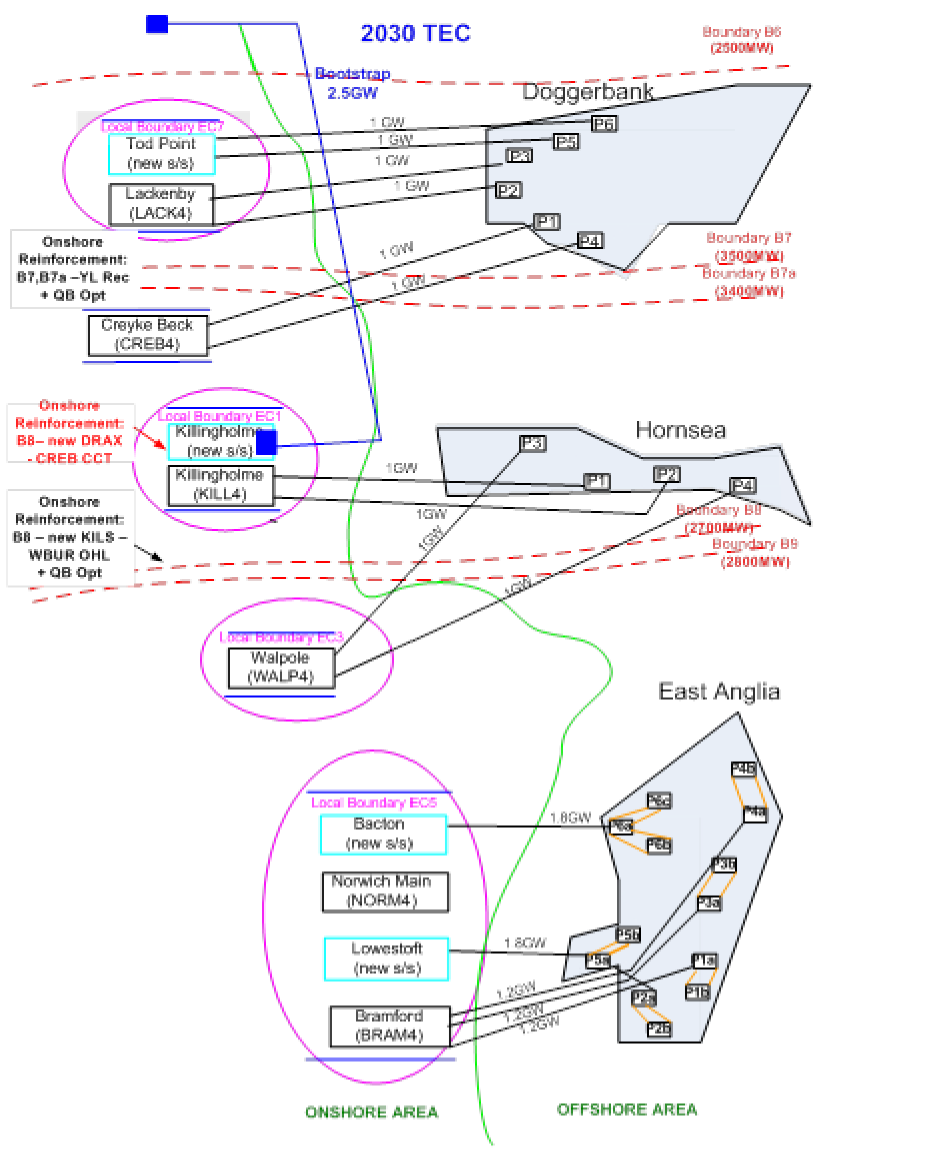
<tr><td>
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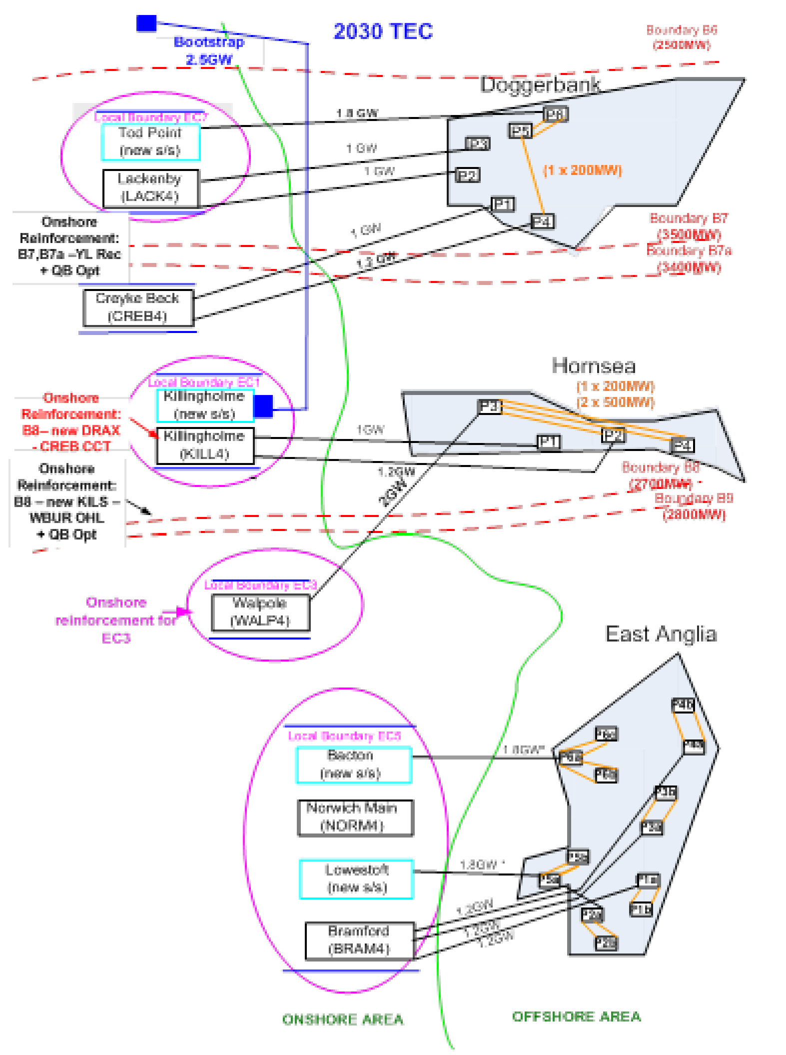
<td>
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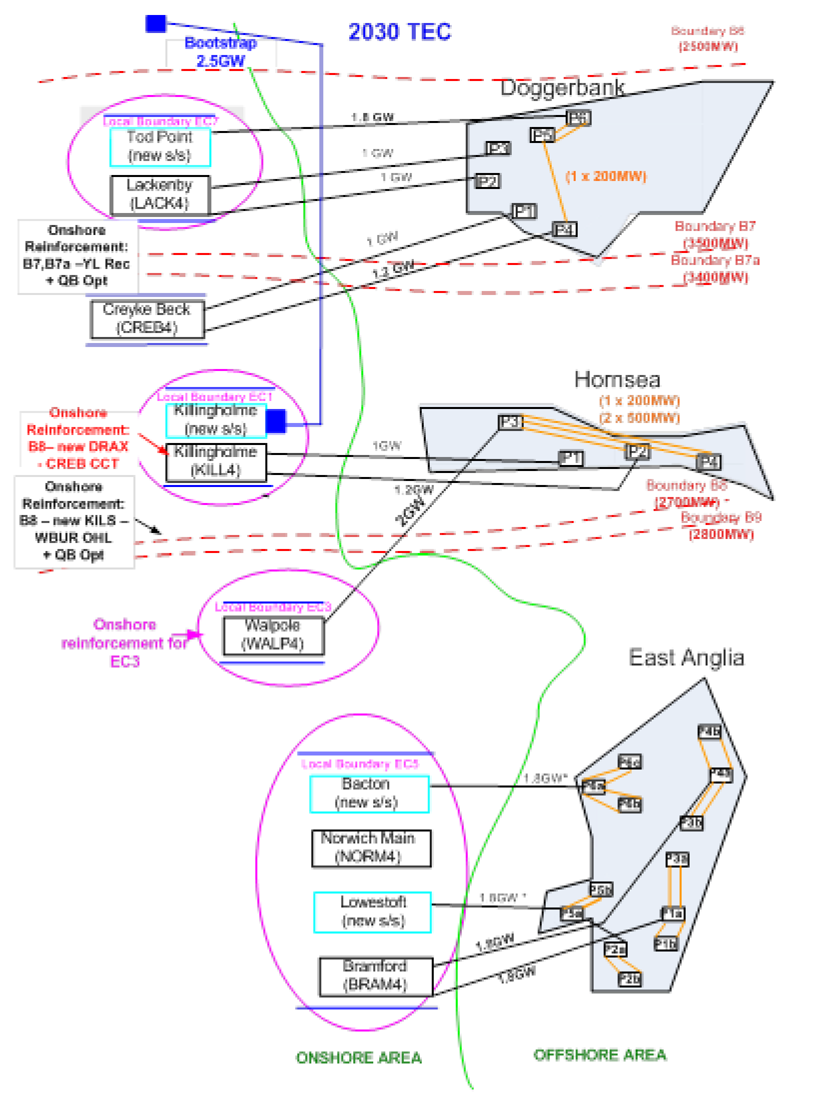
<td>
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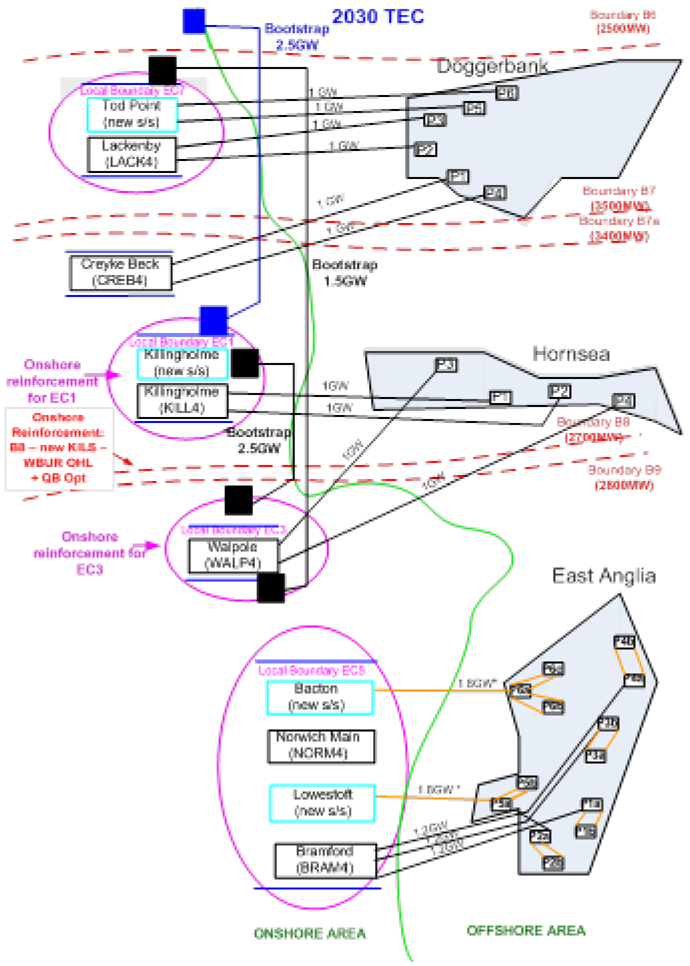
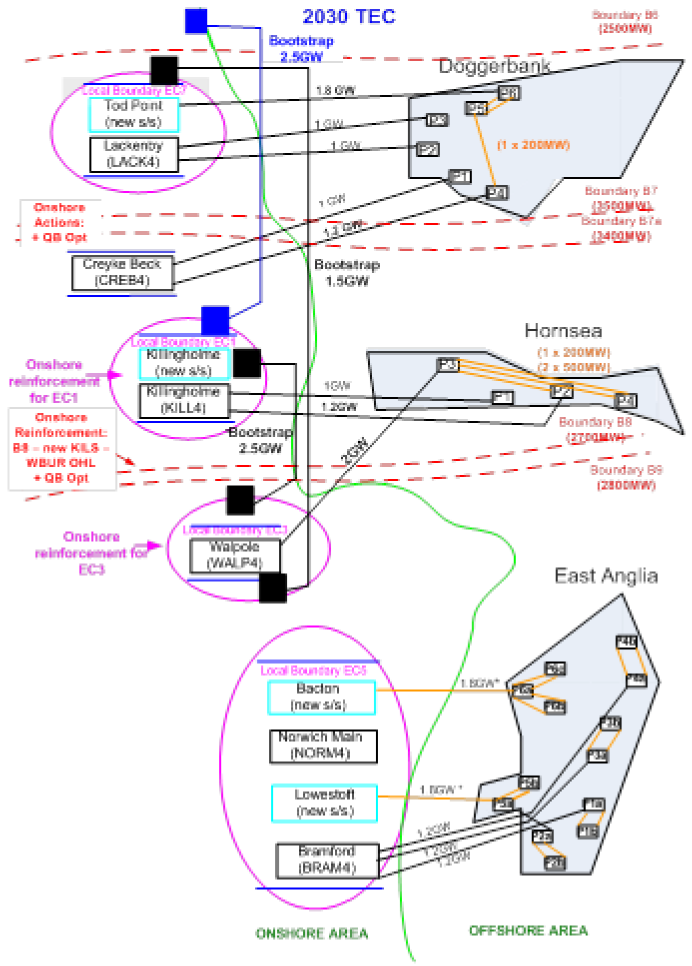
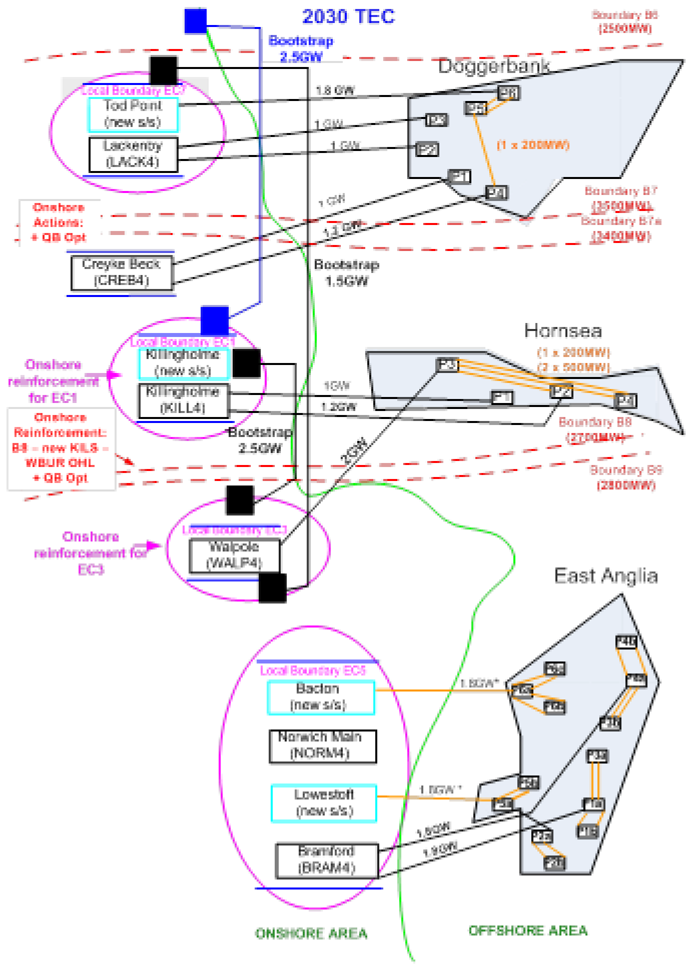
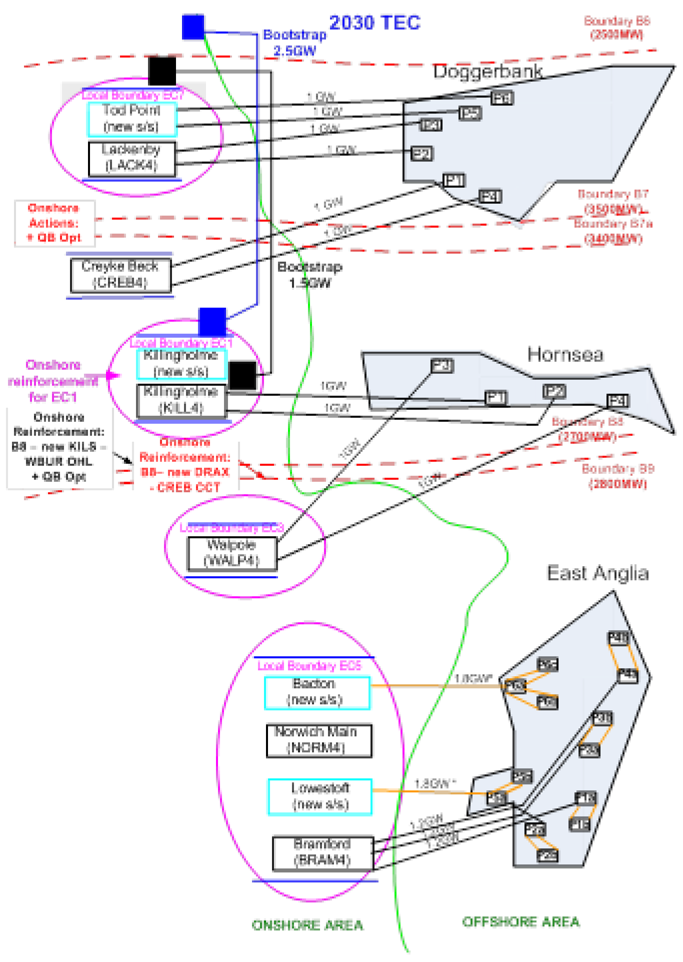
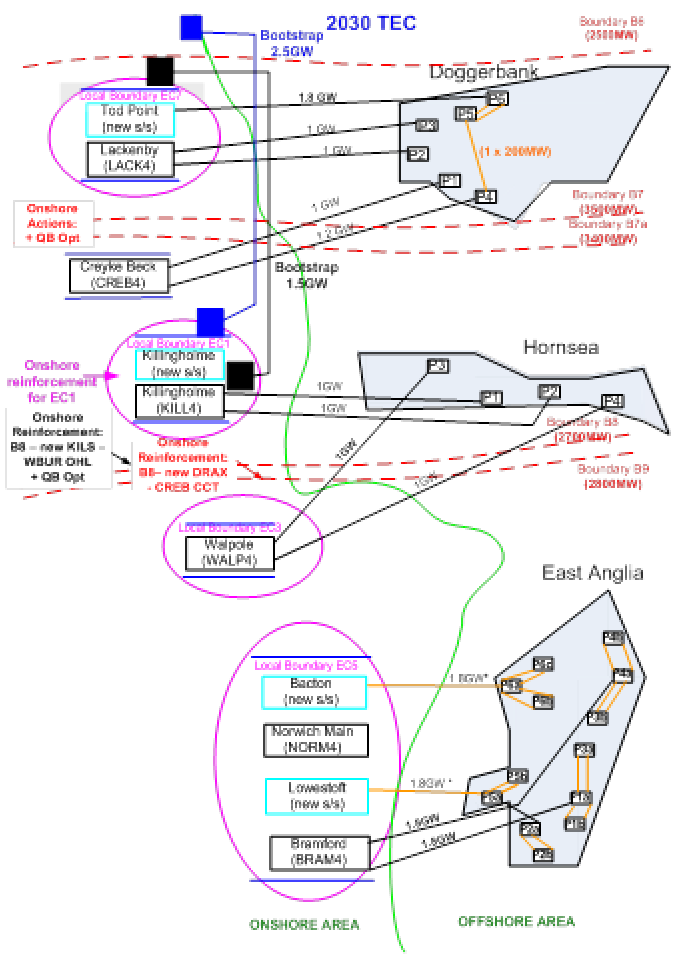
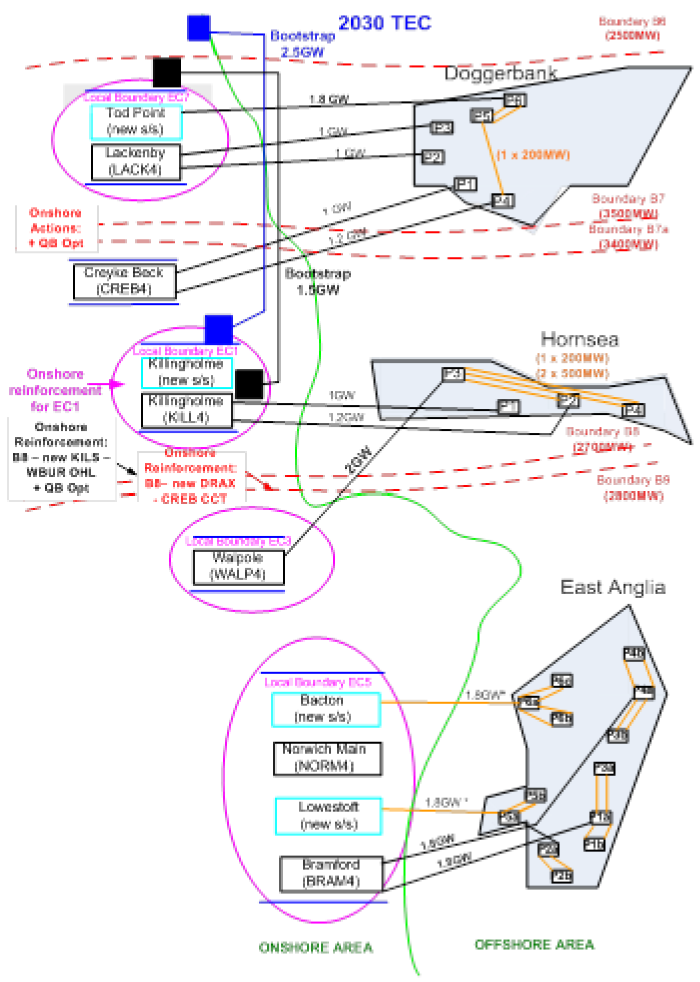
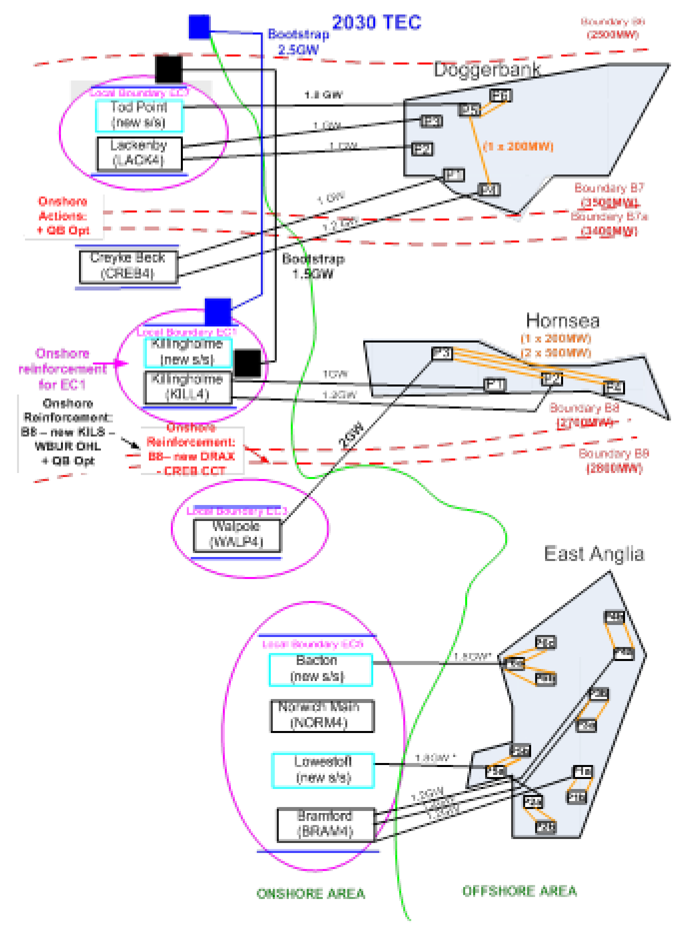
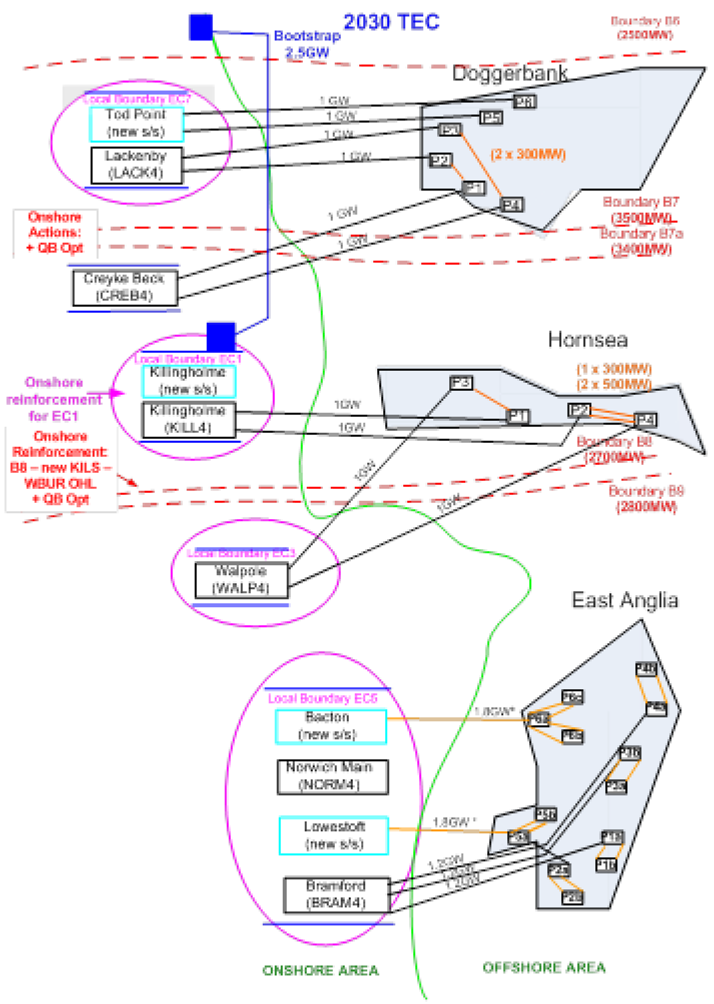
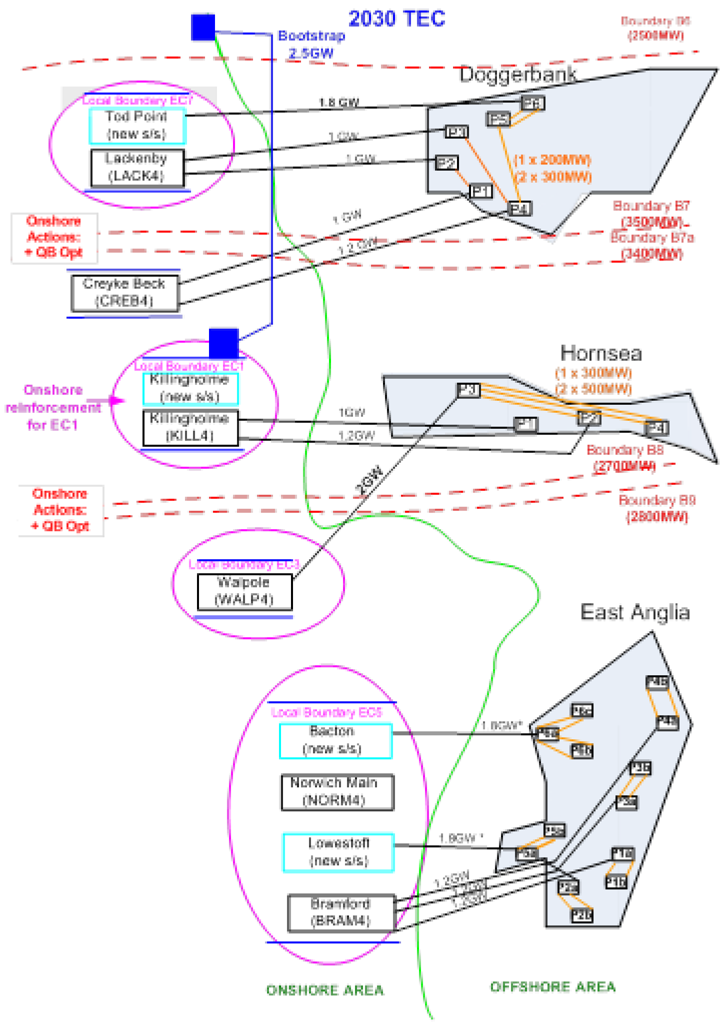
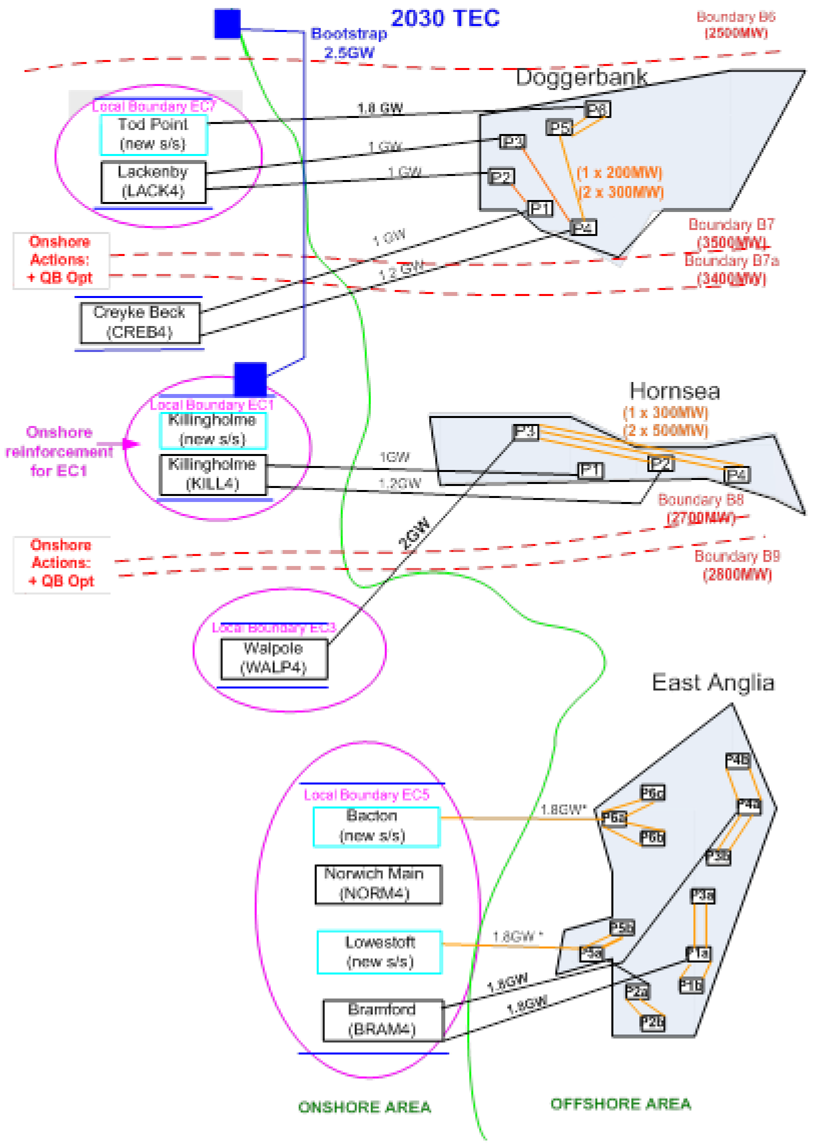
Scenario 1 (2030)

11A - Bootstrap Design 1GW	**11B - Bootstrap Design 2GW**	**11C - Bootstrap Design 2GW**
		

Scenario 1 (2030)

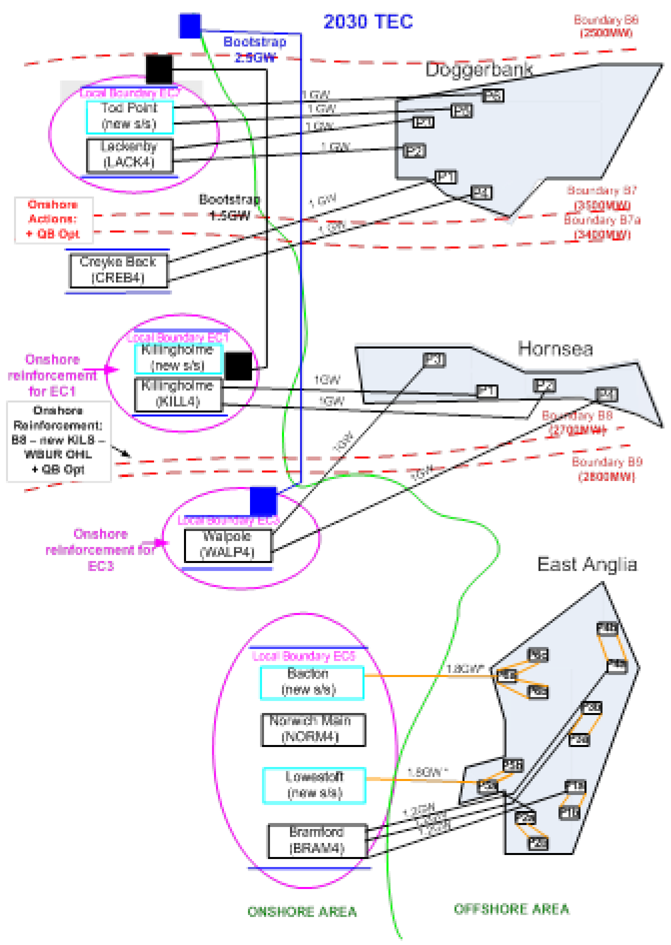
12A – Hybrid Onshore & Bootstrap 1GW	12B – Hybrid Onshore & Bootstrap 1.8GW	12C – Hybrid Onshore & Bootstrap 2GW	12D – Hybrid Onshore & Bootstrap 2GW
			

Scenario 1 (2030)

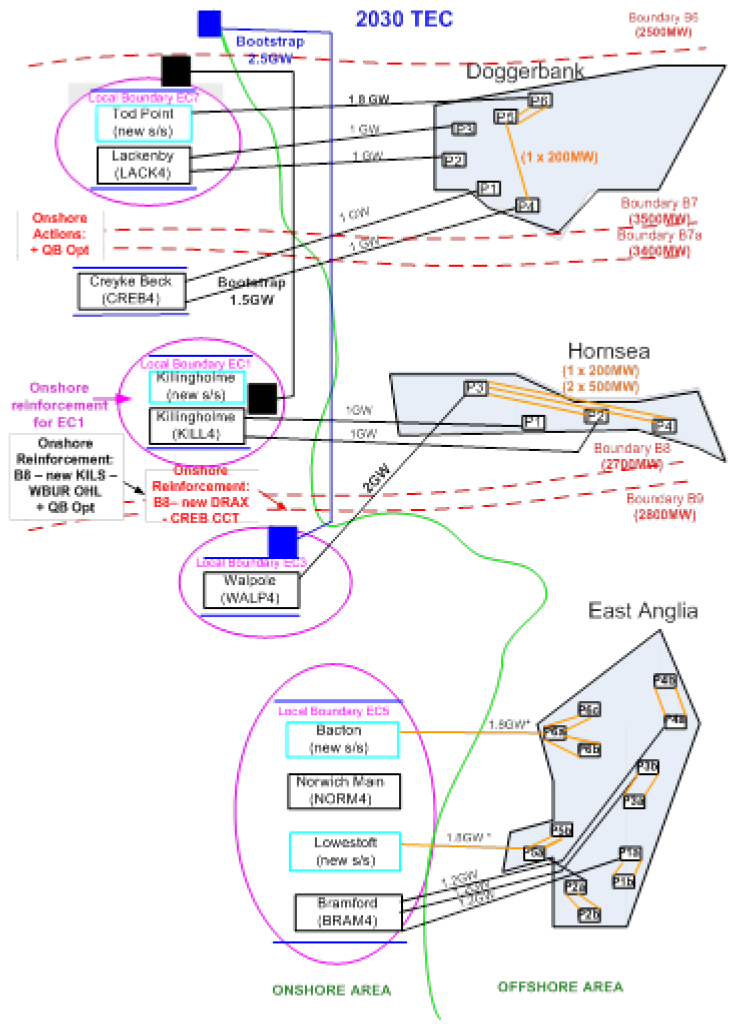
13A – Hybrid Offshore & Bootstrap 1GW	13B– Hybrid Offshore & Bootstrap 2GW	13C– Hybrid Offshore & Bootstrap 2GW
		

Scenario 1 (2030)

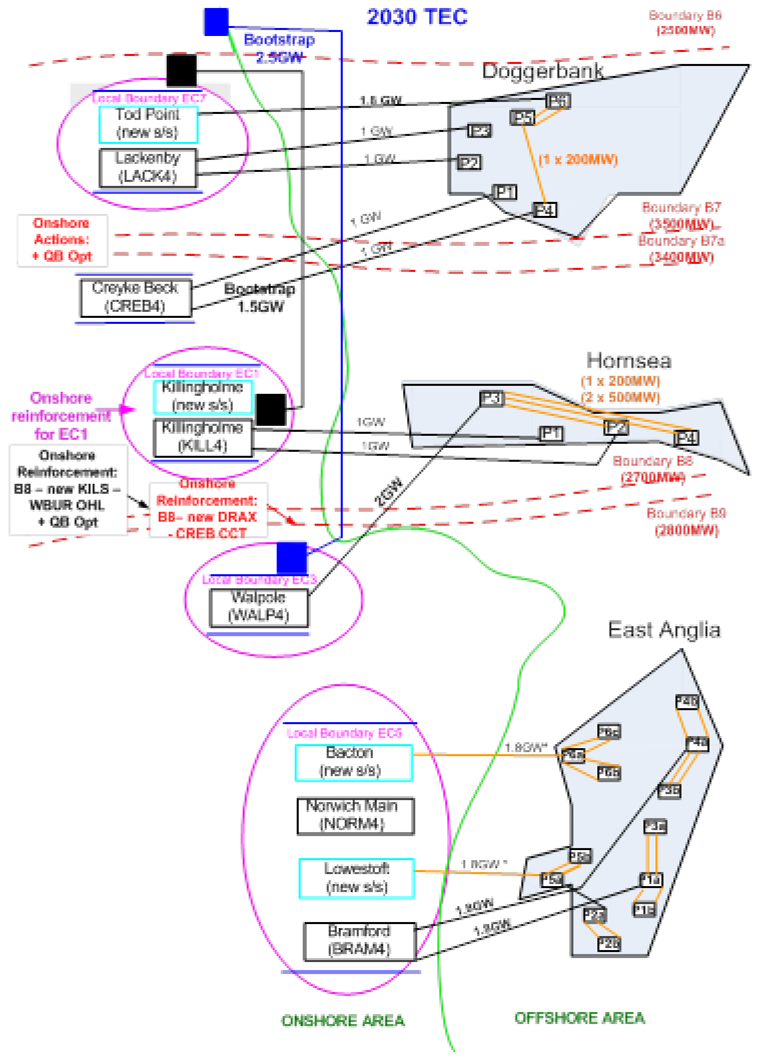
14A – Hybrid Onshore & Bootstrap 1GW



14B – Hybrid Onshore & Bootstrap 2GW

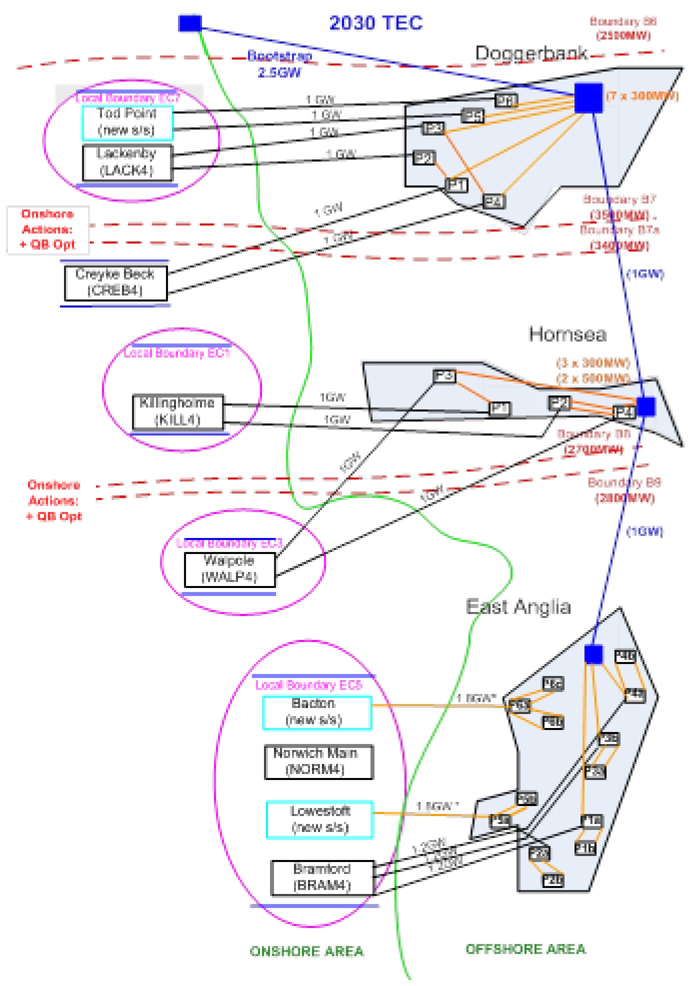


14C – Hybrid Onshore & Bootstrap 2GW

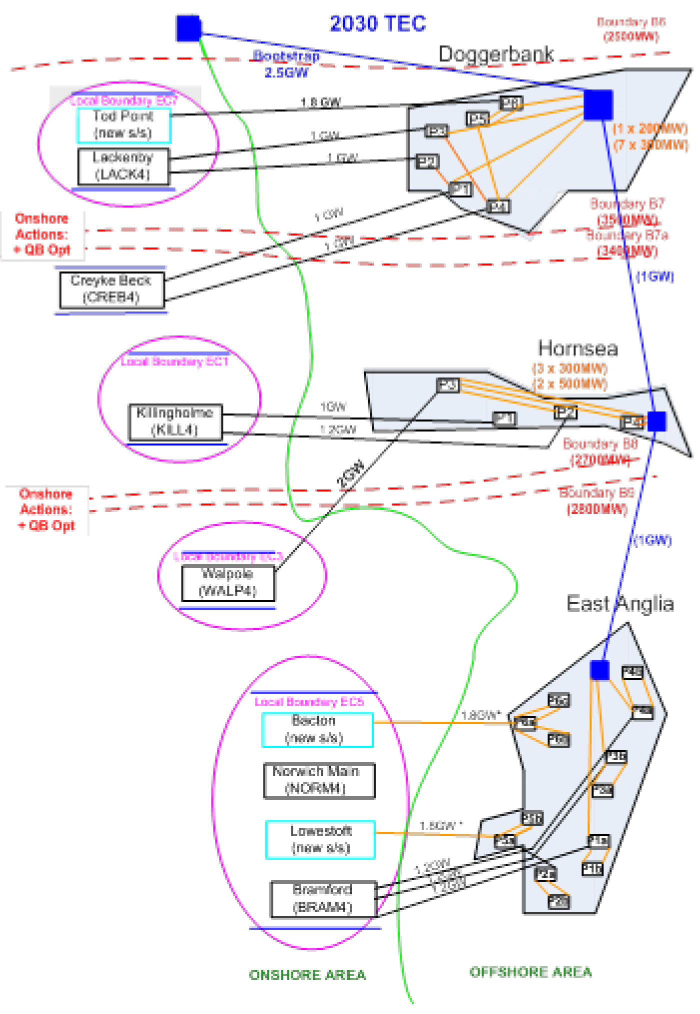


Scenario 1 (2030)

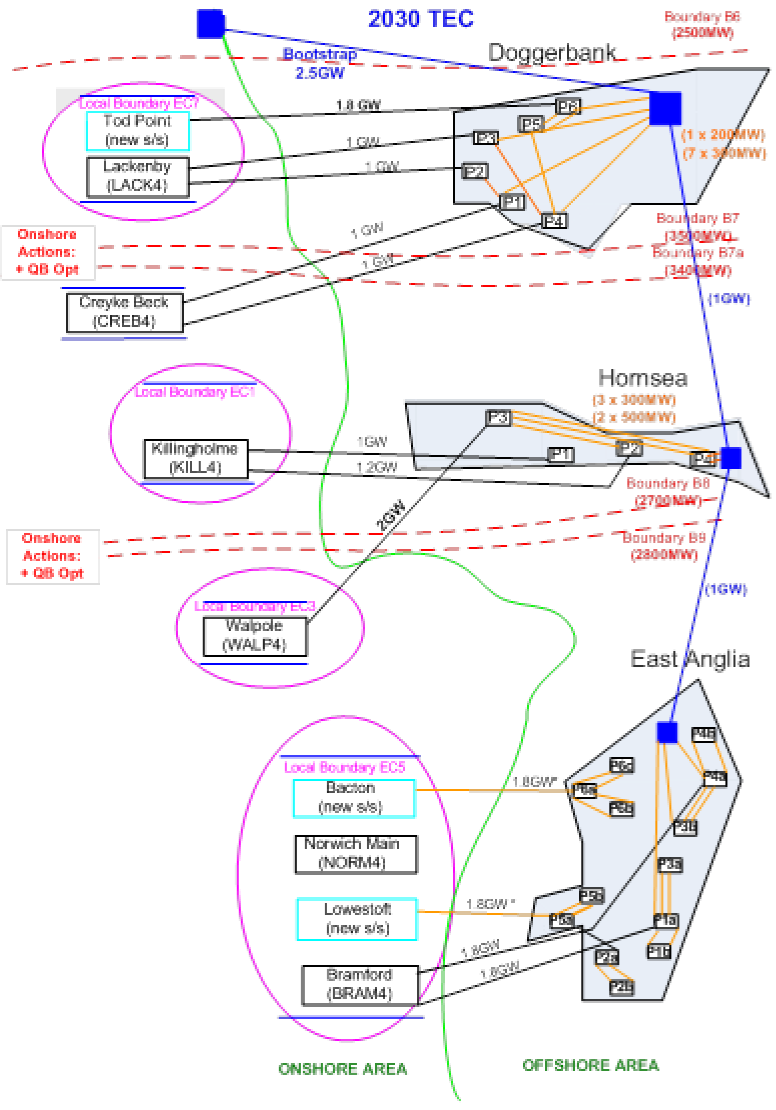
15A – Offshore HVDC 1GW



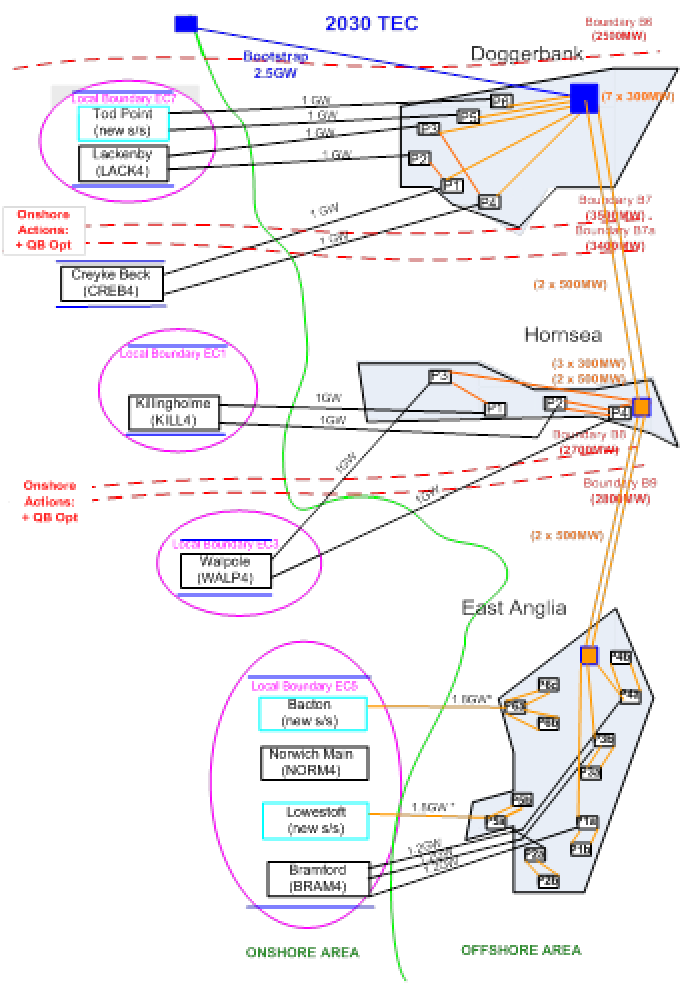
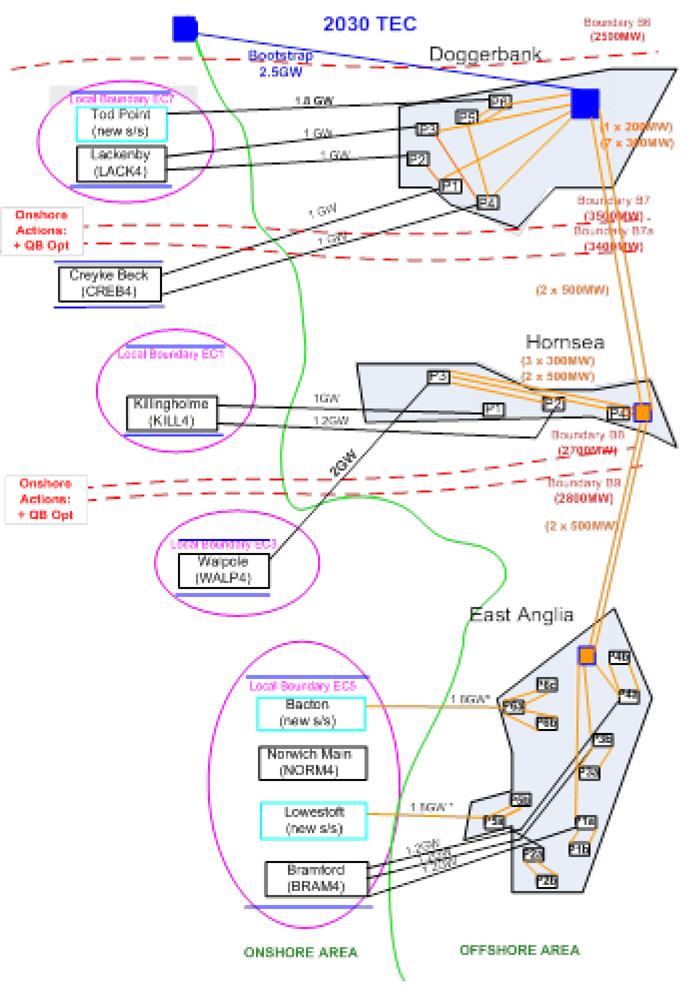
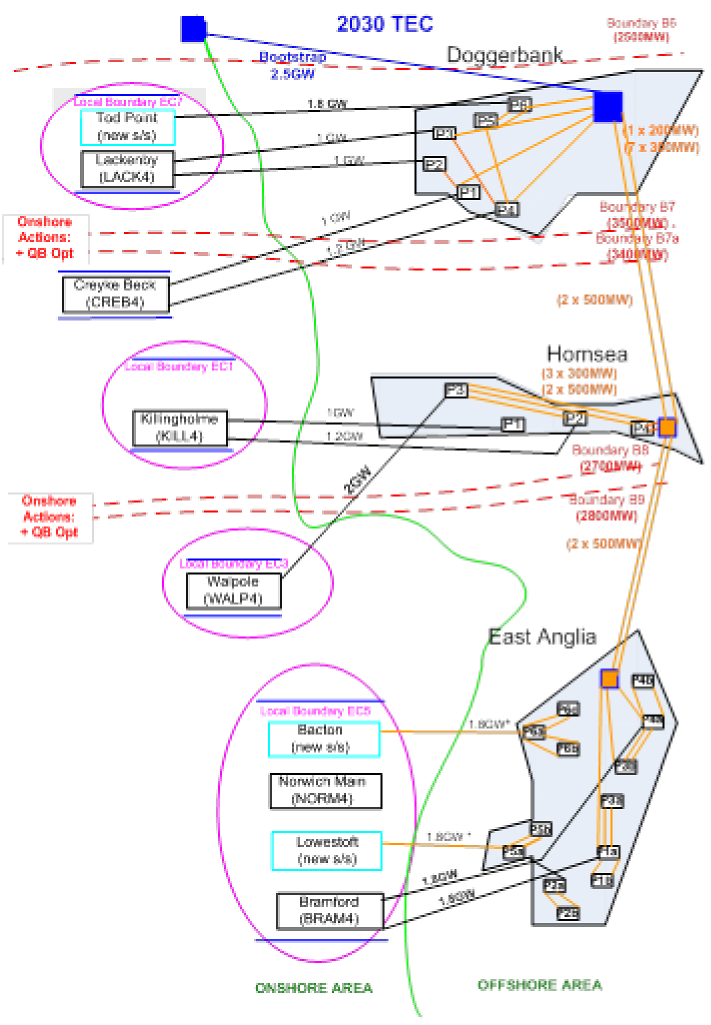
15B – Offshore HVDC 2GW



15C – Offshore HVDC 2GW



Scenario 1 (2030)

16A – Offshore HVAC 1GW	16B – Offshore HVAC 2GW	16C – Offshore HVAC 2GW
		

9 Capital Costing of Proposed Design Solutions

Capital costs for the designs are an important input for the Cost Benefit Analysis (CBA). In this section of the report, the capital costing for all design solutions (onshore, offshore, bootstrap and hybrid) are presented, however only few designs, based on the criteria of operability and capital costs, were progressed into the CBA stage. These designs were selected in conjunction with the System Requirements workstream members. The process involved in calculating the capital costing of the designs was made clear and transparent. The capital costing included the generation build–up from Scenario 1 and Scenario 2, considering that these are the two marginal cases.

Unit Cost of Assets

The unit cost data for each of the assets used for capital costing was provided by the Technology workstream; these figures were also published in Appendix E of the ETYS 2013 document. These costs were agreed upon by members of the System Requirement workstream to be used in the capital costing of the designs. It should be noted that there were few reservations from some members that some of the unit costs were a bit optimistic. The unit costs are included in Appendix 3 of this report.

Cable Distance

The estimated cable distances from the offshore platforms to onshore were provided by offshore developers including the estimated distances between the projects. The table below shows the estimated cable distances to onshore used in capital costing.

DOGGER BANK	Offshore Cable Distance (km)
P1	**212.5**
P2	**261.0**
P3	**222.8**
P4	**215.1**
P5	**210.6**
P6	**246.3**
P1-P2	**72.9**
P1-P3	**28.2**
P1-P4	**30.6**
P2-P3	**41.2**
P2-P4	**95.3**
P2-P6	**49.4**
P3-P4	**35.3**
P3-P5	**34.1**
P4-P5	**31.8**
P5-P6	**36.5**

HORNSEA	Offshore Cable Distance (km)

P1	**150**
P2	**125**
P3	**125**
P4	**138**
P1-P3	**64**
P2-P3	**38**
P1-P4	**29**
P2-P4	**56**
P1-P2	**27**
P3-P4	**38**

EAST ANGLIA	Offshore Cable Distance (km)
P1	**73**
P2	**43**
P3	**140**
P4	**160**
P5	**24**
P6	**68**

The other cable distances assumed are:

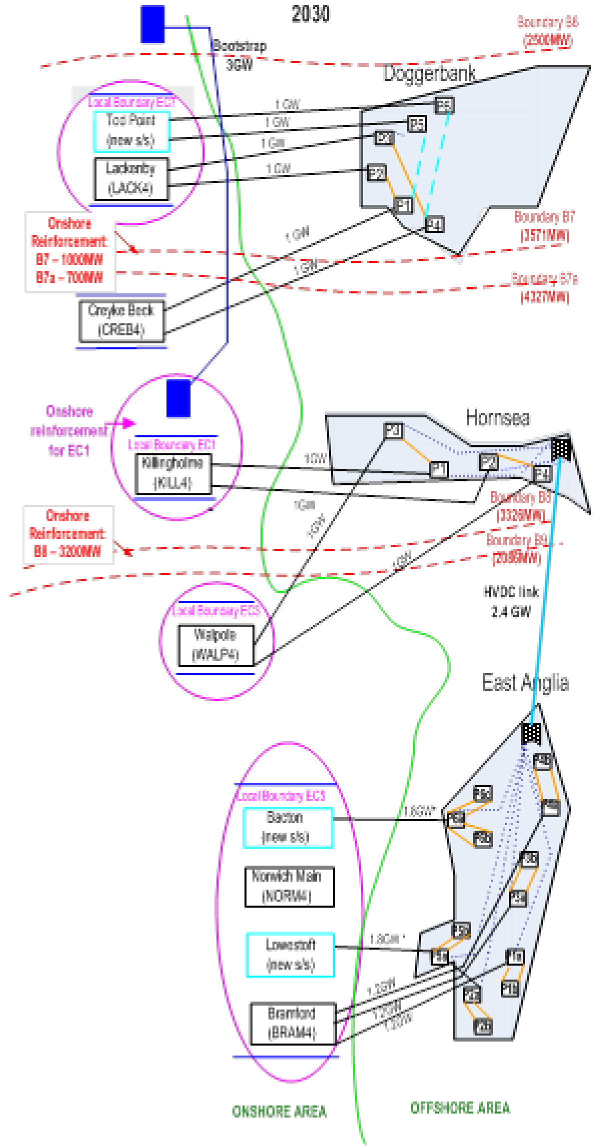
- The distance between Dogger Bank and Hornsea was 120km and the distance between Hornsea and East Anglia was 100km.
- The distance from Scotland (Bootstrap) to EC7, EC1 and EC3 local boundary areas were assumed to be 150km, 250km and 350km respectively.
- Integrating HVDC platform and any connecting offshore windfarm HVDC platform on the same location was assumed to be 30km.

Capital Costing Methodology and Approach

Capital costing of the **Initial Proposed** and **Updated Proposed** designs were calculated and presented in an excel spreadsheet, which was commented on by all System Requirements workstream members. The excel spreadsheet (**Full Capital Costing Matrix)** is attached to this document. It is important to mention that design capital costing is an input sensitivity for the Cost Benefit Analysis (CBA).

Capital costing of the designs was carried out by summing up all the unit costs of HVDC platforms, the total cost of the HVAC and HVDC cables depending on their distances including their installation costs, cost of the onshore converters and cost of any required onshore transmission reinforcement(s) require to facilitate connection. An illustration is shown in an example below (**Scenario 1 – 2030 Hybrid design 1**).

Design



Costing elements:

HVDC platforms (Jacket and Topside: 400kV-750kV):

- Dogger – Six 1GW
- Hornsea – Four 1GW, One 2.4GW
- East Anglia – Three 1.2GW, Two 1.8GW, One 2.4GW

HVAC cables (200MW – 500MW)

- Cost of HVAC cables connecting projects depending on the cable distances and ratings

HVDC cables (Cable Mass Impregnated)

- Cost of HVDC cables to onshore converter site and/or between HVDC platforms depending on the cable distances and ratings

Cable installation costs:

- Cost of "Single Cable, Single trench" technology for installing each HVAC cable
- Cost of "2 single cables; 2 trenches, 10M apart" technology for installing each HVDC cable.

Onshore HVDC Converters

- Cost of onshore converters at each interface point

Bootstrap (Intra-grid link)

- Cost of Onshore converters
- Cost of the HVDC Cable – 3GW
- Installation cost of the HVDC cable

Additional Cost for Onshore Reinforcement(s)

- Costs to facilitate Bootstrap connection within the local boundaries (EC1 and Scottish Transmission Network).

9.1 Summary of Designs for CBA

A range of design options were developed for the different scenarios considered. These designs were developed so as to provide alternative options to achieve the boundary capability shortfalls identified. Options included onshore reinforcements, offshore HVDC links and offshore integration. A total of 86 designs were developed initially for the range of scenarios considered and the table below summarises the options taken forward for the CBA;

Designs	**Years**	
	2021	**2030**
Onshore radial designs	Select the corresponding 2021 build-down design after CBA for the selected 2030 design	Central View 2030 3A Onshore Boots TEC 2030 10A Onshore
TEC	Select the corresponding 2021 build-down design after CBA for the selected 2030 design	Offshore: 15A & 15C Hybrid: 13A & 13C
Central View	X (Not to be Assessed)	Bootstrap: 2A & 2C Offshore: 5A & 5B Hybrid: 4A

Table 11: Designs selected for Cost Benefit Analysis

Designs Selection for the CBA

- The design selection was undertaken at a meeting with the developers
- It was agreed to initially assess the designs for 2030 and thereafter select the corresponding build-down designs for 2021 to understand how the design build-up could be undertaken.
- In selecting the options, it was agreed to have at least one of each design type, i.e. Bootstrap, Offshore and Hybrid designs wherever possible
- The capital costs of the designs were taken into account, for the same capability, the lower capital cost designs were initially taken forward.

10 Operability of Offshore Integrated Designs

System operability assessment involves studying the dynamic performance of the whole system or a specific part the system in order to evaluate the impact that various contingencies may have on system stability and operability. It is of particular importance to assess the operability of the potential integrated offshore wind power park connections due to the size, characteristics and requirements of the solutions.

Operability assessment

Scenario Technology assessment has previously been carried out to establish the protection and control requirements and suggest a control strategy for the potential connection designs developed by the System Requirements Workstream. This assessment has been carried out in two stages: evaluating these requirements for generic connections ranging from radial to interconnected networks and consequently applying the conclusions gained from this stage to the connection designs developed by the System Requirements Workstream.

Two cases have been investigated: high wind factor and low wind factor. In the case of a high wind factor, priority is given to the flows from the offshore AC network onshore; for low wind factor, the spare capacity of the offshore network is used for North-to-South power flows (thereby providing extra transfer capability across the onshore system boundaries).

- A combination of 4 control methods has been used in each of the control scenarios:
- DC voltage control
- Stiff (constant) frequency control
- Frequency droop control
- Stiff power control

This work has further demonstrated various fault detection and clearing approaches under both high and low wind scenarios in the case of a loss of DC link connecting an offshore wind farm or AC system to the onshore AC system. Fast raise of the offshore AC system voltage and frequency, as well as possible overloading of the DC converters have been outlined as the effects that a loss of a DC link may have on the overall system. The following ways of mitigating these effects have been suggested:

- Building additional redundancy into the offshore network to provide alternative routes for power to flow and avoiding wind turbine de-loading
- Operating DC links in parallel only as long as the total generated power offshore fits into N-1 scenario
- Installing AC choppers on the offshore AC collector network to dissipate the excess energy during a fault, in addition to reducing the output from the wind turbines offshore

- Curtailing wind turbine output to fit into N-1 scenario
- Implementing suitable inter-tripping arrangements

This first stage of operability assessment assures that Scenario Technology and several protection and control approaches are available to ensure the offshore assets are protected during and following various fault scenarios.

Building on this knowledge, the impact of the following fault events will need to be assessed to investigate their impact on offshore and onshore system operability:

- AC system fault onshore
- HVDC cable fault offshore
- AC cable fault offshore
- Loss of wind generators (array) offshore.

Onshore and Offshore Operability Assessment Topics

The considerations relating to the onshore system operability are already being assessed routinely and extensively as part of the Electricity Ten Year Statement and other processes, and onshore system stability limits are well known. With the implementation of the integrated offshore solutions, similar approaches will need to be applied to offshore system operability studies, and whole system operability will need to be looked at in the context of offshore and onshore system interactions.

A particular focus is to be given to the following aspects of operability:

Onshore

- System frequency
- System stability
    - Voltage control
    - Power oscillations
    - Power reversal
- Power quality
- Sub-Synchronous Interactions
- Control interaction

Offshore

- Operating an islanded network with low system strength
- Wind turbine/converter control
- AC and DC fault deScenario 1tion, isolation and system recovery
- Power sharing between cables
- Power quality

An important phenomenon that has to be taken into account when assessing system stability and operability is system inertia. The level of system inertia present on the system at any given time is related to the generation dispatch and the characteristics of the loads connected to the system. Every year National Grid produces an economic generation dispatch ranking order according to the Future Energy Scenarios.5 This ranking order informs on which generators are likely to be available every year for the next twenty years therefore containing information on the likely system inertia for each of these years. This is routinely used for the studies carried out as part of the Electricity Ten Year Statement (ETYS) and the same generation dispatch and system inertia assumptions will be used in the integrated offshore system operability assessment.

It is essential to carry out a comprehensive, design-specific assessment of each of the potential integrated connection designs to evaluate the operability constraints and requirements as per the above criteria. Until such specific designs are available, viable generic network topologies can be assessed.

Offshore Windfarm Configurations for Operability Assessment

It is essential to carry out a comprehensive, design-specific assessment of each of the potential integrated connection designs to evaluate the operability constraints and requirements as per the above criteria. Until such specific designs are available, viable generic network topologies can be assessed. The paragraphs below give examples of such generic topologies.

Single Radial AC Connection (Example 1)

This a common approach that is widely implemented in UK and the rest of the world. Depending on the capacity of the wind farm, power is transferred onshore via one or more radial AC links that may be connected to a single or multiple connection points onshore.

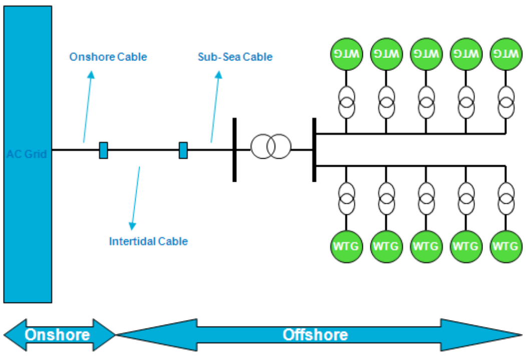


Figure 2: Single Radial AC Connection[6]

[5] http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/61591/UKFES2013FINAL3.pdf

[6] ENTSO-E Network Code Requirements for Generators shall apply

Multiple Onshore AC Connections (Example 2)

The main advantage of this design compared to the radial connection option is that it allows power to be exported onto multiple onshore connection points, and the connection between the two radial links provides an alternative path for power to be transmitted onshore in case one of the radial links is lost.

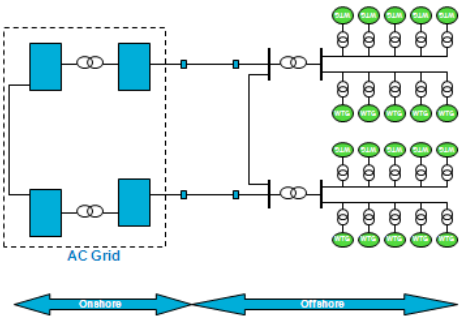


Figure 3: Multiple Onshore AC Connections[2]

Single Radial DC Connection (Example 3)

The use of HVDC links provides a more economical solution for transmitting bulk power flows across long distances compared to AC links. Additional benefits include reduced transmission losses, decoupling between the onshore grid and the wind farm, independent control of active and reactive power, provision of ancillary services (e.g. black start capability from VSC HVDC).

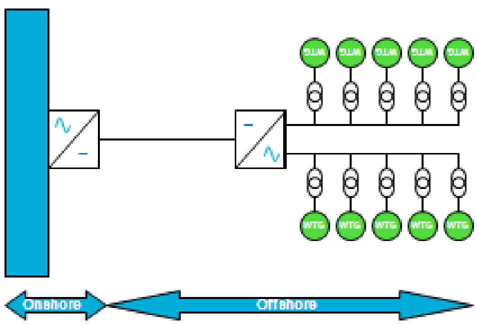


Figure 4: Single Radial DC Connection[7]

Hybrid AC and DC Connection (Example 4)

This example is a combination of examples 2 and 3 and provides away of integrating new connections with existing connections. Similarly to Option 2, his allows power to be transmitted to two onshore connection points and the connection between the radial Ac and DC links provides a level of redundancy.

[7] ENTSO-E Network Code HVDC shall apply

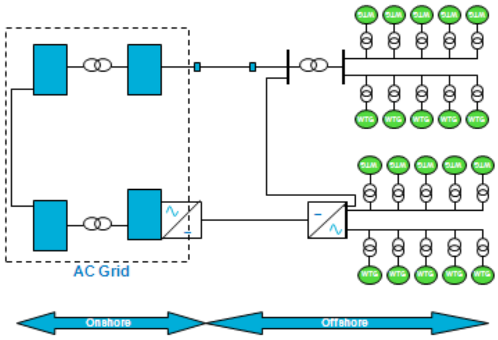


Figure 5: Hybrid AC and DC Connection[3]

Multiple DC Connections with AC Link Offshore and Onshore (Example 5)

Due to the costs of the converters and DC cables, this solution is suitable for connecting wind farms that are very remote from the onshore system. The AC link between the DC sides of the offshore converters provides an alternative path for power to flow in case one of the DC links is lost and also creates a larger offshore AC island, increasing the stability limits and the strength of this island.

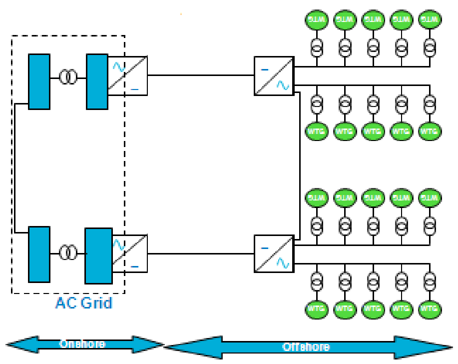


Figure 6: Multiple DC Connections with AC Link Offshore and Onshore[3]

Multiple DC Connections Offshore (Example 6)

This solution is similar to example 6, except for the link between the radial connections which is DC instead of AC. This provides a path between the wind farms whilst also decoupling them from one another.

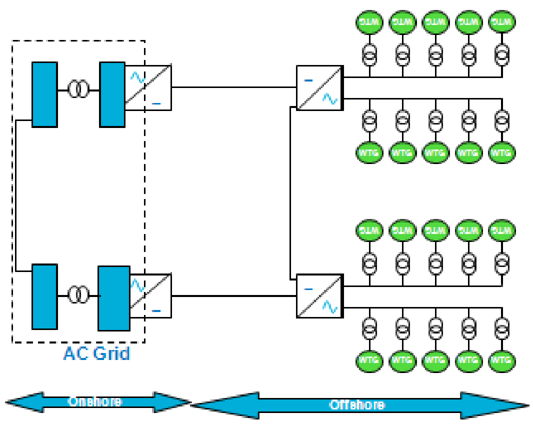


Figure 7: Multiple DC Connections Offshore[3]

Impact Assessment

The impact of these offshore network design choices has been evaluated at a high level for four phases:

- Normal (steady-state) operation
- Operation during a fault
- Post-fault recovery

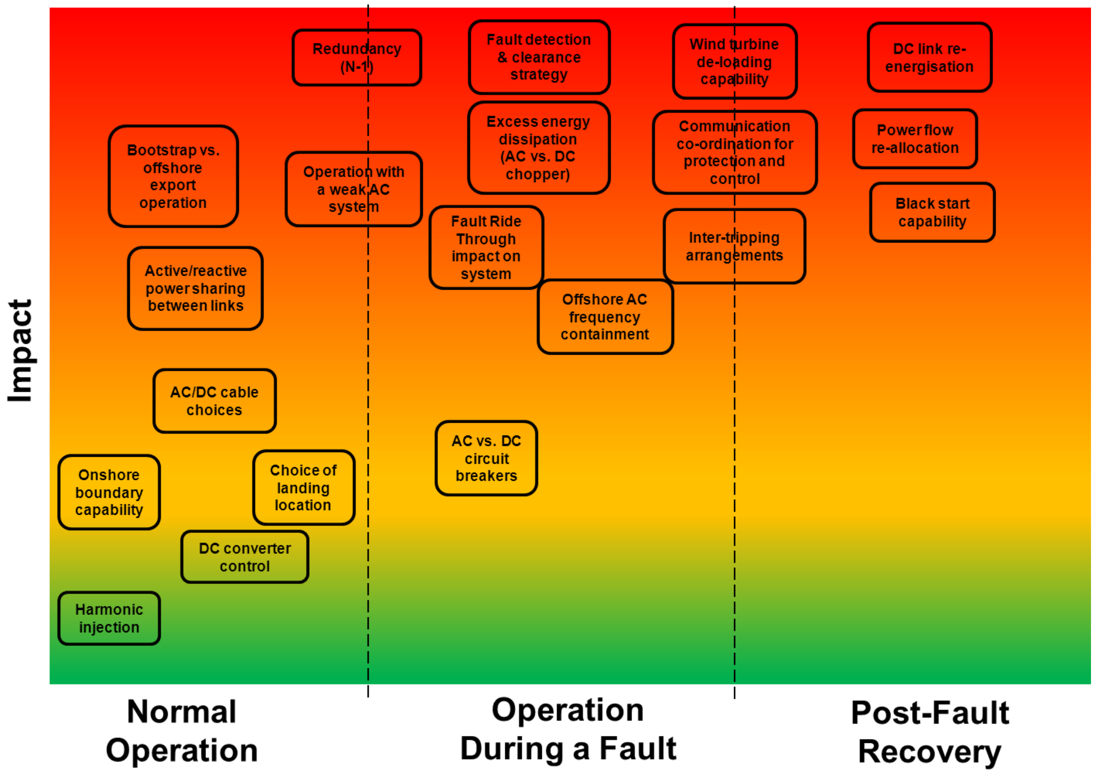


Figure 8: Operability Impact Diagram

The criticality of each of these aspects has been evaluated for each of the six generic connection examples; this is outlined in the sections below. The following assessment criteria have been used:

- Low (L) – solution is widely implemented, standard approaches apply
- Medium (M) – few examples of the solution are currently available, but more in-depth assessment needed than for "Low"
- High (H) – in-depth case-by-case assessment is required, taking into account specific Scenario Technology and/or network parameters

Offshore to Onshore Power Export

Onshore Impact

Post Fault: Depending on fault detection and clearing strategy, as well as fast de-loading and inter-tripping arrangements, the onshore system may see a large loss of infeed resulting in a drop in onshore system frequency, and a voltage dip at the onshore connection point. Grid Code Fault Ride Through (FRT) requirements would apply at the onshore connection point. Subject to DC circuit breakers or fault current blocking converters being used, the onshore converter may provide some voltage support to the onshore system. Control systems must be able to detect faults on the onshore network in close proximity to the onshore converters and respond to these faults in a co-ordinated way so as to prevent the onshore converters from interfering with one another.

***Pre Fault*:** The offshore network has to be operated in a way that allows the stability (especially frequency stability) of the offshore AC grid to be maintained pre and post an onshore system fault

Offshore Impact

***Post Fault*:** For integrated arrangement supporting a total wind generation capacity greater than the maximum normal infeed loss (1800MW as per SQSS 7.2), depending on fault detection and clearing/reconnection strategy different approaches will apply. For clearing approach, as well as fast de-loading and inter-tripping arrangements, the output of one or more of the offshore wind power parks may have to be curtailed, resulting in a negative effect on the frequency and/or voltage behaviour of the offshore AC island(s). Energy dissipation methods and devices need to be incorporated in the offshore network design to avoid raise in offshore DC cable voltage or device overloading that would lead to a cascading loss. Controllers shall positively support transient stability and suitable damping of the frequency and/or voltage effects to which any offshore AC island may be subject to. Subject to DC circuit breakers or fault current blocking converters being used, the offshore converter may provide some voltage support to the offshore system. Alternatively, arrangements limiting the period of disconnection such that the overall effect of disconnection and reconnection over the period of the DC system fault is no worse than the transient loss of load effect occurring upon the onshore AC system for an offshore AC system today (i.e. full power restoration within 250-300ms following a fault), whilst respecting the onshore FRT requirements thereafter.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	L	M	M

Bootstrap Operation

Onshore Impact

***Pre Fault*:** Having an HVDC bootstrap available brings several potential benefits to the onshore system, including increased boundary transfer capability and increased stability margins, especially where a large electrical distance exists between the boundaries.

***Post Fault*:** If the loss/maintenance of a bootstrap leads to the boundary transfer requirement exceeding the boundary transfer capability, either an alternative power flow route needs to be available, or generation needs to be curtailed at the exporting side of the boundary and brought on at the importing side of the boundary in order to find a new generation-demand balance and maintain the system frequency within the statutory limits. The offshore network bootstrap design needs to be developed with these fault/maintenance condition requirements in mind.

Offshore Impact

***Post Fault*:** If there are more than 2 HVDC cables connecting the offshore island(s) onshore, fast power flow reallocation between the cables may allow the bootstrap operation to be restored after a short (on the scale of milliseconds) disturbance to the bootstrap power flow. If there are no more than 2 HVDC cables between the offshore AC island and the onshore system, power flow restoration depends on the fault detection and clearing strategy and the ability to restore the cable back into service. These aspects also influence how quickly following a fault the offshore transmission routes can become available to switch from bootstrap to offshore export scenario.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	M	M	H

DC Cable between Wind Farms Offshore

Onshore Impact

***Pre Fault*:** If the overall stability margins of the individual offshore AC islands are small, this increases the likelihood of one or more of the islands becoming unstable and disconnecting. From the onshore system's perspective, this would be seen as a loss of infeed and depending on the prevailing conditions on the onshore system and the rest of the offshore system, may cause a significant deviation on the onshore system frequency.

Offshore Impact

***Pre Fault*:** Employing HVDC cables for the connections between the individual wind power parks instead of HVAC cables decreases the size of the individual AC islands, which may have a negative effect on the stability of the offshore AC system.

Post Fault: In the case of a loss of HVDC link between the offshore AC islands, the use of DC breakers would allow the converters at either end of the link to remain in service and provide voltage support to the AC islands during the fault, increasing the overall stability of these islands. Without the DC breakers, AC breakers would disconnect both of the converters and the HVDC link, leaving point-to-point connections between the individual offshore islands/wind power parks and the onshore network.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	N/A	N/A	N/A	H

AC Cable between Wind Farms Offshore

Onshore Impact

Pre Fault: Unlike the case above with a HVDC cable between the offshore AC islands, an AC cable increases the size and strength of the offshore AC network, therefore decreasing the possibility of a loss of infeed to onshore system due to short or long term offshore system instability

Offshore Impact

Pre Fault: Having the individual offshore AC islands/wind power parks interconnected with AC links increases the physical size and capacity of the overall offshore AC network consequently increasing the system strength and the overall steady-state stability of the offshore AC network (comparing to having more, smaller offshore AC islands).

Post Fault: In case of a fault on an AC link that is part of an offshore AC island, the loss of this link would result to the same point-to-point network topology as in the scenario above where following a fault a HVDC link between offshore AC islands is isolated with AC circuit breakers. If, however a fault occurs on one of the HVDC links connecting the offshore AC island to the onshore system, a bigger offshore AC island would be expected to have higher system stability margins, making it easier to retain stability during and following a power flow re-distribution.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	M	N/A

DC Chopper

Offshore Impact

During Fault: If a fault occurs on the onshore AC system close the onshore converter, a DC chopper protects the WTG and the HVDC cable. During the fault, no power can be exported onto the onshore system over the HVDC cable that connects to the onshore system closest to the location of the fault; excess energy builds up in the cable and needs to be dissipated by a DC chopper.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

AC Chopper

Offshore Impact

During Fault: In the case of a fault on one of the HVDC cables connecting the Offshore AC island to the onshore grid, AC choppers on the AC side of the offshore converters are able to protect the remaining HVDC cable from overloading by dissipating some of the excess energy produced by the WTG until the WTGs de-load to a level at which all of the power produced by the WTGs can be exported over the remaining HVDC cable thereby avoiding cascading losses on the offshore network. An alternative to this is to have HVDC cables with a higher rating or to limit the export from offshore to onshore to allow more head-room pre-fault.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	N/A	H	M	N/A

Provision of Black Start Capability (VSC Converters)

Onshore/Offshore Impact

Post Fault: In a black start scenario, voltage source converters (VSCs) can create an AC voltage reference according to a specified magnitude, frequency and phase angle requirement. Once the created voltage magnitude has reached approximately 90% of nominal magnitude, the VSC can provide an auxiliary power supply to re-energise and start-up the equipment both onshore and offshore. The converters can also provide voltage and frequency stabilisation during restoration (e.g. mitigate voltage dips after re-connecting large motor loads).

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

Fast Power Reallocation between Cables

Onshore/Offshore Impact

Post Fault: The capability to rapidly (200ms) re-allocate power across the HVDC cables following a fault on one of the cables would ensure that stability is maintained on the offshore grid and that a portion of the power that can be generated by the WTG can still be exported onto the onshore system with one HVDC cable out of service, thus reducing the level of loss of infeed. This capability is closely related to communication and control system capability and settings.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	H	H

AC Circuit Breakers Only

Onshore/Offshore Impact

During Fault**:** In the scenario where there is a fault on one of the HVDC cables, employing only AC breakers would mean that the fault is isolated by opening the AC breaker on the AC sides on the onshore and offshore converters and losing the cable as well as the additional voltage support that could be provided to both the onshore and offshore AC systems by the converters.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	L	M	H

DC Circuit Breakers/Fault Current Blocking Converters

Onshore/Onshore Impact

During Fault: If DC circuit breakers and fault current blocking converters are available for isolating faults on the HVDC cables, only the cable is taken out of service following a fault, leaving the converters in service and available for providing additional support to the onshore and offshore AC systems during and following a fault.

Impact on Example Designs

1	2	3	4	5	6
N/A	N/A	L	L	M	M

Active/Reactive Power Sharing Between Lines

Onshore Impact

Pre Fault: Co-ordinated power sharing between wind farms leads to a more integrated solution which results in more efficient use of transmission assets and reduced costs for the GB consumer, as well as increased transmission flexibility and Security of Supply. Overall, power sharing leads to a stronger network.

During Fault: Support to onshore faults can be maximised via power sharing between links as it increases flexibility of the offshore network.

Offshore Impact

During Fault: The impact of an offshore fault on the one of the DC links can be mitigated by rerouting power from the tripped cable via the second link. Without this capability the wind farm output would have to be ramped down to zero in the event of a fault.

Post Fault: The wind farms can continue delivering power at a reduced rate to the onshore network with one link tripped if power sharing between links is incorporated. Without it, the generator of the tripped link would be out of service.

Impact on Example Designs

1	2	3	4	5	6
N/A	L	N/A	L	M	H

Fault Ride Through capability of the Offshore Network

Onshore Impact

During Fault: FRT results in a stronger network. During onshore faults, the wind farm generators can support the onshore fault if appropriate. With no FRT, the unnecessary tripping of generators can exacerbate the onshore fault by removing voltage support.

Post Fault: The network can be stronger with additional support from offshore generation with FRT. Without it, the network would require voltage support from elsewhere in the network and the wind farm generators would trip unnecessarily. However this is an emerging Scenario Technology and requires agreement between developer and HVDC manufacturer.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	M	H	H

Fast Wind Turbine De - loading Capability

Onshore Impact

During Fault: During a fault on a HVDC link, no fast de-loading capability would result in the large excess power re-routing through the AC wind farm link during times of high wind.

Post Fault: With the above scenario in place, the onshore landing point of the tripped link is receiving zero support whilst the other onshore landing point of the functioning link is receiving excessive power. This situation continues for as long as the turbines are loaded. Onshore reinforcement may be required to handle such imbalance. Fast de-loading capability ensures the latter link sees excess re-routed power for a much shorter period and negates the requirement of onshore reinforcement. This requires strong co-ordination between HVDC link and the wind farms.

Offshore Impact

During Fault: During an onshore fault, the HVDC links can increase power to support the fault area. However if the fault is directly on the offshore system then it is essential that the output of the wind farm is ramped down as fast as possible in conjunction with rerouting the excess power away from the onshore fault. If a fault occurs on a HVDC link, no fast de-loading capability would result in the large excess power re-routing through the AC wind farm link during times of high wind. This risks tripping the second HVDC link and the AC link.

Impact on Example Designs

1	2	3	4	5	6
L	L	L	M	H	H

Communication and Co-Ordination for Protection and Control

Onshore Impact

During Fault: Fast communication is required during a fault to ensure a co-ordinated response which can result in the onshore network being supported by the offshore wind farms. The communication is required between onshore and offshore systems but also between the two offshore wind farms. Without it, containment of faults would be problematic as communication is essential for co-ordination.

Offshore Impact

During Fault: Fast communication is required during a fault to ensure a co-ordinated response which can protect the offshore wind farms from onshore faults and faults on the other HVDC link. The communication is required between onshore and offshore systems but also between the two offshore wind farms. Without it, containment of faults would be problematic as communication is essential for co-ordination.

Impact on Example Designs

1	2	3	4	5	6
L	M	L	M	H	H

From this a hierarchy of considerations can be established, starting with the most impact:

- AC system strength offshore
- Communication and control system co-ordination
- Equipment short-term fault withstand capability
- Arrangements for equipment restoration back into service following a fault.

The above considerations have been ranked according to the time frames at which they would be affected by a fault. As an example, if the AC system off shore is small and has a low system strength, control system latency has to be minimised and energy dissipation devices need to be employed in order to prevent to be overloaded before the fault is isolated.

The criticality of each of these considerations will vary for each of the specific designs. The assessment of how the proposed networks respond to faults at various locations on the offshore and onshore systems will give a visibility of the most critical areas for each design and set the requirements for the capabilities of the less critical areas for them to be able to mitigate this.

Although the Scenario Technology that can be used in the integrated offshore solutions is new and developing, the principle of operability assessment of these designs is no different to onshore wind farm and HVDC interconnector design assessment. A high level of expertise already exists in this area. Once specific designs have been agreed upon, the necessary modelling and system study capability will be available to carry out a detailed assessment.

This is intended to serve as a starting point for discussions between the network licensees, developers, manufacturers and Ofgem to narrow down the critical design choices the impact of which should be studied in more detail.

APPENDICES

Appendix 1: *Unit Cost of Assets*

HVDC PLATFORM	
Rating	**Cost (£M)**
1000 MW @ 320-400 kV	294.5
1250 MW @ 320-400 kV	333
1500 MW @ 450-500 kV *	424
1750 MW @ 450 550 kV *	472
2000 MW @ 500-600 kV *	476.5
2250 MW @ 600-700 kV *	534
2500 MW @ 650-750 kV *	572

HVDC PLATFORM	
Rating	**Cost (£M)**
1000 MW @ 320-400 kV	345
1250 MW @ 320-400 kV	383
1500 MW @ 450-500 kV *	474
1750 MW @ 450 550 kV *	522
2000 MW @ 500-600 kV *	526
2250 MW @ 600-700 kV *	584
2500 MW @ 650-750 kV *	622

HVDC CABLES Mass Impregnated	
Rating (MW) @ 400kV	**MID RANGE (£/m)**
980	0.471
1320	0.497
1540	0.523
1654	0.680
Rating (MW) @ 500kV	**MID RANGE (£/m)**
1226	0.497
1650	0.528
1925	0.550
2067	0.655
Rating (MW) @ 550kV	**MID RANGE (£/m)**
1348	0.525
1815	0.558
2117	0.581
2274	0.684

HVAC 3 Core Subsea Cable		
Rating	**Cost (£M/km)**	
200MW	0.602	
300MW	0.6545	
400MW	0.864	
500MW	**1.0735**	**Extrapolated**

Cable Installation costs	
Rating	**Cost (£M)**
Single cable, single trench	0.5
Twin cable, single trench	0.7
2 single cables; 2 trenches, 10M apart	0.93

HVDC CONVERTERS (VSC)		
Rating	**Cost (£M)**	
1GW	**107.94**	**Extrapolated**
1.25GW	122	
1.5GW	**132.83**	**Extrapolated**
1.6GW	**137.17**	**Extrapolated**
2GW	154.5	
2.5GW	**176.17**	**Extrapolated**
2.7GW	**184.84**	**Extrapolated**
2.8GW	**189.18**	**Extrapolated**
3GW	**197.84**	**Extrapolated**
3.2GW	**206.5**	**Extrapolated**
3.5GW	**219.5**	**Extrapolated**

Required Onshore reinforcement at point of connections (Power injection)	
Local Boundary	**Cost (£M)**
EC1 (Up to 4.3GW)	121
EC3 (Up to 3.8GW)	3
EC3 (Above 3.8GW)	122
EC7(Up to 1.5GW)	4

Required Onshore reinforcement at point of connections (Power Ejection)	
Local Boundary	**Cost (£M)**
EC1 (Up to 2.5GW)	4
EC7 (Up to 1.3GW)	4

HVDC T-Platform Structure	
	Cost (£M)
	50

Integrated Offshore Transmission Project (East)

Appendix 3

Cost Benefit Analysis Work-Stream Report

Contents

1 Introduction

NOTE: Since completion of this work-stream report the assumptions around credible connection dates and volumes of offshore wind generation have changed in response to current market conditions. As stated in the original conclusions if the spread of generation between the three zones considered was to vary then the case for integration could be weakened. Latest market intelligence suggests that the build-up of offshore wind generation is likely to be slower than previously forecast and has potential to deliver volumes below the 10GW lower limit assessed in this analysis. Therefore the conclusions stated in this work-stream report are no longer considered valid. The current view on the least worst regret assessment of integrated designs is given in the main project summary report. While the analysis presented here was correct at the time of assessment, all conclusions are now superseded.

1.1 Context

The Integrated Offshore Transmission Project (East) (IOTP(E)) was set up to identify, develop and examine a range of credible network solutions for the connection of three East Coast Round Three offshore wind farms in the most economic and efficient manner. The development may provide additional transmission capacity to the wider and local system boundaries and improve offshore transmission reliability, depending on the design.

The three projects, referred to as Dogger Bank, Hornsea and East Anglia are managed by different development companies, namely:

Dogger Bank - Forewind

Hornsea - Smart Wind

East Anglia - East Anglia Offshore Wind

Whilst the analysis has been undertaken by National Grid, this project has been coordinated through a joint working group comprised of all major stakeholders including representatives from the parties listed above. The network design options considered in this assessment cover a range of configurations from base radial connection solutions (with and without onshore reinforcements) to various integrated offshore network configurations.

As part of this work, National Grid has undertaken a Cost Benefit Assessment (CBA) using established economic assessment rationale to assess the range of network designs against future scenarios. In simple terms, the objective is to consider the value of any benefits offered by each design, against the additional investment associated with that design. The benefits include both forecast savings in constraint payments made to onshore generation, and the welfare benefit of obtaining higher levels of renewable energy from the three wind farms.

The onshore constraint cost forecasts are produced using a network modelling tool. The welfare benefits are represented as constraint costs on the offshore generation, and are also calculated by the network modelling tool. The investment costs have been calculated using the unit prices provided by the technology work stream. The modelling of the welfare benefit and constraints is described more fully in chapter 4 of this report.

Within this context, this document presents the details of the CBA undertaken by National Grid, as shared with the working group, to provide a vision of the overall economic benefits that could exist.

1.2 Economic Objectives of the Project

The current transmission network capabilities coupled with the range of generation projected to connect/disconnect over the next 20 years will impact on operational costs. These operational costs will increase in the absence of any reinforcements because the network design has evolved to best meet the current generation disposition.

Given that National Grid has an obligation to connect generation in accordance with agreed contracted dates, the key economic objectives of this project are twofold:

- Ensure value for money for the consumers by delivering cost effective reinforcements to ensure economically efficient design and operation of the network.
- Timely delivery of necessary reinforcement(s) to minimise any cost exposure for consumers to either early investment or delayed implementation.

1.3 Study Objectives and Scope

The context outlined above drives the CBA objectives and scope of National Grid Electricity Transmission (NGET) work. Furthermore, consistent with the **Guidance on Strategic Wider Works arrangements in the electricity transmission price control, RIIO – T1,** the objectives of this CBA are:

- To be consistent with our Licence obligations, National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS), the analysis promotes economic and efficient investment.
- To present economic justification for the preferred designs and an explanation of how they compare with the alternative counterfactual case.
- To present evidence on expected long-term value for money for consumers considering a range of sensitivities, and

- To present evidence on optimal timing of the preferred reinforcement option.

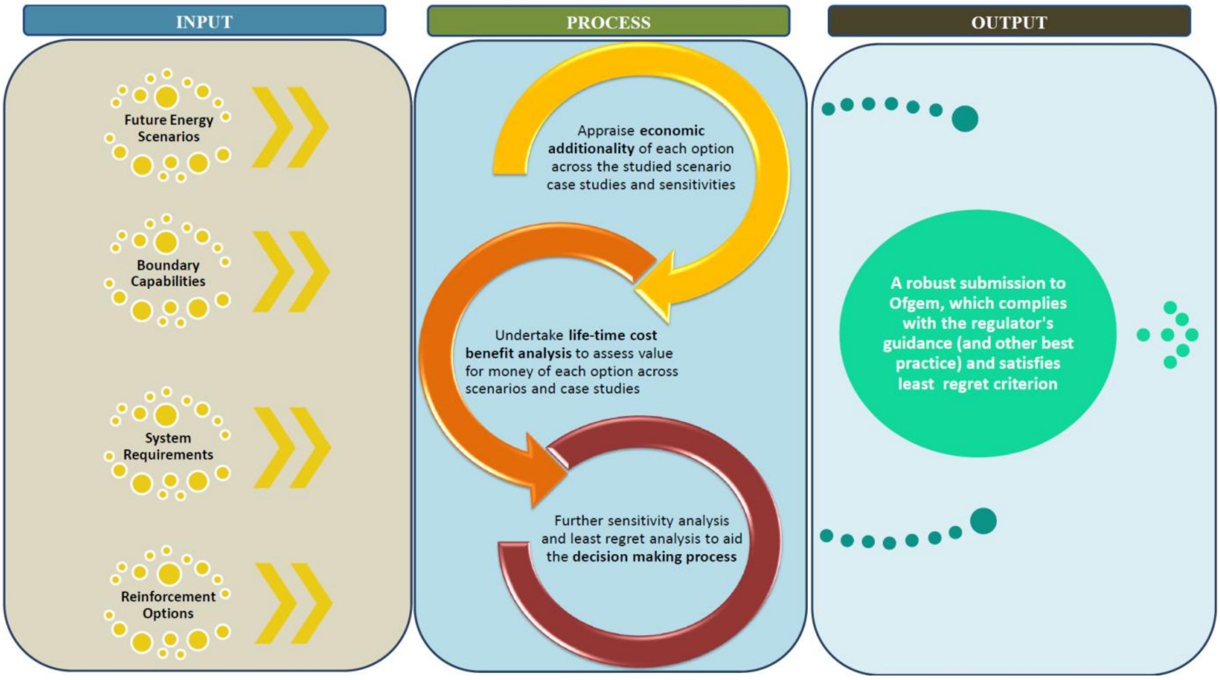
Driven by these objectives the scope of the CBA is outlined below:

- To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across two generation background scenarios.
- To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.
- To undertake a CBA by:
    - Appraising the economic case of the options by adopting the Spackman[1] approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
    - Establishing worst regrets associated with each design/technology appraised.
    - Identifying the Least Worst Regret option overall.
    - Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
- Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

This CBA process is summarised in Figure 1-1 below.

Figure 1-1: National Grid's Cost Benefit Assessment Process

[1] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.



Source: Electricity Ten Year Statement 2013, National Grid

1.4 Structure of the Document

The structure of this CBA document is outlined below:

- **Chapter 1 Introduction** outlines the aims and objectives of the study.
- **Chapter 2 Background** presents boundary capabilities, offshore wind capacity assumptions, wind generation characteristics and offshore network fault rate assumptions.
- **Chapter 3 Options for Economic Appraisal** summarises details of the designs and their costs considered in the CBA.
- **Chapter 4 Counterfactual and Economic Impact of Options** focusses on constraint costs forecasts for the counterfactual case and other designs considered in the CBA
- **Chapter 5 Cost Benefit Assessment** brings together the analysis presented in the earlier chapters using the Spackman approach to develop NPVs, and performs regret analysis to determine the most economic option overall based on minimising regrets across the scenarios.
- **Chapter 6 Sensitivity Analysis** presents the impact of key sensitivities on the analysis presented in Chapter 5. This covers delays on investment and investment cost increase.
- **Chapter 7 Conclusions and Recommendations**.

2 Background

2.1 Introduction

Three large offshore wind generation projects proposing connection along the east coast of Britain from 2020/21 to 2030/31 will impact on the power flows and supply patterns across the transmission system.

Transmission network boundaries B6, B7, B7a, B8, B9 will be impacted primarily by Dogger Bank and Hornsea wind developments, whilst boundary EC5 will be impacted by East Anglia developments. Additionally, local boundaries EC1, EC3, and EC7 may pose a restriction. The potential scale of these developments will also lead to changes of power flow and constraint conditions on the transmission network, particularly when high generation levels are achieved.

Due to the huge array of incremental offshore generation and network build up scenarios, it has not been practical to model development/construction years. Construction is assumed to cover a 10 year period from 2020/21 to 2030/31. No constraint costs (or benefits from partial integration) are assumed during the construction period, but capital costs associated with integration *are* captured and assumed to follow a common annual profile.

The modelling has focussed on the year 2030/31 in which all designs could be fully commissioned and stable. This particular year is assumed representative for the entire asset life. The subsea cables and associated equipment has an assumed life of 40 years. Whilst it could be argued that the network is likely to undergo further changes during a 40 year horizon from 2030/31, it is particularly difficult to forecast the state of the network so far into the future with any sense of accuracy. Consequently, we do not account for speculative projections beyond 2030/31 and simply adopt this year as representative throughout the asset life.

Constraint cost results are taken as the average of 120 discrete model runs for 2030/31, to capture the random nature of fault outages. This ensures a representative inclusion of generation lost as a result of offshore faults, or secured through a secondary (integrated) route to market. This number of simulations has been necessary due to the low fault rates of some of the equipment. Fault rates are assumed constant across the life time of the assets.

The average annual constraint costs derived across the 120 iterative studies are assumed to apply from 2030 for each year of a forty year asset life, and are discounted using the Spackman methodology.

The rest of this chapter discusses the forecast network capabilities, an overview of Future Energy Scenarios 2013 (FES

2013), offshore network fault rate assumptions, wind generation capacity assumptions and generation characteristics.

2.2 Network Capabilities

In order to accommodate new transmission connected generation between now and 2030/31, some network developments will be necessary, irrespective of these offshore wind projects. The extent of these developments is driven by the generation background scenarios of Gone Green and Slow Progression.

Consequently, future transmission boundary capability forecasts have been adopted from National Grid's Electricity Ten Year Statement (ETYS) to form the basis of the onshore network capability. ETYS presents a view by scenario of the likely state of boundary capabilities, based on commissioning dates of new generation.

Where an IOTP(E) design provides additional transmission capability across boundaries, this capability is included in the model assumptions. Where there is no additional capacity associated with the design studied, then the ETYS assumptions remain unaltered.

The network capabilities by boundary for each of the IOTP(E) designs studied can be seen in Appendix 2. Note that the more complex designs have a more complex set of boundary definitions. It is important to note that any boundary capability is sensitive to the demand/generation background used to calculate the capability, and so any change in these can result in network capability changes.

The boundary capabilities (by generation background and by design), also reflect the fact that some transmission assets have a seasonal rating driven primarily by ambient temperatures. The seasons are defined as ***Winter*** (December, January and February) ***Spring/Autumn*** (March, April, May, September, October November) and ***Summer*** (June, July and August).

Subsea cables associated with the IOTP(E) designs do not have seasonal ratings because sea temperatures at depth do not vary much, and water has a much higher thermal mass than air. Consequently, the cable ratings are taken from the design work stream and apply all year.

However, the subsea cables do have statistical fault outage conditions applied in the modelling. Fault outage conditions are an important consideration because even though they are rare, they can impose a significant financial impact if they occur, since the generation may be lost to the wider community. A fault event can lead to increased costs to consumers if the remaining network capability is insufficient for the available generation.

Integrated network designs may mitigate the effect of fault outages by creating secondary transmission routes for generation to reach the market. These characteristics are captured in the modelling in line with fault rate assumptions, boundary capability and wind output levels.

The assumptions for 'per unit' fault rates and Mean Time To Repair (MTTR) for AC and DC primary network components are shown in table 2-1 below: -

Table 2-1 Offshore Fault Rates

	Component	Failure Rate /day	Failure Rate /year	Failure Rate over 40 years	MTTR (days)
DC	Converter	0.0000178	0.0065	0.260	60
	Conv. Transformer	0.0001096	0.0400	1.600	60
	Cable (1km)	0.0000019	0.0007	0.028	60

	Component	Failure Rate /day	Failure Rate /year	Failure Rate over 40 years	MTTR (days)
AC	Transformer	0.000018	0.006600	0.2640	60
	Cable (1km)	0.000002	0.000705	0.0282	60

Source: Cigre Studies and National Grid

The corresponding MTTR period of 60 days is assumed across all equipment types and is regarded as a central view. Faults will in all likelihood be of different durations depending on; their nature, the time of occurrence and ease of access/repair. However, it is difficult to forecast this variance hence a common assumption of sixty days is adopted.

These fault rates are coupled with the corresponding number of units and kilometres of cable for each of the design components, to reflect the total fault rate for each electrical path in each design. The modelling uses random sampling to reflect fault events based on these statistics. The cable distance assumptions from platform-to-shore and platform-to-platform are shown in table 2-2 below: -

Table 2-2 Offshore Distances

DOGGER BANK	Offshore Cable Distance (km)
P1	212.5
P2	261.0
P3	222.8
P4	215.1
P5	210.6
P6	246.3
P1-P2	72.9
P1-P3	28.2
P1-P4	30.6
P2-P3	41.2
P2-P4	95.3
P2-P6	49.4
P3-P4	35.3
P3-P5	34.1
P4-P5	31.8
P5-P6	36.5

HORNSEA	Offshore Cable Distance (km)
P1	150
P2	125
P3	125
P4	138
P1-P3	64
P2-P3	38
P1-P4	29
P2-P4	56
P1-P2	27
P3-P4	38

EAST ANGLIA	Offshore Cable Distance (km)
P1	73
P2	43
P3	140
P4	160
P5	24
P6	68

In addition, three other general cable distance assumptions have been adopted: -

- Where not specified, an integrating High Voltage Direct Current (HVDC) platform to any connecting offshore windfarm HVDC platform on the same zone is 30km
- The distance between Dogger Bank and Hornsea is 120km and the distance between Hornsea and East Anglia is 100km
- The distance from Scotland (Bootstrap) to EC7, EC1 and EC3 local boundary areas are assumed to be 150km, 250km and 350km respectively.

2.3 Future Energy Scenarios 2013

The Future Energy Scenarios[2] (FES) are prepared by National Grid in consultation with key industry stakeholders including the transmission system owners, DECC, and the Electricity Networks Strategy Group (ENSG). The FES outputs are each built on a set of central axioms to represent a credible scenario. Collectively, they are designed to represent a range of possible outcomes, which may be used to examine future network requirements.

FES 2013 comprised two main background scenarios, namely Slow Progression (SP) and Gone Green (GG)

An overview of the key axioms and principles of the Slow Progression and Gone Green background scenarios are:

- **Slow Progression:** Developments in renewable and low carbon energy are comparatively slow and the renewable energy target for 2020 is not met until sometime between 2020 and 2025. The carbon reduction target for 2020 is achieved but not the target for 2030.
- **Gone Green:** Assumes a balanced approach with contributions from different generation sectors in order to meet the environmental targets. GG sees the renewable target for 2020 and the emissions targets for 2020 and 2030 all met.

As described in Chapter 1, these background scenarios, with two assumed levels of offshore wind development at Dogger Bank, Hornsea and East Anglia form the basis of the analysis.

The remainder of this chapter outlines the wind generation capacities and load factor characteristics studied to appraise the efficiency of the investment options.

[2] FES 2013 document can be sourced from http://www2.nationalgrid.com/Media/UK-Press-releases/2013/National-Grid-s-UK-Future-Energy-Scenarios-2013/.

2.4 *Offshore Wind*

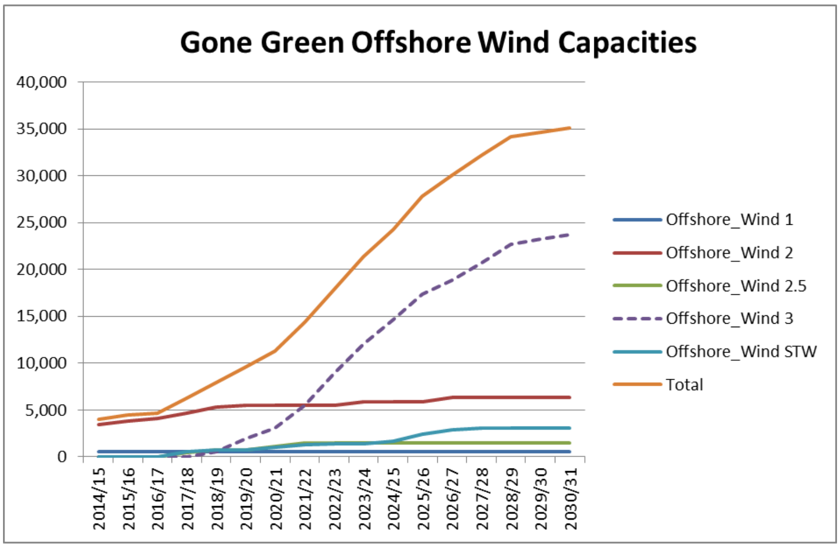
There are two offshore wind generation capacity cases under consideration which are intended to capture a credible range of development outcomes. These two studies are referred to as: -

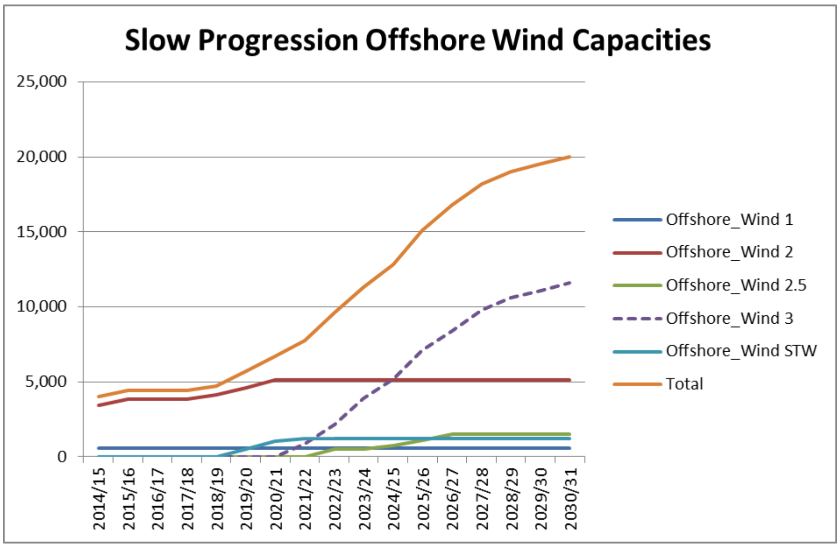
1. Scenario 1 - with a total of 10GW of IOTPE wind capacity
2. Scenario 2 - with a total of 17.2GW of IOTPE wind capacity

Scenario 1 represents the largest wind capacity development across the three wind generation projects based on contracted positions, whilst Scenario 2 was agreed by the working group to reflect a less aggressive overall build programme.

The FES 2013 provides assumptions on the total capacity of offshore wind development based on stakeholder engagement and the agreed scenario axioms. Both the GG and SP scenarios are consistent with IOTP(E) wind capacities. i.e. the modelled wind development capacities of 10.0GW and 17.2GW shown above are within the corresponding offshore wind capacities by FES scenario. The 2030/31 offshore wind capacity assumptions along with the build-up for offshore wind capacity under both FES scenarios are shown in table 2-3 below: -

Table 2-3 Total Wind Capacities by Round





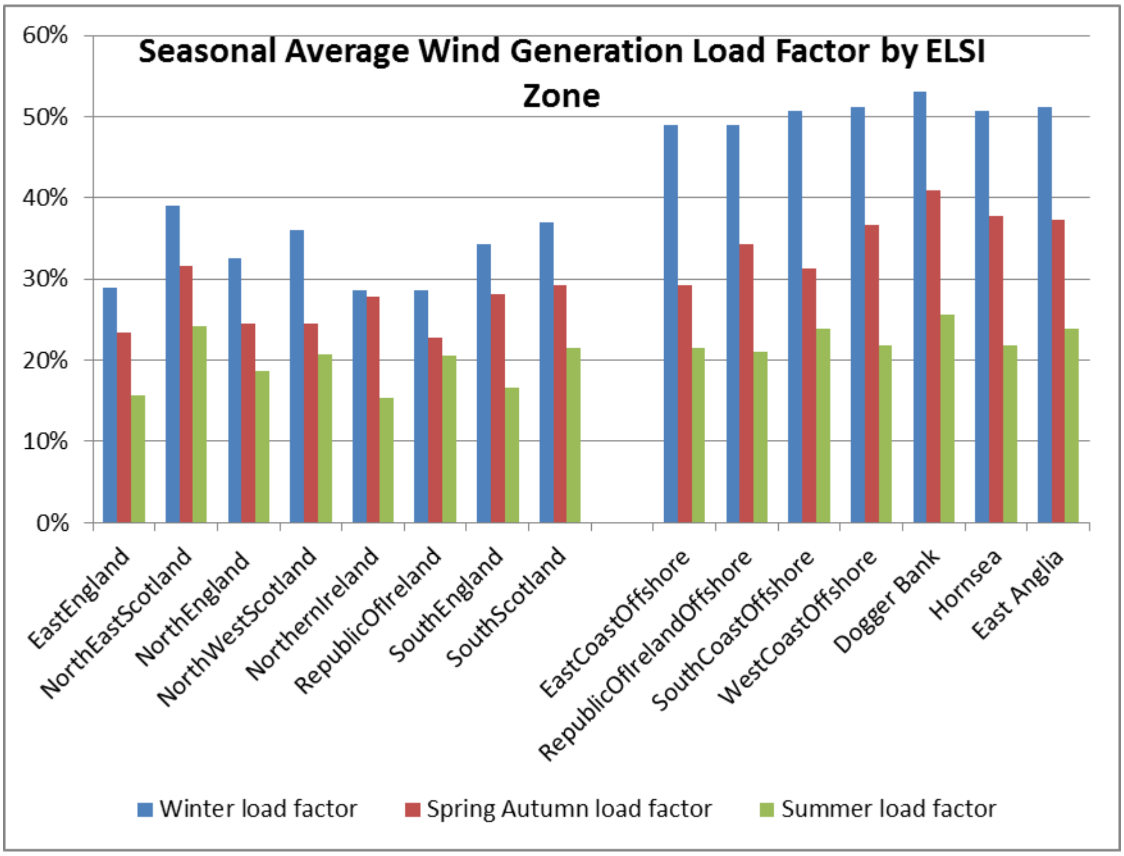
2.5 *Wind Generation Load Factors and Characteristics*

The Electricity Scenario illustrator (ELSI) modelling process samples a ten year historical data set to represent wind generation load levels. The model selects a day from the season under study, and reads the corresponding load factors for each wind zone, for each period of that day. The original source data from which these tables have been derived is from the Meteorological Office. The ten years' worth of data is broken up into 15 geographical zones reflecting locational spread. Consequently, each data sample respects seasonality, time of day effects and locational correlation.

Having this data selection method, means that the full range of credible load factors and zonal correlations is captured in the analyses and the results reflect seasonal and time of day effects.

The seasonal average wind generation load factors by ELSI zone are shown in table 2-4 below: -

Table 2-4 Seasonal Average Wind Load Factors by model Zone



The annual average wind load factors for the three projects Dogger Bank, Hornsea, East Anglia are 40.1%, 37.1% and 37.4% respectively. Evidence suggests this is representative of other offshore wind generation studies.

It can be seen that the offshore zones have better load factors (driven by higher wind speeds) than onshore zones. Similarly, northerly zones (such as Scotland) also benefit from stronger wind speeds. In all zones, load factors are highest in winter and lowest in summer.

Zonal Correlation of ELSI Wind Zones

Zonal correlation of wind generation is an important consideration since this could have a significant impact on power flows and corresponding constraint costs. The correlation matrix between the three key zones Dogger Bank, Hornsea and East Anglia reflects the relative distances between the zones. i.e. neighbouring zones have a higher correlation than more distant zones of Dogger Bank and East Anglia, as shown in table 2-5 matrix below.

Table 2-5 Wind Generation Correlation matrix for IOTP(E) Zones

ELSI Wind Generation Correlation Matrix - New Zones	DoggerBank	Hornsea	East Anglia
DoggerBank		0.85	0.49
Hornsea			0.64
East Anglia			

The wider zonal pattern of correlation for the other ELSI zones exhibit similar trends. Once again, it can be seen that zones in close proximity have higher correlation values than more distant zones. The remaining ELSI zone correlation matrix is shown in table 2-6 below highlighting the highest and lowest correlation values: -

Table 2-6 Wind Generation Correlation matrix for other Zones

ELSI Wind Generation Correlation Matrix	EastEngland	NorthEastScotland	NorthEngland	NorthWestScotland	NorthernIreland	RepublicOfIreland	SouthEngland	SouthScotland	EastCoastOffshore	RepublicOfIrelandOffshore	SouthCoastOffshore	WestCoastOffshore
EastEngland		0.47	0.78	0.39	0.52	0.55	0.69	0.55	0.79	0.59	0.65	0.71
NorthEastScotland			0.65	0.80	0.56	0.49	0.31	0.71	0.49	0.50	0.27	0.49
NorthEngland				0.53	0.68	0.66	0.62	0.77	0.75	0.69	0.56	0.81
NorthWestScotland					0.58	0.51	0.27	0.68	0.36	0.46	0.22	0.43
NorthernIreland						0.91	0.50	0.76	0.48	0.69	0.40	0.69
RepublicOfIreland							0.60	0.73	0.49	0.72	0.47	0.75
SouthEngland								0.44	0.67	0.56	0.85	0.78
SouthScotland									0.50	0.66	0.34	0.67
EastCoastOffshore										***0.62***	***0.70***	***0.74***
RepublicOfIrelandOffshore											0.55	0.82
SouthCoastOffshore												0.75
WestCoastOffshore												

The combination of representative seasonal and time of day load factors, along with representative correlation between zones, provides a reasonable basis to assess the impact on transmission system power flows associated with new wind generation developments.

It should be noted that the ten year wind data set used in ELSI does include a range of stronger and weaker wind characteristics, and as such captures some natural variance. However, this does not eliminate the chance of experiencing unusual weather patterns following commissioning.

3 Options for Economic Appraisal

3.1 Introduction

A key objective of the project, as outlined in Chapter 2, is to deliver efficient network capability to meet future system requirements. In order to meet these requirements, a range of network designs were prepared by the working group, to be taken into the CBA. The CBA appraises these designs against the counterfactual position.

This chapter presents further details of these options.

3.2 Design Options

Fourteen original designs were selected by the working group for CBA from a much wider set of design alternatives. They were chosen to represent the broad range of technology alternatives and include various size links to shore, two bootstrap designs, and various integrated configurations. Some designs are broadly comparable despite the need to accommodate different wind capacities. This allows the results to be grouped by design/technology such that broad comparisons can be made.

Diagrams of all the designs can be found in Appendix 1 which shows the layout and rating of each major asset. The diagrams are illustrative and not to scale.

There are a total of eight network designs associated with the 10GW offshore wind capacity. In summary, the designs have the following labels and key design characteristics: -

The Base Case (Radial Design) – Predominantly 1GW links from offshore hubs to onshore.
Design 2a – Predominantly 1GW links from offshore hubs to onshore, with a 2.5GW near-shore link (Scotland to Walpole) crossing transmission boundaries B6, B7, B7a, B8 and B9.
Design 2c – A mix of 1GW and 2GW links from offshore hubs to onshore, with a 2.5GW near-shore link (Scotland to Walpole) crossing transmission boundaries B6, B7, B7a, B8 and B9.
Design 3a - Predominantly 1GW links from offshore hubs to onshore, with a 2.5GW near-shore link (Scotland to Killingholme) crossing transmission boundaries B6, B7 and B7a.
Design 4a – Same as 3a except for some within zone links between offshore hubs.
Design 5a (Optimised) - Predominantly 1GW links from offshore hubs to shore with a 1GW offshore links between zones.
Design 5b – Larger 1.8GW, 2.0GW and 2.2GW links to shore with 1GW offshore inter-zonal links.

The model results for these seven designs were presented to the Working Group in September and led to significant debate on the economic benefits associated with fewer larger capacity links to shore. Concern was expressed that insufficient analysis had been undertaken to give a representative view of the relative merit of such designs. Consequently, an additional design (5b anticipatory) utilising the largest capacity links to shore, was added to the suite of options to help inform the analysis.

Design 5b (Anticipatory) – Similar to 5a (which was a favoured design initially), but with even larger links than design 5b from Hornsea and East Anglia offshore platforms to shore, and larger 1.2GW offshore inter-zonal links.

Importantly, the suite of designs was chosen to collectively cover a range of cable technologies and configurations, since it is not practical to consider every possible design permutation.

There are a further seven designs associated with the larger 17.2GW offshore wind capacity assumption. These can be summarised as: -

The Base Case (Radial Design) – Predominantly 1GW links from offshore hubs to onshore, sufficient to cater for the larger 17.2GW of wind capacity.
Design 10a - Predominantly 1GW links from offshore hubs to onshore, with a 2.5GW near-shore link (Scotland to Killingholme) crossing transmission boundaries B6, B7 and B7a.
Design 10c - 1GW, 1.2GW, 1.8GW and 2GW links from offshore hubs to onshore, with a 2.5GW near-shore link (Scotland to Killingholme) crossing transmission boundaries B6, B7 and B7a.
Design 13a – Same as 10a, but includes some within zone links between some Dogger Bank platforms and Hornsea platforms.
Design 13c – Same as 10c, but includes more within zone links between Dogger Bank platforms.
Design 15a (Optimised) - Predominantly 1GW and 1.8GW links from offshore hubs to shore with a 1GW offshore mesh between zones.
Design 15c (Optimised) – Similar to 15a with 1GW offshore links between zones, but with some larger capacity links from offshore hubs to shore.

Designs 5a, 15a and 15c are labelled as having been Optimised, which means that their designs were reviewed and improved early in the process.

Some of the 10GW wind capacity designs broadly correspond to the 17.2GW capacity designs. This is a useful feature in that they can be grouped together for regret analysis.

3.3 Option Costs

The capital cost estimates for the designs are presented in table 3-1 below and have been calculated using data provided by the

Technology work stream. These estimates are broad engineering figures and do not have any specific allowance for contingencies or professional fees. A sensitivity increasing costs by 20% is considered in Chapter 6.

The portion of the total design cost attributable to the integration elements is reported separately. The cost portion associated with a radial connection design represents the least cost connection and is the radial counterfactual case against which other designs are assessed.

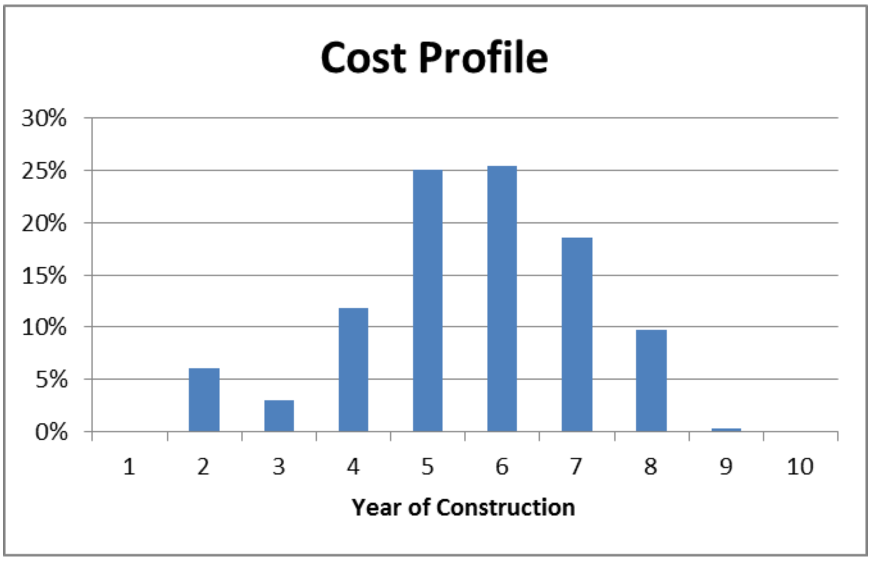
Table 3-1 Capital Cost Forecasts

	IOTP DESIGNS	Radial Cost (£Billion)	Reinforcement Cost (£Billion)	Total Cost (Radial + Reinforcement) (£Billion)
10GW Capacity Designs	Base Case (Radial)	6.33	0.00	6.33
	2a Bootstrap to Walpole and 1GW links	6.33	0.92	7.25
	2c Bootstrap to Walpole and 2GW links	5.54	1.04	6.58
	3a Bootstrap to KILS with 1GW links	6.33	1.10	7.43
	4a Hybrid Bootstrap with 1GW links	6.33	1.05	7.38
	5a Offshore 1GW HVDC (optimised)	6.94	1.40	8.34
	5b Offshore 2GW HVDC (optimised)	5.54	1.26	6.80
	5b (Anticipatory) Offshore 2.2GW	5.44	1.15	6.59
	Base Case (Radial) with onshore reinforcement	6.33	0.87	7.20
17.2GW Capacity Designs	Base Case (Radial)	10.29	0.00	10.29
	10a Onshore Design with 1GW links	10.29	1.43	11.72
	10c Onshore Design with 1GW links	9.64	1.44	11.08
	13a Hybrid offshore and Bootstrap with 1GW links	10.33	1.26	11.59
	13c Hybrid offshore and Bootstrap with 2GW links	9.60	1.05	10.65
	15a Offshore HVDC 1GW (optimised)	10.33	1.81	12.14
	15c Offshore HVDC 2GW (optimised)	10.05	1.53	11.58
	Base Case (Radial) with onshore reinforcement	10.29	0.87	11.16

Source: National Grid

It has not been possible to establish the precise profile of capital cost expenditure for each design at this stage. Therefore, a generic profile has been adopted based on the Western HVDC link project, as shown in diagram 3-2 below. The profile spans a ten year period from 2020/21 to 2030/31 and is thought broadly reflective of large subsea cable projects, in that the majority of the costs fall in the central period of the construction phase.

Table 3-2 Capital Cost Profile



Source: National Grid

The cost of design integration is limited to the additional cost associated with the reinforcement components and does not extend to the underlying radial configuration. Therefore, only the costs associated with integration have been used to calculate the Present Value (PV) of costs for integrated designs. This means we have isolated the additional spend against which any corresponding constraint savings can be compared. The constraint savings are similarly measured relative to the underlying radial configuration.

Appendix 4 shows an alternative method based on minimising the combined investment cost and constraint cost overall, which leads to the same conclusions.

The PV calculation process follows the 'Spackman' methodology which is the accepted approach for large infrastructure projects under regulatory supervision. These cost estimates include the following assumptions:

- A **Weighted Average Cost of Capital or WACC**, which is currently estimated at **4.55% p.a**., and
- A **Social Time Preference Rate or STPR**, which is estimated at **3.5% p.a.** by HM Treasury.

Further details of the Spackman approach and other elements of the CBA are presented in Chapter 5. Chapter 4 outlines the forecast of economic impacts measured in terms of constraint cost savings for designs appraised in this CBA. These forecasts also form part of the CBA presented in Chapter 5.

4 Counterfactual and Economic Impact of Options

4.1 *Introduction*

The **Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1** states that a reinforcement option is economic when the cost of the project is less than the benefit to consumers.

Within this context, this section outlines the forecasts of constraint costs and lost welfare benefits likely to be incurred by consumers in two counterfactual cases (10GW and 17.2GW total IOTP(E) offshore wind capacity) across the two generation backgrounds (Gone Green and Slow Progress). Furthermore, the chapter also presents the PV of constraint costs and lost benefits for each design considered, and subsequent Net Present Values accounting for PV of integration investment costs.

4.2 *Modelling of Constraint Costs and Welfare benefit*

Constraint costs are incurred when the desired power transfer across a transmission system boundary exceeds the maximum operational capability of that boundary. When this occurs, it is necessary to pay generation behind that boundary to reduce production (constrain their output) and replace this energy with generation located in an unconstrained area of the network to balance the system.

Under current arrangements, constraint payments are made to onshore Generators, but not to offshore generators. ROCs / cfd’s are not paid when Generators are not delivering energy. Consequently the consumer will pay less when offshore wind generation is constrained, as the reduced ROC/cfd payments outweigh the cost of bringing on onshore generation. However, established practice in cost benefit assessment of offshore wind is to assume that higher availability brings consumer benefit through its contribution to meeting renewable energy targets, and its potential to offset the need to develop further offshore generation to ensure that targets are met. In the analysis described in this report this benefit is represented by applying constraint costs to offshore generation. The applied constraint cost includes the value of ROCs / cfds that would be paid if the energy was provided.

ELSI is National Grid’s in-house model to prepare medium to long term constraint forecasts on the transmission network. The model is our preferred tool to inform long term investment decisions. ELSI studies have previously been used to demonstrate the economic impact of our RIIO Capex Programme spanning 2010-2030. Equally, it performs a similar role for our Network Development Plan (NDP) analysis and production of the Electricity Ten Year Statement (ETYS), one of our key licence obligations.

ELSI is a Microsoft Excel based model which utilises Visual Basic linear programming to perform optimisations. Additionally, unlike most tools, ELSI adopts a transparent modelling approach, where all input assumptions and algorithms are accessible to the user.

ELSI represents the GB electricity market, in which the energy market is assumed to be perfectly competitive; i.e. there is perfect information for all parties, sufficient competition so that suppliers contract with the cheapest generation first, and that there are no barriers to entry and exit.

The electricity transmission system is represented in ELSI by a series of zones separated by boundaries. The total level of generation and demand is modelled such that each zone contains specific generation capacity by fuel type (CCGT, Coal, Nuclear etc.) and a percentage of overall demand.

Zonal interconnectivity is defined in ELSI to reflect existing and future boundary capabilities. The boundaries, which represent the transmission circuits facilitating this connectivity, have a maximum capability that restricts the amount of power which can be securely transferred across them.

ELSI models the electricity market in two main steps:

- The first step looks at the short run marginal cost (SRMC[3]) of each fuel type and dispatches available generation from the cheapest through to the most expensive, until the total level of GB demand is met. This is referred to as the ‘unconstrained dispatch’. The network is assumed to have infinite capacity and so does not impinge on the unconstrained dispatch.
- The second step takes the unconstrained dispatch of generation and looks at the resulting power transfers across the boundaries. ELSI compares the power transfers with the actual boundary capabilities and re-dispatches generation where necessary to relieve any instances where power transfer exceeds capability (i.e. a constraint has occurred). This re-dispatch is referred to as the ‘constrained dispatch’ of generation.

The algorithm within ELSI will relieve the constraints in the most economic and cost effective way by using the SRMC of each fuel type. The cost associated with moving away from the most economic dispatch of generation (unconstrained dispatch), to one which ensures the transmission network remains within its limits (constrained dispatch) is known as the operational constraint cost and is calculated using the bid and offer price associated with each action.

Like industry benchmark tools for constraint cost forecasts, ELSI includes various input data including:

- Transmission Network

[3] Note that ELSI models SRMC (£/MWh) = Production (£/MWh) + Carbon emissions (£/MWh) + zonal adjuster (£/MWh)

    - Boundary capability assumptions
    - Seasonal ratings
    - Annual outage plan for each boundary
- Economic Assumptions
    - Fuel costs and price of carbon forecasts
    - Thermal efficiency assumptions by fuel type
    - Bid and Offer price assumptions by fuel type based on historical data
    - Seasonal plant availability by fuel type based on historical data
    - Renewable subsidies
    - Forecasts for base load energy price in Europe and Ireland
    - Forecast SRMCs by fuel type, which defines the merit order
    - Zonal SRMC adjuster
- Generation scenarios and sensitivities
- Demand
    - Demand profile or load duration curve
    - Zonal distribution of peak demand
    - Forecast annual peak demand based on two energy scenarios
- Wind generation
    - Represented by sampling ten years of historical daily wind speed data. Each day studied is defined by season and is divided up into four periods within the day.
    - ELSI model disaggregates the wind data into fifteen zones, with Dogger Bank, Hornsea and East Anglia separately represented. This allows for temporal and locational wind diversity in ELSI
- Reinforcements
    - Onshore reinforcements anticipated in ETYS for both generation backgrounds that are delivered by 2030/31.
    - The offshore integrated capability across each boundary provided by each design from 2030/31.

4.3 Forecasts of Constraint Costs: Counterfactual

Best practice when undertaking ex-ante economic appraisals requires a clear definition of the counterfactual for comparison purposes. In particular, the counterfactual involves an assumption about the future state of the network in the absence of other proposals.

For the purpose of this CBA, the counterfactual network state is:

- Radial HVDC links from offshore hubs to onshore connection points utilising 1GW cable technology for the Dogger Bank and Hornsea zones. East Anglia zone utilises a range of cable technologies and includes some within zone links. This offers some redundancy within the zone.
- Limited onshore reinforcements necessary to ensure NETS SQSS compliance. This is based on the wider GB network investment projections identified in the ETYS 2013 out until 2030, and reflects each generation background.

The remainder of this section presents forecasts of constraint costs across the two generation backgrounds and offshore designs. These are compared to the corresponding counterfactual case to establish annual constraint savings.

It is worth noting that all forecasts are modelled and reported for the entire GB network. Furthermore, the forecasts are focussed on 2030/31 since this is considered the earliest date by which the completed system is considered feasible. This year is then adopted over the rest of the asset life.

Table 4-1 presents annual constraint cost forecasts for the counterfactual case and related designs, for the wind capacity scenario totalling 10GW, spread across the three zones.

Table 4-1: Constraint Cost Forecasts for the 10GW Wind Capacity Scenario

10GW IOTP(E) Offshore Wind Capacity Designs	Gone Green Average Annual Constraint Costs (in £m)	Slow Progression Average Annual Constraint Costs (in £m)
Base Case (Radial Design)	952	730
Design 2a	328	260
Design 2c	408	208
Design 3a	441	423
Design 4a	386	300
Design 5a (Optimised)	293	273
Design 5b (Optimised)	407	217
Design 5b (Anticipatory)	371	194
Base Case plus onshore reinforcement	488	362

Source: National Grid

A corresponding table of annual constraint cost forecasts based on the larger 17.2GW wind capacity assumption is shown in Table 4-2 below.

Table 4-2: Constraint Cost Forecasts for 17.2GW Wind Capacity Scenario

17.2GW IOTP(E) Offshore Wind Capacity Designs	Gone Green Average Annual Constraint Costs (in £m)	Slow Progression Average Annual Constraint Costs (in £m)
Base Case (Radial Design)	1,091	1,000
Design 10a	923	634
Design 10c	434	345
Design 13a	425	587
Design 13c	386	451
Design 15a (Optimised)	306	307
Design 15c (Optimised)	336	289
Base Case plus onshore reinforcement	606	494

Source: National Grid

It can be seen that for the radial connection designs the annual constraint costs tend to be larger where greater offshore wind capacity is developed.

4.4 *Economic Impact*

This section presents the forecast of economic impact for the designs appraised in this CBA across both generation backgrounds.

The economic impact is defined as the constraint cost savings as described in Chapter 1 relative to the counterfactual case (radial links to shore), versus the additional cost of integration.

The annual value for constraint savings in 2030/31 for each study is assumed across the entire 40 year asset life and depreciated at the Social time Preference Rate (STPR) of 3.5%.

Constraint savings that may occur as a result of a partial network during the construction phase are ignored, as it is not possible to appraise the wide range of permutations. In this sense the savings could be regarded as pessimistic since some additional savings through a partially built network could offer additional benefit during construction.

Relative to the counterfactual case, each of the related designs offers an annual constraint cost saving. These annual savings are shown below in table 4-3 for the 10GW offshore wind capacity study.

Table 4-3: Central 2030 Constraint Savings

10GW IOTP(E) Offshore Wind Capacity Designs	Gone Green Annual Constraint savings against Base Case (£m)	Slow Progression Annual Constraint savings against Base Case (£m)
Design 2a	624	471
Design 2c	544	522
Design 3a	511	307
Design 4a	566	430
Design 5a (Optimised)	659	458
Design 5b (Optimised)	545	513
Design 5b (Anticipatory)	581	537
Base Case plus onshore reinforcement	464	369

Source: National Grid

Similarly, the annual constraint savings offered by the larger 17.2GW offshore wind capacity studies are shown in table 4-4 below. In some cases, as the scale of design integration increases, the savings in constraint costs relative to the counterfactual case increase.

Table 4-4: TEC 2030 Constraint Savings

17.2GW IOTP(E) Offshore Wind Capacity Designs	Gone Green Annual Constraint Cost Savings against Counterfactual (£m)	Slow Progression Annual Constraint Cost Savings against Counterfactual (£m)
Design 10a	168	366
Design 10c	657	655
Design 13a	667	413
Design 13c	705	550
Design 15a (Optimised)	786	694
Design 15c (Optimised)	756	711
Base Case plus onshore reinforcement	485	507

Source: National Grid

5 Cost Benefit Assessment

5.1 Introduction

At its simplest level, the assessment compares the PV of integration costs with the PV of forecast constraint cost savings. Where the constraint cost savings exceed the integration investment cost, then the investment is considered economic. In order to help develop robust conclusions a range of generation backgrounds, designs and sensitivities have been considered.

This chapter brings together the analysis presented earlier of investment costs and constraint savings to establish an overall Net Present Value (NPV) for each of the different designs. Further details of the methodology along with relevant assumptions used to perform different elements of CBA are presented later in this chapter.

All future values are discounted on an annual basis to account for the time-value of money. The discounting method follows the 'Spackman' methodology, widely recognised and endorsed by utility Regulatory bodies.

The design NPVs are used to perform Regret analysis, and subsequently to determine the most economic option based on a Least Worst Regret (LWR) approach.

5.2 Net Present Value of the Design Options

In order satisfy the Spackman methodology, the future costs associated with integrated design components and constraints savings both have to be represented by a PV. To achieve this for the investment costs, two steps are undertaken: -

- The annual investment costs across the construction phase are 'mortgaged' at a post-tax WACC of 4.5% over the asset life.
- Future payments on investments are discounted at HM Treasury's STPR of 3.5%

Similarly, the PV figures for corresponding constraint cost savings are discounted: -

- This is achieved with the same STPR discount rate of 3.5%. The base year for this is 2014 and the construction runs from 2020/21 to 2030/31, hence the savings do not commence until 2030/31 on completion of the build, and then run for 40 years.

Table 5-1 below presents a matrix summary of the constraint saving PVs and additional integration cost PVs for each design. The table distinguishes the results by Gone Green and Slow Progression backgrounds.

In order to make a comparison between the designs, the investment PV is deducted from the constraint savings PV to give a relative Net Present Value (NPV) for each design. This provides a comparative measure of the value of the scheme with both costs and benefits accounted for.

Table 5-1:PVs and NPVs of the options considered (in £m)

		Gone Green			Slow Progression		
	Design	PV of constraint savings	PV of additional cost of Integration	NPV: Constraints minus Additional costs	PV of constraint savings	PV of additional cost of Integration	NPV: Constraints minus Additional costs
10GW Offshore Wind Capacity	Design 2a	£7,685	£778	£6,907	£5,799	£778	£5,020
	Design 2c	£6,705	£876	£5,829	£6,434	£876	£5,558
	Design 3a	£6,290	£926	£5,363	£3,785	£926	£2,859
	Design 4a	£6,977	£1,043	£5,933	£5,302	£1,043	£4,258
	Design 5a (Optimised)	£8,111	£1,179	£6,932	£5,638	£1,179	£4,459
	Design 5b (Optimised)	£6,716	£1,061	£5,655	£6,323	£1,061	£5,261
	Base Case plus onshore reinforcement	£5,721	£736	£4,985	£4,543	£736	£3,807
	Design 5b (Anticipatory)	£7,159	£968	£6,190	£6,607	£968	£5,639
17.2GW Offshore Wind Capacity	Design 10a	£2,066	£1,204	£861	£4,508	£1,204	£3,303
	Design 10c	£8,095	£1,213	£6,882	£8,067	£1,213	£6,854
	Design 13a	£8,208	£1,061	£7,147	£5,086	£1,061	£4,025
	Design 13c	£8,681	£884	£7,797	£6,772	£884	£5,888
	Design 15a (Optimised)	£9,675	£1,524	£8,150	£8,545	£1,524	£7,021
	Design 15c (Optimised)	£9,305	£1,288	£8,017	£8,758	£1,288	£7,469
	Base Case plus onshore reinforcement	£5,976	£736	£5,239	£6,239	£736	£5,503

Source: National Grid

The analysis confirms that relative to the counterfactual radial link designs, all design alternatives have a positive economic case. This is evident in the positive NPVs which are driven by having greater constraint savings then integration investment costs.

However, values of the designs differ considerably depending on the scale of offshore wind capacity assumption and the generation background. The largest NPVs are attributable to designs for the largest 17.2GW offshore wind capacity coupled with the Gone Green generation background.

Summarising the NPVs for each design gives the table 5-2 below:-

Table 5-2: NPVs Summary

NPVs of each Design £m	Gone Green		Slow Progression	
	10GW	17.2GW	10GW	17.2GW
Base Case plus onshore reinforcement	4,985	-	3,807	-
Design 2a	6,907	-	5,020	-
Design 2c	5,829	-	5,558	-
Design 3a	5,363	-	2,859	-
Design 4a	5,933	-	4,258	-
Design 5a (Optimised)	6,932	-	4,459	-
Design 5b (Optimised)	5,655	-	5,261	-
Design 5b (Anticipatory)	6,190	-	5,639	-
Base Case plus onshore reinforcement	-	5,239	-	5,503
Design 10a	-	861	-	3,303
Design 10c	-	6,882	-	6,854
Design 13a	-	7,147	-	4,025
Design 13c	-	7,797	-	5,888
Design 15a (Optimised)	-	8,150	-	7,021
Design 15c (Optimised)	-	8,017	-	7,469
Max	*6,932*	*8,150*	*5,639*	*7,469*

Given that the analysis must be robust against the uncertainty of generation background and eventual wind capacity, Regret analysis is now considered as it is the acknowledged assessment mechanism for uncertainty of this type.

5.3 Regret Analysis

Regret analysis is designed to identify solutions from a range of possibilities which are least likely to be wrong. It is not designed to pick options that may offer the largest benefit, although this could occur coincidentally. This provides a more robust decision against the range of uncertainties, and minimises the chance of an adverse result impacting consumers.

In this analysis, the regret is defined as the difference in the NPV between ‘the option being considered’ and ‘the best possible option for that scenario’, i.e. all options are considered against the option which provides the maximum NPV (taking into account the investment and operational costs). It follows that the best alternative has zero regret against which all other options are compared.

This analysis is repeated for all scenarios and importantly, different options could be identified as the zero regret (best) alternative in different scenarios. The resulting regret measures are shown in table 5-3 below: -

Table 5-3: Regret Summary

Regrets	Gone Green 10GW Offshore Capacity (£m)	Gone Green 17.2GW Offshore Capacity (£m)	Slow Progression 10GW Offshore Capacity (£m)	Slow Progression 17.2GW Offshore Capacity (£m)	Worst Regret (£m)
Base Case plus onshore reinforcement	1,947	-	1,833	-	1,947
Design 2a	25	-	619	-	619
Design 2c	1,102	-	81	-	1,102
Design 3a	1,568	-	2,780	-	2,780
Design 4a	999	-	1,381	-	1,381
Design 5a (Optimised)	0	-	1,180	-	1,180
Design 5b (Optimised)	1,276	-	378	-	1,276
Design 5b (Anticipatory)	741	-	0	-	741
Base Case plus onshore reinforcement	-	2,911	-	1,966	2,911
Design 10a	-	7,289	-	4,166	7,289
Design 10c	-	1,268	-	615	1,268
Design 13a	-	1,003	-	3,444	3,444
Design 13c	-	353	-	1,581	1,581
Design 15a (Optimised)	-	0	-	448	448
Design 15c (Optimised)	-	134	-	0	134

The integrated design 15c is the least worst regret option overall with £134m of regret.

Grouping the NPVs presented in Table 5-2 into comparable design technologies, wind capacities and generation background provides the basis for regret analysis. The grouping of the designs follows this approach:

- Whilst seeking to retain the major design philosophy (offshore integration, near-shore bootstrap, radial etc.), grouping by cable technology/size.

Therefore, where some 2/2.2GW cables are included in a design this may be grouped with other related designs that also part utilise this technology. The groupings are shown in table 5-4 below: -

Table 5-4: Grouping Summary

Grouping by Design, Technology and by Scenarios:	Designs: 10GW Offshore Capacity	Designs: 17.2GW Offshore Capacity
Base Case plus onshore	Base Case plus onshore	Base Case plus onshore
Bootstrap 1 GW	2a and 3a	10a
Hybrid bootstrap 2 GW	2c	10c
Hybrid offshore 1 GW	4a	13a
Hybrid offshore 2 GW	none	13c
Integrated 1 GW	5a (Optimised)	15a (Optimised)
Integrated 2 GW	5b (Opt.) and 5b (Ant.)	15c (Optimised)

Based on these groupings, the condensed NPV table 5-5 is shown below.

Table 5-5: Grouping NPVs

NPVs of Designs (grouped by Technology) £m	Gone Green		Slow Progression	
	10GW Offshore Capacity (£m)	17.2GW Offshore Capacity (£m)	10GW Offshore Capacity (£m)	17.2GW Offshore Capacity (£m)
Base Case plus onshore	4,985	5,239	3,807	5,503
Bootstrap 1 GW	6,907	861	5,020	3,303
Hybrid bootstrap 2 GW	5,829	6,882	5,558	6,854
Hybrid offshore 1 GW	5,933	7,147	4,258	4,025
Hybrid offshore 2 GW	NA	7,797	NA	5,888
Integrated 1 GW	6,932	8,150	4,459	7,021
Integrated 2 GW	6,190	8,017	5,639	7,469
Max £m	*6,932*	*8,150*	*5,639*	*7,469*

Source: National Grid

For each of the four study combinations the design with the greatest NPV is shaded. In the absence of any uncertainty of outcome, these designs and technologies would offer greatest value.

In all studies, an economic advantage exists relative to the equivalent radial design, demonstrated by the positive NPVs. There is no model result in which a counterfactual radial link design offers an economic benefit relative to the other designs. This will not necessarily hold true for offshore wind capacities below the modelled 10GW level.

Least Worst Regret

The Least Worst Regret (LWR) methodology requires that design preference is based on the option that is least likely to result in an adverse outcome overall. The underlying philosophy is that it is advantageous to pick the solution that has the least chance of being wrong across the range of eventualities, given the uncertainties in forecasts and other assumptions. This approach ensures that unfavourable combinations are avoided. It assumes that all eventualities are seen as credible outcomes at the investment decision.

The measure of regret for each combination of design and scenario is defined as the difference in NPVs between the design in question and the best possible alternative in that scenario. This is derived by taking the difference between the best (largest) NPV in each column and the NPV for each related design. Comparable designs and technologies have been grouped together by row such that the worst regret for each design/technology can be established.

The Worst Regret column is the highest regret value across the four conditions. The resulting regret values are shown in Grouped Regrets table 5-6 below: -

Table 5-6: Grouped Regret Analysis

Design & Technology by Scenarios: Regrets in (£m)	Gone Green		Slow Progression		
	10GW	17.2GW	10GW	17.2GW	Worst Regret
Base Case plus onshore	1947	2911	1833	1966	2911
Bootstrap 1 GW	25	7289	619	4166	7289
Hybrid bootstrap 2 GW	1102	1268	81	615	1268
Hybrid offshore 1 GW	999	1003	1381	3444	3444
Hybrid offshore 2 GW	N/A	353	N/A	1581	1581
Integrated 1 GW	**0**	**0**	1180	448	1180
Integrated 2 GW	741	134	0	0	741

Source: National Grid

This analysis forecasts the regret associated with a design approach for the range of eventualities. The analysis indicates that the Least Worst Regret overall, is an integrated design based on larger 2GW and/or 2.2GW links. This is identified by the lowest value in the Worst Regrets column (£741m worth of regret). This result is driven by design 15c and design 5b anticipatory both of which entail significant offshore integration with some large capacity HVDC links to shore.

However, whilst integration offers economic value with the assumed total wind capacities of 10GW or more, smaller developments may not necessarily have the economies of scale to sustain this result. Similarly, if the spread of wind capacity between the three zones was materially different, or if one zone did not develop, then this would influence this result.

Designs based on 1GW links to shore and a 2.5GW bootstrap from Scotland to England (3a, 10a and 13a) perform poorly with higher levels of regret. There are two reasons for this:

- There is no sharing of transmission assets between the three zones
- The designs offer less network reinforcement across some transmission boundaries.

However, the results are sensitive to both wind capacity and generation background assumptions.

5.4 *Conclusions*

The analysis presented in this Chapter illustrates that across our range of studies, economic value is offered by all designs relative to the counterfactual designs based on radial links to shore.

Based on this analysis, a design approach with offshore integration and inter-zonal offshore links (designs 5a, 5b anticipatory, 15a and 15c) offers greatest economic value and also reduces the levels of regret.

The LWR analysis identifies offshore integration with some larger capacity links (designs 5b anticipatory and 15c) as the preferred design approach overall, accounting for the wind capacity and generation background uncertainty.

Whilst one of the favoured designs (15c) has a 2GW link between Hornsea platform 3 to Walpole substation, there may be an opportunity to refine this (and other) designs and reduce the number of links to shore. This proved attractive with the '5b anticipatory' design.

If the assumptions on IOTP(E) wind capacities, or the spread between the three zones was to differ significantly, then the case for integration could be weakened. We cannot deduce from this study work the precise tipping point for this, but it must lie below the 10GW level captured in these studies. Since the 10GW and 17.2GW capacity assumptions are both considered credible at this stage, this forms a reasonable vision for investment decisions.

Equally, if the wind capacity assumptions increased above the 17.2GW assumption, then it would, in all likelihood, strengthen the case for integration due to economies of scale.

Under the Slow Progression generation background the designs identified by the LWR (5b anticipatory and 15c) are also the best design options with the highest NPVs.

NOTE: Since completion of this work-stream report the assumptions around credible connection dates and volumes of offshore wind generation have changed in response to current market conditions. As stated in the original conclusions if the spread of generation between the three zones considered was to vary then the case for integration could be weakened. Latest market intelligence suggests that the build-up of offshore wind generation is likely to be slower than previously forecast and has potential to deliver volumes below the 10GW lower limit assessed in this analysis. Therefore the conclusions stated in this work-stream report are no longer considered valid. The current view on the least worst regret assessment of integrated designs is given in the main project summary report. While the analysis presented here was correct at the time of assessment, all conclusions are now superseded.

6 Sensitivity Analysis

6.1 Introduction

The focus of this chapter is to present sensitivity analysis to confirm the robustness of the conclusions of Chapter 5. The sensitivities assessed in this chapter are:

- The impact of delays from the earliest service delivery date of 2030/31 for all designs (as requested by the Work Group).
- The impact of a 20% increase in capital costs.

6.2 *Impact of Delays*

This section presents the NPVs of the designs for both generation backgrounds and wind capacity assumptions where delays of up to 9 years occur. This reflects a situation where both constraint savings and investment costs are delayed and discounted into the future No investment costs or constraint savings accrue during the delay period. Discounting follows the same methods and assumptions as detailed in section 5.2, but extends the timeframe to retain the same 40 year asset life.

This test is looking at whether delaying investment would be economically justified i.e. if the savings in investment costs realised in early years exceed the constraint savings foregone.

The results are presented in Tables 6-1 (17.2GW designs) and 6-2 (10GW designs) below. The shaded years identify the year with the greatest NPV hence are the most cost effective timing.

Table 6-1: NPV of options from earliest delivery date and delays of up to 9 years

Net Present Values (£m)	17.2GW Wind Capacity and Gone Green NPVs									
	Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Design 10a	861	936	908	878	848	819	792	765	739	714
Design 10c	6,882	6,754	6,529	6,309	6,095	5,889	5,690	5,498	5,312	5,132
Design 13a	7,147	6,997	6,764	6,535	6,314	6,101	5,895	5,695	5,503	5,317
Design 13c	7,797	7,610	7,355	7,106	6,866	6,634	6,410	6,193	5,983	5,781
Design 15a (Optimised)	8,150	8,006	7,740	7,479	7,226	6,982	6,746	6,517	6,297	6,084
Design 15c (Optimised)	8,017	7,857	7,595	7,339	7,090	6,851	6,619	6,395	6,179	5,970
Base Case Design plus onshore	5,239	5,126	4,955	4,787	4,625	4,469	4,318	4,172	4,031	3,895

Net Present Values (£m)	17.2GW Wind Capacity and Slow Progress NPVs									
	Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Design 10a	3,303	3,296	3,188	3,080	2,976	2,876	2,778	2,684	2,594	2,506
Design 10c	6,854	6,727	6,503	6,284	6,071	5,866	5,668	5,476	5,291	5,112
Design 13a	4,025	3,981	3,849	3,720	3,594	3,472	3,355	3,241	3,132	3,026
Design 13c	5,888	5,765	5,573	5,385	5,203	5,027	4,857	4,692	4,534	4,380
Design 15a (Optimised)	7,021	6,915	6,686	6,460	6,242	6,031	5,827	5,630	5,439	5,255
Design 15c (Optimised)	7,469	7,328	7,084	6,845	6,613	6,390	6,174	5,965	5,763	5,568
Base Case Design plus onshore	5,503	5,380	5,201	5,025	4,855	4,691	4,532	4,379	4,231	4,088

Source: National Grid

Table 6-2: NPV of options from earliest delivery date and delays of up to 9 years

Net Present Values (£m)	10GW Offshore Wind Capacity and Gone Green NPVs									
	Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Design 2a	6907	6740	6515	6295	6082	5876	5677	5485	5300	5121
Design 2c	5829	5708	5517	5165	5151	4977	4808	4646	4489	4337
Design 3a	5363	5262	5087	4915	4749	4588	4433	4283	4138	3998
Design 4a	5933	5803	5604	5410	5221	5039	4864	4694	4530	4371
Design 5a (Optimised)	6932	6799	6573	6351	6136	5929	5728	5534	5347	5166
Design 5b (Optimised)	5655	5556	5371	5190	5014	4845	4681	4522	4370	4222
Base Case Design plus onshore	4985	4880	4717	4557	4403	4254	4111	3972	3837	3708
Design 5b (Anticipatory)	6190	6065	5863	5665	5473	5288	5109	4936	4769	4608

Net Present Values (£m)	10GW Offshore Wind Capacity and Slow Progress NPVs									
	Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Option 2a	5020	4918	4754	4593	4438	4288	4143	4003	3867	3737
Option 2c	5558	5445	5264	4920	4914	4748	4587	4432	4282	4138
Option 3a	2859	2842	2749	2656	2567	2480	2396	2315	2237	2161
Option 4a	4258	4185	4041	3899	3762	3629	3501	3377	3258	3142
Option 5a (Optimised)	4459	4410	4265	4121	3982	3847	3717	3591	3470	3352
Option 5b (Optimised)	5261	5175	5003	4834	4671	4513	4360	4213	4071	3933
Base Case Design plus onshore	3807	3741	3617	3495	3377	3263	3152	3046	2943	2843
Design 5b (Anticipatory)	5639	5532	5348	5167	4992	4824	4661	4503	4351	4204

Source: National Grid

The NPVs for all except one case (Design 10a, Gone Green, 17.2GW wind capacity) are greatest with no delay in investment.

The designs identified in Chapter 5 by the Least Worst Regret analysis (5b anticipatory and 15c) do not benefit from a delay.

The analysis confirms that, in general, optimal timing for investment occurs when wind capacity and transmission capacity are matched, and delays in investment are not justified by the value realised through discounting investment into future years.

6.3 The impact of Investment Cost increases

This sensitivity examines the effect of a 20% increase in the investment costs. The previous analysis is repeated with higher investment cost profiles.

This reflects the chance that investment cost forecasts used in Chapter 5 increase with future market movements. The possibility that investment costs could reduce has not been considered, although such an eventuality would in all likelihood, strengthen the case for investment.

Consequently, a sensitivity based on a 20% increase across the designs has been considered. Whilst the increase is attributable to all design components, it is only the costs associated with integration components that are captured for comparison. This treatment of investment costs is identical to analysis in Chapter 5, and hence offers a like-for-like comparison.

The annual constraint cost savings and their corresponding PV do not change from the Chapter 5 analysis. Only the PV of investment cost is affected. Updating the NPV tables by design and scenario gives the results in table 6-3 below: -

Table 6-3 Net Present Values by Design with 20% Investment Increase

	CAPEX 120%	Gone Green			Slow Progression		
	Design	PV of constraint savings (£m)	PV of additional cost of Integration (£m)	NPV: Constraints minus Additional costs (£m)	PV of constraint savings (£m)	PV of additional cost of Integration (£m)	NPV: Constraints minus Additional costs (£m)
10GW Offshore Wind Capacity	Design 2a	£7,685	£934	£6,751	£5,799	£934	£4,865
	Design 2c	£6,705	£1,051	£5,654	£6,434	£1,051	£5,383
	Design 3a	£6,290	£1,112	£5,178	£3,785	£1,112	£2,674
	Design 4a	£6,977	£1,061	£5,915	£5,302	£1,061	£4,241
	Design 5a (Optimised)	£8,111	£1,415	£6,696	£5,638	£1,415	£4,224
	Design 5b (Optimised)	£6,716	£1,273	£5,443	£6,323	£1,273	£5,049
	Base Case plus onshore	£5,721	£883	£4,837	£4,543	£883	£3,659
	Design 5b (Anticipatory)	£7,159	£1,162	£5,997	£6,607	£1,162	£5,445
17.2GW Offshore Wind Capacity	Design 10a	£2,066	£1,674	£391	£4,508	£1,674	£2,833
	Design 10c	£8,095	£1,455	£6,639	£8,067	£1,455	£6,612
	Design 13a	£8,208	£1,273	£6,935	£5,086	£1,273	£3,813
	Design 13c	£8,681	£1,061	£7,620	£6,772	£1,061	£5,711
	Design 15a (Optimised)	£9,675	£1,829	£7,845	£8,545	£1,829	£6,716
	Design 15c (Optimised)	£9,305	£1,546	£7,759	£8,758	£1,546	£7,211
	Base Case plus onshore	£5,976	£883	£5,092	£6,239	£883	£5,356

The NPVs of each design has reduced due to the increase in investment cost.

Repeating the NPV and Regrets analysis of Chapter 5 using data from table 6-3 above provides a comparable view with the 20% cost increase. This is shown in table 6-4 and 6-5 below.

Table 6-4 NPVs Grouped by Design/Technology with 20% investment Cost Increase

NPVs grouped by Design/Technology £m	Gone Green		Slow Progression	
	10GW Offshore Capacity (£m)	17.2GW Offshore Capacity (£m)	10GW Offshore Capacity (£m)	17.2GW Offshore Capacity (£m)
Base Case plus onshore	4,837	5,092	3,659	5,356
Bootstrap 1 GW	6,751	391	4,865	2,833
Hybrid bootstrap 2 GW	5,654	6,639	5,383	6,612
Hybrid offshore 1 GW	5,915	6,935	4,241	3,813
Hybrid offshore 2 GW	NA	7,620	NA	5,711
Integrated 1 GW	6,696	7,845	4,224	6,716
Integrated 2 GW	5,997	7,759	5,445	7,211
Max £m	*6,751*	*7,845*	*5,445*	*7,211*

Table 6-5 Regret Analysis with 20% Investment Cost Increase

Design & Technology by Scenarios: Regrets in (£m)	Gone Green 10GW Offshore Capacity (£m)	Gone Green 17.2GW Offshore Capacity (£m)	Slow Progression 10GW Offshore Capacity (£m)	Slow Progression 17.2GW Offshore Capacity (£m)	Worst Regret (£m)
Base Case plus onshore	1914	2753	1786	1856	2753
Bootstrap 1 GW	0	7454	581	4378	7454
Hybrid bootstrap 2 GW	1097	1206	63	600	1206
Hybrid offshore 1 GW	836	910	1205	3398	3398
Hybrid offshore 2 GW	N/A	225	N/A	1500	1500
Integrated 1 GW	55	0	1222	496	1222
Integrated 2 GW	754	87	0	0	754

Whilst the Regret values have changed the LWR result remains consistent.

This demonstrates that the designs identified by the LWR analysis in Chapter 5 remains the LWR irrespective of the investment cost increase. This implies that the previous results are robust against cost increases up to and including this 20% bound.

6.4 The impact of Cost Increases and Delays

The impact on the NPV for this 20% investment cost increase, coupled with investment delays for each design has also been considered. This follows the same methodology as previously adopted and described in Chapter 5.

Table 6-6 below shows results of this calculation for each study scenario and wind capacity assumption.

Table 6-6 Delay Analysis with 20% Investment Cost Increase

Net Present Values with +20% CAPEX (£m)	17.2GW Wind Capacity and Gone Green NPVs — Offshore network and wind capacity is built to commission for: -									
Design	2030/31	2031/32	2032/33	2033/34	2034/5	2035/6	2036/7	2037/8	2039/40	2040/41
Design 10a	391	495	475	451	428	406	385	364	344	325
Design 10c	6,639	6,541	6,324	6,110	5,904	5,704	5,511	5,325	5,145	4,971
Design 13a	6,935	6,810	6,584	6,362	6,147	5,939	5,738	5,544	5,356	5,175
Design 13c	7,620	7,454	7,205	6,962	6,726	6,499	6,279	6,067	5,862	5,663
Design 15a (Optimised)	7,845	7,738	7,482	7,229	6,985	6,749	6,521	6,300	6,087	5,881
Design 15c (Optimised)	7,759	7,630	7,377	7,128	6,887	6,654	6,429	6,211	6,001	5,798
Base Case plus onshore	5,092	4,996	4,830	4,667	4,509	4,357	4,209	4,067	3,929	3,797

Net Present Values with +20% CAPEX (£m)	17.2GW Wind Capacity and Slow Progress NPVs — Offshore network and wind capacity is built to commission for: -									
Design	2030/31	2031/32	2032/33	2033/34	2034/5	2035/6	2036/7	2037/8	2039/40	2040/41
Design 10a	2,833	2,854	2,754	2,654	2,556	2,462	2,371	2,283	2,198	2,116
Design 10c	6,612	6,514	6,298	6,085	5,880	5,681	5,489	5,303	5,124	4,950
Design 13a	3,813	3,794	3,670	3,546	3,426	3,310	3,198	3,090	2,986	2,885
Design 13c	5,711	5,609	5,423	5,240	5,063	4,892	4,726	4,566	4,412	4,263
Design 15a (Optimised)	6,716	6,647	6,427	6,211	6,001	5,798	5,602	5,412	5,229	5,052
Design 15c Optimised)	7,211	7,101	6,866	6,634	6,410	6,193	5,983	5,781	5,586	5,397
Base Case plus onshore	5,356	5,251	5,076	4,905	4,739	4,579	4,424	4,274	4,130	3,990

Net Present Values with +20% CAPEX (£m)	10GW Offshore Wind Capacity and Gone Green NPVs Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Design 2a	6751	6603	6383	6167	5959	5757	5563	5374	5193	5017
Design 2c	5654	5554	5369	5179	5012	4843	4679	4521	4368	4220
Design 3a	5178	5099	4930	4764	4602	4447	4296	4151	4011	3875
Design 4a	5915	5807	5614	5424	5241	5064	4892	4727	4567	4413
Design 5a (Optimised)	6696	6592	6373	6158	5950	5748	5554	5366	5185	5009
Design 5b (Optimised)	5443	5369	5191	5016	4846	4683	4524	4371	4223	4081
Base Case plus onshore	4837	4750	4592	4437	4287	4142	4002	3867	3736	3610
Design 5b (Anticipatory)	5997	5894	5698	5506	5320	5140	4966	4798	4636	4479

Net Present Values with +20% CAPEX (£m)	10GW Offshore Wind Capacity and Slow Progress NPVs Offshore network and wind capacity is built to commission for: -									
Design	**2030/31**	**2031/32**	**2032/33**	**2033/34**	**2034/5**	**2035/6**	**2036/7**	**2037/8**	**2039/40**	**2040/41**
Option 2a	4865	4781	4622	4466	4315	4169	4028	3892	3760	3633
Option 2c	5383	5291	5115	4935	4776	4614	4458	4307	4162	4021
Option 3a	2674	2679	2592	2505	2420	2338	2259	2183	2109	2038
Option 4a	4241	4189	4050	3914	3781	3654	3530	3411	3295	3184
Option 5a (Optimised)	4224	4203	4065	3928	3795	3667	3543	3423	3307	3195
Option 5b (Optimised)	5049	4988	4824	4661	4503	4351	4204	4062	3924	3792
Base Case plus onshore	3659	3612	3492	3374	3260	3150	3044	2941	2841	2745
Design 5b (Anticipatory)	5445	5362	5184	5009	4839	4676	4518	4365	4217	4075

These results show that design 10a continues to have a higher NPV with a 1 year delay (discounted). Whilst some minor benefits to optimal investment timing are evident with these results compared to the earlier results, the changes occur on less favourable designs and do not extend beyond one year duration.

The overarching conclusion from this analysis is that delaying investment costs for the more favourable designs will not enhance the Net Present Value of the scheme. It follows that the best economic advantage is gained where network investment is managed to deliver transmission capacity in line with the commissioning of the wind generation.

7 Conclusions and Recommendations

NOTE: Since completion of this work-stream report the assumptions around credible connection dates and volumes of offshore wind generation have changed in response to current market conditions. As stated in the original conclusions if the spread of generation between the three zones considered was to vary then the case for integration could be weakened. Latest market intelligence suggests that the build-up of offshore wind generation is likely to be slower than previously forecast and has potential to deliver volumes below the 10GW lower limit assessed in this analysis. Therefore the conclusions stated in this work-stream report are no longer considered valid. The current view on the least worst regret assessment of integrated designs is given in the main project summary report. While the analysis presented here was correct at the time of assessment, all conclusions are now superseded.

7.1 Conclusions

The **Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1** states that a reinforcement option is economic when the cost of the project is less than the cost consumers would otherwise pay under the counterfactual case.

Given the range of uncertainty presented by various designs, scenarios and sensitivities studied, this CBA has been carried out to illustrate the opportunity to optimise the design of offshore connections to reduce the impact of network constraints borne by the wider community.

The analysis presented in this document demonstrates that integrated designs offer both greater scheme Net Present Values and also represent Least Worst Regret solutions overall. In no circumstance does the Radial connection design offer economic advantage, even when coupled with a £870m onshore reinforcement package. Where IOTP(E) wind capacities of 10GW or more exist these results look stable. Lower wind capacities may not offer the same value.

One key driver for these findings is the value derived in terms of constraint cost mitigation associated with linking the three offshore zones electrically. This enables the sharing of transmission capacity between a much wider set of generation assets. In the analysis undertaken, the offshore constraint costs represent the welfare benefit of obtaining more energy from the wind farms considered, based on established practice that this presents an opportunity to avoid additional renewable generation investment to achieve the same result.

Furthermore, the analysis demonstrates that efficient investment timing is best achieved where transmission capacity becomes available as wind capacity is developed.

The sensitivity analysis with 20% higher investment costs demonstrates that the key findings are robust against this level of cost escalation. Any investment cost savings that may be achievable through market price reductions have been ignored.

7.2 Recommendations

The wider value to consumers in terms of constraint cost savings and welfare benefit over the asset life offered by an integrated network design is significant. None of the modelling studies yield a negative NPV, hence all forms of development (above radial connections) offer savings and economic improvement. The best solutions are wind capacity and generation background sensitive. Accounting for these uncertainties with LWR analysis suggests that integration with inter-zonal links offers the LWR design approach.

The limited number of our studies relative to the huge range of possible combinations and eventualities means that these results can only provide a ***vision*** of where value exists. It is not possible to determine a precise solution due to the near limitless range of variables.

Scope may exist to move from a radial connection design to a more integrated design at a later date. However, this may only be practical if the first development steps make provision for this expansion. Consequently, investment decisions will need to be made early enough if this optionality is to be retained. Given the value attributable to integration where significant wind capacity is developed, it is recommended that this optionality is sought in early developmental steps.

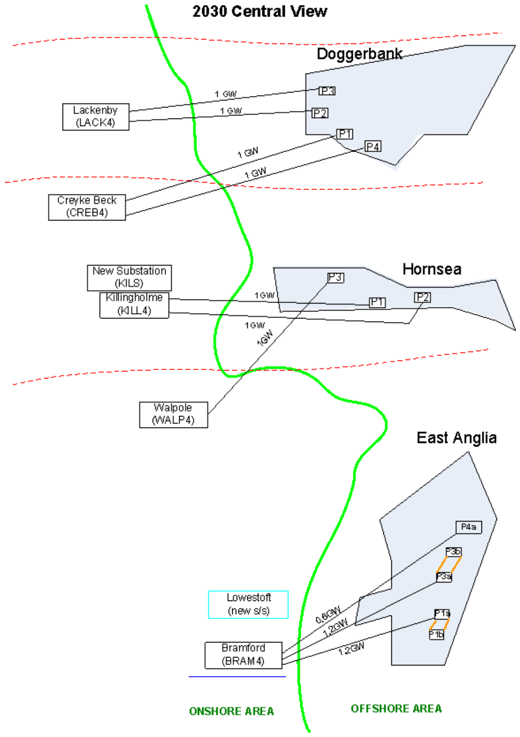
The cost associated with retaining integration optionality is currently unclear. In order to make sound economic judgements this will need costing. Additionally, development of more complex designs could present risk of commissioning delay. If so, it would be appropriate to capture such costs in the analysis.

In order to minimise the chance of stranded assets, investment options should be considered on a step-by-step basis in response to a Needs Case document, following the Strategic Wider Works arrangements detailed in the electricity transmission price control RIIO-T1.

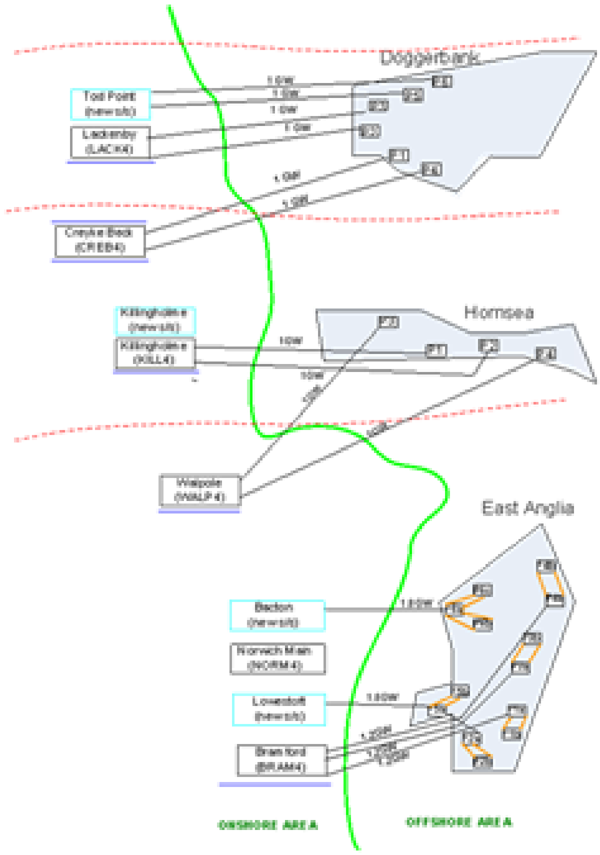
To best ensure value for money for GB consumers, clarity on the likely wind capacity for each of the three zones is a key driver. The wind capacities modelled in this work are sufficient to economically justify a level of integration. Smaller overall wind capacities, or a significantly different spread of the capacity between the three zones would influence the results.

Appendix 1 – Network designs

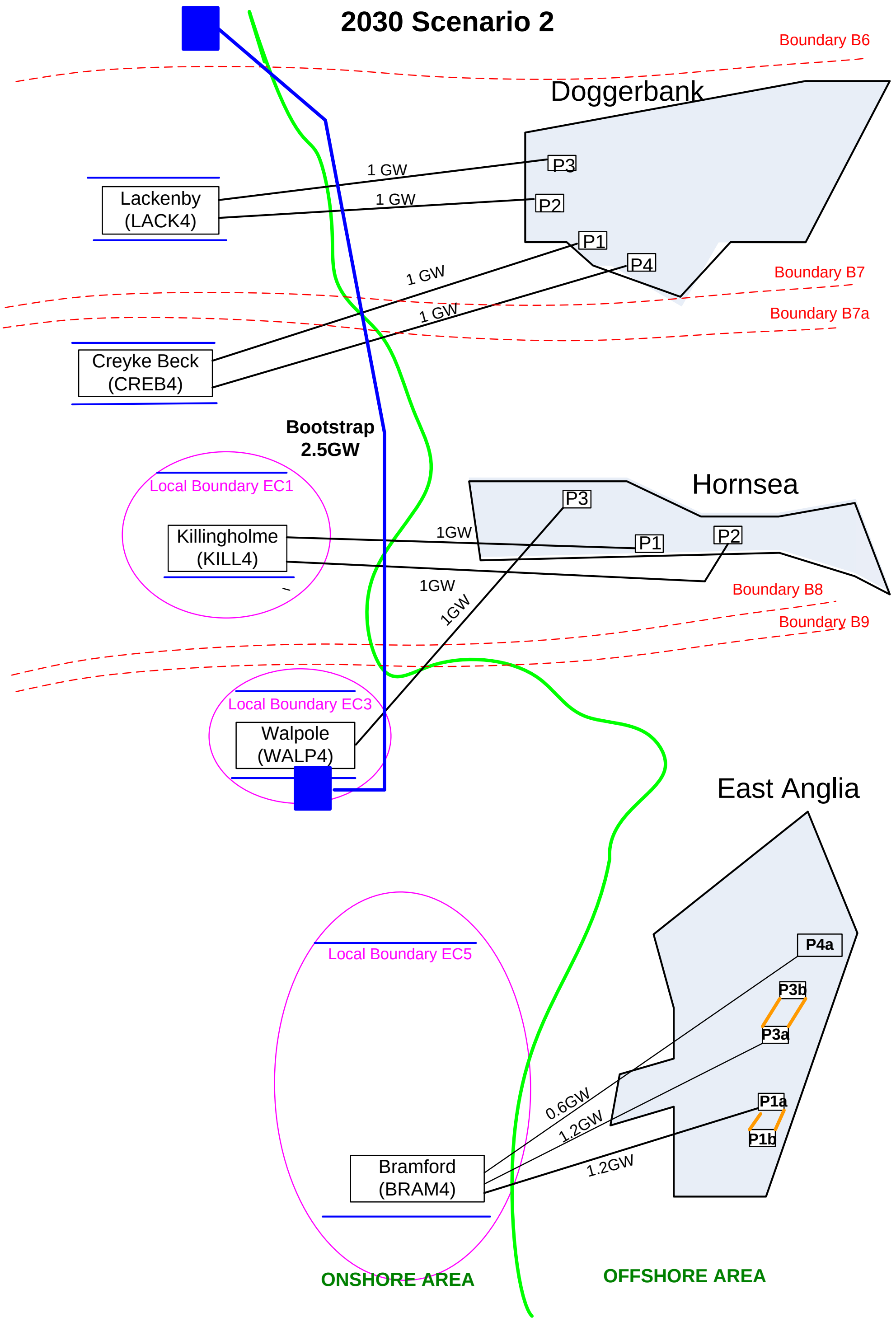
The Base Case Design (Counterfactual) for 10GW Wind Capacities – Radial Links to Shore



The Base Case Design (Counterfactual) for 17.2GW wind capacity – Radial Links to Shore



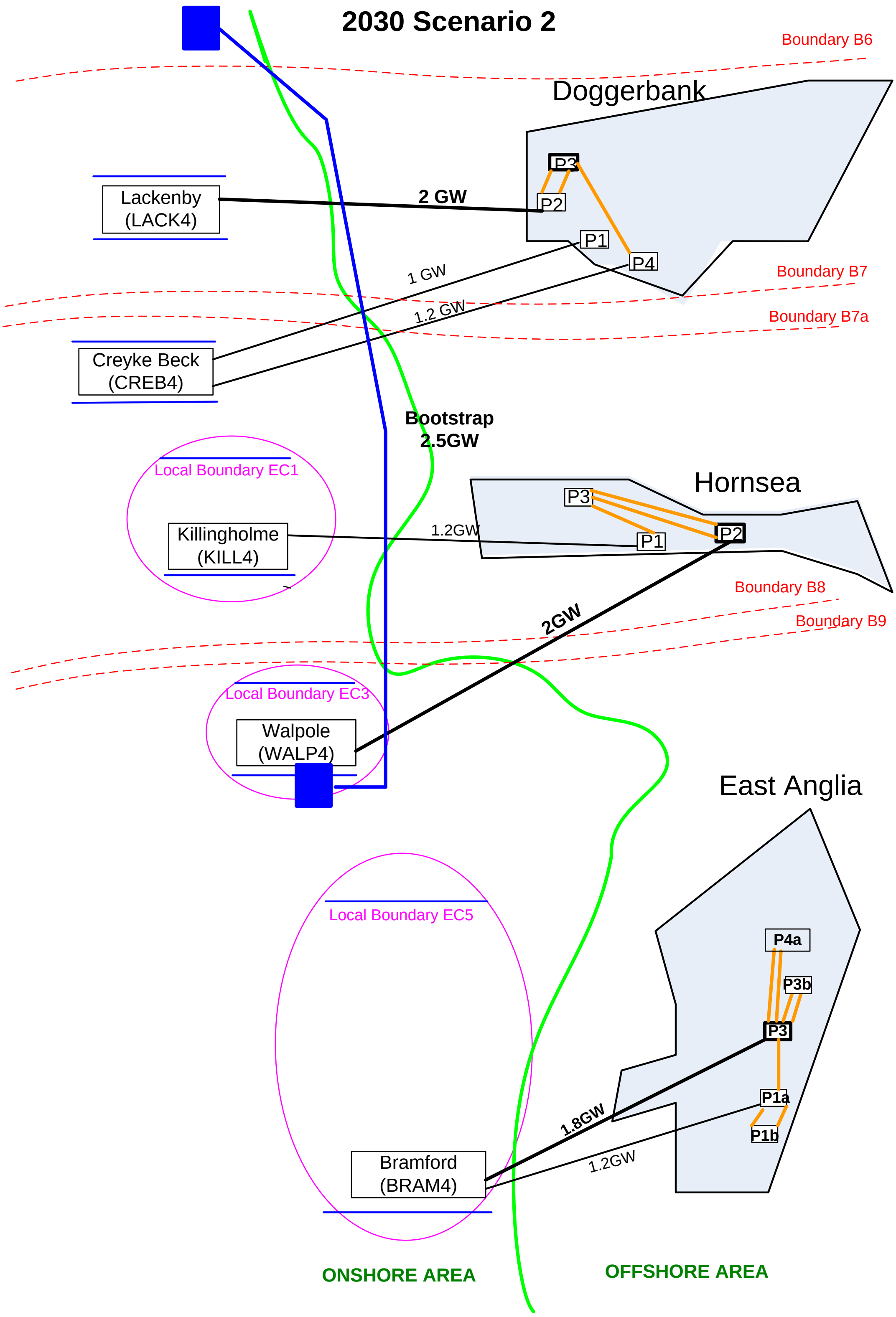
Design 2a - A 2.5GW Bootstrap across B6, B7, B7a, B8 and B9 boundaries and 1GW links to Shore.



Design 2a - Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1GW onshore VSC Converter	703.80		
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
HVDC 1GW radial link at a distance of 43km between P2(600MW) and BRAM4 including cable installation cost and 1GW onshore VSC Converter	462.68		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 350km from Scotland to Walpole(EC3) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and Walpole(EC3)		924.24	
TOTAL	**6330.09**	**924.24**	**7254.23**

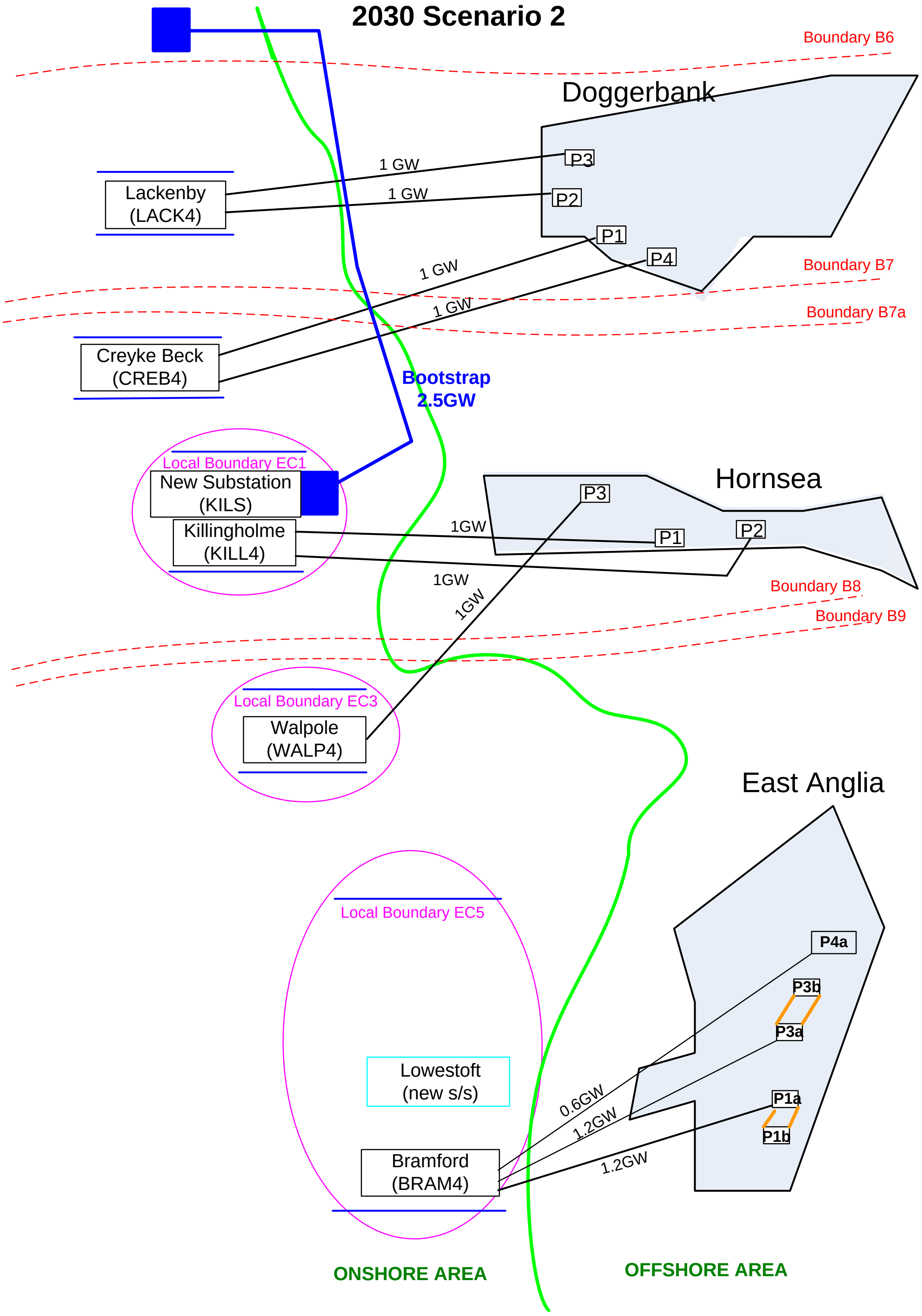
Design 2c - A 2.5GW Bootstrap across B6, B7, B7a, B8 and B9 boundaries and 2GW links to Shore.



Design 2c Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 2GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 2GW onshore VSC Converter	1044.55		
HVDC 1.2GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1.2GW onshore VSC Converter	761.95		
Two 500MW HVAC Cables at a distance of 41.2km from P3 to P2 including cable installation cost	64.83		
Integration HVAC link at a distance of 35.3km from P4 to P3 including cable installation cost		38.90	
Hornsea			
HVDC 1.2GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1.2GW onshore VSC Converter	612.59		
HVDC 2GW radial link at a distance of 125km between P2 and WALP4 including cable installation cost and 2GW onshore VSC Converter	829.06		
Two 500MW HVAC Cables at a distance of 38km from P3 to P2 including cable installation cost	59.79		
Integration HVAC link at a distance of 64km from P1 to P3 including cable installation cost		73.89	
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
HVDC 1.8GW radial link at a distance of 140km between P3(1.2GW) and BRAM4 including cable installation cost and 1.8GW onshore VSC Converter	838.13		
Two 300MW HVAC Cables at a distance of 30km from P4a to P3 including cable installation cost	69.27		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 350km from Scotland to Walpole(EC3) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and Walpole(EC3)		924.24	
TOTAL	**5539.50**	**1037.03**	**6576.53**

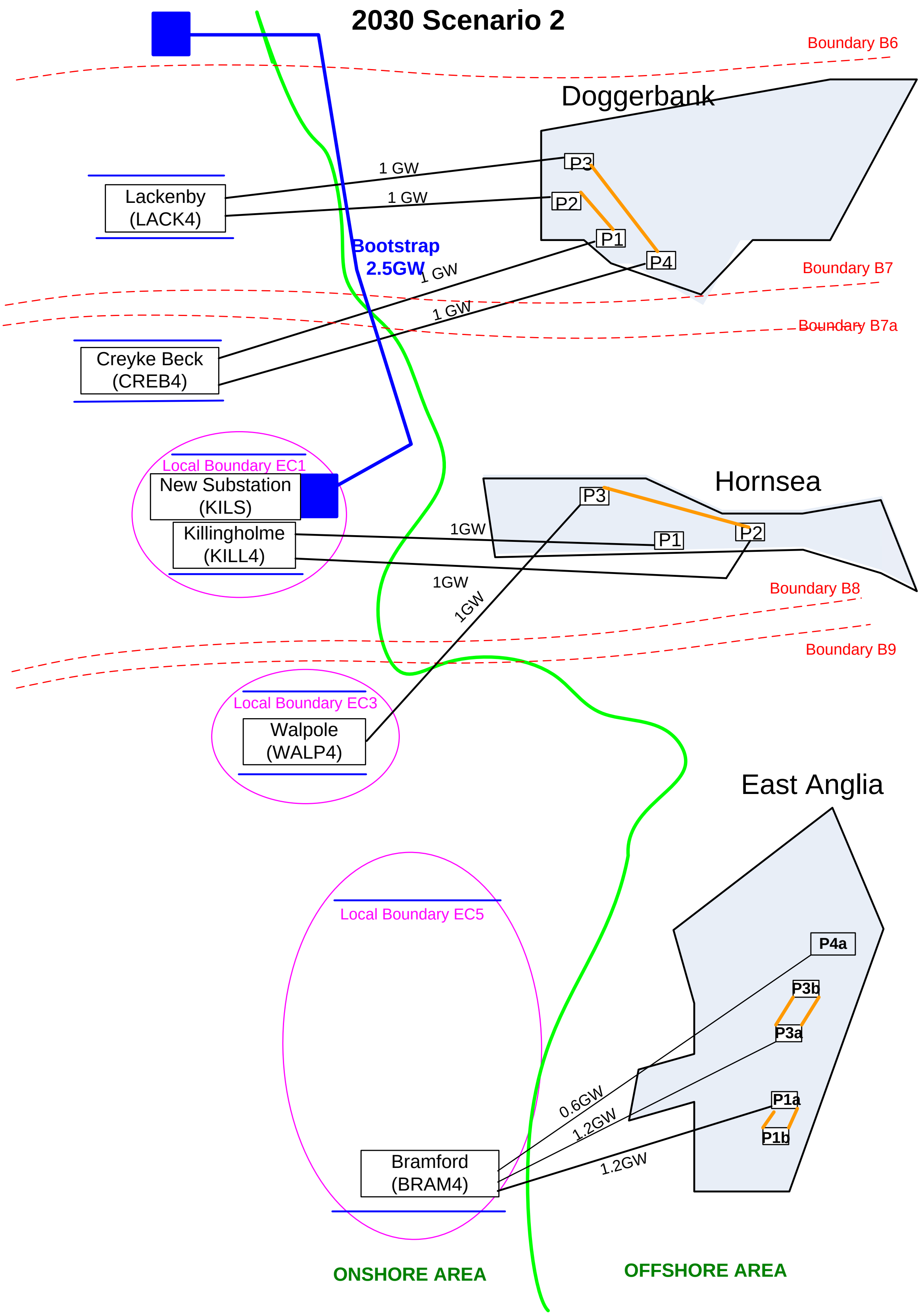
Design 3a – Hybrid 2.5GW Bootstrap



Design 3a – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1GW onshore VSC Converter	703.80		
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
HVDC 1GW radial link at a distance of 43km between P2(600MW) and BRAM4 including cable installation cost and 1GW onshore VSC Converter	462.68		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
Onshore Reinforcement			
Cost of proposed new Substation(New Killingholme South KILS4) and cost of KILS4-WBUR4 new double OHL		220	
TOTAL	**6330.09**	**1100.84**	**7431.83**

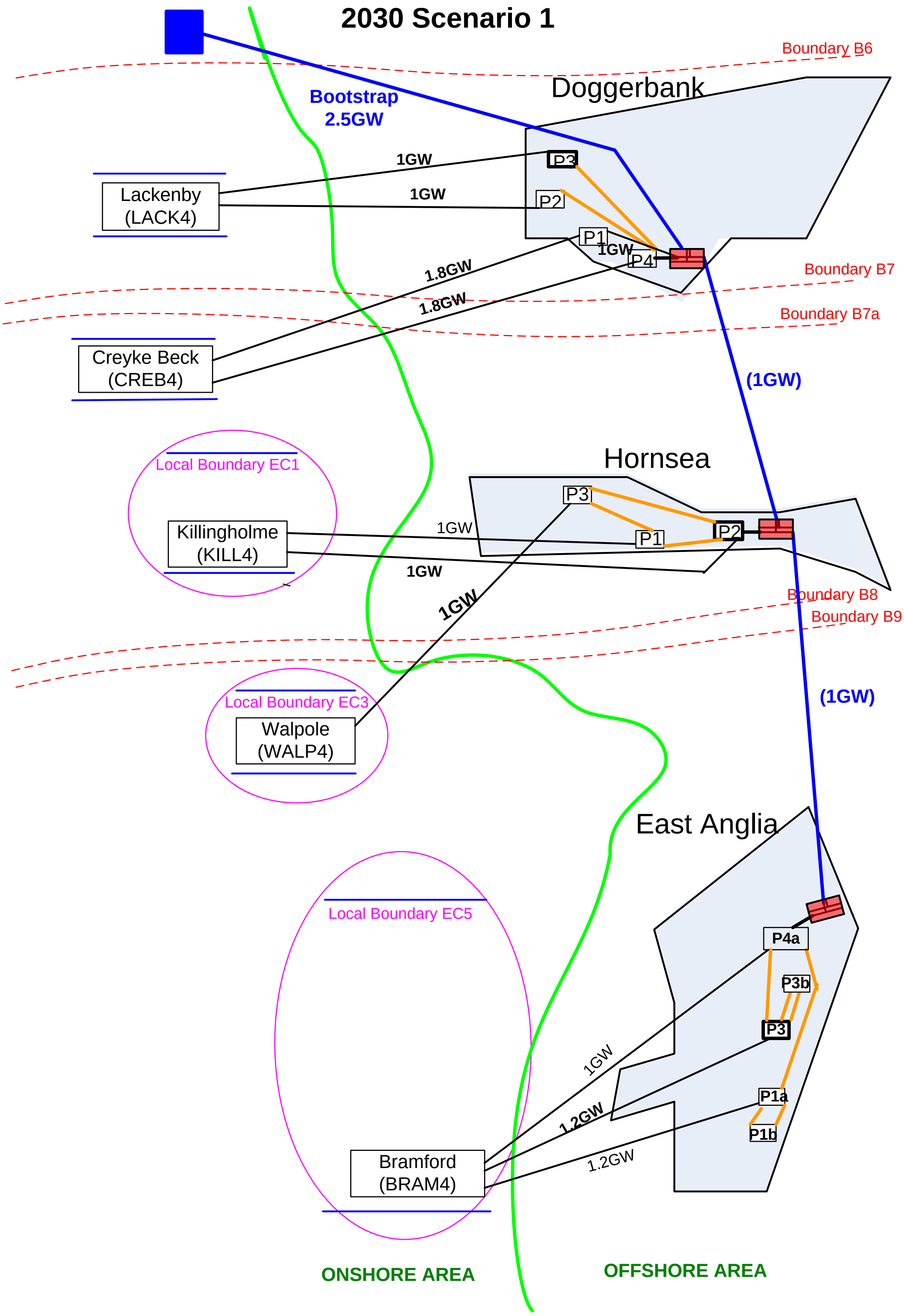
Design 4a - Hybrid 2.5GW Bootstrap with internal links



Design 4a – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1GW onshore VSC Converter	703.80		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
300MW HVAC link at a distance of 38km from P3 to P2 including installation cost		43.87	
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
HVDC 1GW radial link at a distance of 43km between P2(600MW) and BRAM4 including cable installation cost and 1GW onshore VSC Converter	462.68		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
TOTAL	**6330.99**	**1049.63**	**7380.62**

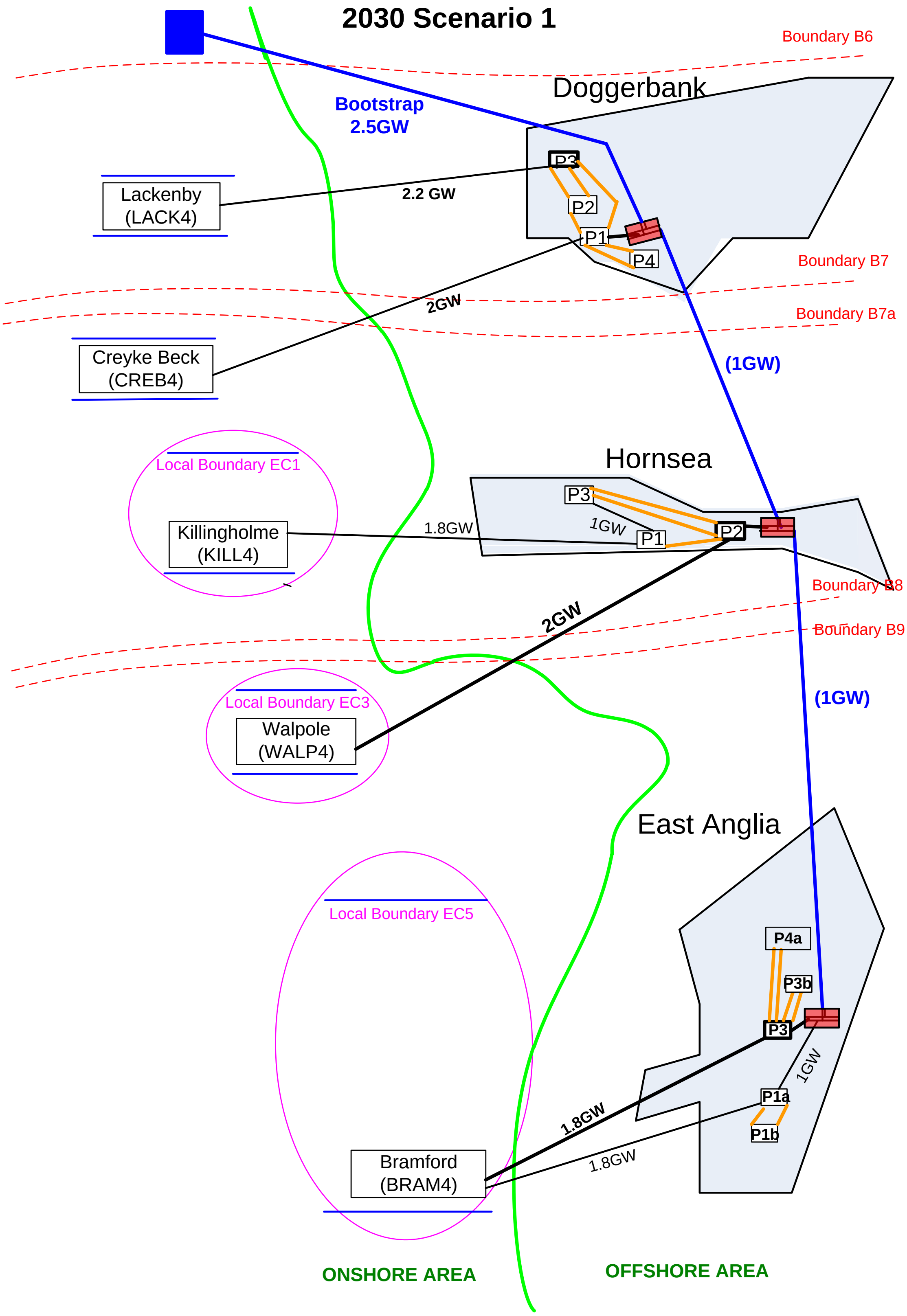
5a (Optimised) – Offshore 1GW Mesh with 1GW links to Shore



5a (Optimised) – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1.8GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	945.39		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1.8GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	949.24		
HVDC 1GW Integrating T-Platform located at Dogger Bank		50	
HVDC 1GW at a distance of 120km from Dogger Bank to Hornsea including cable installation cost		168.12	
HVDC 1GW at a distance of 30.6km from P1 to HVDC integration T-platform including installation cost		42.87	
HVAC 300MW at a distance of 95.3km from P2 to HVDC integration T-platform including installation cost		110.02	
HVAC 300MW at a distance of 35.3km from P3 to HVDC integration T-platform including installation cost		40.75	
2.5GW VSC Converter located in Scotland		176.17	
2.5GW HVDC Cable from Scottish Transmission Network to Dogger Bank at a distance of 200km		322.80	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
300MW HVAC link at a distance of 64km from P3 to P2 including installation cost		73.89	
HVDC 1GW Integrating T-Platform located at Hornsea		50	
HVDC 1GW at a distance of 120km from East Anglia to Hornsea including cable installation cost		168.12	
HVAC 300MW at a distance of 27km from P1 to HVDC integration T-platform including installation cost		31.17	
HVAC 300MW at a distance of 38km from P3 to HVDC integration T-platform including installation cost		43.87	
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
HVDC 1GW radial link at a distance of 43km between P2(600MW) and BRAM4 including cable installation cost and 1GW onshore VSC Converter	462.68		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
HVDC 1GW Integrating T-Platform located at East Anglia		50	
HVAC 300MW at a distance of 30km from P1 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P3 to HVDC integration T-platform including installation cost		34.64	
Onshore Reinforcement			
Additional Enabling Works at CREB4	113.9		
TOTAL	**6935.57**	**1397.06**	**8332.63**

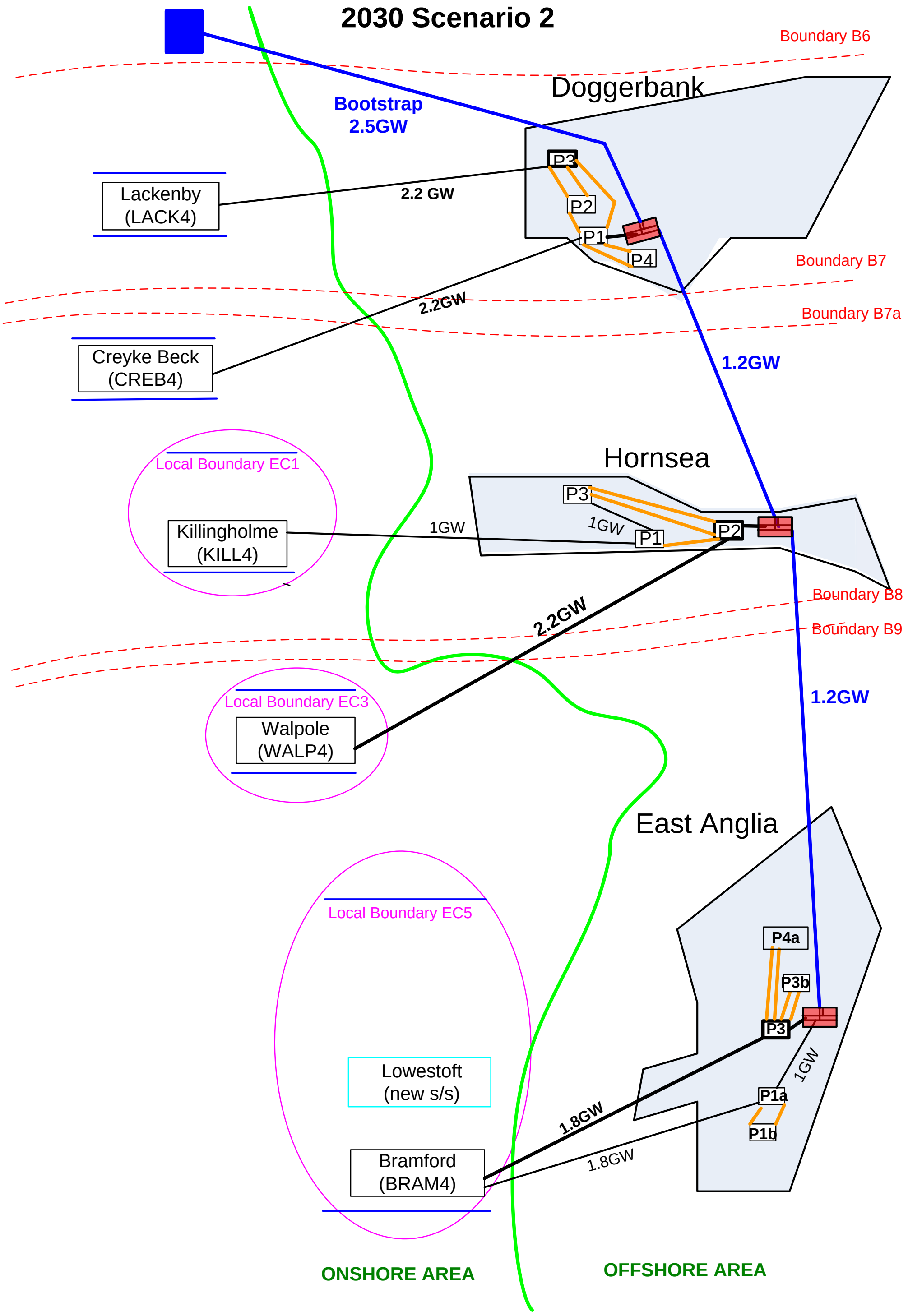
Design 5b – Offshore 1GW Mesh with 2GW links to Shore



Design 5b – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 2GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 2GW onshore VSC Converter	967.71		
HVDC 2.2GW radial link at a distance of 222.80km between P3 and LACK4 including cable installation cost and 2.2GW onshore VSC Converter	1069.77		
Two 500MW HVAC Cables at a distance of 41.2km from P3 to P2 including cable installation cost	64.83		
Two 500MW HVAC Cables at a distance of 30.6km from P4 to P1 including cable installation cost	48.15		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 28.2km from P1 to P3 including installation cost		32.56	
HVDC 1GW Integrating T-Platform located at Dogger Bank		50	
HVDC 1.2GW at a distance of 120km from Dogger Bank to Hornsea including cable installation cost		171.24	
2.5GW VSC Converter located in Scotland		176.17	
2.5GW HVDC Cable from Scottish Transmission Network to Dogger Bank at a distance of 200km		322.80	
Hornsea			
HVDC 1.8GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1.8GW onshore VSC Converter	852.93		
HVDC 2GW radial link at a distance of 125km between P2 and WALP4 including cable installation cost and 2GW onshore VSC Converter	829.06		
Two 500MW HVAC Cables at a distance of 38km from P3 to P2 including cable installation cost	59.79		
Integration HVDC link at a distance of 64km from P1 to P3 including cable installation cost		89.66	
HVDC 1GW Integrating T-Platform located at Hornsea		50	
HVDC 1.2GW at a distance of 120km from Hornsea to East Anglia including installation cost		168.12	
HVAC 300MWlink at a distance of 27km from P1 to HVDC Integration T-Platform located at P2		31.17	
East Anglia			
HVDC 1.8GW radial link at a distance of 73km between P1(1.2GW) and BRAM4 including cable installation cost and 1.8GW onshore VSC Converter	739		
HVDC 1.8GW radial link at a distance of 140km between P3(1.2GW) and BRAM4 including cable installation cost and 1.8GW onshore VSC Converter	838.13		
Two 300MW HVAC Cables at a distance of 30km from P4a to P3 including cable installation cost	69.27		
HVDC 1GW Integrating T-Platform located at East Anglia		50	
HVDC 1GW link at a distance of 30km from P1 to HVDC Integration T-Platform located at P3		42.03	
TOTAL	**5538.64**	**1258.90**	**6797.53**

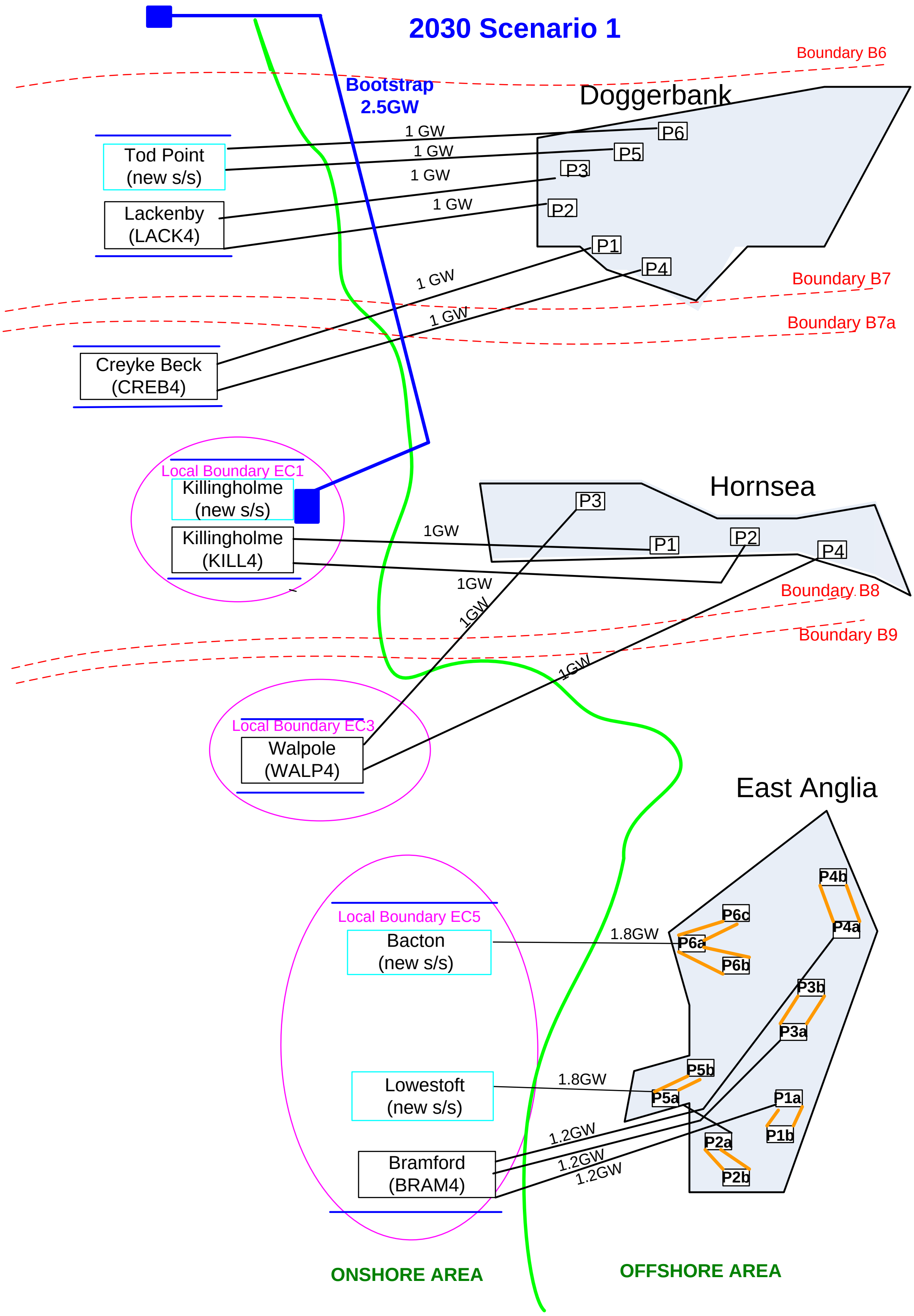
5b Anticipatory 2.2GW links to shore and 1.2GW links between zones



5b Anticipatory – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 2.2GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 2.2GW onshore VSC Converter	1025.21		
HVDC 2.2GW radial link at a distance of 222.80km between P3 and LACK4 including cable installation cost and 2.2GW onshore VSC Converter	1069.77		
Two 500MW HVAC Cables at a distance of 41.2km from P3 to P2 including cable installation cost	64.83		
Two 500MW HVAC Cables at a distance of 30.6km from P4 to P1 including cable installation cost	48.15		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
HVDC 1GW Integrating T-Platform located at Dogger Bank		50	
HVDC 1.2GW at a distance of 120km from Dogger Bank to Hornsea including cable installation cost		171.24	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 2.2GW radial link at a distance of 125km between P2 and WALP4 including cable installation cost and 2.2GW onshore VSC Converter	911.92		
Two 500MW HVAC Cables at a distance of 38km from P3 to P2 including cable installation cost	59.79		
Integration HVDC link at a distance of 64km from P1 to P3 including cable installation cost		89.66	
HVDC 1GW Integrating T-Platform located at Hornsea		50	
HVDC 1.2GW at a distance of 120km from Hornsea to East Anglia		59.64	
HVAC 300MWlink at a distance of 27km from P1 to HVDC Integration T-Platform located at P2		31.17	
East Anglia			
HVDC 1.8GW radial link at a distance of 73km between P1(1.2GW) and BRAM4 including cable installation cost and 1.8GW onshore VSC Converter	739		
HVDC 1.8GW radial link at a distance of 140km between P3(1.2GW) and BRAM4 including cable installation cost and 1.8GW onshore VSC Converter	838.13		
Two 300MW HVAC Cables at a distance of 30km from P4a to P3 including cable installation cost	69.27		
HVDC 1GW Integrating T-Platform located at East Anglia		50	
HVDC 1GW link at a distance of 30km from P1 to HVDC Integration T-Platform located at P3		42.03	
TOTAL	**5438.66**	**1153.54**	**6591.20**

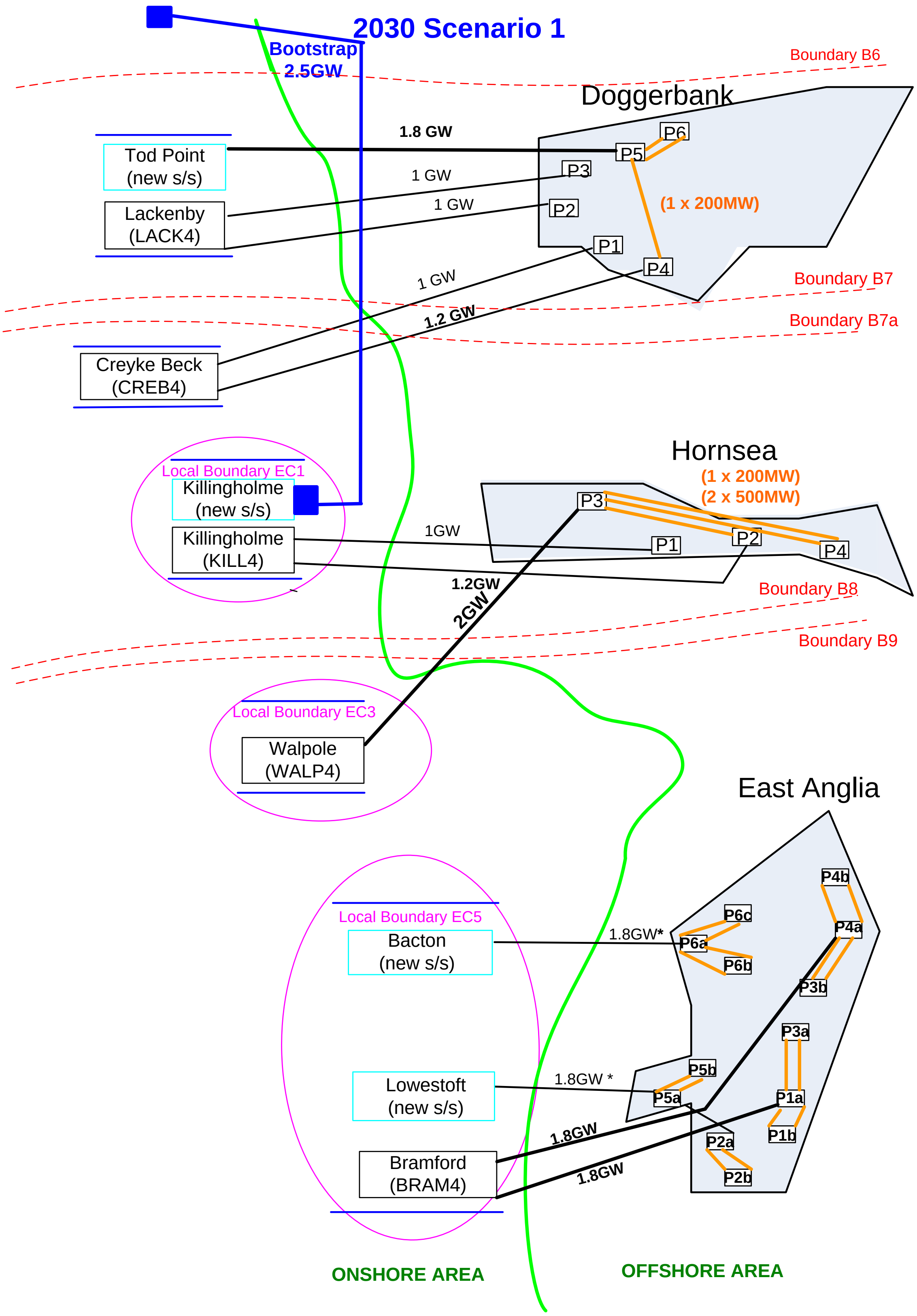
Design 10a – Bootstrap across B6, B7 and B7a Boundaries and onshore B8 reinforcements with 1GW Links to Shore.



Design 10a – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1GW onshore VSC Converter	703.80		
HVDC 1GW radial link at a distance of 210.6km between P5 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	697.49		
HVDC 1GW radial link at a distance of 246.3km between P6 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	747.51		
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 138km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	595.78		
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
HVDC 1.2GW radial link at a distance of 160km between P4 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	683.32		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC Converter	666.51		
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
Onshore Reinforcement			
Cost of proposed new Substation(New Killingholme South KILS4) and cost of KILS4-WBUR4 new double OHL		220	
Yorkshire Lines Reconductoring (1 Cable)		282.3	
TOTAL	**10285.01**	**1425.17**	**11710.18**

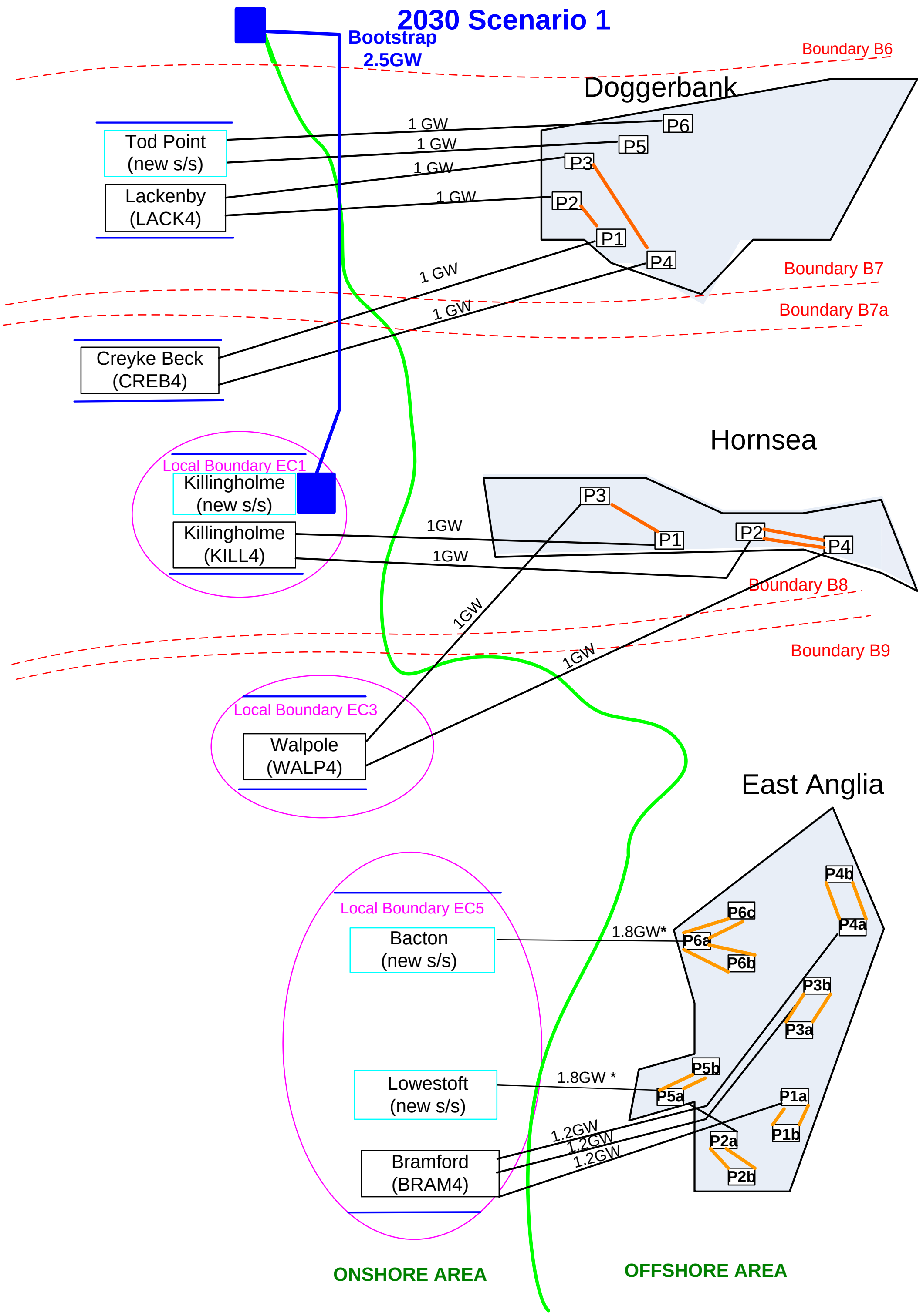
Design 10c - 2.5GW Bootstrap across B6, B7 and B7a Boundaries and onshore B8 reinforcements with 2GW Links to Shore.



Design 10c – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1.2GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1.2GW onshore VSC Converter	761.95		
HVDC 1.8GW radial link at a distance of 210.6km between P5 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1.8GW onshore VSC Converter	942.58		
Two 500MW HVAC Cables at a distance of 36.5km from P6 to P5 including cable installation cost	57.43		
300MW HVAC Cables at a distance of 31.8km from P5 to P4 including cable installation cost	35.04		
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1.2GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1.2GW onshore VSC Converter	633.38		
HVDC 2GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 2GW onshore VSC Converter	829.06		
Two 500MW HVAC Cables at a distance of 38km from P3 to P2 including cable installation cost	59.79		
200MW HVAC Cables at a distance of 38km from P2 to P3 including cable installation cost	41.88		
East Anglia			
HVDC 1.8GW radial link at a distance of 73km between P1(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	739		
1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.8GW radial link at a distance of 160km between P4(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	867.72		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC Converter	666.51		
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
Two 300MW HVAC Cables at a distance of 60km from P3a to P1 including cable installation cost	69.27		
Two 300MW HVAC Cables at a distance of 60km from P3b to P4 including cable installation cost	69.27		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
Onshore Reinforcement			
Cost of proposed new Substation(New Killingholme South KILS4) and cost of KILS4-WBUR4 new double OHL		220	
Yorkshire Lines Reconductoring (1 Cable)		282.3	
Reconductoring Drax-Thorton-Creyke Beck-Keady circuits		53.8	
TOTAL	**9636.45**	**1436.94**	**11073.39**

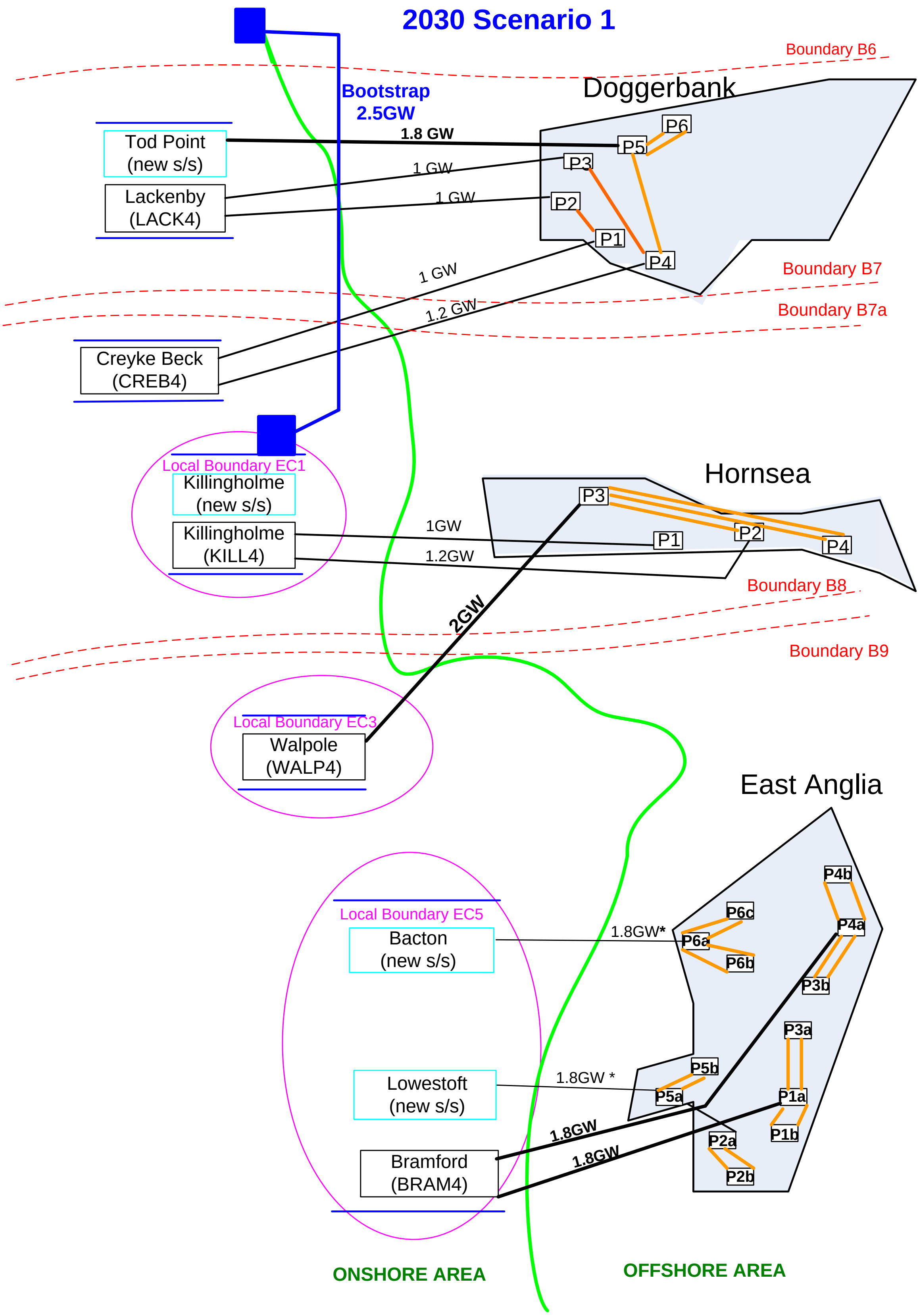
Design 13a - 2.5GW Hybrid Bootstrap across B6, B7 and B7a Boundaries, onshore B8 reinforcements with 1GW Links to Shore.



Design 13a – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1GW radial link at a distance of 215.1km between P4 and CREB4 including cable installation cost and 1GW onshore VSC Converter	703.80		
HVDC 1GW radial link at a distance of 210.6km between P5 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	697.49		
HVDC 1GW radial link at a distance of 246.3km between P6 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	747.51		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 138km between P1 and WALP4 including cable installation cost and 1GW onshore VSC Converter	595.78		
300MW HVAC link at a distance of 64km from P3 to P1 including installation cost		73.89	
Two 500MW HVAC Cables at a distance of 112km from P4 to P2 including cable installation cost		176.23	
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
HVDC 1.2GW radial link at a distance of 160km between P4 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	683.32		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC Converter	666.51		
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
TOTAL	**10327.04**	**1255.88**	**11582.92**

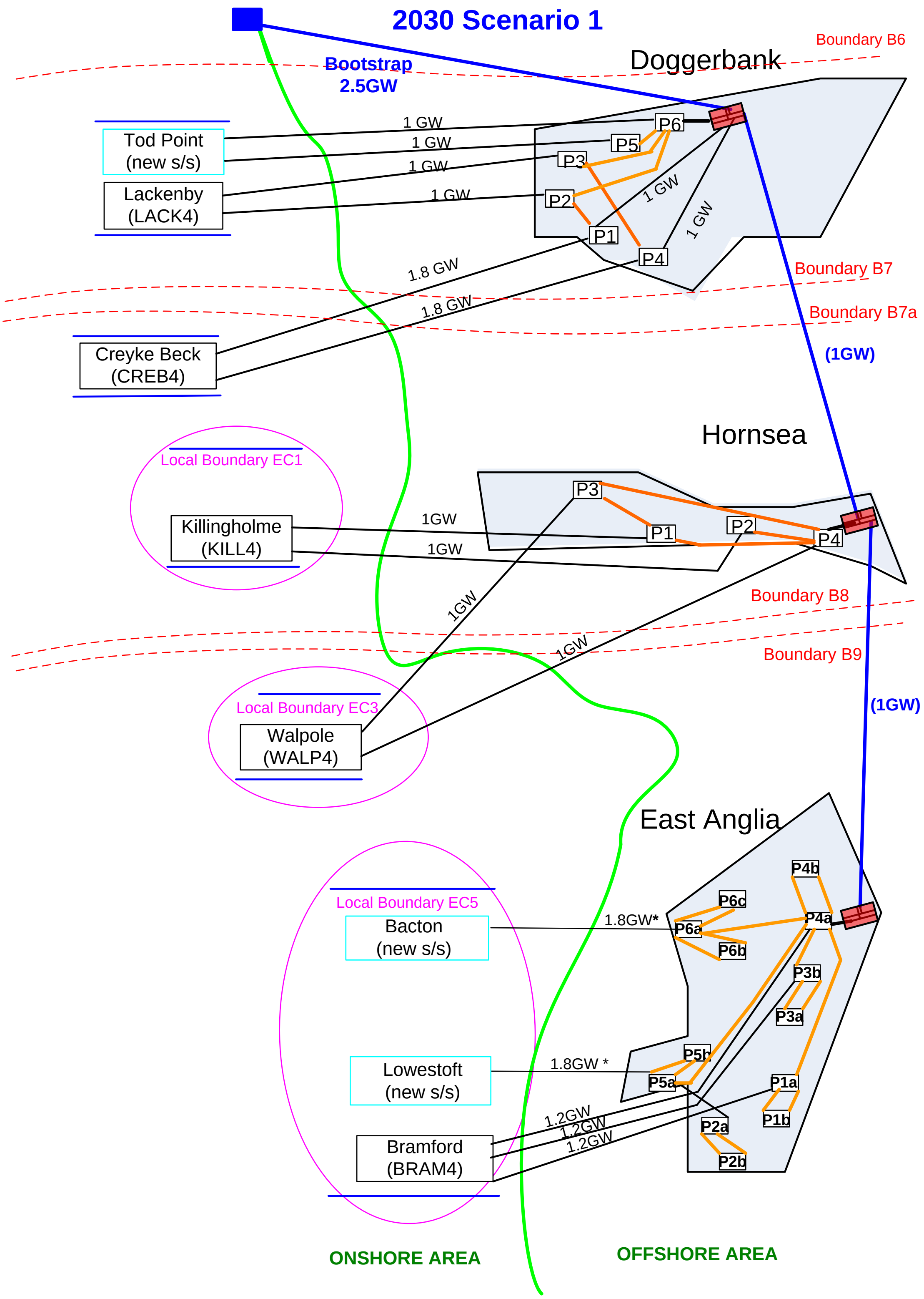
Design 13c - 2.5GW Hybrid Bootstrap across B6, B7 and B7a Boundaries, onshore B8 reinforcements with 2GW Links to Shore.



Design 13c – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1GW radial link at a distance of 212.5km between P1 and CREB4 including cable installation cost and 1GW onshore VSC Converter	700.15		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1.2GW radial link at a distance of 215.1km between P4(1GW) and CREB4 including cable installation cost and 1.2GW onshore VSC Converter	761.95		
HVDC 1.8GW radial link at a distance of 210.6km between P5(1GW) and a proposed new substation Tod Point (TODP4) including cable installation cost and 1.8GW onshore VSC Converter	942.58		
Two 500MW HVAC Cables at a distance of 36.5km from P6 to P5 including cable installation cost	57.43		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
200MW HVAC link at a distance of 31.8km from P4 to P5 including installation cost	35.04		
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1.2GW radial link at a distance of 125km between P2(1GW) and KILL4 including cable installation cost and 1.2GW onshore VSC Converter	633.38		
HVDC 2GW radial link at a distance of 125km between P3(1GW) and WALP4 including cable installation cost and 2GW onshore VSC Converter	829.06		
300MW HVAC link at a distance of 38km from P3 to P1 including installation cost		43.87	
Two 500MW HVAC Cables at a distance of 38km from P4 to P3 including cable installation cost	59.79		
East Anglia			
HVDC 1.8GW radial link at a distance of 73km between P1(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	739		
1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.8GW radial link at a distance of 160km between P4(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	867.72		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC Converter	666.51		
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
Two 300MW HVAC Cables at a distance of 60km from P3a to P1 including cable installation cost	69.27		
Two 300MW HVAC Cables at a distance of 60km from P3b to P4 including cable installation cost	69.27		
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
TOTAL	**9594.57**	**1049.63**	**10644.20**

Design 15a (Optimised) - Offshore Mesh with 1GW links to Shore

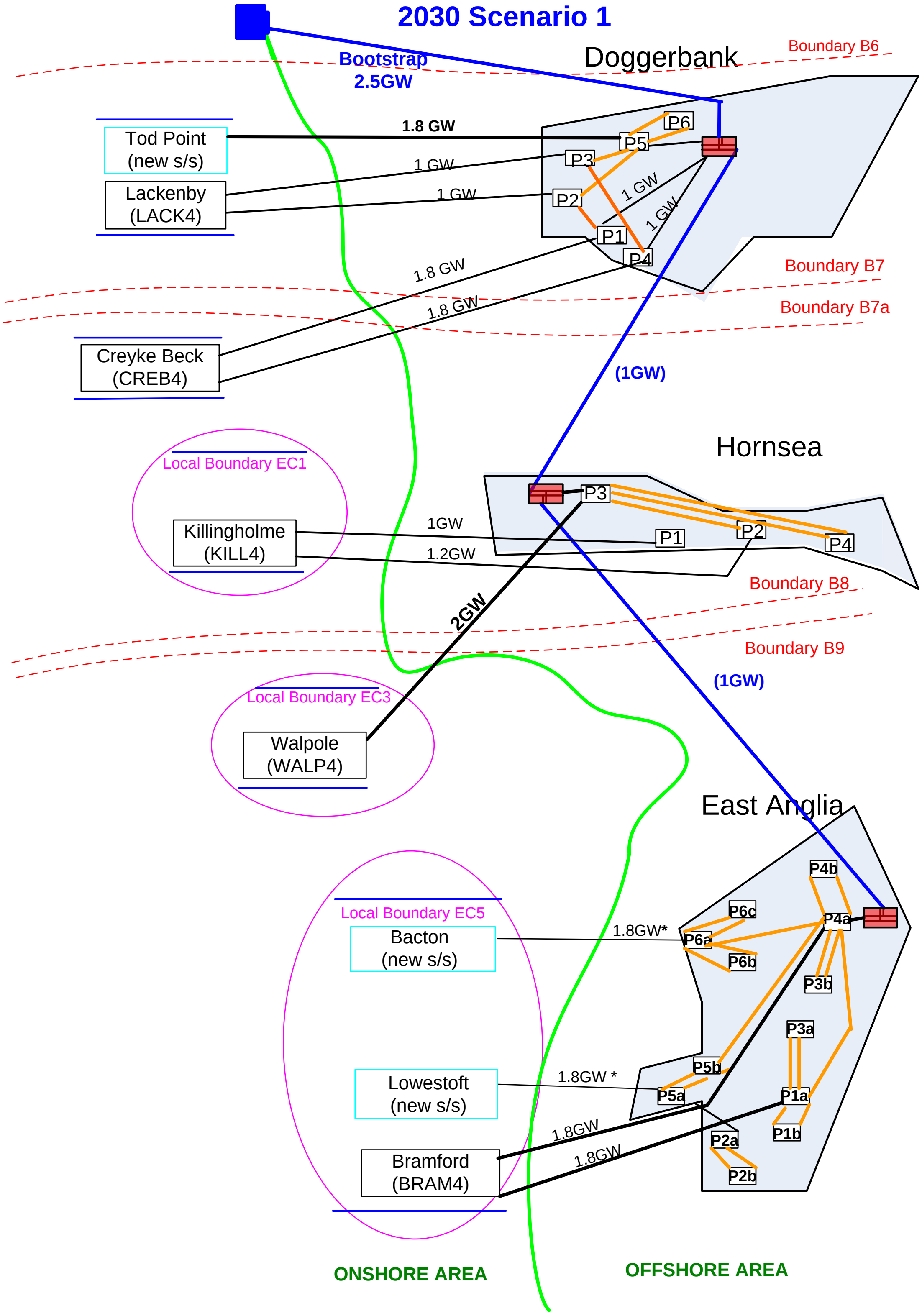


Design 15a (Optimised) - Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1.8GW radial link at a distance of 212.5km between P1(1GW) and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	945.67		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1.8GW radial link at a distance of 215.1km between P4(1GW) and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	949.19		
HVDC 1GW radial link at a distance of 210.6km between P5 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	697.49		
HVDC 1GW radial link at a distance of 246.3km between P6 and a proposed new substation Tod Point (TODP4) including cable installation cost and 1GW onshore VSC Converter	747.51		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
HVDC 1GW Integrating T-Platform located at Dogger Bank		50	
HVDC 1GW at a distance of 120km from Dogger Bank to Hornsea including cable installation cost		168.12	
HVDC 1GW at a distance of 98.8km from P1 to HVDC integration T-platform including installation cost		138.42	
HVAC 300MW at a distance of 49.4km from P2 to HVDC integration T-platform including installation cost		57.03	
HVAC 300MW at a distance of 70.6km from P3 to HVDC integration T-platform including installation cost		81.51	
HVDC 1GW at a distance of 68.3km from P4 to HVDC integration T-platform including installation cost		95.69	
HVAC 300MW at a distance of 36.5km from P5 to HVDC integration T-platform including installation cost		42.14	
2.5GW VSC Converter located in Scotland		176.17	
2.5GW HVDC Cable from Scottish Transmission Network to Dogger Bank at a distance of 200km		322.80	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1GW radial link at a distance of 125km between P2 and KILL4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 125km between P3 and WALP4 including cable installation cost and 1GW onshore VSC Converter	577.57		
HVDC 1GW radial link at a distance of 138km between P4 and WALP4 including cable installation cost and 1GW onshore VSC Converter	595.78		
300MW HVAC link at a distance of 64km from P3 to P1 including installation cost		73.89	
300MW HVAC link at a distance of 56km from P2 to P4 including installation cost		64.65	
HVDC 1GW Integrating T-Platform located at Hornsea		50	
HVDC 1GW at a distance of 100km from East Anglia to Hornsea including cable installation cost		140.1	
HVAC 300MW at a distance of 29km from P2 to HVDC integration T-platform including installation cost		33.48	
HVAC 300MW at a distance of 38km from P3 to HVDC integration T-platform including installation cost		43.87	
East Anglia			
HVDC 1.2GW radial link at a distance of 73km between P1 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	559.17		
1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.2GW radial link at a distance of 140km between P3 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	654.78		
HVDC 1.2GW radial link at a distance of 160km between P4 and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	683.32		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC	666.51		

Converter			
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
HVDC 1GW Integrating T-Platform located at East Anglia		50	
HVAC 300MW at a distance of 30km from P1 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P3 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P5 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P6 to HVDC integration T-platform including installation cost		34.64	
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
TOTAL	**10327.04**	**1810.13**	**12137.18**

Design 15c - Offshore Mesh with 2GW links to Shore



Design 15c – Cost Breakdown

	Radial Cost (£m)	Reinforcement / Integration Cost (£m)	TOTAL
Dogger Bank			
HVDC 1.8GW radial link at a distance of 212.5km between P1(1GW) and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	945.67		
HVDC 1GW radial link at a distance of 261km between P2 and LACK4 including cable installation cost and 1GW onshore VSC Converter	768.10		
HVDC 1GW radial link at a distance of 222.8km between P3 and LACK4 including cable installation cost and 1GW onshore VSC Converter	714.58		
HVDC 1.8GW radial link at a distance of 215.1km between P4(1GW) and CREB4 including cable installation cost and 1.8GW onshore VSC Converter	949.19		
HVDC 1.8GW radial link at a distance of 210.6km between P5(1GW) and a proposed new substation Tod Point (TODP4) including cable installation cost and 1.8GW onshore VSC Converter	942.58		
Two 500MW HVAC Cables at a distance of 36.5km from P6 to P5 including cable installation cost	57.43		
300MW HVAC link at a distance of 72.9km from P2 to P1 including installation cost		84.16	
300MW HVAC link at a distance of 35.3km from P4 to P3 including installation cost		40.75	
HVDC 1GW Integrating T-Platform located at Dogger Bank		50	
HVDC 1GW at a distance of 120km from Dogger Bank to Hornsea including cable installation cost		168.12	
HVDC 1GW at a distance of 98.8km from P1 to HVDC integration T-platform including installation cost		138.42	
HVAC 300MW at a distance of 49.4km from P2 to HVDC integration T-platform including installation cost		57.03	
HVAC 300MW at a distance of 70.6km from P3 to HVDC integration T-platform including installation cost		81.51	
HVDC 1GW at a distance of 68.3km from P4 to HVDC integration T-platform including installation cost		95.69	
HVAC 300MW at a distance of 36.5km from P5 to HVDC integration T-platform including installation cost		42.14	
2.5GW VSC Converter located in Scotland		176.17	
2.5GW HVDC Cable from Scottish Transmission Network to Dogger Bank at a distance of 200km		322.80	
Hornsea			
HVDC 1GW radial link at a distance of 150km between P1 and KILL4 including cable installation cost and 1GW onshore VSC Converter	612.59		
HVDC 1.2GW radial link at a distance of 125km between P2(1GW) and KILL4 including cable installation cost and 1.2GW onshore VSC Converter	577.57		
HVDC 2GW radial link at a distance of 125km between P3(1GW) and WALP4 including cable installation cost and 2GW onshore VSC Converter	829.06		
Two 500MW HVAC Cables at a distance of 38km from P3 to P4 including cable installation cost	59.79		
300MW HVAC link at a distance of 56km from P2 to P1 including installation cost		43.87	
HVDC 1GW Integrating T-Platform located at Hornsea		50	
HVDC 1GW at a distance of 100km from East Anglia to Hornsea including cable installation cost		140.1	
HVAC 300MW at a distance of 38km from P2 to HVDC integration T-platform including installation cost		43.87	
East Anglia			
HVDC 1.8GW radial link at a distance of 73km between P1(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	739		

1GW HVDC platform located for P2(800MW)	294.50		
HVDC 1.8GW radial link at a distance of 160km between P4(1.2GW) and BRAM4 including cable installation cost and 1.2GW onshore VSC Converter	867.72		
HVDC 1.8GW radial link at a distance of 24km between P5(1GW) and a proposed new substation Lowestoft (LOWE4) including cable installation cost and 1.8GW onshore VSC Converter	666.51		
HVDC 1.8GW radial link at a distance of 68km between P6 and a proposed new substation Bacton (BACT4) including cable installation cost and 1.8GW onshore VSC Converter	731.61		
HVDC 1GW at a distance of 30km from P2 to P5 including cable installation cost	42.03		
Two 300MW HVAC Cables at a distance of 60km from P3a to P1 including cable installation cost	69.27		
Two 300MW HVAC Cables at a distance of 60km from P3b to P4 including cable installation cost	69.27		
HVDC 1GW Integrating T-Platform located at East Anglia		50	
HVAC 300MW at a distance of 30km from P1 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P5 to HVDC integration T-platform including installation cost		34.64	
HVAC 300MW at a distance of 30km from P6 to HVDC integration T-platform including installation cost		34.64	
Bootstrap (Intra Grid Link)			
2.5GW HVDC link at a distance of 250km from Scotland to proposed New Killingholme South substation(EC1) including cable installation cost, two 2.5GW onshore VSC Converters and cost of required reinforcement at point of connection in Scotland and New Killingholme South substation(EC1)		880.84	
Onshore Reinforcement			
Cost of Additional Enabling Work at CREB4	113.9		
TOTAL	**10050.43**	**1532.03**	**11582.46**

Appendix 2 – Model Boundary Capabilities by Scenario and Season

TEC2030 Radial	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6	8,000	7,200	6,400	8,000	7,200	6,400
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
DB5	1,000	1,000	1,000	1,000	1,000	1,000
DB6	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
H4	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA2	900	900	900	900	900	900
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	1,200	1,200	1,200	1,200	1,200	1,200
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
B7DB123456	10,600	9,740	8,880	10,600	9,740	8,880
B7DB2356	8,600	7,740	6,880	8,600	7,740	6,880
B7aDB123456	10,400	9,560	8,720	10,400	9,560	8,720
B7aDB2356	8,400	7,560	6,720	8,400	7,560	6,720
B8DB123456H1234	12,200	11,180	10,160	12,200	11,180	10,160
B8DB123456H12	10,200	9,180	8,160	10,200	9,180	8,160
B9DB123456H12	6,900	6,210	5,520	6,900	6,210	5,520
B9DB123456H1234	8,900	8,210	7,520	8,900	8,210	7,520
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC 2030 Radial + Onshore	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6	10,500	9,450	8,400	10,500	9,450	8,400
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
DB5	1,000	1,000	1,000	1,000	1,000	1,000
DB6	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
H4	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA2	900	900	900	900	900	900
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	1,200	1,200	1,200	1,200	1,200	1,200
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
B7DB123456	12,800	11,720	10,640	12,800	11,720	10,640
B7DB2356	10,800	9,720	8,640	10,800	9,720	8,640
B7aDB123456	12,700	11,630	10,560	12,700	11,630	10,560
B7aDB2356	10,700	9,630	8,560	10,700	9,630	8,560
B8DB123456H1234	14,400	13,060	11,720	15,400	14,060	12,720
B8DB123456H12	13,400	12,060	10,720	13,400	12,060	10,720
B9DB123456H12	10,100	9,090	8,080	10,100	9,090	8,080
B9DB123456H1234	11,100	10,090	9,080	12,100	11,090	10,080
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 10a	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6L0	8,000	7,200	6,400	8,000	7,200	6,400
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
DB5	1,000	1,000	1,000	1,000	1,000	1,000
DB6	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
H4	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA2	900	900	900	900	900	900
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	1,200	1,200	1,200	1,200	1,200	1,200
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
B7DB123456L0	11,100	10,240	9,380	11,100	10,240	9,380
B7aDB123456L0	10,900	10,060	9,220	10,900	10,060	9,220
B8DB123456H12	13,400	12,060	10,720	13,400	12,060	10,720
B9DB123456H12	10,100	9,090	8,080	10,100	9,090	8,080
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 10c	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,400	1,400	1,400	1,400	1,400	1,400
DB45	2,000	2,000	2,000	2,000	2,000	2,000
DB456	3,000	3,000	3,000	3,000	3,000	3,000
DB5	1,000	1,000	1,000	1,000	1,000	1,000
DB56	2,000	2,000	2,000	2,000	2,000	2,000
DB6	2,600	2,600	2,600	2,600	2,600	2,600
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,400	1,400	1,400	1,400	1,400	1,400
H23	3,200	3,200	3,200	3,200	3,200	3,200
H3	2,200	2,200	2,200	2,200	2,200	2,200
H4	1,000	1,000	1,000	1,000	1,000	1,000
H34	2,200	2,200	2,200	2,200	2,200	2,200
H234	3,200	3,200	3,200	3,200	3,200	3,200
EA1	1,800	1,800	1,800	1,800	1,800	1,800
EA2	900	900	900	900	900	900
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA4	1,800	1,800	1,800	1,800	1,800	1,800
EA5	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
B6L0	10,500	9,700	8,900	10,500	9,700	8,900
B7DB236L0	12,700	11,760	10,820	12,700	11,760	10,820
B7DB2356L0	12,100	11,160	10,220	12,100	11,160	10,220
B7DB23456L0	13,100	12,160	11,220	13,100	12,160	11,220
B7aDB236L0	12,800	11,850	10,900	12,800	11,850	10,900
B7aDB2356L0	12,200	11,250	10,300	12,200	11,250	10,300
B7aDB23456L0	13,200	12,250	11,300	13,200	12,250	11,300
B8DB123456H12	14,700	13,250	11,800	14,700	13,250	11,800
B8DB123456H1234	16,500	15,050	13,600	16,500	15,050	13,600
B9DB123456H12	11,500	10,370	9,240	11,500	10,370	9,240
B9DB123456H1234	13,300	12,170	11,040	13,300	12,170	11,040
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 13a	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6L0	10,500	9,700	8,900	10,500	9,700	8,900
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	6,800	6,120	5,440
B13	5,500	4,950	4,400	2,300	2,070	1,840
B14	10,800	9,720	8,640	10,400	9,360	8,320
B15	8,000	7,200	6,400	8,600	7,740	6,880
B17	5,500	4,950	4,400	5,700	5,130	4,560
DB1	1,300	1,300	1,300	1,300	1,300	1,300
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB3	300	300	300	300	300	300
DB4	1,300	1,300	1,300	1,300	1,300	1,300
DB5	1,000	1,000	1,000	1,000	1,000	1,000
DB6	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,300	1,300	1,300	1,300	1,300	1,300
H2	1,600	1,600	1,600	1,600	1,600	1,600
H3	1,300	1,300	1,300	1,300	1,300	1,300
H4	1,600	1,600	1,600	1,600	1,600	1,600
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA2	900	900	900	900	900	900
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	1,200	1,200	1,200	1,200	1,200	1,200
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
EA5	1,800	1,800	1,800	1,800	1,800	1,800
B7DB2356L0	12,500	11,560	10,620	12,500	11,560	10,620
B7DB123456L0	13,900	12,960	12,020	13,900	12,960	12,020
B7aDB2356L0	12,600	11,650	10,700	12,600	11,650	10,700
B7aDB123456L0	14,000	13,050	12,100	14,000	13,050	12,100
B8DB123456H3	11,600	10,470	9,340	11,600	10,470	9,340
B8DB123456H13	12,300	11,170	10,040	12,300	11,170	10,040
B8DB123456H123	12,900	11,770	10,640	12,900	11,770	10,640
B8DB123456H1234	13,300	12,170	11,040	13,300	12,170	11,040
B9DB123456H3	8,400	7,590	6,780	8,400	7,590	6,780
B9DB123456H13	9,100	8,290	7,480	9,100	8,290	7,480
B9DB123456H123	9,700	8,890	8,080	9,700	8,890	8,080
B9DB123456H1234	10,100	9,290	8,480	10,100	9,290	8,480
DB34	1,000	1,000	1,000	1,000	1,000	1,000
DB12	2,000	2,000	2,000	2,000	2,000	2,000
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	3,000	2,700	2,400
NW1	6,400	5,760	5,120	1,800	1,620	1,440
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	6,700	6,030	5,360
B15Rev	8,000	7,200	6,400	8,600	7,740	6,880
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 13c	Gone Green			Slow Progression		
	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6L0	10,500	9,700	8,900	10,500	9,700	8,900
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,300	1,300	1,300	1,300	1,300	1,300
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB3	300	300	300	300	300	300
DB4	1,800	1,800	1,800	1,800	1,800	1,800
DB5	1,100	1,100	1,100	1,100	1,100	1,100
DB6	2,600	2,600	2,600	2,600	2,600	2,600
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,500	1,500	1,500	1,500	1,500	1,500
H3	2,300	2,300	2,300	2,300	2,300	2,300
H4	1,000	1,000	1,000	1,000	1,000	1,000
EA13a	1,800	1,800	1,800	1,800	1,800	1,800
EA2	900	900	900	900	900	900
H23	3,200	3,200	3,200	3,200	3,200	3,200
EA43b	1,800	1,800	1,800	1,800	1,800	1,800
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
EA5	1,800	1,800	1,800	1,800	1,800	1,800
B7DB2356L0	12,800	11,860	10,920	12,800	11,860	10,920
B7DB123456L0	14,100	13,160	12,220	14,100	13,160	12,220
B7aDB2356L0	12,900	11,950	11,000	12,900	11,950	11,000
B7aDB123456L0	14,200	13,250	12,300	14,200	13,250	12,300
B8DB123456H124	12,600	11,470	10,340	12,600	11,470	10,340
B8DB123456H1234	13,300	12,170	11,040	13,300	12,170	11,040
DB56	2,100	2,100	2,100	2,100	2,100	2,100
DB456	3,300	3,300	3,300	3,300	3,300	3,300
B9DB123456H124	9,400	8,590	7,780	9,400	8,590	7,780
B9DB123456H1234	10,100	9,290	8,480	10,100	9,290	8,480
DB3456	3,000	3,000	3,000	3,000	3,000	3,000
DB45	2,300	2,300	2,300	2,300	2,300	2,300
DB34	1,500	1,500	1,500	1,500	1,500	1,500
DB12	2,000	2,000	2,000	2,000	2,000	2,000
DB345	2,000	2,000	2,000	2,000	2,000	2,000
H34	2,300	2,300	2,300	2,300	2,300	2,300
H234	3,200	3,200	3,200	3,200	3,200	3,200
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 15a (Opt)	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB3L1	7,000	7,000	7,000	7,000	7,000	7,000
DB3	1,600	1,600	1,600	1,600	1,600	1,600
DB34	3,900	3,900	3,900	3,900	3,900	3,900
DB36L1	6,700	6,700	6,700	6,700	6,700	6,700
DB35L1	7,700	7,700	7,700	7,700	7,700	7,700
DB13L1	8,000	8,000	8,000	8,000	8,000	8,000
DB123L1	9,000	9,000	9,000	9,000	9,000	9,000
DB34L1	7,700	7,700	7,700	7,700	7,700	7,700
DB345L1	8,400	8,400	8,400	8,400	8,400	8,400
DB346L1	8,400	8,400	8,400	8,400	8,400	8,400
DB134L1	9,000	9,000	9,000	9,000	9,000	9,000
DB1234L1	9,700	9,700	9,700	9,700	9,700	9,700
DB6	1,300	1,300	1,300	1,300	1,300	1,300
DB6L1	6,700	6,700	6,700	6,700	6,700	6,700
DB56L1	7,400	7,400	7,400	7,400	7,400	7,400
DB1	2,900	2,900	2,900	2,900	2,900	2,900
DB12L1	8,000	8,000	8,000	8,000	8,000	8,000
DB15L1	8,000	8,000	8,000	8,000	8,000	8,000
DB16L1	8,000	8,000	8,000	8,000	8,000	8,000
DB5	1,300	1,300	1,300	1,300	1,300	1,300
DB5L1	6,700	6,700	6,700	6,700	6,700	6,700
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB12	3,600	3,600	3,600	3,600	3,600	3,600
DB125L1	8,700	8,700	8,700	8,700	8,700	8,700
DB126L1	8,700	8,700	8,700	8,700	8,700	8,700
DB4	2,900	2,900	2,900	2,900	2,900	2,900
DB4L1	7,300	7,300	7,300	7,300	7,300	7,300
DB46L1	8,000	8,000	8,000	8,000	8,000	8,000
DB45L1	8,000	8,000	8,000	8,000	8,000	8,000
DB14L1	8,600	8,600	8,600	8,600	8,600	8,600
DB124L1	9,300	9,300	9,300	9,300	9,300	9,300
EA14L3	3,700	3,700	3,700	3,700	3,700	3,700
EA13L3	3,700	3,700	3,700	3,700	3,700	3,700
EA3	1,500	1,500	1,500	1,500	1,500	1,500
EA1	1,500	1,500	1,500	1,500	1,500	1,500
EA1L3	2,800	2,800	2,800	2,800	2,800	2,800
EA3L3	2,800	2,800	2,800	2,800	2,800	2,800
EA134L3	4,600	4,600	4,600	4,600	4,600	4,600
EA34L3	3,700	3,700	3,700	3,700	3,700	3,700
EA4	1,500	1,500	1,500	1,500	1,500	1,500
EA4L3	2,800	2,800	2,800	2,800	2,800	2,800
EA2	900	900	900	900	900	900
EA5	1,800	1,800	1,800	1,800	1,800	1,800
EA6	1,800	1,800	1,800	1,800	1,800	1,800
EA25	1,800	1,800	1,800	1,800	1,800	1,800
H3	1,800	1,800	1,800	1,800	1,800	1,800
H1	1,300	1,300	1,300	1,300	1,300	1,300
H2	1,600	1,600	1,600	1,600	1,600	1,600
H4	2,100	2,100	2,100	2,100	2,100	2,100
H13	2,500	2,500	2,500	2,500	2,500	2,500
H24	2,500	2,500	2,500	2,500	2,500	2,500
EA134H4L23	6,700	6,700	6,700	6,700	6,700	6,700
EA134H24L23	7,100	7,100	7,100	7,100	7,100	7,100
EA134L23	5,600	5,600	5,600	5,600	5,600	5,600

EA134H1234DB34L123	14,300	14,300	14,300	14,300	14,300	14,300
EA134H1234DB12L123	16,700	16,700	16,700	16,700	16,700	16,700
EA134H1234L123	12,600	12,600	12,600	12,600	12,600	12,600
EA134H1234DB6L123	13,300	13,300	13,300	13,300	13,300	13,300
EA134H1234DB5L123	13,300	13,300	13,300	13,300	13,300	13,300
EA134H1234DB4L123	13,900	13,900	13,900	13,900	13,900	13,900
EA134H1234DB3L123	13,600	13,600	13,600	13,600	13,600	13,600
EA134H1234DB1L123	13,900	13,900	13,900	13,900	13,900	13,900
DB123456L12	12,100	12,100	12,100	12,100	12,100	12,100
DB123456L1	11,100	11,100	11,100	11,100	11,100	11,100
DB123456H4L12	13,200	13,200	13,200	13,200	13,200	13,200
DB123456H24L12	13,600	13,600	13,600	13,600	13,600	13,600
DB123456H3L12	12,900	12,900	12,900	12,900	12,900	12,900
DB123456H13L12	13,600	13,600	13,600	13,600	13,600	13,600
DB123456H1234L123	15,000	15,000	15,000	15,000	15,000	15,000
DB123456H1234EA4L123	15,900	15,900	15,900	15,900	15,900	15,900
DB123456H1234EA3L123	15,900	15,900	15,900	15,900	15,900	15,900
DB123456H1234EA1L123	15,900	15,900	15,900	15,900	15,900	15,900
B6L0	10,500	9,700	8,900	10,500	9,700	8,900
B6DB123456L01	16,600	15,800	15,000	16,600	15,800	15,000
B6L01	11,500	10,700	9,900	11,500	10,700	9,900
B6DB14L01	14,100	13,300	12,500	14,100	13,300	12,500
B7DB2356L01	12,600	11,660	10,720	12,600	11,660	10,720
B7DB123456L01	14,000	13,060	12,120	14,000	13,060	12,120
B7DB123456L012	15,000	14,060	13,120	15,000	14,060	13,120
B7DB123456H34L012	16,900	15,960	15,020	16,900	15,960	15,020
B7DB123456H1234L012	18,000	17,060	16,120	18,000	17,060	16,120
B7aDB2356L01	12,700	11,750	10,800	12,700	11,750	10,800
B7aDB123456L01	14,100	13,150	12,200	14,100	13,150	12,200
B7aDB123456L012	15,100	14,150	13,200	15,100	14,150	13,200
B7aDB123456H34L012	17,000	16,050	15,100	17,000	16,050	15,100
B7aDB123456H1234L012	18,100	17,150	16,200	18,100	17,150	16,200
B8DB123456H13L012	13,800	12,670	11,540	13,800	12,670	11,540
B8DB123456H1234L012	14,300	13,170	12,040	14,300	13,170	12,040
B8DB123456H1234L0123	14,200	13,070	11,940	14,200	13,070	11,940
B8DB123456H1234EA134L0123	16,900	15,770	14,640	16,900	15,770	14,640
B9DB123456H13L012	10,600	9,790	8,980	10,600	9,790	8,980
B9DB123456H1234L012	11,100	10,290	9,480	11,100	10,290	9,480
B9DB123456H1234L0123	11,000	10,190	9,380	11,000	10,190	9,380
B9DB123456H1234EA134L0123	13,700	12,890	12,080	13,700	12,890	12,080
EA134H13L23	7,100	7,100	7,100	7,100	7,100	7,100
EA134H3L23	6,400	6,400	6,400	6,400	6,400	6,400
B6DB3L01	12,500	11,700	10,900	12,500	11,700	10,900
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

TEC2030 15c (Opt)	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
EA13A43BL3	4,600	4,600	4,600	4,600	4,600	4,600
EA13A	2,100	2,100	2,100	2,100	2,100	2,100
EA43BL3	3,100	3,100	3,100	3,100	3,100	3,100
EA25	1,800	1,800	1,800	1,800	1,800	1,800
EA13AL3	3,400	3,400	3,400	3,400	3,400	3,400
EA2	900	900	900	900	900	900
EA13A43B	4,500	4,500	4,500	4,500	4,500	4,500
EA6	1,800	1,800	1,800	1,800	1,800	1,800
B10	5,900	5,310	4,720	5,900	5,310	4,720
EA13A43BH34L23	6,900	6,900	6,900	6,900	6,900	6,900
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
EA13A43BH4L23	5,600	5,600	5,600	5,600	5,600	5,600
B17	5,500	4,950	4,400	7,100	6,390	5,680
B9DB123456H1234EA13A43BL0123	13,700	12,890	12,080	13,700	12,890	12,080
B9DB123456H1234L0123	11,000	10,190	9,380	11,000	10,190	9,380
B9DB123456H1234L012	11,100	10,290	9,480	11,100	10,290	9,480
B9DB123456H134L012	11,400	10,590	9,780	11,400	10,590	9,780
B8DB123456H1234L012	16,900	15,770	14,640	16,900	15,770	14,640
B8DB123456H1234L0123	14,200	13,070	11,940	14,200	13,070	11,940
B8DB123456H1234L012	14,300	13,170	12,040	14,300	13,170	12,040
B8DB123456H134L012	14,600	13,470	12,340	14,600	13,470	12,340
B7aDB123456H234L012	17,300	16,350	15,400	17,300	16,350	15,400
B7aDB123456H34L012	16,400	15,450	14,500	16,400	15,450	14,500
B7aDB123456H4L012	15,100	14,150	13,200	15,100	14,150	13,200
B7aDB123456L012	14,700	13,750	12,800	14,700	13,750	12,800
B7aDB123456L01	14,100	13,150	12,200	14,100	13,150	12,200
B7aDB2356L01	13,000	12,050	11,100	13,000	12,050	11,100
B7DB123456H234L012	17,200	16,260	15,320	17,200	16,260	15,320
B7DB123456H34L012	16,300	15,360	14,420	16,300	15,360	14,420
B7DB123456H4L012	15,000	14,060	13,120	15,000	14,060	13,120
B7DB123456L012	14,600	13,660	12,720	14,600	13,660	12,720
B7DB123456L01	14,000	13,060	12,120	14,000	13,060	12,120
B7DB2356L01	12,900	11,960	11,020	12,900	11,960	11,020
B6DB35L01	13,600	12,800	12,000	13,600	12,800	12,000
B6DB146L01	15,600	14,800	14,000	15,600	14,800	14,000
B6DB123456L01	16,400	15,600	14,800	16,400	15,600	14,800
B6L01	11,200	10,400	9,600	11,200	10,400	9,600
B6L0	10,500	9,700	8,900	10,500	9,700	8,900
DB123456H234L12	14,100	14,100	14,100	14,100	14,100	14,100
DB123456H34L12	13,200	13,200	13,200	13,200	13,200	13,200
DB123456H4L12	11,900	11,900	11,900	11,900	11,900	11,900
DB123456H234EA13AL123	15,500	15,500	15,500	15,500	15,500	15,500
DB123456H234EA43BL123	15,200	15,200	15,200	15,200	15,200	15,200
DB123456L123	11,400	11,400	11,400	11,400	11,400	11,400
DB123456L12	11,500	11,500	11,500	11,500	11,500	11,500
DB6L1	8,000	8,000	8,000	8,000	8,000	8,000
DB6	2,900	2,900	2,900	2,900	2,900	2,900
DB45L1	7,800	7,800	7,800	7,800	7,800	7,800
DB56L1	7,200	7,200	7,200	7,200	7,200	7,200
DB56	2,400	2,400	2,400	2,400	2,400	2,400
DB5	1,100	1,100	1,100	1,100	1,100	1,100
DB456L1	8,500	8,500	8,500	8,500	8,500	8,500
DB456	5,000	5,000	5,000	5,000	5,000	5,000
DB45	3,700	3,700	3,700	3,700	3,700	3,700
DB4L1	7,300	7,300	7,300	7,300	7,300	7,300
DB46L1	9,600	9,600	9,600	9,600	9,600	9,600
DB4	3,200	3,200	3,200	3,200	3,200	3,200

DB356L1	8,500	8,500	8,500	8,500	8,500	8,500
DB36L1	9,000	9,000	9,000	9,000	9,000	9,000
DB345L1	8,200	8,200	8,200	8,200	8,200	8,200
DB3L1	6,700	6,700	6,700	6,700	6,700	6,700
DB346L1	10,000	10,000	10,000	10,000	10,000	10,000
DB34L1	7,700	7,700	7,700	7,700	7,700	7,700
DB3456L1	8,900	8,900	8,900	8,900	8,900	8,900
DB3456	6,000	6,000	6,000	6,000	6,000	6,000
DB345	4,700	4,700	4,700	4,700	4,700	4,700
DB34	4,200	4,200	4,200	4,200	4,200	4,200
DB3	1,600	1,600	1,600	1,600	1,600	1,600
DB1256L1	9,200	9,200	9,200	9,200	9,200	9,200
DB126L1	9,700	9,700	9,700	9,700	9,700	9,700
DB12456L1	10,500	10,500	10,500	10,500	10,500	10,500
DB1245L1	9,800	9,800	9,800	9,800	9,800	9,800
DB124L1	9,300	9,300	9,300	9,300	9,300	9,300
DB123456L1	10,900	10,900	10,900	10,900	10,900	10,900
DB12345L1	10,200	10,200	10,200	10,200	10,200	10,200
DB1234L1	9,700	9,700	9,700	9,700	9,700	9,700
DB123L1	8,400	8,400	8,400	8,400	8,400	8,400
DB12L1	7,700	7,700	7,700	7,700	7,700	7,700
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB156L1	8,500	8,500	8,500	8,500	8,500	8,500
DB16L1	9,000	9,000	9,000	9,000	9,000	9,000
DB13456L1	10,200	10,200	10,200	10,200	10,200	10,200
DB1345L1	9,500	9,500	9,500	9,500	9,500	9,500
DB13L1	8,000	8,000	8,000	8,000	8,000	8,000
DB1456L1	9,800	9,800	9,800	9,800	9,800	9,800
DB145L1	9,100	9,100	9,100	9,100	9,100	9,100
DB134L1	9,000	9,000	9,000	9,000	9,000	9,000
DB14L1	8,600	8,600	8,600	8,600	8,600	8,600
DB1L1	7,000	7,000	7,000	7,000	7,000	7,000
DB12	3,600	3,600	3,600	3,600	3,600	3,600
DB1	2,900	2,900	2,900	2,900	2,900	2,900
H4L2	3,000	3,000	3,000	3,000	3,000	3,000
H234L2	5,200	5,200	5,200	5,200	5,200	5,200
H4	1,600	1,600	1,600	1,600	1,600	1,600
H234	3,800	3,800	3,800	3,800	3,800	3,800
H34L2	4,300	4,300	4,300	4,300	4,300	4,300
H23	4,200	4,200	4,200	4,200	4,200	4,200
H34	2,900	2,900	2,900	2,900	2,900	2,900
H2	1,500	1,500	1,500	1,500	1,500	1,500
H3	3,300	3,300	3,300	3,300	3,300	3,300
H1	1,000	1,000	1,000	1,000	1,000	1,000
EA13A43BH234DB45L123	13,600	13,600	13,600	13,600	13,600	13,600
EA13A43BH234DB4L123	13,100	13,100	13,100	13,100	13,100	13,100
EA13A43BH234DB3456L123	14,700	14,700	14,700	14,700	14,700	14,700
EA13A43BH234DB34L123	13,500	13,500	13,500	13,500	13,500	13,500
EA13A43BH234DB56L123	13,300	13,300	13,300	13,300	13,300	13,300
EA13A43BH234DB3L123	12,500	12,500	12,500	12,500	12,500	12,500
EA13A43BH234DB6L123	13,800	13,800	13,800	13,800	13,800	13,800
EA13A43BH234DB12L123	13,500	13,500	13,500	13,500	13,500	13,500
EA13A43BH234DB456L123	14,300	14,300	14,300	14,300	14,300	14,300
EA13A43BH234DB1L123	12,800	12,800	12,800	12,800	12,800	12,800
EA13A43BH234L123	11,500	11,500	11,500	11,500	11,500	11,500
EA13A43BH234L23	7,800	7,800	7,800	7,800	7,800	7,800
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
EA13A43BL23	5,200	5,200	5,200	5,200	5,200	5,200
EA43B	2,400	2,400	2,400	2,400	2,400	2,400
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 Radial	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6	8,500	7,650	6,800	8,500	7,650	6,800
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	800	800	800	800	800	800
B7DB23	8,000	7,200	6,400	8,000	7,200	6,400
B7DB1234	10,000	9,200	8,400	10,000	9,200	8,400
B7aDB23	8,800	7,920	7,040	8,800	7,920	7,040
B7aDB1234	10,800	9,920	9,040	10,800	9,920	9,040
B8DB1234H12	11,000	9,900	8,800	11,000	9,900	8,800
B8DB1234H123	12,000	10,900	9,800	12,000	10,900	9,800
B9DB1234H12	8,800	7,920	7,040	8,800	7,920	7,040
B9DB1234H123	9,800	8,920	8,040	9,800	8,920	8,040
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 2a	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	800	800	800	800	800	800
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B7DB23L0	10,500	9,700	8,900	10,500	9,700	8,900
B7aDB23L0	11,300	10,420	9,540	11,300	10,420	9,540
B8DB1234H123L0	14,500	13,400	12,300	14,500	13,400	12,300
B8DB1234H12L0	13,500	12,400	11,300	13,500	12,400	11,300
B9DB1234H123L0	12,300	11,420	10,540	12,300	11,420	10,540
B9DB1234H12L0	11,300	10,420	9,540	11,300	10,420	9,540
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 2c	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB23	2,300	2,300	2,300	2,300	2,300	2,300
DB234	3,000	3,000	3,000	3,000	3,000	3,000
DB3	2,300	2,300	2,300	2,300	2,300	2,300
DB34	3,000	3,000	3,000	3,000	3,000	3,000
DB4	1,300	1,300	1,300	1,300	1,300	1,300
H1	1,300	1,300	1,300	1,300	1,300	1,300
H13	2,000	2,000	2,000	2,000	2,000	2,000
H123	3,000	3,000	3,000	3,000	3,000	3,000
H2	3,000	3,000	3,000	3,000	3,000	3,000
H23	2,300	2,300	2,300	2,300	2,300	2,300
H3	1,300	1,300	1,300	1,300	1,300	1,300
EA1	1,500	1,500	1,500	1,500	1,500	1,500
EA13	3,000	3,000	3,000	3,000	3,000	3,000
EA3	2,100	2,100	2,100	2,100	2,100	2,100
EA4	800	800	800	800	800	800
EA34	2,100	2,100	2,100	2,100	2,100	2,100
EA134	3,000	3,000	3,000	3,000	3,000	3,000
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B6DB23L0	13,300	12,450	11,600	13,300	12,450	11,600
B7DB23L0	11,300	10,450	9,600	11,300	10,450	9,600
B7DB1234L0	12,000	11,150	10,300	12,000	11,150	10,300
B7aDB23L0	11,800	10,900	10,000	11,800	10,900	10,000
B7aDB1234L0	12,500	11,600	10,700	12,500	11,600	10,700
B8DB1234H1L0	16,800	15,400	14,000	16,800	15,400	14,000
B8DB1234H13L0	17,500	16,100	14,700	17,500	16,100	14,700
B8DB1234H123L0	18,500	17,100	15,700	18,500	17,100	15,700
B9DB1234H1L0	15,200	13,960	12,720	15,200	13,960	12,720
B9DB1234H13L0	15,900	14,660	13,420	15,900	14,660	13,420
B9DB1234H123L0	16,900	15,660	14,420	16,900	15,660	14,420
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 3a	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	800	800	800	800	800	800
B7DB23L0	10,500	9,700	8,900	10,500	9,700	8,900
B7DB1234L0	12,500	11,700	10,900	12,500	11,700	10,900
B7aDB23L0	11,300	10,420	9,540	11,300	10,420	9,540
B7aDB1234L0	13,300	12,420	11,540	13,300	12,420	11,540
B8DB1234H12	12,700	11,430	10,160	12,700	11,430	10,160
B8DB1234H123	13,700	12,430	11,160	13,700	12,430	11,160
B9DB1234H12	10,800	9,720	8,640	10,800	9,720	8,640
B9DB1234H123	11,800	10,720	9,640	11,800	10,720	9,640
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 4a	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,300	1,300	1,300	1,300	1,300	1,300
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB3	1,300	1,300	1,300	1,300	1,300	1,300
DB4	1,300	1,300	1,300	1,300	1,300	1,300
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,300	1,300	1,300	1,300	1,300	1,300
H3	1,300	1,300	1,300	1,300	1,300	1,300
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	800	800	800	800	800	800
B7DB23L0	11,600	10,750	9,900	11,600	10,750	9,900
B7DB1234L0	13,000	12,150	11,300	13,000	12,150	11,300
B7aDB23L0	12,100	11,200	10,300	12,100	11,200	10,300
B7aDB1234L0	13,500	12,600	11,700	13,500	12,600	11,700
B8DB1234H12	14,300	12,900	11,500	14,300	12,900	11,500
B8DB1234H123	15,000	13,600	12,200	15,000	13,600	12,200
B9DB1234H12	12,700	11,460	10,220	12,700	11,460	10,220
B9DB1234H123	13,400	12,160	10,920	13,400	12,160	10,920
DB12	2,000	2,000	2,000	2,000	2,000	2,000
DB34	2,000	2,000	2,000	2,000	2,000	2,000
H23	2,000	2,000	2,000	2,000	2,000	2,000
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 5a (Opt)	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	2,600	2,600	2,600	2,600	2,600	2,600
DB2	1,300	1,300	1,300	1,300	1,300	1,300
DB3	1,300	1,300	1,300	1,300	1,300	1,300
DB4	2,600	2,600	2,600	2,600	2,600	2,600
DB1L1	6,700	6,700	6,700	6,700	6,700	6,700
DB12L1	7,400	7,400	7,400	7,400	7,400	7,400
DB13L1	7,400	7,400	7,400	7,400	7,400	7,400
DB14L1	7,700	7,700	7,700	7,700	7,700	7,700
DB2L1	6,400	6,400	6,400	6,400	6,400	6,400
DB23L1	7,100	7,100	7,100	7,100	7,100	7,100
DB24L1	7,400	7,400	7,400	7,400	7,400	7,400
DB3L1	6,400	6,400	6,400	6,400	6,400	6,400
DB34L1	7,400	7,400	7,400	7,400	7,400	7,400
DB4L1	6,700	6,700	6,700	6,700	6,700	6,700
H1	1,300	1,300	1,300	1,300	1,300	1,300
H2	1,300	1,300	1,300	1,300	1,300	1,300
H3	1,600	1,600	1,600	1,600	1,600	1,600
H13	2,300	2,300	2,300	2,300	2,300	2,300
H13L2	4,300	4,300	4,300	4,300	4,300	4,300
H3L2	3,600	3,600	3,600	3,600	3,600	3,600
H2L2	3,300	3,300	3,300	3,300	3,300	3,300
EA1	1,500	1,500	1,500	1,500	1,500	1,500
EA3	1,500	1,500	1,500	1,500	1,500	1,500
EA4	1,100	1,100	1,100	1,100	1,100	1,100
EA1L3	2,800	2,800	2,800	2,800	2,800	2,800
EA3L3	2,800	2,800	2,800	2,800	2,800	2,800
EA4L3	2,400	2,400	2,400	2,400	2,400	2,400
DB1234L12	9,700	9,700	9,700	9,700	9,700	9,700
DB1234H2L12	10,400	10,400	10,400	10,400	10,400	10,400
DB1234H3L12	10,400	10,400	10,400	10,400	10,400	10,400
DB1234H13L12	11,400	11,400	11,400	11,400	11,400	11,400
DB1234H123L123	12,000	12,000	12,000	12,000	12,000	12,000
DB1234H123EA1L123	12,900	12,900	12,900	12,900	12,900	12,900
DB1234H123EA3L123	12,900	12,900	12,900	12,900	12,900	12,900
DB1234H123EA4L123	12,500	12,500	12,500	12,500	12,500	12,500
EA134L23	4,800	4,800	4,800	4,800	4,800	4,800
EA134H2L23	5,500	5,500	5,500	5,500	5,500	5,500
EA134H3L23	5,800	5,800	5,800	5,800	5,800	5,800
EA134H13L23	6,500	6,500	6,500	6,500	6,500	6,500
EA134H123L123	10,900	10,900	10,900	10,900	10,900	10,900
EA134H123DB1L123	11,900	11,900	11,900	11,900	11,900	11,900
EA134H123DB2L123	11,600	11,600	11,600	11,600	11,600	11,600
EA134H123DB3L123	11,600	11,600	11,600	11,600	11,600	11,600
EA134H123DB4L123	11,900	11,900	11,900	11,900	11,900	11,900
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B6L01	11,700	10,850	10,000	11,700	10,850	10,000
B6DB1234L01	15,100	14,250	13,400	15,100	14,250	13,400
B7DB23L01	11,400	10,520	9,640	11,400	10,520	9,640
B7DB1234L01	13,400	12,520	11,640	13,400	12,520	11,640
B7DB1234L012	14,000	13,120	12,240	14,000	13,120	12,240
B7DB1234H23L012	15,700	14,820	13,940	15,700	14,820	13,940
B7DB1234H123L012	16,400	15,520	14,640	16,400	15,520	14,640
B7aDB23L01	12,500	11,510	10,520	12,500	11,510	10,520
B7aDB1234L01	14,500	13,510	12,520	14,500	13,510	12,520
B7aDB1234L012	15,100	14,110	13,120	15,100	14,110	13,120
B7aDB1234H23L012	16,800	15,810	14,820	16,800	15,810	14,820
B7aDB1234H123L012	17,500	16,510	15,520	17,500	16,510	15,520
B8DB1234H123L012	14,100	12,890	11,680	14,100	12,890	11,680
B8DB1234H123L0123	14,000	12,790	11,580	14,000	12,790	11,580
B8DB1234H123EA134L0123	16,300	15,090	13,880	16,300	15,090	13,880
B9DB1234H123L012	12,000	11,000	10,000	12,000	11,000	10,000
B9DB1234H123L0123	11,900	10,900	9,900	11,900	10,900	9,900
B9DB1234H123EA134L0123	14,200	13,200	12,200	14,200	13,200	12,200
EA134L3	4,200	4,200	4,200	4,200	4,200	4,200
DB1234L1	9,100	9,100	9,100	9,100	9,100	9,100
DB1234H123L12	12,100	12,100	12,100	12,100	12,100	12,100
EA134H123L12	7,200	7,200	7,200	7,200	7,200	7,200
B8DB1234H12L012	13,700	12,490	11,280	13,700	12,490	11,280
B9DB1234H12L012	11,600	10,600	9,600	11,600	10,600	9,600
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 5b (Opt)	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	3,200	3,200	3,200	3,200	3,200	3,200
DB2	1,200	1,200	1,200	1,200	1,200	1,200
DB3	3,100	3,100	3,100	3,100	3,100	3,100
DB4	900	900	900	900	900	900
DB12	3,200	3,200	3,200	3,200	3,200	3,200
DB123	5,100	5,100	5,100	5,100	5,100	5,100
DB123L1	8,600	8,600	8,600	8,600	8,600	8,600
DB14	2,900	2,900	2,900	2,900	2,900	2,900
DB14L1	6,400	6,400	6,400	6,400	6,400	6,400
DB134L1	6,700	6,700	6,700	6,700	6,700	6,700
DB23	3,100	3,100	3,100	3,100	3,100	3,100
DB23L1	6,600	6,600	6,600	6,600	6,600	6,600
DB234L1	6,900	6,900	6,900	6,900	6,900	6,900
DB1234L1	7,700	7,700	7,700	7,700	7,700	7,700
DB124	2,900	2,900	2,900	2,900	2,900	2,900
DB124L1	6,400	6,400	6,400	6,400	6,400	6,400
DB1234	4,800	4,800	4,800	4,800	4,800	4,800
DB3L1	6,600	6,600	6,600	6,600	6,600	6,600
DB34L1	6,900	6,900	6,900	6,900	6,900	6,900
DB4L1	4,400	4,400	4,400	4,400	4,400	4,400
H1	2,700	2,700	2,700	2,700	2,700	2,700
H2	4,400	4,400	4,400	4,400	4,400	4,400
H3	2,100	2,100	2,100	2,100	2,100	2,100
H13	3,000	3,000	3,000	3,000	3,000	3,000
H123	5,000	5,000	5,000	5,000	5,000	5,000
H123L2	5,800	5,800	5,800	5,800	5,800	5,800
H2L2	5,200	5,200	5,200	5,200	5,200	5,200
H23	4,100	4,100	4,100	4,100	4,100	4,100
H23L2	4,900	4,900	4,900	4,900	4,900	4,900
EA1	3,000	3,000	3,000	3,000	3,000	3,000
EA3	3,300	3,300	3,300	3,300	3,300	3,300
EA4	600	600	600	600	600	600
EA13	5,700	5,700	5,700	5,700	5,700	5,700
EA13L3	5,200	5,200	5,200	5,200	5,200	5,200
EA1L3	3,700	3,700	3,700	3,700	3,700	3,700
EA3L3	4,600	4,600	4,600	4,600	4,600	4,600
EA34	2,700	2,700	2,700	2,700	2,700	2,700
EA134	5,100	5,100	5,100	5,100	5,100	5,100
EA134L3	4,600	4,600	4,600	4,600	4,600	4,600
EA34L3	4,000	4,000	4,000	4,000	4,000	4,000
DB1234L12	8,900	8,900	8,900	8,900	8,900	8,900
DB1234H2L12	10,900	10,900	10,900	10,900	10,900	10,900
DB1234H23L12	10,600	10,600	10,600	10,600	10,600	10,600
DB1234H123L12	11,500	11,500	11,500	11,500	11,500	11,500
DB1234H123L123	12,000	12,000	12,000	12,000	12,000	12,000
DB1234H123EA1L123	13,800	13,800	13,800	13,800	13,800	13,800
DB1234H123EA34L123	13,500	13,500	13,500	13,500	13,500	13,500
DB1234H123EA134L123	14,100	14,100	14,100	14,100	14,100	14,100

EA134L23	5,800	5,800	5,800	5,800	5,800	5,800
EA134H2L23	7,800	7,800	7,800	7,800	7,800	7,800
EA134H23L23	7,500	7,500	7,500	7,500	7,500	7,500
EA134H123L23	8,400	8,400	8,400	8,400	8,400	8,400
EA134H123L123	10,500	10,500	10,500	10,500	10,500	10,500
EA134H123DB4L123	10,800	10,800	10,800	10,800	10,800	10,800
EA134H123DB14L123	12,800	12,800	12,800	12,800	12,800	12,800
EA134H123DB124L123	12,800	12,800	12,800	12,800	12,800	12,800
EA134H123DB3L123	13,000	13,000	13,000	13,000	13,000	13,000
EA134H123DB23L123	13,000	13,000	13,000	13,000	13,000	13,000
EA134H123DB123L123	15,000	15,000	15,000	15,000	15,000	15,000
B6L0	11,000	10,150	9,300	11,000	10,150	9,300
B6L01	10,100	9,250	8,400	10,100	9,250	8,400
B6DB3L01	12,600	11,750	10,900	12,600	11,750	10,900
B6DB23L01	12,600	11,750	10,900	12,600	11,750	10,900
B6DB123L01	14,600	13,750	12,900	14,600	13,750	12,900
B7DB1234L012	13,000	12,120	11,240	13,000	12,120	11,240
B7DB1234H2L012	15,000	14,120	13,240	15,000	14,120	13,240
B7DB1234H23L012	14,700	13,820	12,940	14,700	13,820	12,940
B7DB1234H123L012	15,600	14,720	13,840	15,600	14,720	13,840
B7aDB1234L012	14,100	13,110	12,120	14,100	13,110	12,120
B7aDB1234H2L012	16,100	15,110	14,120	16,100	15,110	14,120
B7aDB1234H23L012	15,800	14,810	13,820	15,800	14,810	13,820
B7aDB1234H123L012	16,700	15,710	14,720	16,700	15,710	14,720
B8DB1234H123L0123	15,600	14,390	13,180	15,600	14,390	13,180
B8DB1234H123EA1L0123	16,800	15,590	14,380	16,800	15,590	14,380
B8DB1234H123EA34L0123	17,100	15,890	14,680	17,100	15,890	14,680
B8DB1234H123EA134L0123	17,700	16,490	15,280	17,700	16,490	15,280
B9DB1234H123L0123	13,500	12,500	11,500	13,500	12,500	11,500
B9DB1234H123EA1L0123	14,700	13,700	12,700	14,700	13,700	12,700
B9DB1234H123EA34L0123	15,000	14,000	13,000	15,000	14,000	13,000
B9DB1234H123EA134L0123	15,600	14,600	13,600	15,600	14,600	13,600
B7DB1234L01	11,800	10,920	10,040	11,800	10,920	10,040
B7aDB1234L01	12,900	11,910	10,920	12,900	11,910	10,920
B8DB1234H123L012	15,100	13,890	12,680	15,100	13,890	12,680
B9DB1234H123L012	13,000	12,000	11,000	13,000	12,000	11,000
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

CENTRAL2030 Radial + Onshore	Gone Green			Slow Progression		
Model Boundary	Winter	Spr/Aut	Summer	Winter	Spr/Aut	Summer
B6	11,000	9,900	8,800	11,000	9,900	8,800
B10	5,900	5,310	4,720	5,900	5,310	4,720
B12	8,300	7,470	6,640	7,200	6,480	5,760
B13	5,500	4,950	4,400	5,500	4,950	4,400
B14	10,800	9,720	8,640	10,800	9,720	8,640
B15	8,000	7,200	6,400	8,000	7,200	6,400
B17	5,500	4,950	4,400	7,100	6,390	5,680
DB1	1,000	1,000	1,000	1,000	1,000	1,000
DB2	1,000	1,000	1,000	1,000	1,000	1,000
DB3	1,000	1,000	1,000	1,000	1,000	1,000
DB4	1,000	1,000	1,000	1,000	1,000	1,000
H1	1,000	1,000	1,000	1,000	1,000	1,000
H2	1,000	1,000	1,000	1,000	1,000	1,000
H3	1,000	1,000	1,000	1,000	1,000	1,000
EA1	1,200	1,200	1,200	1,200	1,200	1,200
EA3	1,200	1,200	1,200	1,200	1,200	1,200
EA4	800	800	800	800	800	800
B7DB23	10,200	9,180	8,160	10,200	9,180	8,160
B7DB1234	12,200	11,180	10,160	12,200	11,180	10,160
B7aDB23	11,100	9,990	8,880	11,100	9,990	8,880
B7aDB1234	13,100	11,990	10,880	13,100	11,990	10,880
B8DB1234H12	14,200	12,780	11,360	14,200	12,780	11,360
B8DB1234H123	15,200	13,780	12,360	15,200	13,780	12,360
B9DB1234H12	12,000	10,800	9,600	12,000	10,800	9,600
B9DB1234H123	13,000	11,800	10,600	13,000	11,800	10,600
SC1	5,900	5,310	4,720	5,900	5,310	4,720
EC1	9,400	8,460	7,520	5,500	4,950	4,400
EC3	3,600	3,240	2,880	3,600	3,240	2,880
EC5	7,600	6,840	6,080	7,300	6,570	5,840
NW1	6,400	5,760	5,120	5,600	5,040	4,480
NW2	6,700	6,030	5,360	4,900	4,410	3,920
NW3	7,200	6,480	5,760	5,400	4,860	4,320
NW4	7,700	6,930	6,160	5,000	4,500	4,000
B15Rev	8,000	7,200	6,400	8,000	7,200	6,400
SC1Rev	5,900	5,310	4,720	5,900	5,310	4,720

Appendix 3 – Constraint Bid Volumes by Offshore Zone

The optimisation process in the ELSI model adopted for this analysis does not allow accurate reporting of constraint costs by boundary. This is because some actions can resolve more than one constraint hence allocation is indeterminate, hence it is not possible to identify the location of corresponding Offer actions.

However, ELSI can track where Bid actions are taken and the volumes. This offers insight into the volume of lost generation by network designs for each of the offshore zones (Dogger Bank, Hornsea and East Anglia). The model results are shown below. All values are negative owning to the model nomenclature for Bid actions.

Gone Green background and 17.2GW Wind Capacity

GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN
	TEC 30 Radial: counterfactual	TEC 30 Option 10a	TEC 30 Option 10c	TEC 30 Option 13a	TEC 30 Option 13c	TEC 30 Option 15a	TEC 30 Option 15c	TEC 30 Radial plus onshore
Zone	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.
Dogger Bank Sub Total	-0.671	-0.878	-0.620	-0.512	-0.437	-0.157	-0.259	-0.652
Hornsea Sub Total	-0.369	-0.185	-0.253	-0.085	-0.129	-0.049	-0.089	-0.382
East Anglia Sub Total	-0.380	-0.459	-0.506	-0.345	-0.241	-0.274	-0.322	-0.376
Totals	**-1.420**	**-1.523**	**-1.378**	**-0.942**	**-0.807**	**-0.480**	**-0.669**	**-1.409**
Total GB Bids (TWh)	-14.587	-12.119	-5.330	-5.919	-5.537	-4.665	-4.834	-7.802

Gone Green background and 10GW Wind Capacity

GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN	GONE GREEN
	Central Radial: counterfactual	Central Option 2a	Central Option 2c	Central Option 3a	Central Option 4a	Central Option 5a	Central Option 5b	Central plus onshore
Zone	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.
Dogger Bank Sub Total	-0.600	-0.096	-0.484	-0.343	-0.313	-0.082	-0.245	-0.600
Hornsea Sub Total	-0.212	-0.083	-0.104	-0.265	-0.146	-0.067	-0.029	-0.212
East Anglia Sub Total	-0.241	-0.075	-0.131	-0.241	-0.305	-0.054	-0.035	-0.241
Totals	**-1.053**	**-0.254**	**-0.718**	**-0.849**	**-0.764**	**-0.203**	**-0.309**	**-1.053**
Total GB Bids (TWh)	-12.177	-5.122	-5.502	-5.901	-5.148	-4.577	-6.026	-6.332

Slow Progression background and 17.2GW Wind Capacity

SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.
	TEC 30 Radial: counterfactual	TEC 30 Option 10a	TEC 30 Option 10c	TEC 30 Option 13a	TEC 30 Option 13c	TEC 30 Option 15a	TEC 30 Option 15c	TEC 30 Radial plus onshore
Zone	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.
Dogger Bank Sub Total	-0.663	-0.857	-0.620	-0.512	-0.437	-0.157	-0.259	-0.652
Hornsea Sub Total	-0.369	-0.185	-0.253	-0.085	-0.129	-0.049	-0.089	-0.382
East Anglia Sub Total	-0.380	-0.458	-0.394	-0.345	-0.177	-0.272	-0.234	-0.376
Totals	**-1.413**	**-1.501**	**-1.266**	**-0.942**	**-0.743**	**-0.478**	**-0.582**	**-1.409**
Total GB Bids (TWh)	-14.497	-7.539	-3.936	-9.001	-7.345	-5.138	-4.536	-6.779

Slow Progression background and 10GW Wind Capacity

SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.	SLOW PROG.
	Central Radial: counterfactual	**Central Option 2a**	**Central Option 2c**	**Central Option 3a**	**Central Option 4a**	**Central Option 5a**	**Central Option 5b**	**Central plus onshore**
Zone	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.	Average TWh pa.
Dogger Bank Sub Total	*-0.600*	*-0.096*	*-0.484*	*-0.314*	*-0.313*	*-0.082*	*-0.245*	*-0.600*
Hornsea Sub Total	*-0.212*	*-0.083*	*-0.104*	*-0.265*	*-0.146*	*-0.067*	*-0.029*	*-0.212*
East Anglia Sub Total	*-0.241*	*-0.075*	*-0.132*	*-0.241*	*-0.305*	*-0.054*	*-0.035*	*-0.241*
Totals	**-1.053**	**-0.254**	**-0.720**	**-0.820**	**-0.764**	**-0.203**	**-0.309**	**-1.053**
Total GB Bids (TWh)	-11.044	-4.635	-2.200	-6.478	-4.124	-5.106	-3.596	-4.523

The results show that IOTP(E) Bid volumes range from 0.2TWh to 1.5TWh pa. within a total national Bid volume ranging from 2.2TWh to 14.6TWh depending on the design and generation background.

Many of the designs with integration lead to lower IOTP(E) Bid volumes and lower GW Bid volumes overall, than the corresponding radial design. This suggests that integration can reduce the impact to consumers by providing secondary routes for the generation to reach the market.

Whilst the operational cost of these IOPT(E) constraint actions cannot be identified from the model, they would be comparatively expensive since the Bid value reflects lost renewable subsidies as well as the value of the energy.

Appendix 4 – An Alternative Appraisal of Design Present Values

The appraisal methodology detailed in Chapter 5 revolves around measuring changes relative to a counterfactual position. An alternative to this is to seek to minimise the total Present Value of all costs (both investment and constraints) and simply regard the counterfactual base case (radial links to shore) as one of the possible designs. The rationale for this is that all these costs and welfare benefits will ultimately be borne by the consumer, hence the objective is to minimise the sum total of them.

The table below shows the total cost NPVs for each design group for each scenario. The lowest cost options indicate least cost to the consumer for that scenario.

Total NPV Cost by Group (£m)	10GW Wind, Gone Green	17.2GW Wind, Gone Green	10GW Wind, Slow Progress	17.2GW Wind, Slow Progress
Radial Designs	17,056	22,103	14,327	20,986
Radial plus onshore	12,068	16,860	10,517	15,480
Bootstrap 1 GW	10,146	21,233	9,303	17,675
Hybrid bootstrap 2 GW	10,561	14,665	8,104	13,576
Hybrid offshore 1 GW	10,963	14,981	9,909	16,986
Hybrid offshore 2 GW	N/A	13,717	N/A	14,509
Integrated 1 GW	10,629	13,986	10,373	13,999
Integrated 2 GW	10,116	13,884	7,938	13,315

Regret analysis can be utilised in a same way as it was in Chapter 5. This time we are comparing each design with the least cost option. Grouping these by similar technology/design as previously gives the following regret measures: -

Options / Scenarios: Regrets (£m)	10GW Wind, Gone Green	17.2GW Wind, Gone Green	10GW Wind, Slow Progress	17.2GW Wind, Slow Progress	Worst Regret (£m)
Radial Designs	6940	8386	6389	7671	8386
Radial plus onshore	1952	2165	2579	2165	2579
Bootstrap 1 GW	30	7517	1365	4360	7517
Hybrid bootstrap 2 GW	445	949	166	261	949
Hybrid offshore 1 GW	848	1264	1971	3671	3671
Hybrid offshore 2 GW	NA	0	NA	1194	1194
Integrated 1 GW	514	270	2434	684	2434
Integrated 2 GW	0	168	0	0	168

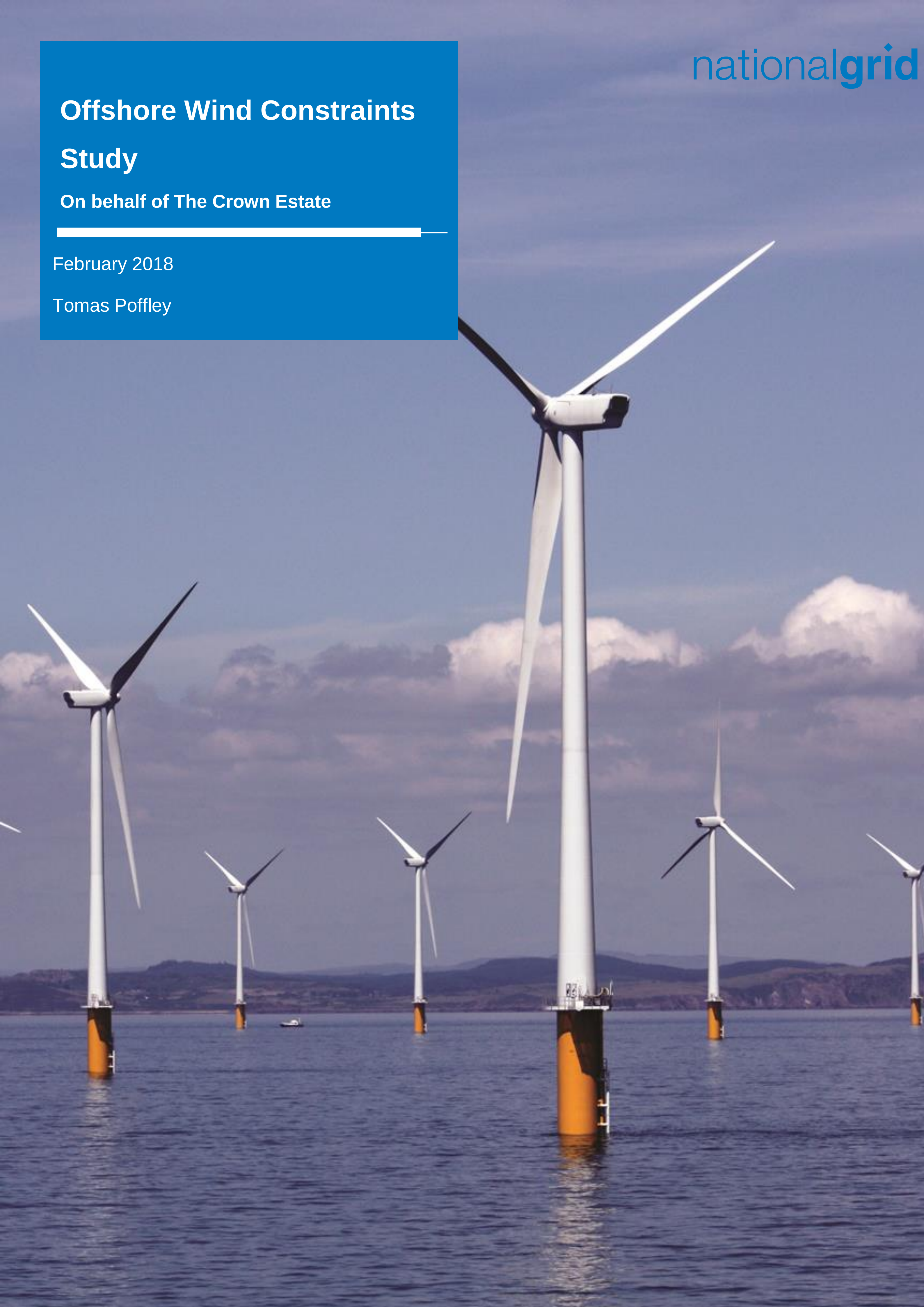
The Least Worst Regret continues to be the integrated designs with larger links. This is consistent with the other assessment approach and adds some resilience to the findings.

Offshore Wind Constraints Study

On behalf of The Crown Estate

February 2018

Tomas Poffley



Contents

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1 Introduction

National Grid System Operator was commissioned by The Crown Estate (TCE) to undertake a desktop feasibility study assessing the possible impacts of connecting new offshore wind generation in various locations to the transmission system in England and Wales. This report details the methodology, assumptions and results from this study, which has been performed by National Grid System Operator. The main output from this study is a series of maps illustrating the likely transmission system cost impacts of connecting different sized offshore wind projects over the timeframe 2025-2040 and under the scenarios considered. This report should not be considered as a full Cost Benefit Analysis but as an indicator only of potential transmission system cost impacts from the connection of new offshore wind.

1.1 Context

The Crown Estate owns virtually the entire sea bed out to the 12 nautical mile territorial limit, including the rights to explore and utilise the natural resources of the UK continental shelf (excluding oil, gas and coal). The Energy Act 2004 vested rights to The Crown Estate to licence the generation of renewable energy on the continental shelf within the Renewable Energy Zone out to 200nm[1]. The Crown Estate has approached National Grid for a study on potential offshore wind farm impacts on GB electricity transmission network capability and impact on system costs. The research has been commissioned in the context of TCE's consideration of TCE's announcement[1] in November 2017 that it is considering the potential for new offshore wind leasing.

1.2 Study Objectives and Scope

This feasibility study was designed to test the impact of different offshore wind farm capacities connecting to various parts of the electricity transmission network in England and Wales. Certain parts of the GB transmission network tend to be more congested than others due to an abundance of generation or lack of power transfer capability. Any new generation capacity connecting to the system is likely to have an impact on levels of congestion (positive or negative), depending on where it is located. Any increase in congestion can be solved in two ways:

- **Management of network congestion through the balancing mechanism**. This results in additional constraint costs as a result of the GB System Operator (SO) having to buy and sell energy on different parts of the network to ensure it remains safe and operable at all times.

[1] Source: https://www.thecrownestate.co.uk/energy-minerals-and-infrastructure/offshore-wind-energy/

These costs are recovered through Balancing Services Use of System (BSUoS) charges which recover the cost of day-to-day operation of the transmission system. Both generators and suppliers are liable for these charges, which are calculated daily as a flat tariff for all users

- **Investment in new transmission assets to increase transfer capability in specific parts of the network**. This network investment results in a reduction in constraint costs over the lifetime of the offshore wind farm but incurs significant CAPEX costs. These costs are recovered through Transmission Network Use of System (TNUoS) charges, which all generators pay according to their generation capacity and geographical location.

The two methods above can be considered alternatives when looking at the impact on transmission system costs of a new offshore wind farm project. This feasibility study has focussed on constraint costs as opposed to CAPEX costs of wider reinforcement works. The reasons for this are outlined below:

1. Constraint costs are a good indicator of the risk factors offshore wind developers should consider for projects beyond 2025. More congested areas of the network will require significant reinforcement to allow the offshore wind farms to connect and as such could delay connection dates or see generators incur additional charges if charging structures were to change.
2. CAPEX costs can vary significantly across different projects. These costs are very dependent on environmental and consenting factors that can be difficult to quantify. The System Operator currently does not forecast these costs given their complexity, however if they were considered instead of the chosen methodology of balancing mechanism costs, outcomes of this analysis would likely be very similar as areas with high balancing costs would likely have the largest spend on reinforcement.

To assess the suitability of different network connection locations for new offshore wind projects, a RAG (Red, Amber, Green) status has been developed and applied to each studied area of the electricity transmission network for every studied year (2025-2040), and is based on the additional constraint costs arising from the connection of new offshore wind generation (detailed in section 2). Since these costs have been calculated as a comparison to the counterfactual, these additional constraint costs have proved to be negative (constraint savings) in certain cases where the offshore wind relieves some network congestion. Power projects can relieve network congestion by injecting power into areas which would otherwise draw power from further away behind bottlenecks.

The modelling of future electricity market conditions and constraint costs has been performed in BID3, National Grid’s long-term constraint forecasting tool. More detail on the calculation of these costs and

BID3 can be found in National Grid's Long Term Constraint Forecasting and Market Modelling report[2].

All costs in this study have been designed to be reflective of the impact of costs passed onto consumers through transmission investment or system balancing costs arising from the potential new offshore wind generation connections. Projected balancing mechanism costs have been adjusted to present value using the Spackman methodology. The Spackman methodology adjusts all future absolute costs (or savings) to present value using a discount rate of 3.5% (the Social Time Preference Rate as prescribed in the Treasury Green Book). Details on how this is applied can be found the Long-term constraint modelling report[2].

Developer connection costs have not been considered in this study as these costs are internalised by the offshore windfarm developer and form part of their development costs. Connection costs are determined on a case-by-case basis in accordance with National Grid's published charging methodology[3], taking into account factors such as project characteristics, location, local works required to facilitate the connection and deeper system reinforcement works. Further, the study has not taken into account ongoing TNUoS charges that a generator would incur once connected. These are determined on a locational basis in accordance with National Grid's published charging methodology[3], which is updated and published on an annual basis. 2016/17 charging zones are illustrated in Appendix E.

Supporting information is provided in appendices.

2 Methodology and Modelling Assumptions

2.1 Future Energy Background and Counterfactual

In order to assess the potential impact of future offshore wind connections it was necessary to model the changing generation and demand backgrounds that contribute to future network congestion costs. National Grid uses the Future Energy Scenarios[4] (FES) in order to perform any analysis on future energy markets.

For the purposes of this study, the Two Degrees (TD) FES scenario was chosen as the background to determine future generation capacity, demand, and interconnector flows with neighbouring energy markets. This is the most ambitious scenario in terms of offshore wind deployment, and represents a future which more closely aligns with the ambitions as articulated in the Government's Clean Growth

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2 https://www.nationalgrid.com/sites/default/ files/documents/Longterm%20Market%20and%20Network%20Constraint%20Modelling.pdf
3 https://www.nationalgrid.com/uk/electricity/charging-and-methodology/transmission-network-use-system-tnuos-charges
4 http://fes.nationalgrid.com

Strategy[5]. To support the analysis, a sensitivity study on Steady State has also been conducted to ensure the results apply across the full range of future energy backgrounds in GB. Table 1 below shows a summary of generation capacities assumed in both these scenarios.

Generation Capacity in GW	Two Degrees				Steady State			
	Nuclear	Wind	CCGT	Inter-connector	Nuclear	Wind	CCGT	Inter-connector
2025	4.7	27.7	22.5	15.6	4.7	17.4	34.9	8.4
2030	8.5	33.2	19.1	18.5	1.2	23.1	38.5	9.8
2035	15.7	37.2	11.7	19.7	4.6	22.7	33.3	9.8
2040	15.7	40.2	7.7	19.7	4.6	20.9	29.9	9.8

Table 1: Generation capacities (in GW) for select fuel types in Steady State and Two Degrees

To avoid over-estimation of future constraint costs, planned future transmission network investments have been applied to the GB energy market background. The results of Network Options Assessment[6] (NOA) 3 were used to align the FES backgrounds with necessary transmission investment. NOA optimises the GB transmission network under each scenario to ensure constraint costs and capex of transmission reinforcement are balanced at a level that is optimal for consumers to ensure the network is suitable for bulk power transfer flows under each FES scenario without overinvesting.

The counterfactual for the purposes of this analysis has been used to calculate the base level of constraint costs on top of which the costs and savings of additional wind capacity have been calculated. The counterfactual has been modelled using the TD energy background in tandem with the future transmission reinforcement strategy under the TD scenario from NOA3. Since transmission investment in this path is optimised for the TD energy background without any additional generation, the addition of new offshore wind capacity in various parts of England and Wales could present significant changes to congestion management costs in the balancing mechanism.

2.2 Modelling Assumptions

2.2.1 Geographical Scope

In order to gain an accurate picture of balancing mechanism costs, it was important to model interconnector behaviour since they make up a significant part of the future GB energy background in all Future Energy Scenarios. As such, in the first stage of this analysis, the whole of the ENTSO-E area has been modelled in BID3 to capture European energy market price behaviour. This stage of

[5] https://www.gov.uk/government/publications/clean-growth-strategy
[6] https://www.nationalgrid.com/uk/publications/network-options-assessment-noa

the modelling (the dispatch) aimed to replicate the day-ahead market position across Europe. Once the dispatch position was set, a focus is placed on GB in the modelling to calculate balancing mechanism costs (the re-dispatch). The re-dispatch activated transmission boundary constraints and forced the model to adjust interconnector and generation positions in GB in order to respect the limitations in power transfer between different regions of GB.

While only substations in England and Wales have been considered in this analysis as connection locations for new offshore wind, all of GB has been modelled in detail to properly capture the dynamics of power transfer from Scotland into England. Full details on this methodology can be found in National grid’s Long Term Constraint Forecasting modelling report.

2.2.2 BID3 Modelling Parameters

For the purposes of this study, the parameters listed below have been chosen to produce a detailed study on new offshore wind connection locations. Further information on all of the below can be found in the aforementioned long term modelling report.

- Single year case collection (2013 chosen as an average year for wind speeds, demand, solar irradiation). This includes offshore wind load factors for 24 offshore wind regions in GB which were the focus of this study, as well as the related weather and demand patterns across Europe.
- Perfectly competitive market (no scarcity rent)
- No thermal ramping (an SO study has found negligible benefit for extra computation time)
- 2920 hours of 8760 hours in a year to be modelled (Previous SO studies have shown a negligible effect of only considering every 3rd hour as opposed to all hours)
- Transmission constraint costs for 2040+ have been assumed as a flat rate in line with 2040

2.3 Offshore Wind RAG Calculation

2.3.1 Substation Grouping

To avoid studying every costal substation across England and Wales in this analysis, they have been grouped together. This grouping was performed by consulting with regional experts in National Grid Transmission Owner’s network planning team. Substations were grouped into study areas based on the following criteria:

1. The grouped area did not cross any major transmission system boundaries
2. All substations in the study area were considered to be affected by the same bottlenecks causing network congestion.

The map in appendix A shows how this grouping has taken place for this analysis. In total, 21 separate study areas are considered in England and Wales for this analysis.

For every study area, three sizes of wind farm have been studied to capture the full range of potential offshore wind connection generation capacity sizes. These were 500MW, 1000MW and 1500MW. This has been done to focus the analysis in geographical connection locations rather than highlighting the difference between connecting different wind farm sizes which is considered to be a fairly linear relationship (i.e. connecting 1000MW over 500MW will roughly double additional constraint savings or costs)

2.3.2 Studied Connection Years

The Crown Estate asked for analysis to be completed for a wide range of potential connection years for new offshore wind. 2025 is the first considered year for a new connection of offshore wind to account for project lead times. This extends to 2040 as the final considered year. For every connection year, the projects are considered to have a 25 year economic life. For example, a wind farm connecting in 2040 has had its constraint costs calculated until 2064 to assess the wind farm over its full lifetime.

2.3.3 RAG Status Calculation

A RAG status has been applied to each wind connection study area for every potential connection year (2025-2040). On one end of the scale, a red status is intended to reflect a study area that would result in increased network congestion costs versus the baseline while a green study area reflects network savings. While the red status does reflect higher network constraint costs in this analysis, it is important to note that this analysis only considers the transmission system impacts in terms of congestion costs, and is not a full Cost Benefit Assessment of new offshore wind projects. Many positive effects of new offshore wind (reduction in carbon emissions, lower whole prices etc.) are not considered and therefore a red status does not imply that a connection study area has a negative economic impact overall.

The red or green status' are assigned purely to visually represent the relativity of transmission cost impacts in the connection study areas based on project size. Furthermore, it is important to note that a red status does not mean that it is not possible to connect a future offshore wind project in the study years considered. Moreover, it purely indicates that balancing costs would be higher as a result of the injection of that additional capacity relative to an area with a green status.

The overall constraint costs or reductions in £GBP have been omitted from this report as they are considered commercially sensitive information. Instead, the study areas are allocated a network impact indicator (NII) on a scale of 1 to -1 to show relative impact. Using this, 1 Indicates a relatively large increase in network constraint costs while -1 indicates a decrease in these costs.

The calculation to allocate the network impact indicator is performed as follows:

$$NII = \frac{Constraint\ savings\ or\ cost}{Max|Constraint\ savings\ or\ cost|}$$

It is worth noting again that this calculation was performed across all studied wind farm capacities. This allows for direct comparison between the NII of a 500MW wind farm to a 1500MW wind farm.

The banding of the NII into a colour for the purposes of producing graphical maps in the output is shown below.

Band Values	Band Name
-1.00 to -0.50	1
-0.50 to -0.15	2
-0.15 to -0.05	3
-0.05 to 0.00	4
0.00 to 0.05	5
0.05 to 0.15	6
0.15 to 0.50	7
0.50 to 1.00	8

Table 2: Banding table for converting network impact indicator into RAG status

The non-linear scale for this table has been deliberately chosen by National Grid to achieve a reasonably even distribution of connection study areas amongst the bands. This is particularly important for the analysis on the 500MW offshore wind project size as a linear scale would distort the results to all lie within the same band, preventing differentiation amongst these options.

3 Results

The majority of results are presented alongside this report in the form of heat maps displaying the RAG status for every studied connection year for all 3 wind farm sizes. The map of study areas is shown in figure 1 below.

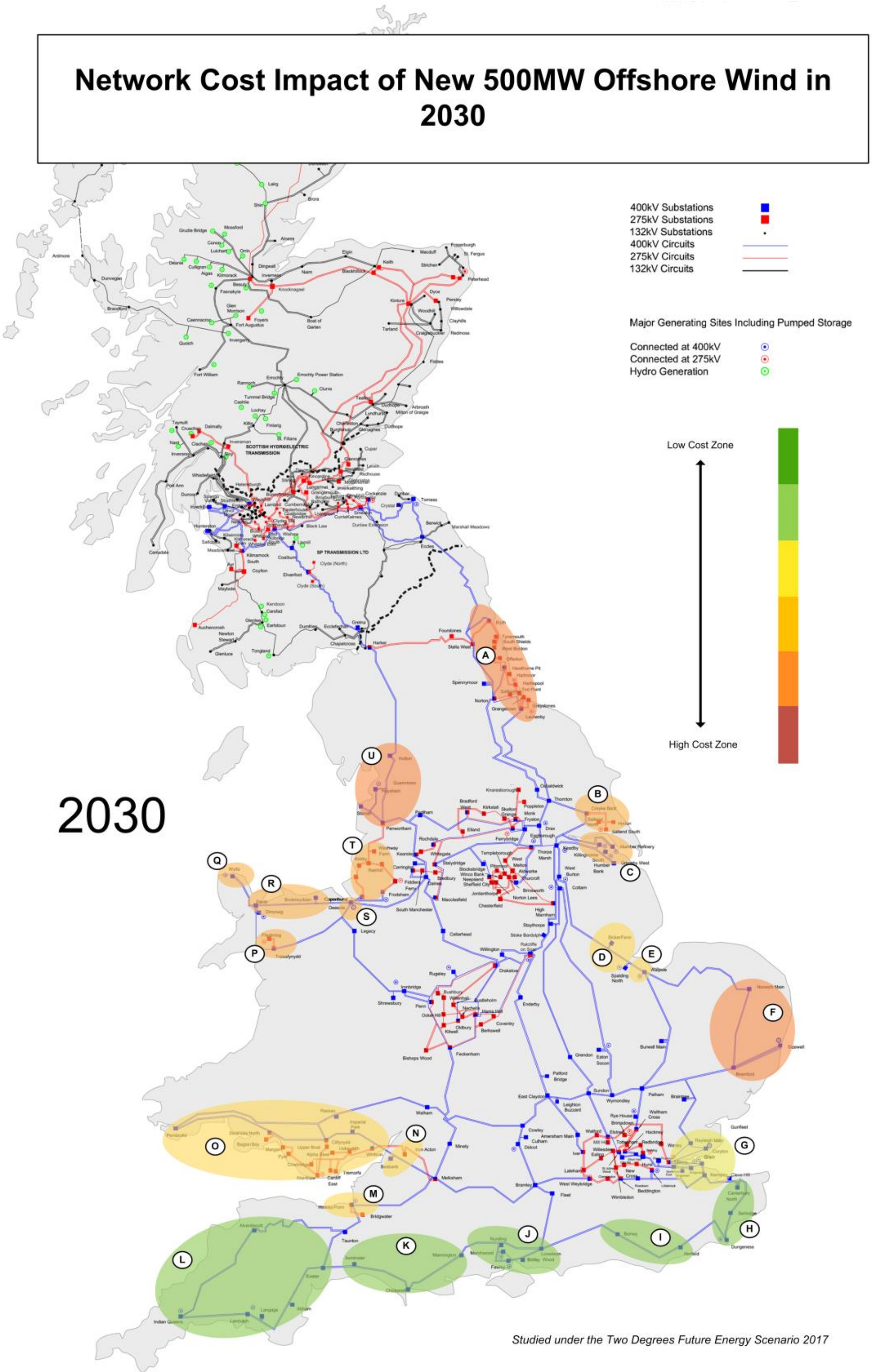


Figure 1a: Map of study areas in England and Wales. Results shown are for 2030 connection date for a 500MW wind farm in a Two Degrees background

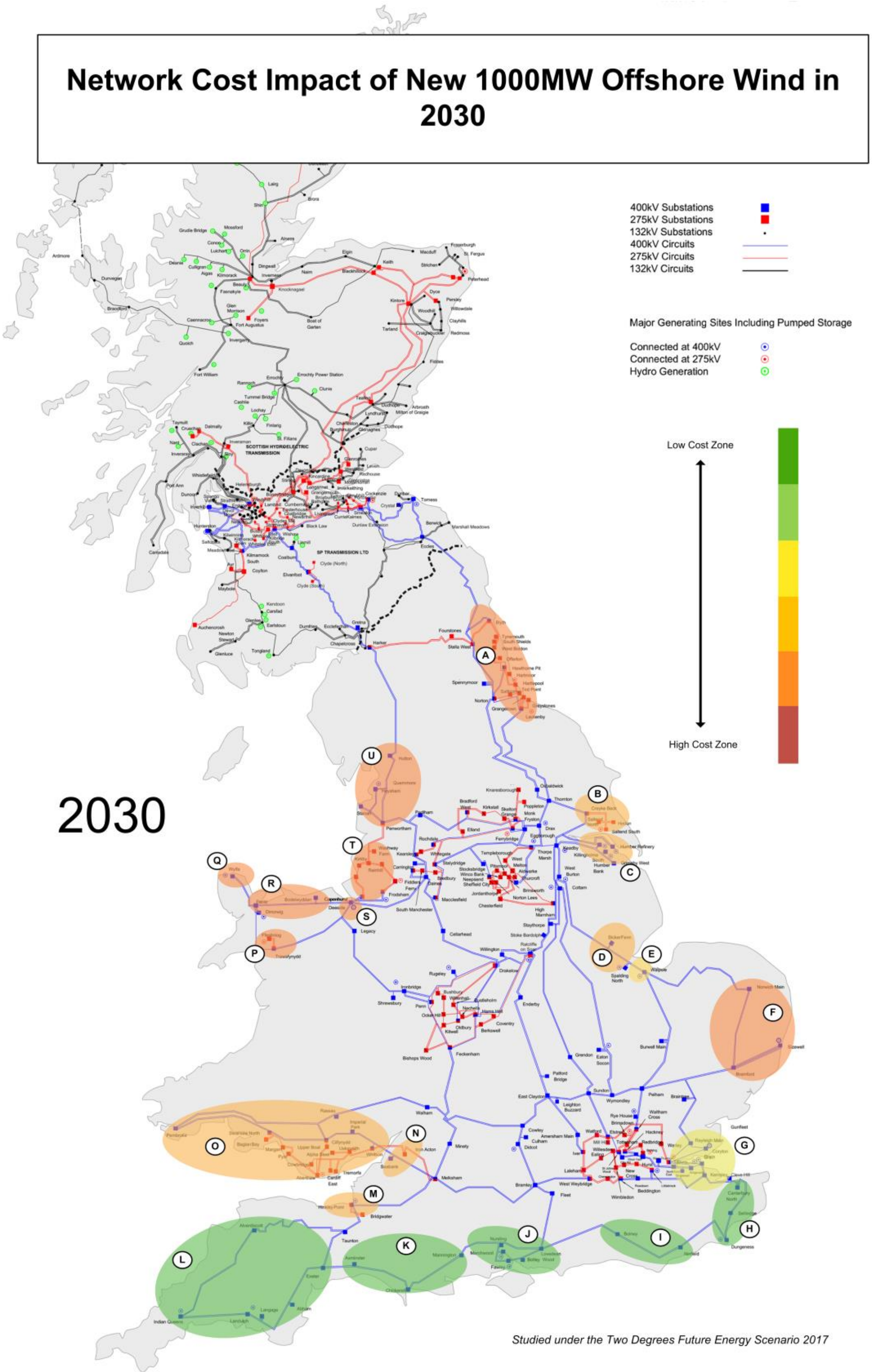


Figure 1b: Map of study areas in England and Wales. Results shown are for 2030 connection date for a 1000MW wind farm in a Two Degrees background

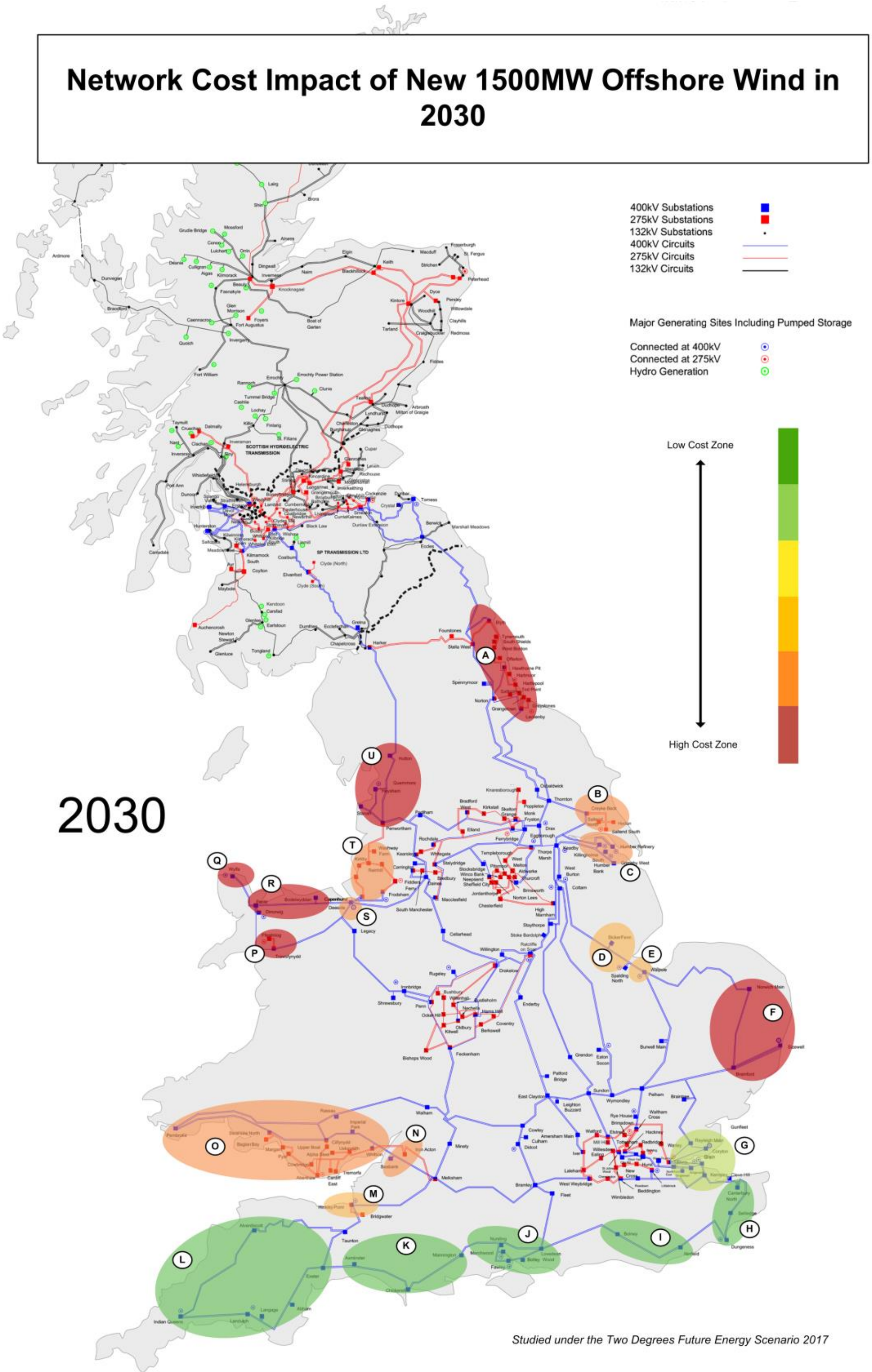


Figure 1c: Map of study areas in England and Wales. Results shown are for 2030 connection date for a 1500MW wind farm in a Two Degrees background

The tables below show the results for the 1500MW offshore capacity study for a selection of connection years along with the banding RAG status assignment. The tables for all wind farm sizes can be found in Appendix C.

1500MW	2025	2030	2035	2040
A	0.63	0.51	0.42	0.35
B	0.26	0.23	0.18	0.15
C	0.26	0.23	0.18	0.15
D	-0.04	0.10	0.12	0.09
E	-0.04	0.10	0.13	0.11
F	0.48	0.67	0.70	0.62
G	-0.04	-0.06	-0.05	-0.05
H	-0.72	-0.94	-0.98	-0.85
I	-0.83	-0.96	-0.99	-0.86
J	-0.67	-0.73	-0.74	-0.64
K	-0.65	-0.71	-0.73	-0.67
L	-0.67	-0.75	-0.77	-0.67
M	-0.03	0.10	0.13	0.11
N	0.01	0.15	0.18	0.16
O	0.01	0.15	0.17	0.15
P	0.55	0.52	0.40	0.34
Q	0.85	0.55	0.41	0.34
R	0.85	0.56	0.42	0.36
S	0.33	0.28	0.22	0.19
T	0.32	0.26	0.19	0.16
U	0.74	0.60	0.50	0.41

1500MW	2025	2030	2035	2040
A	8	8	7	7
B	7	7	7	6
C	7	7	7	6
D	4	6	6	6
E	4	6	6	6
F	7	8	8	8
G	4	3	3	3
H	1	1	1	1
I	1	1	1	1
J	1	1	1	1
K	1	1	1	1
L	1	1	1	1
M	4	6	6	6
N	5	7	7	7
O	5	7	7	7
P	8	8	7	7
Q	8	8	7	7
R	8	8	7	7
S	7	7	7	7
T	7	7	7	7
U	8	8	7	7

Table 3: Network Impact indicator for the addition of 1500MW of wind (left) with applied RAG banding (right)

The tables show the relative cost impact of connecting a 1500MW project across the study areas. The 500MW, 1000MW and 1500MW tables found in Appendix C all demonstrate very similar trends in terms of RAG status assignment. In the TD scenario, the relatively low cost areas (or where there are cost savings) (i.e. along the South Coast) are driven by interconnector behaviour and their proximity to large demand centres. The relatively high cost areas are reflective of the constraints on the transmission system. A full discussion of results drivers is presented in the next section.

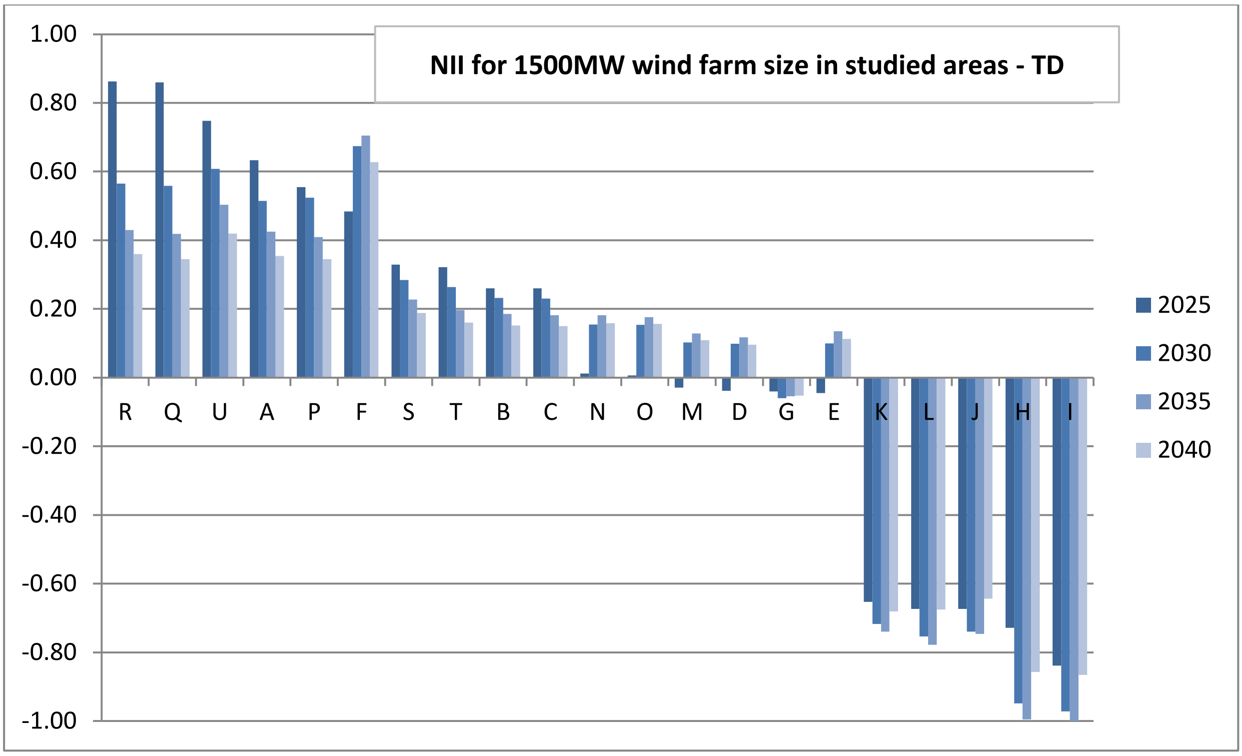


Figure 2: Network Impact Indicator for a selection of connection years for the addition 1500MW offshore wind capacity in Two Degrees

In most study areas network constraint costs have increased due to additional wind capacity connecting. Since the network is currently optimised for the TD FES scenario, any additional generation has the impact of increasing network power transfer requirements beyond the levels it has been optimised for in NOA. This causes the additional constraint costs for most study areas.

A general trend of decreasing network impact over time can be clearly seen in the graph above. While this isn't applicable to all study areas due to localised variations in generation patterns, the general trend can be explained due to two main drivers:

- Increased network transfer capability in later years. The transmission investment aligned to the TD FES scenario sees most large scale transmission projects completed around 2030 which ease network congestion in most areas of England and Wales. This presents lower constraint costs in the counterfactual and additional wind cases leading to lower additional costs from building a wind farm.
- The Social Time Preference Rate (detailed in section 2) reducing the value of additional costs in later years. As these costs are further out into the future, using the Spackman methodology these are weighted less heavily. This is considered prudent as later connections will allow the GB System Operator and Transmissions Owners further time to facilitate these connections and optimise the GB network to reduce total transmission system costs. The same

methodology is used for the build of future transmission assets and since the balancing mechanism costs are considered alternative to investment, they are weighted accordingly.

4 Results Drivers and Discussion

This section details the main drivers the difference in NII across various connection study areas and their resulting network impact indicator. In most cases, drivers behind study areas have been grouped together where they demonstrate similar behaviours due to the same drivers. Throughout this section, figures appear with zonal generation capacity plotted against boundary transfer capability. Boundary transfer capability is a value which determines how much power transfer can flow over given areas of the network. In general, the transfer capability and generation capacity are optimised such that an increase in generation capacity is met with an increase in transfer capability (through the build of new transmission assets). As such, where graphs demonstrate increasing generation capacity with little increase in transfer capability, large costs are incurred to reduce generation output behind these boundaries and balance the network. The boundary transfer capability has been converted into a multiplier with 1 representing today's transfer capability. This has been done to avoid sharing sensitive transmission owner data in this report.

4.1 Study Area F – East Anglia

As shown in Figure 1, study area F is one of the few areas where the NII rises significantly throughout the analysis period.

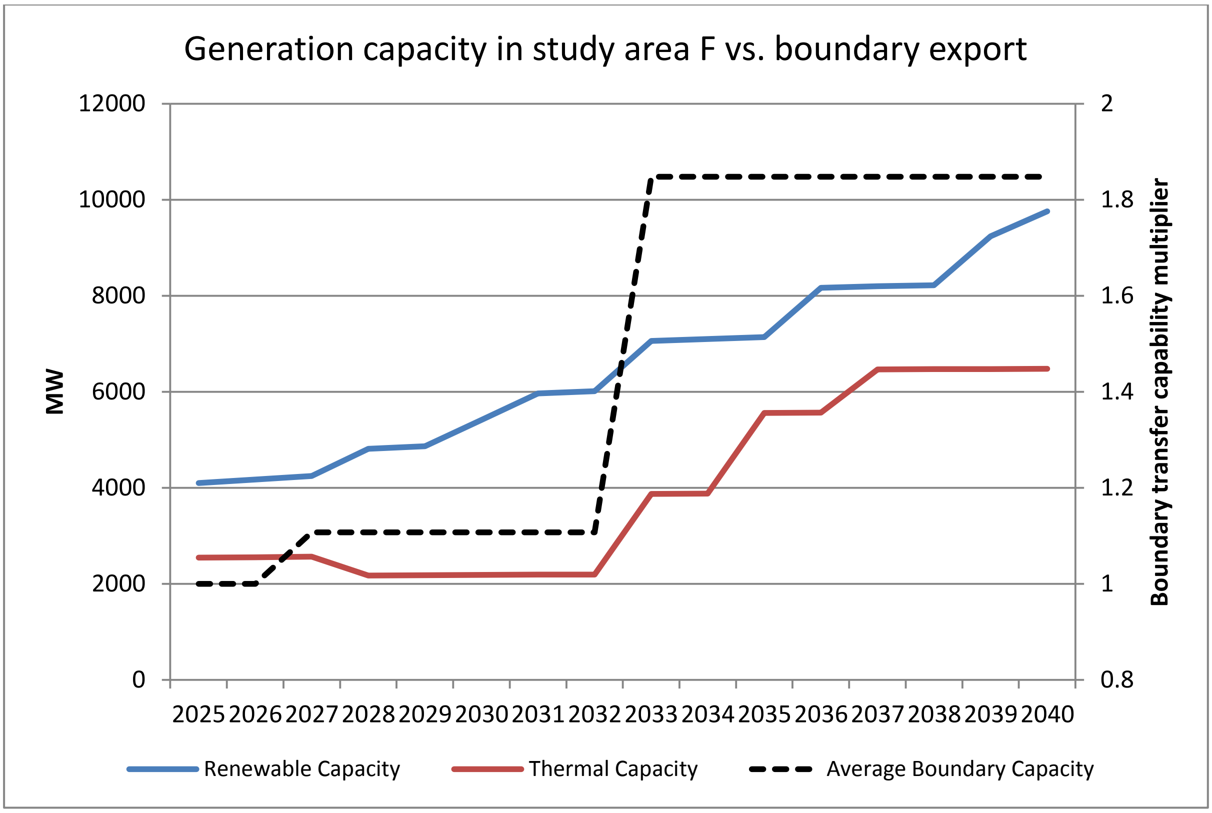


Figure 3: Generation and average annual boundary transfer capacity of study area F.

The increase in Network Impact Indicator can be explained by the consistent rise of generation capacity within study area F in the TD FES scenario. Each rise in renewable capacity in figure 3 can be attributed to the connection of an offshore wind project, with most increases in thermal plant attributable to new nuclear generation (the total generation capacities in figure 3 are subject to change as updated information becomes available). Even with the rise in boundary transfer capability in 2033 due to a major asset build, the consistent rise in generation results in study area with a very high NII. With the addition of new offshore capacity beyond what is shown in figure 3, constraint cost rises of approximately 50% in GB in are likely to be incurred in managing network congestion due to increasing export requirements in this study area with limited network transfer capability. Since this study area primarily consists of offshore wind and nuclear generation, balancing mechanism costs are relatively high per MWh as these are far more expensive to bid off in the balancing mechanism than traditional thermal generation such as CCGT due to the lost opportunity cost associated with not receiving subsidy payments if the plant doesn’t run.

4.2 South Coast

Study Areas H, I, J K and L along the south coast all demonstrate clear network savings in this study and as such appear as a strong green in the RAG status. The main driver behind this result is displayed in figure 4. Since TD has been chosen as the energy background for this study, GB sees a large increase in renewable capacity. This lowers average wholesale prices in GB due to a sharp rise in offshore wind capacity. The result of this is an increase in exports, specifically to the continental Europe of which most interconnectors are based on the south coast. By building additional offshore wind capacity along the south coast, larger north-south bulk power transfer can be avoided and as such north-south congestion is alleviated resulting in reduced balancing mechanism costs. Figure 4 shows the reduction in expected north-south power transfer when building additional wind capacity in the south. Since north-south congestion contributes to the majority of balancing mechanism costs in later years, this reduction in expected north-south power transfer results in large savings.

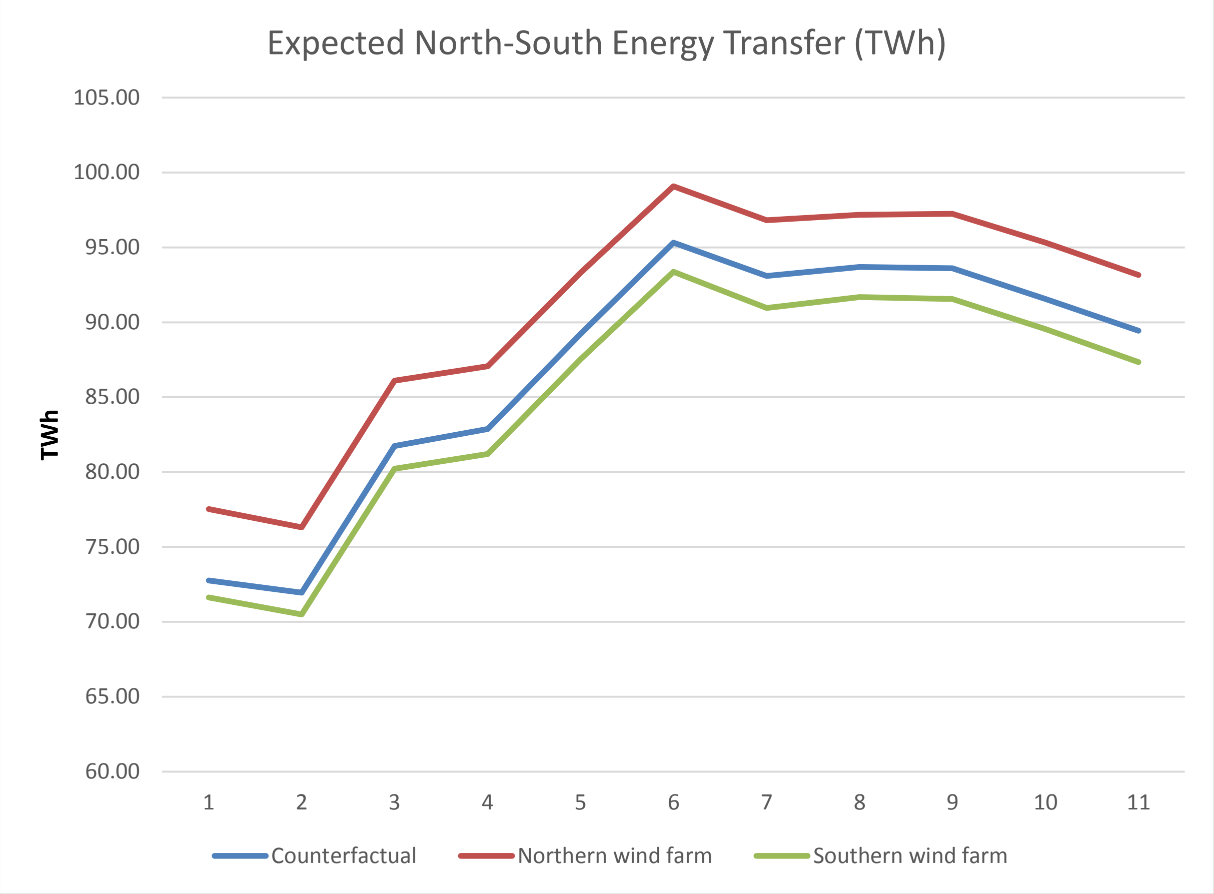


Figure 4: Required energy transfer (in TWh) over the B8 transmission boundary (major north-south dividing line across England and Wales) for the counterfactual run and additional wind capacity in the north and south

4.3 North Wales

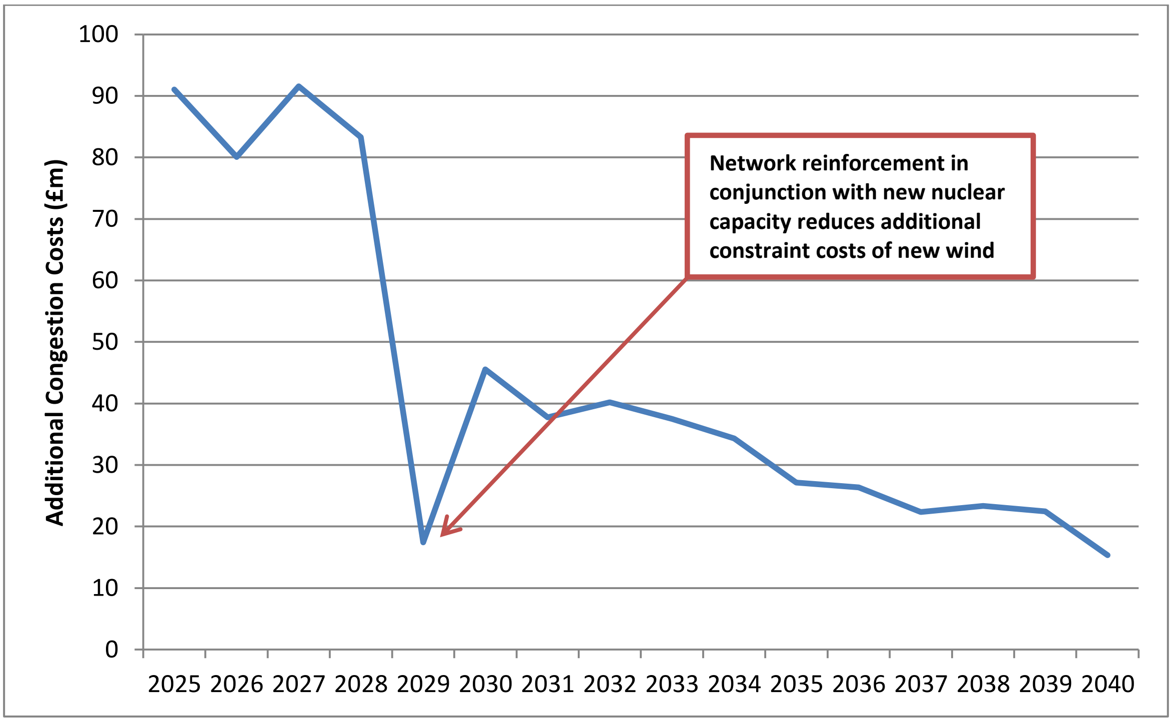


Figure 5: Congestion costs in study areas Q and R for 1000MW additional offshore wind

Figure 5 highlights the large network impact indicator observed in early years in study areas 17 and 18. The export capability of these study areas is heavily limited by current weak network transfer capability prior to any major reinforcement build. With the addition of 1000MW of new offshore wind (the same results apply to 500MW and 1500MW wind farm sizes with the impact on costs being relative to their size), the additional constraint costs peak heavily from 2025 until 2029 when new asset builds increase the export capacity of this study area. Currently this network reinforcement is only planned in order to connect new nuclear capacity which is planned in the area. Without this nuclear capacity, it becomes clear from the early years of constraint costs that new transmission transfer capability would be required to facilitate the export of offshore wind capacity out of these study areas into the rest of England and Wales.

5 Sensitivity Analysis

Although the TD FES scenario best suits the purposes of this study, sensitivity analysis on the Steady State (SS) FES scenario has been conducted in order to assess whether results have been driven by specific factors in TD or whether they apply across a range of future energy backgrounds. SS presents a vastly different energy landscape to TD in which growth in renewable capacity is not as rapid and the generation mix remains fairly similar to today's levels. This scenario also assumes a much lower level of GB interconnection with other European countries (approximately 9GW in 2040 as opposed to TD which has 20GW in 2040). All result tables for this sensitivity analysis can be found in Appendix D.

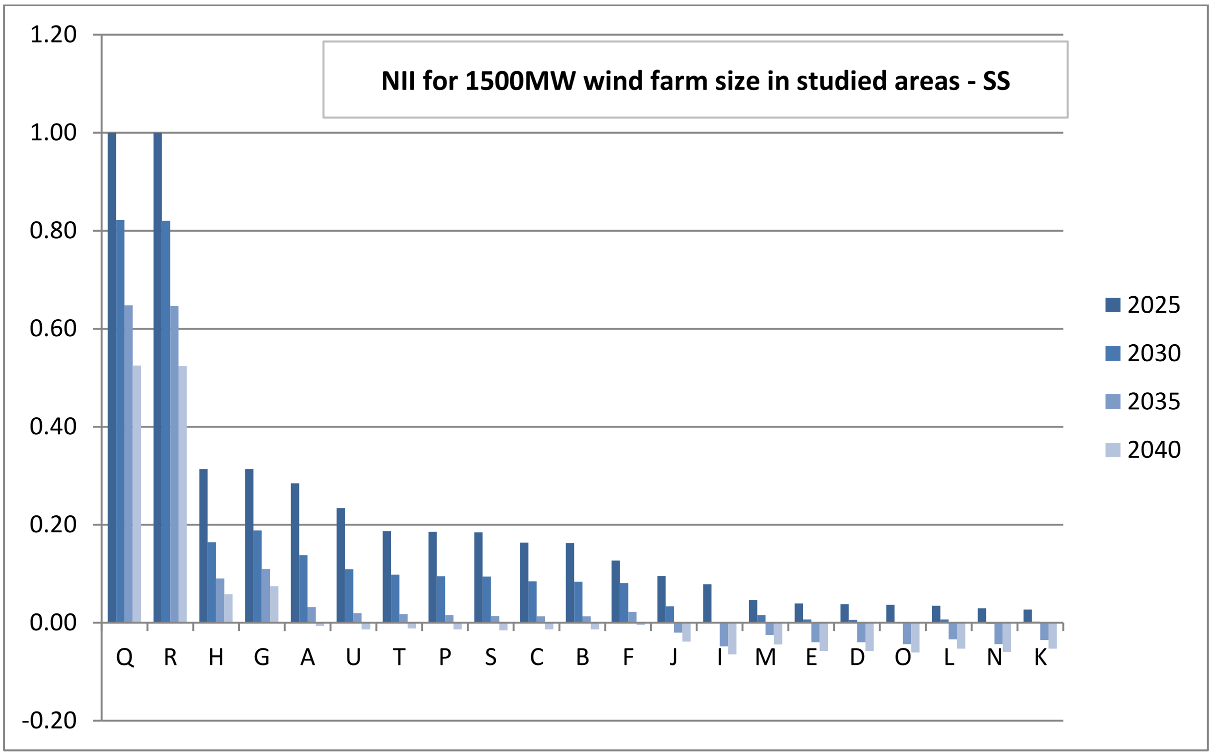


Figure 6: Network Impact Indicator for a selection of connection years for the addition 1500MW offshore wind capacity in Steady State

Figure 6 presents the results from the SS sensitivity analysis for select study years for 1500MW wind farm size. From the graph it is clear to see that there are two study areas, Q and R, which result in noticeably higher NII. These study areas lie in North Wales. Referencing figure 1 it can be seen that this reaffirms this area as having high NII regardless of GB energy background. A general trend towards decreasing NII can also be observed across all study areas. This is driven by the same reasons TD sees lower NII in future years. It is further driven by the fact that in SS the majority of constraint costs in future years are observed due to congestion in Scotland. When studying England and Wales connection locations, any additional generation in these areas alleviates network congestion in Scotland and hence reduces NII.

Table 4 shows a direct comparison of study areas and their relative rank (1 having the lowest NII and 21 having the highest) in 2025 for the 1500MW wind farm size.

	Ranking of Study areas in 2025	
	TD	SS
I	1	8
H	2	19
J	3	9
L	4	3
K	5	1
E	6	6
G	7	18
D	8	5
M	9	7
O	10	4
N	11	2
C	12	12
B	13	11
T	14	15
S	15	13
F	16	10
P	17	14
A	18	17
U	19	16
Q	20	21
R	21	20

Table 4: Ranking of 1500MW wind farm study areas based on NII. 1 corresponds to lowest NII while 21 corresponds to highest.

From Table 4 it can be seen that in general, there is alignment between the two scenarios, further solidifying the TD study results for these study areas. With a few exceptions, lower ranked study areas in TD correspond to lower ranked study areas in SS and vice versa.

Study areas H and G stand out as exceptions to the general agreement between TD and SS results. This is driven by the behaviour of interconnectors in these study areas. While in TD, interconnector capacity in these study areas exports power out of GB the majority of the time, in SS these interconnectors tend to import due to higher wholesale prices in SS relative to TD driven by lower renewable generation capacities. Imports in these study areas cause network congestion as power is expected flow out of these study areas into high demand regions such as London. This congestion is not observed in exporting conditions as generation in these study areas is exported through the interconnectors rather than flowing into demand areas in GB.

6 Summary

All analysis in this report was conducted on the latest data available as of January 2018 and as such results for individual study areas are subject to change as the certainty of the energy landscape becomes clearer closer to 2025.

Through the modelling and analysis of future electricity markets in GB and Europe, this report has assessed the impact of different offshore wind farm capacities on various parts of the electricity transmission network in England and Wales from 2025 onwards. The impact of new wind projects was measured through the forecasting of future balancing mechanism costs with and without the new wind farms in each study area. These costs have been portrayed as a RAG status on maps which include each study area evolving over a time series from 2025 to 2040.

While these balancing mechanism costs (and hence the RAG statuses) do not directly impact individual developer costs, they are passed onto consumers and as such it is in the System Operator's interest to ensure these costs remain as low as possible.

The main analysis was conducted on a Two Degrees future energy scenario and demonstrated that, in general, new offshore wind placed in study areas further south in England and Wales resulted in cost savings for GB consumers due to their proximity to high demand zones and exporting interconnectors. Sensitivity analysis was conducted on a Steady State future energy scenario which confirmed the general trend of the Two Degrees scenario with a few exceptions. Since Two Degrees and Steady State both capture opposite ends of the potential future energy landscape in GB, this sensitivity analysis confirms that the majority of analysis presented here is likely to hold for all potential energy futures.

The exceptions to the sensitivity analysis agreeing with the main analysis (in two study areas) were areas in which interconnector behaviour has a relatively high impact on network congestion. This disagreement between the two scenarios is reflective of the uncertainty of future energy markets in GB and Europe and as such the RAG status of these areas will be difficult to determine until closer to the connection dates studied (2025-2040).

7 Appendix A: Glossary

Balancing Mechanism: Great Britain has a free energy market that is open to competition in generation and supply. A balancing mechanism was introduced in 2001 as part of a new trading arrangement, agreed by the Government and the regulator. Each power station makes a ‘bid’ that reflects what they are willing to be paid – or to pay – to be taken off or moved on to the network. The costs occurred due to the balancing action is balancing cost.

Transmission Boundary: The transmission system is split by boundaries that cross important power-flow paths where there are limitations to capability or where National Grid expects additional bulk power transfer capability will be needed. System Security and Quality of Supply Standards (SQSS) is applied to work out the National Electricity Transmission System (NETS) boundary requirements.

BSUoS: The BSUoS charge recovers the cost of day-to-day operation of the transmission system. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff for all users. BSUoS charges depend on the balancing actions that National Grid takes each day.

CAPEX: capital expenditure - an expense is considered to be a capital expenditure when the asset is a newly purchased capital asset or an investment that improves the useful life of an existing capital asset.

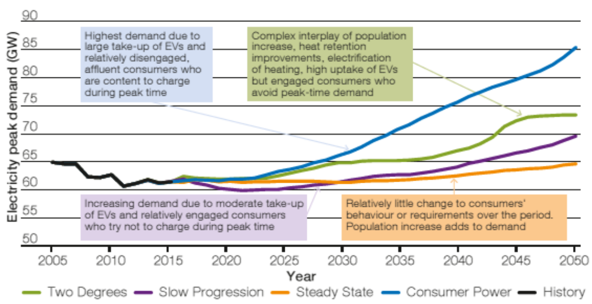
Constraint cost: It refers to compensation offered to generators who are unable to load all their electricity due to network limitation and generators who turn up to provide the energy needed in another area of the country.

ENTSO-E: the European Network of Transmission System Operators, represents 43 electricity transmission system operators (TSOs) from 36 countries across Europe. ENTSO-E was established and given legal mandates by the EU’s Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising the gas and electricity markets in the EU.

Future energy Scenarios (FES): Based on the energy trilemma of security of supply, affordability and sustainability, Future Energy Scenarios are a range of plausible and credible pathways for the future of energy from today to 2050. In FES 2017, there are four scenarios, Consumer Power, Two Degrees, Steady State and Slow Progression.

The 2017 scenario matrix

Electricity peak demand



Interconnector: Electricity interconnectors are the physical links which allow the transfer of electricity across borders.

Intermittent generation: this phrase describes a power source that doesn't produce a constant amount of energy. The most obvious of this type is energy generated by a wind farm, which will vary according to how windy it is. Sometimes there will be very little wind, and sometimes the wind will be too strong and the turbines will shut down automatically for their own protection.

NOA: Network Options Assessment recommends which reinforcement options and when the TOs should invest in them in an uncertain world; whether TOs should delay or continue current projects and indicate the optimum level of interconnection to other European electricity grids to maximise socio-economic welfare, based on market-driven analysis.

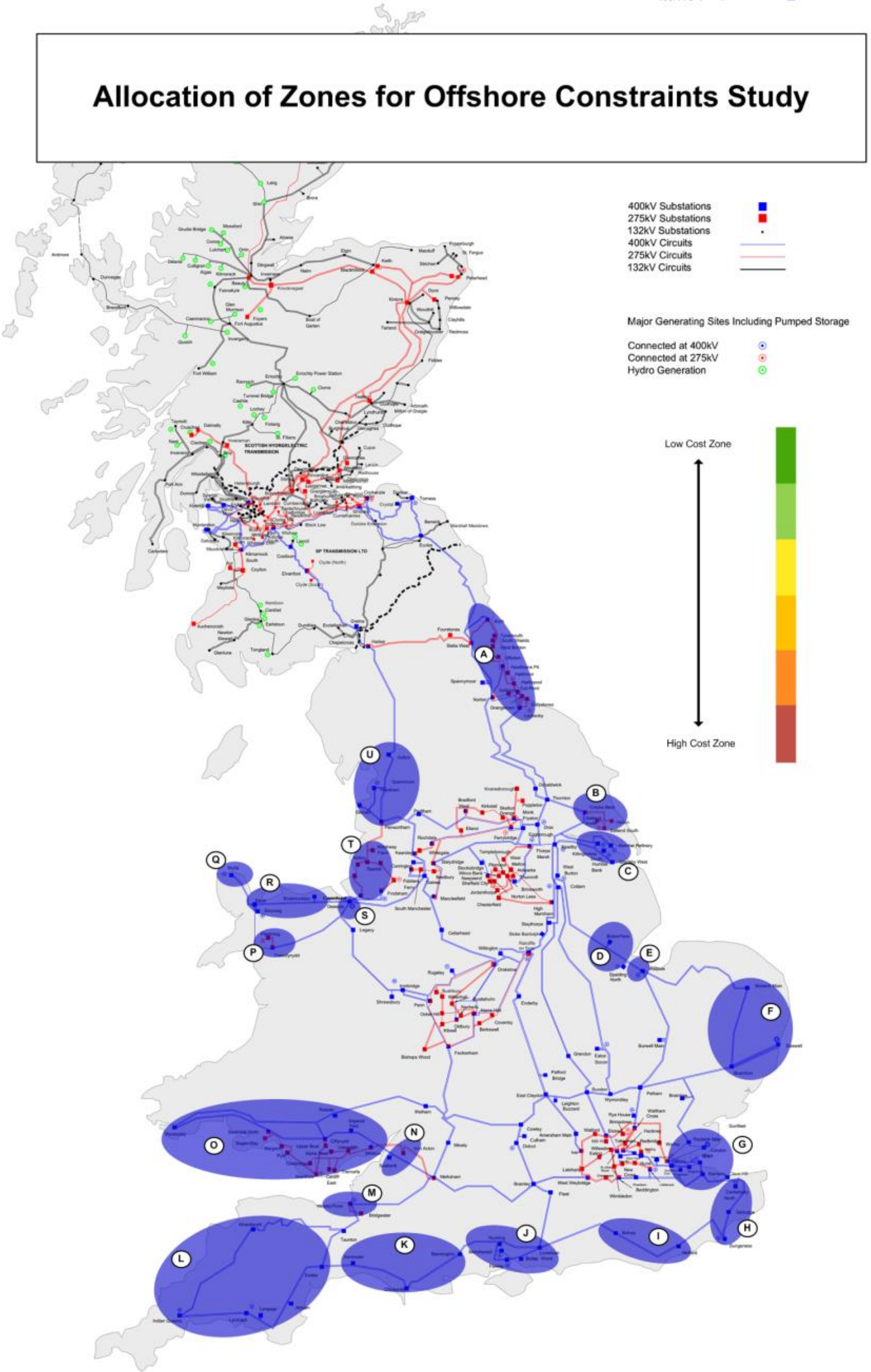
Ofgem: The Office of Gas and Electricity Markets (Ofgem) regulates the monopoly companies which run the gas and electricity networks. It takes decisions on price controls and enforcement, acting in the interests of consumers and helping the industries to achieve environmental improvements. Ofgem is a non-ministerial department.

System Operator: Britain's electricity transmission network transmits high-voltage electricity from where it is produced to where it is needed throughout the country. The system is made up of high voltage electricity wires that extend across Britain and nearby offshore waters. It's owned and maintained by regional transmission companies, while the system as a whole is operated by a single System Operator (SO). The role is performed by National Grid Electricity Transmission (NGET).

Transmission constraint: It is congestion in the transmission system that prevents surplus power being transmitted to other parts of the country when there isn't enough demand to use it. This might happen, for instance, if it's very windy over several days and wind farms are producing much more energy than usual, or if demand is much lower than usual.

TNUoS: Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmilssion system in England, Wales, Scotland and Offshore. Generators are charged according to their Transmission Entry Capacity (TEC). Suppliers are charged based on their demand forecast. All tariffs are based on which geographical study area Users are connected to.

8 Appendix B: Allocation of substations to study areas



9 Appendix C: Results Tables - TD

9.1 500MW

500MW	2025	2030	2035	2040
A	7	7	6	6
B	6	6	5	5
C	6	6	6	5
D	4	5	5	5
E	4	5	5	5
F	6	7	7	7
G	4	4	4	4
H	2	2	2	2
I	2	2	2	2
J	2	2	2	2
K	2	2	2	2
L	2	2	2	2
M	4	5	5	5
N	4	5	6	5
O	4	5	5	5
P	6	6	6	6
Q	7	6	6	6
R	7	6	6	6
S	6	6	6	6
T	6	6	6	5
U	7	7	7	6

500MW	2025	2030	2035	2040
A	0.18	0.15	0.13	0.11
B	0.06	0.05	0.04	0.03
C	0.07	0.07	0.06	0.04
D	-0.02	0.03	0.04	0.03
E	-0.03	0.02	0.02	0.02
F	0.11	0.18	0.20	0.18
G	-0.02	-0.02	-0.02	-0.02
H	-0.24	-0.32	-0.33	-0.29
I	-0.28	-0.32	-0.32	-0.28
J	-0.25	-0.26	-0.26	-0.23
K	-0.26	-0.29	-0.26	-0.22
L	-0.26	-0.28	-0.28	-0.24
M	-0.02	0.02	0.03	0.03
N	0.00	0.04	0.06	0.05
O	-0.01	0.03	0.05	0.04
P	0.11	0.11	0.09	0.08
Q	0.17	0.15	0.11	0.09
R	0.17	0.14	0.11	0.09
S	0.09	0.08	0.06	0.05
T	0.08	0.07	0.06	0.05
U	0.22	0.19	0.17	0.15

9.2 1000MW

1000MW	2025	2030	2035	2040
A	7	7	7	7
B	7	6	6	6
C	7	6	6	6
D	4	6	6	6
E	3	5	6	6
F	7	7	7	7
G	4	4	4	4
H	2	1	1	1
I	1	1	1	1
J	2	1	1	2
K	2	1	1	2
L	2	1	1	2

1000MW	2025	2030	2035	2040
A	0.38	0.31	0.26	0.21
B	0.15	0.14	0.12	0.10
C	0.15	0.15	0.12	0.10
D	-0.03	0.07	0.09	0.07
E	-0.05	0.04	0.07	0.05
F	0.27	0.40	0.43	0.39
G	-0.03	-0.05	-0.04	-0.04
H	-0.49	-0.63	-0.66	-0.58
I	-0.57	-0.66	-0.68	-0.59
J	-0.48	-0.52	-0.52	-0.45
K	-0.44	-0.54	-0.55	-0.48
L	-0.48	-0.53	-0.54	-0.47

M	4	6	6	6
N	4	6	6	6
O	4	6	6	6
P	7	7	7	7
Q	7	7	7	7
R	7	7	7	7
S	7	7	6	6
T	7	7	6	6
U	7	7	7	7

M	-0.03	0.05	0.07	0.06
N	-0.01	0.08	0.10	0.09
O	-0.02	0.08	0.10	0.09
P	0.28	0.27	0.20	0.17
Q	0.44	0.32	0.24	0.20
R	0.46	0.35	0.27	0.23
S	0.19	0.16	0.13	0.11
T	0.18	0.16	0.12	0.10
U	0.46	0.39	0.33	0.28

9.3 1500MW

1500MW	2025	2030	2035	2040
A	8	8	7	7
B	7	7	7	6
C	7	7	7	6
D	4	6	6	6
E	4	6	6	6
F	7	8	8	8
G	4	3	3	3
H	1	1	1	1
I	1	1	1	1
J	1	1	1	1
K	1	1	1	1
L	1	1	1	1
M	4	6	6	6
N	5	7	7	7
O	5	7	7	7
P	8	8	7	7
Q	8	8	7	7
R	8	8	7	7
S	7	7	7	7
T	7	7	7	7
U	8	8	7	7

1500MW	2025	2030	2035	2040
A	0.63	0.51	0.42	0.35
B	0.26	0.23	0.18	0.15
C	0.26	0.23	0.18	0.15
D	-0.04	0.10	0.12	0.09
E	-0.04	0.10	0.13	0.11
F	0.48	0.67	0.70	0.62
G	-0.04	-0.06	-0.05	-0.05
H	-0.72	-0.94	-0.98	-0.85
I	-0.83	-0.96	-0.99	-0.86
J	-0.67	-0.73	-0.74	-0.64
K	-0.65	-0.71	-0.73	-0.67
L	-0.67	-0.75	-0.77	-0.67
M	-0.03	0.10	0.13	0.11
N	0.01	0.15	0.18	0.16
O	0.01	0.15	0.17	0.15
P	0.55	0.52	0.40	0.34
Q	0.85	0.55	0.41	0.34
R	0.85	0.56	0.42	0.36
S	0.33	0.28	0.22	0.19
T	0.32	0.26	0.19	0.16
U	0.74	0.60	0.50	0.41

10 Appendix D: Results Tables - SS

10.1 500MW

500MW	2025	2030	2035	2040
A	6	5	4	3
B	6	5	4	4
C	6	5	4	4
D	6	5	4	3
E	6	5	4	3
F	6	5	4	4
G	6	6	5	4
H	6	6	4	4
I	6	5	4	3
J	6	5	4	3
K	5	5	4	3
L	6	5	4	3
M	6	5	4	3
N	6	5	4	3
O	6	5	4	3
P	6	5	4	4
Q	7	6	5	4
R	7	6	5	4
S	6	5	4	4
T	6	5	4	4
U	6	5	4	4

NII	2025	2030	2035	2040
A	0.12	0.03	-0.03	-0.05
B	0.11	0.04	-0.02	-0.04
C	0.11	0.04	-0.02	-0.04
D	0.07	0.02	-0.03	-0.05
E	0.07	0.02	-0.03	-0.05
F	0.09	0.03	-0.02	-0.04
G	0.15	0.06	0.00	-0.02
H	0.15	0.05	0.00	-0.02
I	0.08	0.01	-0.04	-0.05
J	0.06	0.01	-0.04	-0.06
K	0.05	0.01	-0.04	-0.05
L	0.06	0.01	-0.04	-0.06
M	0.07	0.02	-0.03	-0.05
N	0.06	0.01	-0.03	-0.05
O	0.07	0.02	-0.03	-0.05
P	0.11	0.04	-0.02	-0.04
Q	0.16	0.08	0.02	-0.01
R	0.16	0.08	0.02	-0.01
S	0.11	0.04	-0.02	-0.04
T	0.11	0.04	-0.02	-0.04
U	0.11	0.04	-0.02	-0.04

10.2 1000MW

1000MW	2025	2030	2035	2040
A	7	6	4	4
B	6	6	4	4
C	6	6	4	4
D	6	5	4	3
E	6	5	4	3
F	6	5	4	4
G	7	6	5	5
H	7	6	5	5
I	6	5	4	3
J	5	4	4	3
K	5	4	4	3
L	5	4	4	3
M	6	5	4	3

NII	2025	2030	2035	2040
A	0.19	0.07	-0.01	-0.04
B	0.13	0.06	-0.01	-0.03
C	0.13	0.06	-0.01	-0.03
D	0.05	0.01	-0.04	-0.06
E	0.05	0.01	-0.04	-0.06
F	0.10	0.04	-0.01	-0.03
G	0.22	0.12	0.05	0.02
H	0.22	0.10	0.03	0.01
I	0.07	0.00	-0.05	-0.06
J	0.04	0.00	-0.05	-0.06
K	0.02	-0.01	-0.05	-0.06
L	0.04	0.00	-0.05	-0.06
M	0.05	0.01	-0.04	-0.05

N	5	5	4	3
O	6	5	4	3
P	6	6	4	4
Q	7	7	7	7
R	7	7	7	7
S	6	6	4	4
T	6	6	4	4
U	7	6	4	4

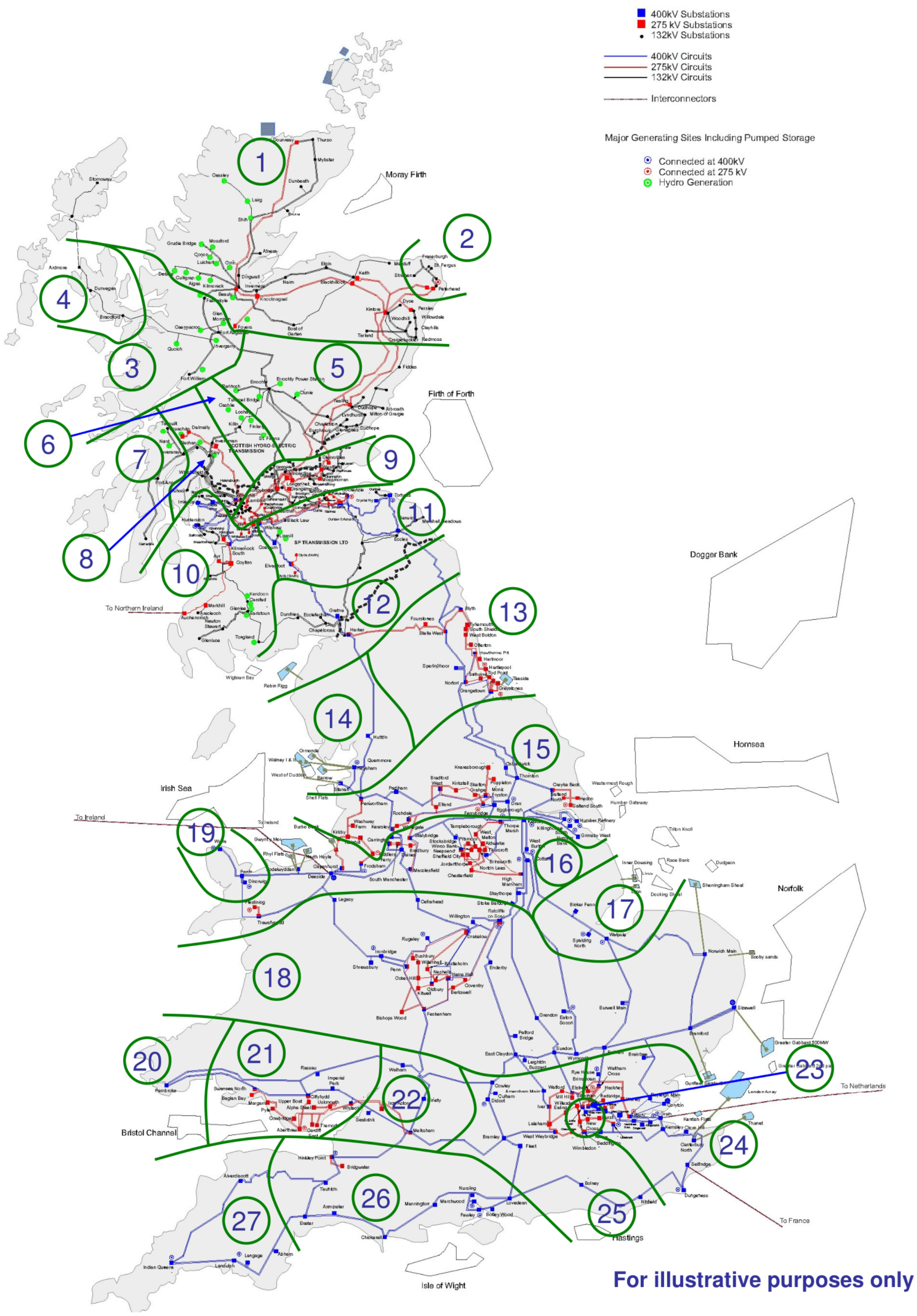
N	0.04	0.00	-0.04	-0.06
O	0.05	0.01	-0.04	-0.06
P	0.14	0.06	-0.01	-0.03
Q	0.42	0.31	0.21	0.15
R	0.42	0.31	0.21	0.15
S	0.14	0.06	-0.01	-0.03
T	0.15	0.07	0.00	-0.03
U	0.16	0.06	-0.01	-0.04

10.3 1500MW

1500MW	2025	2030	2035	2040
A	7	6	5	4
B	7	6	5	4
C	7	6	5	4
D	5	5	4	3
E	5	5	4	3
F	6	6	5	4
G	7	7	6	6
H	7	7	6	6
I	6	4	4	3
J	6	5	4	4
K	5	5	4	3
L	5	5	4	3
M	5	5	4	4
N	5	4	4	3
O	5	5	4	3
P	7	6	5	4
Q	8	8	8	8
R	8	8	8	8
S	7	6	5	4
T	7	6	5	4
U	7	6	5	4

NII	2025	2030	2035	2040
A	0.28	0.14	0.03	-0.01
B	0.16	0.08	0.01	-0.01
C	0.16	0.08	0.01	-0.01
D	0.04	0.01	-0.04	-0.06
E	0.04	0.01	-0.04	-0.06
F	0.13	0.08	0.02	0.00
G	0.31	0.19	0.11	0.07
H	0.31	0.16	0.09	0.06
I	0.08	0.00	-0.05	-0.07
J	0.10	0.03	-0.02	-0.04
K	0.03	0.00	-0.04	-0.05
L	0.03	0.01	-0.03	-0.05
M	0.05	0.02	-0.03	-0.04
N	0.03	0.00	-0.04	-0.06
O	0.04	0.00	-0.04	-0.06
P	0.19	0.09	0.02	-0.01
Q	1.00	0.82	0.65	0.52
R	1.00	0.82	0.65	0.52
S	0.18	0.09	0.01	-0.02
T	0.19	0.10	0.02	-0.01
U	0.23	0.11	0.02	-0.01

11 Appendix E: TNUoS charging zones 2016/2017



Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional 70% Load Factor	Intermittent 30% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.84	13.26	7.19	1.31	20.63	12.48
2	East Aberdeenshire	3.71	6.84	7.19	1.31	17.00	10.55
3	Western Highlands	2.60	11.21	6.90	1.31	18.65	11.57
4	Skye and Lochalsh	-1.43	11.21	8.37	1.31	16.10	13.04
5	Eastern Grampian and Tayside	2.20	10.11	6.39	1.31	16.98	10.73
6	Central Grampian	4.05	10.03	6.33	1.31	18.71	10.65
7	Argyll	3.07	7.95	9.78	1.31	19.72	13.47
8	The Trossachs	3.19	7.95	4.77	1.31	14.83	8.46
9	Stirlingshire and Fife	3.65	7.03	4.43	1.31	14.31	7.85
10	South West Scotland	2.01	7.41	4.43	1.31	12.94	7.96
11	Lothian and Borders	4.00	7.41	2.01	1.31	12.50	5.54
12	Solway and Cheviot	1.76	4.58	3.03	1.31	9.30	5.71
13	North East England	3.79	2.38	1.83	1.31	8.59	3.85
14	North Lancashire and The Lakes	1.87	2.38	1.78	1.31	6.62	3.80
15	South Lancashire, Yorkshire and Humber	4.56	0.49		1.31	6.21	1.46
16	North Midlands and North Wales	3.54	0.06		1.31	4.89	1.33
17	South Lincolnshire and North Norfolk	1.61	-0.07	0.00	1.31	2.86	1.29
18	Mid Wales and The Midlands	1.22	-0.14		1.31	2.44	1.27
19	Anglesey and Snowdon	4.78	1.58		1.31	7.20	1.78
20	Pembrokeshire	8.07	-3.44		1.31	6.97	0.28
21	South Wales & Gloucester	5.40	-3.53		1.31	4.23	0.25
22	Cotswold	2.16	2.53	-5.95	1.31	-0.71	-3.88
23	Central London	-3.83	2.53	-5.29	1.31	-6.04	-3.22
24	Essex and Kent	-4.46	2.53		1.31	-1.38	2.07
25	Oxfordshire, Surrey and Sussex	-1.80	-2.08		1.31	-1.95	0.68
26	Somerset and Wessex	-2.13	-3.47		1.31	-3.25	0.27
27	West Devon and Cornwall	-1.62	-5.61		1.31	-4.24	-0.37

Table E1: TNuOS charges for 2016/17