nationalgrid

Electricity Ten Year Statement

UK electricity transmission

NOVEMBER 2012

This is the first edition of the Electricity Ten Year Statement (ETYS), which replaces the former National Grid electricity publications namely the Seven Year Statement (SYS) and the Offshore Development Information Statement (ODIS).

ETYS is produced by National Grid with the assistance of the two onshore Transmission Owners (TOs), Scottish Power Transmission (SPT) and Scottish Hydro Electric Transmission (SHE Transmission). The objective of the publication is to provide clarity and transparency on the potential development of the National Electricity Transmission Systems (NETS). The document considers this development through strategic network modelling and design capability, while trying to capture future uncertainty with regards to the generation mix, operation of the network and technology development.

In delivering the ETYS we set ourselves various key objectives based upon your views expressed in our April 2012 consultation:

- To provide a document with a high level of clarity.
- To ensure that there is a high degree of transparency around our assumptions and the analysis that we provide.
- To publish an electricity document that utilises enhanced modelling capability to illustrate the development of the transmission system, taking into account the considerable future uncertainties and the interaction between the onshore and offshore network going forwards.

In addition, we have included an outline of our proposed Network Development Policy (NDP) which defines how we will assess the need to progress wider transmission system reinforcements to meet the requirements of our customers in an economic and efficient manner. Please note that the proposed NDP is a National Grid policy and applies to the onshore electricity transmission system in England & Wales.

We hope that you will agree that we have met these targets, although we do recognise that this is the first edition and that future publications will benefit from further input from its readership.

In order to make the 2013 edition of the ETYS even better and ensure that we continue to add value through the information that we provide, I encourage you to tell us what you think by writing to us at transmission.etys@nationalgrid.com. Please also refer to the way forward chapter of this document for further information on our 2013 ETYS consultation process and how you can provide feedback.

I hope that you find this an informative and useful document and look forward to receiving your feedback.

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Executive summary

The purpose of the ETYS is to illustrate the future development of the National Electricity Transmission System (NETS) under a range of plausible energy scenarios and to provide information to assist customers in identifying opportunities to connect to the NETS. To meet these aims this document details a range of potential future energy mixes, the subsequent development of the transmission system under these scenarios and the challenges this presents with regard to the operation of the system.

The UK has legislation in place setting limits on the emissions of greenhouse gases as far ahead as 2050. There is also legislation mandating a minimum level of renewable energy in 2020. A single forecast of energy demand does not give a sufficiently rich picture of possible future developments so National Grid now carries out analysis based on different scenarios that between them cover a wide range of possible energy futures.

A significant part of these energy scenarios is the future power generation and demand mix. The scenarios used to underpin our network development present significant challenges in terms of transmission planning, in light of the uncertainties surrounding the energy landscape as the UK makes the transition to a low carbon economy in 2020 and onwards.

The development of the NETS is influenced by a number of key factors including:

- the generation and demand outlook
- generation type
- regulatory policy changes (e.g. offshore integration review)
- offshore design approaches
- technology development
- management of future uncertainty and investment risk.

Generation, demand and the evolution of regulatory policies are captured by considering the future energy scenarios outlined above. These scenarios provide the basis for technical analysis to identify transmission network development needs. A credible range of potential developments and opportunities are identified and assessed to ensure an economic and efficient transmission system is maintained.

As a means to assess and report transmission system capability it is useful to consider the transmission system split by boundaries. Boundaries separate the system across multiple parallel transmission routes. The boundary capability is an expression of the maximum power transfer that can be securely transferred across the transmission routes. A review of the boundary capabilities is provided in this document and for each boundary the transmission network reinforcements required to securely enable the maximum expected power transfer is provided. More than 25 local and wider boundaries have been analysed in this way.

Some of the northern boundaries could grow by up to five times their current capability under certain scenarios. The southern boundaries see less pronounced changes in power transfer requirements but there is still enough generation development to potentially warrant significant future transmission reinforcement. Additionally very large new generation connections are anticipated in many parts of the network, such as the potential new nuclear connections or multiple large offshore wind connections around the Humber area. To capture the impact of these types of connections, these localised transmission areas have been enclosed with local boundaries to investigate the power transfer requirements and identify suitable network reinforcements. Such reinforcements are particularly sensitive to transmission investment risk.

Offshore transmission development and the development of technologies such as High Voltage Direct Current (HVDC) transmission technologies will play a very big part in both the future requirements and delivery of future transmission capability. An integrated approach to the development of the offshore networks helps provide capacity, control and flexibility that are needed for the effective development of the future transmission network across many of the critical system boundaries.

In addition to the uncertainty facing the transmission network with regard to the quantity, type and location of new generation and the extent and location of new interconnection, the lead-time for reinforcement of the wider transmission network can also be greater than the lead-time for the development of new generation projects. In order to manage this difference in lead-times, we are developing and formalising a Network Development Policy (NDP), some of which is detailed in Chapter 3.

The NDP aims to identify the requirements for further transmission investment and considers the balance between the risks of investing too early in wider transmission reinforcements, which include the risk of inefficient financing costs and an increased stranding risk, with the risks of investing too late, which include inefficient congestion costs.

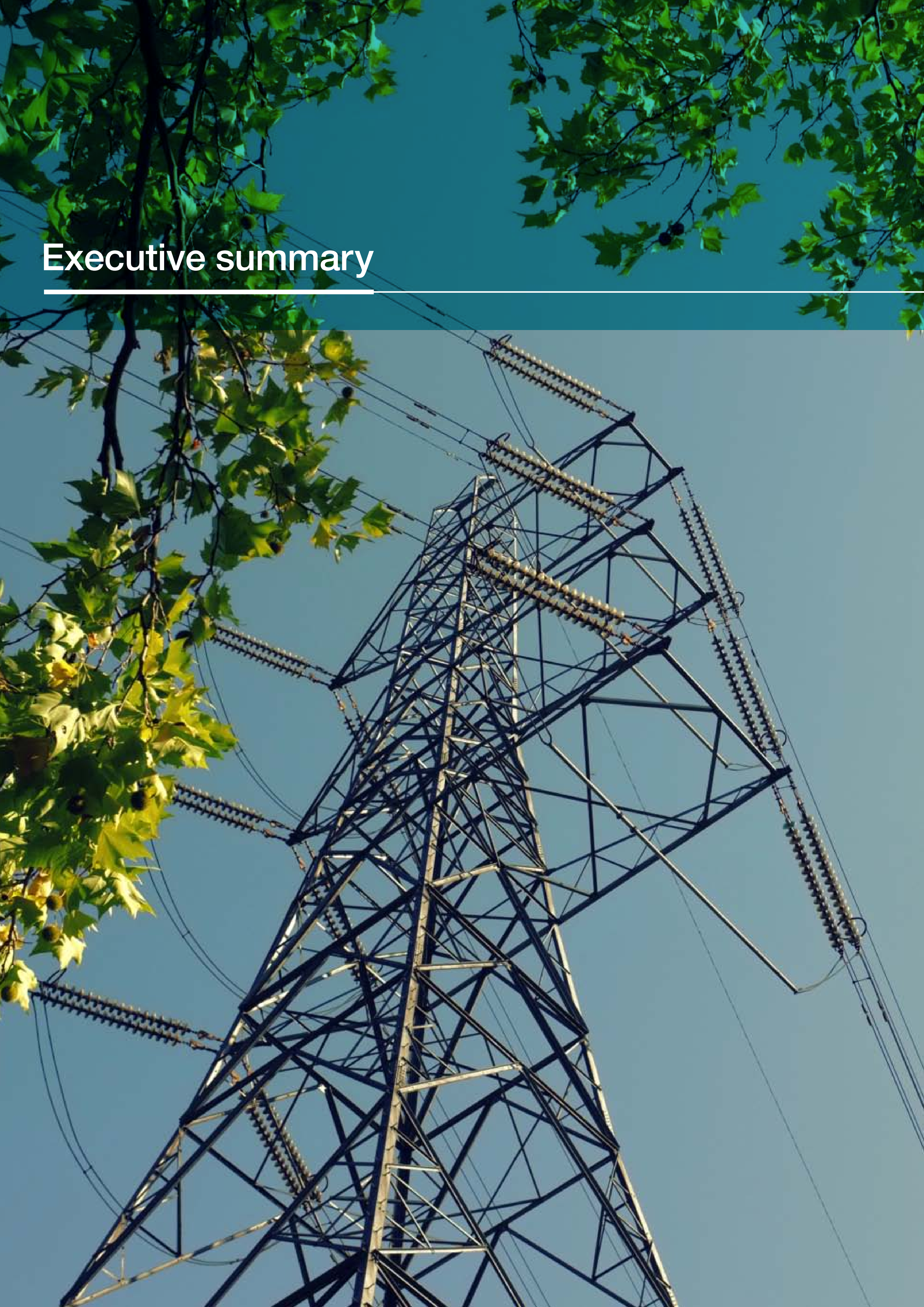
The key output of the NDP is the identification of the best course of action to take in the current year, selected through minimising investment regrets against a range of credible scenarios and sensitivities. Given the uncertainty that we face, the decision process with which the preferred combination of transmission solutions will be chosen needs to be well-structured and transparent. This will allow stakeholders to understand why decisions to build, and not to build, have been taken.

Having identified how the transmission system may be developed, we also need to consider how the operation of the network may change. This requires identifying the key changes to the system, the impact of such changes, and a careful assessment of mitigating measures required to ensure continued safe and secure, reliable, and efficient design and operation of the transmission system.

One key change to the network is the transition from a relatively predictable/controllable generation portfolio dominated by fossil fuel synchronous generation, to one including a significant level of non-synchronous plant with intermittent output. There are also important changes to consider related to electricity demand, where loads may become more flexible and price sensitive. This could be combined with increasing levels of embedded generation, and in the longer term increased levels of electricity storage, which combined could see less predictable levels of transmission system demand. The degree of change will depend on the future energy outlook and the key system design and operational challenges associated with those scenarios are as follows:

- The falling level of synchronous generation in service, particularly at low demand periods, will reduce system inertia making frequency management more of a challenge.

Executive summary



- Falling fault levels on the system could jeopardize the functionality of certain protection devices, the commutation of High Voltage Direct Current (HVDC), and impact on a range of quality of supply issues. There are already difficulties in managing the voltage profile at low demand periods in certain areas of the network and this may be increased by a reduction in system strength.

- Rapid changes in renewable output, including wind generation 'cutting out' at high wind speeds, will have to be matched by changes in conventional generation. As this plant is connected at different locations on the network, there will be significant power flow volatility.

We are confident that mitigating measures can be developed to tackle these issues. We envisage that this will include innovative approaches and will create new opportunities for customers through commercial solutions to these problems, such as flexible demand and fast frequency response.

In summary there are significant challenges ahead with respect to both the development and operation of the transmission network, with both these areas providing commercial opportunities for customers.

Finally, one important aspect to consider when reading this document is that the future energy outlook is uncertain, hence the range of scenarios presented in this document. The actual development of the NETS can and may differ from the illustrations included in this document and the outcomes included in this document should therefore not be used as the basis for any financial, planning consent, commercial or engineering decisions.

Chapter one
Introduction

The aims of the Electricity Ten Year Statement (ETYS) publication are to illustrate the potential future development of the National Electricity Transmission System (NETS) and to help existing and future customers to identify connection opportunities on both the onshore and offshore transmission system. This introductory chapter outlines the approach we have undertaken in order to achieve these aims and sets out the scope of the ETYS.

1.1 Background

In April 2012 we conducted an industry consultation process for the development of an ETYS publication which resulted in overwhelming stakeholder support for the overall approach outlined below. We have detailed this consultation programme, the feedback received from our customers and the output from the process in our 'ETYS Way Forward' publication which can be found on our website.

The 2012 ETYS is the first GB electricity ten year statement to be published and has been produced as a direct result of feedback from our customers. The document forms part of a new suite of publications which is underpinned by our Future Energy Scenarios. This enables the analysis in both the ETYS and its sister publication – the Gas Ten Year Statement (GTYS) – to have a consistent base when assessing the potential future development of both the gas and electricity transmission networks.

Our view is that the harmonisation of a number of our previous publications, including the SYS and ODIS, enables customers to access relevant and timely information in a single document that captures both the onshore, offshore and interconnected network.

The first ETYS publication also represents the start of a new stakeholder consultation process. Following the publication of the first edition of the document we will gather views from the industry to enable us to continually evolve the document and incorporate the views of our stakeholders. Our planned approach to future stakeholder engagement is outlined in Chapter 5.

1.2 Methodology

The document itself will focus on the potential development of the NETS using network modelling and analysis around a range of energy scenarios: Slow Progression, Gone Green and Accelerated Growth, while ensuring that the network is developed in such a way to meet customer connection dates. These energy scenarios are detailed in our Future Energy Scenarios publication, which can also be found on our website. An overview of these scenarios can also be found in Chapter 2.

Future Energy Scenarios

In addition to these three scenarios, further analysis has been produced focusing on the contracted background, which includes any existing or future project that has a signed connection agreement with us.

The use of energy scenarios rather than focusing purely on the contracted generation background is one of the key developments of the ETYS. These scenarios have been developed via a full, wide-ranging industry consultation and enable an assessment of the development of the transmission network against a range of plausible generation and demand backgrounds.

The main focus of the network modelling and analysis contained within the ETYS uses the Gone Green scenario; however analysis has also been undertaken using the Slow Progression and Accelerated Growth scenarios, in order to provide a range of potential future developments and provide greater clarity on potential future connection opportunities.

To help align the ETYS with other National Grid publications and to assist in providing a longer-term view, the analysis contained within the document covers a detailed ten-year study period, with ‘lighter touch’ less detailed analysis considering the period from 2022 to 2032.

1.3 Navigation through the document

Following this introductory chapter the ETYS consists of a further five sections which are:

Scenarios – this chapter describes the key elements in each of the three main scenarios as well as an overview of the contracted background. It also includes analysis on 'plant margins' under the three energy scenarios to further assist customers in identifying future market opportunities.

Network Capability and Future Requirements – This section builds on the previous chapter and illustrates the potential development of the network under the scenarios previously detailed. Future network requirements and reinforcements required under these scenarios are identified here, along with an identification of different transmission design strategies. This is the section where the illustration of the NETS, including detailed system maps of both the onshore and offshore areas, can be found.

In order to assess the potential impact of future requirements on the transmission system it is useful to consider the NETS in terms of specific regions separated by boundaries across which bulk power is transmitted. This section is therefore structured in a way that discusses each of these boundaries, and therefore regions, in turn.

For each boundary there is a description of the boundary, detail of the generation background, an identification of the potential reinforcements under the different scenarios analysed and a discussion of the potential future boundary capability and therefore opportunities. This analysis forms the bulk of the document.

This chapter also discusses the potential development of an integrated offshore network and the impact of increased levels of interconnection and outlines our Network Development Policy (NDP). This defines how we will assess the need to progress wider transmission system reinforcements to meet the requirements of our customers in an economic and efficient manner.

System Operation – Following the identification of how the network may look in the future, this chapter focuses on the challenges and opportunities associated with the operation of the transmission system in the future. The focus is on how network operation will need to change given the changing generation mix and increase of renewable generation.

This section also highlights where there may be opportunities for customers to provide services in support of system operation such as balancing or ancillary services.

Way Forward – We are committed to ensuring that the ETYS continues to evolve over time and that each year our customers have the opportunity to shape the development of this document. This chapter details the process which will run alongside production of the 2013 ETYS to ensure that the publication continues to evolve and that our stakeholders can shape the document.

Appendices – In addition to the main ETYS document itself there are also several data appendices to this publication which can be found on our website. The appendices contain all the relevant technical and numerical data in support of the analysis shown in the ETYS.

The appendices include:

- System Schematics – geographical drawings of the existing and potential future NETS.
- Technical Network Data – data tables that include information such as substation data, transmission circuit information, reactive compensation equipment data and indicative switchgear ratings.
- Power flows – diagrams showing power flows for the full NETS.
- Fault level analysis – fault levels calculated for the most onerous system conditions at the time of peak winter demand.
- Generation Data - tables and graphs which will show the fuel type split data for each of the scenarios and also an extract of the contracted background. This appendix will also show a table which will enable linking of study zones to boundaries.
- Technology – in conjunction with key manufacturer suppliers we have produced a series of technology sheets which look at the present and future technologies associated with the development of both the onshore and offshore transmission system.

Chapter two
Scenarios

2.1
Future Energy Scenarios

Our energy scenarios are produced annually following an industry consultation process which is designed to encourage debate and help shape the assumptions that underpin the final scenarios. Following completion of this year's stakeholder engagement programme the 2012 scenarios were published in National Grid's UK Future Energy Scenarios document. As described in the introduction this document uses these scenarios and assumptions as the basis of the analysis.

All three energy scenarios have been considered in the development of this document, in addition to the contracted generation background. The analysis carried out within ETYS is based around the three future energy scenarios which provide a range of potential reinforcements and outcomes.

The 2012 UK Future Energy Scenarios document was published in September 2012 and can be accessed at the following link: www.nationalgrid.com/corporate/About+Us/futureofenergy/

Future Energy Scenarios

The focus of this document is on the development of the transmission network. The generation and demand figures quoted are therefore 'transmission demand' and 'transmission connected' generation. In the Future Energy Scenarios figures include all generation regardless of whether it is connected to the transmission or distribution network. Although the scenarios are identical, the reporting of the figures is different so care should be taken when comparing figures. To account for the impact of generation connected to the distribution networks, this capacity is treated as 'negative demand' on the transmission network. More detail on this approach is included in section 2.3.

2.2
ETYS background and scenarios

Slow Progression – developments in renewable and low carbon energy are relatively slow in comparison to Gone Green and Accelerated Growth and the renewable energy target for 2020 is not met until some time between 2020 and 2025. The carbon reduction target for 2020 is achieved but not the indicative target for 2030.

Gone Green – this is the main analysis case for the ETYS and assumes a balanced approach with contributions from different generation sectors in order to meet the environmental targets. Gone Green sees the renewable target for 2020 and the emissions targets for 2020, 2030 and 2050 all met.

Accelerated Growth – this scenario has more low carbon generation, including renewables, nuclear and Carbon Capture and Storage (CCS), coupled with greater energy efficiency measures and electrification of heat and transport. Renewable and carbon reduction targets are all met ahead of schedule.

Contracted Background – this refers to all generation projects that have a signed connection agreement with National Grid. Assumptions regarding closures have only been made where we have received notification of a reduction in Transmission Entry Capacity (TEC) or there is a known closure date driven by binding legislation such as the Large Combustion Plant Directive (LCPD).

Each scenario background has its own generation mix (at a generating unit level) and demand assumptions, as outlined in the following sections.

What are the targets?

- UK and EU legislation sets targets for renewable energy and emission of greenhouse gases. Renewables are governed by the 2009 Renewable Energy Directive which sets a target for the UK to achieve 15% of its total **energy** consumption from renewable sources by 2020.
- The Climate Change Act of 2008 introduced a legally binding target to reduce greenhouse gas emissions by at least 80% below the 1990 baseline by 2050, with an interim target to reduce emissions by at least 34% in 2020. The Act also introduced 'carbon budgets', which set the trajectory to ensure the targets in the Act are met.
- These budgets represent legally binding limits on the total amount of greenhouse gases that can be emitted in the UK for a given five-year period. The fourth carbon budget covers the period up to 2027 and should ensure that emissions will be reduced by around 60% by 2030.

Electricity Market Reform

Electricity Market Reform[1] as outlined in the draft Energy Bill, includes the introduction of new long term contracts (Feed-in Tariff with Contracts for Difference), a Carbon Price Floor, a Capacity Mechanism, including demand response as well as generation, and an Emissions Performance Standard (EPS) set at 450g CO_2/kWh to reinforce the requirement that no new coal-fired power stations are built without CCS, but also to ensure necessary investment in gas can take place.

Our analysis of EMR is ongoing, but we have taken account of the main themes in deriving our electricity generation backgrounds and assume that the mechanisms will play a part in maintaining adequate plant margins and will ensure that there is sufficient renewable and low carbon generation to meet the renewable and carbon targets in the Gone Green and Accelerated Growth scenarios.

1 www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

2.3 Demand

This section describes the electricity demand assumptions for each of the scenarios.

2.3.1 Demand Definition

For the purposes of the ETYS demand is included at its assumed peak day level. The assessment of electricity network adequacy tends to focus on the transmission system peak day demand as this is often the most onerous demand condition the network needs to be able to accommodate and will therefore drive many of the required reinforcements.

Peak demand is defined within the ETYS as transmission peak demand including losses and excluding station demand and exports. Also no pumping demand at pumped storage stations is assumed to occur at peak times and is therefore excluded.

Small embedded generation is treated as 'negative demand' for the purposes of calculating transmission demand. Our assumptions on this sector are included in section 2.9 – Embedded generation.

The electricity transmission peak day demand forecast is derived from detailed analysis on annual electricity consumption. The historic relationship between annual electricity consumption and transmission system peak demand is used to form the basis for future relationships between the annual and peak demands, taking into account how future changes may affect this relationship. Our annual electricity demand projections are derived from a number of key drivers, including:

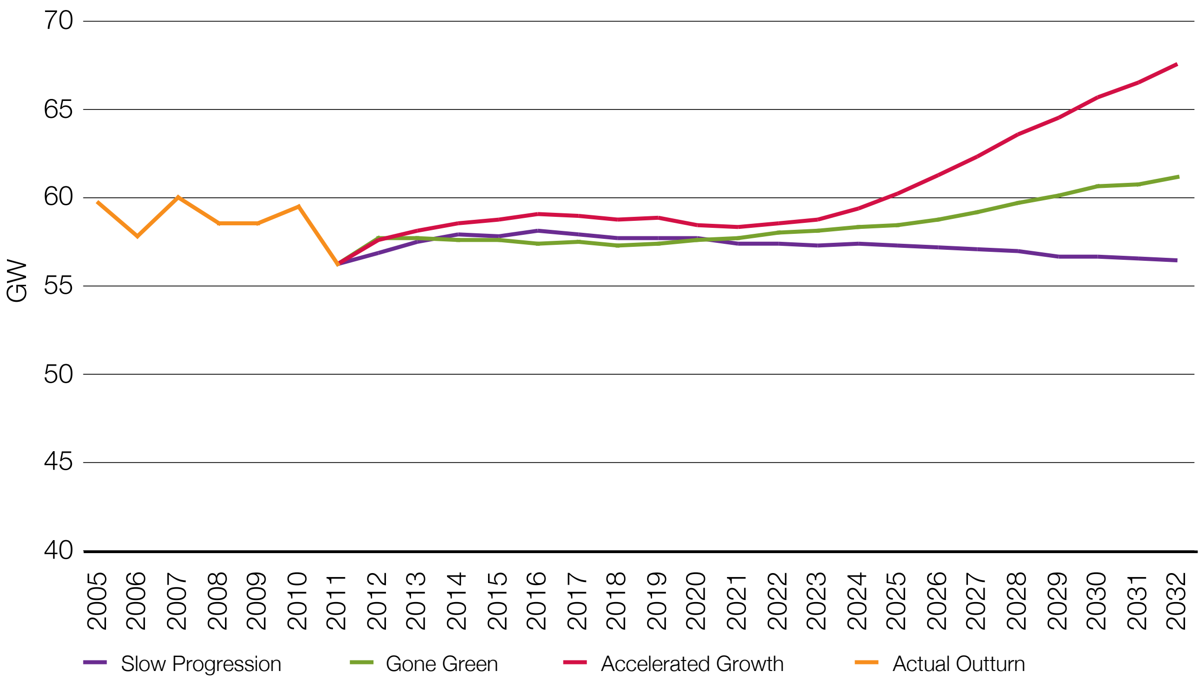
- historic annual electricity consumption
- economic background, including fuel price
- energy efficiency measures.

Detailed description of projections for economic assumptions, energy efficiency measures, electric vehicles, heat pumps and the impact of time-of-use tariffs can be found in National Grid's 2012 UK Future Energy Scenarios document.

Peak demand projections for all three scenarios and user-based forecasts are shown in Figure 2.1.

Demand

Figure 2.3.1:
Peak outturn and forecast



Transmission peak demand was 56.1 GW in 2011/12, compared to 58.1 GW in 2010/11. The main reason for this difference is the effect of the 'double-dip' in the economy with other factors such as increases in energy efficiency and a rise in embedded generation. The lower levels of economic growth have seen a reduction in electricity demand, particularly in the industrial and commercial sectors. Energy efficiency measures, such as more efficient light-bulbs and appliances have also helped to reduce underlying demand, with the growth in distribution network connected (embedded) generation, noticeably renewable generation, reducing demand on the transmission network.

When accounting for small embedded generation, we make an assumption regarding the level of output to include at the time of peak demand. This methodology is similar to that outlined in Section 2.5 which covers plant margins and the treatment of generation at the time of peak demand. Small embedded wind generation is included at 5% of maximum capacity to account for the intermittent nature of wind generation. This allows an assessment of the most onerous condition in respect of transmission demand, with sensitivity analysis undertaken to assess the impact of higher levels of embedded wind generation (which effectively reduces transmission demand).

In Slow Progression, end-users' peak demand is anticipated to fall, predominantly from industrial and commercial sectors as economic growth is slow. Transmission peak demand continues to rise in the next decade due to slower development in embedded generation and energy efficiency measures. In this scenario, electric vehicles and heat pumps have minimal effects at peak.

In Gone Green, Transmission demand growth is slow over the next decade as increases in non-domestic demand due to a stronger economic outlook are offset by increasing embedded generation and energy efficiency. The number of electric vehicles increases compared to Slow Progression; however, time-of-use tariffs limit peak charging in this scenario, adding around 1 GW to peak towards 2030. Heat pumps reduce peak demand up to the middle of the next decade as the saving from replacing existing resistive heating outweighs the increase from displacement of gas heating. By 2030 domestic heat pumps are replacing gas heating and add around 1 GW to peak demand. This growth in the electrification of heat and transport increases peak demand in the period post 2020.

In Accelerated Growth, Transmission demand is stronger than in the other scenarios and non-domestic demand grows rapidly in line with economic assumptions. Again transmission demand growth is offset somewhat by embedded generation growth and increased energy efficiency. The number of electric vehicles increases significantly, but again, time-of-use tariffs limit charging at times of peak demand. In this scenario, up to 3 GW of EV charging could take place at peak. For heat pumps, there are similar trends in this scenario compared to Gone Green, though additional heat demand (from new housing and displacement of gas-fired heating) is greater in Accelerated Growth. Heat pumps add around 1.2 GW to the peak by 2030. The strong growth in the electrification of heat and transport results in much stronger growth in peak demand post 2020.

For the contracted background, the Gone Green demand profile has been applied.

2.4 Generating capacity

This section provides some more detail for the generation capacity backgrounds for the scenarios and outlines the key changes over the period to 2032 in each of the cases.

2.4.1 Generating Capacity Definition

The values shown within this section are only for capacity that is classed as 'transmission capacity'. This is generally generation capacity that is classified as 'large'[1] and therefore does not include any small embedded generation. Embedded generation not included in these values is accounted for in the assessment of transmission demand as discussed in the Section 2.3.

2.4.2 Slow Progression 2012

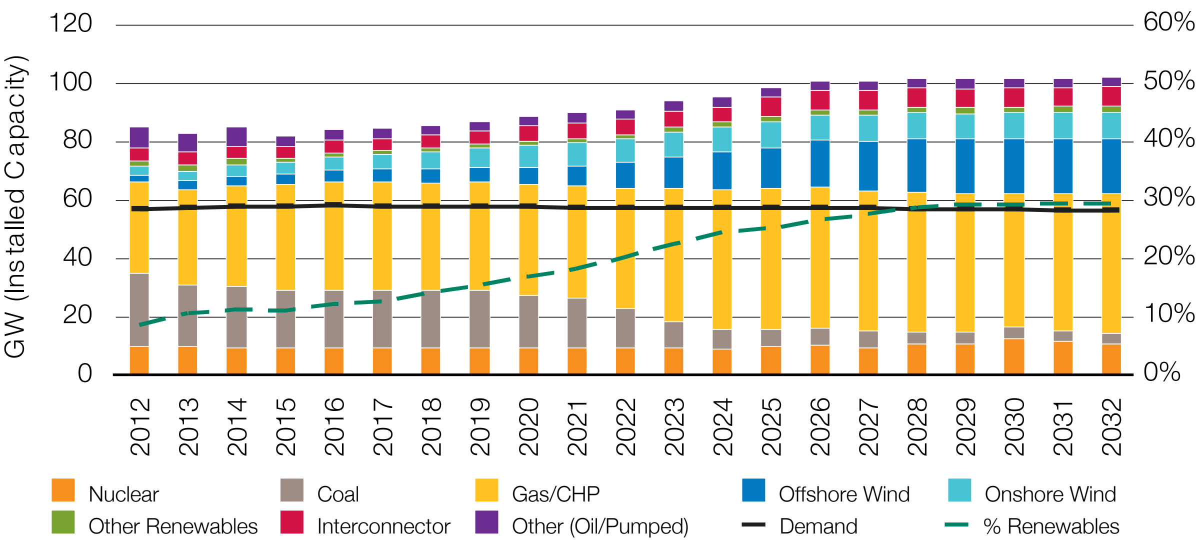
This scenario has a lower emphasis on renewable generation over the period. The key messages for this scenario are shown below:

- Gas capacity increases over the period to 2020 by 7 GW and to a total of 49 GW by 2032 showing a total increase over the period of 16 GW.
- Growth in wind capacity is considerably slower in this scenario in comparison to Gone Green and Accelerated Growth and reaches 13 GW by 2020 and 28 GW by 2032 (19 GW being offshore wind), showing a total increase over the period of approximately 22 GW (the vast majority of this being offshore wind).
- Other renewables excluding wind remain fairly static over the full period to 2032 showing only approximately a 300 MW increase.
- Coal capacity shows a slower decline than in the Gone Green scenario showing a 7 GW decrease by 2020 leaving 18 GW of coal capacity. Between 2020 and 2032 coal declines further, to 4 GW by the end of the period.
- Nuclear capacity remains fairly static over the period rising from 10 GW in 2012 to 13 GW by 2030 before falling back to 11 GW by 2032.

Figure 2.4.1 illustrates the capacity mix for Slow Progression;

1 National Grid: What size is my power station classed as? www.nationalgrid.com/uk/Electricity/GettingConnected/FAQs/Question+12.htm

Figure 2.4.1:
Slow progression generation mix



The existing level of renewables at 2012 in this scenario is 8.5% of total generating capacity which will rise to 17% in 2020 and finally increasing to 30% in 2032.

2.4.3
Gone Green 2012

As described in section 2.2 the Gone Green scenario assumes a generation mix that will meet the CO2 and renewable targets. The key messages from this generation background and how it develops over time are:

- Wind reaches 25 GW of capacity by 2020 (17 GW of this being offshore) and 49 GW by 2032 (37 GW of this being offshore).
- Other renewables excluding wind and including hydro, biomass and marine show an increase on current levels of 1.3 GW to 2020 and 2.9 GW over the full period to 2032.
- Gas/CHP generation capacity increases overall over the full period showing a 3.3 GW increase between 2012 and 2020 and a further 3 GW by 2032, resulting in an overall increase of 6.3 GW.
- Coal capacity decreases dramatically over the period to 2032, with the existing 25 GW decreasing to 18 GW by 2020 and to 12 GW by 2032. This is due to the LCPD and Industrial Emissions Directive (IED) legislation.
- Carbon Capture and Storage (CCS) assumptions within this scenario show the introduction of this technology into the generation capacity mix from 2025 onwards with a total of 1.2 GW of CCGT plant fitted with CCS by the end of the period in 2032.
- Nuclear capacity increases by a total of approximately 5 GW over the period taking the total nuclear generating capacity to 14.7 GW in 2032.

Figure 2.4.2:
Gone green installed capacity mix

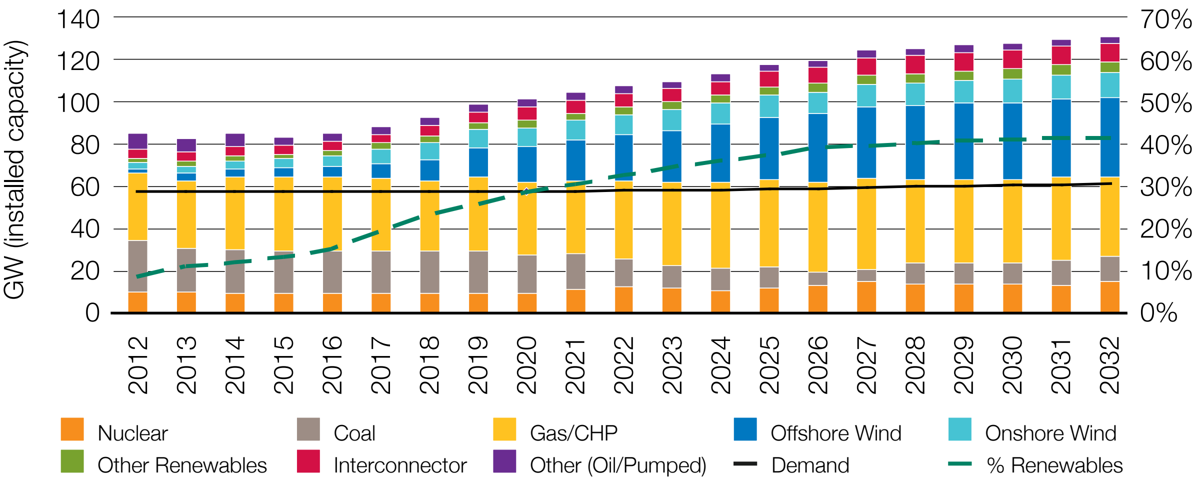


Figure 2.4.2 illustrates the capacity mix for the Gone Green background over the study period.

The existing level of renewables at 2012 in this scenario is 8.5% which will rise to 28.5% in 2020 and finally increasing to 41.5% in 2032.

2.4.4 Accelerated Growth 2012

The Accelerated Growth scenario shows a much steeper increase in the level of renewables generation capacity than Gone Green and Slow Progression. The key messages for this scenario are shown below:

- Wind generation capacity increases steeply in this scenario and reaches 33 GW by 2020 and 64 GW by 2032 showing a total increase over the period of 59 GW.
- Gas-fired capacity shows a total increase over the period to 2032 of approximately 5 GW.
- Coal capacity shows a net decrease over the period to 2032 of approximately 12 GW, the total coal capacity in 2020 is 20 GW with the total decreasing to 12 GW in 2030 but rising slightly again by 2032 as new CCS capacity comes on line.
- Nuclear generation decreases over the period to 2020 by 1 GW, however increases over the full period to 2032 by a total of 8 GW, with the introduction of new nuclear plant.
- Other renewables which include marine, hydro and biomass also increase steeply over the period to 2032 showing a total generating capacity increase of approximately 6 GW, taking the total installed capacity to 7.7 GW.

Figure 2.4.3:
Accelerated growth installed capacity mix

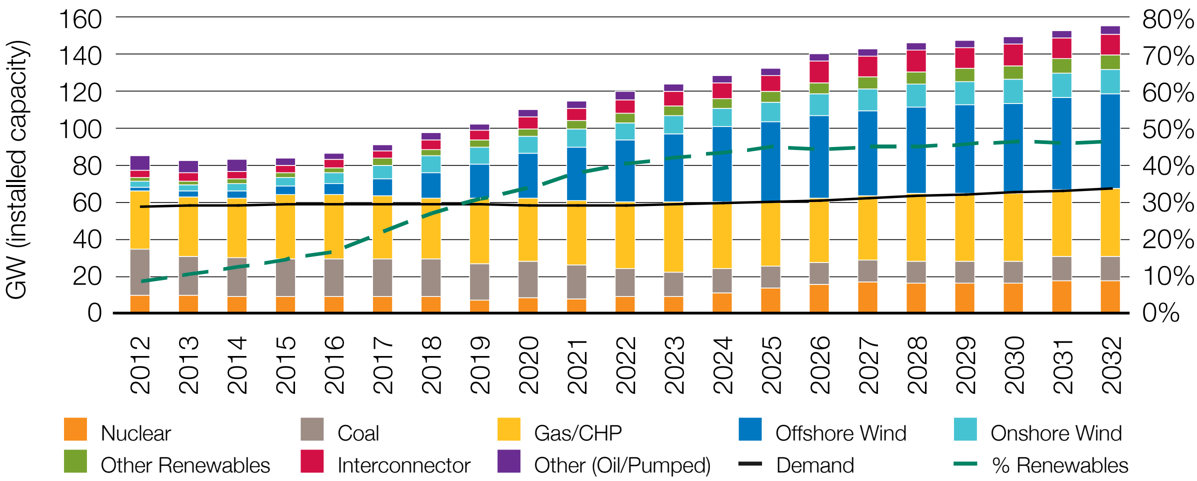


Figure 2.4.3 illustrates the capacity mix for Accelerated Growth.

With Accelerated Growth being the scenario with the most rapid build up of renewables the percentage level of installed renewable capacity in 2020 is 34% which increases to 46% in 2032.

2.4.5 Contracted Background

The contracted background used for ETYS was taken from the Transmission Networks Quarterly Connections Update (TNQCU), issued in September 2012. It should be noted that when analysing the contracted background the generation mix includes all projects that have a signed connection agreement and no assumptions are made about the likelihood of a project reaching completion.

Some of the key messages for the contracted background are:

- A large increase in contracted wind overall but especially offshore wind with a starting level of 3.6 GW in 2012 rising to a total of 40 GW of generation that currently has a signed connection agreement.
- A decrease in coal generation amounting to 5.5 GW over the full period, this reflects the known LCPD closures.
- A rise in nuclear generation capacity which currently has a signed connection agreement results in a total increase over the period to 2032 of 20 GW.

Generating capacity

Figure 2.4.4:
Contracted background capacity mix

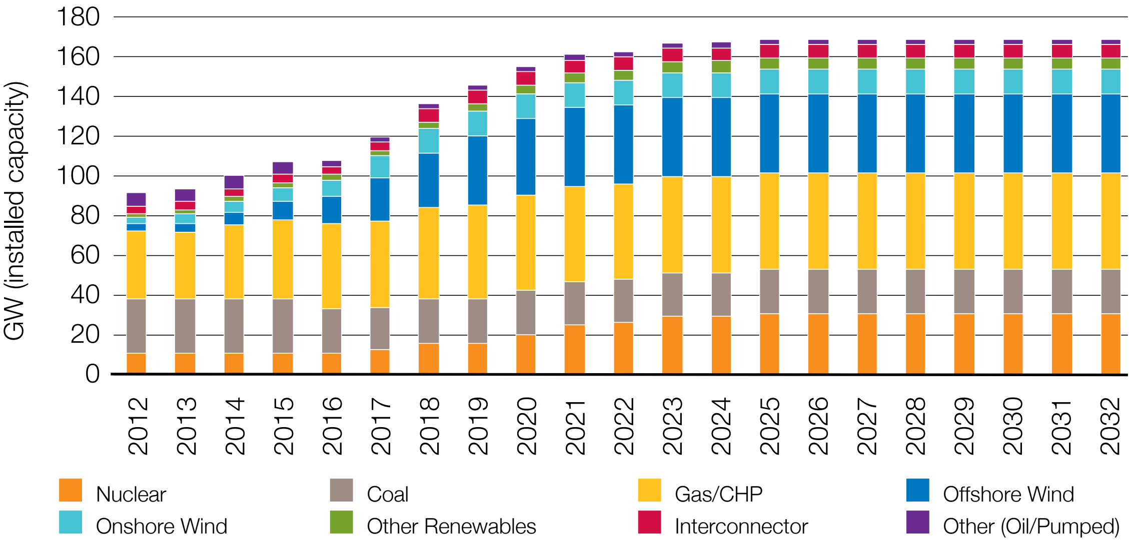
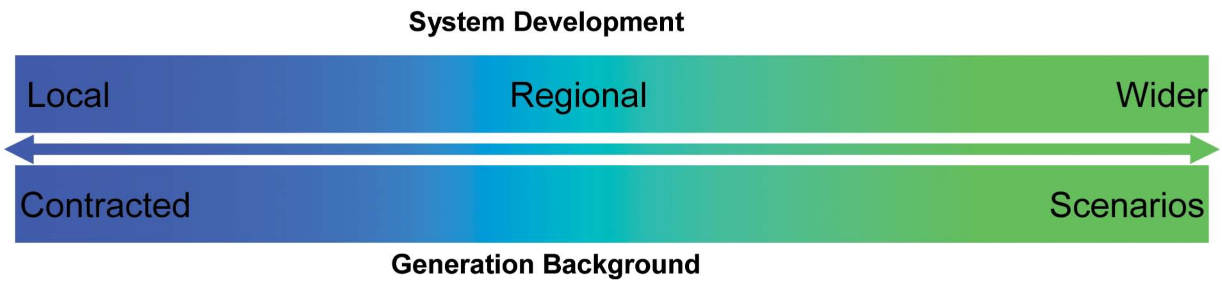


Figure 2.4.4 illustrates the capacity mix for the contracted background.

Please note that as we continue to sign new connection agreements on an ongoing basis the latest TNQCU, which is available on the National Grid website, should be referred to for an updated position.

Figure 2.4.5:
System development and use of generation backgrounds



2.4.6 Sensitivity Analysis

The generation background that underpins each scenario can be described as a credible way in which the underlying premise of the scenario will be met. We recognise, however, that subtle differences in the make-up of the generation background may have a significant impact on the future development of the transmission system. Therefore it is prudent to assess these 'sensitivities' to the main scenarios. The approach we have taken is to take the underlying principles of the Gone Green scenario e.g. 30 GW of wind capacity in 2020, and analyse the impact on a regional basis. What is the impact of moving 'x' GW of capacity from one location to another, while keeping the total in that particular scenario the same?

Alongside this, it is prudent to assess the impact, on a regional basis, of generation projects being developed to the contracted connection date. In essence, this results in a variant of the Gone Green scenario and the contracted background on a regional basis. This allows an assessment of specific areas where there may be a need for additional and/or earlier reinforcement than in the three main energy scenarios.

The way in which the contracted background and the three main scenarios complement each other with regard to the development of the network is illustrated above. Simply at a local level reinforcement is driven by the connection agreements in the contracted background, with the wider system development being scenario-driven. At a regional level the contracted background is considered alongside the scenarios by means of the sensitivity analysis described above.

2.5
Plant margins

This section brings together the information described earlier in this chapter on demand projections and future generation capacity mix and assesses the status of future generation projects and the 'plant margin' assumed in the different energy scenarios. The plant margin is defined as the amount of generation capacity available over and above the level of peak demand.

2.5.1
Project Status

Figure 2.5.1 shows the current status of the projects included in the contracted generation background. These categories are broadly defined as follows:

Existing – this is the level of generation capacity already built and commercially generating.

Under Construction – the level of generation capacity which is currently being built.

Consents Approved – generation projects that have obtained the relevant consents to proceed.

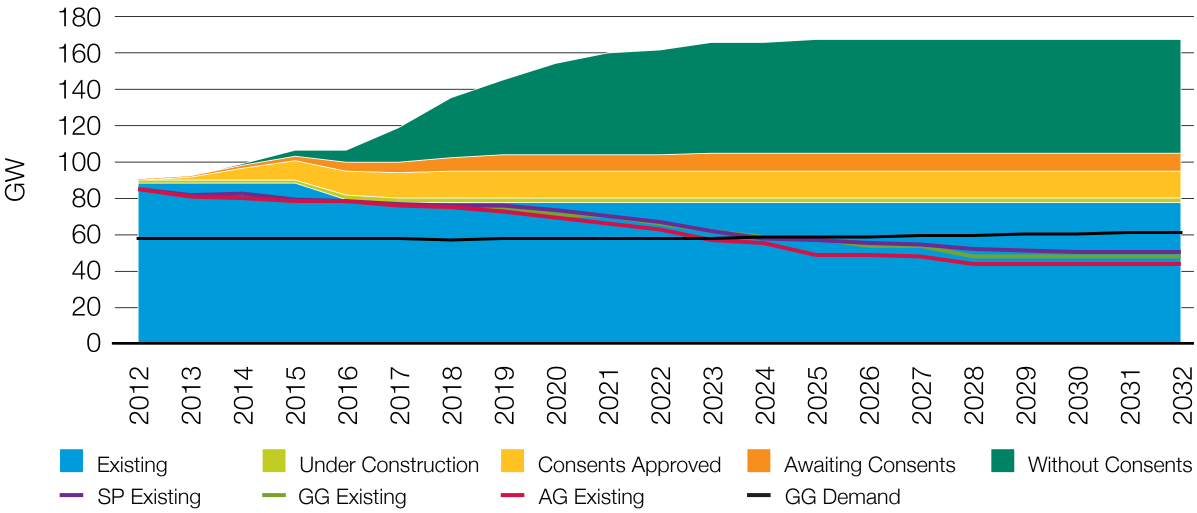
Awaiting Consents – these are generation projects that have applied for the relevant consents to proceed but are awaiting a decision.

Scoping – these are projects that have a signed connection agreement only but have not yet applied for any consents.

In addition Figure 2.5.1 includes the level of 'existing' generation assumed in each of the three energy scenarios. These figures include assumptions on plant closures within each of the scenarios and highlights when new generation will be required in these scenarios. This is explored further in the assessment of plant margins later in this section, but the impact of environmental legislation and ageing plant can be seen as existing generation falls due to these plant closures.

A significant proportion of the contracted generation is in the scoping phase, with the majority of this being low-carbon generation such as offshore wind and new nuclear plant. Around 15 GW of plant has the relevant consents with just over 9 GW of this being CCGT plant.

Figure 2.5.1:
Contracted background Vs existing scenarios



2.5.2
Plant Margin Analysis

When assessing plant margins it is important to consider the definition of the numbers being quoted. Traditionally we have referred to a '20% plant margin' and for the purposes of this section we have included data on both this traditional measure and on a de-rated plant margin basis. This allows a comparison with other publications, such as the Ofgem Capacity Assessment, which tend to focus on this de-rated approach. This calculation uses peak demand and then reduces the level of generation capacity to include an assumed level of availability at the time of peak demand. The '20% margin' approach that has been used in previous publications includes no reduction in generation capacity, except for wind generation which is reduced to 5% of its maximum capacity. This plant margin of 20% is then assumed to be maintained in future scenario assessments, this being deemed adequate to maintain the required level of security of supply. The de-rated margin equivalent of the 20% figure is approximately 8%, but this can vary depending on the generation mix and the assumptions made with respect to availability. These figures should therefore be only used as a guide.

2.5 continued
Plant margins

Figure 2.5.2:
20% scenario plant margins

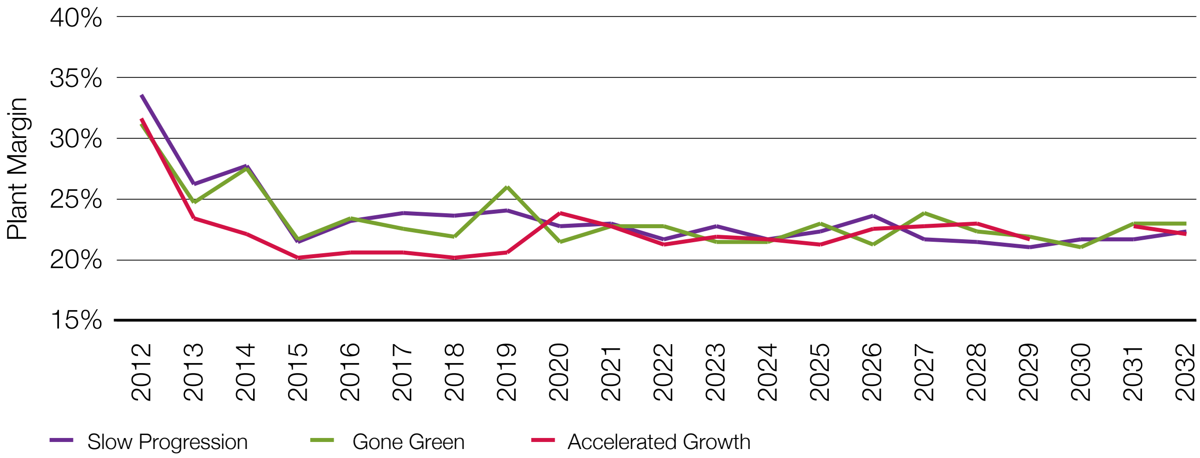


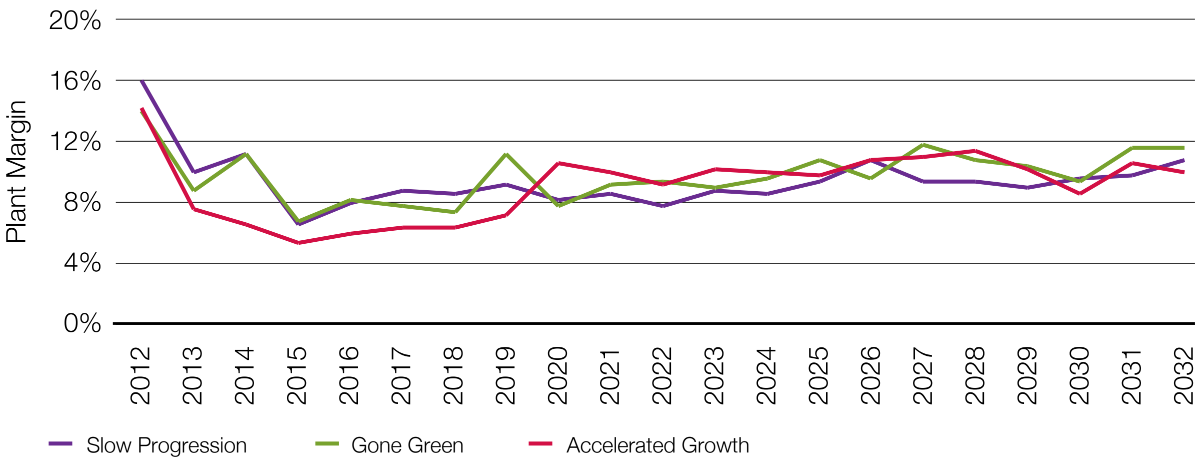
Figure 2.5.2 shows the future plant margins based on the traditional '20%' approach, with Figure 2.5.3 showing plant margins on a de-rated basis. We constructed each scenario to maintain a margin of at least 20% (or the de-rated equivalent), assuming no imports from Europe and the aforementioned 5% contribution from wind.

The following analysis shows the de-rated plant margins for each of the scenarios. Each generation type has been de-rated as shown in Table 2.5.1 right.

Table 2.5.1:
De-rated fuel type margins

Fuel Type	% Rating
Biomass	87%
CCGT	89%
CHP	89%
Coal	89%
GT	90%
Hydro	92%
Nuclear	86%
OCGT	77%
Offshore Wind	8%
Oil	81%
Onshore Wind	8%
Pumped Storage	95%
Tidal	35%
Wave	35%

Figure 2.5.3:
Scenario de-rated plant margins



A key aspect of this calculation is that wind is de-rated down to 8%, a slightly more optimistic view than the 5% used in the traditional approach. Wind is de-rated to a low level as experience has shown that at times of high system demand, levels of output from wind can be lower than 10% of the maximum potential output. However, given the unpredictable nature of wind generation output, Figure 2.5.4 shows the plant margin calculation if wind generation capacity is de-rated to various levels of output.

Figures 2.5.2 and 2.5.3 show the different de-rated plant margins calculations for each of the scenarios and show that these all decrease from their current levels. This is principally due to the relatively high plant margins that are evident in the market today, driven mainly by a reduction in electricity demand due to the economic climate. In addition 10 GW of CCGT plant has either connected since 2009 or is currently under construction. The fall in plant margins in all scenarios over the next few years is driven mainly by coal plants closing due to the Large Combustion Plant Directive (LCPD). The lowest plant margin in all scenarios is in 2015 when all of the plant affected by the LCPD is due to close. The figures reported here for the Gone Green scenario are slightly higher than in Ofgem's Capacity Assessment due to a slight difference in methodology relating to the treatment / inclusion of reserve for the single biggest infeed loss.

In the short term the difference between the scenarios is driven by differing demand assumptions as the generation assumptions for each scenario are broadly similar for the first three to four years of the outlook.

2.5 continued
Plant margins

Figure 2.5.4:
Gone green wind sensitivities

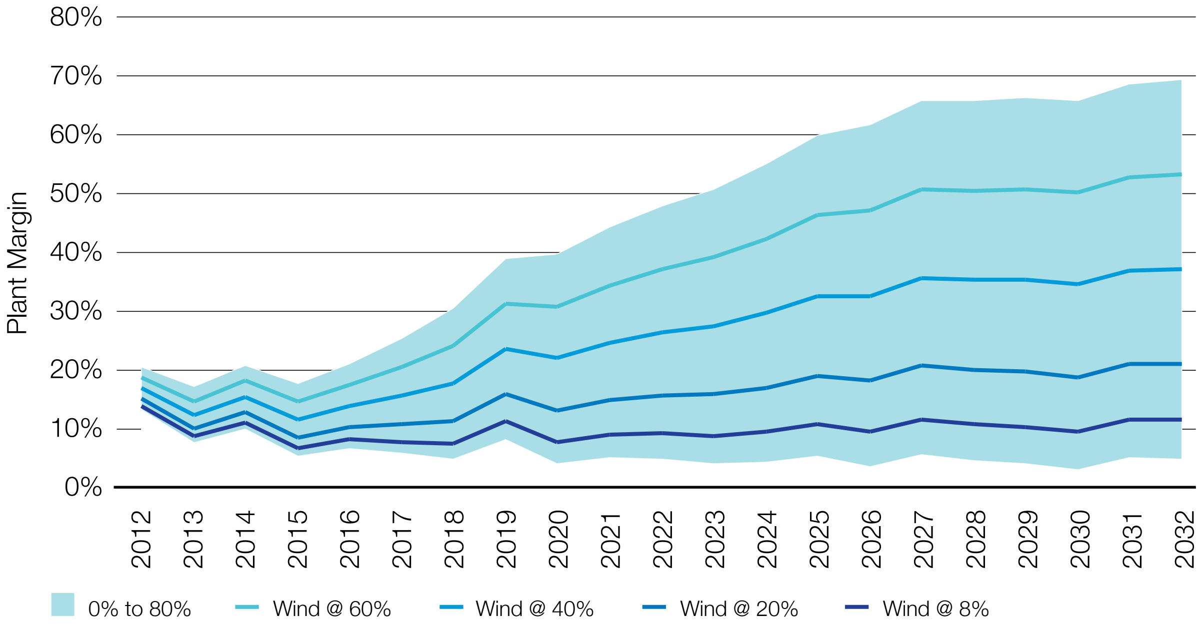


Figure 2.5.4 shows how these de-rated margins would be affected by different assumptions for the level of wind generation availability in the Gone Green scenario. This highlights the importance this assumption has, with the range growing significantly as the amount of wind capacity in this scenario increases. This also highlights that the variance in wind generation availability will have a significant effect on how we operate the transmission system, with the amount of capacity assumed in each scenario based on an assumption that, for security of supply purposes, wind availability is low. These operational challenges are explored in detail in Chapter 4 of this document.

2.6 Renewables

One of the key elements for all of the scenarios is the level of renewable generation assumed, as this has a major impact on both network development and network operation. The focus on renewables in this section is a direct consequence of the ETYS document replacing the Offshore Development Information Statement (ODIS) in addition to the Seven Year Statement. The aim is to ensure that information provided in the ODIS continues to be available, recognising that other types of generation are just as important when focusing on the development of the transmission network.

This section discusses in more detail four of the renewable generation types that could have a direct impact on the transmission system – offshore wind, onshore wind, marine and biomass. Other renewable generation types that connect principally to the distribution networks are discussed later in this chapter.

Renewables Obligation[1]

The Renewables Obligation (RO) is currently the main support scheme for renewable electricity projects in the United Kingdom. The key elements of the obligation are:

- The RO was introduced in 2002 and is set to continue until 2017 when the new arrangements that will form part of the Electricity Market Reform (EMR) outputs will replace the RO.
- It places an obligation on UK suppliers of electricity to source an increasing proportion of their electricity as renewable generation.
- Accredited renewable generators are issued with Renewable Obligation Certificates (ROCs) for each megawatt hour (MWh) of eligible energy generated, multiplied by a factor that is dependent on the type of generation technology. Renewable generators can sell their ROCs to electricity suppliers.
- Suppliers meet their obligations by presenting sufficient ROCs. Where they do not have sufficient ROCs to meet their obligations, they must pay an equivalent amount into a fund, the proceeds of which are paid back on a pro-rata basis to those suppliers that have presented ROCs.
- The RO had an original operational end date of 2027, which has subsequently been extended to 2037 with an associated limit of 20 years support for accredited generation.

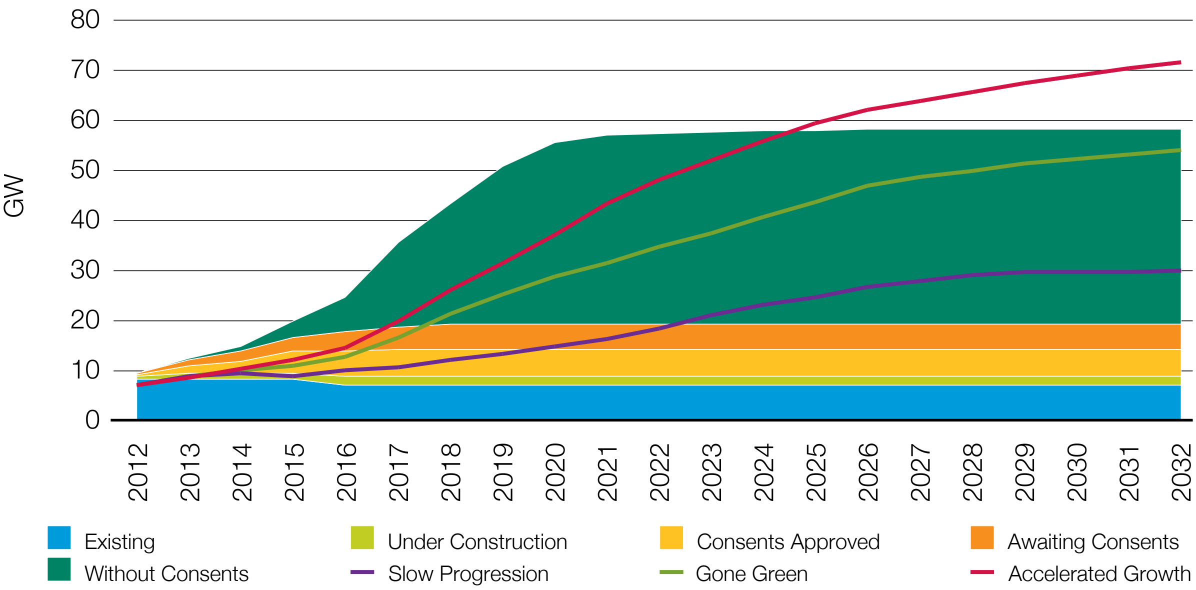
A banding review for the period 2013 to 2017, which details the number of ROCs available for each MWh generated by different types of renewable generation, was undertaken by the government earlier this year[2]. More detail can be found in the government report, with the key elements related to transmission connected generation being:

- The ROC level for offshore wind will be 2 ROCs per MWh over the first two years of the banding review period, falling to 1.9 in 2015/6 and 1.8 in 2016/7.
- The level of support for onshore wind for the banding review period will be reduced to 0.9 ROCs per MWh, guaranteed until at least March 2014, with a review into onshore wind industry costs being undertaken before ROC levels for 2014 to 2017 are finalised.
- The support levels for dedicated biomass plant will be 1.5 ROCs per MWh, decreasing to 1.4 ROCs per MWh in 2016/17. Biomass conversions will receive 1 ROC per MWh over the banding review period.
- Tidal generation to receive 2 ROCs per MWh in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17. Wave generation to receive 5 ROCs per MWh up to a 30 MW capacity limit and 2 ROCs per MWh above the cap.

1 www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/renew_obs/renew_obs.aspx
2 www.decc.gov.uk/assets/decc/11/consultation/ro-banding/5936-renewables-obligation-consultation-the-government.pdf

Renewables

Figure 2.6.1:
Renewables contracted background by stage



The analysis shown in Figure 2.11 includes offshore wind, onshore wind, biomass, hydro and marine generation comparing the split contracted background against the scenario backgrounds.

Figure 2.6.1 shows there is an existing level of around 7 GW of renewable generating capacity, with the Gone Green scenario renewable capacity level in 2020 at approximately 30 GW. Therefore if the Gone Green scenario is to be met then a further 25 GW of renewable generation (out of a total 45 GW of renewable contracted future generation with completion dates before 2020), will need to connect to the transmission system by 2020.

Slow Progression shows a level of 15 GW of renewable generation capacity connected to the transmission system by 2020, showing an increase of 8 GW on current existing levels. There is around 7 GW of further renewable generation currently with consents.

Accelerated Growth shows a steep increase in renewable generation capacity by 2020 resulting in an increase on current existing levels of 30 GW. In the longer term there is an assumed growth in renewable generation that exceeds the current level of contracted renewable generation.

In summary, renewable generation plays a large part in all of the scenarios over the period to 2032 and there is currently enough contracted generation capacity to meet the levels required under the Slow Progression and Gone Green scenarios. The majority of these generation projects, however, are currently in the scoping or without consents phase of development.

The government review of ROC banding shows that there is still commitment to renewable generation technologies, which is emphasised by the level of renewable generation growth in our scenarios, particularly Gone Green and Accelerated Growth. In order to meet the long-term environmental targets out to 2050 then there will need to be a continued focus on low carbon generation and renewable generation will undoubtedly have a role to play.

2.6.1 Offshore Wind

Offshore wind has the potential to have a significant impact on the future development of the transmission network and particularly in the Gone Green and Accelerated Growth scenarios, it plays a significant role in the future energy mix.

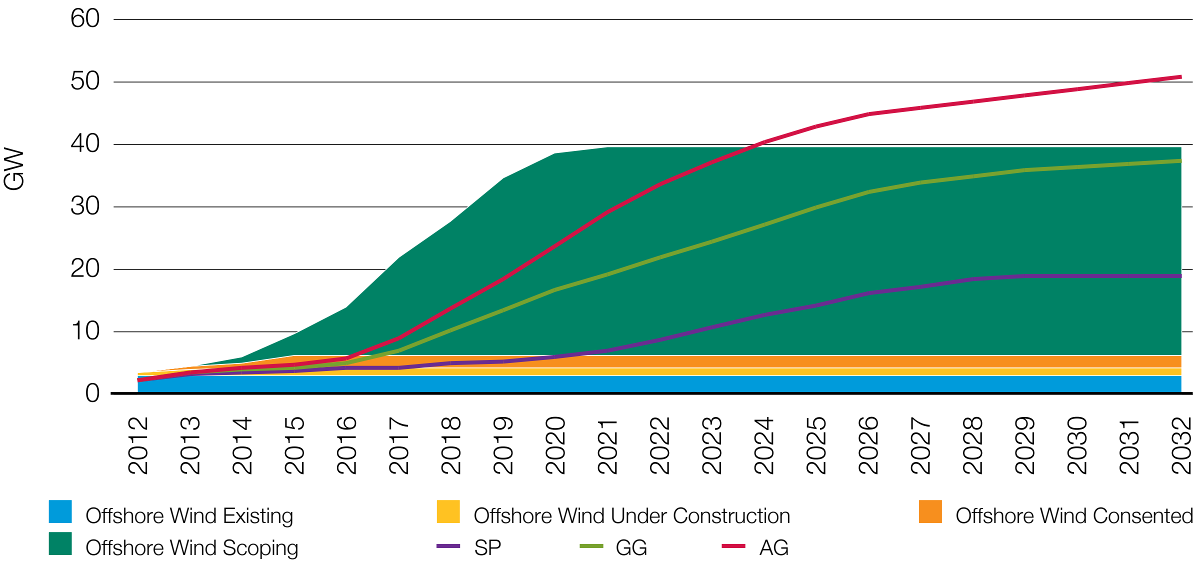
The Crown Estate has facilitated a series of leasing rounds under which areas of the seabed have been made available for the development of offshore wind farms. Table 2.6.1 shows the potential for each leasing round and also how much of this capacity is operational, under construction or in the scoping phase of development.

Table 2.6.1:
Offshore wind potential
Source:
The Crown Estate

Round Name	Status	Indicative Capacity (MW)
Round 1	Operational	1027
	Under Construction	62
Round 2	Operational	484
	Partially Operational	1155
	Under Construction	1476
	Under Development	4138
Round 1 & 2 Extensions	Under Development	1539
Scottish Territorial Waters	Under Development	4845
Round 3 Zones	Under Development	36515
TOTAL OFFSHORE WIND POTENTIAL		**51241**

Table 2.6.1 shows the current potential for offshore wind generation capacity as being 51.2 GW based on The Crown Estate leasing rounds. Figure 2.6.2 shows the current contracted position for offshore wind against the requirement for offshore wind generation in each of the three scenarios over the period to 2032.

Figure 2.6.2:
Offshore wind contracted Vs scenarios



In the Gone Green scenario there is 17 GW of offshore wind in 2020. The current level of offshore generation capacity that is either existing or will be under construction by 2020 is 4.0 GW, therefore leaving a total of 12 GW (of the 34 GW that is contracted with a signed connection agreement and completion date before 2020) to be connected to the transmission system by this point. By the end of the period the Gone Green scenario shows an offshore wind generating capacity of 37 GW.

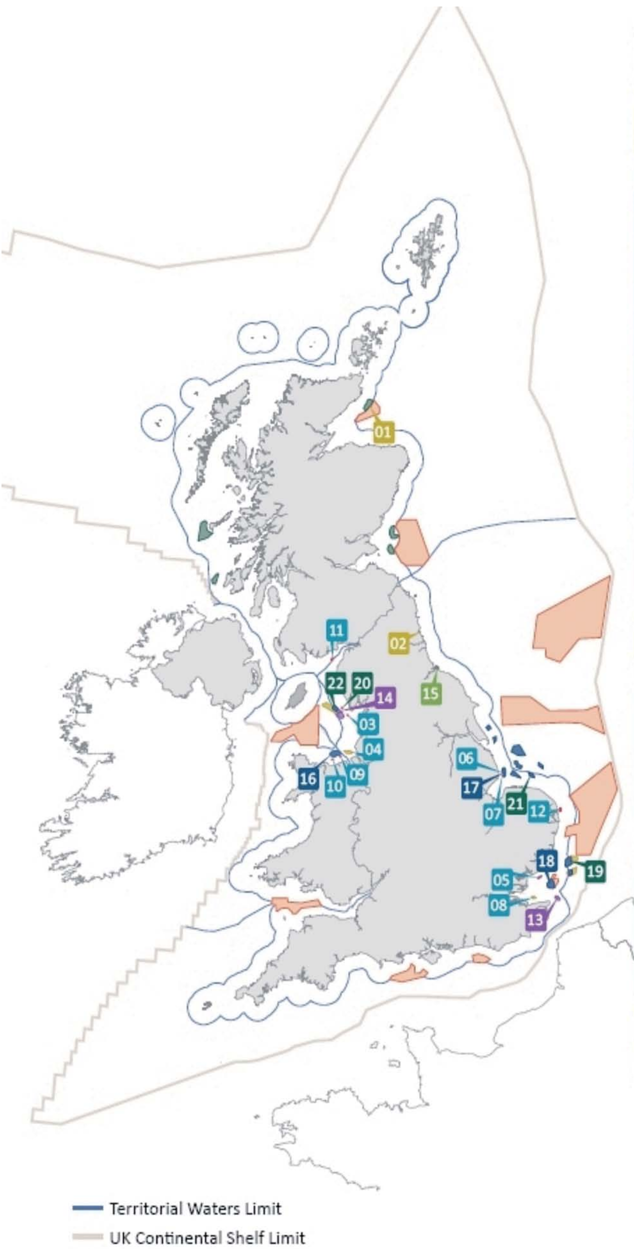
There is a large amount of capacity that is in the scoping phase of project development which, based on historical observations, indicates that there is the possibly that some of these generation projects will not progress to completion. It is worth noting that the amount of generation in the contracted background is not yet fully commensurate with the total potential indicated through the Crown Estates leasing rounds.

Slow Progression shows that the level of offshore wind in this scenario at 2020 is 6 GW. As mentioned above, 4 GW of this generation capacity is either already connected to the transmission system or will be by 2020 and there is enough generation with consents to provide the additional 2 GW in this scenario.

Accelerated Growth shows the level of offshore generation capacity at 2020 is 24 GW which is 7 GW higher than the level shown in the Gone Green scenario, meaning that a further 20 GW on top of current levels will need to connect to the transmission system by 2020 if this scenario were to be met.

The following maps were published by The Crown Estate of the offshore system, showing firstly in Figure 2.6.3 the projects that are operational and under construction and secondly in Figure 2.6.4 the offshore projects that are under development.

Figure 2.6.3:
Offshore projects in operation or under construction
Source:
The Crown Estate



No	Project name	Equity investors	Capacity (MW)
Operational demo sites			
01	Beatrice Demo	SSE	10
02	Blyth	E.On	4
Round 1 operating assets			
03	Barrow	Centrica, Dong	90
04	Burbo Bank	Dong	90
05	Gunfleet Sands I & II	Dong, Marubeni	173
06	Inner Dowsing	Centrica, TCW	97
07	Lynn	Centrica, TCW	97
08	Kentish Flats	Vattenfall	90
09	North Hoyle	RWE, JP Morgan IIF, Prudential M&G	60
10	Rhyl Flats	RWE	90
11	Robin Rigg (E&W)	E.On	180
12	Scroby Sands	E.On	60
Round 2 operating assets			
13	Thanet	Vattenfall	300
14	Walney 1	Dong, SSE, PGGM & Dutch Ampere	184
Round 1 assets under construction			
15	Teesside	EDF	62
Round 2 assets under construction			
16	Gwynt y Môr	RWE, Siemens, Stadtwerke Munchen	576
17	Lincs	Centrica, Dong, Siemens	270
18	London Array 1	Dong, E.On, Masdar	630
Round 2 partially operational sites			
19	Greater Gabbard	RWE, SSE	504
20	Ormonde	Vattenfall	150
21	Sherringham Shoal	Statkraft, Statoil	317
22	Walney 2	Dong, SSE, PGGM & Dutch Ampere	184

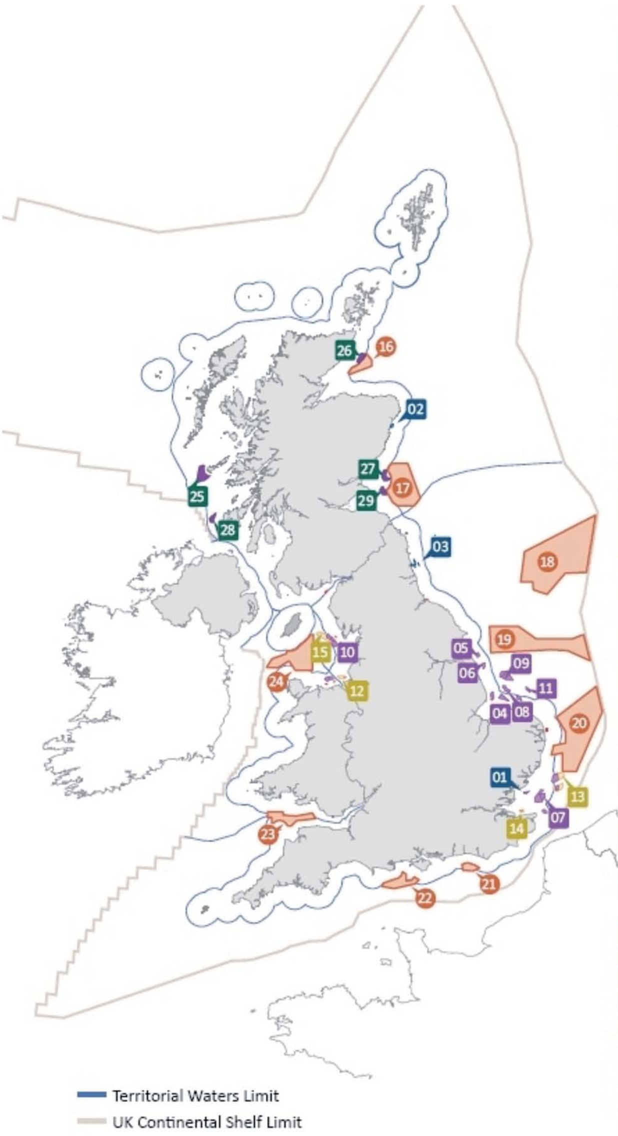
Round 1 and 2 extension sites

Round 3 zones

Scottish territorial waters sites

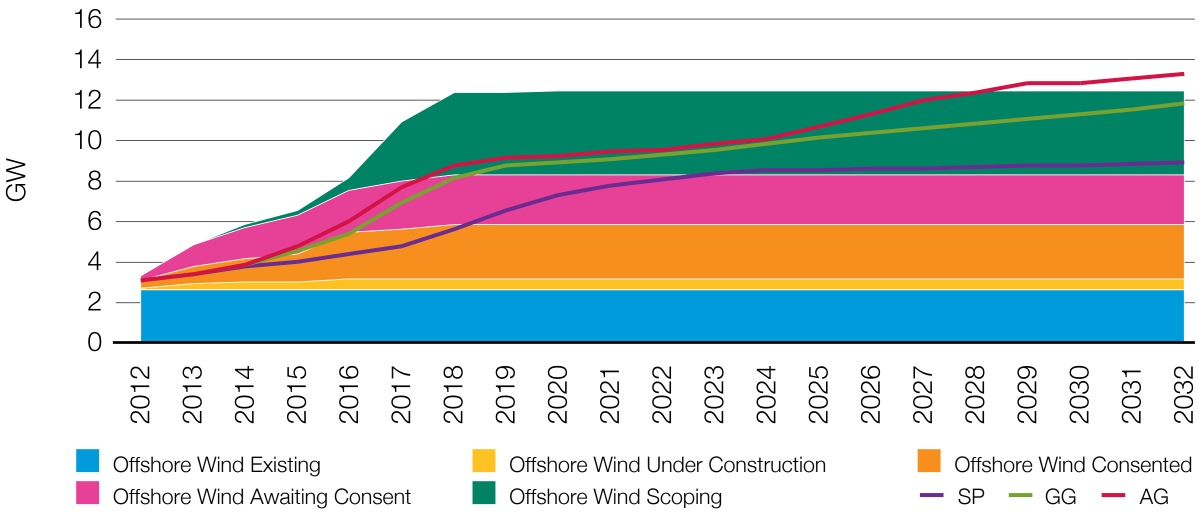
2.6 continued
Renewables

Figure 2.6.4:
Offshore projects under development
Source:
The Crown Estate



No	Project name	Developer	Indicative Capacity (MW)
Demo sites			
01	Gunfleet Sands 3	Dong	12
02	Aberdeen Bay European Offshore Wind Deployment Centre	Vattenfall Wind Power UK, and Aberdeen Renewable Energy Group (AREG)	Up to 100MW
03	Blyth offshore wind demons-tration site	New and Renewable Energy Centre (NAREC)	Up to 100MW
Round 2 sites			
04	Docking Shoal	Centrica	540
05	Westermost Rough	Dong	240
06	Humber Gateway	E.On	219
07	London Array 2	Dong, E.On	370
08	Race Bank	Centrica	620
09	Triton Knoll	RWE	900-1200
10	West of Duddon Sands	Iberdrola, Dong	389
11	Dudgeon	Warwick	560
Round 1 and 2 extension sites			
12	Burbo Bank Extension	Dong	234
13	Galloper Extension	SSE, RWE	504
14	Kentish Flats 2 Extension	Vattenfall	51
15	Walney Extension	Dong	750
Round 3 zones			
16	Moray Firth	EDP Renovaveis, Repsol	1300-1500
17	Firth of Forth	SSE, Fluor	3465
18	Dogger Bank	RWE, SSE, Statkraft, Statoil	9000-12800
19	Hornsea	Mainstream, Siemens, Dong	4000
20	East Anglia	Iberdrola, Vattenfall	7200
21	Rampion	E.On	665
22	Navitus Bay	Eneco, EDF	900-1200
23	Atlantic Array	RWE	1500
24	Irish Sea	Centrica, Dong	4185
Scottish territorial waters sites			
25	Argyll Array	Iberdrola	1800
26	Beatrice	SSE, Repsol	1000
27	Inch Cape	EDP Renovaveis, Repsol	905
28	Islay	SSE	690
29	Neart na Gaoithe	Mainstream	450

Figure 2.6.5:
Onshore wind contracted Vs scenarios



2.6.2 Onshore Wind

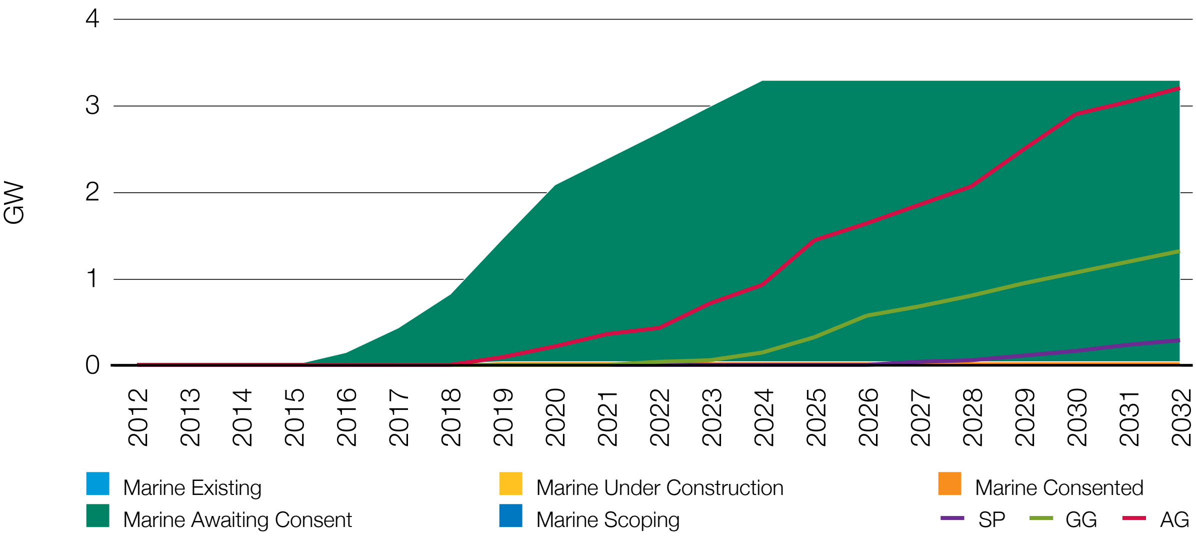
Figure 2.6.5 shows the current contracted position for onshore wind against the assumption for onshore wind generation under each of the three scenarios over the period to 2032.

In the Gone Green scenario the level of onshore wind required in 2020, if the scenario is to be met, is 9 GW. The level of onshore wind generation capacity that is either currently existing or under construction and due to connect to the system before 2020 is 3 GW. This therefore leaves a total of 6 GW (of the 9 GW that is contracted with a signed connection agreement and completion date before 2020) to be connected to the transmission system by this point. By the end of the period the Gone Green scenario shows an onshore wind generating capacity of 12 GW.

Slow Progression shows that the level of onshore wind in this scenario at 2020 is 7 GW. As mentioned above 3 GW of this generation capacity is either already connected to the transmission system or will be by 2020 and there is currently sufficient generation with the relevant consents to provide the additional 4 GW.

Accelerated Growth shows the same level of onshore wind generation capacity at 2020 as the Gone Green scenario reaching a total of 9 GW by this point and a total of 13.5 GW by the end of period.

Figure 2.6.6:
Marine contracted Vs scenarios



2.6.3 Marine

Figure 2.6.6 shows the current contracted position for marine (wave and tidal generation) against the requirement for marine generation under each of the three scenarios over the period to 2032.

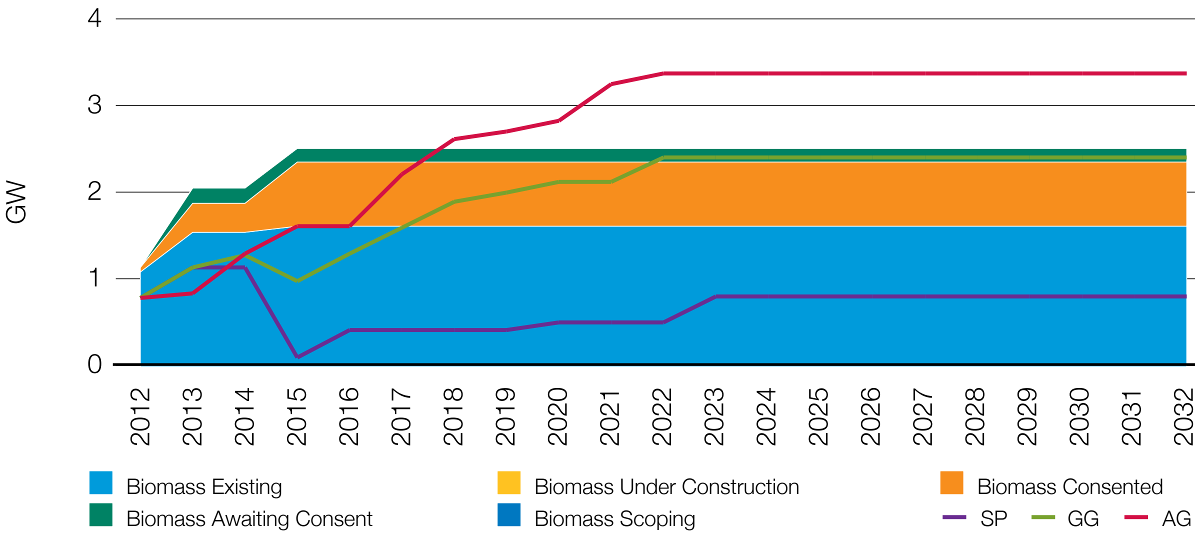
In the Gone Green scenario the level of marine generation capacity required in 2020, if the scenario is to be met, is 20 MW. The current level of marine generation capacity that is either existing or under construction is 7 MW, therefore leaving a total of 13 MW (of the 2 GW that is contracted with a signed connection agreement and completion date before 2020) to be connected to the transmission system by this point. By the end of the period the Gone Green scenario shows a marine generating capacity of around 1.3 GW.

In Slow Progression, marine is assumed to develop very slowly due to high costs, with minimal deployment by 2030.

In Accelerated Growth, there is a stronger build up of marine capacity, mainly post 2030.

Apart from the 7 MW of existing or under construction capacity all marine generation is currently in the scoping phase.

Figure 2.6.7:
Biomass contracted Vs scenarios



2.6.4 Biomass

Figure 2.6.7 shows the current contracted position for biomass capacity generation against the requirement for biomass generation under each of the three scenarios over the period to 2032.

The information in this chart is distorted slightly by the assumption in the scenarios that a significant proportion of any future biomass developments may be from the conversion of existing coal-fired capacity into a dedicated biomass generation. Assumptions around these conversions may not be reflected in the contracted background as the stations identified will currently be classified as fossil fuel stations.

Therefore, the graph shows under the contracted background there is currently only just enough generation with a signed connection agreement to meet the level of biomass generation for the Gone Green scenario and not enough to meet Accelerated Growth.

Under the Gone Green scenario the level of biomass generation capacity required in 2020, if the scenario is to be met, is approximately 2 GW. The current level of biomass generation capacity that is either existing or under construction is 1 GW therefore leaving a total of 1 GW (all of which is contracted with 0.7 GW having obtained consents) to be connected to the transmission system by this point. By the end of the period the Gone Green scenario shows a biomass generating capacity of approximately 2.4 GW.

In the Slow Progression scenario there is a limited level of biomass growth, with no further conversions apart from those already operational or currently being converted, and an assumption that these plants will close in 2016.

In Accelerated Growth there is strong growth in biomass with a total capacity of around 3.5 GW reached of which 1.5 GW is conversions.

2.7
Interconnectors

Our assumptions on the capacity of interconnectors with continental Europe vary between scenarios, although we have assumed the same level of interconnection capacity to Ireland across all three scenarios.

Ireland

In all years for Slow Progression (and to a lesser extent Gone Green) and in this decade for Accelerated Growth, we expect Great Britain to be a net exporter of electricity to Northern Ireland via the existing Moyle interconnector and to Ireland via the new East-West interconnector.

We anticipate that exports from GB will increase following the addition of the East-West interconnector, although some displacement of flows may take place. For Slow Progression we expect the level of Irish exports to increase slightly to 2030. Over the longer term in Gone Green and Accelerated Growth, we expect net exports from GB to gradually decline as Ireland develops more indigenous power generation, notably wind capacity and in the Accelerated Growth scenario, we anticipate imports from Ireland will exceed exports from GB by the 2020s.

Europe

- In the Slow Progression scenario there is limited new interconnection, with total GB capacity reaching 6.6 GW by 2030. We anticipate that GB will continue to be a net importer from continental Europe with imports increasing by 2030 in line with the gradual increase in interconnector capacity.
- In Gone Green the level of interconnection capacity increases to 8.6 GW by 2030. We expect both annual imports and exports to rise from current levels in line with the increase in interconnection capacity, with exports increasing markedly from the latter part of this decade onwards as renewable generation increases so that GB becomes a net exporter to the continent by the early 2020s.
- For Accelerated Growth the level of interconnection capacity increases significantly to 11.6 GW by 2030. We anticipate that the growth in renewable generation and increase in interconnection capacity will result in GB becoming a net exporter at the end of this decade with significant increases in exports and reductions in imports by 2030.

At times of peak electricity demand we assume that electricity will always be flowing from GB to Ireland (except for Accelerated Growth in the 2020s), but that the interconnectors between GB and continental Europe will be neither importing nor exporting at times of peak demand. The direction of flow of interconnectors is a key sensitivity that is assessed when analysing the development of the transmission network.

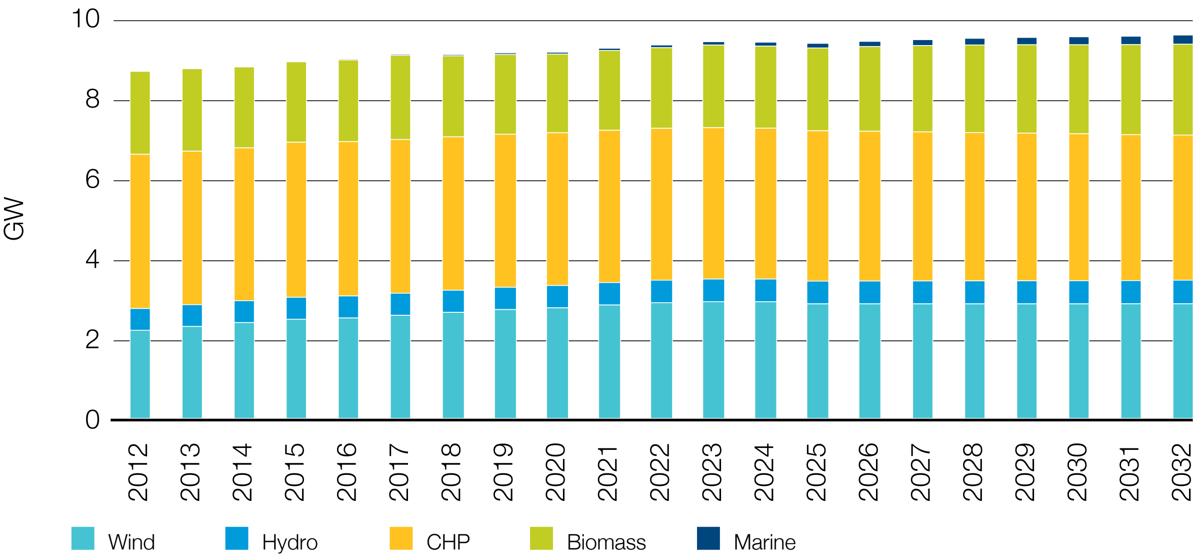
Further information on specific interconnector projects can be found in Chapter 3.

2.8 Non-GB generation

In addition to the interconnector capacity discussed in section 2.7, the scenarios also consider generation that may connect to the NETS from outside of Great Britain. There is currently 3 GW of wind generation in Ireland that has a signed connection agreement with us. There are, however, various governmental and regulatory challenges regarding these connection types. The potential impact of these connections on the transmission network and the potential integration with other developments in this region of the network is discussed in Chapter 3.

2.9
Embedded generation

Figure 2.9.1:
Slow progression embedded generation



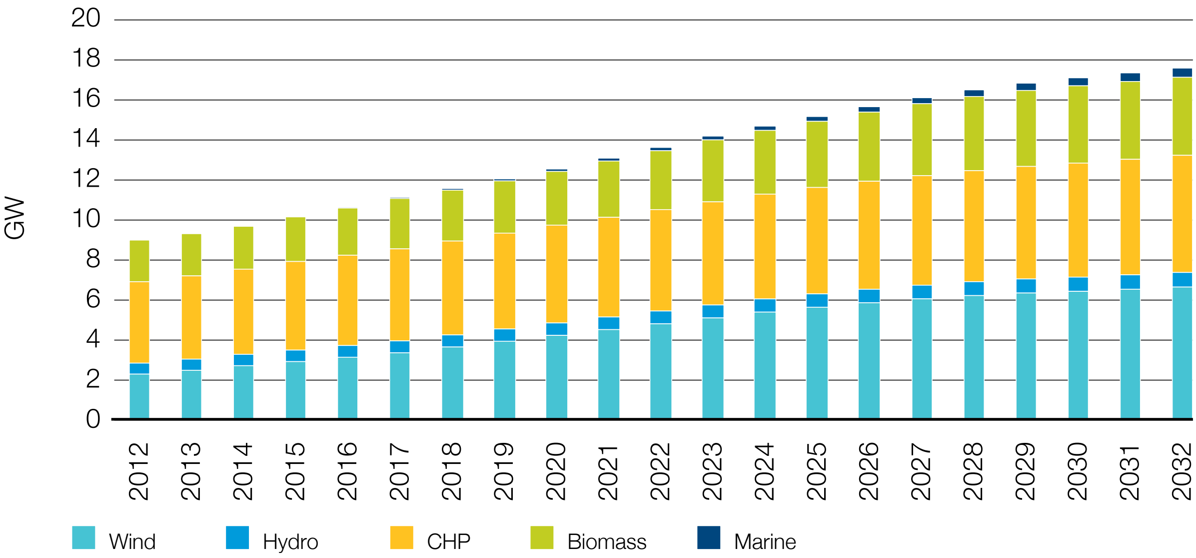
This section describes the embedded generation capacity mix for each of the scenarios as the analysis so far in this chapter has focused only on transmission connected generation capacity. A definition of what we class as 'embedded generation' can be found in section 2.4.1. In the assessment of transmission demand, this embedded generation is treated as 'negative demand' as outlined in section 2.3.

Renewable technologies are more likely to be connected to the distribution grid than fossil and nuclear generation as they are not sufficiently scalable in many locations to make a transmission connection economically viable. In England and Wales, embedded generation will generally consist of projects that are under 100 MW capacity in total. In Scottish Power's transmission area (South Scotland) this threshold falls to 30 MW and in Scottish Hydro Electric's transmission area (North Scotland) it is 10 MW.

2.9.1
Slow Progression

Figure 2.9.1 shows the embedded generation capacity mix for Slow Progression out to 2032. As can be seen from the graph the levels of embedded generation remain fairly static throughout the period with a net increase of only 0.90 GW over the whole period reflecting the underlying principles of this scenario.

Figure 2.9.2:
Gone green embedded generation

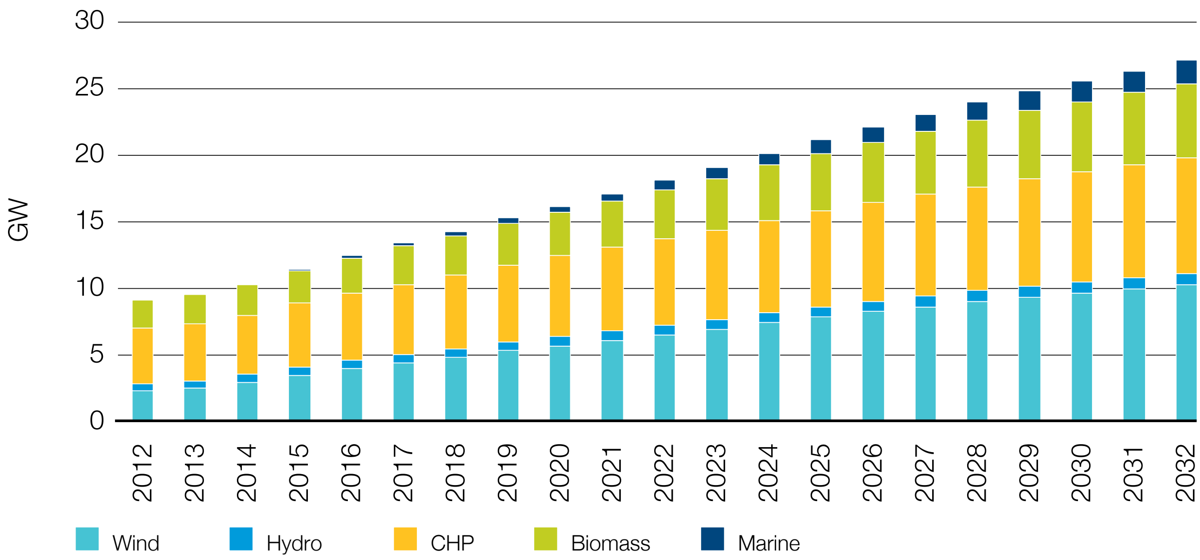


2.9.2 Gone Green

Figure 2.9.2 shows the embedded generation capacity mix for Gone Green which shows more robust levels of growth than Slow Progression, underpinned by higher fuel and carbon prices as well as some technology improvements.

- Embedded wind shows the largest increase in capacity over the period to 2032, showing a steady increase from 2.2 GW in 2012 to 6.6 GW by the end of the period. The vast majority of embedded wind will continue to be onshore due to the proposed size of the installations.
- Hydro shows a little growth over the period resulting in a total increase of 180 MW, continuing current installation rates.
- Combined Heat and Power (CHP) generation increases modestly over the period to 2032 resulting in a total increase of 1.8 GW on current levels.
- After wind, biomass is the second largest increase seen in this scenario with a total increase in generation capacity of 1.8 GW.
- Marine embedded generation shows an increase, albeit small, with a total increase over the period of 450 MW.

Figure 2.9.3:
Accelerated growth embedded generation

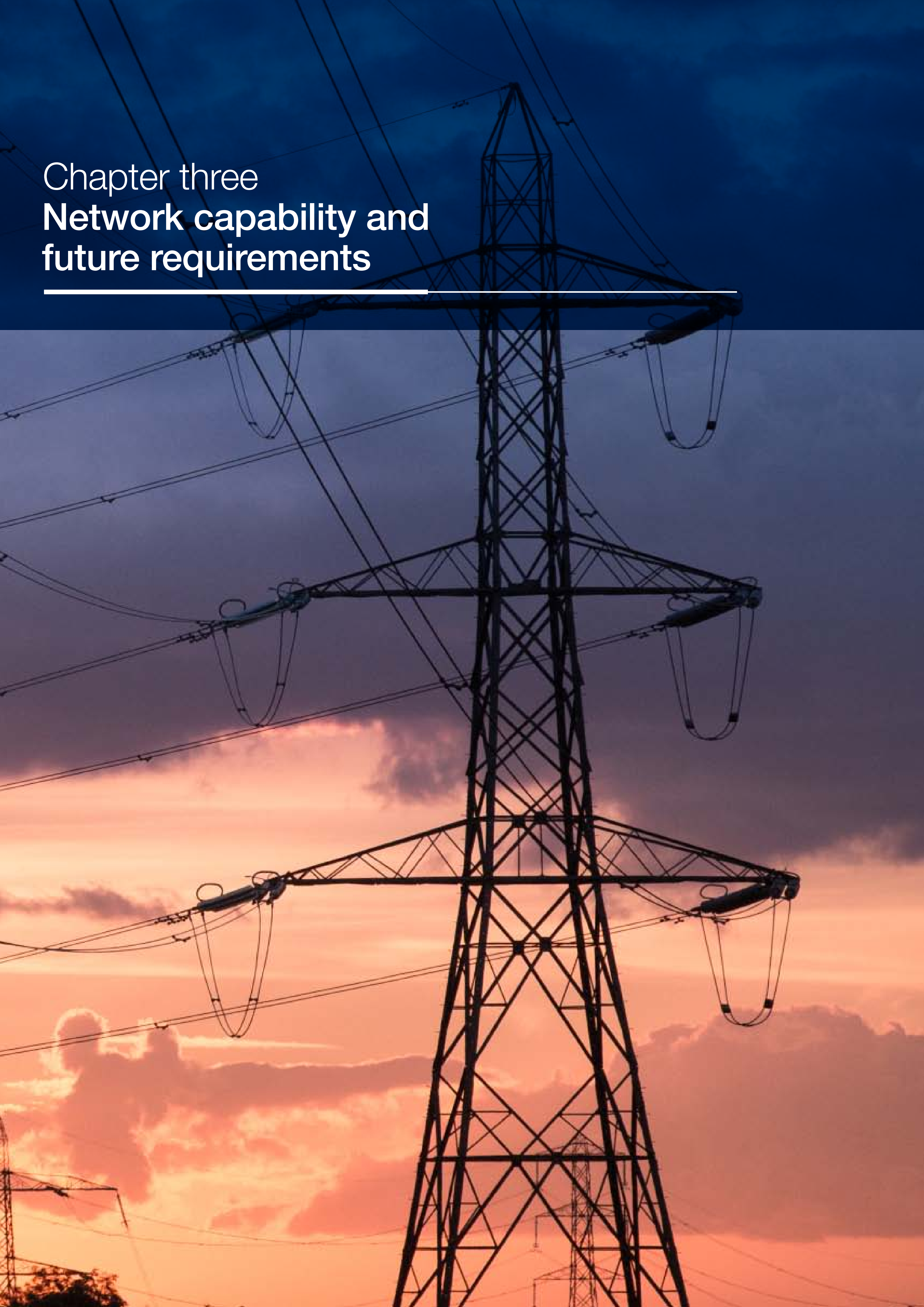


2.9.3 Accelerated Growth

Figure 2.9.3 illustrates the changing embedded generation capacity mix for Accelerated Growth. This scenario assumes higher fuel and carbon prices than the Gone Green scenario and some significant improvements to planning and technology which results in much stronger growth over the period to 2032.

- As in Gone Green wind sees the largest increase over the period with total growth of 7.9 GW.
- CHP and Biomass show the next largest increases following wind with total increases of 4.6 GW and 3.4 GW respectively.
- Hydro generation increases steadily from current levels of 500 MW to approximately 900 MW by the end of the period.
- Marine embedded generation capacity increases by a total of 1.7 GW over the period to 2032.

Chapter three
Network capability and future requirements



3.1
Introduction

This chapter details the potential future development of the National Electricity Transmission System (NETS), using the generation and demand scenarios outlined in Chapter 2. In this chapter you will find an assessment of the impact of future generation requirements at both a regional level and across the major system boundaries, using strategic modelling techniques. The information contained should assist in enabling you to identify future opportunities to connect to the transmission system under a range of plausible outcomes.

The boundary assessment sections include a summary of the generation that affects the boundary and an identification of the potential reinforcements required under each of the scenarios. This forms the bulk of this chapter.

In addition to the boundary assessment, this chapter also discusses the potential development of an integrated offshore network and the impact of increased levels of interconnection.

This chapter also outlines our proposed Network Development Policy (NDP) which defines how we will assess the need to progress wider transmission system reinforcements to meet the requirements of our customers in an economic and efficient manner. Please note that this is a National Grid Policy and applies to the onshore electricity transmission system in England & Wales.

3.2 Background

Historically the NETS has developed and adapted to significant change, notably the adoption by generators of new preferred energy sources, along with major structural changes and ongoing regulatory development. This context of evolution and adaptation is expected to continue and even accelerate in future years with increased levels of volatility and uncertainty. This chapter discusses the consequential impact on transmission system requirements and our proposals for dealing with this future.

Power station sites are largely determined by the location of their required fuel. In integrated utilities, generation and transmission may be planned together and the issues arising are those of developing economic and technically viable solutions for transferring power from remote locations. As described in Chapter 2 there is significant uncertainty surrounding the development of generation. To manage this challenge we have developed a flexible approach in developing future transmission capacity which allows us to respond to future requirements, whilst minimising the risk of asset stranding.

Transmission connected generation is distributed, with large groups of generation clustered around fuel sources such as coal mines, oil and gas terminals, transport corridors and sea access. These generators are supported by good electrical access to the large demand centres typically found in highly populated areas, such as London, Birmingham, Edinburgh, Manchester and Glasgow.

With the expected growth in nuclear power and wind as primary sources of energy, generation is expected to move increasingly towards the periphery of the system and more significantly towards the north of the system including Scotland. This gives rise to increased power transfers and associated reinforcements which in turn present substantial consent and technology challenges.

The development of the NETS is largely driven by generation development, which in the UK is governed by market forces. This has led to significantly increased volumes of developments proposed to meet the environmental targets, a number of which remain uncertain. The NETSO and Transmission Owners (TOs) deal with this uncertainty by considering a number of future scenarios, as described in Chapter 2, from which a range of indicative reinforcements emerge and upon which an assessment of appropriate reinforcement options and associated risks may be made.

When planning future transmission capacity any major transmission change can take many years to plan, construct and commission. Between the conception and delivery of a transmission scheme, changes in background assumptions can occur which may affect both the need and requirements of the scheme. By employing strategic planning the risks associated with background uncertainty are reduced.

3.3
Co-ordinating the overall transmission network

There are a number of design approaches that could be utilised to determine how best to design the transmission network in order to connect those parties seeking a transmission connection. By taking a holistic overview of transmission infrastructure design and allowing the sharing of transmission infrastructure between onshore and offshore projects where feasible, it will be possible to design and construct the wider transmission network to be flexible and adaptable for current and future energy requirements.

A co-ordinated approach to wider transmission design will ensure the resilience of the overall network onshore and offshore, and will assist with providing wider energy integration with our European neighbours. It will also allow greater energy diversity which could be called upon to meet the UK's electricity demand.

Ofgem is currently consulting on improvements to the offshore transmission regime to better support efficient network co-ordination. The Integrated Transmission Planning and Regulation (ITPR) review[1], announced in May 2012, will take this further in looking at how best to achieve co-ordination across multiple TOs and differing regulatory regimes for onshore, offshore and interconnectors.

1 www.ofgem.gov.uk/Networks/Trans/ElectTransPolicy/itpr/index.aspx

3.4
Design criteria for the NETS

The National Electricity Transmission System (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 safety, reliability and power quality is maintained. Thus any modification to the transmission system, for example new generation connections, external connections and/or changes to demand must satisfy the requirements of the SQSS. The SQSS is applicable to all GB transmission licensees including National Grid, Offshore Transmission Owners (OFTOs) and the Scottish Transmission Owners.

When applying this standard we utilise the scenarios as described in Chapter 2 in order to assess the performance of the NETS. Under these conditions and for defined secured events, for example faults and subsequent loss of transmission equipment, the standard specifies limits to the loss of power infeed from generating stations and loss of supply capacity at grid supply points. In addition, following such secured events no unacceptable conditions should occur. These conditions include: overloading of any primary transmission equipment, unacceptable voltage conditions and system instability as defined in the SQSS.

The security standard allows for connection design variations which in some cases may fall below the minimum required by application of the deterministic rules contained within these standards. This may typically occur when facilitating the connection of a particular type of equipment and may result in reduced transmission investment. Nevertheless this will be acceptable if system security and the safety of other customers are not compromised. Conversely, variations requiring additional transmission investment beyond the minimum required by the SQSS are also possible if an acceptable economic case can be made.

3.4.1
Generation, Demand and Interconnectors

In the case of generator connections, demand connections and interconnectors the standard requires that following prescribed faults and loss of circuits, loss of power infeed should be limited and unacceptable conditions avoided.

In the case of an individual generator or power station, loss of infeed is dependent upon factors such as generating unit size and the station connection arrangements. Loss of infeed may often be determined by inspection; however the risk of unacceptable conditions must be determined by detailed analysis. This requires the calculation of circuit flows, voltages and generator stability risk following faults and loss of circuits. The results of such calculations are presented later in this chapter.

These results identify critical circuits which can limit the transfer from an area. This process uses the concept of a boundary separating the area from the main system and crossing the connecting circuits. These circuits are then tripped individually (N-1) and in pairs (N-2) and the transfer capabilities of remaining boundary circuits is determined.

The boundary capability is then the highest power transfer that can be securely achieved. Capability is often limited by the flow on one specific circuit, and can change as conditions on the transmission system change. For example, where a change of generating pattern modifies the power sharing of the circuits then the capability and the limiting circuit can change as a consequence.

Where more than one generating station or source of power infeed is connected, a similar process is adopted. In such cases additional boundaries may be drawn in order to consider the export from the whole group. The number of boundaries required will depend on the topology of the network.

Interconnectors may operate in importing or exporting mode. This can contribute significantly to the variability of boundary transfer and so adds to the number of conditions to be considered. For example the French interconnector at Sellindge has the ability to export or import up to 2 GW thus requiring the transmission system to accommodate a variability of 4 GW. Increasing numbers of interconnectors are expected to connect to the system so range and volatility in system power flows will increase.

3.4.2 Offshore Co-ordination

When considering the connection of offshore generation, particularly from the large offshore wind zones, two different design methodologies have been considered.

- **Radial**
  Point-to-point connection from the offshore substation to a suitable onshore collector substation utilising currently available transmission technology.
- **Co-ordinated**
  A co-ordinated offshore and onshore design approach using AC cables and HVDC interconnection between offshore platforms and development zones using the anticipated future transmission technology. This is optimised for an economic and efficient holistic design.

Figure 3.4.1 shows how the different design strategies affect the design of an illustrative 4 GW offshore wind farm development. The network design is developed to be delivered in a staged approach to ensure timely investment and minimal stranding risk.

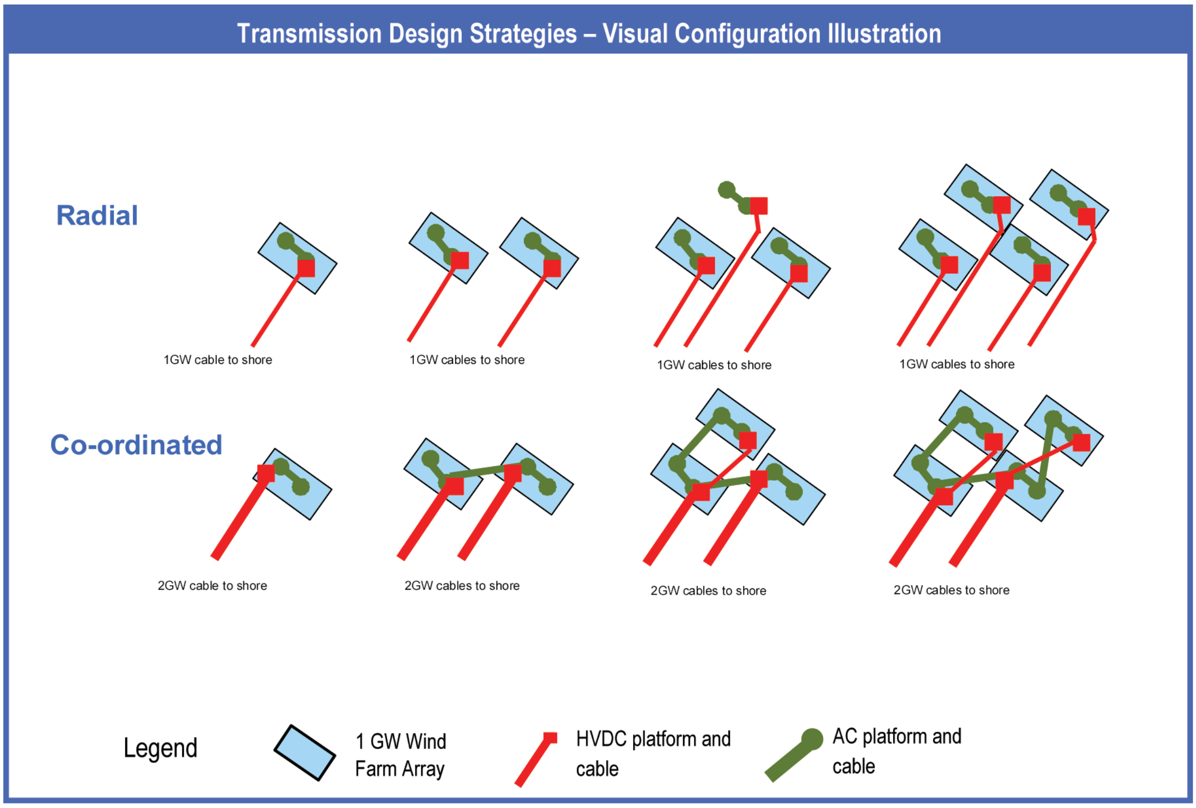
Interconnection between the offshore platforms occurs at a later stage (shown as stage 2 in Figure 3.4.1) of co-ordinated design strategy. In the event of the loss of any single offshore cable, the co-ordinated design strategy provides an alternative path for the power to the onshore collector substation. Whilst there may not be sufficient transmission capacity to accommodate the full generation output following an outage, there should be sufficient capacity to cover the majority of the output. If the onshore connection points are separate then the interconnection offshore offered by the co-ordinated design provides a transmission path between the two points. If at least one of the circuits is of HVDC construction – which is highly likely for the offshore connections – then the flow of power is directly controllable. This capability is very useful for network operation as both onshore and offshore power flows can be operationally controlled by the influence of the HVDC circuits.

In addition to local offshore interconnection, the larger offshore generation areas within reasonable distance of each other may offer interconnection opportunities and share onshore collector substation capacity.

3.4 continued
Design criteria for the NETS

HVDC systems, particularly the modem VSC designs, allow direct active control of the power passing from one end to the other of the DC circuits. When combined with offshore interconnection and parallel operation with the onshore system, the opportunity arises to benefit the onshore power flows. By boosting or restricting power flow along the offshore HVDC circuits power flow in the AC onshore system may be directed away from areas of electrical constraint. This active power control is a distinct advantage over the more traditionally passive AC circuits.

Figure 3.4.1:
Offshore transmission design strategy configurations

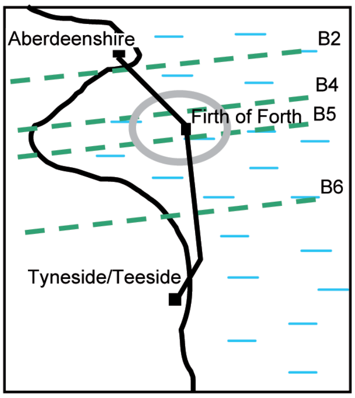


Co-ordinated designs have been developed for the large offshore wind farm projects where benefit can be identified. The primary areas where co-ordination has been proposed are the Crown Estate Round 3 zones of the Firth of Forth, Dogger Bank, Hornsea, East Anglia and the Irish Sea. These areas offer the distinct possibility of parallel co-ordination with the onshore system due to their size and location, since links between zones compare well with links to shore in terms of length and estimated cost. The smaller and more isolated projects along the South Coast, Scotland and from earlier connection rounds are generally not as attractive for co-ordination and are assumed to mostly remain of radial design. There is still the potential to connect smaller offshore wind farms in a co-ordinated manner, such as those off the North West Coast of England and the West Coast of Scotland. Where such opportunities are identified, they will be included in any evaluation as appropriate.

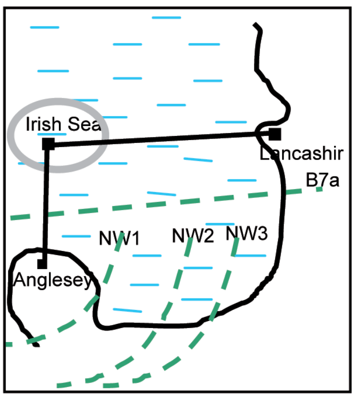
The co-ordination of the Round 3 zones mentioned above could conceptually look like Figure 3.4.2 and provide transmission boundary support to a number of major system boundaries as shown.

Figure 3.4.2:
Offshore Coordination

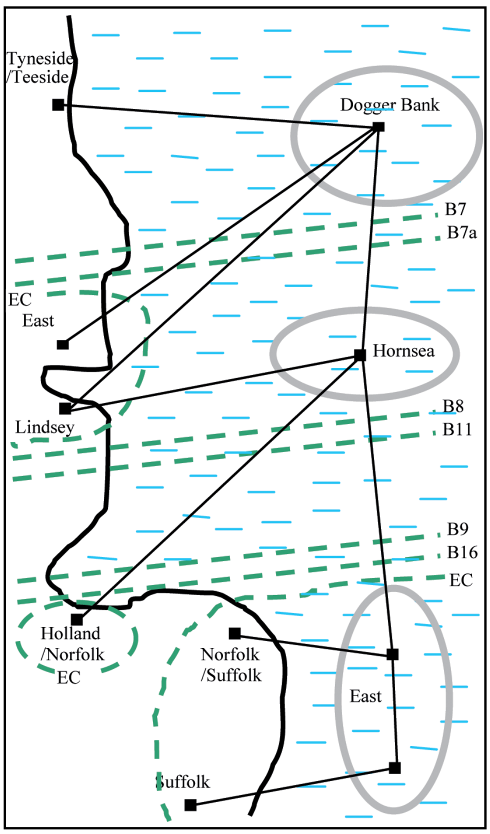
Firth of Forth



Irish Sea



East Coast



3.4 continued
Design criteria for the NETS

As part of the process of developing and implementing the connection of any offshore generation, each offshore connection will be subject to an inclusive optioneering process in order to evaluate design options in the wider context and to agree the optimum design. In this assessment there is a need to balance the conflicting priorities of network benefit, cost and build programme with their associated risks. Co-operative work between all the parties involved is the key to ensuring the timely delivery of an economic and appropriate network solution.

It is clear that the connection of large scale offshore generation will trigger major network reinforcements, either onshore or offshore and the required planning and construction programmes will be extensive. This is especially true when taking into account offshore supply chain considerations. It is expected that a significant amount of strategic pre-construction work will be required well ahead of actual implementation in order to manage the effective delivery of an overall efficient solution and it will be important that this vision is not lost whilst handling the local details of each individual connection.

The benefits of an integrated approach and a co-ordinated offshore design are further described in the National Grid and Crown Estate joint 'Offshore Transmission Network Feasibility Study'.[1]

The offshore integration adds north-south boundary capability to multiple boundaries in the north-east, near the Humber region and further south. During fault conditions it becomes possible to reduce the power injection into stressed areas from the offshore wind farms without constraining the offshore wind generation, assuming it is not operating at 100% output at this time.

To demonstrate the potential benefits of offshore wind farm co-ordination, the offshore to onshore cables installed as generators connect are treated as additional reinforcements. As with other reinforcements the capabilities under the Gone Green scenario are shown in the boundary requirement graphs. The particular connection points, and the order in which cables are installed will affect the released capability, and so the presented capabilities and the years in which they are released represent one possible solution. Offshore design assumptions have been made, based on the current Contracted Background, and ongoing discussions with developers, but remain subject to change.

3.4.3
National Grid Network Development Policy (NDP)

The most significant uncertainty facing the transmission network is the quantity, type and location of the connected generation and the extent and location of new interconnection to other systems. This problem is compounded by circumstances in which the lead-time for reinforcement of the wider transmission network is greater than the lead-time for the development of new generation projects.

In order to ensure that generation developers receive connection dates consistent with their expectations, the Connect and Manage access arrangements have removed the contractual link between new generation connection dates and the completion of wider system works. The connection of new generation is no longer reliant on the completion of wider works, but is subject to completion of connection and enabling works.

1 www.nationalgrid.com/uk/Electricity/OffshoreTransmission/OffshoreApproach/

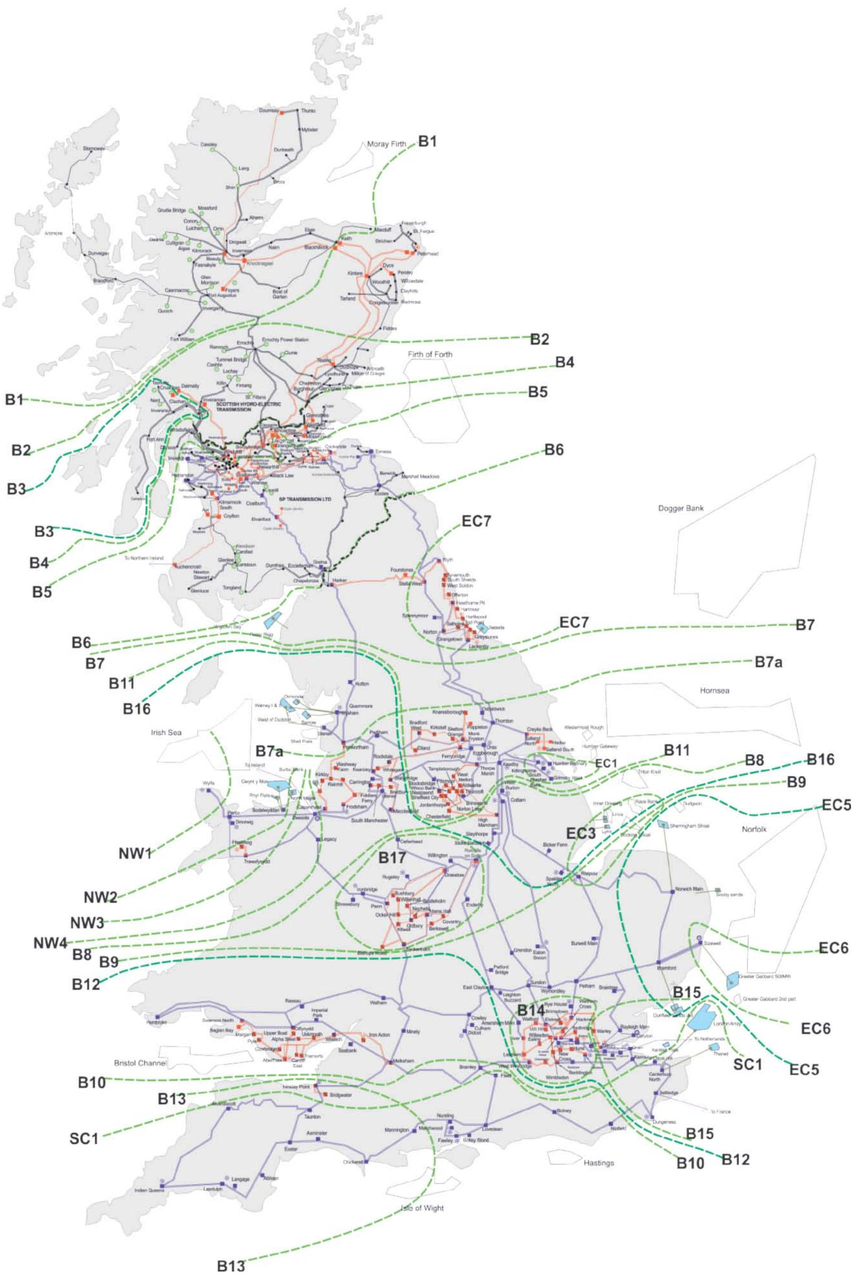
To manage this situation, we need to balance the risks of investing too early in wider transmission reinforcements, which include the risk of inefficient financing costs and an increased stranding risk, with the risks of investing too late, which include inefficient congestion costs. To this end, following discussions between Ofgem and our stakeholders, the Network Development Policy (NDP) is being developed to address these challenges.

The NDP sets out how we will make decisions about the choice and timing of wider transmission network reinforcements such that the network continues to be planned in an economic and efficient manner. This will involve making use of the available information to balance the risks of inefficient financing costs, stranding and inefficient congestion costs.

As required by NDP, a summary of the inputs and outputs of this process are published in this document.

Design criteria for the NETS

Figure 3.4.3:
Boundary map (England, Wales, Scotland and offshore)



3.4.4 Opportunity Identification and Boundary Discussion

The following sections present the results of boundary assessments across the NETS. Opportunities for new connections may be identified by looking at the prospective connections against the different scenarios and the associated transmission developments. Using the mapping for areas to affected boundaries provided in Table 3.4.1 below, the effect of a new connection on the transmission boundary requirements can be identified. A new connection could have an impact on any boundary but only those that could impede transmission access are marked as affected.

Table 3.4.1:
Mapping of geographic areas to boundaries

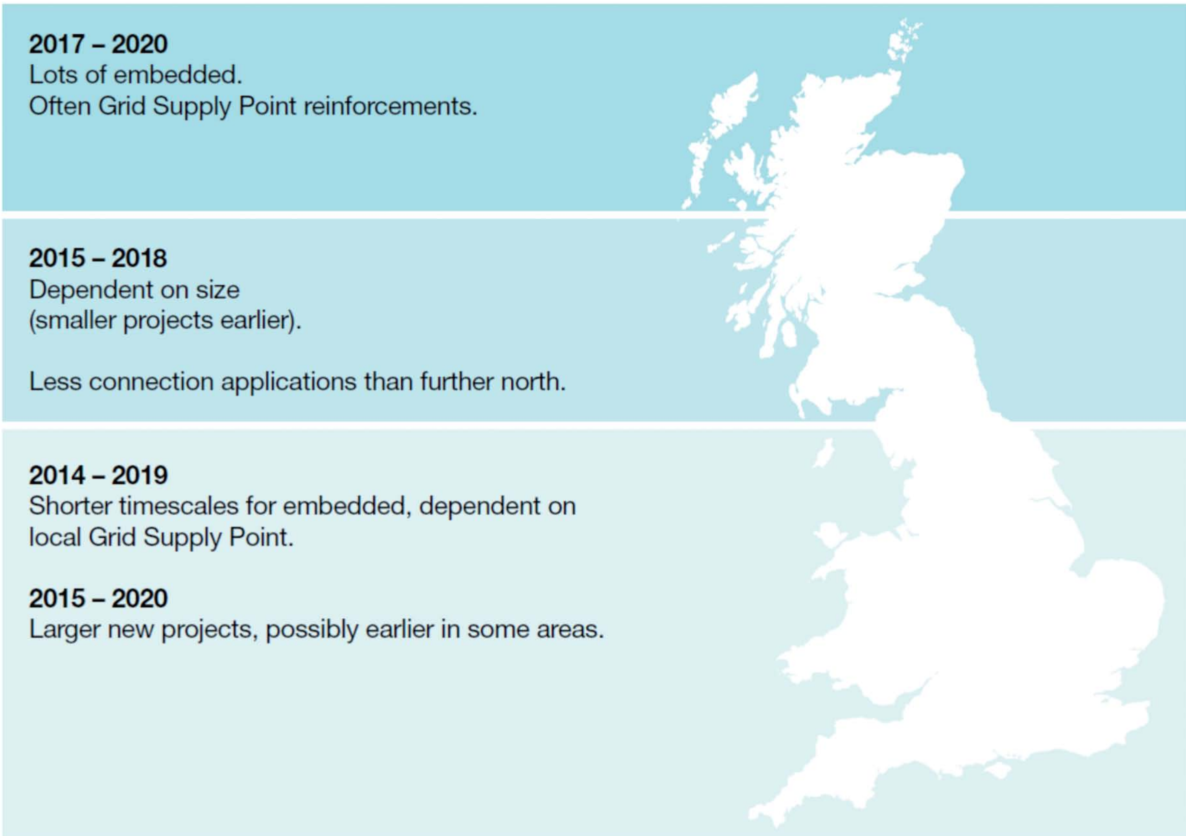
	Impacted Boundaries																										
Open Zone	**B1**	**B2**	**B3**	**B4**	**B5**	**B6**	**B7**	**B7a**	**B8**	**B9**	**B10**	**B11**	**B12**	**B14**	**B15**	**B16**	**B17**	**NW1**	**NW2**	**NW3**	**NW4**	**EC1**	**EC3**	**EC5**	**EC6**	**EC7**	**SC1**
Above B1	X	X	X	X	X	X	X	X				X				X										X	
B1 – B2		X	X	X	X	X	X	X				X				X										X	
Within B3			X	X	X	X	X	X				X				X										X	
B2 – B4				X	X	X	X	X				X				X										X	
B4 – B5					X	X	X	X				X				X										X	
B5 – B6						X	X	X				X				X										X	
B6 – B7							X	X	X			X				X										X	
B7 – B7a								X	X			X				X											
B7a – B8									X	X		X				X	X				X						
B8 – B9										X			X				X						X				
B9 – B10											X																X
Above B11								X	X			X				X											
Below B12											X		X	X	X												X
Within B13											X																X
Within B14											X		X	X	X												X
Within B15											X		X		X									X			X
Within B16								X	X			X				X						X	X				
Within B17									X	X			X			X	X										
Within NW1																		X									
NW1 – NW2																			X								
NW2 – NW3																			X	X	X						
NW3 – NW4									X	X											X						
Within EC1									X			X										X					
Within EC3										X						X							X	X			
Within EC5														X	X									X			X
Within EC6																									X		
Within EC7							X																			X	
Below SC1											X		X		X												X

3.4 continued
Design criteria for the NETS

As new connections can be reliant on transmission reinforcement and system access it can take some time to establish new connections. The following diagram (Figure 3.4.4) indicates the likely earliest connection dates for new generators. Further details of the connection process and updates of the contracted commercial position are available on the Electricity Transmission Networks Quarterly Update webpage.[1]

1 www.nationalgrid.com/uk/Electricity/GettingConnected/ContractedGenerationInformation/TNQuUpdate/

Figure 3.4.4:
Likely connection dates



3.4.5
Boundary Assessment in Transmission planning

The assessment of boundary capability is extended to the Main Interconnected Transmission System (MITS) by considering large system areas and using wider system boundaries. These are designed and drawn to highlight critical circuit groups where transfers may approach or exceed capabilities.

The SQSS specifies separate methodologies for local generator boundaries and wider system boundaries. The differences lie primarily in the level of generation and demand modelled, which in turn directly affect the level of boundary transfer to be accommodated:

- **Local Boundaries:** In the case of local boundaries the generation is set at its registered capacity and the local demand is set to that which may reasonably be expected to arise during the course of a year of operation. This process seeks to ensure that generation is unlikely to be constrained by local issues throughout the year.
- **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 results in a 'Planned Transfer' level. For each system boundary a transfer 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 both generator unavailability, and also weather variations.

Demand seen by the transmission system is affected by the level of embedded generation connected to the distribution system. The treatment of embedded generation when considering demand on the transmission system is detailed in section 2.3.

In this chapter assessments of transmission capability requirements are presented firstly for boundaries associated with local generation, and then for those boundaries associated with transfers in the wider system.

3.4.6
Wider Boundaries: Security and Economy Criteria

The 'Planned Transfer' of a boundary, as defined by the SQSS, is based on the balance of generation and demand on each side of the boundary. The 'Required Transfer' of a boundary is the Planned Transfer value with the addition of an allowance based on an empirical calculation defined in the SQSS.

The whole of this allowance is applied for single circuit losses and half of the allowance is applied for double circuit losses. Thus the value of the Required Transfer is lower for the more severe secured event. 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.

3.4 continued
Design criteria for the NETS

The Security Criterion: The object of this criterion is to ensure that demand can be supplied securely, without undue reliance on either intermittent generators or imports from interconnectors. The background is set by:

- Determining, from a ranking order, the conventional generation required to meet 120% of peak demand, based on the generation capacity.
- 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. Based on this the Planned and Required Transfer values are calculated in the usual way.

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. Further explanation can be found later in this chapter in section 3.8.6.

The Economy 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 Economy 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 usual way.

If a comparison with the Economy Criterion identifies additional reinforcements, a further CBA should be performed in order to refine the timing of a given investment. Further details can be found in the SQSS (Chapter 4, Appendix E).

In networks where there is a significant volume of renewable generation it is expected that the application of the Economy Criteria will require more transmission capacity than the Security Criteria to ensure there is sufficient transmission capacity. For some boundaries which may be defined by areas which are predominantly demand driven, or which rely on conventional generators, the security background may produce a higher boundary requirement.

The Required Transfers presented in this chapter are calculated for both criteria and the higher of the two is plotted on the appropriate graphs for future years.

3.4.7
Boundaries Assessed

- Local boundaries: These enclose smaller areas of the NETS that 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 covered by this document, the local boundaries presented enclose areas where significant growth in generation is expected and high boundary transfer is likely.

  In North Wales, NW1, NW2, NW3 are used to reflect the impact of new onshore wind, offshore wind and nuclear generation in the area.

  On the East Coast EC1, EC3, EC5, EC6 and EC7 are selected to reflect the impact of new generation, in particular new nuclear generation and large tranches of offshore wind.

- Wider Boundaries: Wider system boundaries are those that separate large areas of the GB transmission system containing significant quantities of demand and generation. These wider boundaries have been established and developed over time as being representative of the transmission system transfer capacity.

  These wider boundaries, namely B1 through to B17, are shown in Figure 3.4.2 below, and continue to evolve. In this document the seventeen boundaries have been extended to incorporate offshore projects, and two new wider boundaries, NW4 and B7a, have been added.

- In addition a sensitivity case is shown for the London B14 boundary, which is significantly influenced by the assumptions of power flow on the continental interconnectors. This sensitivity referred to as B14 (e) sets all interconnectors to maximum export capacity.

3.4.8
Presentation of Boundary Requirements and Reinforcements

When presenting the SQSS boundary requirements for each boundary and scenario, a graph is produced similar to the example shown on page 64 in Figure 3.4.5. Each scenario has its own boundary requirement plot from which the boundary needs can be identified. The boundary transmission capability is shown as a dashed line, starting with the current boundary capability and changing as the scenarios progress. Stepped, incremental changes in the boundary capability such as shown in Figure 3.4.5 at points A and B correspond with the delivery of reinforcements.

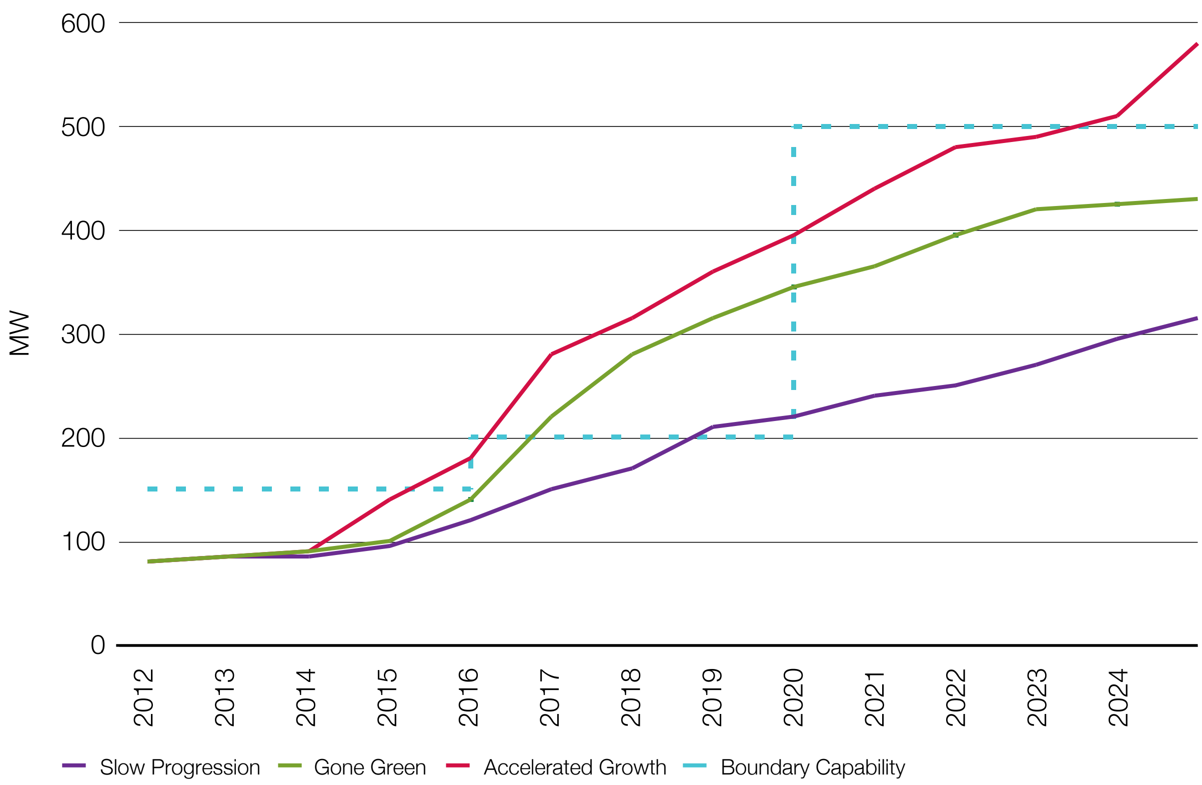
A number of reinforcements that are proposed in this document can provide capabilities over multiple boundaries. In these cases, the reinforcements will be given names for ease of reference in accordance to the boundary that first triggers the reinforcement. For example, the Eastern HVDC Link provides capability on B4, B6, B7 and B7a and is first by B6. It has been given a reference of B6-R03.

For consistency all graphs, tables, figurers and reinforcements within a certain boundary are also labelled with the relevant boundary codes e.g “EC” for East Coast and NW for North Wales etc...

Design criteria for the NETS

To ensure consistency with previous years the boundary capability graphs are shown in MW, this is something that will be reviewed going forwards. The offshore co-ordination benefits develop in conjunction with offshore generation connections so multiple dates are presented, corresponding to the incremental steps of development. A full list of the generation in the contracted background is included in Appendix F.

Figure 3.4.5:
Example boundary graph



3.5
East Coast local boundaries

3.5.1
East Coast and East Anglia – Overview

The East Coast and East Anglia transmission network consists of a number of generation groups (Humber, Walpole area and the East Anglia Loop) which are connected to the main 400kV system via a strong 400kV spine from Creyke Beck to Keadby, Walpole and Pelham. There are strong ties from Bramford to the London demand centre via Pelham.

A large volume of new generation is forecast to connect to this region in the period to 2032, including significant volumes of offshore wind farms and nuclear generation as well as some CCGT projects.

The North Sea has some of the largest proposed offshore generation projects, including the Dogger Bank, East Anglia and Hornsea Crown Estate Round 3 lease zones. Overall there is the potential for over 25 GW of capacity from the East Coast and East Anglia (from the Crown Estate Round 1, 2 and 3 offshore wind farm projects). Connection of these 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 Humber group consists of two 400kV double circuit lines running from Keadby towards Killingholme, with one continuing towards Grimsby on the coast. These lines gather outputs of power stations on the south side of the Humber and feed it into the main system at Keadby. From Keadby transmission circuits link the East Coast system via West Burton, Spalding North, and Bicker Fen into Walpole. There are also significant generation connections at West Burton and Keadby, adding to the power requiring throughput. The transmission system in the Walpole area is characterised by a double circuit ring that links Walpole, Norwich, Bramford, Pelham and Burwell Main substations. Pelham substation provides additional interconnection between the East Anglia region and other sections of the transmission system.

In addition to the offshore wind, the North East could see the connection of multiple HVDC links from Scotland and an interconnector with Norway. These would result in increased power injections into this region.

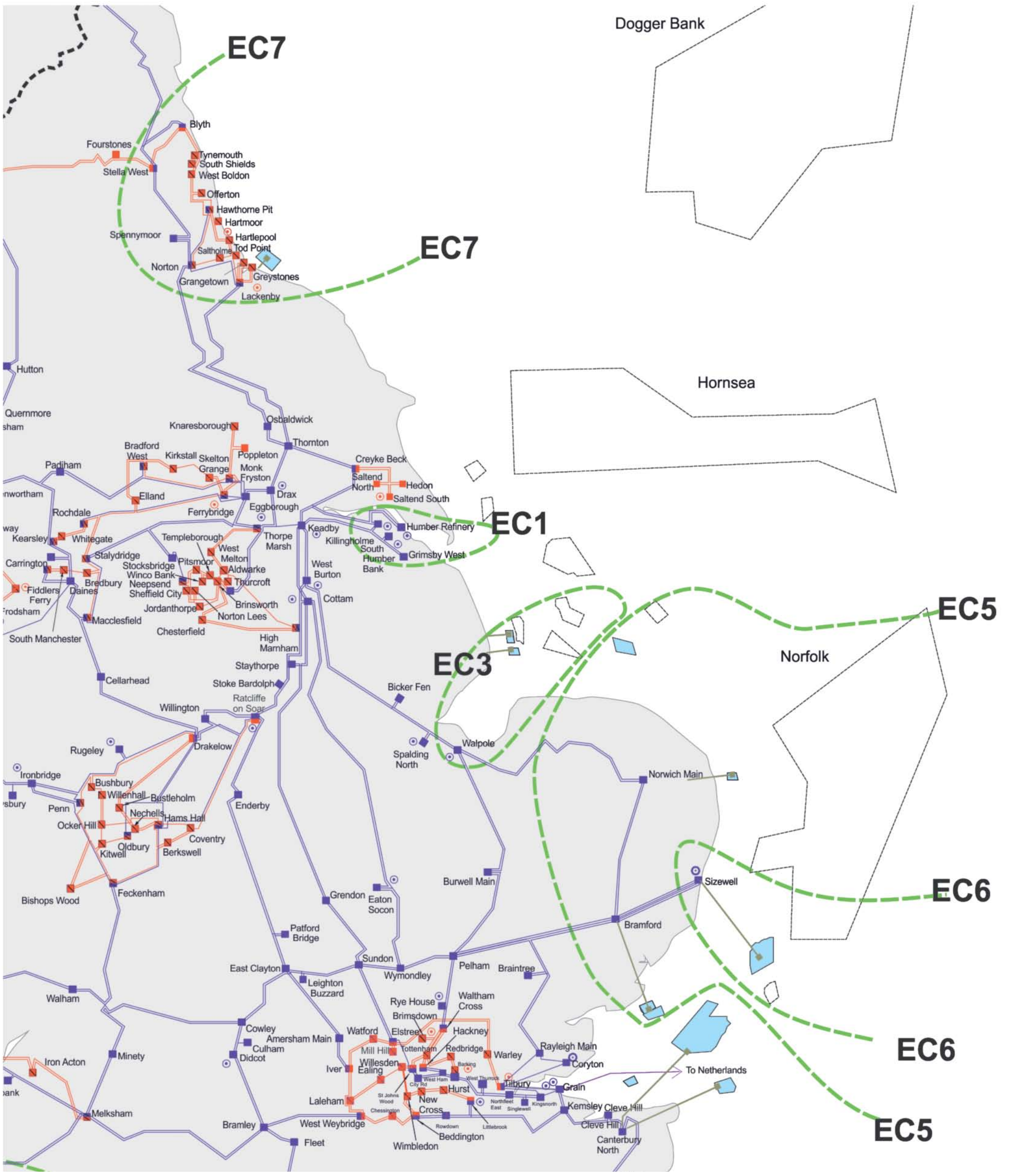
With multiple connection points to the proposed offshore wind farm zones, it is possible to provide transmission capacity by interconnecting within those zones. In determining the optimum network solution, consideration is given to both offshore and onshore elements.

3.5.2
Overview of Boundaries

Many of the local transmission limitations for the East Coast and East Anglia Network can be described with five local boundaries, EC1, EC3, EC5, EC6 and EC7. These boundaries are treated as local boundaries as described in Section 3.4.2. A large volume of new generation is considered within our scenarios to connect in this region, including nuclear generation, CCGT projects and the aforementioned offshore wind farms.

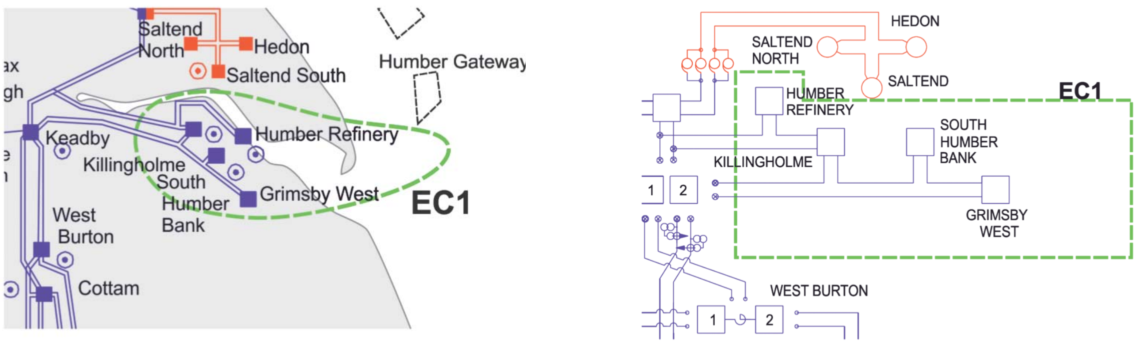
East Coast local boundaries

Figure EC1:
Geographical representation of East Coast Boundaries



3.5.3
Boundary EC1

Figure EC1.1:
Geographical and single line representation of boundary EC1



Boundary EC1 is an enclosed local boundary consisting of four circuits that export power to the Keadby substation. There are two circuits from Killingholme and two single circuits from Humber Refinery and Grimsby West. The maximum power transfer out of this boundary is currently 5.5 GW which is limited by thermal overloads on the boundary circuit.

Generation Background
The Humber area enclosed by boundary EC1 is already a congested area of the transmission system with 4 GW of CCGT generators connected. Consideration is given to the connection of up to 6 GW of new offshore wind generation which will potentially outstrip any potential closures. Currently there is 2 GW of contracted offshore wind generation to connect in this area.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 68 in Table EC1.1. As the circuits around the boundary are already of high ratings the scope for increasing the rating of the existing circuits are limited and most of the possible reinforcements involve the creation of new circuits.

3.5 continued
East Coast local boundaries

Table EC1.1:
List of potential reinforcement projects in the EC1 boundary

Ref	Reinforcement	Works Description
EC1-R01	Killingholme South substation, new transmission route to West Burton and Humber circuits reconductoring	Creation of a new 400kV substation at Killingholme South, construction of new transmission route to West Burton and reconductoring of Humber circuits
OS Link-01	Teesside–Humber Offshore Integration	Offshore integration between Teesside, Dogger Bank offshore project and Humber region
OS Link-02	Humber–Wash Offshore Integration	Offshore integration between Humber, Dogger Bank, Hornsea offshore project and Wash region

Boundary Discussion and Opportunities
Figure EC1.2 below shows the required transfer. The figure also shows the reinforcements selected and the benefit from the co-ordinated offshore links to meet increasing requirements. Table EC1.2 identifies the selected reinforcements, and their timing, for each scenario.

Figure EC1.2:
Generation background and capability for boundary EC1

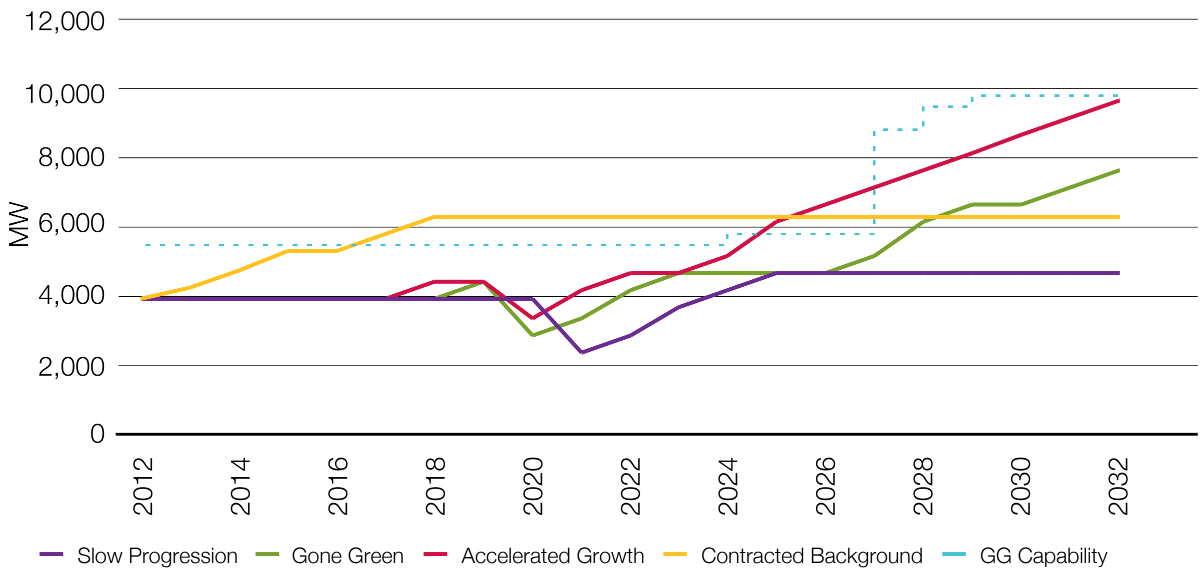


Table EC1.2:
Reinforcement date for each scenario

Scheme	SP	GG	AG	C
EC1-R01	–	2027	2024	–
OS Link-01	–	2027 2028	2024 2025	–
OS Link-02	–	2024 2029	2023 2025 2026 2028 2030	–

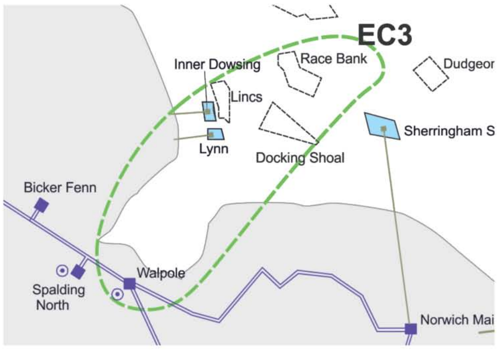
Currently, OHL thermal ratings are given for winter, spring/autumn and summer. These take into account the different ambient temperatures across the year, so give fixed ratings for each season. There is currently a trial underway of circuit monitoring – and potentially control – equipment in the Humber region, known as the Humber SmartZone. This equipment monitors the temperature of OHLs and allows the use of dynamic ratings, potentially increasing the thermal rating available. This area has been chosen for the trial due to the costal nature of the area and the expectation of future high levels of wind generation.

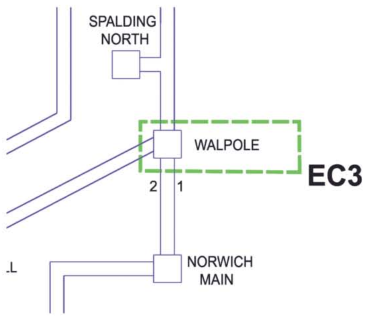
Under the Gone Green scenario the increase in capability seen in 2024 and 2029 is provided by the potential co-ordinated offshore link OS Link-R02 as some of the offshore wind connects. The required transfer across the boundary starts to ramp up after 2026 due to the connection of further offshore wind farms. From 2027, reinforcement EC1-R01 could provide sufficient capacity to satisfy the future scenario requirements. This reinforcement could be deferred a year later due to pure boundary requirements but the 2027 date is driven by the substation build required to facilitate the connection of further offshore wind. Under the Accelerated Growth scenario reinforcement EC1-R01 could be required from 2024. The order of the reinforcements identified in Table EC1.2 is subject to further evaluation.

3.5 continued
East Coast local boundaries

3.5.4
Boundary EC3

Figure EC3.1:
Geographical and single line representation of boundary EC3





Boundary EC3 is a local boundary surrounding the Walpole substation and includes the six 400kV circuits out of Walpole. These are two single circuits from Walpole to Bicker Fen and Walpole to Spalding North and two double circuits from Walpole to Norwich and Walpole to Burwell Main. Walpole is a critical substation in supporting significant generation connections, high demand and high network power flows along the East Coast network which is why it is selected for local boundary assessment. The most significant fault outage condition overloads the boundary circuit and limits the transfer capability of EC3 to about 3.2 GW. The current main constraint on the boundary is the high power flow through the Walpole–Bicker Fen and Walpole–Spalding North circuits due to the high volume of generation within EC1 and its surrounding areas.

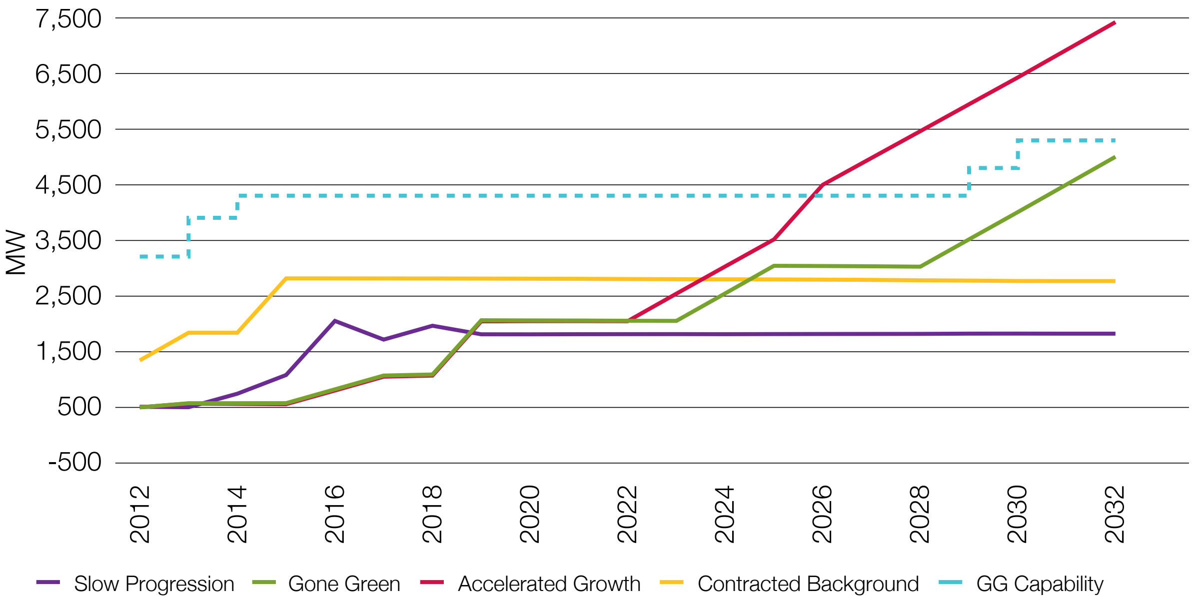
Generation Background
There is just over 1 GW of CCGT generation connected within the boundary. There is the potential for up to 7 GW of new generation including future generation including offshore wind and new CCGT. The scenarios cover a range of first connection dates and potential volumes for this generation. Currently there is 1.2 GW of offshore wind generation contracted to connect in this area.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 71 in Table EC3.1.

Table EC3.1:
List of potential reinforcement projects in the EC3 boundary

Ref	Reinforcement	Works Description
EC3-R01	Walpole rebuild	Construction of a new 400kV substation at Walpole to improve its thermal capability (5000A)
EC5-R08	New substation near Walpole and new transmission route	Establish a new 400KV double busbar substation near Walpole with connection to the existing substation. New transmission route from the new near Walpole substation to the Cottam–Eaton Socon circuits
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region

Figure EC3.2:
Generation and capability for boundary EC3



3.5 continued
East Coast local boundaries

Boundary Discussion and Opportunities
Figure EC3.2 on page 71 shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the proposed reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for all scenarios is detailed in Table EC3.2.

Table EC3.2:
Reinforcement date for each scenario

Scheme	SP	GG	AG	C
EC5-R08	–	–	2024	2020[1]
OS Link-03	–	2029	2026 2027 2028	–

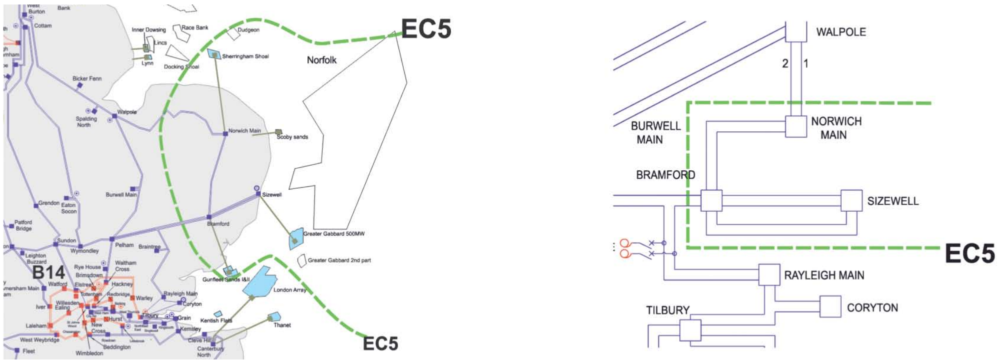
The current capability meets the present boundary requirement and continues to do so throughout the period under the Slow Progression and Contracted Backgrounds. The Gone Green scenario shows a modest increase in generation until 2018. The sharp increases from 2019 are due to expected new CCGT connecting within the boundary, and then the connection of Round 3 offshore wind farms from 2024. The existing capability of the EC3 boundary is sufficient to sustain the generation levels under the Gone Green scenario, with growth in the required transfer in later years catered for by capability provided through coordinating the offshore design, and as a result no additional reinforcements are required until 2032.

Although the Accelerated Growth scenario shows rapid growth in required transfer after 2023, this is met by scheme EC5-R08, which is triggered for boundary EC5 before it is required for this boundary. The same scheme is also triggered for the Contracted Background by EC5.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.5.5
Boundary EC5

Figure EC5.1:
Geographical and single line representation of boundary EC5



The local boundary EC5 covers part of East Anglia including the substations of Norwich, Bramford and Sizewell. Crossing the boundary is a double circuit between Norwich–Walpole and single circuits from Bramford to Pelham and Bramford to Braintree. There is enough generation enclosed by the boundary so that power is typically exported out of the enclosed zone, predominantly along the southern circuits. The maximum boundary transfer capability is currently limited to 3.4 GW due to thermal overload on the boundary circuits.

Generation Background
There is about 2.6 GW of generation connected within this boundary, including nuclear, gas and some offshore wind. The scenarios consider a full range of potential offshore wind, nuclear and new CCGT. Currently there is 8.3 GW of offshore wind generation contracted to connect in this area.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 74 in Table EC5.1. A number of reinforcements have been identified in order to increase this boundary's capability.

Boundary Discussion and Opportunities
Figure EC5.2 on page 75 shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table EC5.2.

East Coast local boundaries

Table EC5.1:
List of potential reinforcement projects in the EC5 boundary

Ref	Reinforcement	Works Description
EC5-R01	Rayleigh–Coryton–Tilbury	Reconductor the existing circuit which runs from Rayleigh Main–Coryton South–Tilbury with higher rated conductor
EC5-R02	Bramford–Twinstead	New transmission route from Bramford to the Twinstead Tee Point creating Bramford–Pelham and Bramford–Braintree–Rayleigh Main double circuits. Installation of an MSC at Barking[1]
EC5-R03	Braintree–Rayleigh	Reconductoring of the Braintree–Rayleigh circuits with higher rated conductor
EC5-R04	Walpole QBs	Installation of two Quadrature Boosters at Walpole in the Bramford–Norwich circuits
B14(e)-R06	Elstree–Waltham Cross–Tilbury uprate	Uprating Elstree, Tilbury and Warley substation from 275kV to 400kV and uprating the 275kV circuits to 400kV
EC5-R05	Kemsley–Littlebrook–Rowdown	Reconductor the existing double circuit which runs from Kemsley–Littlebrook–Rowdown with higher rated conductor
EC5-R06	Rayleigh Reactor	Install one 225 MVAr reactor at Rayleigh Main.
EC5-R07	Tilbury–Kingsnorth– Northfleet East	Reconductor the existing double circuit which runs from Tilbury–Kingsnorth–Northfleet East with higher rated conductor
EC5-R08	New substation near Walpole and new transmission route	Establish a new 400KV double busbar substation near Walpole with connection to the existing substation. New transmission route from the new near Walpole substation to the Cottam–Eaton Socon circuits

This boundary has sufficient capability until 2027 under the Slow Progression scenario. But under other scenarios and the Contracted Background, a number of reinforcements are required to facilitate the rapid increase in forecasted generation. The increase in generation until 2022 is mainly due to the addition of wind generation from the offshore wind farms off the Norfolk coast. The increase in transfer in this boundary in later years is due to commissioning of nuclear generation within this zone which occurs in all scenarios.

1 www.bramford-twinstead.co.uk/

Figure EC5.2:
Generation and capability for boundary EC5

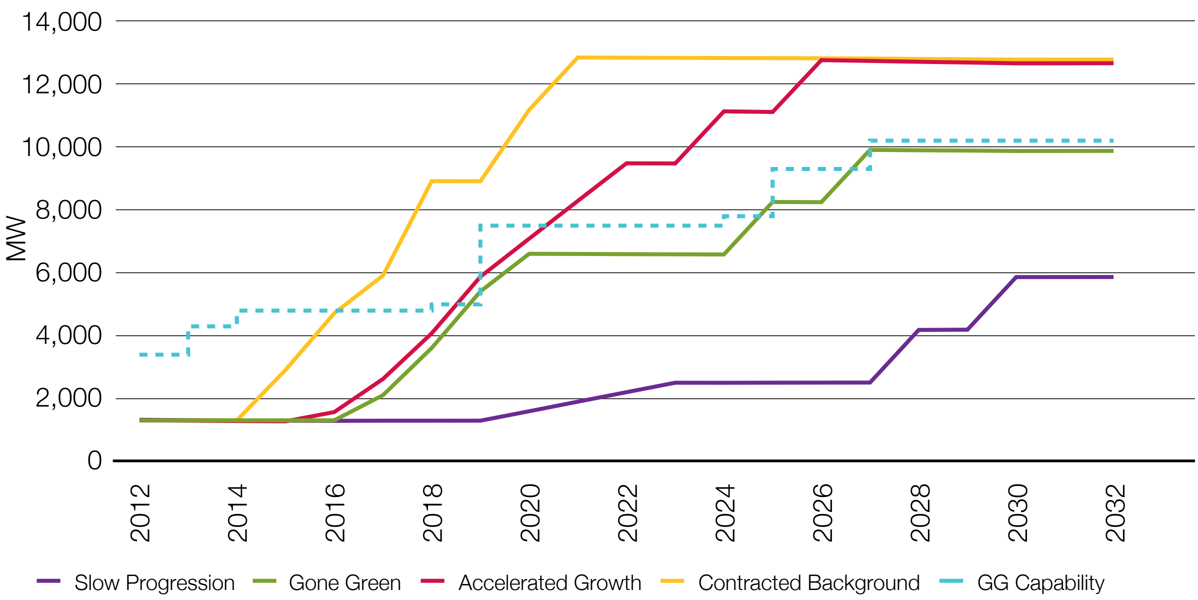


Table EC5.2
Reinforcement date for each scenario

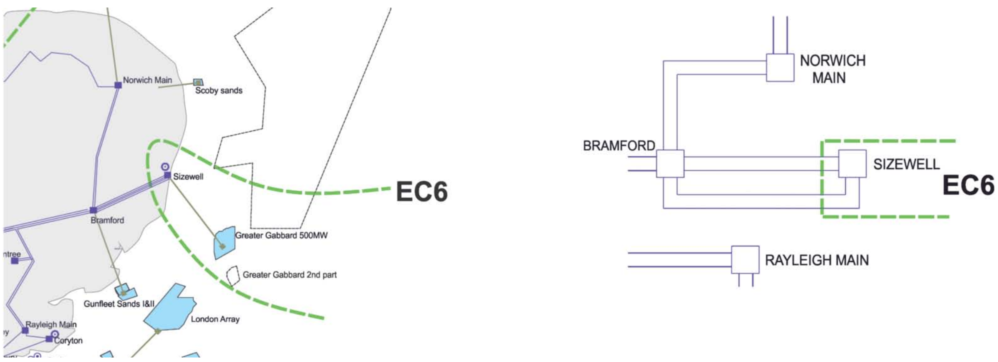
Scheme	SP	GG	AG	C
EC5-R01	2028	2018	2018	2015
EC5-R02	2027	2019	2019	2017
EC5-R03	2030	2019	2019	2017
EC5-R04	–	2025	2021	2018
B14(e)-R06	–	2024	2019	2018
EC5-R05	–	2027	2022	2018
EC5-R06	–	2027	2022	2018
EC5-R07	–	2027	2022	2018
EC5-R08	–	–	2024	2020

Under the Gone Green and Accelerated Growth Scenario, between 2018 and 2019 reinforcements (EC5-R01–EC5-R03) are required to facilitate new connections. In the Contracted Background not only are the reinforcements required earlier but additional reinforcements are required, including reconductoring and voltage uprating schemes by 2018 (EC5-R05–EC5-R07). Alternatively in addition to (EC5-R02) it may be possible to utilise offshore interconnection between the East Anglia and Hornsea Round 3 zones to provide capacity out of the zone, but this would need considering in conjunction with requirements for other boundaries further north and further studies on the wider impact will be required to properly assess this option.

3.5 continued
East Coast local boundaries

3.5.6
Boundary EC6

Figure EC6.1:
Geographical and single line representation of boundary EC6



Local boundary EC6 is located within boundary EC5 and is currently defined by four circuits from Sizewell to Bramford. The current transfer capability is limited to 2.4 GW due to the circuit ratings and configuration that was designed to meet only the needs of the current nuclear generation at Sizewell.

Generation Background
Presently there is 1.7 GW of installed generation capacity connected within EC6. In addition to the existing generation, the scenarios consider new nuclear and offshore wind generation.

Potential Reinforcements
The connection of significant new generation within EC6 will require the reinforcements identified in Table EC6.1 below. The EC6-R02 Bramford reinforcement has also been included in this list, as without it the export from this boundary would be restricted by limited substation configuration capability.

Table EC6.1:
List of potential reinforcement projects in the EC6 boundary

Ref	Reinforcement	Works Description
EC6-R01	Bramford–Sizewell Reconductoring	Reconductoring of the existing Bramford – Sizewell circuits with higher rated conductor
EC6-R02	Bramford substation	Rebuild the Bramford substation

Boundary Discussion and Opportunities
Figure EC6.2 below shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table EC6.2.

Figure EC6.2:
Generation and capability for boundary EC6

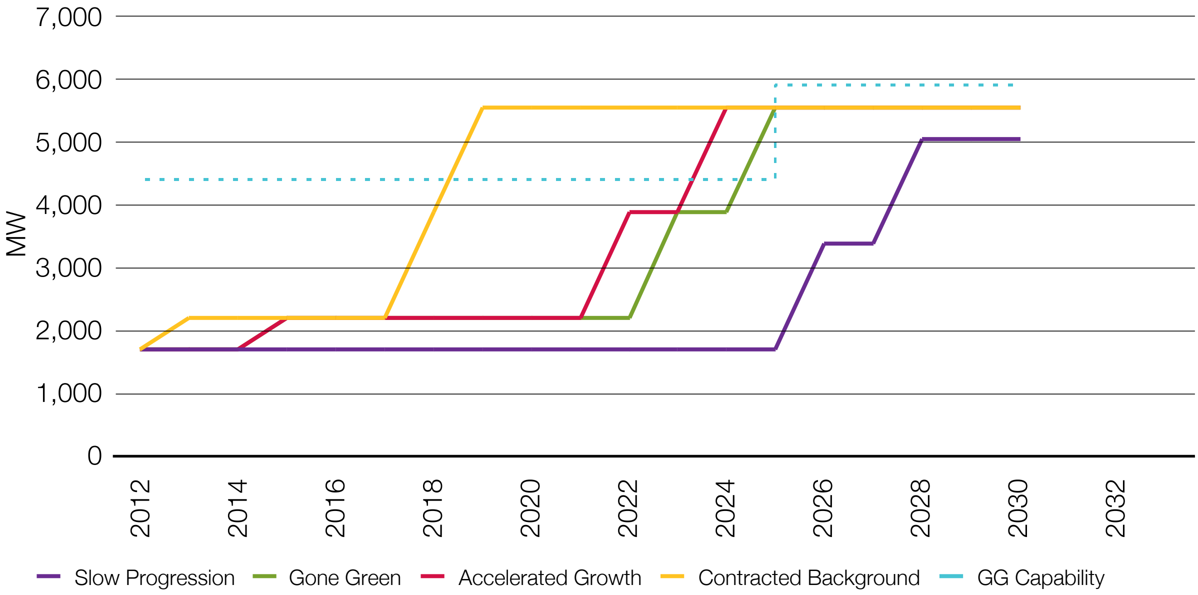


Table EC6.2:
Reinforcement date for each scenario

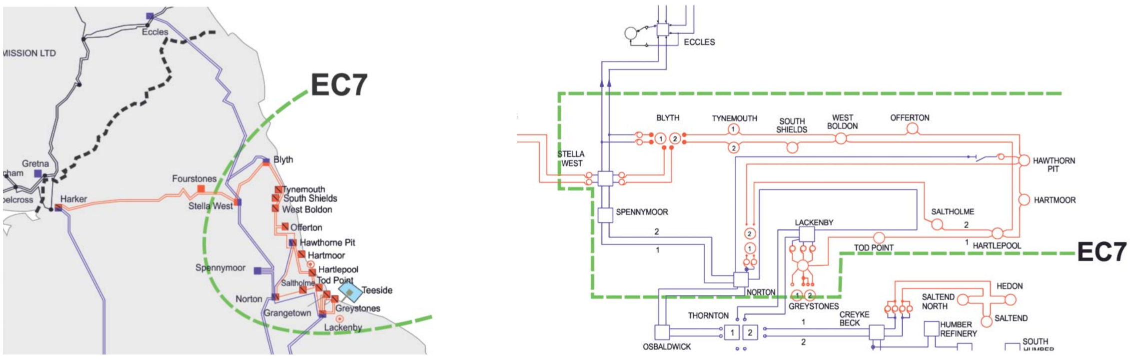
Scheme	SP	GG	AG	C
EC6-R01	2028	2027	2026	2021
EC6-R02	2028	2027	2026	2021

Due to the highly localised nature of the boundary, connection of a large nuclear generator will present a step change in the required transfer, requiring reinforcement EC6-R01.

3.5 continued
East Coast local boundaries

3.5.7
Boundary EC7

Figure EC7.1:
Geographical and single line representation of boundary EC7



Boundary EC7 is a local boundary that encompasses the north east of England. One of the principle Anglo-Scottish double circuits – the 400kV Eccles–Stella West–Norton circuit – passes through the region. At the southern end a second 400kV circuit crosses the boundary. Within the boundary is a ring of predominantly 275kV circuits that serve local demand and carry any generation surplus in the area to the 400kV circuits. This area is constrained by north-south power flows and is traditionally characterised as an exporting area, with the 400kV circuits at the southern end of the boundary liable to limit transfers.

Generation Background
Current generation capacity within the boundary consists of 1.2 GW of nuclear generation and 0.2 GW of other smaller thermal plant. New offshore wind generation is likely to have the biggest impact on this boundary. There is currently 4 GW of offshore wind in the contracted background within this boundary.

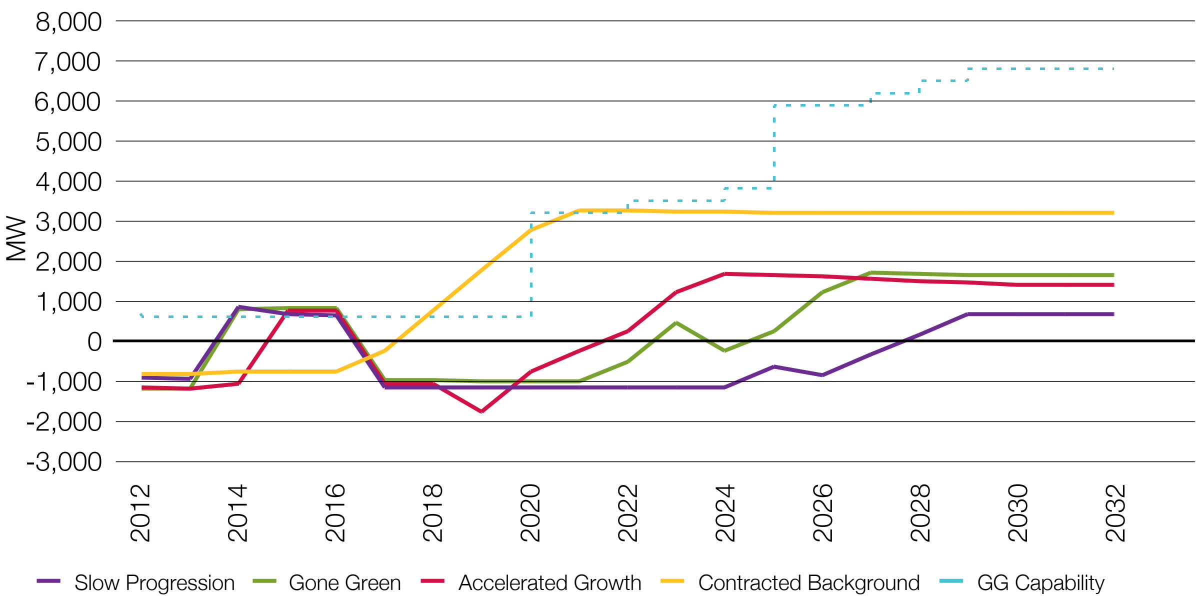
A future HVDC interconnector to Norway may also connect into the north-east coast and is currently contracted for connection in 2018 at 1.4 GW capacity.

Potential Reinforcements
The connection of new generation within EC7 will trigger the boundary reinforcements identified in Table EC7.1 on page 79. As much of the transmission within the EC 7 boundary is of 275kV construction, it is of lower capability than the 400kV sections so large new connections will require upgrading of the local 275kV part of the system. Those local reinforcements that are heavily dependent on the location of specific generation projects are not listed here.

Table EC7.1:
List of potential reinforcement projects in the EC7 boundary

Ref	Reinforcement	Works Description
EC7-R01	Uprate Saltholme to Lackenby to 400kV	New 400kV Tod Point and Saltholme substations and uprate of the 275kV circuits between them to operate at 400kV
B7a-R03	Yorkshire Lines reconductoring to 3100MVA	Reconductoring the existing two double circuits crossing B7 in the East, Lackenby–Thornton and Norton–Osbaldwick with higher rated conductor
OS Link-01	Teesside–Humber Offshore Integration	Offshore integration between Teesside, Dogger Bank offshore project and Humber region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region

Figure EC7.2:
Generation background and capability for boundary EC7



East Coast local boundaries

Table EC7.2:
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B7a-R03	–	2020[1]	2018[1]	2018[1]
EC7-R01	2028	2025	2022	2019
OS Link-01	2025 2027	2022 2024 2027 2028	2019 2021 2024 2025 2027 2029	2017 2019
OS Link-03	–	2029	2026 2028 2028	–

1 Reinforcement date triggered by prior requirement from boundary in the reference name

Boundary Discussion and Opportunities
Figure EC7.2 shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the proposed reinforcements for the Gone Green scenario. North to south power flows load the circuits to an extent that additional export capability is difficult to realise. Suggested timing and selection of the reinforcements for all scenarios is detailed in Table EC7.2.

This region currently imports but the trend in future years is for the region to move to export as new offshore wind generation connects. The export capability is insufficient to meet the predicted future required transfers for all the scenarios other than Slow Progression. For the Contracted background there is a need for significant reinforcement, but the B7a-R03 Yorkshire lines reconductoring, triggered by B7a and the Saltholme upgrade EC7-R01 will more than meet this requirement. If the existing nuclear power station closes then this will free additional boundary capacity.

There is the potential for additional offshore HVDC links from Scotland to connect into this region, potentially adding 4 GW or more of cross-boundary through flow.

The Norwegian interconnector will place an additional 1.4 GW of boundary capacity requirement when importing to GB but at the default scenario assumption of no interconnector power flow, there is not additional stressing of the boundary.

3.6
North Wales local boundaries

3.6.1
North Wales – Overview

The onshore network in North Wales comprises a 400kV circuit ring that connects Pentir, Deeside and Trawsfynydd substations. A 400kV double circuit spur crossing the Menai Strait and running the length of Anglesey connects the nuclear power station at Wylfa to Pentir. A short 275kV double circuit cable spur from Pentir connects Dinorwig pumped storage power station. In addition, a 275kV spur traverses north of Trawsfynydd to Ffestiniog pumped storage power station. The majority of this circuitry is of double circuit tower construction. However, only a single 400kV circuit connects Pentir to Trawsfynydd within the Snowdonia National Park, which is the main limiting factor for capacity in this area.

There are a number of existing offshore wind farm sites connected to North Wales. There is also a Round 3 zone that has been designated 4.2 GW of wind generation. The geographical spread of the zone and the limited transmission capacity in North Wales means it is preferable to connect the northern part of the Round 3 zone to the East at Stanah on the English north-west coast. This provides increased connection diversity for the wind farm and reduces the transmission requirements in North Wales. With multiple connection points to the proposed offshore wind farm zone, it is possible to provide transmission capacity by interconnecting within this zone. In determining the optimum network solution consideration is given to both offshore and onshore elements. Section 2.8 refers to the potential for generation outside of GB to connect to the GB network, some of which could be accommodated within this region.

With a combination of AC and HVDC through an integrated offshore network it is possible to manage power flows by means of the HVDC control systems. The offshore integration adds boundary capability for both the North Wales boundaries (NW1 to NW4) and boundary B7a. North to South power flows are assisted by the additional circuitry allowing additional power injection into North Wales and during fault conditions in North Wales it becomes possible to reduce the North Wales power injection from the offshore wind farm.

3.6.2
Overview of Boundaries

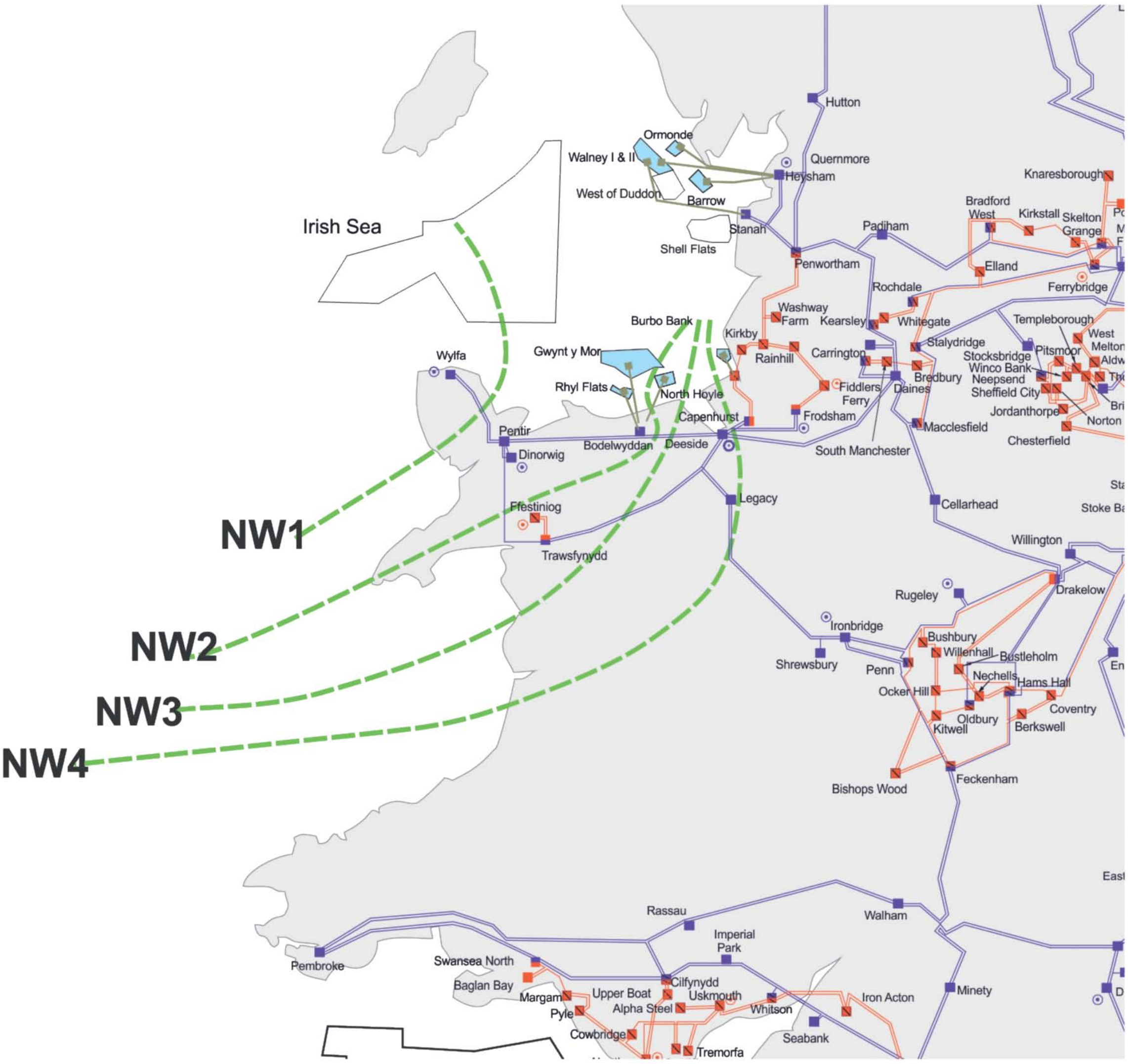
The transmission system within North Wales is described by 4 nested boundaries, NW1, NW2, NW3 and NW4. Boundary NW1, NW2 and NW3 are treated as local boundaries as described in Section 3.4. Boundary NW4 is treated as a wider boundary as also described in Section 3.4.

The boundaries of North Wales extend into the waters of the Irish Sea and include the offshore projects of the Irish Sea Round 3 zone and Round 1 and 2 projects. Some of the transmission development options for this region include the potential for new offshore transmission circuits.

Additional information is available on the National Grid major projects website www.nationalgrid.com/uk/Electricity/MajorProjects/NorthWalesConnection

3.6 continued
North Wales local boundaries

Figure NW1:
Geographical representation of North Wales boundaries



3.6.3
Boundary NW1

Figure NW1.1:
Geographical and single line representation of boundary NW1

Boundary NW1 is a local boundary which crosses the one double circuit on Anglesey between Wylfa and Pentir substations. Transfer capability is limited by the infeed loss risk criterion which is currently 1,320 MW and will change to 1,800 MW from April 2014. If the infeed loss risk criterion is exceeded, reinforcement of the boundary will be necessary by means of adding a new transmission route across the boundary.

Generation Background
With the pending closure of the existing nuclear power station at Wylfa there will be no transmission connected generation on Anglesey until some of the potential new generation connects. The scenarios consider a range of offshore wind, new nuclear, CCGT and other generation. There is currently 2 GW of additional offshore wind and 3.6 GW of nuclear in the contracted background within this boundary.

Potential Reinforcements
A number of potential reinforcements have been identified for the NW1 boundary to meet the required power transfers. Table NW1.1 on page 84 lists possible reinforcements that have been identified for boundary NW1 including a brief works description.

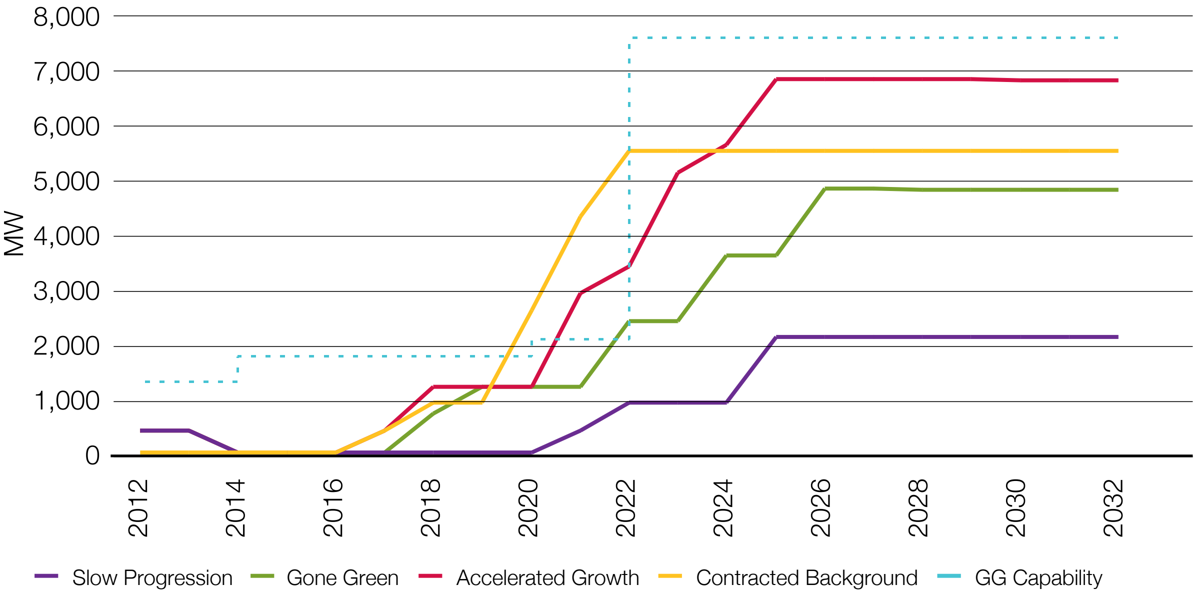
North Wales local boundaries

Table NW1.1:
List of potential reinforcement projects in the NW1 boundary

Ref	Reinforcement	Works Description
NW1-R01	New 400 kV, Pentir–Wylfa Transmission Route	New Pentir–Wylfa 400kV transmission route. Extension of Pentir 400 kV substation. Modifications to Wylfa substation
B8-R01	Wylfa–Pembroke HVDC Link	2 GW HVDC link from Wylfa/Irish Sea to Pembroke. Substation extension at Wylfa and Pembroke.
OS-Link-05	Lancashire–North Wales Offshore Integration	Offshore Integration between North Wales, Irish Sea offshore projects and Lancashire region

Boundary Discussion and Opportunities
Figure NW1.2 below shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table NW1.2.

Figure NW1.2:
Generation and capability for boundary NW1



1 Reinforcement date triggered by prior requirement from boundary in the reference name

Table NW1.2:
Selection and timing of reinforcements

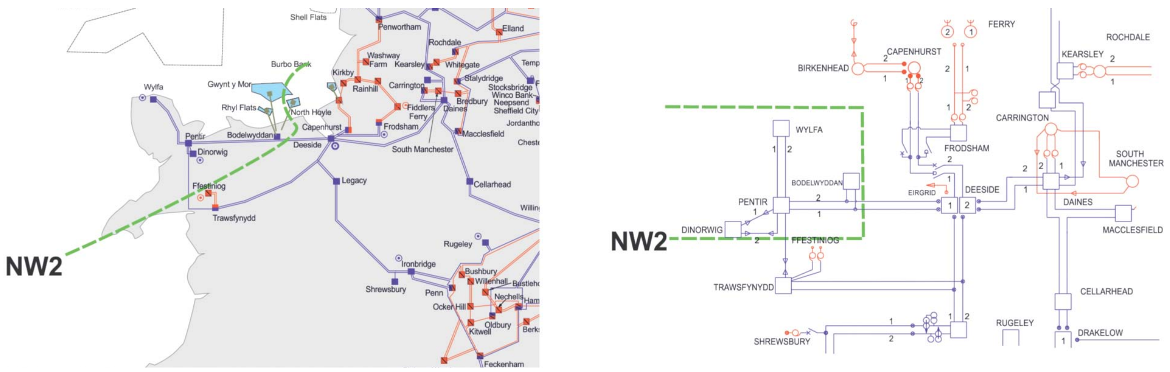
Ref	SP	GG	AG	C
NW1-R01[1]	2025	2022	2021	2020
B8-R01	–	2022[1]	2022[1]	2019[1]
OS-Link-05	–	2020	2019	2019

The total generation in boundary NW1 is lower than the 1,800 MW infeed loss risk criterion until 2022 for the Gone Green scenario, 2021 in Accelerated Growth, 2020 for the Contracted Background and 2025 for Slow Progression. The proposed integration of the Round 3 Irish Sea offshore wind farm will improve the boundary capability as soon as both the Anglesey and Lancashire connections are established together with the interconnecting circuitry. In the Contracted Background, Gone Green and Accelerated Growth scenarios a Wylfa–Pembroke HVDC link will provide the additional capacity. The suggested date shown for this reinforcement is triggered by the requirements for B8 and other boundaries before the NW1 need.

3.6 continued
North Wales local boundaries

3.6.4
Boundary NW2

Figure NW2.1:
Geographical and single line representation of boundary NW2



This local boundary bisects the North Wales mainland close to Anglesey and as shown in Figure NW2.1 above, crosses through the Pentir to Deeside 400kV double circuit and Pentir to Trawsfynydd 400kV single circuit. The existing boundary capability is 1.5 GW, limited by the single circuit connecting Pentir to Trawsfynydd.

Generation Background

Dinorwig pumped storage power station is located behind this boundary. The treatment of this has a significant impact on the necessary reinforcements as it has a wide operating range from full demand (pumping) to full generation. For this analysis, we have assumed less than the maximum capacity for the pump storage units. Across the scenarios a range of offshore wind and new nuclear is considered in addition to the non-GB generation developments identified in section 2.8. There is currently 3 GW of additional offshore wind and 3.6 GW of new nuclear in the contracted background within this boundary.

Potential Reinforcements

A number of potential reinforcements up until 2032 are listed in Table NW2.1 on page 87. The existing circuits are already of high ratings and possible reinforcements proposed are construction of new circuits.

Table NW2.1:
List of potential reinforcement projects in the NW2 boundary

Ref	Reinforcement	Works Description
NW2-R01	Establish second Pentir–Trawsfynydd 400 kV New Transmission Route	Reconductor existing 132 kV circuit for operation at 400 kV Reconfiguration and extension of Pentir 400 kV substation Increase the capacity of the cable link crossing the Glaslyn Estuary to be equivalent to the overhead line
B8-R01	Wylfa–Pembroke HVDC Link	2 GW HVDC link from Wylfa/Irish Sea to Pembroke. substation extension at Wylfa and Pembroke
NW3-R03	Pentir–Deeside Reconductoring	Reconductor the Pentir–Deeside existing double circuit with higher rated conductor
OS-Link-05	Lancashire–North Wales Offshore Integration	Offshore Integration between North Wales, Irish Sea offshore projects and Lancashire region
OS Link-04	Irish Integration	Controllable interconnection between the Irish Wind circuits connecting to Pentir and Pembroke

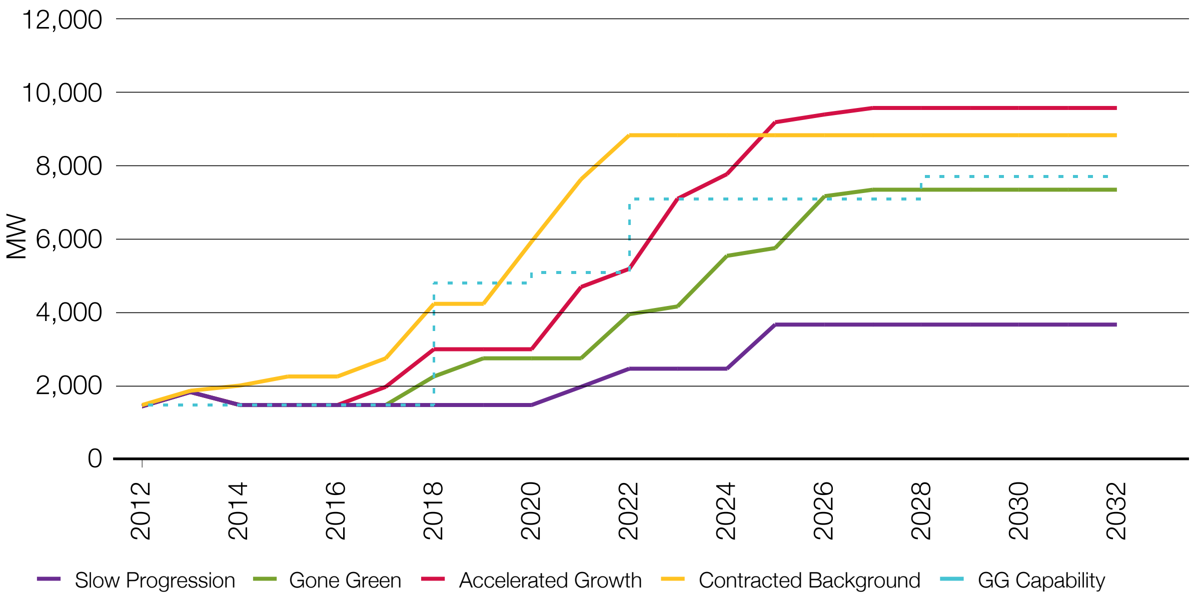
Boundary Discussion and Opportunities
Figure NW2.2 on page 89 shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table NW2.2.

Table NW2.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
NW2-R01	2021	2018	2018	2018
NW3-R03	–	–	2024	2020
B8-R01	–	2022	2022	2019
OS-Link-05	–	2020[1]	2019	2019
OS Link-04	–	2028	2025	2018

North Wales local boundaries

Figure NW2.2:
Generation and capability for boundary NW2



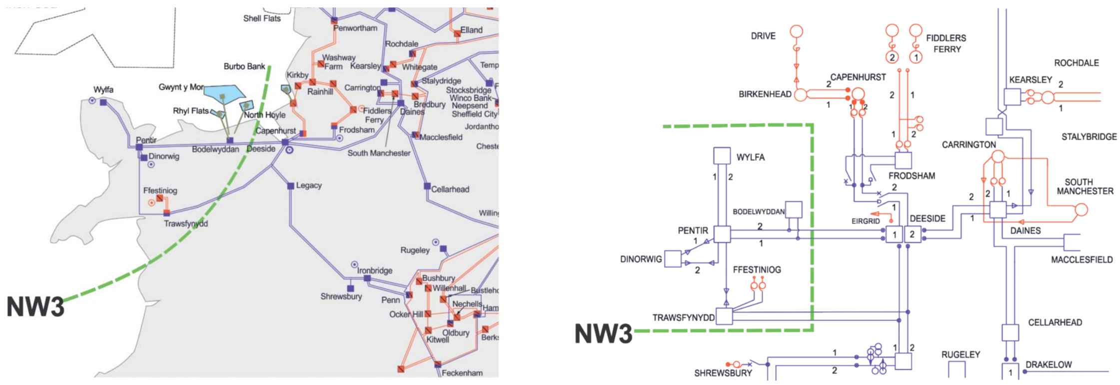
1 Reinforcement date triggered by prior requirement from boundary in the reference name

The establishment of a second Pentir to Trawsfynydd circuit (NW2-R01) increases the capability. The earliest this reinforcement can be delivered is 2018 due to construction and outages planning availability.

Due to the volume of generation connecting at sites in both North and South Wales this creates the opportunity for new offshore routes which allow generation to be transferred from the North Wales to South Wales group or vice versa in the event of system faults. Transmission capability improvements from this are shown in the graph and Table NW2.2 (OS Link-04 and OS Link-05). The alternative, of connecting the entire 3 GW generation to one group, would require major onshore system reinforcements to accommodate generation post-fault, most likely a new transmission route across either North or South Wales.

3.6.5
Boundary NW3

Figure NW3.1:
Geographical and single line representation of boundary NW3



Boundary NW3 provides capacity for further generation connections in addition to those behind NW1 and NW2. The boundary is defined by a pair of 400kV double circuits from Pentir to Deeside and Trawsfynydd to the Treuddyn Tee. Figure NW3.1 above illustrates the boundary NW3. The current capability for boundary NW3 is 2.9 GW, limited by thermal capacity across the boundary circuits.

Generation Background
In addition to the generators enclosed by boundaries NW1 and NW2 the NW3 boundary also encloses the Ffestiniog pumped storage units. Ffestiniog has 4 generator turbines, each rated at 90 MW. No change to the generation in the zone between NW2 and NW3 is currently considered in the scenarios and there is no additional contracted generation within this zone.

Potential Reinforcements
Most of the potential reinforcements determined for NW2 also provide capability for NW3. Table NW3.1 on page 90 lists a brief works description.

3.6 continued
North Wales local boundaries

Table NW3.1:
List of potential reinforcement projects in the NW3 boundary

Ref	Reinforcement	Works Description
NW3-R01	Reconductor Trawsfynydd–Treuddyn	Reconductor Trawsfynydd–Treuddyn Double circuit with higher rated conductor
B8-R01	Wylfa–Pembroke HVDC Link	2 GW HVDC link from Wylfa/Irish Sea to Pembroke. Substation extension at Wylfa and Pembroke
NW3-R03	Pentir–Deeside Reconductoring	Pentir–Deeside existing double circuit reconductor
NW3-R05	Deeside–Trawsfynydd series compensation	120 MVar series compensation
OS-Link-05	Lancashire–North Wales Offshore Integration	Offshore Integration between North Wales, Irish Sea offshore projects and Lancashire region
OS Link-04	Irish Integration	Controllable interconnection between the Irish Wind circuits connecting to Pentir and Pembroke

Boundary Discussion and Opportunities
Figure NW3.2 shows the required boundary transfer from 2012 to 2032 under the four scenarios as well as the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table NW3.2.

Figure NW3.2:
Generation and capability for boundary NW3

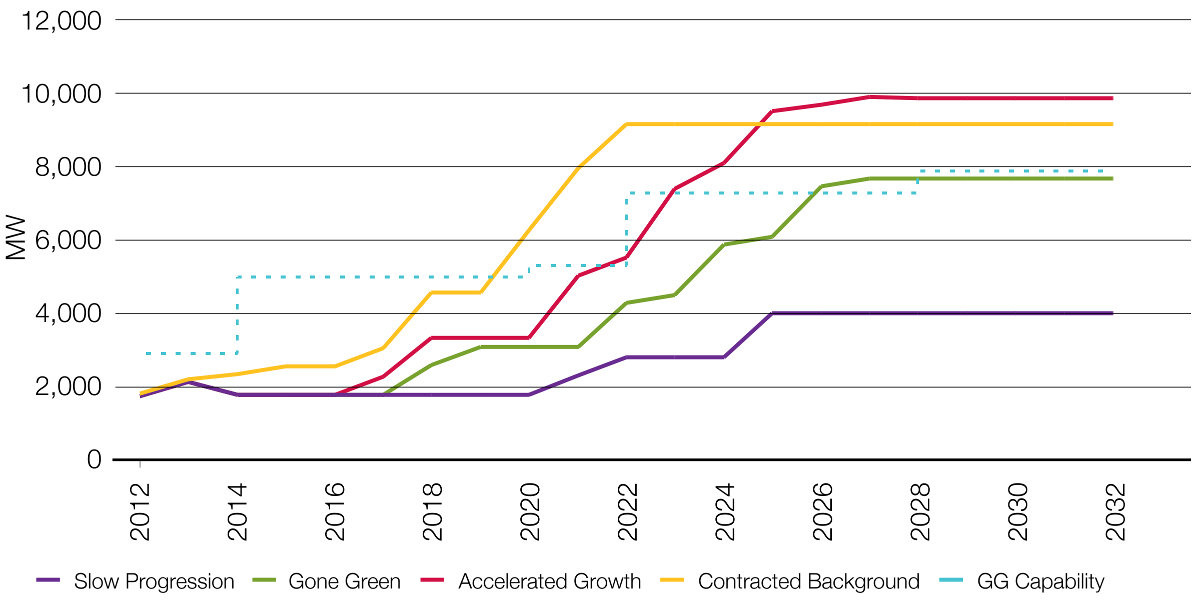


Table NW3.3:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
NW3-R01	2014	2014	2014	2014
NW3-R-R01	–	–	2024	2020
B8-R01	–	2022[1]	2022	2019
NW3-R05	–	–	2025	2021
OS-Link-05	–	2020	2019	2019
OS Link-04	–	2028	2025	2018

Reconductoring of the Trawsfynydd to Treuddyn Tee route (NW3-R01) is planned in 2014 as a result of asset condition drivers rather than boundary capability drivers. This reinforcement forms the first part of a suite of anticipatory investments in North Wales, designed to deliver increased transmission capacity in readiness for the first stages of new nuclear and wind farm generation connecting in North Wales.

The scheme timings marked for the Gone Green scenario may appear early but are triggered by the requirements for boundary B8.

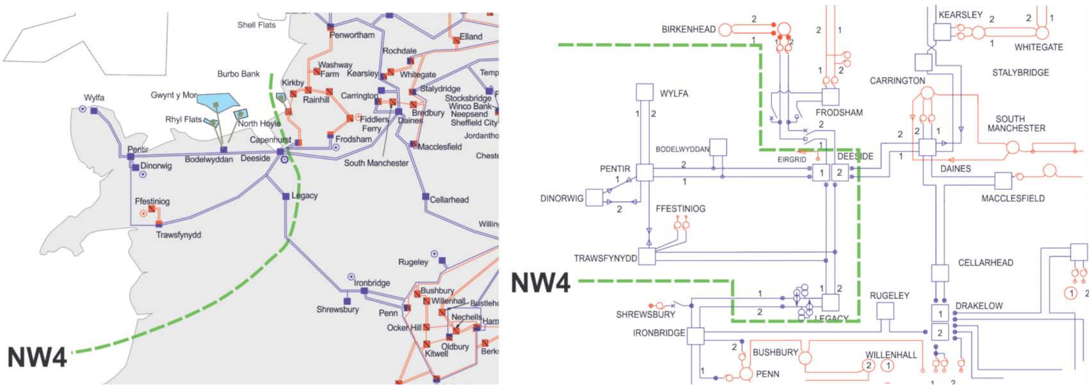
As with the other North Wales boundaries, offshore integration can help increase the boundary capability by providing circuit capacity across the boundary. For the later years in the Accelerated Growth scenario and Contracted Background, additional capability may be required when considering this boundary under high generation output conditions.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.6 continued
North Wales local boundaries

3.6.6
Boundary NW4

Figure NW4.1:
Geographical and single line representation of boundary NW4



The only wider boundary in North Wales is boundary NW4 and is generally an exporting boundary. As shown in Figure NW4.1 above, there are 3 double circuits crossing this boundary; Legacy to Ironbridge, Deeside to Capenhurst and Deeside to Daines.

Generation Background

Three thermal plants are currently connected between boundary NW3 and NW4. The only changes to this generation are the possible closure of some of this plant. The boundary transfer requirement for NW4 is therefore dominated by generation connecting in NW1 and NW2. The East-West Interconnector to Ireland connects at Deeside and is scheduled to be fully operational by the end of this year with a capacity of 500 MW.

Potential Reinforcements

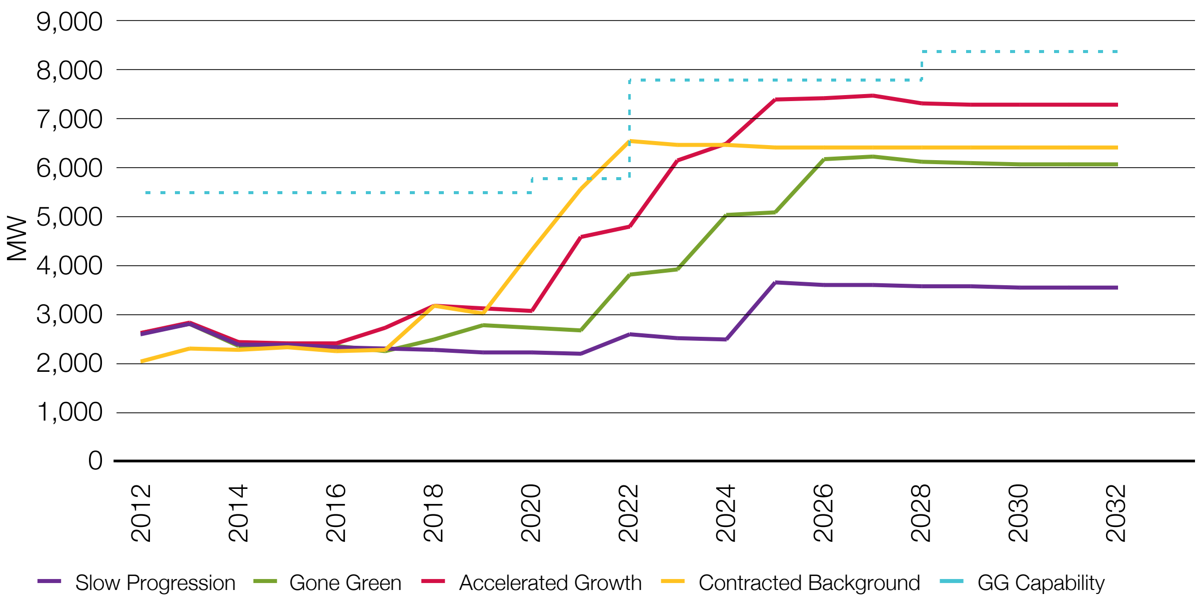
Although boundary NW4 does not directly trigger any reinforcements, it benefits from reinforcements triggered by other boundaries, without which the existing capability would be insufficient in the later years for most scenarios. Table NW4.1 on page 93 and Table NW4.2 on page 94 list the potential reinforcements proposed in North Wales that have an impact on boundary NW4.

Table NW4.1:
List of potential reinforcement projects in the NW4 boundary

Ref	Reinforcement	Works Description
B8-R01	Wylfa–Pembroke HVDC Link	2 GW HVDC link from Wylfa/Irish Sea to Pembroke. Substation extension at Wylfa and Pembroke
OS-Link-04	Lancashire–North Wales Offshore Integration	Offshore Integration between North Wales, Irish Sea offshore projects and Lancashire region
OS Link-05	Irish Integration	Controllable interconnection between the Irish wind circuits connecting to Pentir and Pembroke

Boundary Discussion and Opportunities
Figure NW4.2 below shows the required boundary transfer from 2012 to 2032 under the four scenarios as well the capability provided by the potential reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table NW4.2.

Figure NW4.2:
Generation and capability for boundary NW4



3.6 continued
North Wales local boundaries

Table NW4.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B8-R01	–	2022[1]	2022	2019
OS-Link-05	–	2020[1]		
2019	2019			
OS Link-04	–	2028	2025	2018

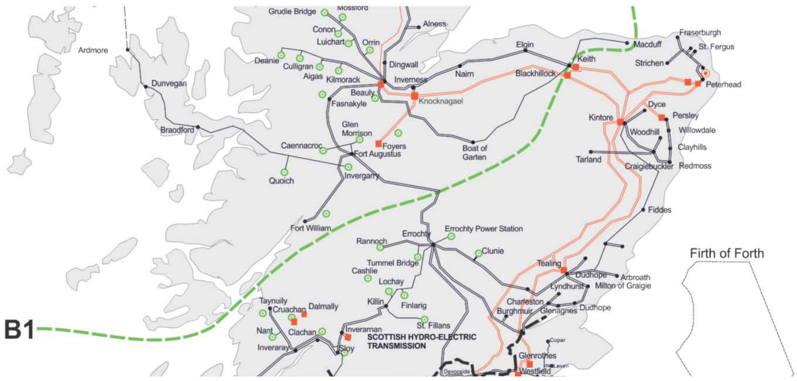
Boundary NW4 has an existing capability of 5.5 GW. The capability will increase as a result of reinforcements required by other boundaries.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7
Wider boundaries

3.7.1
Boundary B1

Figure B1.1:
Geographical representation of boundary B1



The Boundary B1 runs from the Moray coast near MacDuff to the West coast near Oban, separating the north-west of Scotland from the southern and eastern regions. The area to the north-west of Boundary 1 is inclusive of the Western Isles, Skye, Mull, Moray, Caithness, Beauly, and Orkney. The boundary crosses the 275kV double circuits running eastwards from Beauly and the double circuit running southwards from Fort Augustus. The present B1 boundary capability is around 500 MW.

The existing transmission infrastructure in northwest Scotland is relatively sparse, formed from 275 kV and 132 kV assets. Some of the large new generation projects are in places remote from any form of strong transmission infrastructure so new infrastructure is required both for connection and to support power export out of the area. New renewable generation connections north of the boundary are expected to massively increase the export requirements across the boundary as can be seen in Figure B1.2.

Generation Background

In all of the generation scenarios, there is an increase in the power transfer through B1 due to the large volume of renewable generation connecting to the north of this boundary. This is primarily onshore wind and small scale hydro, however, there is the prospect of significant hydro, wave and tidal generation resources being connected in the longer term. The contracted generation behind B1 within the time horizon covered by this ETYS includes the renewable generation on the Western Isles, Orkney and the Shetland Isles as well as a range of large and small onshore wind developments. It is also expected that some marine generation will connect in this zone within the ETYS time period. Under all scenarios the total generation above the B1 boundary increases. This large generation increase is not likely to be offset by any closure of generation plants.

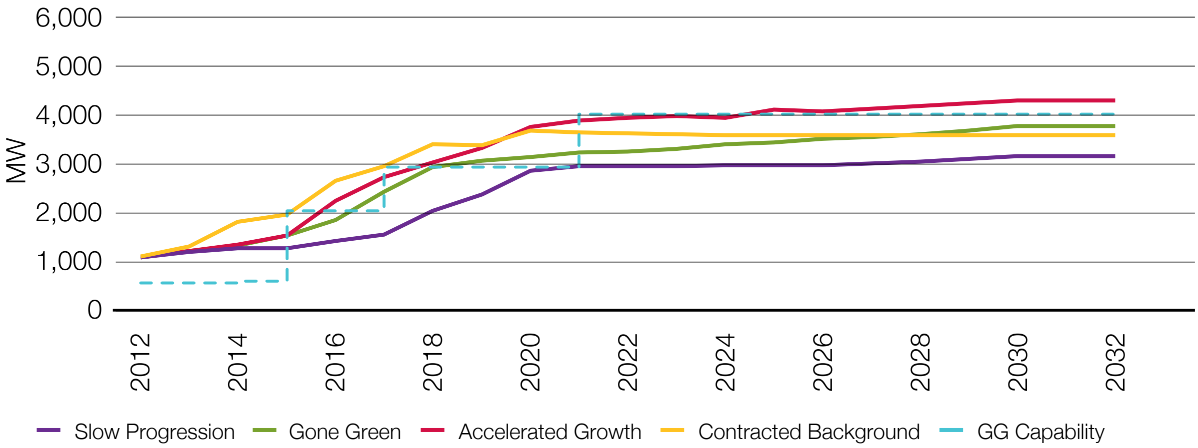
Potential Reinforcements

Several reinforcement projects, as summarised in Table B1.1, have been identified to cater for the increasing power exports across boundary B1. The Beauly to Denny reinforcement (B1-R01) extends across boundaries B2 and B4 providing additional capability for these as well as Boundary B1.

Table B1.1:
List of existing and potential reinforcement projects for the B1 boundary

Ref	Reinforcement	Works Description
B1-R01	Beauly–Denny Overhead Line (OHL) Reinforcement	Under construction. Replace the existing Beauly/ Fort Augustus/ Errochty/ Bonnybridge 132kV OHL with a new 400kV tower construction which terminates at a new substation near Denny. One circuit to be operated at 400kV and the other at 275kV. Associated AC substation works.
B1-R02	Beauly–Blackhillock–Kintore 275kV	Under construction. Replace the conductors on the existing 275kV double circuit line between Beauly, Knocknagael, Blackhillock and Kintore with higher capacity conductors
B1-R03	Caithness–Moray Reinforcement	Caithness multi-terminal ready HVDC link. New 800 MW HVDC converter at Spittal in Caithness with an 800 MW cable to a cable jointing bay at Noss Head on the Caithness coast. From the cable jointing bay a 1200 MW subsea cable will extend to a 1200 MW converter connected to a new 400kV busbar at Blackhillock in Moray. This arrangement will allow the integration of Shetland generation via an HVDC link to a future DC bussing point in Caithness (see Zone1-Z02). AC substation works at Blackhillock and new substations at Thurso South, Spittal, Fyrish and Loch Buidhe. Replace the existing conductor on one side of the Beauly-Loch Buidhe overhead line. Replace existing 132kV overhead line with a 275kV line between Dounreay and Spittal. New 132kV overhead line between Spittal and Mybster to harvest renewable generation.
B1-R04	Beauly–Blackhillock 400kV	New 400kV double circuit between Beauly and Blackhillock

Figure B1.2:
Required transfer and capability for boundary B1



Boundary Discussion

Figure B1.2 above shows the required transfer capabilities from 2012 to 2032 for the four different generation scenarios, as well as the proposed reinforcements and their estimated completion dates for the Gone Green scenario. Beneath, Table B1.2 identifies the completion dates for the reinforcement projects required for each scenario.

Table B1.2
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B1-R01	2015	2015	2015	2015
B1-R02	2014	2014	2014	2014
B1-R03	2020	2017	2017	2017
B1-R04	2025	2021	2021	2021

The timing of the reinforcement projects reflect the earliest possible implementation dates. Consequently the implementation dates in the AG scenario are the same as Gone Green irrespective of an indicated earlier completion requirement.

The current B1 boundary capability is insufficient to satisfy the boundary transfer requirement for the first few years under all scenarios. This is due to generation being connected ahead of the required reinforcement in accordance with the Connect and Manage access framework. Two key reinforcements to the B1 boundary which are both currently under construction are the Beauly–Blackhillock–Kintore project (B1-R02) and the Beauly–Denny project (B1-R01) which are forecast for completion in 2014 and 2015 respectively. The completion of these reinforcements will increase the B1 boundary capability from around 500 MW to around 2000 MW.

3.7 continued
Wider boundaries

Reinforcement of the Caithness transmission network (B1-R03) also provides a significant increase in capacity across the B1 boundary. The proposed reinforcement comprises the installation of an HVDC link between Spittal in Caithness and Blackhillock on the Moray coast along with associated AC system works on the mainland network. This has the effect of providing an additional circuit across B1 and increases the capacity of the boundary from around 2000 MW to around 2900 MW.

In the Gone Green scenario the transfers across B1 indicate the requirement for further reinforcement across this boundary by around 2020. Consequently consideration is being given to construction of a double circuit 400kV overhead line between Beauly and Blackhillock (B1-R04) to provide the required capability. This could increase the B1 boundary capability to around 4000 MW.

There are a number of other reinforcement projects to the north of the B1 boundary which are necessary to secure the network and for the connection of generation in this area as indicated in Table B1.3.

Table B1.3:
List of reinforcement projects within the zone to the north of the B1 boundary

Ref	Reinforcement	Works Description
Zone1-Z01	Beauly–Mossford	New 132kV substation at Corriemollie to accommodate wind generation in the area. Rebuild of existing 132kV twin overhead line with a new higher capacity double circuit line. Due for completion in 2014
Zone1-Z02	Shetland HVDC	New 600 MW HVDC link from a new substation at Kergord in Shetland to a new DC bussing point at Sinclairs Bay in Caithness to integrate with the Caithness–Moray reinforcement (B1-R03). Due for completion in 2017
Zone1-Z03	Western Isles HVDC	New 450 MW HVDC link from a new substation at Gravir on Lewis to the 400kV busbar at Beauly. Due for completion in 2016
Zone1-Z04	Orkney AC and HVDC	New AC subsea cable from a new substation near the Bay of Skaill on Orkney to Dounreay. Due for completion in 2016. New 600 MW HVDC link from the Bay of Skaill on Orkney to the DC bussing point in Caithness to integrate with the Caithness–Moray reinforcement (B1-R03). Due for completion in 2020
Zone1-Z05	Beauly–Tomatin	Rebuild part of the existing overhead line between Beauly and Boat of Garten and create a new 132 kV Switching station at Tomatin. The line will be turned into the Knocknagael substation. Due for completion in 2018
Zone1-Z06	Foyers–Knocknagael	Replace conductors on existing 275kV overhead line between Foyers and Knocknagael substations. Due for completion in 2015
Zone1-Z07	Lairg–Loch Buidhe	New 132kV substation at Lairg to accommodate wind generation in the area. Replace existing 132kV single circuit overhead line with a new higher capacity 275kV double circuit line between Lairg and Loch Buidhe. Due for completion in 2018
Zone1-Z08	Thurso–Gills Bay	New 132kV substation Gills Bay to accommodate marine generation in the southern part of the Pentland Firth. New 132kV overhead line from Gills Bay to a new Thurso South substation created under B1-R03. Due for completion in 2016
Zone1-Z09	Beauly–Loch Buidhe	Replace existing 132kV overhead line with a 275kV line between Beauly and Loch Buidhe. Due for completion in 2020

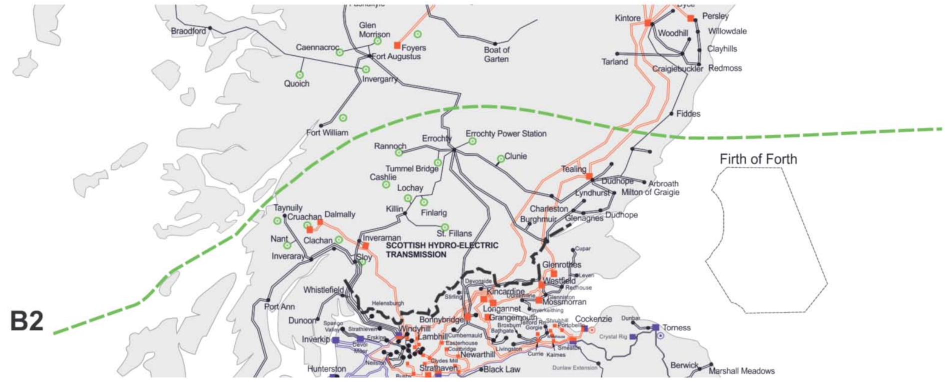
3.7 continued
Wider boundaries

The significant interest from generation developers on the large island groups of the Western Isles, Orkney and Shetland means that new transmission infrastructure will be required to connect these to the mainland transmission network. Current proposals are for the Western Isles to be connected using an HVDC transmission link from Gravir on Lewis to Beauly substation. It is also proposed to use an integrated multi-terminal HVDC link to connect Shetland to the mainland via a DC switching stations at Sinclairs Bay in Caithness. The growth of small onshore renewable generation on mainland Orkney together with the significant growth in marine generation around Orkney and the Pentland Firth requires transmission infrastructure to be taken to Orkney. It is currently proposed to install an AC subsea cable from Bay of Skaill, on the western side of Orkney, to Dounreay. This would be followed by a 600 MW HVDC link from the Bay of Skaill to the DC switching stations at Sinclairs Bay in Caithness when the capacity is required.

The proposed routes for new transmission tower lines and subsea cables will undergo detailed environmental impact assessment and will be subject to consents and planning approval.

3.7.2
Boundary B2

Figure B2.1:
Geographical representation of boundary B2



The Boundary B2 cuts across the Scottish mainland from the East coast between Aberdeen and Dundee to near Oban on the West coast. The boundary cuts across the two double circuit 275 kV circuits and a 132 kV single circuit in the east as well as the 132kV double circuit running southwards from Fort Augustus and as a result it crosses all the main North-South transmission routes from the North of Scotland. The thermal generation at Peterhead lies between the B1 and B2 boundaries as does the proposed future 1.4 GW North Connect Interconnector with Norway which is contracted to connect at Peterhead by 2021. The present B2 boundary capability is around 1600 MW.

Generation Background
In all of the generation scenarios, there is an increase in the power transfer through B2 due to the connection of a large volume of generation north of the B2 boundary, primarily onshore and offshore wind with the prospect of significant marine generation resource being connected in the longer term. The contracted generation behind the B2 boundary within the time horizon covered by this ETYS includes both offshore and onshore wind generation. There is also the potential for an increase in pumped storage plant behind B1. Thermal generation at Peterhead is also located behind B2. Under all scenarios generation increases behind B2.

Potential Reinforcements

Several reinforcement projects, as summarised in Table B2.1, have been identified to cater for the increasing power exports across the B2 boundary. The Beauly to Denny reinforcement (B1-R01) extends across B1, B2 and B4 and provides an increase in capability across them all. Similarly, the East Coast 400kV upgrade (B2-R01) and the Eastern HVDC link (B6-R03) extend across both boundaries B2 and B4 providing additional capability for both.

Table B2.1:
List of existing and potential reinforcement projects for the B2 boundary

Ref	Reinforcement	Works Description
B1-R01	Beauly–Denny Overhead Line (OHL) Reinforcement	Under construction. Replace the existing Beauly/ Fort Augustus/ Errochty/ Bonnybridge 132kV OHL with a new 400kV tower construction which terminates at a new substation near Denny
B2-R01	East Coast 400kV	Re-insulate the existing 275kV circuit between Blackhillock, Kintore and Kincardine for 400kV operation. New 400kV busbars will be required at Rothienorman, Kintore, and Alyth. Two new Phase Shifting Transformers installed at Blackhillock Reconfigure the Errochty 132kV network.
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit via Torness with associated AC network reinforcement works at each end. Possible Offshore HVDC integration in the Firth of Forth area
B7-R03	Eastern HVDC link 3	A new ~2 GW submarine HVDC link from Peterhead to England with associated AC network reinforcement works on both ends

Boundary Discussion

Figure B2.2 on page 103 shows the required transfer capabilities from 2012 to 2032 for the four different generation scenarios, as well as the capacity provided by the proposed reinforcements for the Gone Green scenario. Beneath, Table B2.2 identifies the reinforcement projects required for each scenario. The timing of the reinforcement projects reflect the shortest possible implementation dates. Consequently the implementation dates in the Accelerated Growth scenario are the same as Gone Green irrespective of an indicated earlier completion requirement.

Figure B2.2:
Required transfer and capability for boundary B2

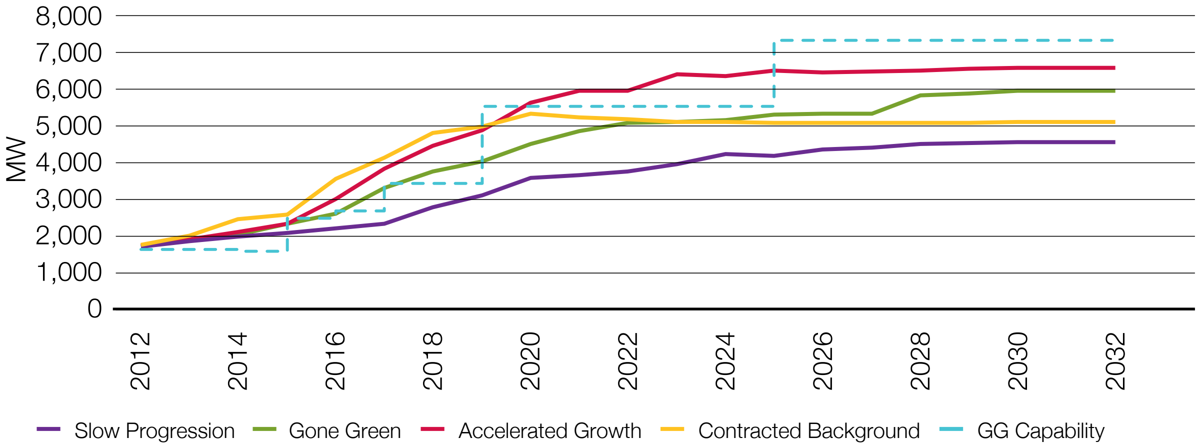


Table B2.2:
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B1-R01	2015	2015	2015	2015
B2-R01	2018	2017	2017	2017
B6-R03	2020	2019	2019	2019
B7-R03	–	2025	2020	2020

Generation to the north of this boundary is increasing at a significant rate due to the high volume of contracted renewable generation seeking connection in this area. Consequently, the boundary transfers are also increasing at a similar rate.

The increase in the required transfer capability for this boundary across all generation scenarios indicates the need to reinforce the transmission system on both the West and East transmission routes. The proposed Beauly to Denny reinforcement (B1-R01) on the westerly route, required for the B1 boundary, also provides increased capability for the B2 boundary. The Beauly–Denny reinforcement is due to be completed by the end of 2015 and will increase the B2 North South boundary capability from around 1600 MW to around 2500 MW. This is adequate for the Gone Green scenario up until 2016.

Beyond this, additional reinforcement of the B2 boundary will be required for all generation scenarios. The proposed East Coast 400kV upgrade (B2-R01) comprises an upgrade of one of the existing 275kV east coast routes between Blackhillock and Kincardine, to 400kV using existing infrastructure that is currently operated at 275kV but which is constructed at 400kV. This increases the B2 capability from around 2500 MW to around 3400 MW by 2017.

Wider boundaries

To facilitate further connection of large volumes of wind, a new Eastern HVDC link (B6-R03) between Peterhead, Torness and Hawthorn Pit in the north east of England, is also proposed in 2019 for all the scenarios except Slow Progression, where a later 2020 delivery date is more suitable. This increases the B2 capability to around 5500 MW. After 2022, there is little growth in the Slow Progression required transfer, predominantly due to a reduced amount of generation in the Round 3 and Scottish Territorial Waters wind farm zones, and no assumed CCGT generation connecting in the later part of the period. Accordingly, no further reinforcements are required beyond the first HVDC link (B6-R03).

For the other scenarios it can be seen that the predicted continual growth in generation connections requires a very challenging programme of works to facilitate. A second new Eastern HVDC link (B7-R03) could be delivered post 2020 if required to facilitate the growth in marine and wind generation. For the contracted background, there is a far greater pace of wind farm connection in the early years, with the required transfer peaking around 2020 after which point it levels off at around 6 GW across B2. The dates shown for required reinforcements represent the earliest possible delivery dates.

There are a number of other reinforcement projects to the north of the B2 boundary which are necessary to secure the network and for the connection of generation in this area.

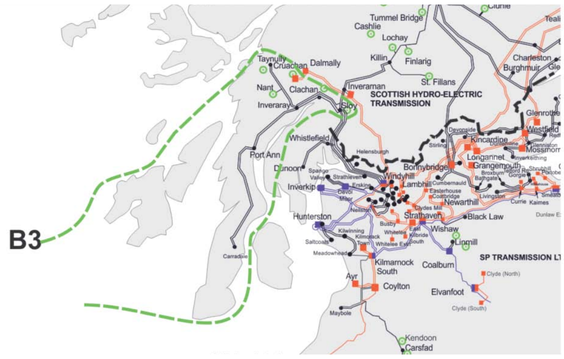
Table B2.3:
List of reinforcement projects within the zone to the north of the B2 boundary

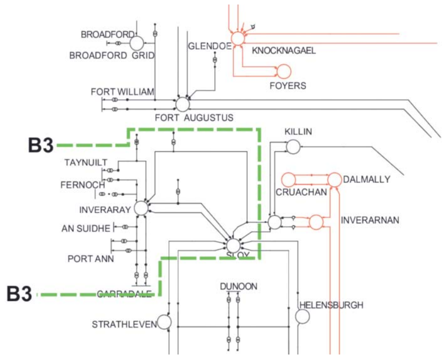
Ref	Reinforcement	Works Description
Zone2-Z01	Peterhead 400kV Busbar	New 400kV substation at Peterhead to connect the Moray Firth offshore generation and the Eastern HVDC link to Hawthorne Pit via the Torness area. Due for completion in 2016
Zone2-Z02	Peterhead–Rothienorman 400kV Upgrade	Re-insulate the existing 275kV circuit between Peterhead and Rothienorman for 400kV operation. Due for completion in 2017

The proposed transmission tower lines upgrades, new and extended substations and subsea cables will undergo detailed environmental impact assessment and will be subject to consents and planning approval.

3.7.3
Boundary B3

Figure B3.1:
Geographical and single line representation of boundary B3





Boundary B3 is a local boundary within the SHE Transmission system and encompasses Argyll and the Kintyre peninsula. It cuts across the circuits running to the south of the Sloy and Inverarnan substations. The present boundary capability is 350 MW.

Generation Background
The contracted generation within the B3 boundary increases from around 380 MW in 2012 to around 510 MW in 2017. After 2017 the contracted generation remains approximately constant although there is the potential for further generation in this area. The generation comprises large and small scale hydro generation, onshore wind and small scale marine generation. Approximately half of the generation total is wind with a small volume of marine and hydro accounting for the remainder.

Potential Reinforcements
One reinforcement project is presently proposed for the B3 boundary, as summarised in Table B3.1.

Table B3.1:
List of potential reinforcement projects for the B3 boundary

Ref	Reinforcement	Works Description
B3-R01	Kintyre–Hunterston Link	Installation of two new 220kV subsea cables between a new substation at Crossaig on Kintyre and Hunterston in Ayrshire. Installation of phase shifting transformers at Crossaig on the 132kV Port Ann circuits. Rebuild of the existing 132kV overhead line between Crossaig and Carradale substations

3.7 continued
Wider boundaries

Table B3.2:
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B3-R01	2015	2015	2015	2015

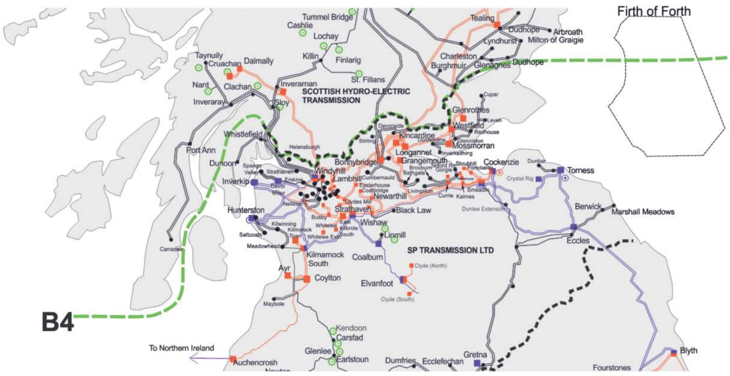
Boundary Discussion
The existing network in this area is made up of a radial 132kV system between Sloy and Inveraray and then from Inveraray via radial 132kV double circuits to Taynuilt near Oban and Carradale in the southern part of the Kintyre peninsula. The B3 boundary is a local boundary with a demand at time of the GB system peak of only 56 MW which is significantly exceeded by the generation in the area.

Assessment of B3 gives a clear requirement for reinforcement across the B3 boundary.

The proposed reinforcement for the B3 boundary comprises the installation of two 220kV subsea cable links from Crossaig, 13km north of Carradale, to Hunterston in Ayrshire. The reinforcement is due for completion in 2015/16 and will increase the B3 capability from 350 MW to around 500 MW. Renewable generation continues to increase in the Kintyre and Argyll area with a significant volume in the consent process with the Argyll and Bute Council prior to application for connection to the grid. Consequently further reinforcement may be required in the future to address the regional zonal boundary capacities that exist within the main B3 boundary, in particular between Carradale, Taynuilt and Inveraray.

3.7.4
Boundary B4

Figure B4.1:
Geographical representation of boundary B4



The B4 boundary separates the transmission network at the SP Transmission and SHE Transmission interface running from the Firth of Tay in the east to near the head of Loch Long in the west. With increasing generation in the SHE Transmission area for all generation scenarios the required transfer across B4 is expected to significantly increase over the period covered by the ETYS.

The boundary is crossed by 275 kV double circuits to Kincardine and Westfield in the east, a 132 kV double circuit to Bonnybridge, near Denny and by two 132 kV double circuits from Sloy to Windyhill in the west. A major reinforcement across B4 is currently under construction. The Beauly to Denny upgrade involves the replacement of the existing 132 kV double circuit route between Beauly and Denny with a new 400 kV tower construction. One circuit on the new route will operate at 400kV and the other at 275kV.

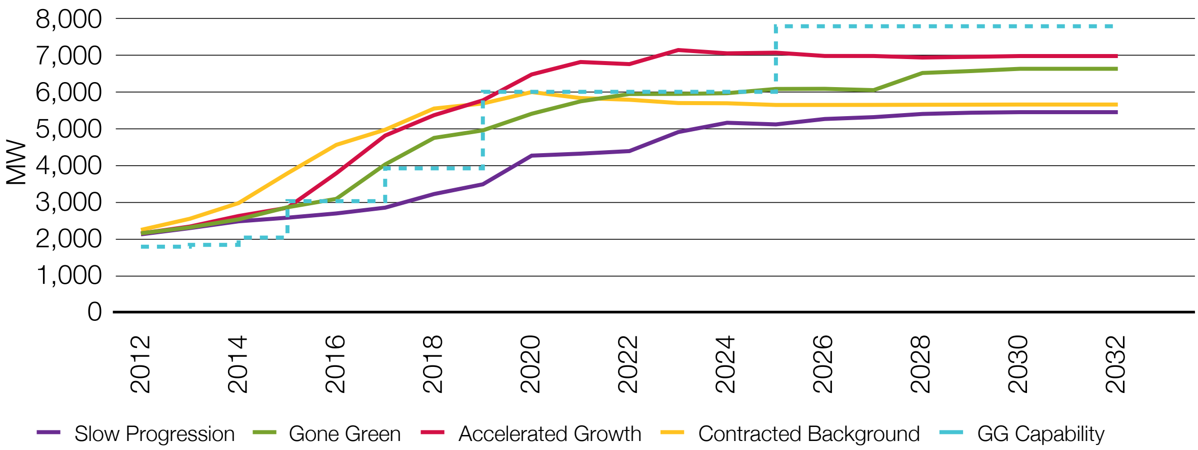
Generation Background
In all of the ETYS generation scenarios, the power transfer through B4 increases due to the significant volumes of generation connecting north of the B4 boundary, including all generation above the B1 and B2 boundaries. This is primarily onshore and offshore wind generation with the prospect of significant marine generation resource being connected in the longer term. The generation behind the B4 boundary includes around 3.5 GW of offshore wind generation.

Potential Reinforcements
Several reinforcement projects, as summarised in Table B4.1, have been identified to cater for the increasing power transfers across boundary B4. Some of these reinforcements such as the Beauly to Denny and East Coast 400kV upgrades extend across two or more boundaries providing additional capability for all relevant boundaries. The timing of the reinforcement projects reflect the later of the required reinforcement year and the earliest possible implementation date.

Table B4.1:
List of potential reinforcement projects for the B4 boundary

Ref	Reinforcement	Works Description
B1-R01	Beauly–Denny Overhead Line (OHL) Reinforcement	Replace the existing Beauly/ Fort Augustus/ Errochty/ Braco/ Bonny Bridge 132kV OHL with a 400kV tower construction. One circuit to be operated at 400kV and the other at 275kV. Associated AC substation works. Due for completion 2015
B2-R01	East Coast 400kV	Re-insulate the existing 275kV circuit between Blackhillock, Kintore and Kincardine for 400kV operation. New 400kV busbars will be required at Rothienorman, Kintore, and Alyth. Two new Phase Shifting transformers to be installed at Blackhillock substation. Reconfigure the Errochty 132kV network. Reactive reinforcement as required. Due for completion 2017.
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit via Torness with associated AC network reinforcement works at each end. Possible Offshore HVDC integration in the Firth of Forth area
B7-R03	Eastern HVDC link 3	A new ~2 GW submarine HVDC link from Peterhead to England with associated AC network reinforcement works on both ends
B4-R01	Tealing–Westfield 275kV Upgrade	The rating of existing Tealing–Westfield 275kV overhead line have been increased by removing the restriction on conductor joints and fittings. Completed in 2012
B4-R02	Tealing–Westfield–Longannet 275kV Upgrade	Investigate re-profiling of existing 275kV overhead line to 65oC and associated works to increase the circuit ratings

Figure B4.2:
Required transfer and capability for boundary B4



Boundary Discussion

Figure B4.2 above shows the required transfers from 2012 to 2032 for the four different generation scenarios, as well as the B4 capability for the proposed reinforcements in the Gone Green scenario. Beneath, Table B4.2 identifies the reinforcement projects required for each scenario, the timing of which reflect the earliest possible implementation dates. Under the Slow Progression scenario, project delays are reflected where appropriate.

Table B4.2:
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B1-R01	2015	2015	2015	2015
B2-R01	2017	2017	2017	2017
B6-R03	2020	2019	2019	2019
B7-R03	–	2025	2020	–
B4-R01	2012	2012	2012	2020
B4-R02	2019	2019	2019	2019

Wider boundaries

The increase in the required transfer capability over the ETYS period clearly indicates the need to reinforce the transmission system across the B4 boundary. The current B4 capability is insufficient to satisfy the boundary transfer requirement for the first few years under the Gone Green and Contracted scenarios. This is due to generation being connected ahead of the required reinforcement in accordance with the Connect and Manage access framework.

The proposed Beauly to Denny reinforcement will increase the capacity of the B4 boundary significantly from around 1800 MW to around 3000 MW in 2015. The East Coast 400kV reinforcement will increase the B4 boundary capability from around 3000 MW to around 3900 MW.

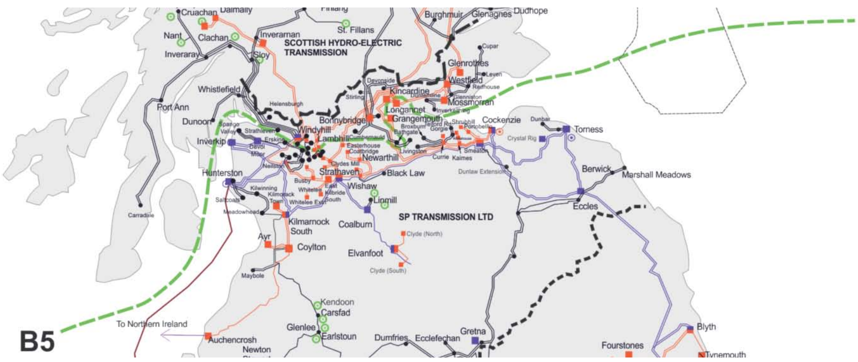
Smaller incremental upgrades to the SHE Transmission network including the installation of phase shifting transformers at Blackhillock, the reconfiguration of the Errochty 132kV busbar and the incremental works on the Tealing–Westfield–Longannet circuits allow optimisation of power flows though the network will provide small but very cost effective increases in the B4 boundary capability.

Beyond this the proposed Eastern HVDC link (B6-R03). After 2022, there is little growth in the Slow Progression required transfer, predominantly due to a reduced amount of generation in the Round 3 and Scottish Territorial Waters wind farm zones, and no assumed CCGT generation connecting in the later part of the period. Accordingly, no further reinforcements are required.

For the other scenarios the predicted ongoing growth in generation requires a very challenging programme of works to facilitate connections. A second new Eastern HVDC link could be delivered post-2020 if required to provide the transmission capacity to support the growth in marine and wind generation. For the contracted background, there is a far greater pace of wind farm connection in the early years, with the required transfer peaking around 2019 after which point it gently decreases, primarily due to the high volume of contracted generation connections in England and Wales. The dates shown for reinforcements in this case represent earliest possible delivery dates.

3.7.5
Boundary B5

Figure B5.1:
Geographical representation of boundary B5



Boundary B5 is internal to the SP Transmission system and runs from the Firth of Clyde in the west to the Firth of Forth in the east. The Generating Stations at Longannet and Cruachan, together with the demand groups served from Windyhill, Lambhill and Bonnybridge 275kV Substations, are located to the north of B5. The existing transmission network across the boundary comprises three 275kV double circuit routes; one from Windyhill 275kV Substation in the west and one from each of Kincardine and Longannet 275kV Substations in the east.

The area to the north of B5 typically contains an excess of generation and the predominant direction of power flow across the boundary is from north to south. The capability of the boundary is presently limited by thermal considerations to around 3.6 GW. The boundary capability is required to increase significantly, with generation increasing to the north of B5 in all scenarios.

Generation Background
In all of the ETYS scenarios, there is an increase in the export requirement across B5. This is due to the connection of a large volume of generation throughout the north of Scotland, primarily on and offshore wind. This includes up to 9.3 GW of wind generation north of B5 over the ETYS period. This large generation increase is supplemented by marine, CCGT and CCS projects and is only partially offset, to varying degrees, by closure of ageing coal and gas plants.

Potential Reinforcements
Potential B5 reinforcements for the period to 2032 are listed in Table B5.1 on page 112. A number of these reinforcements also have a positive impact on adjacent boundaries. The indicated timing of the projects reflects the later of the required reinforcement year and earliest possible implementation date. In view of the prevailing thermal limit and the incremental reinforcement works which have already been completed, the next reinforcement is likely to require the establishment of new circuits across the boundary.

Table B5.1:
List of potential reinforcement projects of works for the B5 boundary

Ref	Reinforcement	Works Description
B5-R01	Central 400kV Upgrade	Create two new north to south Denny–Wishaw 400 / 275kV circuits via a new section of double circuit overhead line from the Bonnybridge area to the existing Newarthill / Easterhouse route
B5-R02	East Coast 400kV Upgrade	Uprate the circuits on the overhead line route south from Kincardine towards Edinburgh from 275kV to 400kV operation and establish three new 400kV substations at Kincardine, Grangemouth and in West Lothian
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit via Torness with associated AC network reinforcement works at each end. Possible Offshore HVDC integration in the Firth of Forth area
B7-R03	Eastern HVDC link 3	A new ~2 GW submarine HVDC link from Peterhead to England with associated AC network reinforcement works on both ends

Boundary Discussion and Opportunities
Figure B5.2 below shows the required transfer capabilities from 2012 to 2032 for the three scenarios and the Contracted Background, as well as the optimum reinforcements and their timing for the Gone Green scenario. Beneath, Table B5.2 identifies the reinforcements selected for each scenario.

Figure B5.2:
Required transfer and capability for boundary B5

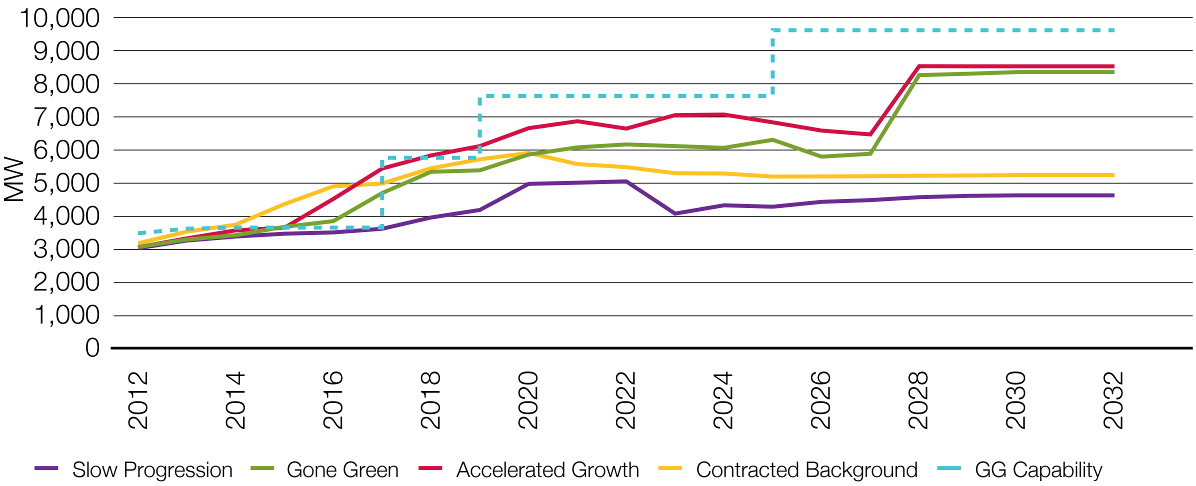


Table B5.2:
Selection and timing of reinforcements

Scheme	SP	GG	AG	C
B5-R01	2017	2017	2017	2017
B6-R03		2019	2018	
B7-R03		2025	2020	2020

A number of schemes which significantly improve the capability of B5 have recently been completed. These include the thermal uprating of 275kV circuits on the Longannet to Clyde's Mill corridor, the installation of a series reactor at Windyhill for power flow control purposes and the installation of a second 400/275kV transformer at Strathaven.

Due to the connection of renewable generation throughout the north of Scotland, the current boundary capability is expected to become insufficient around the middle of the decade. The increase in the required transfer capability clearly indicates the need to reinforce the transmission system across B5.

Taking into account the significant changes anticipated in the generation mix in the period to 2020 and beyond, SP Transmission is undertaking pre-construction design and engineering work on prospective upgrades to boundary B5. Undertaking pre-construction engineering work positions the delivery of any project such that construction can commence when there is sufficient confidence that the reinforcement is necessary.

Two primary onshore reinforcement options are being evaluated: the Central 400kV Upgrade (B5-R01) and the East Coast 400kV Upgrade (B5-R02).

The first option utilises existing infrastructure between Denny and Bonnybridge, Wishaw and Newarthill and a portion of an existing double circuit overhead line between Newarthill and Easterhouse. A new section of double circuit overhead line is required from the Bonnybridge area to the existing Newarthill / Easterhouse route. Together with modifications to substation sites, this option will create two new north to south circuits through the central belt: a 275kV Denny / Wishaw circuit and a 400kV Denny / Wishaw circuit, thereby increasing B5 capability.

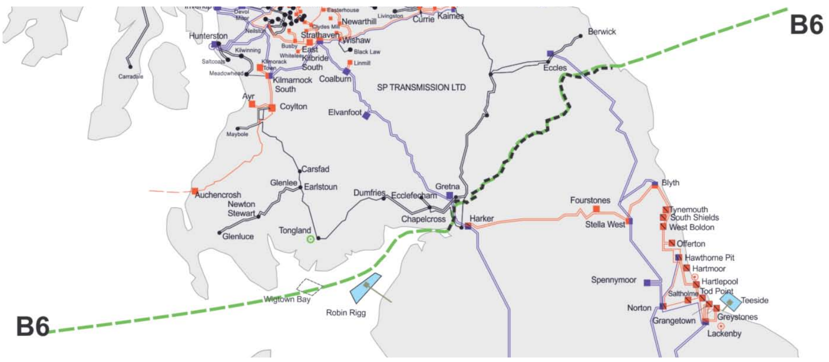
As part of the second option, the circuits on the overhead line route south from Kincardine towards Edinburgh via Grangemouth will be uprated from 275kV to 400kV operation, together with the installation of a higher capacity conductor system on existing towers. This will require new 400kV substations at Kincardine and Grangemouth and a new 400kV substation in West Lothian to facilitate a connection to existing 400kV east – west circuits.

It is expected that further reinforcement of this boundary will also be required to facilitate further connection of large volumes of wind. A new Eastern HVDC link is required around 2018 or 2019 in the Gone Green and Accelerated Growth scenarios. Both of these scenarios also require further reinforcement around 2027 due to the level of offshore wind generation and assumed CCS generation connecting in the later part of the period.

3.7 continued
Wider boundaries

3.7.6
Boundary B6

Figure B6.1:
Geographical representation of 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 are 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.

Generation Background
Across all scenarios there is an increase in the export from Scotland to England due to the connection of additional generation in Scotland, primarily onshore and offshore wind. This generation increase is partially offset by the expected closure of between 3 to 7 GW of ageing coal, gas and nuclear plants, which varies in each scenario.

Small embedded generation within Scotland can make a significant change to the boundary requirements as demonstrated in the boundary requirement graph of Figure 6.2. More than 600 MW of small embedded wind generation capacity could be installed by 2030. The definitions of what is classed as small embedded generation can be found in section 2.4.1.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed in Table B6.1 on page 115. Due to the current stability and voltage limitations, the first reinforcement installs suitable compensation equipment to relieve these constraints.

Table B6.1:
List of potential reinforcement options and description of works for the B6 boundary

Ref	Reinforcement	Works Description
B6-R01	Series and Shunt compensation	Series compensation to be installed in Harker–Hutton, Eccles–Stella West and Strathaven–Harker routes. Two 225MVar MSCs are to be installed at Harker, one at Hutton, two at Stella West and one at Cockenzie. Strathaven–Smeaton route uprated to 400kV and cables at Torness uprated
B6-R02	Western HVDC link	A new 2.4 GW (short term rating) submarine HVDC cable route from Deeside to Hunterston with associated AC network reinforcement works on both ends.
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit via Torness with associated AC network reinforcement works at each end. Possible Offshore HVDC integration in the Firth of Forth area
B6-R04	Harker–Strathaven reconductoring + Series compensation	Reconductoring the existing 400kV Harker–Strathaven double circuit with higher rated conductor and additional Series compensation
B6-R05	Eastern HVDC link 2	A new ~2 GW submarine HVDC link between Lackenby and Torness with associated AC network reinforcement works on both ends
B7-R03	Eastern HVDC link 3	A new ~2 GW submarine HVDC link from Peterhead to England with associated AC network reinforcement works on both ends

Boundary Discussion and Opportunities

Figure B6.2 on page 116 shows the boundary required transfer values from 2012 to 2032 for the four different scenarios, as well as the Gone Green optimised reinforcements and a demonstration of the potential impact of small embedded wind farm output. By 2030 the small embedded wind farms could produce more than 500 MW of boundary requirement change. Table B6.2 identifies the reinforcements selected for each scenario.

Figure B6.2:
Required transfer and capability for boundary B6

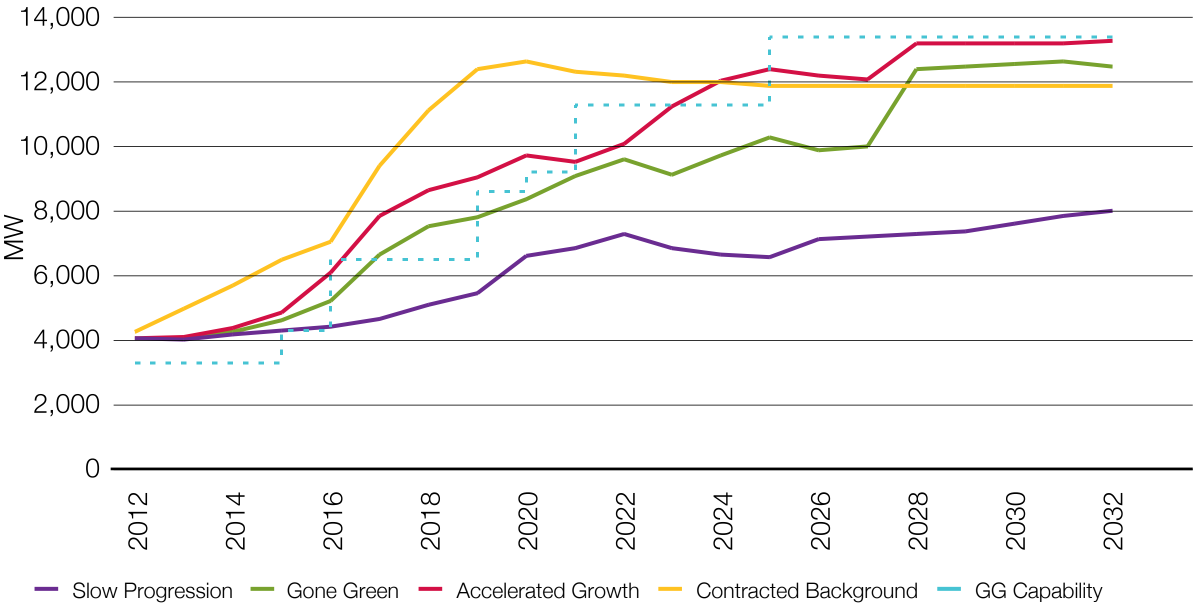


Table B6.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B6-R01	2015	2015	2015	2015
B6-R02	2016	2016	2016	2016
B6-R03	2020	2019	2019	2019
B6-R04	–	2020	2022	2020
B6-R05	–	2021	2019	2019
B7-R03	–	2025[1]	2020[1]	2020[1]

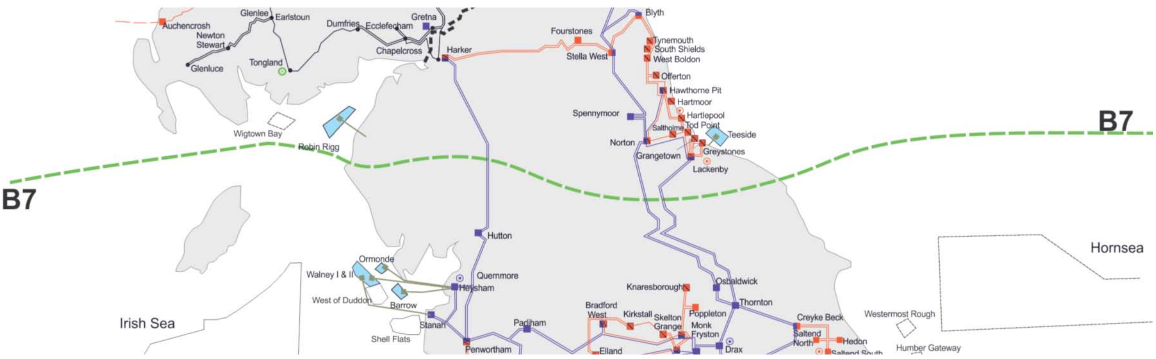
The current boundary capability is insufficient to satisfy the boundary transfer requirement. A number of schemes have already been delivered to improve the capability, and two schemes in progress are the insertion of new series and shunt compensation on the existing circuits and the creation of a new Western HVDC link, which are forecast to be delivered at their earliest possible dates of 2015 and 2016 respectively. However, to ensure sufficient transmission capacity, a new Eastern HVDC link is also required at or before the earliest possible date of 2019 for all the scenarios except Slow Progression, where a later 2020 delivery date is more suitable.

For Gone Green and Accelerated Growth the reinforcements identified represent a significant challenge if they are to be delivered by the dates specified. In the Gone Green scenario the timing of these reinforcements is brought forward by the needs of boundaries B7 and B7a. In the latter part of the period, the required transfer levels for the Gone Green and Accelerated Growth scenarios, peaking at approximately 12.5 GW and 13 GW respectively, represent more than three times the current transmission requirement. As a consequence of Connect and Manage the build up of contracted generation is much faster than in other scenarios. Reinforcement will be delivered at the earliest opportunity.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7.7
Boundary B7

Figure B7.1:
Geographical representation of 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.

Generation Background

In all scenarios there is an increase in generation output over the period considered, as the boundary is influenced by everything north of Teesside. In addition to that identified in the B6 section there is a further 4 GW of offshore wind, 3 GW of new nuclear and 1.4 GW of new interconnector capacity contracted to connect.

Potential Reinforcements

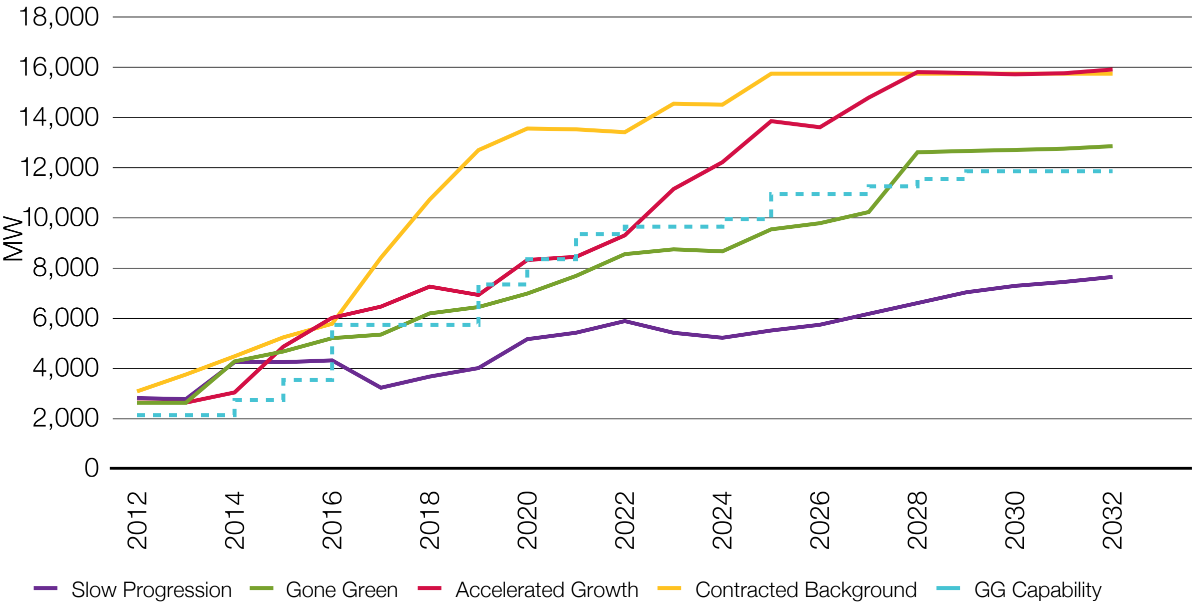
Potential reinforcements for the period to 2032 are listed in Table B7.1 on page 118. This boundary tends to be limited by thermal constraints, so most of the reinforcements involve either upgrading existing lines or constructing new ones.

Wider boundaries

Table B7.1:
List of potential reinforcement projects in the EC1 boundary

Ref	Reinforcement	Works Description
B6-R01	Series and Shunt compensation	Series compensation to be installed in Harker–Hutton, Eccles–Stella West and Strathaven–Harker routes. Two 225MVar MSCs are to be installed at Harker, one at Hutton, two at Stella West and one at Cockenzie. Strathaven–Smeaton route uprated to 400kV and cables at Torness uprated
B7-R01	Harker–Hutton reconductoring	Reconductoring of the Harker–Hutton–Quernmore circuits with higher rated conductor
B6-R02	Western HVDC link	A new 2.4 GW (short-term rating) submarine HVDC cable route from Deeside to Hunterston with associated AC network reinforcement works on both ends
B7-R02	Harker–Stella West series compensation	Installation of series compensation in the Harker–Stella West circuits
B7a-R03	Yorkshire Lines reconductoring to 3100MVA	Reconductoring the existing two double circuits crossing B7 in the East, Lackenby–Thornton and Norton–Osbaldwick with higher rated conductor
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit with associated AC network reinforcement works on both ends. Possible Offshore HVDC integration in the Firth of Forth area
B6-R05	Eastern HVDC link 2	A new ~2 GW submarine HVDC link between Lackenby and Torness with associated AC network reinforcement works on both ends
B7-R03	Eastern HVDC link 3	~2 GW of second HVDC link from Peterhead to England with associated AC network reinforcement works on both ends
B7-R04	New Cumbria–Lancashire transmission route	Construction of new transmission route from Cumbria to Lancashire across the B7 and B7a boundaries
OS Link-01	Teesside–Humber Offshore Integration	Offshore integration between Teesside, Dogger Bank offshore project and Humber region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region

Figure B7.2:
Required transfer and capability for boundary B7



Boundary Discussion and Opportunities

Figure B7.2 above shows the required transfer capabilities from 2012 to 2032 for the four different scenarios, as well as the optimum reinforcements and their timing for the Gone Green scenario. Beneath, Table B7.2 identifies the reinforcements selected for each scenario.

Wider boundaries

Table B7.2:
Selection and timing of reinforcements

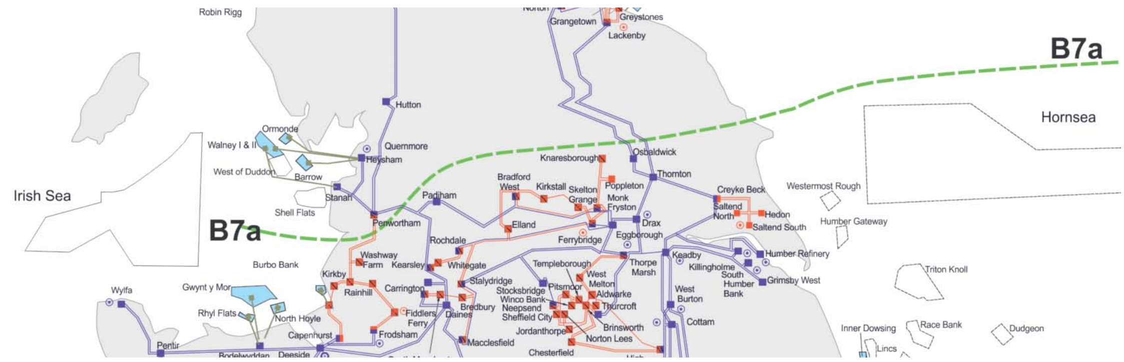
Ref	SP	GG	AG	C
B6-R01	2015	2015	2015	2015
B7-R01	2014	2014	2014	2104
B6-R02	2016	2016	2016	2016
B7-R02	2029	2019	2016	2016
B7a-R03	–	2020	2018	2018
B6-R03	2026	2019	2019	2019
B6-R05	–	2021	2019	2019
B7-R03	–	2025	2020	2020
B7-R04	–	–	2025	2023
OS Link-01	2025 2027	2022 2024 2027 2028	2019 2021 2024 2025 2027 2029	2017 2019
OS Link-03	–	2029	2026 2028 2030	–

The Harker–Hutton (B7-R01) reconductoring and Western HVDC link (B6-R02) works will increase system capability significantly by 2016. In order to realise the full benefit of B7-R01, the series and shunt compensation scheme on B6 (B6-R01) is required.

In the Slow Progression scenario, an Eastern HVDC link in 2020, and the Harker–Stella West series compensation in 2029 is required. As identified in section B6, for Gone Green and Accelerated Growth the reinforcements identified represent a significant challenge if they are to be delivered by the dates specified. The integrated connection of offshore wind generation provides additional capability in later years. The connection of new nuclear generation in the Contracted and Accelerated Growth backgrounds requires an additional transmission route across the boundary (B7-R04) which would increase capability by an estimated 3.5 GW. The Contracted Background still requires further reinforcement from 2023, as does Gone Green from 2028. These could include additional offshore or onshore circuitry, but at this time detailed solutions have not been developed.

3.7.8
Boundary B7a

Figure B7a.1:
Geographical representation of 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 boundary intersects two double 400kV circuits in the east and a 400kV double circuit and a 275kV double circuit south of 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.

Generation Background
The generation background for B7a is dominated by the generation north of B7. Within the region between B7 and B7a, a number of approximately 100–200 MW sized offshore wind farms are already connected with further similar developments expected in the next few years. This is partially offset by the anticipated closure of some existing generation. The most significant changes to generation in this region predominantly occurs after 2020, with the connection of 1.75 GW of offshore wind. Anticipated closures of existing generation may result in little overall change in the generation surplus within this region.

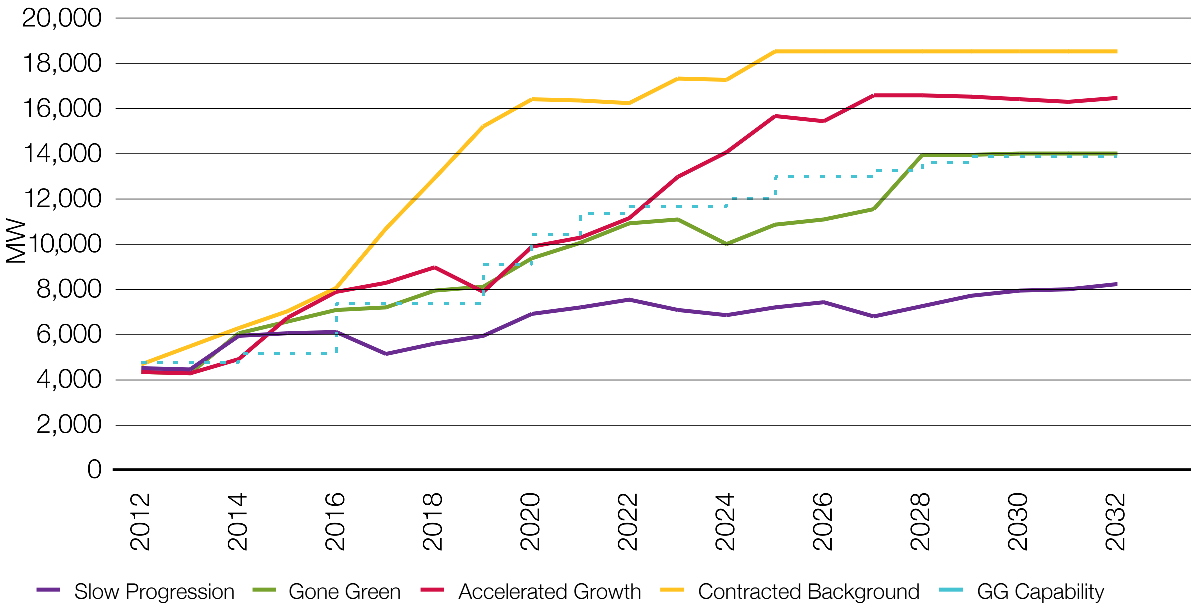
Potential Reinforcements
Potential reinforcements for the period to 2032 are listed in Table B7a.1 on page 122. This boundary is primarily limited by thermal ratings, so the reinforcements focus on uprating existing lines, or constructing new ones.

3.7 continued
Wider boundaries

Table B7a.1:
List of potential reinforcement projects in the B7a boundary

Ref	Reinforcement	Works Description
B7a-R01	Penwortham QBs	Installation of Quadrature Boosters south of Penwortham
B6-R02	Western HVDC link	A new 2.4 GW (short term rating) submarine HVDC cable route from Deeside to Hunterston with associated AC network reinforcement works on both ends
B7a-R02	Mersey Ring Stage 1	Voltage uprate of the 275kV double circuit overhead line from Penwortham to Kirkby to 400kV operation including construction of a new Washway Farm 400/132kV substation with 2X400/132kV 240MVA SGTs adjacent to the existing site, and a new Kirkby 400kV substation
B7a-R03	Yorkshire Lines reconductoring to 3100MVA	Reconductoring the existing two double circuits crossing B7 in the East, Lackenby–Thornton and Norton–Osbaldwick with higher rated conductor
B6-R03	Eastern HVDC link 1	A new ~2 GW submarine HVDC cable route from Peterhead to Hawthorn Pit with associated AC network reinforcement works on both ends. Possible Offshore HVDC integration in the Firth of Forth area
B6-R05	Eastern HVDC link 2	A new ~2 GW submarine HVDC link between Lackenby and Torness with associated AC network reinforcement works on both ends
B7-R03	Eastern HVDC link 3	~2 GW of second HVDC link from Peterhead to England with associated AC network reinforcement works on both ends
B7-R04	New Cumbria–Lancashire transmission route	Construction of new transmission route from Cumbria to Lancashire across the B7 and B7a boundaries
OS Link-01	Teesside–Humber Offshore Integration	Offshore integration between Teesside, Dogger Bank offshore project and Humber region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region
OS-Link-05	Lancashire–North Wales Offshore Integration	Offshore Integration between North Wales, Irish Sea offshore projects and Lancashire region

Figure B7a.2:
Required transfer and capability for boundary B7a



Boundary Discussion and Opportunities

Figure B7a.2 above shows the required transfer capabilities from 2012 to 2032 for the four different scenarios, as well as the optimum reinforcements and their timing for the Gone Green scenario. Beneath, Table B7a.3 identifies the reinforcements selected for each scenario.

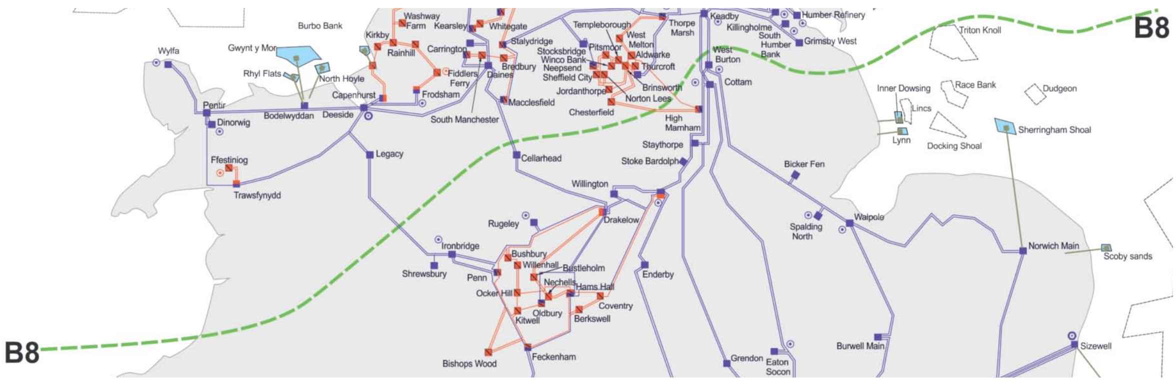
Due to increased transfers in the next few years, work is currently underway to install QBs at Penwortham and to construct the Western HVDC link by 2016. For the Slow Progression scenario there is sufficient capability up to 2026 at which point the first Eastern HVDC link will be required. As with boundaries B6 and B7, for all other scenarios a similar, very challenging programme of works is required with many of the same reinforcements needed. Three Eastern HVDC links are required by 2025 as well as the Mersey Ring and Yorkshire line reconductoring to facilitate the connection of wind farms further north. The capability is incrementally improved by the integrated offshore connections. Due to the fact all offshore generation in this region is not yet contracted it is not possible to deploy OS Link-03 economically in the contracted background scenario. As for boundary B7, B7-R04 adds 3.5 GW capability in the Accelerated Growth and Contracted scenarios when nuclear generation connects, which is sufficient to meet required transfers throughout the rest of the period.

Table B7a.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B7a-R01	2014	2014	2014	2014
B6-R02	2016	2016	2016	2016
B7a-R02	–	2019	2018	2018
B7a-R03	–	2020	2018	2018
B6-R03	2026	2019	2019	2019
B6-R05	–	2021	2019	2019
B7-R03	–	2025	2022	2020
B7-R04	–	–	2025	2023
OS Link-01	2025 2027	2022 2024 2027 2028	2019 2021 2024 2025 2027 2029	2017 2019
OS Link-03	–	2029	2026 2028 2030	
OS link-05	–	2020	2019 2021 2023	–

3.7.9
Boundary B8

Figure B8.1:
Geographical representation of 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 including Scotland, Northern England and Northern Wales from the Midlands and Southern demand centres. The boundary crosses four major 400kV double circuits, with two of those passing through the East Midlands while the other two pass through the West Midlands, and a limited 275kV connection to South Yorkshire. Generation from Scotland continues to be transported south, leading to the high transfer level across B8. The east of B8 is traditionally a congested area due to the large amount of existing generation in the Humber and Aire valley regions. The east areas also suffer from high fault levels which constrains the running arrangements of several substations in the area. The current boundary capability of 11.3 GW is limited by voltage restrictions.

Generation Background
The significant changes described in previous boundary commentaries (B1–B7, NW1–NW4, EC1) also apply to this boundary and the net effect is shown in Figure B8.2. The area between B7 and B8 is currently dominated by thermal generation. A range of new generation connections and closures are considered across the scenarios including offshore wind and thermal generation.

Potential Reinforcements
Table B8.1 lists the reinforcement options which will improve the B8 boundary capability to meet the potential increases in transfer requirements from 2012/13 to 2031/32.

Table B8.1:
List of potential reinforcement projects in the B8 boundary

Ref	Reinforcement	Works Description
B8-R01	Wylfa–Pembroke HVDC	A new 2–2.5 GW HVDC submarine link from Wylfa/Irish Sea to Pembroke with converter stations at both ends. Substation extension at Wylfa and Pembroke
B8-R02	Reactive compensation support	A number of MSCs either side of the B8 and B9 boundary
B11-R01	Midlands–South strategy	Reconductor the High Marnham–West Burton 400kV circuits with higher rated conductor
B17-R02	Reconductor Cellarhead–Drakelow	Reconductor the Cellarhead–Drakelow double circuit with higher rated conductor
EC1-R01	Killingholme South Substation, new transmission route to West Burton and Humber circuits reconductoring	Creation of a new 400kV substation at Killingholme South, construction of new transmission route to West Burton and reconductoring of Humber circuits
EC5-R08	New substation near Walpole and new transmission line	Establish a new 400KV double busbar substation near Walpole with connection to the existing substation. New transmission route from the new near Walpole substation to the Cottam–Eaton Socon circuits
EC5-R04	Walpole QBs	Installation of two Quadrature Boosters at Walpole in the Bramford–Norwich circuits
OS Link-02	Humber–Wash Offshore Integration	Offshore integration between Humber, Dogger Bank, Hornsea offshore project and Wash region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region
OS Link-04	Irish Integration	Controllable interconnection between the Irish Wind circuits connecting to Pentir and Pembroke

Boundary Discussion and Opportunities

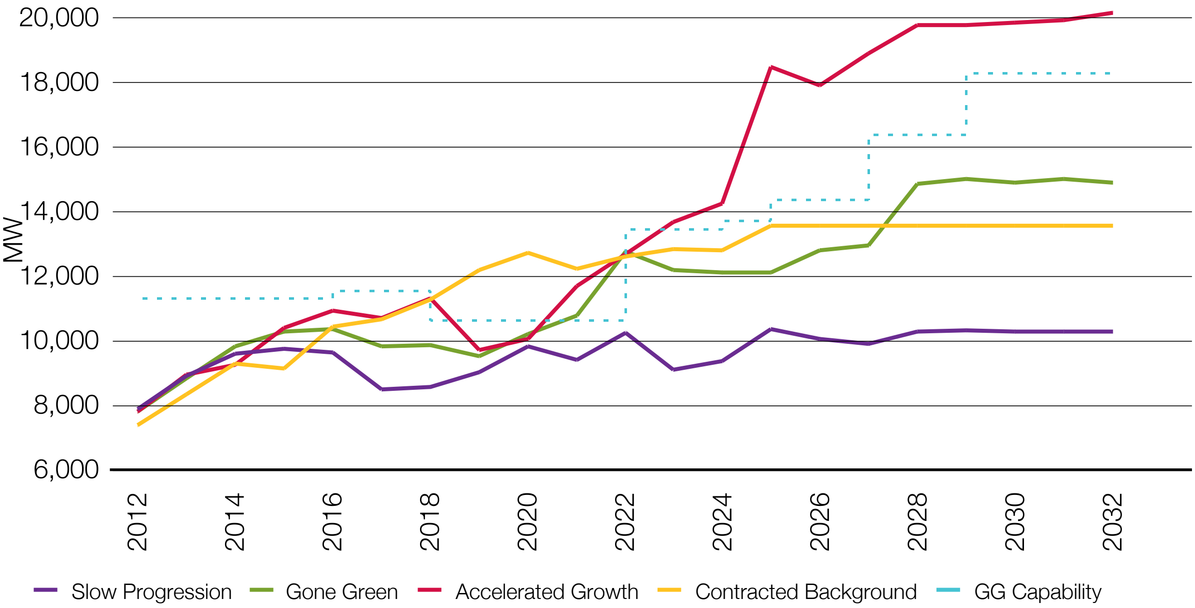
Boundary B8 has traditionally been heavily loaded at the time of winter peak due to high north to south power flows. Several offshore wind farms are expected to connect north of B8. These new connections drive the trend of significant increases in required transfers for all scenarios, as shown in Figure B8.2 with the exception of Slow Progression which increases slowly in the next few years then remains steady beyond 2020.

Reactive energy support in the areas with long heavily loaded circuits is the key to sustain the high level of power transfer across the boundary.

Changes in the capacity and geographic locations of the generation in the Midlands could lead to variations in the B8 boundary capability throughout the years of analysis.

Figure B8.2 below shows the required transfer capabilities from 2012 to 2032 for the four different scenarios, as well as the optimum reinforcements and their timing for the Gone Green scenario. Beneath, Table B8.2 identifies the reinforcements selected for each scenario.

Figure B8.2:
Required transfer and capability for boundary B8



The existing infrastructure will sustain the additional transfer requirements up to 2020 except for in the Contracted Background, despite changes in the generation background leading to a capability decrease. Onshore reinforcement will be required for the Contracted Background around 2018. B8-R01 will be required in all scenarios with the exception of Slow Progression to satisfy the transfer requirement by creating an extra route for the power to flow south. The HVDC link will provide shared benefits across several wider boundaries.

In addition to B8-R01, offshore integration in the East Coast and Wales (OS Link-02, OS Link-03, and OS Link-04) will provide transfer capability to B8 and reduce the requirement for onshore reinforcements. Together with onshore

3.7 continued
Wider boundaries

reinforcements (B11-R01, B17-R02, EC1-R01, EC5-R08, EC5-R06), boundary B8 will have the capability of meeting required transfers. Beyond 2024 in the Accelerated Growth scenario voltage requirement limitations start to impact the boundary capability of B8. B8-R02 will resolve these limitations. Table B8.2 shows the year the reinforcements of B8 are required, and the available date of potential co-ordinated offshore links.

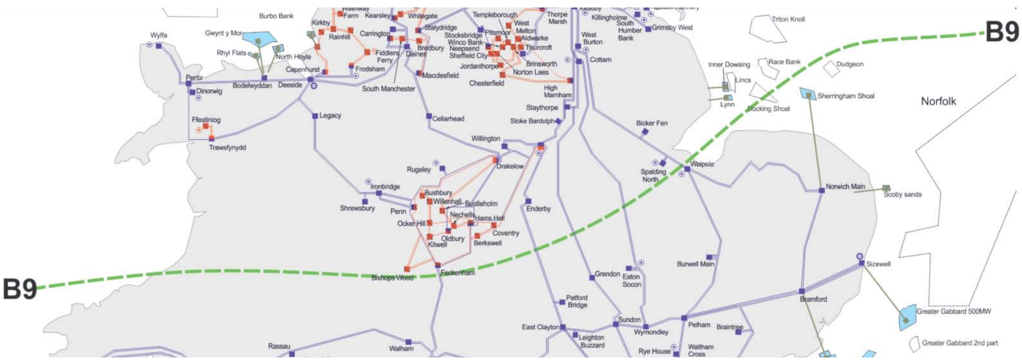
Table B8.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B8-R01	–	2022	2022	2019
B8-R02	2031	2029	2024	2018
B11-R01	–	–	2025[1]	–
B17-R02	2031[1]	2029[1]	2024[1]	2018[1]
EC1-R01	–	2027[1]	2024[1]	–
EC5-R08	–	–	2024[1]	2020[1]
EC5-R04	–	2025[1]	2021[1]	2018[1]
OS Link-02	–	2024[1]	2023 2025[1]	–
OS Link-03	–	2029[1]	2026 2028 2030[1]	–
OS Link-04	–	2025[1]	2025[1]	2018[1]

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7.10
Boundary B9

Figure B9.1:
Geographical representation of boundary B9



The Midlands to South 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. These long and heavily loaded circuits present voltage compliance challenges, which makes delivering reactive compensation support in the right area key for maintaining high transfer capability. Developments in the East Coast and the East Anglia regions, such as the locations of offshore wind generation connection and the network infrastructure requirements, will have a significant impact on both the transfer requirement and capability of B9. The current boundary capability is 12.6 GW, limited by thermal and voltage restrictions.

Generation Background
The significant changes described in previous boundary commentaries (B1–B8, NW1–NW4, EC1) also apply to this boundary and the net effect is shown in Figure B8.2. The area between B8 and B9 is currently dominated by thermal generation in the West Midlands and Trent Valley. A range of new generation connections and closures are considered across the scenarios including offshore wind and thermal generation.

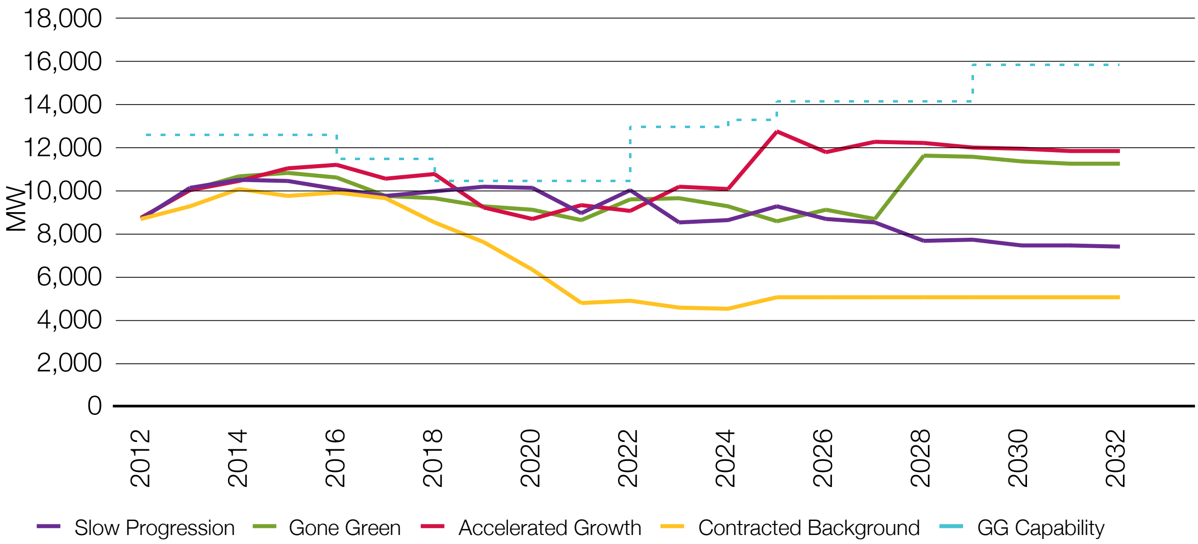
Potential Reinforcements
Table B9.1 lists reinforcement options which will improve the B9 boundary capability to meet the potential increases in required transfer levels from 2012/13 to 2031/32.

Table B9.1:
List of potential reinforcement projects in the B9 boundary

Ref	Reinforcement	Works Description
B8-R01	Wylfa–Pembroke HVDC	A new 2-2.5 GW HVDC submarine link from Wylfa/Irish Sea to Pembroke with converter stations at both ends. Substation extension at Wylfa and Pembroke
B8-R02	Reactive compensation support	A number of MSCs either sides of the B8 and B9 boundary
B11-R01	High Marnham–West Burton uprate	Reconductor the High Marnham–West Burton 400kV circuits with higher rated conductor
B17-R02	Reconductor Cellarhead–Drakelow	Reconductor the Cellarhead–Drakelow double circuit with higher rated conductor
EC5-R08	New substation near Walpole and new transmission line	Establish a new 400KV double busbar substation near Walpole with connection to the existing substation. New transmission route from the new near Walpole substation to the Cottam–Eaton Socon circuits
EC5-R04	Walpole QBs	Installation of two Quadrature Boosters at Walpole in the Bramford–Norwich circuits.
OS Link-02	Humber–Wash Offshore Integration	Offshore integration between Humber, Dogger Bank, Hornsea offshore project and Wash region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region
OS Link-04	Irish Integration	Controllable interconnection between the Irish Wind circuits connecting to Pentir and Pembroke

Boundary Discussion and Opportunities
Figure B9.2 shows the required transfers of B9 across all the scenarios slowly increase in the next few years due to the growing generation capacity in the north. The transfers then decrease due to thermal plant closures and East Coast offshore wind generation connected to the south of this boundary. Transfer requirements for Accelerated Growth and Gone Green increase beyond 2025 and 2028 respectively as additional renewable generation connects north of B9. Required transfer for the Contracted Background decreases during 2017 to 2021 as wind generation and new nuclear units connect in East Anglia.

Figure B9.2:
Required transfer and capability for boundary B9



There is sufficient capacity across this boundary to meet requirements of all the scenarios until 2024. The boundary benefits from many projects that are required by the East Coast, North Wales and B8, B11 boundaries, including offshore reinforcements (B8-R01, OS Link-02, OS Link-03, OS Link-04) and onshore reinforcements (B8-R02, B11-R01, B17-R02, EC5-R08, EC5-R06). Table B9.2 shows the year the reinforcements of B9 are required, and the available date of potential co-ordinated offshore links.

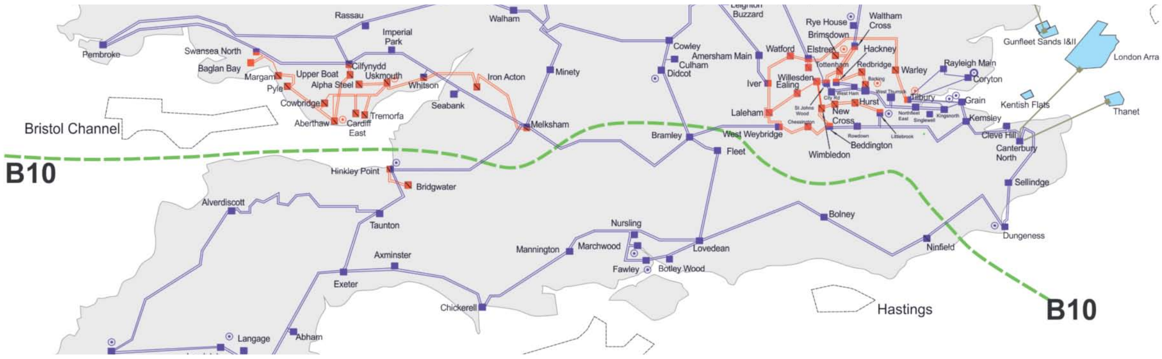
Table B9.3:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B8-R01	–	2022[1]	2022[1]	2019[1]
B8-R02	2031[1]	2029[1]	2024	2018[1]
B11-R01	–	–	2025[1]	–
B17-R02	2031[1]	2029[1]	2024[1]	2018[1]
EC5-R08	–	–	2024[1]	2020[1]
EC5-R04	–	2025[1]	2021[1]	2018[1]
OS Link-02	–	2024[1]	2023 2025[1]	–
OS Link-03	–	2029[1]	2026 2028 2030[1]	–
OS Link-04	–	2025[1]	2025[1]	2018[1]

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7.11
Boundary B10

Figure B10.1:
Geographical representation of boundary B10



Boundary B10 encompasses the South West peninsula and the South Coast. B10 is characterised by four 400kV double circuits from Hinkley Point to Melksham, Ninfield to Dungeness, Bramley to Didcot and Bramley to West Weybridge. B10 is traditionally a heavily importing boundary with higher demand than generation. The capability of the boundary is around 6 GW.

Generation Background

The existing generation within this boundary is mostly thermal, as well as the nuclear generator at Hinkley Point. There is over 5 GW of renewable generation and 3.3 GW of new nuclear generation capacity contracted to connect within this boundary.

The scenarios consider a full range of potential offshore wind, nuclear and other renewable generation. All scenarios show a gradual increase in total generation from current levels of 5 GW.

Potential Reinforcements

Potential reinforcements for the period to 2032 are listed on page 133 in Table B10.1.

1 www.nationalgrid.com/uk/Electricity/MajorProjects/HinkleyConnection/

Table B10.1:
List of potential reinforcement projects in the B10 boundary

Ref	Reinforcement	Works Description
B13-R01	Hinkley Point–Bridgewater–Seabank 400kV Transmission Circuit[1]	New 400kV substation at Hinkley Point New 400kV transmission line from Hinkley to Seabank Reconstruction of Bridgewater substation for 400kV operation Uprate Bridgewater to Melksham to 400kV

Boundary Discussion and Opportunities

Figure B10.2 below shows the required transfer for B10 from 2012 to 2032 for the four different scenarios, as well as the boundary capability for Gone Green including any increase from reinforcements selected to meet increasing requirements. Table B10.2 identifies the selected reinforcements, and their timing, for each scenario.

Figure B10.2:
Required transfer and capability for boundary B10

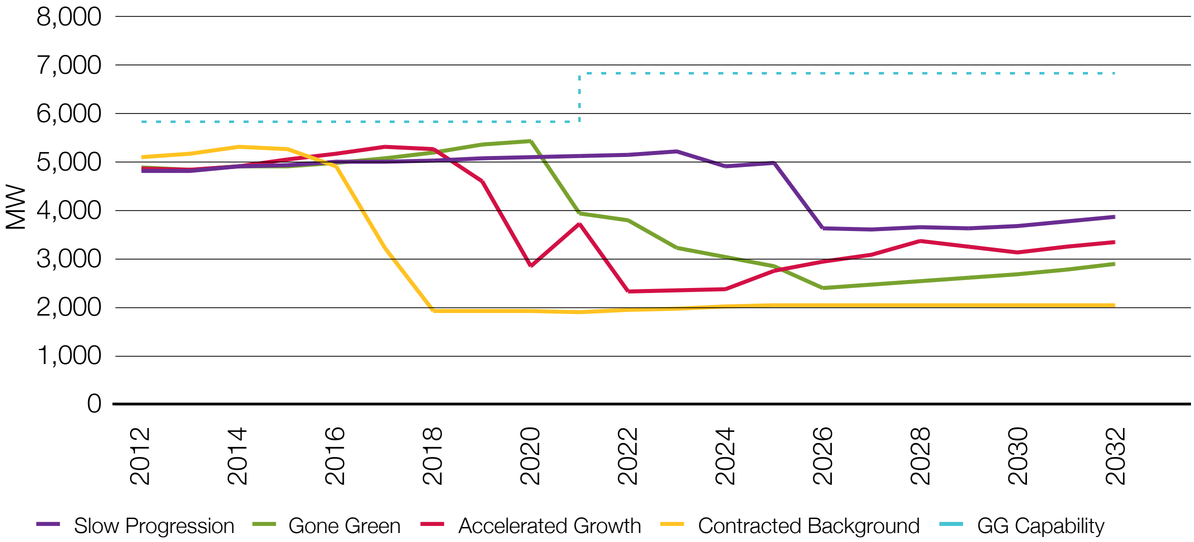


Table B10.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B13-R01	2024[1]	2021[1]	2020[1]	2017[1]

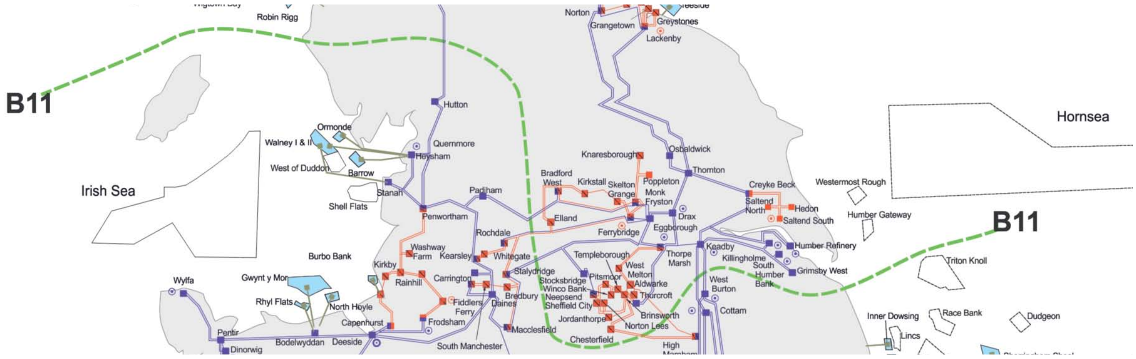
Due to the importing characteristic of boundary B10, as the generation within the boundary increases the required transfer decreases in all four scenarios. The current boundary capability is sufficient to facilitate new generation connections within the boundary in all four scenarios. Reinforcements identified for boundary B13 also benefit boundary B10.

Due to the geographic spread and close proximity to shore of the offshore wind zones in this region, it is considered unlikely that there will be economic network benefit in providing offshore interconnection between these zones. Such opportunities are unlikely to benefit boundary capability.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7.12
Boundary B11

Figure B11.1:
Geographical map of boundary B11



Boundary B11 intersects the north of England. From west to east it crosses through the Harker–Hutton 400kV circuits, before sweeping south across three pairs of circuits between the Yorkshire and Cheshire/Lancashire areas. It then runs east between Nottinghamshire and Lincolnshire south of the Humber area, cutting across the Keadby–Cottam and Keadby–West Burton lines. To the north and east of the boundary are the power exporting regions of Scotland, Yorkshire and the Humber. It is currently limited to a maximum power transfer of 9.2 GW by voltage compliance issues.

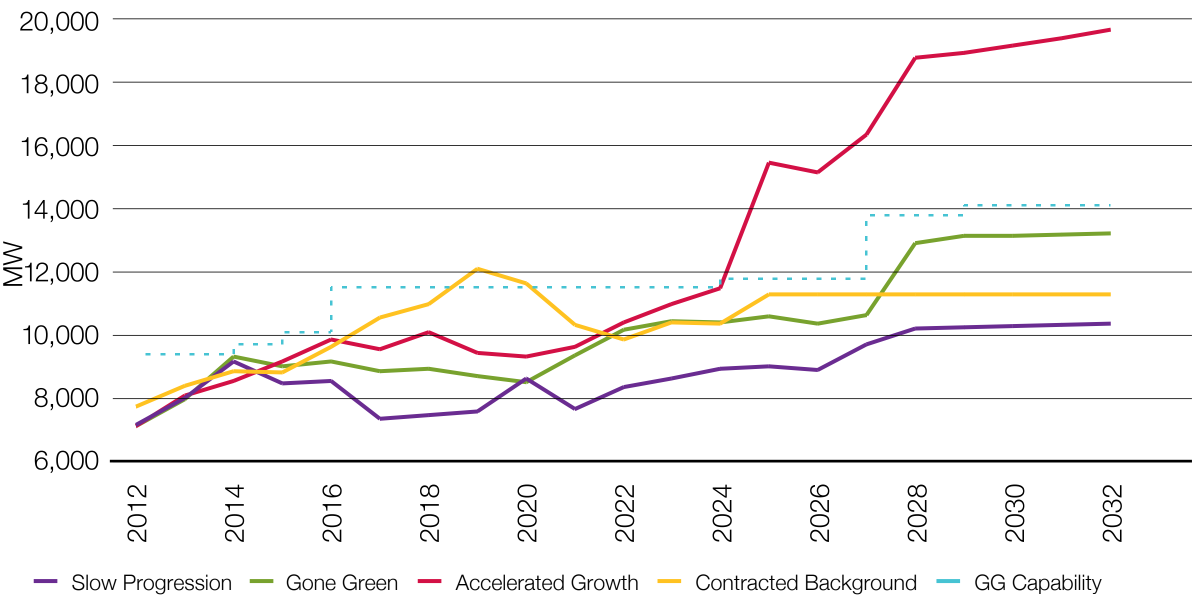
Generation Background
The significant changes described in previous boundary commentaries (B1–B7, EC1 and EC7) also apply to this boundary and the net effect is shown in Figure B11.2. A range of new generation connections and closures are considered across the scenarios including offshore wind and thermal generation.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 136 in Table B11.1.

Table B11.1:
List of potential reinforcement projects in the B11 boundary

Ref	Reinforcement	Works Description
B6-R01	Series and Shunt Compensation	Series compensation to be installed in Harker–Hutton, Eccles–Stella West and Strathaven–Harker routes. Strathaven–Smeaton route uprated to 400kV and cables at Torness uprated
B7-R01	Harker–Hutton Reconductoring	Reconductoring of the Harker–Hutton–Quernmore circuits with higher rated conductor
B6-R02	Western HVDC Link	A new 2.4 GW (short-term rating) submarine HVDC cable route from Deeside to Hunterston with associated AC network reinforcement works on both ends
EC1-R01	Killingholme South Substation, new transmission route to West Burton and Humber circuits reconductoring	Creation of a new 400kV substation at Killingholme South, construction of new transmission route to West Burton and reconductoring of Humber circuits
B11-R01	Midlands–South Strategy	Reconductor the High Marnham–West Burton 400kV circuits with higher-rated conductor
OS Link-02	Humber–Wash Offshore Integration	Offshore integration between Humber, Dogger Bank, Hornsea offshore project and Wash region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region

Figure B11.2:
Required transfer and capability for boundary B11



1 Reinforcement date triggered by prior requirement from boundary in the reference name

Boundary Discussion and Opportunities
Figure B11.2 above shows the required transfer capabilities from 2012 to 2032 for three scenarios and the contracted background, as well as the optimum reinforcements and their timing for the Gone Green scenario. Table B11.2 identifies the reinforcements selected for each scenario.

Table B11.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	CB
B6-R01	2015[1]	2015[1]	2015[1]	2015[1]
B7-R01	2014[1]	2014[1]	2014[1]	2014[1]
B6-R02	2016[1]	2016[1]	2016[1]	2016[1]
EC1-R01		2027[1]	2024	–
B11-R01	–		2025	–
OS Link-02	–	2024[1]	2023 2026	–
OS Link-03	–	2029[1]	2026 2028 2030[1]	–

Wider boundaries

An initial increase in required transfers by 2014 in all scenarios is caused by the closure of up to 6 GW of ageing thermal plant south of the boundary and approximately 1 GW of wind commissioning to the north.

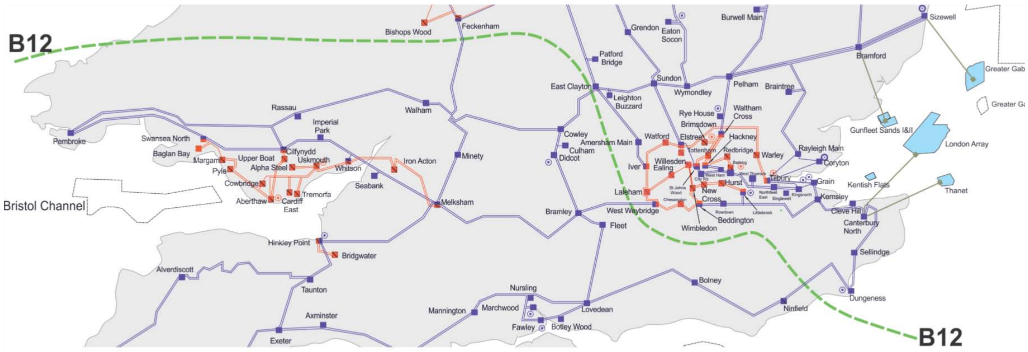
For the Contracted background, early connection of significant volumes of offshore wind in the north results in a very large increase in required transfer levels by 2019, but significant wind and nuclear connections further south reduce this by 2021 and no further reinforcements are warranted.

For all scenarios the boundary capability is expected to be sufficient to meet power flow requirements until 2024. From 2024 onwards under Accelerated Growth further reinforcements will be required but this will be re-evaluated as the future power flow patterns become clearer.

For Gone Green, in 2028 significant closures occur in the south, increasing the required transfer significantly. Reinforcement EC1-R01 triggered by EC1 in 2027 provides ample capability beyond the period of interest, and offers some opportunity for further connections close to the boundary.

3.7.13
Boundary B12

Figure B12.1:
Geographical representation of boundary B12



Boundary B12 encompasses South Wales, the South West and a large section of the South Coast; with four 400kV double circuits, Feckenham–Walham, Cowley–Sundon and Cowley–East Claydon, Bramley–West Weybridge and Dungeness–Ninfield circuits. There is a large volume of both demand and generation within the boundary. Existing generation is mostly thermal, at locations such as Pembroke, Fawley and Didcot and large nuclear units at Hinkley Point and Oldbury. The boundary is generally expected to export in Winter Peak conditions.

Generation Background

Boundary B12 currently contains 13.8 GW of thermal generation and is expected to accommodate up to 8 GW of new renewable generation connections by 2032. Some closure of existing thermal generation is expected within this boundary.

Potential Reinforcements

Potential reinforcements for the period to 2032 are listed on page 140 in Table B12.1.

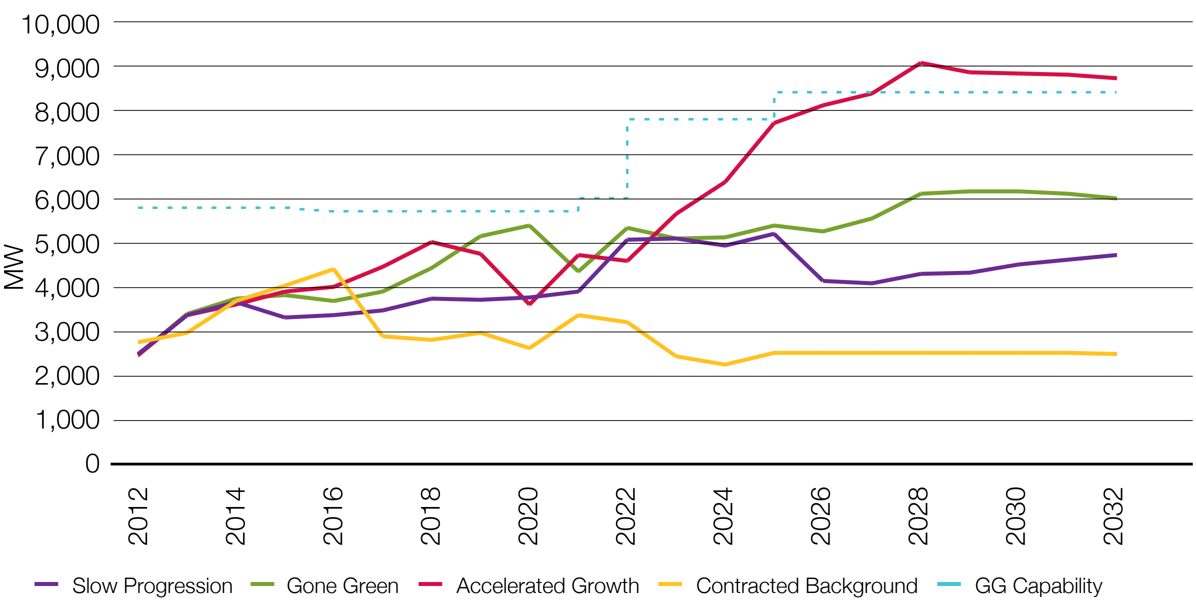
Wider boundaries

Table B12.1:
List of potential reinforcement projects in the B12 boundary

Ref	Reinforcement	Works Description
B8-R01	Wylfa–Pembroke HVDC link	2–2.5 GW HVDC link from Wylfa/Irish Sea to Pembroke Substation extension at Wylfa and Pembroke
B14(e)-R02	Sundon–Cowley turn in	Turn-in the existing Sundon–Cowley circuit into East Claydon to form Sundon–East Claydon double circuit and East Claydon–Cowley double circuit
OS Link-04	Irish Integration	Controllable interconnection between the Irish Wind circuits connecting to Pentir and Pembroke

Boundary Discussion and Opportunities
Figure B12.2 below shows the required transfer for B12 from 2012 to 2032 for the four different scenarios, as well as the boundary capability, including any increase from reinforcements selected to meet increasing requirements. Table B12.2 identifies the reinforcements, and their timing to satisfy each scenario requirements.

Figure B12.2:
Required transfer and capability for boundary B12



1 Reinforcement date triggered by prior requirement from boundary in the reference name

Table B12.2:
Selection and timing of reinforcements

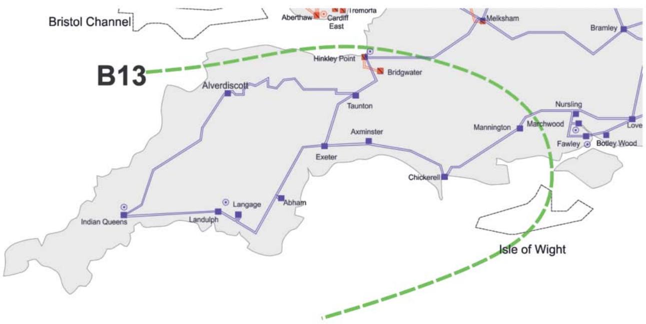
Ref	SP	GG	AG	C
B8-R01	–	2022[1]	2022[1]	2019[1]
B14(e)-R02	–	2021[1]	2017[1]	2017[1]
OS Link-04	–	2025[1]	2025[1]	2018[1]

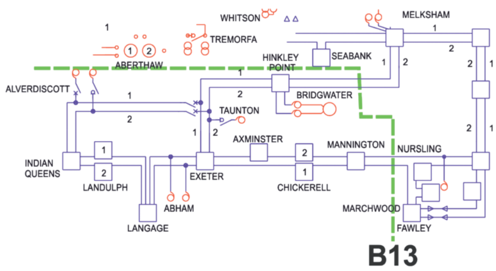
Boundary B12 is generally an exporting boundary with its current capability significantly in excess of its current required transfer. If significant new generation north of the Boundary connects as in the Accelerated Growth scenario then the requirements begin to exceed the current capability after 2023. B12 is compliant under all scenarios until 2027 when reinforcement may need to be considered for the Accelerated Growth scenario. Additional benefit to the boundary capability is provided by B8-R01, B14(e)-R01 and OS Link-04 which are triggered by boundaries B8, B14(e) and NW2.

Table B12.2 shows the timing of these network developments as driven by the respective boundaries. While all these reinforcements are not required for B12, the improvement in capability represents an opportunity for further connections to be facilitated behind the boundary.

3.7.14
Boundary B13

Figure B13.1:
Geographical and single line representation of boundary B13





Wider boundary B13 is defined as the southernmost tip of the UK below the Severn Estuary, encompassing Hinkley Point in the south-west and stretching as far east as Mannington. It is characterised by the Hinkley Point to Melksham double circuit and the Mannington circuits to Nursling and Fawley. It is a region with a high level of localised generation as well as local zonal demand. The boundary is currently an importing boundary with the demand being higher than the generation at peak conditions. With the potential of new generation connecting to the south-west, including new nuclear and wind generation, the boundary is expected to change to export more often than import. The current import and export capability is around 2 GW.

Generation Background
This boundary currently contains approximately 2.3 GW of nuclear and thermal generation. There is the potential for new nuclear, offshore wind and marine in this area.

The scenarios consider a full range of potential offshore wind, nuclear and other renewable generation.

Potential Reinforcements
Potential reinforcements for the period to 2030 are listed on page 143 in Table B13.1.

1 www.nationalgrid.com/uk/Electricity/MajorProjects/HinkleyConnection/

Table B13.1:
List of potential reinforcement projects in the B13 boundary

Ref.	Reinforcement	Works Description
B13-R01	Hinkley Point–Bridgewater–Seabank 400kV Transmission Circuit[1]	New 400kV substation at Hinkley Point. New 400kV transmission line from Hinkley to Seabank Reconstruction of Bridgewater substation for 400kV operation Uprate Bridgewater to Hinkley Point to 400kV
B13-R02	Bramley–Melksham reconductoring	Reconductoring of circuits with higher rated conductor between Bramley and Melksham

Boundary Discussion and Opportunities

Figure B13.2 below shows the variation in B13 boundary requirements from 2012 to 2032 under the three scenarios and the contracted background, as well as the capability provided by the proposed reinforcements for the Gone Green scenario. The timing and selection of the reinforcements for each scenario is detailed in Table B13.2

Figure B13.2:
Required transfer and capability for boundary B13

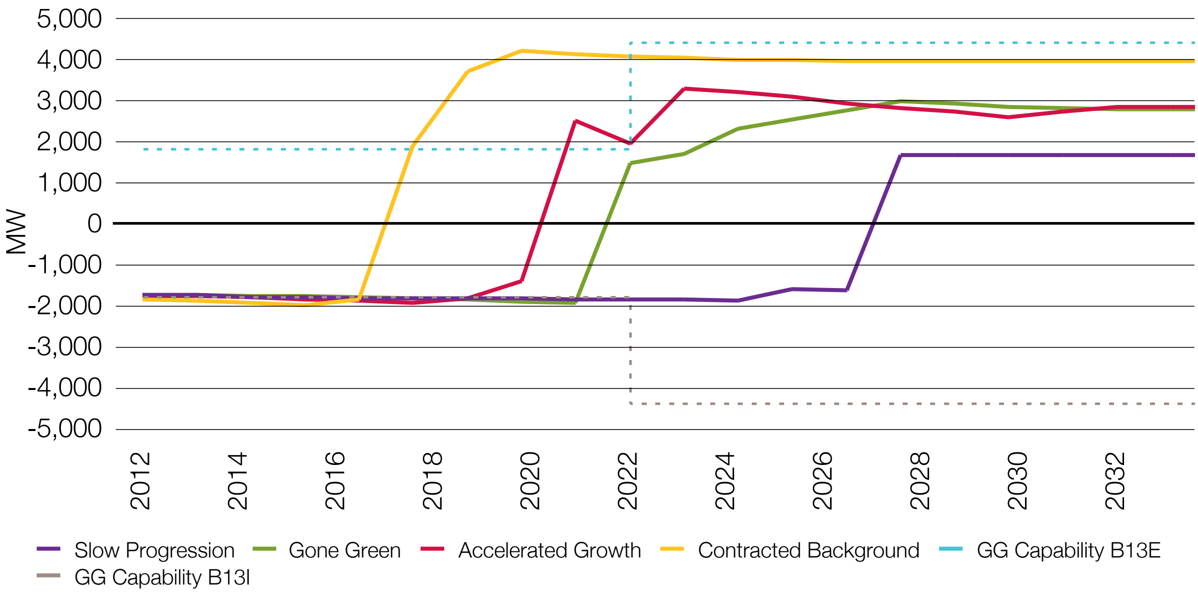


Table B13.2:
Selection and timing of reinforcements

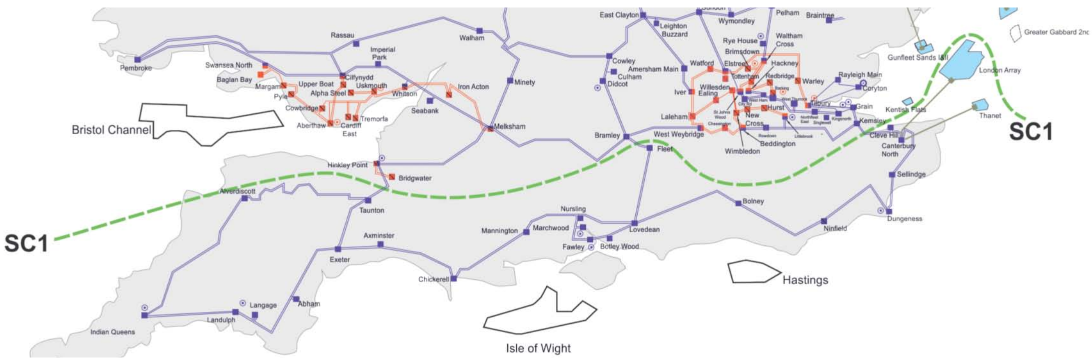
Ref	SP	GG	AG	C
B13-R01	2024	2021	2020	2017

The boundary retains it's ~2 GW importing characteristic until the commissioning of the new nuclear and renewable generation as can be seen in Figure B13.2 after 2016.

The current boundary capability appears sufficient to accommodate up to 4 GW of new generation connections but due to the sparse nature of the existing transmission network and large unit sizes of the new nuclear connections, the proposed new circuit (B13.1) is required for the first new nuclear generator unit in order to maintain system stability. The reinforcement dates in Table B13.2 have therefore been aligned to the first nuclear unit connection.

3.7.15
Boundary SC1

Figure SC 1.1:
Geographical representation of boundary SC1



This boundary as shown in Figure SC1.1 runs parallel to the south coast of England between the Severn and Thames Estuaries, crossing three major double circuits: Canterbury North–Cleve Hill in the East, Hinkley point–Taunton in the West and Bramley–Fleet in the centre. The subsystem enclosed is historically an importing area of the system. Future scenarios include new wind farms and new HVDC interconnection to Europe, which gives rise to the risk of significant variation in the transfer levels.

Generation Background
Installed generation broadly matches demand but a reduced contribution from older plant plus the potential for exports to France via the 2 GW IFA interconnector may result in an import into the region. The potential for further interconnection capacity could impact on the required transfers and may increase imports into the region.

This import is reduced by the potential connection of new generation. Within this area, there is an opportunity for up to 5.7 GW of offshore wind connections in the contracted background.

The scenarios consider a full range of potential offshore wind and interconnector generation.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 146 in Table SC1.1.

Table SC1.1:
List of potential reinforcement projects in the SC1 boundary

Ref	Reinforcement	Works Description
SC1-R01	Dungeness–Sellindge reconductoring	Reconductor Dungeness to Sellindge 400kV double circuit to higher capability
SC1-R02	Sellindge–Canterbury reconductoring	Reconductor Sellindge to Canterbury North 400kV double circuit to higher capability
SC1-R03	Reactive compensation at Canterbury substation	SVCs and MSC at HVDC Terminal

Boundary Discussion and Opportunities
Figure SC.1.2 illustrates the range of possible Required Transfers arising in the scenarios and the Contracted Background. The boundary capability including contribution from additional reinforcements is also illustrated for the Gone Green scenario. Table SC1.2 identifies the selected reinforcements, and their timing, for each scenario.

Figure SC1.2:
Required transfer and capability for boundary SC1

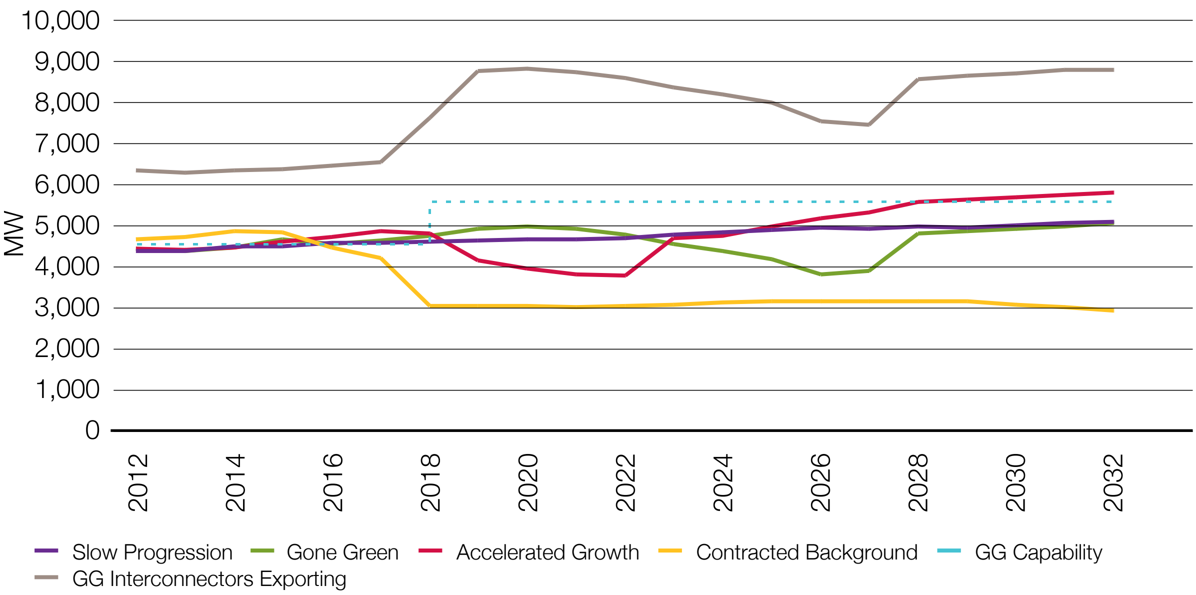


Table SC1.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
SC1-R01	2018	2018	2018	2018
SC1-R02	2018	2018	2028	2018
SC1-R03	2018	2018	2018	2018

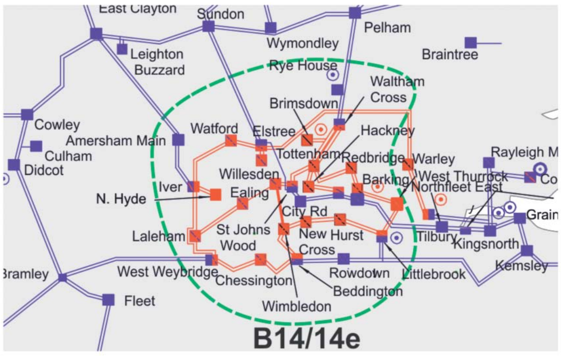
As this boundary is an importing boundary, large generation connections in the Contracted Background cause a drop in required transfers. The effect of the interconnectors under fully exporting conditions is plotted based on the Gone Green scenario, demonstrating the impact on boundary transfers.

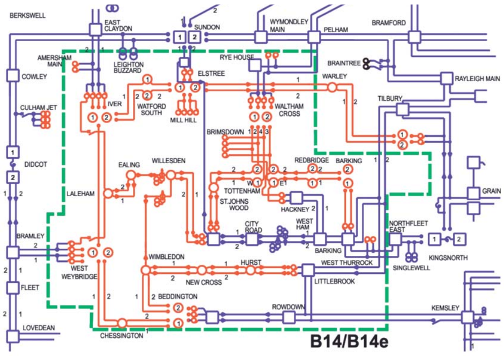
The reinforcements SC1-R01 to SC1-R03 are triggered due to the connection of new interconnectors on the South coast and the delivery date is consistent with the interconnector contracted dates and system access periods.

Due to the geographic spread yet close proximity to shore of the offshore wind zones it is considered unlikely that there will be economic network benefit in providing offshore interconnection between zones and such opportunities are unlikely to benefit boundary capability.

3.7.16
Boundary B14

Figure B14.1:
Geographical and single line representation of boundary B14





Boundary B14 (and B14(e) as discussed later) encloses London and is characterised by high local demand and minimal generation. London's energy import relies heavily on a number of 400KV circuits and a 275kV circuit bringing power from the surrounding areas. Due to the large importing requirement, the North London circuits crossing this boundary are heavily loaded under winter peak conditions. The circuits are further stressed when the European interconnectors export. The north London circuits can also be a bottleneck for power flow from the East Coast and East Anglia regions.

Generation Background
There is currently little generation in the London area with demand mainly met by generation outside the boundary. Major new generation projects are not expected within the boundary across any of the scenarios. As this a predominantly demand driven boundary the demand growth is the dominant factor in the boundary's requirements.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 149 in Table B14.1. Network reinforcements for this boundary are heavily dependent on the flow on interconnectors. B14(e), as discussed later, therefore drives most of the reinforcements which impact this boundary.

Table B14.1:
List of potential reinforcement projects in the B14 boundary

Ref	Reinforcements	Works Description
B14(e)-R01	Hackney–Tottenham–Waltham Cross uprate and Pelham Rye House reconductor	Uprating and reconductoring of the Hackney–Tottenham–Brimsdown–Waltham Cross double circuit. Reconductoring of Pelham–Rye House circuit. Construction of new 400kV substation at Waltham Cross. Modification to Tottenham substation. Installation of two new transformers at Brimsdown substation
B14(e)-R02	Sundon–Cowley turn-in	Turn-in the existing Sundon–Cowley circuit into East Claydon to form Sundon–East Claydon double circuit and East Claydon–Cowley double circuit
B14(e)-R03	Elstree turn in and 400kV series reactor	Turn-in the Sundon 2 circuit to the 400kV substation and install a second series reactor
B14(e)-R04	West Weybridge–Beddington–Chessington uprate	Uprating the 275KV overhead line route connecting substations at West Weybridge, Chessington and Beddington to 400kV
B14(e)-R05	Elstree–St John's Wood second cable	Installation of a second circuit through the existing St John's Wood–Elstree cable tunnel
B14(e)-R06	Elstree–Tilbury–Warley uprate	Uprating Elstree, Tilbury and Warley substation from 275kV to 400kV and uprating the 275kV route

Boundary Discussion and Opportunities
Figure B14.2 on page 150 shows the required transfer for Boundary B14 from 2012 to 2032 for the three scenarios and the Contracted Background, as well as the boundary capability for Gone Green including any increase from reinforcements selected to meet increasing requirements. Table B14.2 identifies the selected reinforcements, and their timing, for each scenario.

Figure B14.2:
Generation Background and capability for boundary B14

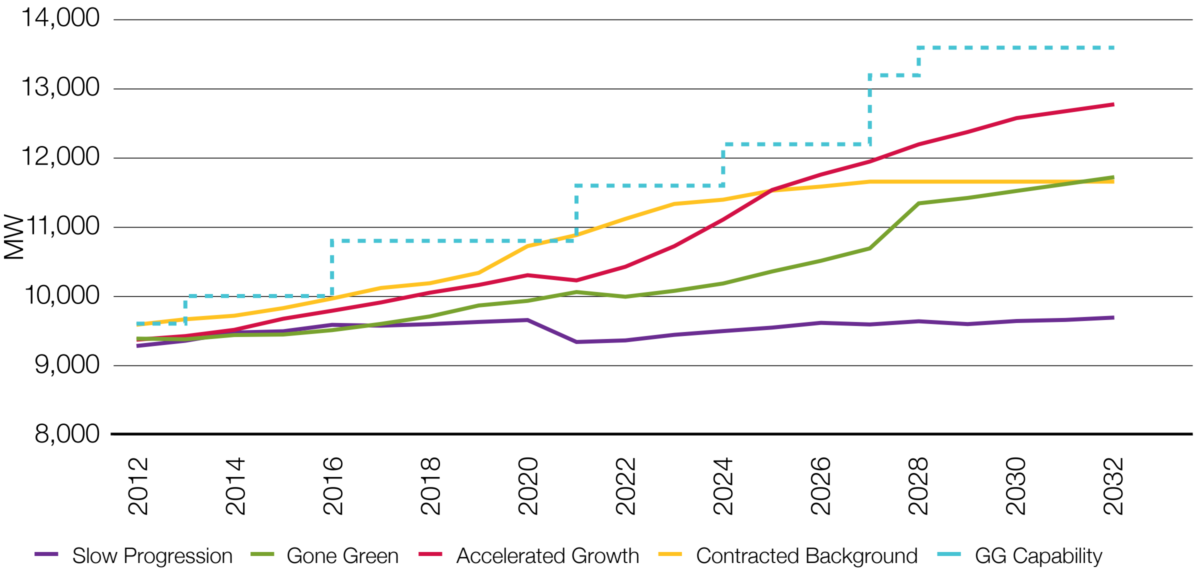


Table B14.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B14(e)-R01	2016	2016	2016	2016
B14(e)-R02	–	2021	2017	2017
B14(e)-R03	–	2021	2017	2017
B14(e)-R04	–	2028	2025	2021
B14(e)-R05	–	2027	2023	2019
B14(e)-R06	–	2024	2019	2018

A combination of increases in demand and closures of local generation units across the scenarios increases the required transfers into London. This leads to an increase in required transfer, the rate of which is dependent on the scenario under consideration.

Reinforcements driven by B14(e) boundary will provide sufficient capability for the transfer requirement across B14 under Gone Green, Accelerated Growth, Slow Progression and the Contracted background. Table B14.2 shows the timing of these reinforcements as required in B14(e) and Figure B14.2 shows the impact of B14(e) reinforcements on this boundary. Given the reinforcements are driven mainly by interconnector exporting conditions, their timing will be subject to robust cost benefit analysis (NDP) to determine the most cost efficient date for construction.

3.7.17
Boundary B14(e)

Boundary B14(e) is the boundary capability associated with the B14 circuits under conditions where the interconnectors export to continental Europe.

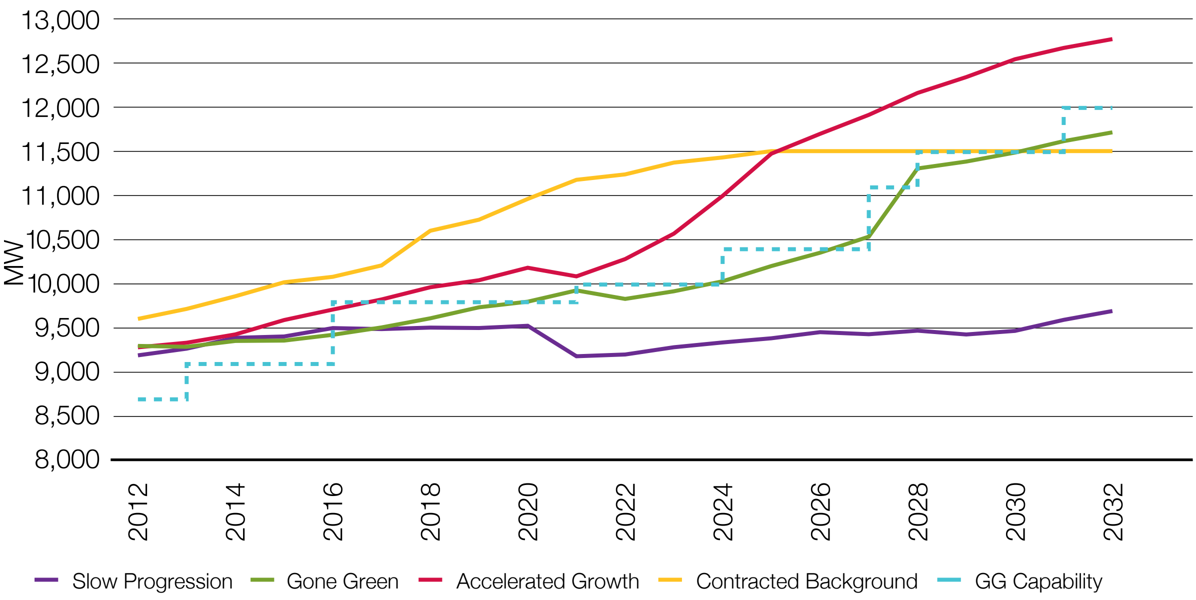
Generation Background
The generation background remains the same as explained in section 3.7.16. (boundary B14) above. For this variation the existing interconnectors are assumed at full export conditions; this corresponds to 3 GW export to France and Netherlands. As further interconnection is considered this increases to a potential of 4 GW total export.

Potential Reinforcements
Potential reinforcements for the period to 2030 are listed below in Table B14(e).1.

Table B14(e).1:
List of potential reinforcement projects in the B14(e) boundary

Ref	Reinforcements	Works Description
B14(e)-R01	Hackney–Tottenham–Waltham cross uprate and Pelham Rye House reconductor	Uprating and reconductoring of the Hackney–Tottenham–Brimsdown–Waltham Cross double circuit. Reconductoring of Pelham–Rye House circuit. Construction of new 400kV substation at Waltham Cross. Modification to Tottenham substation. Installation of two new transformers at Brimsdown substation
B14(e)-R02	Sundon–Cowley turn-in	Turn-in the existing Sundon–Cowley circuit into East Claydon to form Sundon–East Claydon double circuit and East Claydon–Cowley double circuit
B14(e)-R03	Elstree turn-in and 400kV series reactor	Turn-in the Sundon 2 circuit to the 400kV substation and install a second series reactor
B14(e)-R04	West Weybridge–Beddington–Chessington uprate	Uprating the 275KV overhead line route connecting substations at West Weybridge, Chessington and Beddington to 400kV
B14(e)-R05	Elstree–St John's Wood second cable	Installation of a second circuit through the existing St John's Wood–Elstree cable tunnel
B14(e)-R06	Elstree–Tilbury–Warley uprate	Uprating Elstree, Tilbury and Warley substation from 275kV to 400kV and uprating the 275kV route
B14(e)-R07	Reactive compensation support	Reactive compensation support to South London area
B14(e)-R08	Reactive compensation support	Reactive compensation support to North London area

Figure B14(e).2:
Required transfer and capability for boundary B14(e)



Boundary Discussion and Opportunities
With the HVDC links to Europe exporting, there is additional transfer necessary into the South East, which results in larger through-flow across London, causing a fall in the boundary B14(e) capability, limited by both voltage and thermal compliance issues.

The set of reinforcements listed in Table B14(e).2 provide sufficient boundary capability to facilitate the suggested European interconnection and allow unrestricted access to the European Energy Market. The benefits of these reinforcements for the Gone Green scenario are illustrated in Figure B14(e).2. The timing of reinforcements within the different scenarios is shown in Table B14(e).2, although this will be subject to robust cost benefit analysis (NDP) to determine the most cost efficient date for building the reinforcements. The calculated boundary transfer exceeds the capability from 2012 if the interconnectors are fully exporting to Europe. However the earliest possible year for delivering the identified B14(e)-R01 reinforcement is 2016. For the Accelerated Growth scenario, B14 remains non compliant, under interconnector exporting conditions, from 2028 onwards despite delivery of all the suggested reinforcements. This situation will need to be re-evaluated in the future as the status of generation, demand and interconnection becomes clearer.

In 2018 there is a proposal to connect an additional 1 GW interconnector to Belgium resulting in further decrease in boundary capability. This is not reflected in Figure B14(e).2 page 152, but it is clear that it may bring forward the required date of some reinforcements and necessitate additional ones.

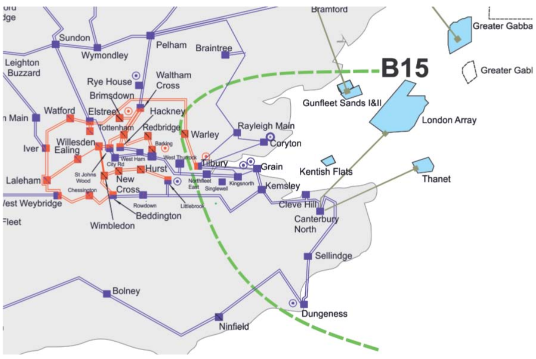
Table B14(e).2:
Selection and timing of reinforcements

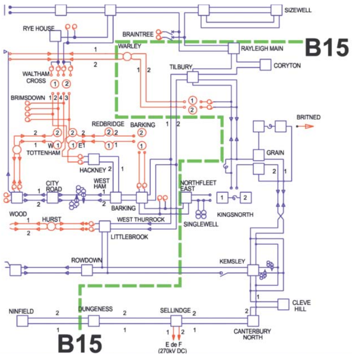
Ref	SP	GG	AG	C
B14(e)-R01	2016	2016	2016	2016
B14(e)-R02	–	2021	2017	2017
B14(e)-R03	–	2021	2017	2017
B14(e)-R04	–	2028	2025	2021
B14(e)-R05	–	2027	2023	2019
B14(e)-R06	–	2024	2019	2018
B14(e)-R07	–	2031	2026	–
B14(e)-R08	–	2031	2026	–

3.7 continued
Wider boundaries

3.7.18
Boundary B15

Figure B15.1:
Geographical and single line representation of boundary B15





B15 is the Thames Estuary boundary, enclosing the south-east corner of England. It has significant existing thermal generation and wind connections from the east. New nuclear generation is contracted for connection within this boundary. B15 is an exporting boundary feeding the demand in London and interconnectors to Europe.

Generation Background
Current generation within the boundary totals around 9 GW. The overall generation levels within the boundary initially decrease across all scenarios due to closures offsetting any new generation connections. A range of thermal and new nuclear generation connections are considered across the scenarios.

Potential Reinforcements
Potential reinforcements for the period to 2032 are listed on page 155 in Table B15.1.

Table B15.1:
List of potential reinforcement projects in the B15 boundary

Ref	Reinforcement	Works Description
B14(e)-1	Hackney–Tottenham–Waltham cross uprate and Pelham Rye House reconductor	Uprating and reconductoring of the Hackney–Tottenham–Brimsdown–Waltham Cross double circuit. Reconductoring of Pelham–Rye House circuit. Construction of new 400kV substation at Waltham Cross. Modification to Tottenham substation. Installation of two new transformers at Brimsdown substation

Boundary Discussion and Opportunities
Figure B15.2 below shows the required transfer for Boundary B15 from 2012 to 2032 for the three different scenarios and the Contracted Background, as well as the boundary capability including any increase from reinforcements selected to meet increasing requirements. Table B15.2 on page 156 identifies the selected reinforcements, and their timing, for each scenario.

Figure B15.2:
Required transfer and capability for boundary B15

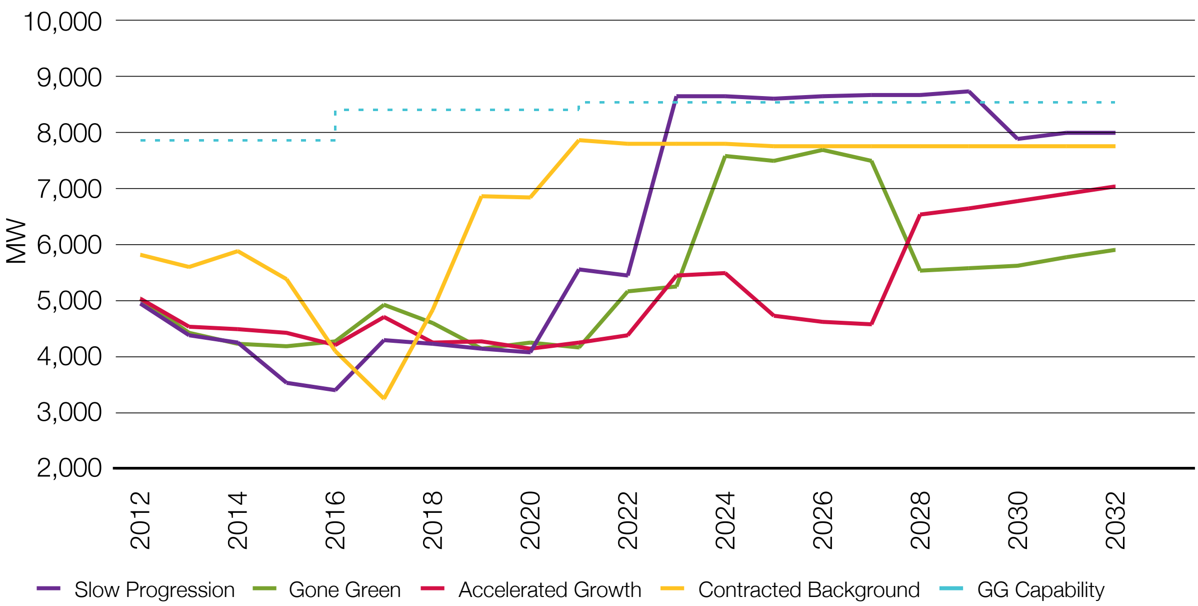


Table B15.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B14(e)-R01	2016[1]	2016[1]	2016[1]	2016[1]

B15 is generally an exporting boundary. The required transfer across B15 increases after 2017 for the Contracted Background. This corresponds to new generation connections of nearly 6 GW.

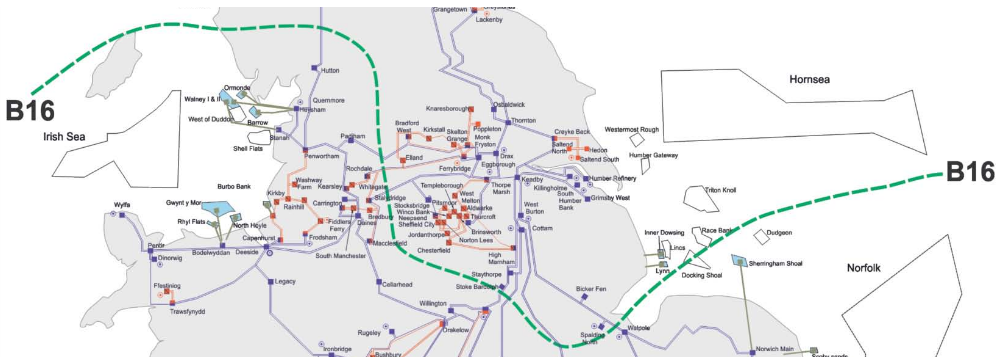
The boundary is compliant for Gone Green, Accelerated Growth and the Contracted Background up to 2032 due to the combination of new generation connections and closures.

Slow Progression, despite having a lower level of total generation than the Contracted Background, has the highest required transfer. This is because the transfer requirement switches from the economy to the security criteria of the SQSS, due to higher levels of thermal plant and a lower level of wind generation than the other scenarios. In this scenario, the boundary is non-compliant from 2022. This non-compliance can be partly relieved by the B14(e)-R01 reinforcement as described under boundary B14(e). This situation will need to be re-evaluated in the future as the status of generation, demand and interconnection becomes clearer.

1 Reinforcement date triggered by prior requirement from boundary in the reference name

3.7.19
Boundary B16

Figure B16.1:
Geographical map of boundary B16



B16 follows the path of B11 in the west, while in the east it also encompasses the areas of Nottinghamshire and Lincolnshire, thus incorporating additional generation from these regions. The boundary crosses the four double circuits running south from Nottinghamshire (West Burton / Cottam), instead of the two circuit pairs south of Keadby. Similarly to B11, B16 is considered a boundary that carries power from north to south. B16 is currently limited to a maximum transfer of just over 15 GW.

Generation Background
The significant changes described in previous boundary commentaries (B1–B7, EC1 and EC7) also apply to this boundary and the net effect is shown in Figure B16.2. A range of new generation connections and closures are considered across the scenarios including offshore wind and thermal generation.

Potential Reinforcements
Table B16.1 lists the options of reinforcements which will improve the B16 boundary capability to meet the potential increases in transfer requirements in the period to 2032.

Table B16.1:
List of potential reinforcement projects in the B16 boundary

Ref	Reinforcement	Works Description
B6-R01	Series and Shunt compensation	Series compensation to be installed in Harker–Hutton, Eccles–Stella West and Strathaven–Harker routes. Two 225MVar MSCs are to be installed at Harker, one at Hutton, two at Stella West and one at Cockenzie. Strathaven–Smeaton route uprated to 400kV and cables at Torness uprated
B6-R02	Western HVDC link	A new 2.4 GW (short-term rating) submarine HVDC cable route from Deeside to Hunterston with associated AC network reinforcement works on both ends
B7-R01	Harker–Hutton reconductoring	Reconductoring of the Harker–Hutton–Quernmore circuits with higher rated conductor
B11-R01	Midlands–South strategy	Reconductor the High Marnham–West Burton 400kV circuits with higher rated conductor
EC5-R08	New substation near Walpole and new transmission line	Establish a new 400KV double busbar substation near Walpole with connection to the existing substation. New transmission route from the new near Walpole substation to the Cottam–Eaton Socon circuits
EC5-R04	Walpole QBs	Installation of two Quadrature Boosters at Walpole in the Bramford–Norwich circuits
OS Link-02	Humber–Wash Offshore Integration	Offshore integration between Humber, Dogger Bank, Hornsea offshore project and Wash region
OS Link-03	Teesside–Wash Offshore Integration	Offshore integration between Teesside, Dogger Bank, Hornsea offshore projects and Wash region

Boundary Discussion and Opportunities
Figure B16.2 on page 159 shows the required transfer capabilities from 2012 to 2032 for the three scenarios and the Contracted Background, as well as the optimum reinforcements and their timing for the Gone Green scenario. Table B16.2 identifies the reinforcements selected for each scenario.

Figure B16.2:
Required transfer and capability for boundary B16

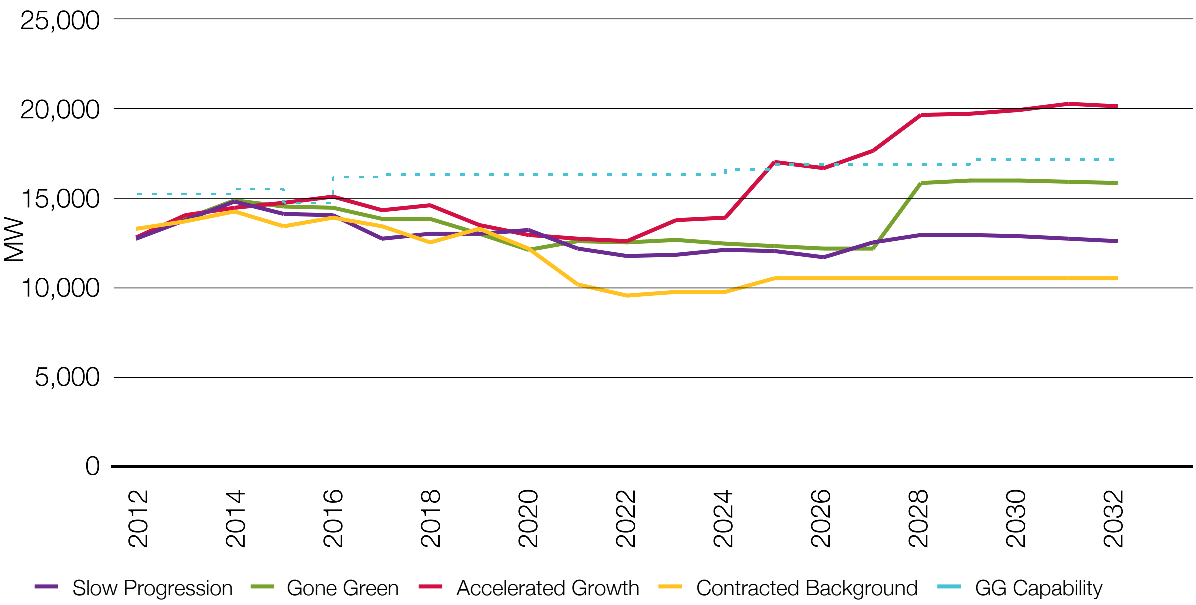


Table B16.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	CB
B6-R01	2015[1]	2015[1]	2015[1]	2015[1]
B6-R02	2016[1]	2016[1]	2016[1]	2016[1]
B7-R01	2014[1]	2014[1]	2014[1]	2014[1]
B11-R01	–	–	2025[1]	–
EC5-R08	–	–	2024[1]	2020[1]
EC5-R04	–	2025[1]	2021[1]	2018[1]
OS Link-02	–	2024[1]	2023 2025[1]	–
OS Link-03	–	2029[1]	2026 2028 2030	–

1 Reinforcement date triggered by prior requirement from boundary in the reference name

Boundary B16 has a high transfer capability which will sustain the development of new generation in the north of the boundary. The drop in capability shown on Figure B16.2 in 2015 is due to generation background changes, shifting power flow patterns in this area.

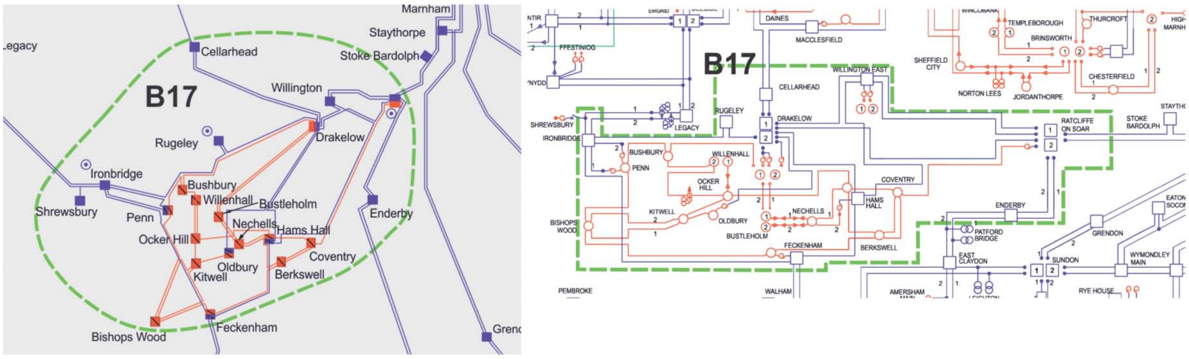
The transfer requirements of B16 increase steadily in the early years due to the expected closure of generation south of the boundary. The transfer requirements then decrease across all three scenarios and the Contracted Background due to generation closures in Yorkshire and the Humber region and generation development to the south of the boundary in Wales and the West Midlands.

3.7 continued
Wider boundaries

As one of the wider boundaries which intersect the middle of Great Britain, B16 crosses the same circuits as several other boundaries, and therefore the capability is improved by the same reinforcements as for those boundaries. If the East Coast offshore wind generation continues to develop as in the Accelerated Growth scenario, boundary B16 becomes non-compliant and will require further reinforcements. This situation will need to be re-evaluated in the future as the status of generation and demand becomes clearer.

3.7.20
Boundary B17

Figure B17.1:
Geographical and single line representation of boundary B17



Enclosing the West Midlands, Boundary B17 is heavily dependent on importing power from the north to meet within boundary demand due to a lack of local generation. Boundary B17 is surrounded by five 400kV double circuits but internally the circuits in and around Birmingham are mostly 275kV. Much of the north to south power flows seen by boundaries B8 and B9 also pass straight through B17, putting significant loading on these circuits. The existing boundary capability is in the region of 6 GW.

Generation Background
The existing generation within B17 is predominantly thermal plant. This boundary shows some development in thermal generation across all scenarios.

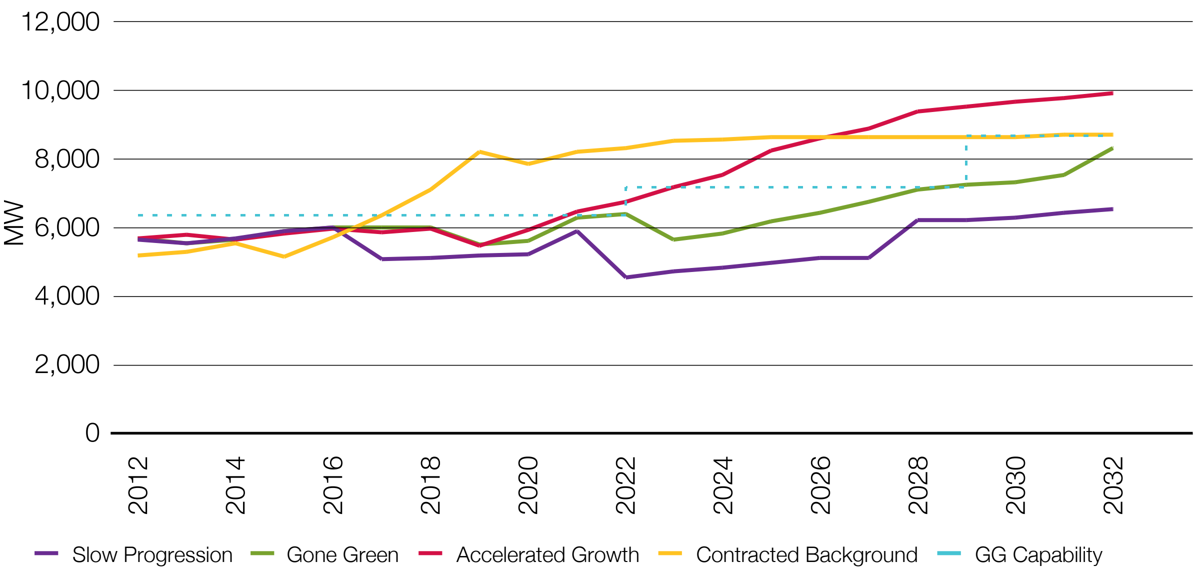
Potential Reinforcements
Potential network reinforcements which have an impact on this boundary for the period to 2032 are listed on page 162 in Table B17.1.

Table B17.1:
List of potential reinforcement projects in the B17 boundary

Ref	Reinforcement	Works Description
B17-R01	Reactive compensation support	Reactive support to the West Midlands area
B8-R01	Wylfa–Pembroke HVDC	2-2.5 GW HVDC link from Wylfa/Irish Sea to Pembroke. Substation extension at Wylfa and Pembroke.
B17-R02	Cellarhead–Drakelow reconductoring	Reconductor Cellarhead–Drakelow 400kV double circuit

Boundary Discussion and Opportunities
Figure B17.2 below shows the required transfer for Boundary B17 from 2012 to 2032 for the three scenarios and the Contracted Background, as well as the Gone Green boundary capability, including any increase from network changes. Table B17.2 identifies the network reinforcements affecting this boundary, and their timing, for each scenario.

Figure B17.2:
Required transfer and capability for boundary B17



1 Reinforcement date triggered by prior requirement from boundary in the reference name

Table B17.2:
Selection and timing of reinforcements

Ref	SP	GG	AG	C
B17-R01	2031	2029	2024	2018
B8-R01	–	2022[1]	2022[1]	2019[1]
B17-R02	2031	2029	2024	2018

B17 is an importing boundary. Closures of thermal plant within the boundary, an increase in local demand, and SQSS scaling factors due to growth in generation outside the boundary increase the transfer requirements.

Boundary B17 experiences voltage compliance issues, exacerbated by the potential generation closures. To compensate, additional reactive support in the form of reinforcement B17-R01 is required.

Reinforcement B8-R01, driven by the B8 boundary, has significant impact on the capability for B17. This is reflected in Figure B17.2 and its timing, based on the requirement for B8 is shown in Table B17.2.

3.8
Proposed National Grid Network Development Policy (NDP) process

3.8.1
NDP description

The proposed Network Development Policy (NDP) defines how we will assess the need to progress wider transmission system reinforcements to meet the requirements of our customers in an economic and efficient manner.

This section sets out the annual process by which the NDP is intended to be applied to the onshore electricity transmission system in England and Wales. In addition, we have included a summary of output from the initial application of the NDP analysis with a fully worked example of the Northern England region in the Appendices. At the relevant stages of the NDP process, we will engage with our stakeholders.

There are a number of major steps from identifying a future need for reinforcement, through considering all available solutions to provide the incremental network capability, to selecting and documenting the preferred solution for delivery.

This annual process will be used to review and update decisions as additional information is gained, for example in response to changing customer requirements or via the feedback from stakeholder engagement. The proposed NDP provides a plan for the following year to drive the timely progression of investment in wider works. We will engage stakeholders on annual updates to the key forecast data used in this decision-making process, and share the outputs from this process with our stakeholders through the annual publication of this document.

The NDP sets out how National Grid intend to make decisions about the choice and timing of wider transmission network reinforcements within England and Wales such that the network continues to be planned in an economic and efficient manner. It is envisaged that this will involve making use of the available information to balance the risks of inefficient financing costs, stranding and inefficient congestion costs. The main output of the NDP is the best course of action in the current year selected through minimising regrets against a range of credible scenarios and sensitivities.

Other outputs of the proposed NDP is a plan for the following year to drive the timely progression of investment in wider works. Another output is a ten-year view of the network capability required and the network solutions that could be developed to meet customers' requirements.

3.8.2
Inputs

Future Energy Scenarios
The NDP process will utilise the energy scenarios as well as the Contracted Background to form the background against which studies and analysis will be carried out.

Sensitivities
Sensitivities are used to enrich the analysis for particular boundaries to ensure that issues, such as the sensitivity of boundary capability to the connection of particular generation projects, are adequately addressed. In developing sensitivities, judgement is applied to consider regional variations in generation connections and anticipated demand levels that still meet the scenario objectives.

For example, the contracted generation background on a national basis far exceeds the requirements for credible scenarios, but on a local basis, the possibility of the contracted generation occurring is credible and there is a need to ensure customer requirements are met. A "one in, one out" rule will be applied: any generation added in a region of concern will be counter-balanced by the removal of a generation project of similar fuel type elsewhere to ensure that the scenario is kept whole. This effectively creates a local contracted sensitivity that still meets the underlying axioms and assumptions of the main scenarios but accounts for local sensitivities to the location of generation.

The inclusion of this local contracted sensitivity will generally form a high local generation case and allow the maximum regret associated with inefficient congestion costs to be assessed. In order to ensure that the maximum regret associated with inefficient financing costs and increased risk of asset stranding is assessed; for example, consideration will be given to a low generation sensitivity where no new local generation connects. This will be known as the no new local generation sensitivity. This is particularly important where the breadth of scenarios considered do not include a low generation case.

The Regional Strategies will make it clear where additional sensitivities have been used to identify a future boundary capability requirement.

The NDP process uses the three scenarios, the local contracted and no new local generation sensitivities to form the background for which studies and analysis are carried out.

3.8.3
Identify future transmission capability requirements

For every boundary, the future capability necessary under each scenario and sensitivity is calculated by the application of the security standards. The network at peak system demand is used to outline the minimum required transmission capability for both the Security and Economy criteria. The security standards have been described in more detail in Section 3.4.

Proposed National Grid Network Development Policy (NDP) process

3.8.4 Identify future transmission solutions

This stage identifies all potential transmission solutions that could provide additional capability across the boundary concerned, including a review of any solutions previously considered. Consideration will be given to low-cost investments, operational and investment options and whether an individual solution or a combination of solutions (known here as a transmission strategy) will resolve the identified capability constraint.

Potential transmission solutions are presented in Table 3.8.1 below in order of increasing likely cost.

Table 3.8.1:
Potential transmission solutions

Category	Transmission solution	Nature of constraint			
		Thermal	Voltage	Stability	Fault Levels
Low cost investment	Co-ordinated Quadrature Booster Schemes	✔	✔		
	Automatic switching schemes for alternative running arrangements	✔	✔	✔	✔
	Dynamic ratings	✔			
	Enhanced generator reactive range through reactive markets		✔	✔	
	Fast switching reactive compensation		✔	✔	
Operational	Availability contract	✔	✔	✔	
	Intertripping	✔	✔	✔	
	Reactive demand reduction		✔		
	Generation advanced control systems	✔	✔	✔	
Investment	Hot-wiring overhead lines	✔			
	Overhead line reconductoring or cable replacement	✔			
	Reactive compensation (MSC, SVC, reactors)		✔	✔	
	Switchgear replacement	✔			✔
	New build (HVAC / HVDC)	✔	✔	✔	✔

The range of solutions identified will be sufficiently wide and include both small-scale reinforcements with short lead-times as well as larger-scale alternative reinforcements which are likely to have longer lead-times.

In developing this range of solutions, the Replacement Priority of existing transmission assets and alignment with asset replacement programmes will be considered. If an asset is to be replaced in the relevant timescales, then the marginal cost associated with rating enhancement (rather than the full cost of replacement and enhancement) will be calculated and recorded for the purposes of the application of the Network Development Policy.

The NDP does not cover all schemes presented earlier in this chapter as no immediate decision is required for schemes further than ten years before they are required.

The factors shown in Table 3.8.2 on page 168 will be identified for each transmission solution to provide a consistent basis on which to perform cost benefit analysis at the next stage.

Proposed National Grid Network Development Policy (NDP) process

Table 3.8.2:
Transmission solution factors

<table>
<tr><th>Factor</th><th colspan="3">Definition</th></tr>
<tr><td>Output(s)</td><td colspan="3">The calculated impact of the transmission solution on the boundary capabilities of all boundaries, the impact on network security and the forecast impact on transmission losses</td></tr>
<tr><td>Lead-time</td><td colspan="3">An assessment of the time required to develop and deliver each transmission solution; this comprises an initial consideration of planning and deliverability issues, including dependencies on other projects. An assessment of the opportunity to advance and the risks of delay will be incorporated[1]</td></tr>
<tr><td>Cost</td><td colspan="3">The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases. The risk of over-/under-spend (for example, due to uncertainty associated with the levels of undergrounding required) will also be quantified to improve the consideration of solutions; a marginally higher mean expected cost may be preferred if the risk of over-spend is significantly reduced[2]</td></tr>
<tr><td rowspan="6">Stage[3]</td><td colspan="3">The progress of the transmission solution through the development and delivery process. The stages are as follows:</td></tr>
<tr><td rowspan="4">Pre-construction</td><td>Scoping</td><td>Identification of broad need case and consideration of number of design and reinforcement options to solve boundary constraint issues</td></tr>
<tr><td>Optioneering</td><td>The need case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified</td></tr>
<tr><td>Design</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process</td></tr>
<tr><td>Planning</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction</td></tr>
</table>

It is possible that alternative solutions will be identified during each year and that the next iteration of the NDP process will need to consider these developments alongside any updates to known transmission solutions, the scenarios or commercial assumptions.

1 It is recognised that there can be significant lead-time risk for a number of major infrastructure projects, e.g. new OHL that require planning consents.

2 Due to commercial sensitivity, the cost of the individual projects are not provided here. However, we are including the percentage pre-construction cost to aid understanding of the analysis.

3 These project categorisations are consistent with definitions defined as part of the ENSG process and published by DECC.

1 The Electricity Scenarios Illustrator (ELSI model) and a user guide are available at: www.talkingnetworkstx.com/consultation-and-engagement.aspx

3.8.5
Estimate lifetime costs for transmission solutions

Following the identification of the range of possible network solutions, the next step is to determine the total lifetime costs (including operational costs) associated with each transmission solution against each of the scenarios.

The Electricity Scenarios Illustrator (ELSI) model will be used to determine forecast constraint costs and transmission losses for transmission solutions against the agreed set of scenarios and sensitivities.

The ELSI model was developed by National Grid to support the stakeholder engagement process for the purposes of our RIIO-T1 submission[1]. Our stakeholders have been presented with the tool and associated information to allow them to perform their own analysis on the possible development of wider works. Simplifications have been made within the tool to allow this to be made publicly available whilst ensuring that any compromise on accuracy is minimal.

The model requires the inputs for existing boundary capabilities and their future development to be calculated in a separate analysis package and neither their dependence on generation and demand nor the power sharing across circuits is modelled. The model is a simplification of a complex analysis tool with several limitations on constraint forecasting, including:

- limited representation of generation dynamic performance
- limited number of samples used for generator availability modelling
- assumes ideal curtailment of demand and immediate restoration
- limited modelling of European market implications
- simplified modelling of network availability (maintenance outages considered but construction outages neglected).

The key assumptions within the ELSI model are shown in Table 3.8.3 below.

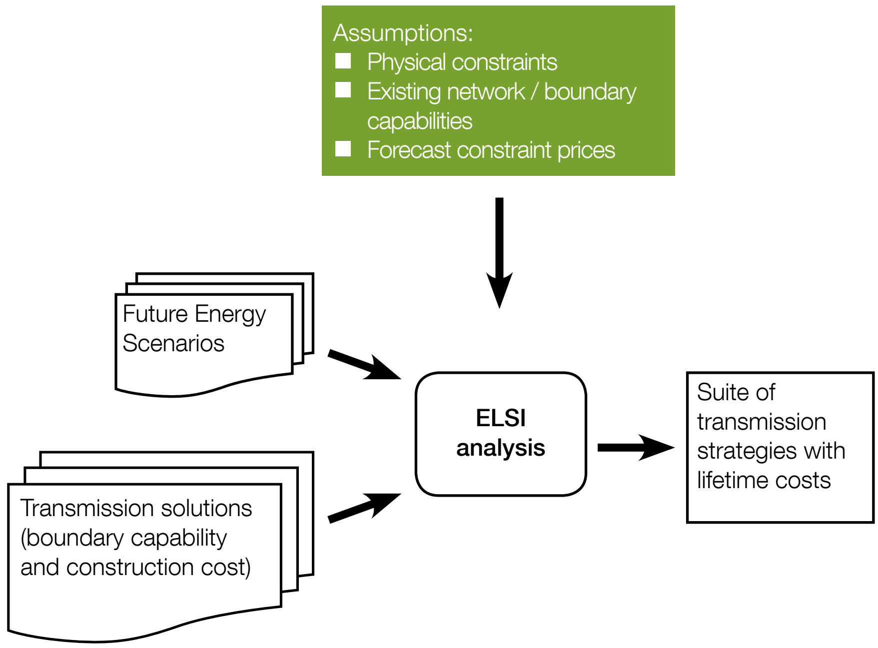
Table 3.8.3:
Key Assumptions with ELSI

Assumption	Validation of assumption
Generation and demand backgrounds	Consulted on through the UK FES process
Network capabilities	Calculated using power system analysis package and reported within ETYS and RRP
Cost profile and lead-times of reinforcements	National Grid investment process as described above
Forecast constraint prices	Balancing market costs and Short-Run Marginal Costs (SRMC)

These key assumptions will be reviewed annually and any significant changes will be identified and presented through the UK FES consultation, Regulatory Reporting Pack (RRP) and this document. The output of the ELSI analysis is the cost of different transmission solutions.

Proposed National Grid Network Development Policy (NDP) process

Figure 3.8.1:
ELSI inputs, assumptions and outputs



The full lifetime cost analysis includes forecast transmission investment costs, constraint costs (based on the prices observed in the Balancing Mechanism) and the cost of transmission losses. This analysis is consistent with the recent paper by the Joint Regulators Group (JRG) "Discounting for CBAs involving private investment, but public benefit". The cost of transmission reinforcements is annuitised at the post-tax weighted average cost of capital. This is then added to the constraint and losses costs in each year, and the totals are discounted at the Treasury's social time preference rate.

ELSI uses the more detailed energy scenarios to complete this analysis out to 2030. Then, in order to estimate full lifetime costs, the values from 2030 are duplicated to give 45 years of data.

Lifetime cost analysis will be undertaken against various different transmission strategies (combinations and timings of transmission solutions) until the lowest costs are found for each of the scenarios and sensitivities. The first stage of this process involves the application of engineering judgement to combinations and timings of transmission solutions based on the capability deficits calculated through the application of the security standards and the capabilities delivered by each of the transmission solutions. The results from this first stage allow finer adjustments in choice and timing to be made to finalise the selected strategy.

3.8.6
Development of current year options

If the strategies that provide the lowest lifetime cost for each of the scenarios are different, there is a risk of regret, and we will develop a set of competing options which seek to minimise it.

We have considered the 'do nothing' option.

We have initially focused on the strategies which require a decision to be made in the current year. If a reinforcement with a lead-time of four years is required against one scenario in six years' time, a decision is not required this year. In our options analysis, we have simply assumed that it will be constructed for that scenario but not constructed for the others.

We have considered any restrictions to the movement of reinforcements between years (either deferral or advancement). For example, outage availability may mean that it is not possible to delay the commissioning of a reinforcement from year t to year (t+1) because other planned outages in year (t+1) would cause high congestion costs or demand insecurity.

Consideration of transmission solution commitment
In most cases, the commitment required to progress physical network solutions will be in sequential stages from scoping, through optioneering and pre-construction to construction works, with more detailed information revealed and more expenditure at risk of being stranded as they progress.

This allows regret minimising options based on particular stages to be developed. For example, the option to complete pre-construction allows the earliest commissioning date to be achieved against a scenario for which the reinforcement is required, and allows work to cease with minimal regret against a scenario for which it is not required.

It may also be possible to minimise regrets by considering the potential for assets to be reused in other network investments if the project turns out not to be required.

Consideration of alternative transmission solutions
It should be noted that the options considered are not limited to those that constitute one of the minimum cost strategies. For example, consider a boundary with significant uncertainty, where doing nothing is the minimum cost solution for one scenario but completing a large, high-cost reinforcement is the minimum cost solution for another. When considering both scenarios, the best option may be to complete an incremental reinforcement which reduces regret until there is sufficient certainty regarding the scenario that will outturn to commit (or not) to the large reinforcement.

Selection of preferred option
Least regret analysis
The regret associated with each of the current-year options will be calculated against each of the scenarios. The regret against a particular scenario is defined as the difference in cost between the option and the best possible transmission strategy for that scenario.

The preferred option is then selected based on the least regret approach. The worst regrets associated with each of the current-year options are identified, and the option with the 'least worst' regret is chosen.

Proposed National Grid Network Development Policy (NDP) process

Table 3.8.4:
Example 'least regret' analysis

Option	Scenario A	Scenario B	Scenario C	Worst regret
1	£40m	£0m	£30m	£40m
2	£0m	£185m	£100m	£185m
3	£5m	£40m	£80m	£80m
4	£40m	£160m	£0m	£160m

This is illustrated in Table 3.8.4 above, where option 1 is selected as the preferred solution for the following year.

The analysis process will be further developed to include an increased number of decision points (i.e. instead of assuming that all information is revealed in a year, we will seek to include decision points further into the future when it is likely that more information has been revealed).

Test selected transmission strategy against security criterion

Once a transmission solution or strategy has been selected with a least regret delivery date, it is necessary to consider whether this decision is robust against the security criterion contained in the security standards. If the criterion is not met, we will consider the economic implications of a wider range of issues including (but not limited to):

- safety and reliability
- value of lost load and loss of load probability (to the extent that this is not already included in the ELSI treatment, i.e. ideal curtailment of demand and immediate restoration)
- cost of reduced security on the system
- operational cost of constraints to complete the solution.

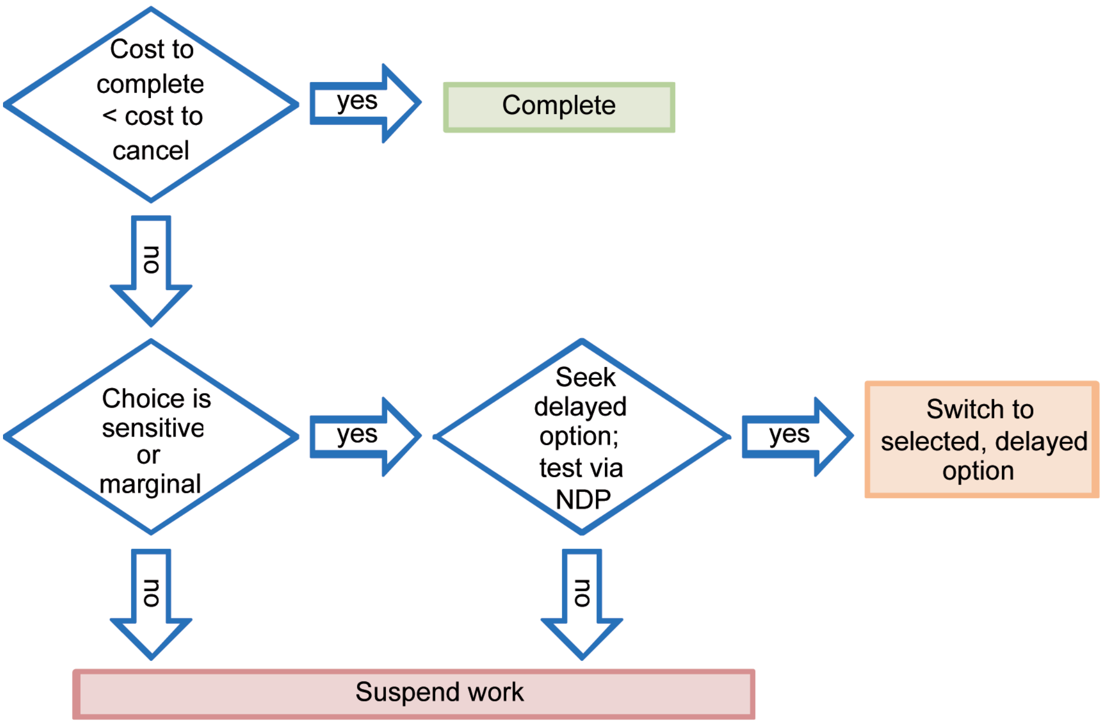
If the economic implications of these considerations outweigh the cost of reinforcement to meet the security criterion, then investment in the transmission strategy is required to ensure we continue to build an economic and efficient network.

If the cost of reinforcement to meet the security criterion outweighs the economic implications, a derogation will be sought from Ofgem to not reinforce and diverge from the security standards.

Stopping or delaying a transmission strategy

As time progresses, it is possible that a transmission strategy selected in a prior year will no longer be the least regret option identified in the current year. In this event, the transmission strategy will be reviewed in detail to understand the committed cost to date and cost of cancellation. If the project is so far progressed that the cost of cancellation is greater than the cost to complete (for example, if pre-existing plant has been removed and scrapped and new plant would be required regardless of the re-forecast network benefit), the transmission strategy would be allowed to complete.

Figure 3.8.2:
Stopping or delaying a transmission strategy



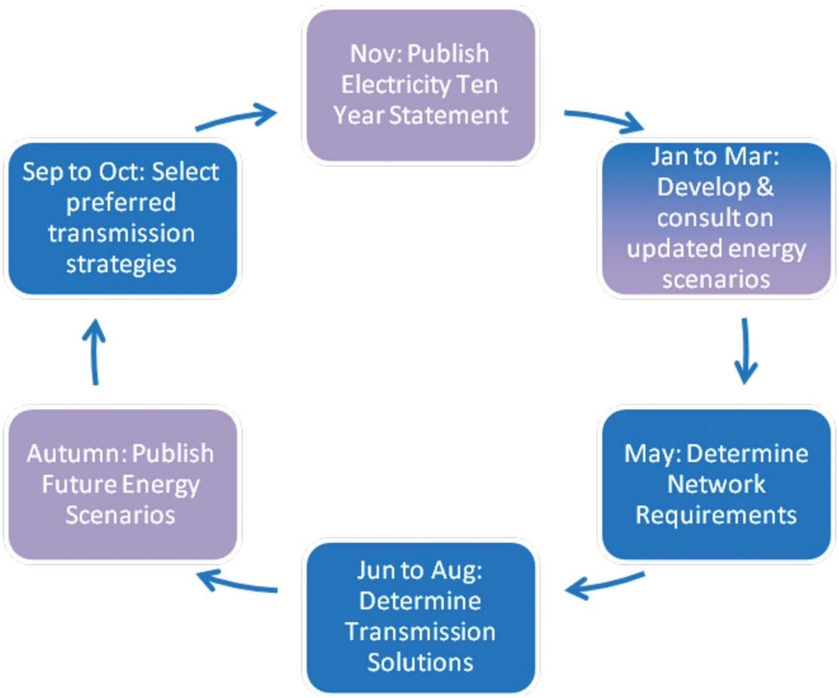
Otherwise, if the decision is marginal and sensitive to a discrete assumption change, options to slow or delay completion of the transmission strategy and hence reduce potential regret will be sought. These options can then be considered as part of the least regret analysis, and one of these might then become the selected transmission strategy.

If it is clear that a transmission strategy is no longer preferred under all revised scenarios and that the cost of cancellation is less than the cost to complete, work would be suspended and any associated, sanctioned projects would be deferred or closed.

In the case of physical reinforcements (construction projects), any committed spend on plant will be assessed for possible re-deployment on other construction projects. For example, overhead line conductor (especially if it has not been cut to section lengths) can be diverted to other projects at minimal marginal cost. This activity will form part of the cost of cancellation analysis.

3.8 continued
Proposed National Grid Network Development Policy (NDP) process

Figure 3.8.3:
Annual timetable



3.8.7
Annual timetable

The blocks shown in blue are the elements of the process which are mainly internal to National Grid. The light purple blocks are external publications within which feedback is sought from stakeholders. As part of the development of the UK Future Energy Scenarios, there is a stakeholder engagement process.

3.8.8
NDP outputs by region

Following an NDP review of the England and Wales transmission solutions, the following sections show a summary of the initial NDP findings by region. In addition, we have included a fully worked example for the Northern England region in the Appendices.

For all regions, the identification of future transmission capability requirements is provided in the earlier sections of this chapter.

For regions where the boundary transfers are driven by a large number of generators, the three main scenarios have been used for further analysis and results shown.

For regions where the boundary transfers are sensitive to a few generators, the three scenarios, a local contracted sensitivity and a no new generation sensitivity have been considered for further analysis and results shown.

The list of investment options provided in the next section for all regions has been created by considering:

- the nature of the boundary capability deficit against required transfer (e.g. stability deficit on Boundary B6)
- the cost order of solutions with low investment solutions and inexpensive options first (e.g. reactive compensation switching)
- a wide range of solutions (e.g. HVDC versus AC solutions, smaller versus larger reinforcements, projects with different lead-times, onshore versus offshore considerations)
- the Replacement Priority for transmission assets affected.

Northern England
Identification of transmission solutions

The Anglo-Scottish reactive compensation, Harker–Hutton reconductoring and Penwortham QBs projects are close to completion and therefore have been included in the baseline used for this analysis. Significant commitments have also been made to progress the Western HVDC link following extensive engagement with Ofgem as part of the TII process, so this has also been included in the baseline for further analysis.

The potential further transmission solutions that have been considered in the Northern England zone are shown in Table 3.8.5 on page 177.

Table 3.8.5:
Northern England transmission solutions

Ref	Options – Transmission Solutions	Boundary	Lead-time (years)	Pre-construction Cost (% of total cost)	Stage of the Project
B6-R03	Eastern HVDC Link – Peterhead to Hawthorn Pit	B4 B6 B7 B7a	6	2	Optioneering
B6-R05	Eastern HVDC Link 2 – Torness to Lackenby	B6 B7 B7a	6	2	Scoping
B7-R03	Eastern HVDC link 3 – Peterhead to England	B4 B6 B7 B7a	6	2	Scoping
B7a-R02	Mersey Ring	B7a	5	2	Optioneering
B6-R04	Reconductor Harker–Strathaven + Series compensation	B6 B7	4	2	Scoping
B7a-R03	Yorkshire Lines reconductoring	B7 B7a	4	2	Scoping
OS Link-01 OS Link-03	Teesside–Humber–Wash Offshore Integration Stage 1	B7 B7a	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 2	B7 B7a	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 3	B7 B7a	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 4	B7 B7a	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 5	B7 B7a	6	2	Scoping
OS Link-05	Cumbria–North Wales Offshore Integration	B7a	6	2	Scoping

Proposed National Grid Network Development Policy (NDP) process

Table 3.8.6:
Lowest cost strategies for each scenario

Scenario	Strategy	
	Transmission solution	**Completion date**
Slow Progression	Nothing	N/A
Gone Green	Eastern HVDC Link 1	2019
	Mersey Ring	2017
Accelerated Growth	Eastern HVDC Link 1	2018

Selection of transmission solution and timing

Calculation of operational costs for transmission solutions

Cost benefit analysis was completed with various different strategies (combinations and timings of transmission solutions) until the lowest cost was found for each of the scenarios.

The lowest cost strategies for each of the scenarios are shown in Table NDP.6 above.

The Gone Green scenario drives higher year-round transfers than the Accelerated Growth scenario across boundary B7a between 2018 and 2024. This means that the Mersey Ring reinforcement is required under the Gone Green scenario, but not the Accelerated Growth scenario.

Development of current year options

The table above shows that the minimum cost strategies for each of the scenarios are different, and therefore there is a risk of regret.

The Eastern link project can be divided into pre-construction and construction stages. This creates the option to complete the lower cost pre-construction element under all scenarios such that the construction phase can proceed to time under the Accelerated Growth scenario, or the project can be mothballed with minimal regret under the Slow Progression scenario.

The pre-construction element of the Mersey ring project has already been completed. The construction element has a lead-time of five years, and therefore has to be initiated this year to achieve the minimum cost strategy for the Gone Green scenario.

The current-year options that have been considered are:

- complete Eastern link pre-construction
- start Mersey ring construction
- complete Eastern link pre-construction and start Mersey ring construction
- do nothing.

Selection of preferred current year option

The regrets for each of the current year options against each of the scenarios are shown in Table 3.8.7 on page 179.

Table 3.8.7:
Northern England reinforcement options and regrets

2012 option	Gone Green	Accelerated Growth	Slow Progression	Worst regret
Eastern link pre-con	£11m	£0m	£12m	£12m
Mersey ring (2017)	£0m	£193m	£15m	£193m
Eastern link pre-con & Mersey ring (2017)	£1m	£15m	£27m	£27m
Nothing	£10m	£178m	£0m	£178m

The worst regrets for each of the options are shown. The Eastern link pre-construction option represents the 'least worst' regret.

Whilst the Eastern link pre-construction option represents the best option, if the Accelerated Growth scenario were to be omitted from the analysis then the 'Do nothing' option would become the best option. Even without the Accelerated Growth scenario, the lead-time risks associated with a project as complex as the Eastern link could cause significant congestion costs against the Gone Green scenario if completion is delayed. This means that the completion of the pre-construction work remains the best option.

Outputs

The Eastern link pre-construction is to be taken forward in 2013/14.

3.8 continued
Proposed National Grid Network Development Policy (NDP) process

North Wales
Identification of transmission solutions

The Trawsfynydd–Treuddyn Tee reconductoring which is being progressed as part of the TII process is due to be completed in 2014 and therefore has been included in the baseline for further analysis. This project has been aligned with the requirement for asset replacement of the fittings on these circuits, allowing safe access for maintenance without the need to take a double circuit outage on the Deeside–Legacy–Trawsfynydd three-ended circuits.

The potential transmission solutions that have been considered in the North Wales area are shown in Table 3.8.8. The output capability has been assessed using local peak conditions.

Table 3.8.8:
North Wales transmission solutions (Investment options)

Ref	Options – Transmission Solutions	Boundary	Lead-time (years)	Pre-construction Cost (% of total cost)	Stage of the Project
NW2-R01	2nd Pentir–Trawsfynydd	NW2	4	2	Optioneering
B8-R01	Wylfa–Pembroke HVDC Link	NW1	6	4	Optioneering
		NW2			
		NW3			
		NW4			
		B8			
		B9			
		B12			
		B17			
NW1-R01	2nd Pentir–Wylfa route	NW1	5	4	Optioneering
NW3-R03	Pentir–Deeside reconductoring	NW2	3	1	Scoping
		NW3			
NW3-R04	Pentir–Trawsfynydd reconductoring	NW2	3	2	Scoping
OS Link-05	Cumbria–North Wales Offshore Integration	NW1	6	2	Scoping
		NW2			
		NW3			
		NW4			

Table 3.8.9:
Lowest cost strategies for each scenario

Scenario	Strategy	
	Transmission solution	Completion date
Slow Progression	2nd Pentir–Trawsfynydd circuit	2021
Gone Green	2nd Pentir–Trawsfynydd circuit	2018
	2nd Wylfa–Pentir route	2022
	Wylfa-Pembroke HVDC link	2024
Accelerated Growth	2nd Pentir–Trawsfynydd circuit	2018
	2nd Wylfa–Pentir route	2021
	Wylfa-Pembroke HVDC link	2024
Local Contracted Sensitivity	2nd Pentir–Trawsfynydd circuit	2018
	2nd Wylfa–Pentir route	2020
	Wylfa–Pembroke HVDC link	2020
No New Generation in region	None	N/A

Selection of transmission solution and timing

Calculation of operational costs for transmission solutions

Cost benefit analysis was completed with various different strategies (combinations and timings of transmission solutions) until the lowest cost was found for each of the scenarios.

The lowest cost strategies for each of the scenarios are shown in Table 3.8.9 above.

Development of current year options

The table above shows that the minimum cost strategies for each of the scenarios are different, and therefore there is a risk of regret.

The 2nd Pentir–Trawsfynydd circuit project is needed for all scenarios ranging from 2016/17 in the local contracted sensitivity to 2021 in the Slow Progression scenario. Due to the lead-times of the project, the earliest date that this project can be delivered is 2018/19.

The 2nd Wylfa–Pentir project is currently going to public consultation on route corridor options as part of the Planning Inspectorate (PINS) process for planning consents. The construction element has a lead-time of six years from now, and therefore has to be initiated this year to achieve a delivery of the project by 2018.

Selection of preferred option

The current year options and regrets against each of the scenarios and sensitivities are shown in Table NDP.10 on page 182.

Proposed National Grid Network Development Policy (NDP) process

Table 3.8.10:
Current year options and regrets

Strat	2012 Option	Regrets(£m)					
		Slow Progression	Gone Green	Accelerated Growth	Local contracted sensitivity	No new generation in region	Worst regrets
1	Do nothing	0	10.2	9.8	4.7	0	10.2
2	Commit to Pentir–Trawsfynydd	0.6	0	0	0	9.3	9.3
3	Pentir–Trawsfynydd Pre-Con Wylfa–Pembroke	1.3	0.1	0.1	0	9.5	9.5
4	Pentir–Trawsfynydd Pre-Con Wylfa–Pentir	5.9	0.6	0.4	0.2	14.8	14.8
5	Pentir–Trawsfynydd Pre-Con Wylfa–Pentir Pre-Con Wylfa–Pembroke	6.6	0.8	0.6	0.2	14.8	14.8

The worst regrets for each of the options are shown. The preferred option is to progress with the 2nd Pentir–Trawsfynydd option for the current year.

Table NDP.10 shows a number of regrets that are very low, for example, the regret associated with committing to Pentir–Trawsfynydd second circuit against the Slow Progression scenario is only £0.6m. This represents three years of financing costs for the first year of committed spend on the project (£9.3m). This spend will occur three years earlier than necessary if we choose this option and the Slow Progression scenario outturns.

The 2nd Wylfa–Pentir project is required for 2020 under the local contracted sensitivity and there is significant lead-time risk for new overhead lines that require planning consents. Provided the cost commitment is small, it is therefore prudent to progress with the development of the project to ensure that customers are not unduly exposed to the risk of high constraints if the customer connections materialise within contracted timescales.

Outputs

The construction of the 2nd Pentir–Trawsfynydd is to be taken forward in 2013/14.

East Coast and East Anglia
Identification of transmission solutions

The Norwich–Sizewell turn-in and Bramford substation extension projects are close to completion and therefore have been included in the baseline for further analysis. These projects combine to provide a further capability of 1.7 GW to boundary EC5.

The potential transmission solutions that have been considered in the East Coast and East Anglia region are shown in Table 3.8.11 on page 184. The output capability has been assessed using local peak conditions

Table 3.8.11:
East Coast transmission solutions

Ref	Options – Transmission Solutions	Boundary	Lead-time (years)	Pre-construction cost (% of total cost)	Stage of the project
EC5-R02	Bramford–Twinstead	EC5	6	4	Planning
B14(e)-R06	Elstree–Waltham Cross–Tilbury uprate	EC5 B14	7	2	Planning
EC5-R03	Braintree–Rayleigh reconductoring	EC5	4	2	Optioneering
EC5-R01	Rayleigh–Coryton–Tilbury	EC5	4	1	Optioneering
EC5-R04	Walpole QBs	EC5	3	1	Optioneering
EC5-R05	Kemsley–Littlebrook–Rowdown	EC5	4	1	Optioneering
EC5-R06	Rayleigh Reactor	EC5	2	1	Optioneering
EC5-R07	Tilbury–Kingsnorth–Northfleet East	EC5	4	1	Scoping
EC1-R01	Killinghilme South substation, Killingholme South–West Burton, Humber circuits reconductoring	EC1	7	4	Optioneering
OS Link-01 OS Link-02 OS Link-03	Teesside–Humber–Wash Offshore Integration Stage 1	EC1	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 2	EC1 EC3	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 3	EC1 EC3	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 4	EC1	6	2	Scoping
	Teesside–Humber–Wash Offshore Integration Stage 5	EC1 EC3	6	2	Scoping

Calculation of operational costs for transmission solutions
Cost benefit analysis was completed with various different strategies (combinations and timings of transmission solutions) until the lowest cost was found for each of the scenarios.

Table 3.8.12:
Lowest cost strategies for each scenario

Scenario	Strategy	
	Transmission solution	**Completion date**
Slow Progression	Nothing	N/A
Gone Green	Bramford–Twinstead	2020
	Braintree–Rayleigh reconductoring	2020
	Rayleigh–Coryton–Tilbury reconductoring	2020
	Walpole QBs	2021
Accelerated Growth	Bramford–Twinstead	2021
	Braintree–Rayleigh reconductoring	2021
	Elstree–Waltham Cross–Tilbury 275 to 400kV upgrade	2022
	Rayleigh–Coryton–Tilbury reconductoring	2018
	Walpole QBs	2021
	Kemsley–Littlebrook–Rowdown	2022
	Tilbury–Kingsnorth–Northfleet East reconductoring	2022
Local Contracted Sensitivity	Bramford–Twinstead	2018
	Braintree–Rayleigh reconductoring	2018
	Elstree–Waltham Cross–Tilbury 275 to 400kV upgrade	2019
	Rayleigh–Coryton–Tilbury reconductoring	2018
	Walpole QBs	2018
	Kemsley–Littlebrook–Rowdown	2020
	Tilbury–Kingsnorth–Northfleet East reconductoring	2020
No New Generation Sensitivity	Nothing	N/A

The lowest cost strategies for each of the scenarios are shown in Table 3.8.12 above.

Proposed National Grid Network Development Policy (NDP) process

Development of current year options

The table on page 185 shows that the minimum cost strategies for each of the scenarios are different, and therefore there is a risk of regret.

The lowest cost strategy for Slow Progression is to do nothing further in the area. The lowest cost strategy for the local contracted sensitivity requires both the Bramford–Twinstead and the Elstree–Waltham Cross–Tilbury 275 to 400kV upgrade to be considered in the current year.

The pre-construction element of the Bramford–Twinstead and the Elstree–Waltham Cross–Tilbury 275 to 400kV upgrade projects has already been completed. The construction elements have a lead-time of six and seven years respectively and therefore have to be initiated this year to achieve the minimum cost strategy for the local contracted sensitivity.

The current-year options that have been considered are:

- commit to a further one year spend for Bramford–Twinstead (delivery 2018)
- commit to a further one year spend for Elstree–Waltham Cross–Tilbury (delivery 2019)
- commit to a further one year spend for Bramford–Twinstead (2018) and Elstree–Waltham Cross–Tilbury (2019)
- do nothing further.

Selection of preferred option

The options and regrets against each of the scenarios and sensitivities are shown in Table 3.8.13 below.

Table 3.8.13:
East Coast reinforcement options and regrets

Strat	2012 Option	Regrets(£m)					
		Slow Progression	Gone Green	Accelerated Growth	Local Contracted Sensitivity	No New Generation in Region	Worst Regrets
1	Commit to Bramford–Twinstead	35	2	3	7	35	35
2	Commit to Elstree–Waltham Cross–Tilbury	43	43	4	192	43	192
3	Commit to Bramford–Twinstead and Elstree–Waltham Cross	77	45	8	0	77	77
4	Do nothing	0	0	0	199	0	199

The worst regrets for each of the options are shown. The progression with Bramford–Twinstead for the current year is the preferred option.

Whilst the Bramford–Twinstead option represents the best option, it was noted that the local contracted sensitivity were to be omitted from the analysis then the ‘Do nothing’ option would become the best option. It is worth noting that whilst stopping and then re-starting community engagement activities is a theoretical option, this would actually significantly increase costs. These increases are not captured in this analysis.

Outputs

Further spend on the Bramford–Twinstead project will be committed in 2013/14.

South West and South Coast

Identification of transmission solutions

The potential transmission solutions that have been considered in the South West and South Coast region are shown in Table 3.8.14 below. The output capability has been assessed using winter peak conditions.

Table 3.8.14:
South West and South Coast transmission solutions

Ref	Options – Transmission Solutions	Boundary	Lead-time (years)	Pre-construction Cost (% of total cost)	Stage of the Project
SC1-R03	Reactive compensation at Canterbury substation	SC1	5	4	Design
SC1-R01 SC1-R02	Dungeness–Sellindge–Canterbury reconductoring	SC1	4	1	Design
B13-R01	Hinkley Point–Bridgewater–Seabank 400kV Transmission Circuit	B13	9	4	Planning
B13-R02	Bramley–Melksham Reconductoring	B13	4	1	Optioneering

Table 3.8.15:
Lowest cost strategies for each scenario

Scenario	Strategy	
	Transmission solution	**Completion date**
Slow Progression	Hinkley Point–Seabank	2026
	Reactive compensation at Canterbury substation	2021
Gone Green	Hinkley Point–Seabank	2021
	Reactive compensation at Canterbury substation	2020
	Dungeness–Sellindge–Canterbury reconductoring	2021
Accelerated Growth	Hinkley Point–Seabank	2020
	Reactive compensation at Canterbury substation	2020
	Dungeness–Sellindge–Canterbury reconductoring	2021
Local Contracted Sensitivity	Hinkley Point–Seabank	2019
	Reactive compensation at Canterbury substation	2019
	Dungeness–Sellindge–Canterbury reconductoring	2019
No New Generation Sensitivity	None	N/A

Selection of transmission solution and timing

Calculation of operational costs for transmission solutions

Cost benefit analysis was completed with various different strategies (combinations and timings of transmission solutions) until the lowest cost was found for each of the scenarios.

The lowest cost strategies for each of the scenarios are shown in Table 3.8.15 above.

The South Coast MSCs and SVCs are needed in all scenarios between 2019 and 2021. Due to optimisation and alignment of works, these MSCs are due to be delivered in stages up to 2019. The decision will be reviewed annually and the best economic balance sought after considering the outage alignment and year of requirement.

Proposed National Grid Network Development Policy (NDP) process

Development of current year options

The table on page 189 shows that the minimum cost strategies for each of the scenarios are different, and therefore there is a risk of regret.

The pre-construction element of the Dungeness–Sellindge–Canterbury project has already been completed. The construction element has a lead-time of four years, and the earliest date this is required for any scenario is 2019/20. The scheme can therefore be delayed with no regret.

For the South West, the current-year options that have been considered are:

- commit to the next year of spend for Hinkley Point–Seabank for delivery by 2019
- progress with pre-construction for Bramley–Melksham for delivery in 2018
- commit to the next year of spend for Hinkley Point–Seabank and progress with pre-construction for Bramley–Melksham for delivery in 2018
- do nothing.

Selection of preferred option

The options and regrets against each of the scenarios and sensitivities are shown in Table 3.8.16 below.

Table 3.8.16:
Current year options and regrets

Strat	2012 Option	Regrets(£m)					
		Slow Progression	Gone Green	Accelerated Growth	Local Contracted Sensitivity	No New Generation in Region	Worst regrets
1	Do Nothing	0	0	0	759	0	759
2	Commit to Pre-Con Bramley–Melksham	25	25	2	783	25	783
3	Commit to Hinkley Point–Seabank	8.8	3	1	0	41	41
4	Hinkley Point–Seabank	8.8	28	3	1	66	66

The worst regrets for each of the options are shown. Progressing Hinkley Point–Seabank is the least regret option.

Whilst the Hinkley Point–Seabank option represents the best option, it is also noted that if the local contracted sensitivity were to be omitted from the analysis then the 'Do nothing' option would become the best option. It is worth noting that whilst stopping and then re-starting community engagement activities is a theoretical option, this would actually significantly increase costs. These increases are not captured in this analysis.

Outputs

The Hinkley Point–Seabank project is to be taken forward in 2013/14.

London
Identification of transmission solutions

The potential transmission solutions that have been considered in the London area shown in Table 3.8.17 below. The output capability has been assessed using winter peak conditions.

Table 3.8.17:
London transmission solutions

Ref	Options – Transmission Solutions	Boundary	Lead-time (years)	Pre-construction Cost (% of total cost)	Stage of the Project
B14(e)-R01	Hackney–Tottenham–Waltham Cross uprate and Pelham Rye House reconductor	B14 B15	6	2	Planning
B14(e)-R02 B14(e)-R03	Sundon–Cowley turn-in Elstree turn-in and 400kV series reactor	B14	5	1	Optioneering
B14(e)-R04	West Weybridge–Beddington–Chessington uprate	B14	6	4	Optioneering
B14(e)-R05	Elstree–St John's Wood second cable	B14	6	1	Scoping
B14(e)-R06	Elstree–Tilbury–Waltham Cross uprate	B14 EC5	7	2	Planning

Table 3.8.18:
Lowest cost strategies for each scenario

Scenario	Strategy	
	Transmission solution	**Completion date**
Slow Progression	Hack–Tott–Walx 275 to 400kV upgrade	2017
	Sundon–Cowley and Elstree Turn-in	2021
Gone Green	Hack–Tott–Walx 275 to 400kV upgrade	2017
	Sundon–Cowley and Elstree Turn-in	2019
Accelerated Growth	Hack–Tott–Walx 275 to 400kV upgrade	2017
	Sundon–Cowley and Elstree Turn-in	2019

Selection of transmission solution and timing

Calculation of operational costs for transmission solutions

Cost benefit analysis was completed with various different strategies (combinations and timings of transmission solutions) until the lowest cost was found for each of the scenarios.
The lowest cost strategies for each of the scenarios are shown in Table 3.8.18 above.

Development of current year options

The table above shows the minimum cost strategies for each of the scenarios.

All the strategies include the Hackney–Tottenham–Waltham Cross 275 to 400kV upgrade by 2017. The only difference between the strategies is the timing of the Sundon–Cowley and Elstree turn-in project. This is required in 2019 for Gone Green and Accelerated Growth and 2021 for Slow Progression.

Since the lead-time for the Sundon–Cowley and Elstree turn-in project is only five years, a decision on the timing of these projects is not required this year.

This means that each of the lowest cost strategies can be achieved without risk of regret. On this basis the Hackney–Tottenham–Waltham Cross 275 to 400kV upgrade project will be committed to this year.

Outputs

The Hackney–Tottenham–Waltham Cross 275 to 400kV upgrade project is to be taken forward in 2013/14.

3.9
Development consents

The illustrative transmission systems contained in this document do not consider specific requirements for consent or planning permission. However, such planning permissions will be a key factor in the actual physical development of NETS. The following section provides a high level overview of the key aspects of the planning process which will be applicable for connecting an offshore generation projects to the NETS.

3.9.1.
Planning Consents

England and Wales

In England and Wales, the consenting process for nationally significant infrastructure projects (NSIPs) is defined in the Planning Act 2008[1]. The National Infrastructure Directorate (NID) within the Planning Inspectorate[2] is responsible for consideration of development consent applications in respect of NSIP proposals and for making recommendations to the relevant Secretaries of State responsible for deciding whether consent should be granted.

These requirements apply to major energy generation, energy infrastructure in the form of overhead lines, cables and pipelines over certain thresholds, as well as railways, ports, major roads, airports and water and waste infrastructure. National policy is set out by Ministers in a series of National Policy Statements (NPS's).[3] The Act also imposes requirements on project promoters to consult affected parties and local communities prior to submitting an application and promoters are encouraged to do so early when developing proposals so as to allow projects to be shaped and influenced by consultation feedback.

The Act sets out mandatory pre-application procedures which includes notification, consultation and publicity requirements. NGET is committed to meeting and if appropriate exceeding the requirements of the Planning Act 2008. NGET will engage and consult affected parties in the development of its projects, demonstrating how local communities' and other stakeholders' views have been taken into consideration. Our commitments in this regard are described in more detail in our Stakeholder Community & Amenity Policy[4] which also outlines how we seek to meet our statutory responsibilities under Schedule 9 of the Electricity Act 1989[5]: to have regard to the preservation of amenity in the local area. National Grid has also published a document that seeks to describe in more detail, National Grid's approach to the design and routeing of new electricity transmission lines[6].

Where an offshore renewable energy scheme is a NSIP development (over 100 MW of installed generation capacity) then the developer will apply to the Planning Inspectorate for a Development Consent Order (DCO).

Scotland

In Scotland, new infrastructure is consented through the Scottish Government. Applications to construct and operate offshore renewable generation of any capacity are made to Marine Scotland[7] which grants a marine licence for the works under the Marine (Scotland) Act 2010.[8] Marine Scotland makes a recommendation to Scottish Ministers who grant section 36 consent under the Electricity Act 1989.[9]

1 www.legislation.gov.uk/ukpga/2008/29/contents
2 www.communities.gov.uk/localgovernment/decentralisation/localismbill/ www.services.parliament.uk/bills/2010-11/localism.html
3 www.infrastructure.independent.gov.uk/legislation-and-advice/national-policy-statements/
4 www.nationalgrid.com/NR/rdonlyres/21448661-909B-428D-86F0-2C4B9554C30E/39991/SCADocument6_2_Final_24_2_13.pdf
5 www.nationalgrid.com/uk/LandandDevelopment/SC/Responsibilities/
6 www.nationalgrid.com/NR/rdonlyres/E9F96A2A-C987-403F-AE7D-BDA07821F2C8/55465/OurApproach.pdf
7 http://scotland.gov.uk/About/Directorates/marinescotland
8 www.legislation.gov.uk/asp/2010/5/contents
9 www.legislation.hmso.gov.uk/acts/acts1989/Ukpga_19890029_en_2.htm www.legislation.gov.uk/ukpga/1989/29/section/36

1 www.legislation.gov.uk/ukpga/2009/23/contents
2 www.defra.gov.uk/environment/marine/protect/planning/
3 www.archive.defra.gov.uk/environment/marine/documents/ourseas-2009update.pdf
4 www.marinemanagement.org.uk
5 www.scotland.gov.uk/About/People/Directorates/marinescotland
6 http://wales.gov.uk/?lang=en
7 www.doeni.gov.uk
8 www.marinemanagement.org.uk/licensing/index.htm
9 www.legislation.gov.uk/ukpga/Geo6/12-13-14/74
10 www.legislation.gov.uk/ukpga/1985/48
11 www.legislation.gov.uk/ukpga/2009/23/contents
12 www.communities.gov.uk/publications/planningandbuilding/dcosimpactassessment

3.9.2. Marine Planning

The Marine and Coastal Access Act 2009[1] and the Marine (Scotland) Act 2010[8] establishes the legislative basis for the marine planning and licensing process in the UK. The Acts aim to provide an integrated approach that brings together marine management decisions and allows for joined-up decision making. The new marine planning framework and marine licensing system came into force in April 2011.

Marine Planning

An overarching UK Marine Policy Statement (March 2011)[2] provides a framework for preparing marine plans and taking decisions affecting the marine environment. The Marine Policy Statement supports the UK's high level marine objectives[3] and will be implemented through marine plans in England, Scotland, Wales and Northern Ireland.

For marine planning purposes UK waters will be divided into 'inshore' regions (0–12 nautical miles from the shore) and 'offshore' regions (12–200 nautical miles from the shore). Marine plans will be developed for each marine region. Plans are anticipated to have a life of approximately 20 years and will be kept under regular review during their lifetime.

The Marine Management Organisation (MMO)[4], Marine Scotland[5] Welsh Government[6] and the Department of the Environment for Northern Ireland[7] are responsible for the marine planning systems in their authority areas.

Marine Licensing

The new legislation introduced changes to the system for marine consenting and licensing and has moved from a system where multiple consents were required under multiple Acts to a more streamlined approach where a single 'marine licence' is required.[8]

In the past multiple licensing regimes and authorities regulated marine development, and included consent under the Coast Protection Act 1949[9] (CPA consent) and a licence under the Food and Environment Protection Act 1985[10] (FEPA licence).

Since April 2011 the requirements contained in CPA consents and FEPA licences have been brought together into a single marine licence for which the MMO, Welsh Government, Marine Scotland and the Department of the Environment for Northern Ireland act as licensing authorities. These bodies determine marine licence applications for offshore generation development projects. In England and Wales the Planning Inspectorate will determine applications for offshore generation development projects greater than 100 MW in size. Any associated infrastructure including cabling, collector stations and converter stations would required consent under the Marine and Coastal Access Act 2009[11] but the developer may choose for this to be consented by the Planning Inspectorate as 'associated development' and a marine licence will be issued as part of the Development Consent Order (DCO)[12] in consultation with the marine bodies.

Table 3.9.1 provides an indicative timeline for the offshore planning process for an offshore generation (larger than 100 MW of installed generation capacity) project connecting to the electricity network.

Development consents

Table 3.9.1:
Indicative timeline for the offshore planning process for offshore generation (greater than 100 MW of installed generation capacity) Connecting to or using the National Electricity Transmission System in Great Britain

Stage	Time	Activity	Responsible Party
Project development		Strategic Environmental Assessment (SEA), Zones for tender Site identification and selection Site awarded	DECC, Planning Inspectorate The Crown Estate Offshore Developers The Crown Estate
		Agreement for lease	The Crown Estate
	6 months	Connection application to National Grid Electricity Transmission	National Grid Electricity Transmission (NGET)
Pre-application	1 to 2 years	Options appraisal, Environmental Impact Assessment (EIA) Screening / EIA Scoping Statutory stakeholder consultation and public consultation Marine Surveys Environmental Impact Assessment (EIA) / Environmental Statement	Planning Inspectorate, Marine Management Organisation, Scottish Government, Marine Scotland, Welsh Government, Local Authorities and Port Authorities Offshore Developer/Offshore Transmission Owner (OFTO)
Consenting	1 year	Development Consent Order under the Planning Act 2008 (England and Wales) Consent under s36 Electricity Act 1989 / Marine Licence (Scotland)	Secretary of State (England & Wales) Scottish Government / Marine Scotland
Post-decision	6 months	Final investment decision (for offshore infrastructure)	Offshore Developer/OFTO
	6 months	Place construction contracts, delivery of offshore infrastructure	Offshore Developer/OFTO
	2+ years	Construction of offshore infrastructure	Offshore Developer/OFTO
	3 months	Connection and Commence Operation	Offshore Developer/OFTO/NGET

3.10
Technologies

Table 3.10.1:
HVDC technology advancements

HVDC Technology Advancements			
Technology	**Maximum Currently Installed**	**Maximum Installation Currently Planned or Built**	**Maximum (Near Term – 2020) Achievable Rating**
VSC Converters	400 MW ± 150 kV	- 1000 MW @ ± 320 kV Bipole - 715 MW @ ± 500 kV Monopole	2000 MW @ ±500 kV
CSC Converters	7200 MW ± 800 kV	7200 MW @ ± 800 kV	7200 MW @ ± 800 kV
XLPE Cables	200 MW / Cable @ 200 kV	500 MW / Cable @ ± 320 kV	1000 MW / Cable @ 500 kV
MI Cables	600 MW / Cable @ 500 kV	800 MW / Cable @ 500 kV	1500 MW / Cable @ ±600 – 650 kV (PPLP Technology)

The relevant transmission technologies, outlined in Appendix E, have been further reviewed in consultation with the main European manufacture suppliers. The reviewed technology including the advancements below has been applied when developing the suggest transmission changes.

Technology Advancements

The ongoing development of HVDC equipment technologies, such as subsea cables and converter stations, means that energy transfer capability is continuously improving. For example, it is now feasible to develop an offshore converter station with a capacity in the region of 1000 MW. Within the next few years it is anticipated that the technology will have progressed to the extent that 2000 MW capacity is achievable, as outlined in Table 3.10.1.

In principle, there are no anticipated technical barriers to deploying the proposed connection designs as discussed and agreed at the Technology Workshop, facilitated by NGET, in April 2011.[1] Although voltage/power ratings are in excess of those presently installed, these are achievable through incremental development rather than requiring a fundamental step change.

Series reactive compensation is now firmly in the development phase for insertion in Anglo-Scottish circuits. This will be the first deployment of capacitive series compensation on the NETS.

A new 400KV transmission pylon design is being developed by National Grid and Danish architects Brystrup following a successful design competition. The new design aims to help satisfy future engineering needs whilst being aesthetically pleasing and environmentally friendly. A preferred T-pylon design is currently being prepared ready for a prototype to be produced and tested. It is hoped that the T-pylon design will be ready for deployment within the next four to five years.

1 www.nationalgrid.com/NR/rdonlyres/444EB282-E38C-41DE-8282-6F83F93C17D0/46591/ODISTechnologyWorkshop13thApril2011_FinalVersion.pdf

3.11
Potential Development of Integrated Offshore Network

3.11.1
Dogger Bank Zone

From Figure 2.13 it can be seen that there is potential for some 9–12.8 GW of offshore wind generation in the Dogger Bank Zone (of which 6 GW is presently contracted to connect from 2016 to 2021. Additional offshore generation from the Dogger Bank Zone could be accommodated in either the EC7, EC3 or EC1 region, however, which option is adopted, additional transmission capacity out of the EC7, EC3 and EC1 group (see Figures EC7.2, EC3.2 and EC1.1) and provision of additional transmission capacity across boundary B7 (see Figure B7.2). This could be provided by either onshore or offshore reinforcements. By providing an offshore link between EC7 and EC1 via Dogger Bank, it will provide transmission capacity to connect the offshore wind to the main interconnected system, thus reinforcing B7 and B7a, but under outage conditions in either region EC7 or EC1 it will be possible to divert power to EC1 or EC7 respectively, thus further mitigating the need for further reinforcements in either of these zone. Depending on timing of volumes of offshore generation in the Dogger Bank region, the integrated offshore network (shown in Appendix A Figure 4.4b) could offer a more economic and environmentally friendly solution than the onshore options described in Table B7.1.

3.11.2
Hornsea Zone

From Figure 2.13 it can be seen that there is potential for some 4 GW of offshore wind generation in the Hornsea Zone (of which 2 GW is presently contracted to connect from 2014 south of the Humber with full capacity of 2 GW reached by 2021. Additional offshore generation from the Hornsea Zone could be accommodated in either the EC3 or EC1 region, however, whatever option is adopted, additional transmission capacity may be needed out both the EC1 and EC3 group (see Figures EC1.2 and EC.2) and potentially provision of additional transmission capacity across boundary B8 (see figure). This could be provided by either onshore or offshore reinforcements. By providing an offshore link between EC1 and EC3 via Hornsea, it will provide transmission capacity to connect the offshore wind to the main interconnected system, thus reinforcing B8, but under outage conditions in either region, EC1 or EC3, it will be possible to divert power to EC3 or EC1 respectively. This would mitigate the need for further reinforcements in either of these zones. Depending on the timing and volumes of offshore generation in the Hornsea region, the integrated offshore network (shown in Appendix A Figure 4.4b) could offer a more economic and environmentally friendly than the onshore options described in Table B8.1.

3.11.3
Dogger Bank and Hornsea Zones

As described above, there is the potential for some 13–16.8 GW of offshore wind generation in the Round 3 Dogger Bank and Hornsea zones. In considering these zones in isolation, it will lead to significant more investment requirements[1] than if considered in an integrated co-ordinated manner. There is a range of potential solutions available, both onshore and offshore, than can increase the transmission capability across B7 and B8. As the onshore and offshore generation develops, the network solutions will be developed further, ensuring that the proposed solution can be

1 www.nationalgrid.com/uk/Electricity/OffshoreTransmission/OffshoreApproach/

developed incrementally alongside the generators, thus minimising redundancy risk, whilst facilitating future development.

3.11.4 East Anglia Zone

The Round 3 East Anglia Zone as seen in Figure 2.13 has the potential for 7.2 GW of offshore wind generation capacity. Connection contracts are in place for the full 7.2 GW with staged connection dates from 2016 to 2021 to connection points within East Anglia. The connection points are contained within the EC5 and EC6 boundaries with the transmission requirements shown in Figures EC5.2 and EC6.2. By offshore co-ordination within the East Anglia offshore zone increased supply security will be attainable. With a co-ordinated connection with Hornsea or Dogger Bank additional boundary capability will be provided across the B8 and B9 boundaries. The offshore zone could also be considered for co-ordination with Belgium or Netherlands projects to provide additional interconnection capacity between the countries.

3.11.5 South Coast Zone

Figure 2.13 shows two Round 3 zones off the south coast and south-west peninsula of England, Rampion just south of Brighton and Navitus Bay to the south-west of the Isle of Wight, and there is potential for some 1.5–1.9 GW of offshore wind generation in total from these two zones. As the affected boundaries B10 and SC1 are generally net importers, it is anticipated that this generation can be accommodated within the zone as the generation will tend to balance the local demand.

Both of these Round 3 generating zones are close to the coast line and the indicative capacity for each zone is small enough that the use of AC technology is expected to be the most cost effective solution to connect the offshore zones to the onshore network, with connections to existing substations likely to be the most straightforward. The low level of existing generation in the area coupled with local demand requirements results in smaller impacts on load flows and only minor local reinforcements are expected to be required to facilitate these connections. Due to the large geographic split of the two offshore zones and the pattern of predicted network flows on the south coast circuits, it is unlikely that any offshore links between zones will be cost effective options to meet network reinforcement requirements.

Although, there are offshore contracted connections from outside the zone which are due to connect in a similar region onshore, these further connections will use DC technologies due to distance from the coast line and it is unlikely that integrating with the other zones will be economic as it will require combining AC and DC technologies.

3.11.6 Bristol Channel Zone

Figure 2.13 highlights a single Round 3 zone in the Bristol Channel area, Atlantic Array, and there is potential for some 1.5 GW of offshore wind generation in total from this zone.

This Round 3 generating zones is close to the coast line and the indicative capacity for the zone is small enough that the use of AC technology is expected to be the most cost effective solution to connect the offshore zones to the onshore network. Although the furthest extent of the zone may be close to the limit of a practical AC circuit connection, the collector network within the zone is unlikely to be such that DC technologies will be necessary. Potential onshore connection points cover both the South Wales peninsula and the south-west coast. Examining boundary requirements for B12 and B13 reveals that connection to the south-west coast is preferable as B13 is generally a net importer and the generation will help to balance local demand with a beneficial effect on the required boundary capacity. The South Wales coastal circuits near Cardiff and Swansea are predominantly 275kV and provide little support for additional generation without replacement or upgrading to 400kV. Adding additional generation to these circuits will increase the B12 transfer requirement.

There is an opportunity to integrate this zone with potential generation proposed in Irish territories (onshore and offshore). Such connections would inevitably require DC technologies due to the distances involved, the capacities will be such that there will be little headroom for integration and the programmes are not expected to align. The possibility of a tidal barrage exists in this area, of anticipated capacity 5–10 GW, depending on exact location. Should such a barrage project proceed it is likely that extensive reinforcement and upgrade would be required to both the north and south of the channel. This possibility has only been considered at a high level to date.

3.11.7 Irish Sea Zone

There is a single Round 3 zone in the Irish Sea area, off the north coast of Wales, from which there is potential for some 4.2 GW of offshore wind generation in total.

The majority of this zone is within 50 km of the shore of Anglesey so the use of AC technology is considered appropriate for these near shore parts. The northern parts can be over 60 km from the shore, reaching the practical limit of AC cabling, and would most likely require and HVDC connection. This northern section is comparatively as close to the Lancashire coast as the North Wales coast so it is a practical proposition to connect to a substation in Lancashire in order to separate the zone across different onshore connection points to help distribute the power infeed from the wind generation reducing the loading impact at the connection sites. Consideration of the transfer requirements for the North Wales boundaries NW1, NW2, NW3 and NW4 also reveals that alternative connection points away from Anglesey help to reduce pressure on these boundaries and mitigate the immediate need for onshore reinforcement.

An integrated design with additional interconnections within the zone could give additional benefits by reducing the number of connections to shore and providing circuit diversity to the offshore generation. Further it will introduce some additional transfer capability across the B7a boundary, either mitigating or deferring the need for additional onshore reinforcements. The use of HVDC technology within this boundary link will allow greater control of power flows which will provide increased ability to take power from the North Wales area which is traditionally a region of high generation export.

There is currently great interest in connecting significant levels of wind generation from outside the zone, either from Irish territorial waters or from the Irish mainland itself. The distances involved will require the use of HVDC technology and the indicative capacities will require multiple links to the onshore network, most likely to

North Wales, South Wales and possibly beyond. There are a range of potential network design solutions, depending on the rate of growth and timing of the generation. A co-ordinated solution will allow incremental development, thus minimising redundancy risk whilst facilitating future development which can be incorporated as further offshore generation is developed. Further, by integrating at the source of these links outside the zone, it is expected that network transfer benefits can be achieved having the benefit of mitigating the onshore reinforcements that would be required if each connection point were analysed in isolation. The network solution will continue to be explored as the interest and opportunity for such connections increases alongside the evolving commercial and regulatory clarity.

3.11.8 Scotland Zone

There are two Round 3 zone in the Scotland area, Moray Firth and Firth of Forth, from which there is potential for some 4.7–5 GW of offshore wind generation in total. There are also a number of smaller Scottish territorial waters sites with an indicative capacity of some 5 GW in total, as well as 1.6 GW split across a number of sites in the Pentland Firth and Orkney Waters strategic marine power development area.

The most significant opportunities for the development of offshore integration lie in the Moray Firth and Firth of Forth zones. Both zones are far enough from the coast that a requirement for HVDC technology can be assumed, although the parts of the zones closer to the coast may only warrant AC connections. However, a significant penetration of HVDC presents the opportunity for within zone interconnection in order to offset the number of offshore to onshore links, with selected oversizing of some of these links when compared to the likely radial alternative design.

For the Firth of Forth zone it is proposed to investigate additional connections offshore to the network in the north-east of England. For the Moray Firth zone, additional interconnection in this manner will bridge the northernmost section of the network and provide an efficient method of connecting the links to the more remote Orkney and Shetland developments. It is expected that these arrangements will mitigate an extensive upgrade or reinforcement of significant parts of the Scottish network and the Scotland to England onshore circuits.

The widespread nature of the proposed generating sites in the North Scotland zone gives rise to the possibility of establishing a DC switching station that could connect the mainland network to the Moray Firth, Orkney and Shetland developments, although this would require significant technological innovation and development.

For the west coast of Scotland, the Argyll Array and the Islay developments will both require lengthy HVDC radial circuits to connect to the onshore network. It may be beneficial such that these links, and interconnecting the developments to provide a parallel HVDC offshore transmission route that could provide redundancy to both wind farms and assist in managing the power flow on the onshore AC network, whilst minimising the resultant onshore reinforcement requirements.

3.12
European interconnection

Increased interconnectivity between European Member States will play an essential role in facilitating competition by developing the European electricity market and the transition to a low carbon electricity sector by efficiently integrating various types of renewable generation, particularly offshore wind.

Current and planned interconnection

1. There are four existing interconnectors between GB and other markets:
   a. **IFA** (1986) – 2000 MW interconnector between France and GB jointly owned by National Grid Interconnector Limited (NGIL)[1] and the French transmission company Réseau de Transport d'Electricité (RTE)
   b. **Moyle** (2002) – 450 MW interconnector from Scotland to Northern Ireland, 80 MW into Scotland owned by Northern Ireland Energy Holdings and operated by the System Operator for Northern Ireland (SONI)
   c. **BritNed** (2011) – 1000 MW interconnector between the Netherlands and GB jointly owned by NGIL and the Dutch transmission company TenneT
   d. **EWIC** (2012) – 500 MW interconnector from Ireland to GB owned by the Irish System Operator, EirGrid

2. Additionally, there are currently four more interconnectors with signed connection agreements that are expected to commission before or around 2020:
   a. **NEMO** (2017) – 1000 MW interconnector between Belgium and GB jointly owned by NGIL and the Belgian transmission company Elia
   b. **IFA2** (2019) – 1000 MW interconnector between France and GB jointly owned by NGIL and RTE
   c. **NSN** (2018) – 1400 MW interconnector between Norway and GB jointly owned by NGIL and the Norwegian transmission company Statnett
   d. **Northconnect** (2021) – 1400 MW interconnector between Norway and GB jointly owned by five partners: Agder Energi, E-CO, Lyse, Scottish and Southern Energy and Vattenfall AB

3. There are further projects which have applied for PCI status (projects of common interest) under the Commission's energy infrastructure package, and other projects that are already in the public domain. These are set out in the table below, but we recognise that there may be others of which we are currently not aware, so this list is not exhaustive

4. Ofgem are currently developing a new regulatory regime for interconnectors and we welcome applications from both these 'cap and floor' regulated and exempt third party projects.

1 A wholly owned subsidiary of National Grid Plc.

Table 3.12.1

450 MW to NI
xx MW from NI

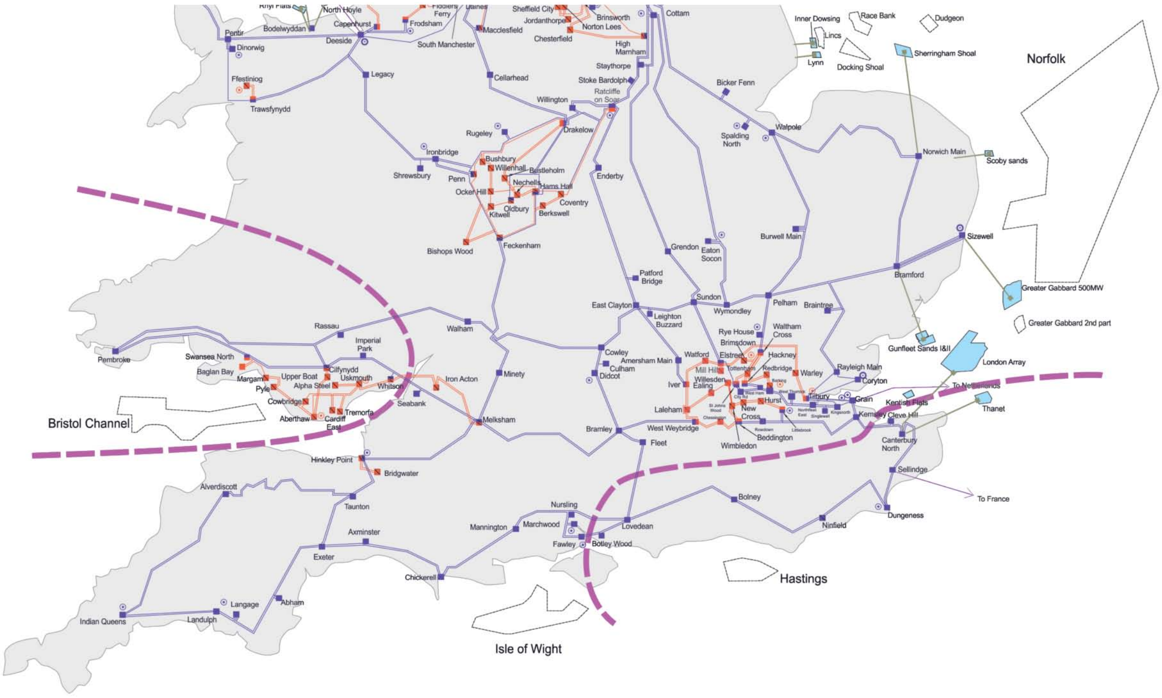
Name	Owner(s)	Connects to	Capacity	Key dates
Operational interconnectors				
IFA	NGIL and RTE	France	2000 MW	Operational 1986
Moyle	NI Energy Holdings	Northern Ireland	450 MW to NI xx MW from NI	Operational 2002
BritNed	NG and TenneT	The Netherlands	1000 MW	Operational 2011
EWIC	Eirgrid	Ireland	500 MW	Commissioning 2012
Contracted interconnectors				
Nemo	NGIL and Elia	Belgium	1000 MW	Contracted 2017
NSN	NGIL and Statnett	Norway	1400 MW	Contracted 2018
IFA 2	NGIL and RTE	France	1000 MW	Contracted 2019
Northconnect	Agder Energi, E-CO, Lyse, Scottish and Southern Energy and Vattenfall AB	Norway	1400 MW	Contracted 2021
Others in public domain (applied for PCI status or pre-feasibility studies announced)				
Channel Cable UK	Europagrid	France	1000 MW	2016 (PCI)
Eleclink	Star Capital & Eurotunnel	France	500 + 500 MW	2017 (PCI)
BritIb	Transmission Capital	Spain	1000 MW	2017 (PCI)
Iceland-UK	TBC	Iceland	TBC	2019
Denmark-UK	Energinet	TBC	TBC	2020+
EWIC2	EirGrid proposal	Ireland	500 MW	2020+ (PCI)
Spain-UK	REE proposal	Spain	1000 MW	2025 (PCI)

It is expected that an increasing amount of intermittent renewable generation across Europe will require stronger interconnection between countries. The extension of the electrical transmission infrastructure into the seas around the European countries to connect the offshore generation adds the opportunity to further extend that infrastructure to join the countries together.

In December 2010 the ten governments of the North Seas countries (Ireland, UK, France, Belgium, Luxembourg, Netherlands, Germany, Denmark, Sweden and Norway) signed a Memorandum of Understanding aimed at providing a co-ordinated, strategic development path for an offshore transmission network in the Northern Seas. The North Seas Countries' Offshore Grid Initiative (NSCOGI) is seeking to establish a strategic and co-operative approach to improve current and future energy infrastructure development. This initiative is now progressing the work that ENTSO-E published in February 2011 (Figure 3.12.1) which concluded that there are benefits in developing an integrated offshore grid provided there is both a requirement for increased cross border trading capacity, driven by the markets, and significant and increasing volumes of offshore renewables between the period 2020 to 2030.

3.13
Areas of future interest

Figure 3.13.1:
Potential areas for new boundaries (note the boundaries drawn are indicative of the areas of interest and further work will be required to refine their exact shape)



The boundaries currently assessed reflect previously identified areas of the transmission system likely to be stressed in the future. Assumptions around future generation and demand patterns continue to evolve and as such the potential effects on the transmission system will also change. Therefore the boundaries studied are continually subject to review. There are currently two additional areas of the transmission system identified that are potentially areas of high stress in the future. Interest has been expressed for additional new connections in South Wales which will require some further analysis to investigate together with the interactions with North Wales and the South West Peninsula.

In the South East of England, the volume of proposed interconnection to continental Europe will present challenges in terms of the high potential variability of flows through this region from fully exporting, fully importing and cross European transfers. Some of these stresses have been identified already as they affect B14 as shown in the B14(e) sensitivity discussion, but there could also be effects outside of London.

These areas are identified on Figure 3.13.1. The boundaries drawn are indicative of the regions of interest, and do not represent actual proposals for boundaries. Further work to refine the circuits of interest will be undertaken, and if necessary, additional boundaries will be considered in the 2013 ETYS.

Chapter four
System operation

4.1 Introduction

The previous chapter discussed in detail the potential development of the National Electricity Transmission System (NETS) under a range of energy scenarios. In Chapter 4 we discuss the impact of the changing transmission system on the operation of the network. Increasing levels of low carbon generation present a range of challenges with respect to the operation of the transmission system. This will also present opportunities as we explore different approaches to the way we manage an increasingly complex network.

4.1 continued
Introduction

We have consulted extensively with stakeholders to identify how the design and operation of the electricity transmission system will develop (e.g. Operating the Network in 2020 consultations[1], RIIO 'Talking Networks' consultations and engagement). Our focus has been on enabling an orderly transition that facilitates the achievement of climate change targets, and provides a solid foundation for the further change required in the period out to 2050.

The key change to the network is the transition from a generation mix dominated by fossil fuel synchronous generation, to a generation mix which includes far more low carbon and intermittent asynchronous generation and interconnectors. The level of change in the generation capacity mix is dependent on a number of factors which are covered by our range of scenarios described in Chapter 2[2]. Another important challenge is the increase in the number of embedded generators which impact on the transmission demand profile (both minimum and maximum demand), flows on the transmission system and system performance issues such as voltage, fault level and inertia. Potential increases in the penetration of electric vehicles, electricity storage and a range of demand side management programmes may also change the demand profile and impact on system operation.

These challenges are likely to be at their most extreme during periods of high wind generation output and low demand, as the level of installed wind capacity on the system may be even higher than the demand during low demand periods. The graphs below show the level of wind production at 70% of installed capacity in spot years out to 2030 compared with summer minimum demand levels, in the three main scenarios.

1 Operating the Electricity Networks in 2020 www.nationalgrid.com/NR/rdonlyres/DF928C19-9210-4629-AB78-BBAA7AD8B89D/47178/Operatingin2020_finalversion0806_final.pdf

2 The contracted background is not analysed in this section as we are considering system issues rather than local connection issues.

Figure 4.1.1:
Slow progression wind production

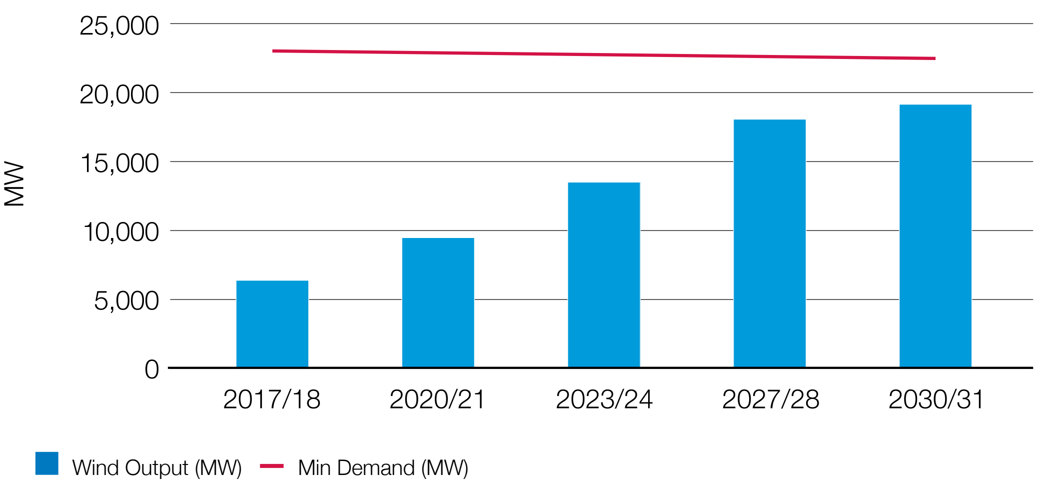


Figure 4.1.2:
Gone green wind production

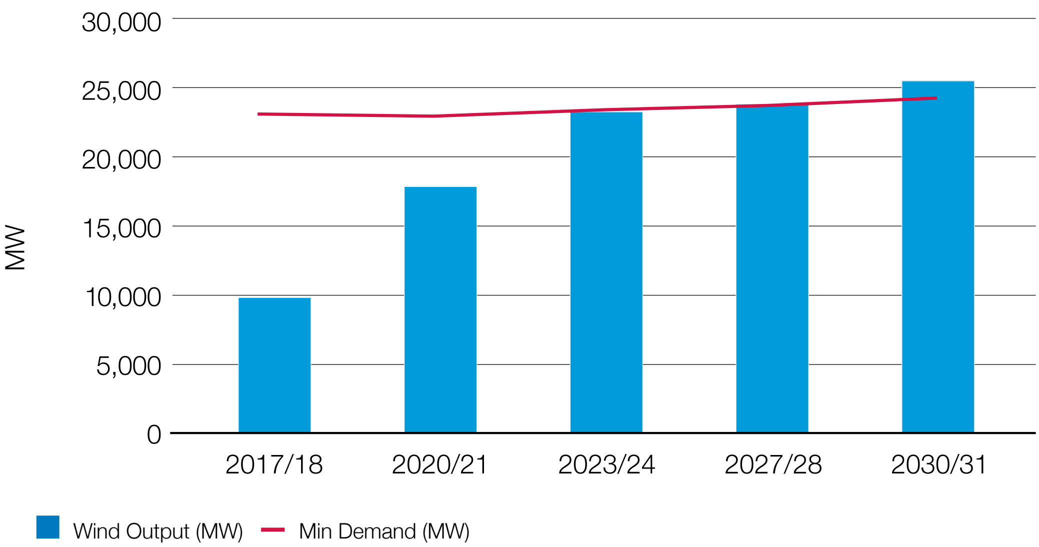
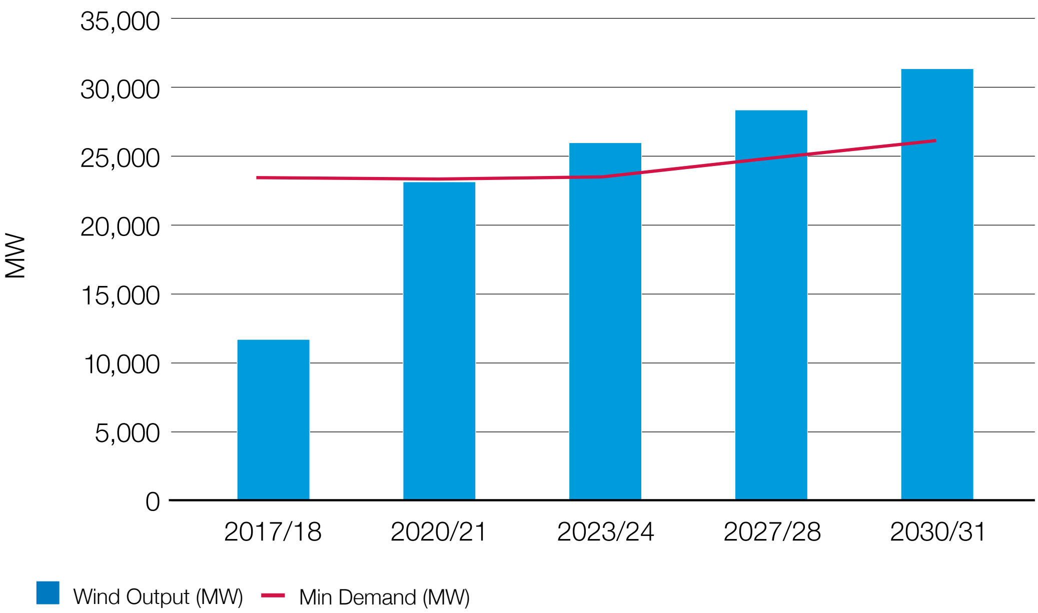


Figure 4.1.3:
Accelerated growth wind production



4.1 continued
Introduction

In Slow Progression the level of wind output is likely to be below the minimum level of demand. In Gone Green and Accelerated Growth there are occasions beyond 2020 when the level of wind output may exceed the minimum level of demand. With an assumption that nuclear power provides a level of 'baseload' generation, then occasions when the power output of wind and nuclear in combination may exceed the minimum demand may occur earlier than identified above, and more frequently.

This outlines one of the key potential challenges facing us and in addition there are a number of other issues considered over the course of this chapter. These are generally common issues that are applicable to all three scenarios. This chapter discusses these issues in detail and highlights the resulting impact on the network:
- system inertia and fault level changes
- voltage and Reactive Power management
- intermittent generation and interconnector volatility requiring additional reserves and causing power flow volatility both in magnitude and direction
- high wind speed shut down.

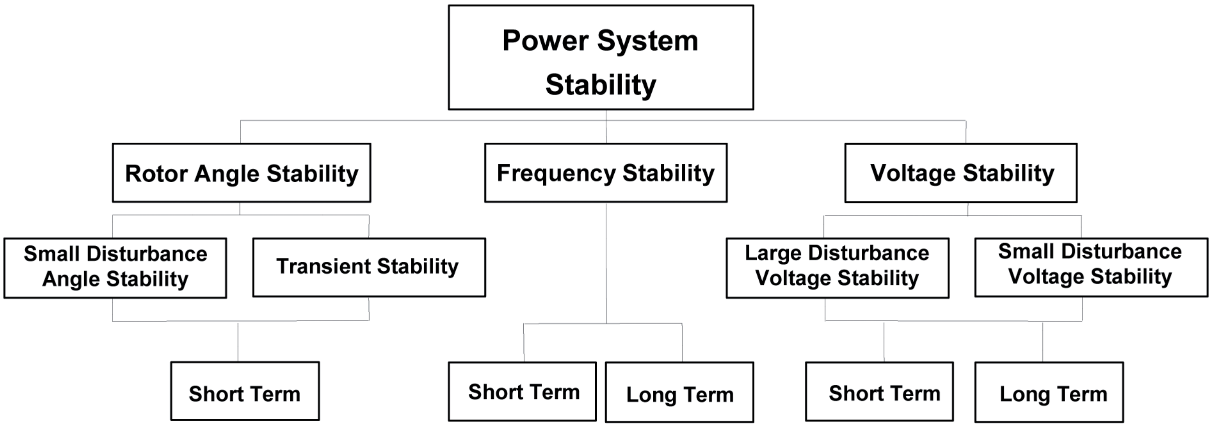
The next section discusses the issues and challenges for the operation of the system in the context of the different scenarios. Various technical issues are described and analysed in detail. In the final section some potential mitigating measures are considered. The aim is to ensure the system is operated in the most secure and efficient way whilst maximising the use of the network capacity under a range of scenarios. The chapter concludes by identifying what opportunities exist to assist in meeting these challenges.

Despite the challenges that the changes to the network will present, we have identified a range of potential solutions on how we will need to adapt the way we operate to ensure continued successful management of the power system.

The issues and challenges briefly described above will be discussed throughout this chapter under the following headings:
- system operability
- system design and operating challenges; and
- opportunities.

4.2
System operability

Figure 4.2.1:
Classification of power system stability



Our principal role as system operator is to maintain a safe, secure, compliant, and economic system. This section discusses the technical aspects of system operability and the impact of each element on the operation of the system.

In the context of security of supply, maintaining a stable power system is the main focus. The importance of the stability of a power system is to ensure the ability of the system to remain operable and synchronised during various disturbances (e.g. loss of generation, loss of circuit after a fault in the transmission line). For power systems worldwide, traditionally dominated by large central generators, this varied power system stability task has been classified into segments described in Figure 4.2.1.

The figure above illustrates the day-to-day stability challenges applicable to almost any large power system. The three main classes consist of rotor angle, frequency, and voltage stability. These have been the focus in designing appropriately robust networks and have also been the foundation for our National Electricity Transmission System Operator (NETSO) policies.

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) accounts for all aspects of system stability, at the design and operation stage, by specifying the system performance requirements. These stability challenges are very familiar to us. For instance, as an island power system with no AC link to other large power systems, it is important to maintain a balance between frequency stability, the size of the largest potential loss of infeed to the system, the costs of de-loading plant, and providing frequency control services. The connection between the generators in England and Wales and those in Scotland requires appropriate Power System Stabiliser (PSS) at these stations and possibly Power Oscillation Damping (POD) facilities in future HVDC interconnectors.

4.2 continued

System operability

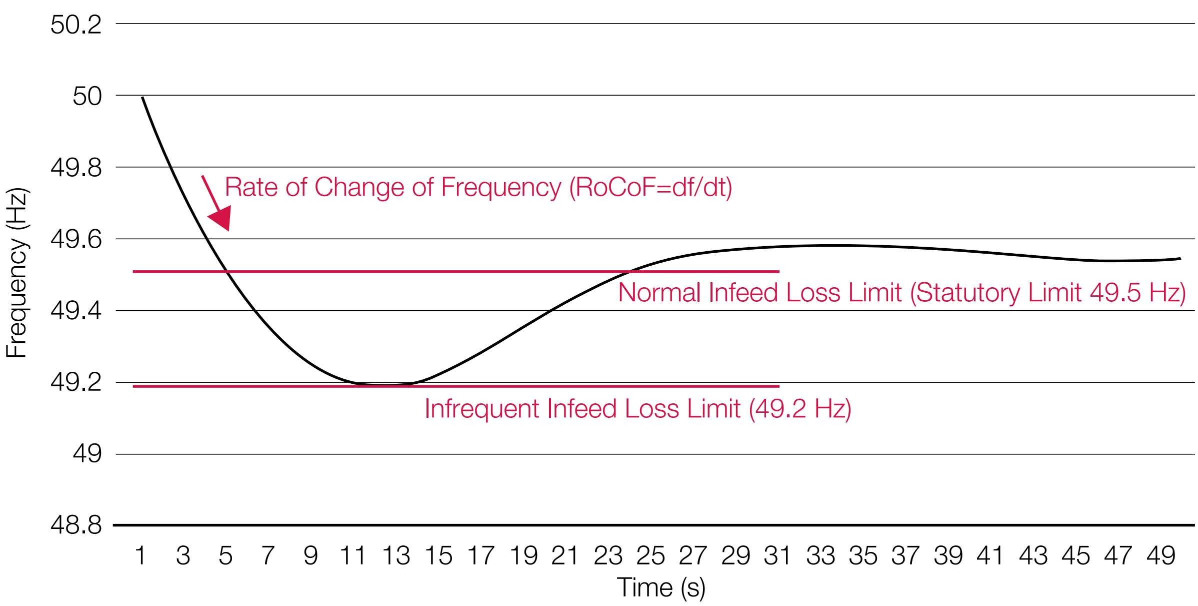
The new stability challenges can be classified as follows (with further details in subsequent sections):

- Frequency management – linked to low overall system inertia resulting in high rates of change of frequency following a large generator or interconnector loss.
- Voltage management – due to the widespread absence of reactive resources from generation (previously in the central part of the network) required to regulate the system voltage during high renewable energy systems operation located mainly in Scotland and Offshore.
- Low fault levels on the system during times of high renewable output (solar PV and wind).

Under the Slow Progression scenario, the system operation issues remain largely unchanged until 2020. The slower build-up of large offshore wind farms under the Slow Progression scenario delays the transformation from a predominantly synchronous generation based power system, to an asynchronous generation based power system. For Gone Green and to a greater degree in Accelerated Growth, new additional stability challenges emerge. These require earlier consideration, and form the theme of this chapter.

4.3
System design and operation challenges

Figure 4.3.1:
System frequency limits and concept of RoCoF



4.3.1
Impact on System Inertia

Inertia and Rate of Change of Frequency (RoCoF)
A synchronous generating unit (mainly large steam or gas turbine generating plant) operating in the electrical power system will deliver its stored energy (in the rotating mass of the shaft of the turbine) to the system on falling system frequency. This inertia response will help to slow down the initial fast drop of the system frequency and hence a reduction of "Rate of Change of Frequency (RoCoF)" and is measured in Hertz per second (Hz/s). Interconnectors and converter interfaced generating plant will not be able to deliver this inertia response at a time of falling system frequency leading to a higher RoCoF than current level.

System inertia will reduce as a result of increasing the penetration of asynchronous generators which have no or very little natural inertia compared to large synchronous generators (due to the absence of a large rotating mass in the generator). Under all three scenarios, the reduction in system inertia is visible. The degree of reduction is dependent on how much asynchronous plant is connected, and the generation output of this plant, which in turn determines how much synchronous plant is left running at any time.

4.3 continued
System design and operation challenges

Reduction of system inertia may have two effects on the frequency management:

a. The impact on the Rate of Change of Frequency (RoCoF): After a loss of generation, the frequency will start to drop rapidly. With falling inertia the RoCoF increases. This may pose a challenge for a system operator as embedded generators may also trip if RoCoF exceeds the setting of the Loss of Mains (LOM) protection which utilises the RoCoF. LOM is used to protect against the risks of the generator continuing to run as part of a non-viable isolated system.

b. The impact on statutory frequency limit: Apart from the rapid change in the frequency, there is also a risk that the statutory frequency limit is violated. The restoration of balance between supply and demand through the current primary response sources may take a few seconds, and hence the frequency can fall significantly before the primary response arrests the fall.

The following charts show the change in total system inertia (calculated in GVA.s) for the scenarios, at different years and during low demand periods:

Figure 4.3.2:
System inertia changes for Slow Progression at 70% wind power output (H= System Inertia)

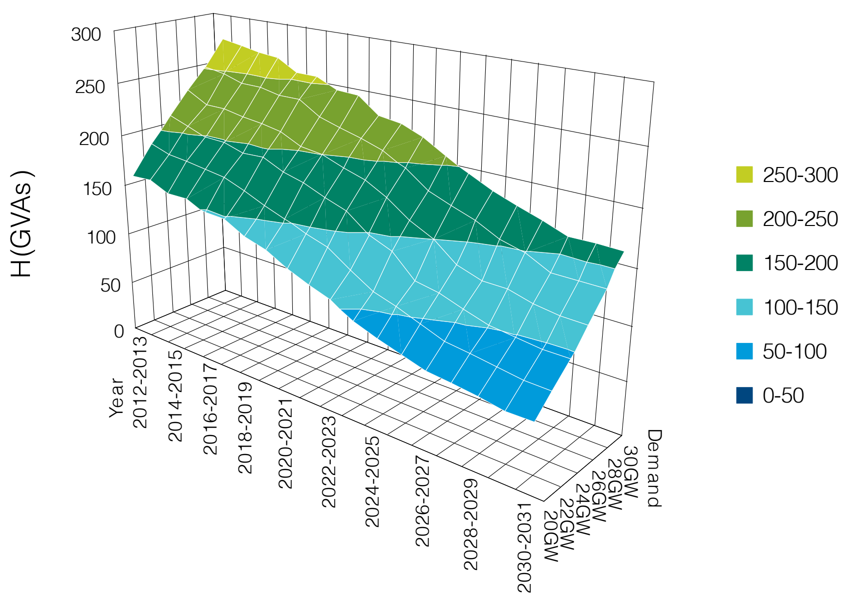


Figure 4.3.3:
System inertia changes for Gone Green at 70% wind power output (H= System Inertia)

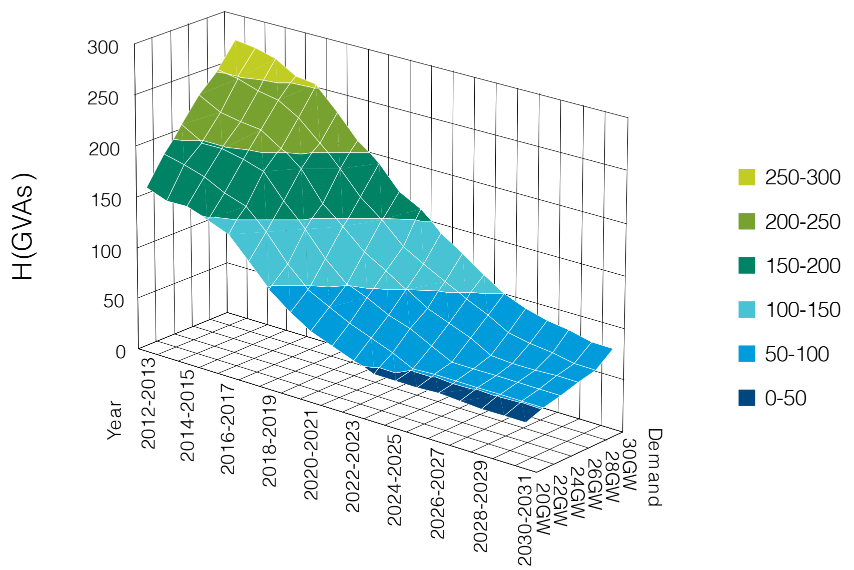
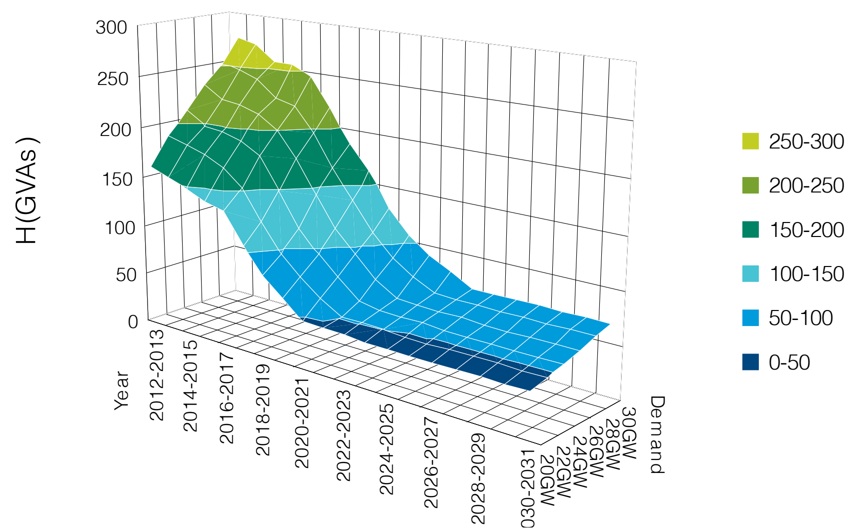


Figure 4.3.4:
System inertia changes for Accelerated Growth at 70% wind power output (H= System Inertia)



4.3 continued
System design and operation challenges

In the early years, the three scenarios have a very similar generation capacity mix and as a result the overall system inertia is almost the same, but varies slightly due to demand differences. With respect to system inertia the deviations in the scenarios are significant post-2020.

The impact of the low overall system inertia is a substantially higher risk in frequency management unless mitigating actions are taken. Wind and PV generally contribute little or no inertia of their own and this can become critical during low demand conditions (summer minimum demand scenario). Considering the rate of installation of deeply embedded solar PV (1 GW has been installed during 2011), the minimum demand seen at the transmission level may reduce even more. This means, the number of hours that the system inertia may be low will increase, and this may expose the system to more risk in terms of frequency management.

Potential Mitigating Measures
There are two key challenges with regard to frequency management. One is to control the RoCoF, and the other is to limit the frequency deviation after a loss of infeed. It is important that the measures proposed are economic and support the move towards the environmental targets, therefore, limiting the largest infeed to a lower value, or constraining the generators to limit RoCoF are not the most economic options .

Methods that address the issues identified above include:

Low Load Operation of Synchronous Generators – Synchronous generators connected to the system but at low load operation mode may still provide inertia to the system. This is usually not an optimal operating point for the generators in terms of unit cost (£/MWh), but may still be required for securely operating the system in the absence of other more feasible solutions.

Fast Frequency Response – System inertia is provided by the rotating mass of directly connected generators (i.e. not decoupled through power electronics such as solar PV and some wind turbines). The initial RoCoF depends on the size of infeed loss (causing a mismatch between generation and demand), and the level of system inertia.

Alternative solutions to manage the initial RoCoF issue may include providing additional inertia from new technologies such as flywheels. However, this technology is still at a very early stage of development. The alternative to having mechanical inertia to manage RoCoF issue would be to provide fast acting power injection (typically within 200ms), or the use of demand side response to mitigate the demand / generation imbalance. Therefore, the concepts Fast Frequency Response, and/or synthetic inertia in the context of frequency management have been introduced which may be provided from:

- certain generators capable of a very fast power ramp-up
- dynamic demand side response to disconnect/delay the load immediately
- fast power injection from interconnectors.

4.3.2
Impact on System Strength (Fault Levels)

Strength in Power System
Fault level studies are typically carried out to ensure that the maximum fault levels that can potentially arise at specific locations on the system do not exceed the ratings of switchgear. These studies also aim to provide confidence that the protection-related assets installed on the system are adequate and will not be loaded beyond their rated capabilities; i.e. current breaking capability of circuit breaker. Where fault levels are exceedingly high, measures such as splitting substations or installing fault current limiters are used to reduce fault levels. Therefore, it is important to carry out these studies under a scenario to capture the maximum possible fault level on a busbar.

The fault level of a system provides a good indication of the strength of the network which in turn, reflects on its ability to remain stable following disturbances. A system with a high fault level is therefore less prone to instabilities and power quality issues (such as large voltage steps, flicker and harmonics) when compared to a weaker system having a lower fault level.

It is desirable that fault levels are not excessively high from a protection and asset life perspective but at the same time are not too low from a system strength point of view. Therefore the right balance in fault levels needs to exist to ensure that both the asset life and system strength are not compromised.

Up to now, the generation mix of Great Britain has been predominantly based on synchronous generation which has a relatively large contribution to fault levels. Depending on the scenario, the generation mix is expected to change radically to accommodate large amounts of generation from asynchronous generators such as wind turbines where their fault contribution is less than the synchronous generators.

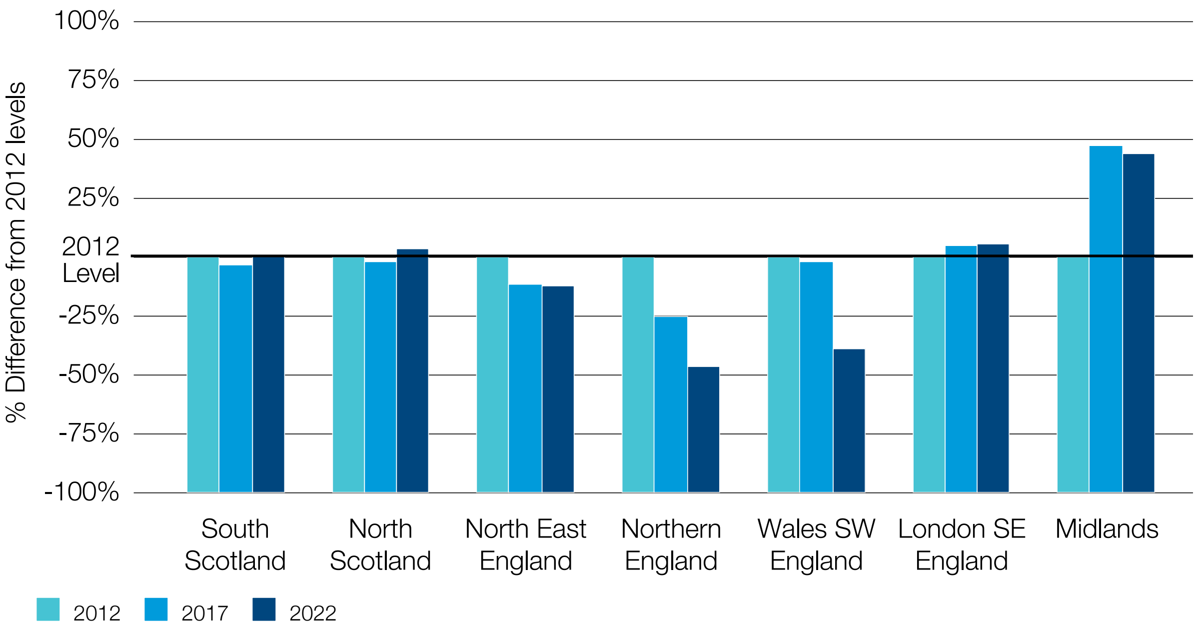
Preliminary studies have been carried out to obtain an overview of how fault levels are expected to change up to 2022. These are presented in the following section.

The graphs below show the average trend in fault levels on the system for different scenarios. Whenever a high level of asynchronous generation is present in an area and fewer synchronous generators are connected to the system, the fault level at that part of the system is reduced.

The fault level results presented in this section are estimated for the spot years 2012, 2017 and 2022 and are based on the generation mix in each of the different scenarios.

A demand of approximately 30 GW, corresponding to a modest summer demand level, was used to despatch the required level of generation under the assumption that the output from renewable plants (wind and wave) was scaled to 70% of their capacities. The assessment has considered different regional areas, rather than a specific busbar on the network to better show the trend in fault level reduction. The results shown in this section illustrate the percentage changes in fault level from the 2012 base case.

Figure 4.3.5:
Fault level variation for the Slow Progression Scenario (covering the lower range of demand)

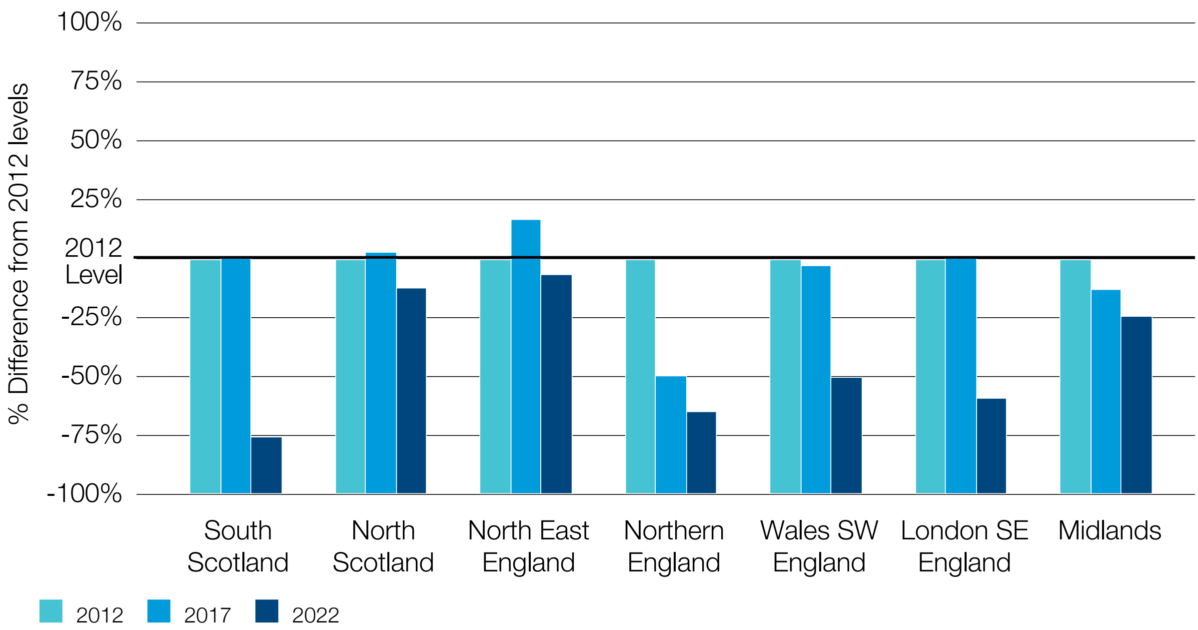


The chart above illustrates the trend in fault levels from 2012 to 2022 under the Slow Progression scenario.

By the year 2017, the study shows that in the North and South of Scotland regions, Wales and South West region, and North East of England region, there is a small reduction in the minimum fault level. This is due to the replacement of synchronous generators by asynchronous generators which have less contribution during faults. The reduction in network strength for the Northern region of England is more pronounced (25% reduction). This is mainly due to the synchronous generators in the North being replaced in the merit dispatch order by new CCGT units in other regions. Due to these new CCGT units, there may be an improvement in network strength in the Midlands region and the South East region. For the northern and southern parts of Scotland, there is a slight increase in fault levels due to small increase in synchronous generation in northern Scotland.

By the year 2022, for the North East of England, Midlands and South East regions, the fault levels remain almost constant as the levels of synchronous generation do not change between 2017 and 2022. The substantial drop in the Wales and South West region is due to the replacement of about 3 GW of synchronous generation in this region by asynchronous generation spread across the system.

Figure 4.3.6:
Fault level variation for the Gone Green Scenario (covering the lower range of demand)



The chart above illustrates the trend in fault levels from 2012 to 2022 under the Gone Green scenario.

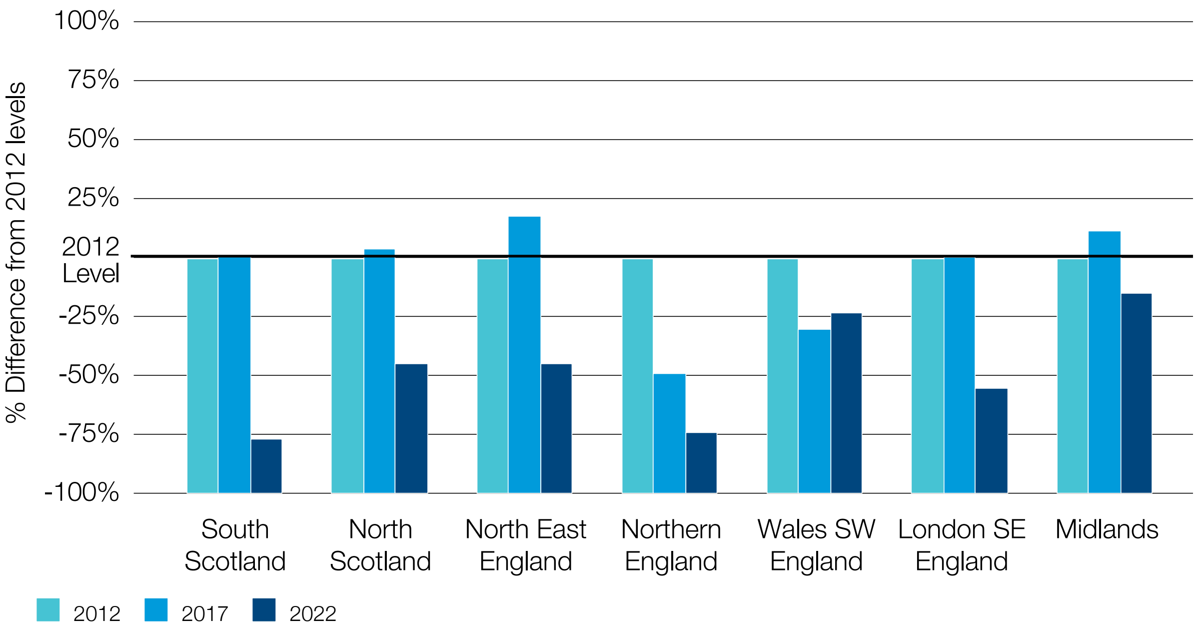
The study shows that for the Scottish regions and the North East of England region, there is an increase in fault levels of about 2% and 17% respectively. For the latter area, the higher fault levels are mainly due to an increase in synchronous generation.

Although there is a small reduction of synchronous generation in Scotland from 2012 to 2017 (about 125 MW), the fault levels increase because of network changes such as the effect of series compensation. In the network model used, the reinforcements essentially reduce the electrical distance between Scotland and the North East of England. This reduction in impedance along with the increase in synchronous generation in the North East of England causes a greater fault in-feed, therefore explaining the slight rise in fault levels in the Scottish areas. In Northern England, Wales and the Midlands, the drop in fault levels is due to a large amount of synchronous generation falling outside the merit dispatch order due to an increase in the penetration of asynchronous plants.

By the year 2022, about 60% of synchronous generation would be preceded by asynchronous plants in the merit order when compared to the 2017 levels. The largest reduction in synchronous generation occurs in the Wales and South West and South East regions. This explains the drastic decrease in fault levels in these regions.

4.3 continued
System design and operation challenges

Figure 4.3.7:
Fault level variation for the Accelerated Growth Scenario (covering the lower range of demand)



The chart above illustrates the trend in fault levels from 2012 to 2022 under the Accelerated Growth scenario.

The trend in the 2017 fault levels in the Accelerated Growth scenario is very similar to that in the Gone Green scenario with the exception of the Wales and South West region and the Midlands region. Under the Accelerated Growth scenario, the level of synchronous generation drops at a faster rate in Wales and South West thereby causing a more prominent reduction in fault levels. when compared to the Gone Green scenario.

With the exception of Wales and South West in 2022, all areas face a reduction in fault levels from their 2017 values. This is because the level of synchronous generation is expected to drop by about 70% to prioritise generation from asynchronous sources.

The connection of new nuclear units compensates for the other synchronous generators which become out of merit in the Wales and South West area. For a 30 GW level of demand, new nuclear units are dispatched in the merit order and therefore cause the fault level to rise in the Wales and South West region.

The results demonstrate that there is a direct link between the level of synchronous generation and the fault levels on the system.

There are other factors which will affect the minimum fault level in a region of the system and as a result, the findings presented in this section can only be used as a guideline to reflect the general trend expected in minimum fault levels. The results also represent a snapshot of how fault levels may vary on the basis of a 30 GW demand and asynchronous plants scaled to 70%. At an even lower demand e.g. 20 GW with a higher penetration of renewables e.g. 100%, the minimum fault levels will reduce even further.

The reduction in system strength may have some consequences which are described below:

Voltage and Reactive Power Management

Reactive power to support and stabilise system voltage is currently provided locally using reactive power compensation equipment, and by generators set to voltage control. This allows better control over the voltage on the grid, one of the key system stability factors. Inadequate reactive power may result in low voltage, an increase in network losses, and voltage instability. Excessive reactive power on the network causes the voltage to rise.

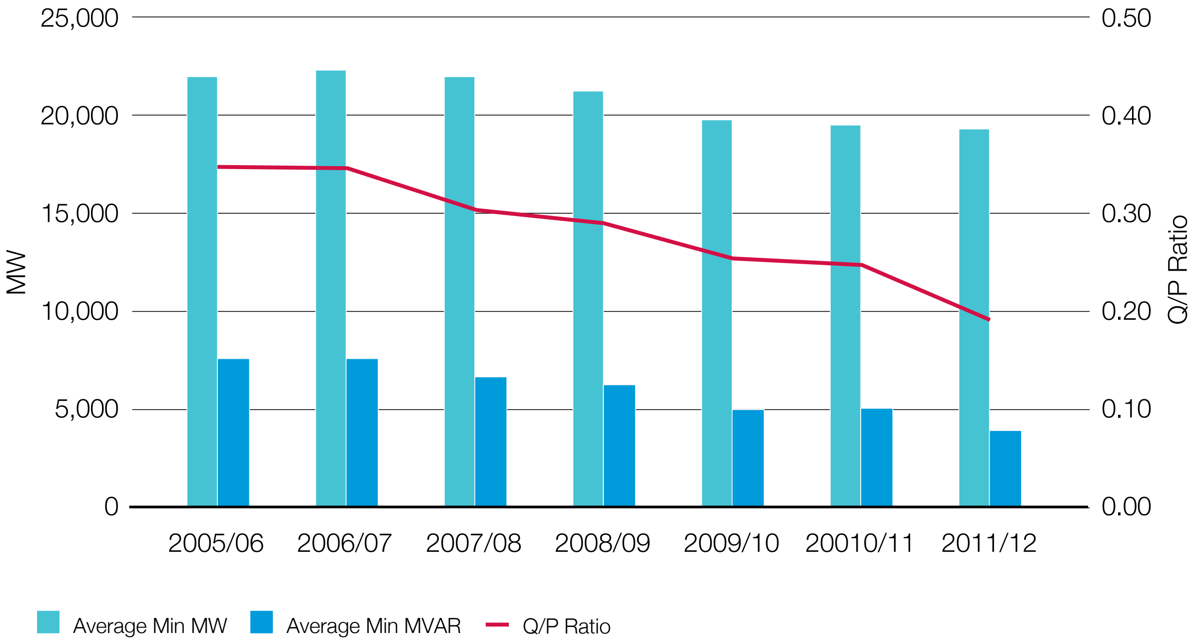
High voltage transmission assets (cables, circuit breakers, transformers, current and voltage transformers, etc.) are designed for operating continuously within a set voltage range, albeit with a short period of time allowed outside this set range. Periods exceeding the range of over 15 minutes in duration may have an adverse affect on plant asset life.

High volt situations under low demand conditions are now increasing due to several factors including:
- development of underground cables in the distribution and transmission grid
- lack of generation support in specific areas; and
- reduction in reactive demand.

This issue is worse overnight, when the demand for electricity is lower, and therefore the charging current produced by lightly loaded circuits increases the voltage on the system. This is most severe in cable dominant areas. The reactive power consumption of the load also has an impact on the voltage profile. The following figure illustrates the historic trend of reactive power demand during minimum demand periods.

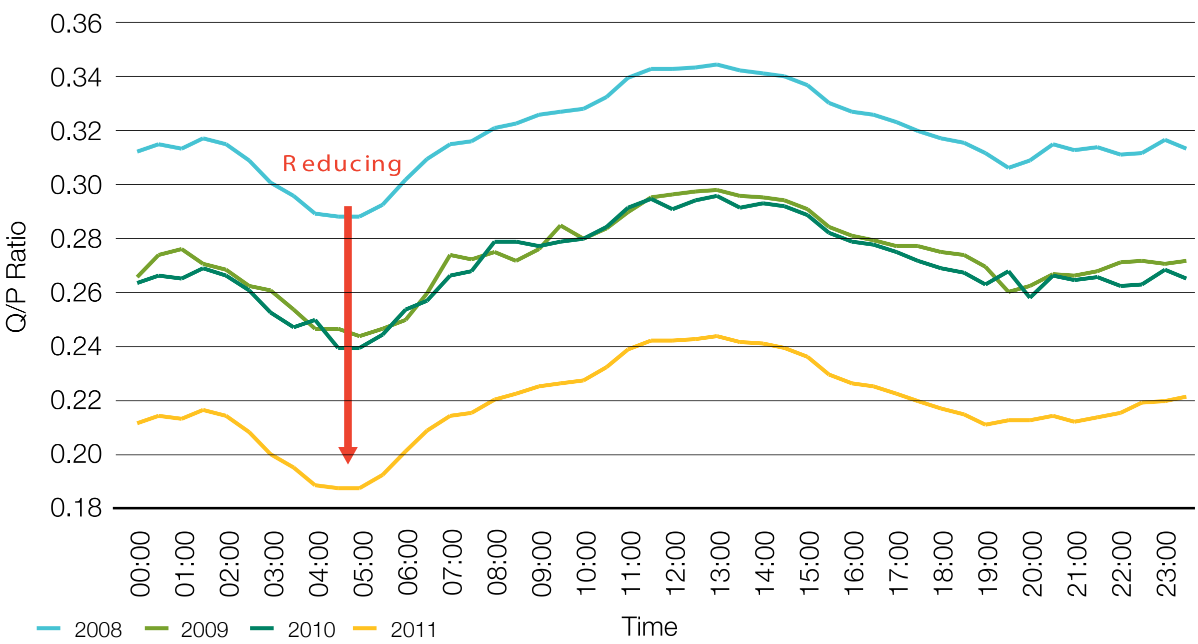
System design and operation challenges

Figure 4.3.8:
Average active and reactive power demand (average of 3 lowest each year)



The ratio between reactive power and active power demand (Q/P ratio) has reduced over the past few years. The graph above shows the Q/P ratio over a 24hr period in summer minimum demand periods since 2005/6. As illustrated, the Q/P ratio is almost half the level it was in 2008.

Figure 4.3.9:
Q/P ratio over a 24hr period in summer minimum demand periods



Under all future scenarios large numbers of coal plants installed in the centre of the network are decommissioned. Simultaneously, large offshore wind farms connected to the periphery of the system can only provide localised reactive power support (at the point of connection) to the grid. The new Combined Cycle Gas Turbine (CCGT) generators requiring cooling water are also located closer to the shore and the periphery of the system. This may result in having strong reactive power control capability around the network extremities through the connection of these generators, but a lack of such capability in the central parts of the system.

The consequences of this are complex and may result in reduced boundary transfer capability, system stability issues, including inter-area oscillation, and problems with voltage management. Therefore, we are investigating the exact cause of the high voltage observed overnight by working with distribution companies. The solutions to address this issue currently being considered include investment in reactive power compensation devices, and managing the output of generators local to the affected regions.

Protection Sensitivities to Low Fault Level

Protection devices will be affected because as under the low fault level case, the speed of response to eliminate the fault is reduced. Furthermore with increasing penetration of asynchronous generation and interconnectors there may be cases when the load current and the fault current become close to each other, implying that the detection of faults will become more challenging.

4.3 continued
System design and operation challenges

Quality of Supply Issues – The reduction in fault levels weakens the overall strength of the network which in turn can gives rise to quality of supply issues such as large voltage steps, harmonics and flicker.

HVDC Commutation Failure – Voltage disturbance is one of the key reasons for commutation failure on HVDC Links. Voltage disturbances are generally caused by system faults or switching events. These events are unpredictable and therefore the system must be robust enough to survive them or be able to recover from them successfully. In a system with low fault levels, the severity of such voltage disturbance may be such that it does not allow the minimum extinction angle required by the Thyristor to perform block/de-blocking in a Line Commutated Current (LCC) HVDC system. Therefore, the probability of commutation failures in LCC-based HVDC is greater for weak networks.

In the design of the HVDC projects, and in order to identify the appropriate technology, we give consideration to fault level variations over the lifetime of the project.

Potential Mitigating Measures to tackle low system strength issues

Use of FACTS Devices – The Flexible AC Transmission System (FACTS) devices such as Static Var Compensator (SVC) are used in the network in various locations for better voltage control and maintaining system stability. There is however scope for the system-wide control of such devices to improve powerflow control between different boundaries, manage voltage in certain areas, and enhance system stability. Advanced control systems may also allow the devices to contribute to some complex power system stability challenges such as low frequency oscillation.

Synchronous Compensators – A synchronous generator spinning at synchronous speed connected to the system contributes to system strength for voltage control, and provides fault current contribution due to its inductive nature. A synchronous compensator retains some of the properties of a synchronous generator but without requiring the whole power plant to operate. It may be beneficial for the new generators to be designed in such a way that they can be declutched from the turbine (main mechanical driver) to operate as a synchronous compensator. Further consideration needs to be given regarding the conversion feasibility for older generators.

The benefits in the short term are mainly regional which indicates that the option to process a conversion should be taken on a case-by-case basis in order to determine the regional benefits.

4.3.3
Power Flow Volatility

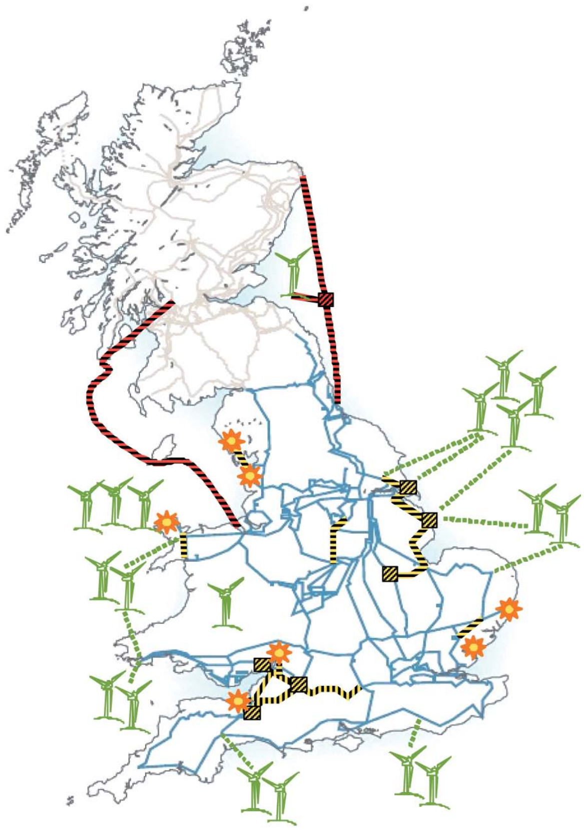
In the GB power system historically the power flowed from north to south. This was due to surplus of generation in the north and the location of the principal demand centres in the south and Midlands.

Connection of large Power Park modules and especially large offshore wind farms may result in large variations in the power flow magnitude and direction on various paths which historically have always had a unidirectional power flow. Such variations may even happen within the day as the output from wind generation varies. The challenge is to take into account the effect of such power flow variations at the system design stage as these variations can affect the voltage profile, system losses and boundary flow capability. There will also be challenges for the system operator such as a more volatile system which may include increased switching actions, a change of running arrangements throughout the day (e.g. for fault level management), an increased burden of outage management and changes in the required post-fault actions.

The figures below show the changes in power flow direction across the three scenarios with different levels of wind penetration and different locations of wind generation output. The four cases analysed are:

- case 1: 0% wind penetration
- case 2: 70% wind penetration
- case 3: Windy in South (70% wind power production), and only 10% wind power production in the North (above B8 Boundary)
- case 4: Windy in the West and Irish Sea region (70% wind power production and only 10% wind power production in the East.

Figure 4.3.10:
Potential location of Large Power Park Modules



4.3 continued
System design and operation challenges

Figure 4.3.11:
Comparison of powerflows and dependency to wind output for Slow Progression scenario in 2022

Figure 4.3.12:
Comparison of powerflows and dependency to wind output for Gone Green scenario in 2022

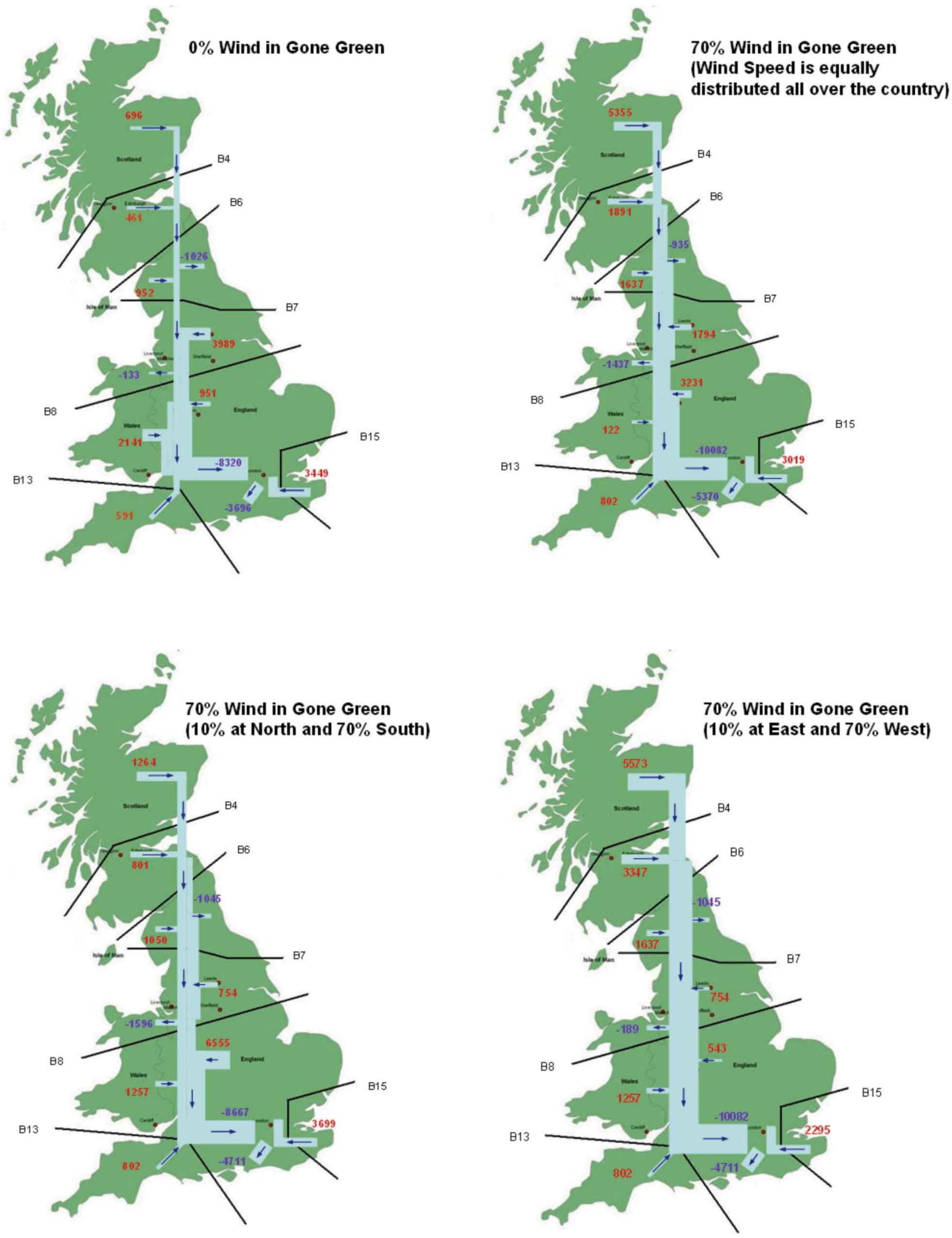
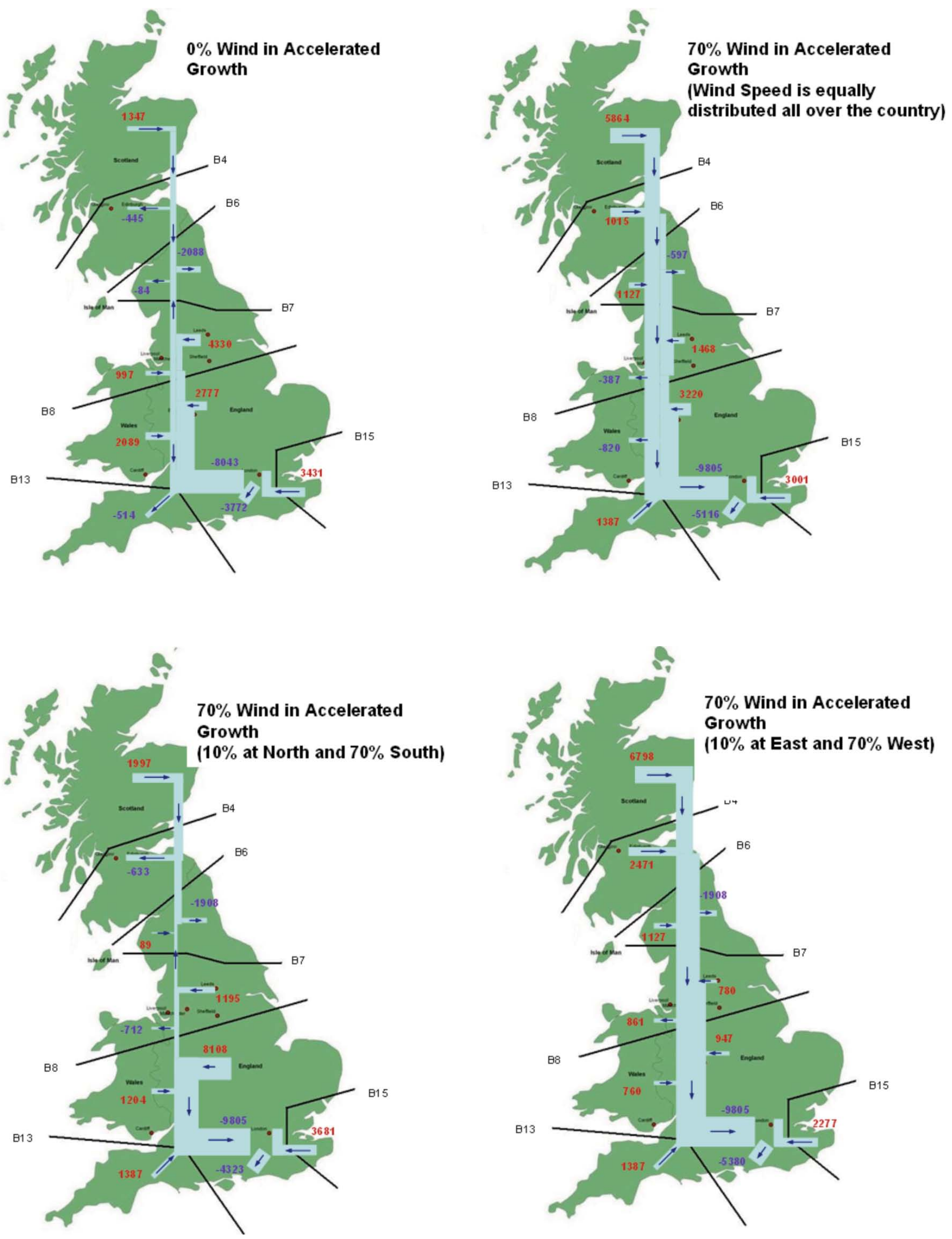


Figure 4.3.12:
Comparison of powerflows and dependency to wind output for Accelerated Growth scenario in 2022



Depending on the level of wind on the system in different scenarios, the power flows across the system are very sensitive to both wind output and location. The magnitude of change in the flow to and from an area for Slow Progression is noticeable mainly over Anglo-Scottish interconnectors due to dependency of powerflow in this power corridor to the level of wind power generation in Scotland. For other areas, there is significant change in the powerflow magnitude when considering the variations in regional wind power output. In Gone Green, the challenges with regard to change in the magnitude of powerflow to and from an area is more severe as the level of installed wind power generation is higher in many areas. For Accelerated Growth, the powerflow direction could become south to north considering the variations in regional wind power output. The change in powerflow direction for other areas is also noticeable due to the change in wind power output in different cases.

4.3.4 System Balancing

As the NETSO we have the responsibility to balance the transmission system in an efficient and economic way. Up until pre gate closure (one hour before the real time), this is delivered by facilitating a market-based approach aiming to minimise costs. Post gate closure, more direct control is assumed via the Balancing Services Market and Balancing Mechanism.

System balancing ensures that:
- at any given time, the balance between generation and demand including network losses, is maintained
- there is enough generation and demand side reserve (also termed 'margin') that can be dispatched rapidly; usually between 10–30 seconds to cater for the level of generation/demand imbalance specified in the SQSS
- the transmission network can securely transfer the power from one region of the country to another.

The key indicator for system balancing is the system frequency which in a balanced system will be equal to the nominal frequency (namely 50.0 Hz in the GB power system). Another important aspect is the cost of balancing the system. Any unplanned change in demand/generation in the balancing market, or constraint on economic power transfers, may result in significant balancing costs incurred by the system operator.

In operational timescales dramatic changes in the generation mix in terms of technology and location are increasingly expected from day to day and even hour to hour. The figure on page 232[1] illustrates this through an example of operation for a winter month (January) in 2030, reusing the weather and demand profiles experienced in January 2000. The wind production is scaled up to that which would be associated with 40 GW of installed wind capacity. This is roughly in line with the wind capacity in 2020 in the Accelerated Growth scenario, 2025 in the Gone Green scenario while in the Slow Progression scenario the installed wind capacity is 28 GW in 2030.

1 Impact of Intermittency, Poyry summary report, July 2009 www.uwig.org/ImpactofIntermittency.pdf

System design and operation challenges

Figure 4.3.13:
British market in January 2030 with 2000 weather

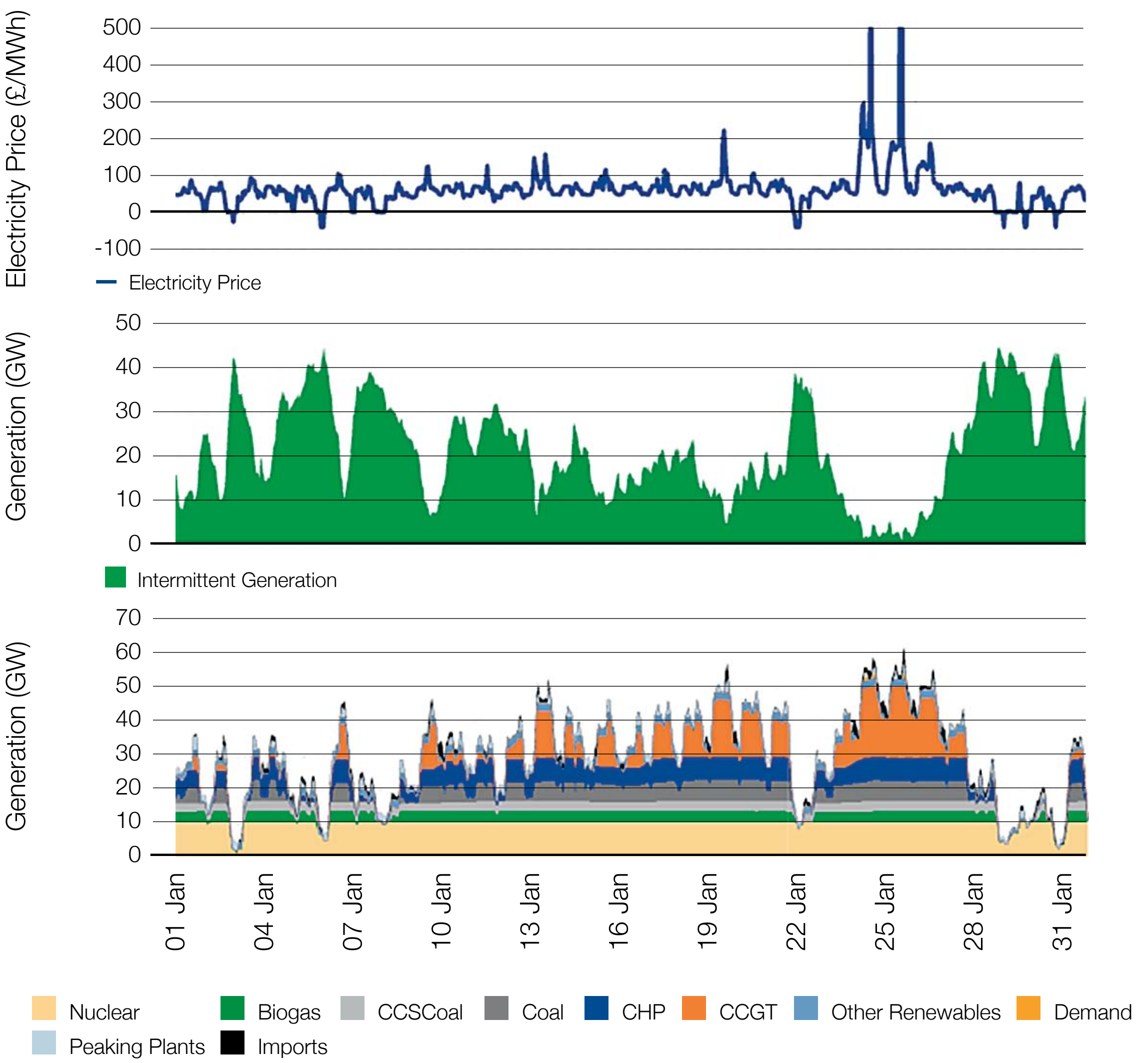
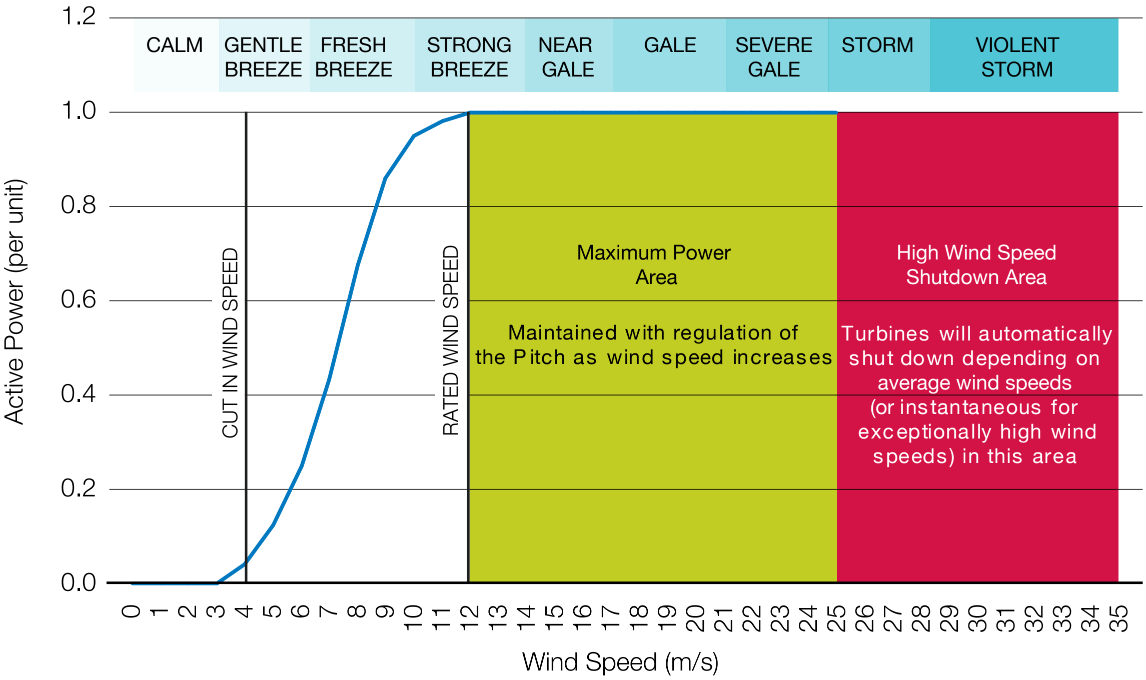


Figure 4.3.13 can only be an approximate forecast, but it does illustrate that unless wind is curtailed, all other generation technologies including nuclear have to reduce or even shut down completely. Here the assumption is no external power exchanges, i.e. no further wind imported and none exported. This illustration is at the highest demand of winter and these issues will become more pronounced when demand is lower. Further analysis shows that there may be events (around 10 times per year) that wind output exceeds the demand.

Figure 4.3.14:
Wind turbine power output curve



4.3.5 High Speed Wind Shut Down

A further challenge is the potential impact on system operation of wind cut-out, which happen when wind speeds are in excess of technical limits for the wind turbines, typically 25 m/s. This results in the loss of power production from wind farms and therefore a rapid reduction in power supply to the grid in stormy weather.

Such incidents have happened in the past; for instance the major hurricane in West Denmark[1] in January 2005 forced turbines to shut down within hours of running at a near maximum output (output dropped from 100% to nearly 0% in less than four hours). Although our geographical area gives more varied wind conditions, due to being an island power system the effect of those storms on power production could be severe. Uncertainty over the way wind farms shut down adds additional challenges.

We are working with manufacturers, developers and operators to find appropriate ways to improve wind output forecasts and investigate the merits of different mitigation measures.

1 Andersen, P., "Da stormen tog til stod møllerne af." "[When the storm increased, the turbines switched off]." Eltra magasinet, 1, February 2005.

4.4 Opportunities

The previous section discussed the challenges for design and operation of the transmission system. To tackle system inertia, and system strength (fault level) issues, some potential mitigating measures were discussed. To carefully manage the effects of the change in the generation capacity mix, significant improvements in the design and operation of the transmission system are needed, moving effectively towards the concept of **"Smarter Design and Operation"**. This concept considers the opportunities in generation, transmission, distribution and the supply side at different stages of the design and operation of the transmission system.

It will be important to enable asynchronous generation technologies and interconnectors to provide synthetic inertia. Demand side response may increasingly need to provide frequency management as the thermal generation portfolio changes its role in the context of high asynchronous generation installations. Likewise it will be necessary to deliver system-wide control of Flexible AC Transmission System (FACTS) devices to manage constraints and provide better interaction at distribution and transmission interface points to improve reactive power management. The different application of existing technologies (e.g. using interconnectors to better manage frequency management challenges) is likely to be a further example of such smarter transmission planning and operation. The measures described in this section include a range of technology and policy options helping to mitigate the new challenges.

4.4.1 Automatic Generation Control (AGC)

Many system operators divide the techniques required to address the power generation and demand imbalance issue into three timescales:

- response to address imbalance measured in 1 to 10 seconds and delivered automatically by generator governors
- AGC operates on a 10 to 30 second timescale and is delivered by the system operator automatically sending corrective actions to generator controllers
- manual despatch operating at longer time periods to restore overall balance.

These three techniques act together in a co-ordinated way to control the frequency of the system.

As NETSO we do not currently use AGC. The relatively moderate amounts of short-term variation (compared to what can be expected in the future) in generation, demand and interconnection combined with the high inertia of the system has allowed us to manage frequency with governor action, load controllers and manual despatch mechanisms. With more wind penetration, smart demand response and the greater volatility of interconnector flows expected in future, coupled with reducing system inertia, the level of frequency response required will have to increase. Therefore, it will be not be economic and practical to operate the system without the use of AGC.

We are conducting studies to investigate how AGC might improve the control of the system, and the likely cost to implement. By working closely with the industry we can also identify what might be required to introduce this change.

4.4.2
Parallel Operation of AC and DC Systems

The fundamental process that occurs in a HVDC system is the conversion of electrical current from AC to DC (rectifier) at the transmitting end and from DC to AC (inverter) at the receiving end. The rectifier and inverter can be either a Thyristor-based LCC or an Insulated-Gate Bipolar Transistor (IGBT) based voltage sources converter (VSC). Both LCC-HVDC and VSC HVDC employ switching commutation in order to perform conversion and they are currently in operation in the Network. The control of powerflows on a HVDC link is possible whereas in an AC system, the power will flow depending on the route's impedance. Powerflow control capability on the HVDC links, and additional features such as power reversal (rapid power reversal is only available in VSC-based HVDCs), ramp-up and ramp-down capability provide great opportunities in both the design and operation of the system.

Many power system stability issues such as voltage and rotor angle stability may be managed better by the parallel operation of the AC and DC systems and by considering dynamic response characteristics of HVDC systems.

4.4.3
Dynamic Thermal Rating

National Grid and many other transmission utilities apply a constant seasonal thermal rating for overhead lines. This rating is a conservative value, which in turn is likely to be lower than the actual thermal rating which varies with the weather conditions. The thermal rating is calculated based on the thermodynamic balance between the heat generated inside the conductor and the heat lost by the conductor through radiation and convection. The transmission capacity of overhead transmission lines is often constrained by temperature limitations on the conductors. One strategy connected with smart energy transmission is to calculate present and future transmission capacities of the lines based on actual weather conditions and forecasts, supplemented by real time measurements rather than relying on a static and conservative fixed value. An increased transmission capacity can then be enabled for time scales where a reliable weather forecast is available or where measurements such as conductor tension measurements have been fitted. These techniques can also be applied to further enhance short-term ratings, taking into account the actual loading of the previous period.

4.4 continued
Opportunities

4.4.4
Interconnectors

Interconnector capacity is forecast to increase in all scenarios. The additional interconnectors, which improve access to other European power systems, may add complexity to the transmission network in terms of powerflows. Managing the powerflow on the interconnectors, and the impact of simultaneous import/export on the onshore grid, are some of the challenges related to additional interconnector capacity.

Despite these challenges, from a system design and operation point of view, the interconnectors may provide some additional services to enhance the grid's stability – in the short term by sharing reserve with the rest of Europe, and in the longer term by enhancing system stability through providing fast frequency response, dynamic reactive power support (VSC-HVDC links at zero transfer may provide reactive power for voltage management), and power oscillation damping.

4.4.5
Improved Demand Side Management (DSM)

Various Demand Side Response services may be provided by demand customers. For real power this can be provided at all levels – from large industrial consumers, commercial consumers and domestic consumers. These services can be automated by using movements in system frequency as the controlling quantity or they may be switched via a remote signal, e.g. by an aggregator. For reactive power and voltage management, co-ordinated demand side management with distribution systems can enhance the voltage control capability in the system. Some of these services are currently being provided at a limited scale but DSM may be able to expand to incorporate the advent of electric vehicles and heat pumps (particularly in the period post-2020.

4.4.6
Energy Storage

The storage of energy available to be converted into electrical energy is possible in various forms such as batteries, pumped storage, and in lesser known or used forms such as Compressed Air Energy Storage (CAES) and flywheels. Energy storage technology could play a significant role in the operation of the transmission networks by improving the utilisation of renewable generation, the provision of flexible balancing services, and tackling some of the system design and operation issues, particularly with regard to inertia and fast frequency response.

Chapter five

Way forward

5.1
Introduction

This is the first edition of the ETYS and the document will undoubtedly evolve. We encourage you to provide feedback and comments on this document and to participate in our stakeholder engagement programme in 2013.

Please provide any feedback on all aspects of the 2012 ETYS via e-mail:

transmission.etys@nationalgrid.com

5.2 Continuous development

Our aim going forwards is to ensure that we adopt the following principles to enable the ETYS to continue to add value in the future:

- seek to identify and understand the views and opinions of all our stakeholders
- provide opportunities for engagement all the through the process
- endeavour to enable constructive debate to take place, creating open and two-way communication processes
- base the engagement around assumptions, drivers and outputs upon which stakeholders can make an informed decision
- provide feedback on how views expressed have been considered and the outcomes of any engagement process.

It is intended that the ETYS annual review process will ultimately facilitate the continuous development of the Statement and encourage participation from interested parties with the view of enhancing future versions of the ETYS in accordance with our licence provisions.

5.3
Stakeholder engagement

The ETYS will be the subject of an annual review process, facilitated by National Grid, and involving all customers who use this publication. The purpose of this review is to ensure the aims of the document continue to be met and the ETYS evolves alongside industry developments. Some of the areas to consider are:

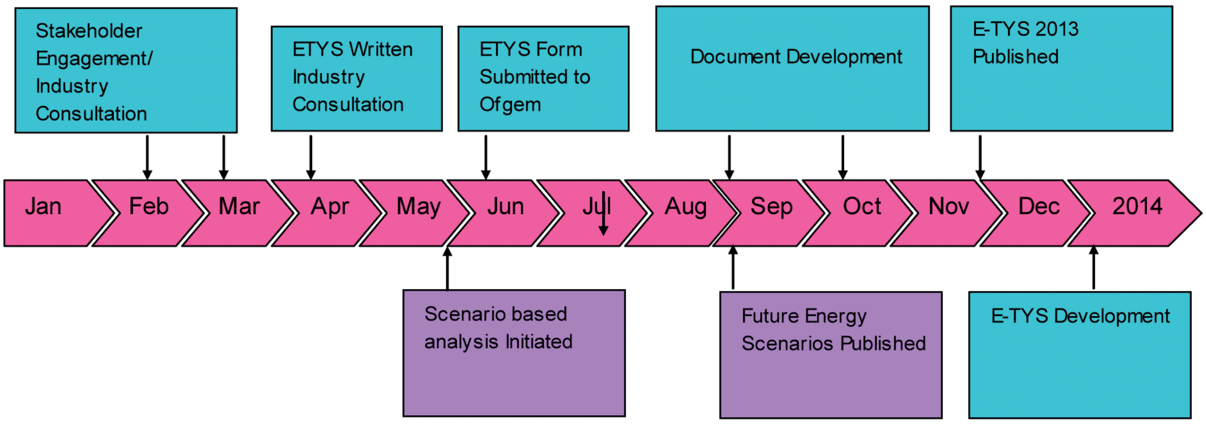
- Does the ETYS meet the stated aims of:
  - illustrating the future development of the transmission system in a co-ordinated and efficient way?
  - providing information to assist customers in identifying opportunities to connect to the transmission network?
- Are there any areas where the ETYS can be improved to meet these aims?

In addition to the development of the ETYS document we are keen to canvass views on our Network Development Policy approach to identifying future network reinforcements. It should be noted that the NDP only applies to the development of the network in England and Wales, but any views on the approach to network development in Scotland are of course welcome.

5.4
Timetable for 2013 engagement

Although the timetable for our 2013 ETYS engagement programme has yet to be finalised and will also be influenced by the development of our new licence conditions. The intended timetable for 2013 is as follows:

Figure 5.4.1:
ETYS engagement timeline 2013

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Notes

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