nationalgrid

Electricity Ten Year Statement 2014

UK electricity transmission

NOVEMBER 2014

Welcome to the 2014 edition of the Electricity Ten Year Statement.

Richard Smith
Head of Network Strategy

This publication is the conclusion of our annual planning cycle and describes how the electricity transmission network will evolve to meet future needs, driven by our 2014 Future Energy Scenarios (FES)[1] published in July 2014. The ETYS is part of our suite of "future of energy" documents: the FES, ETYS and GTYS, and I hope you agree they create a clear and compelling story of the future.

We aim to give you an insight into the future development and operability of the system over the next twenty years. We hope that you are able to do this from the current document and to assess the opportunities that it presents you as future or current connectee and as a stakeholder to understand our future plans. So far some great work has been done in the ETYS as we seek to understand the views of our stakeholders.
We have received some excellent feedback on last year's document through a variety of channels. The detail of the feedback and what we have done can be found in chapter 6, the 'Way Forward', that also includes our future engagement plans.
We encourage your participation to help us create an even more valuable document for you. We will build on last year's engagement using a greater variety of channels and seek to understand further the needs of our stakeholders and the uses of the document to further enhance the ETYS.

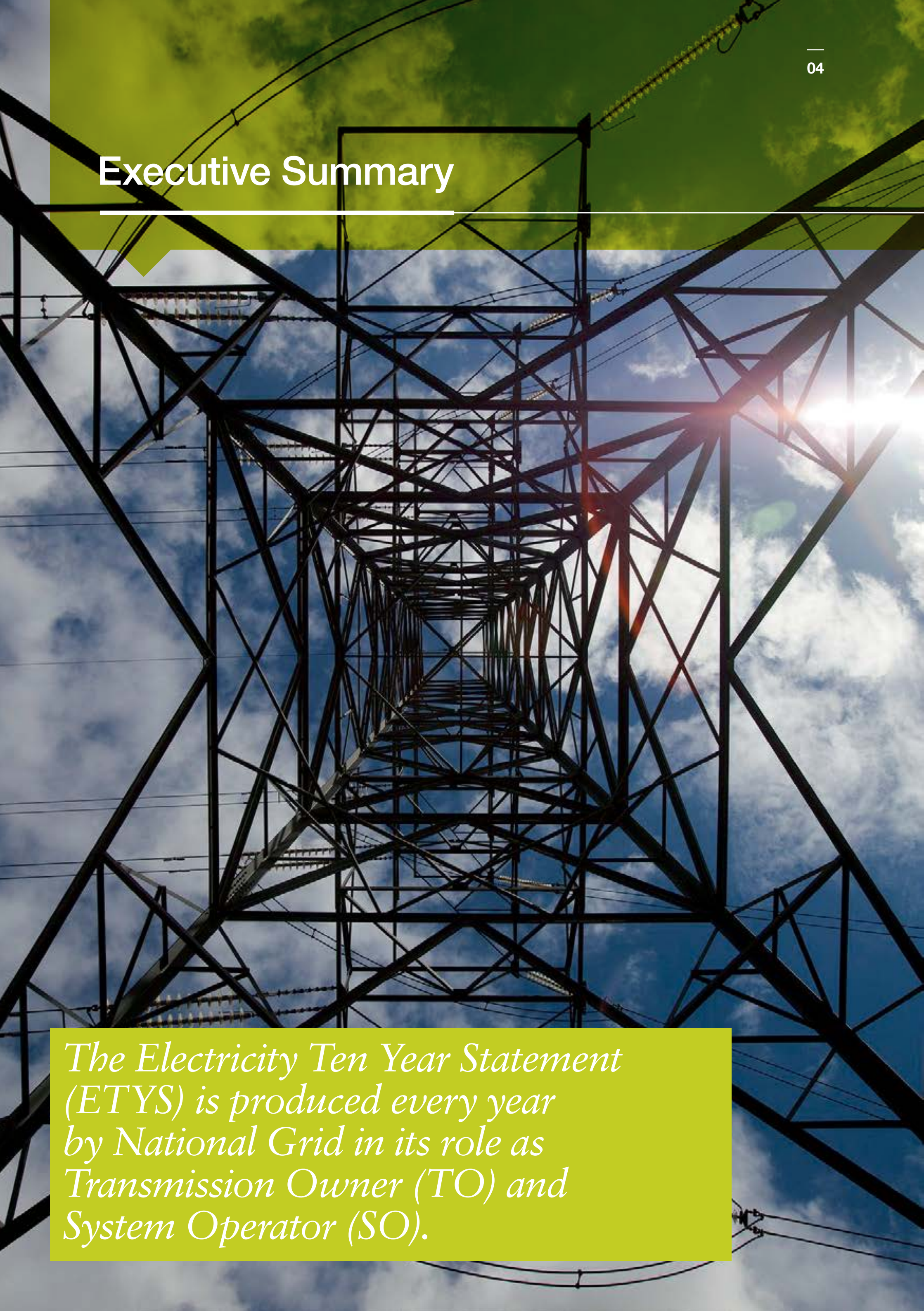
Our Network Development is driven in the main by the requirements of our customers supported by our Future Energy Scenarios. The combination of our Future Energy Scenarios and the transmission owners network development policies within the network companies allow us to make strategic business investments. These strategic business investments and requirements, along with the opportunities these present for customers, are reported within this document. We wholeheartedly believe in transparency and have again published more information than before as we look to provide greater clarity on the decisions we have made with respect to future network development.

We were delighted with the response to the System Operability Framework (SOF) earlier in the year and we encourage you to read about the application of the framework in chapter 5 and what our challenges are for the future operation of a low carbon grid.

I hope you find this a useful and interesting document. The release in November marks the start of the next annual cycle. If you have supported our ETYS process by participating in our stakeholder engagement activities, I thank you. If you haven't, I encourage you to get involved: we will listen to your views and you will help shape our next ETYS production. I also encourage you to tell us what you think by writing to us at **transmission.etys@nationalgrid.com**, completing our Feedback Form[2], engaging us at future stakeholder events or meeting us at National Grid House.

[1] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/
[2] https://www.surveymonkey.com/s/2014ETYS

Executive Summary

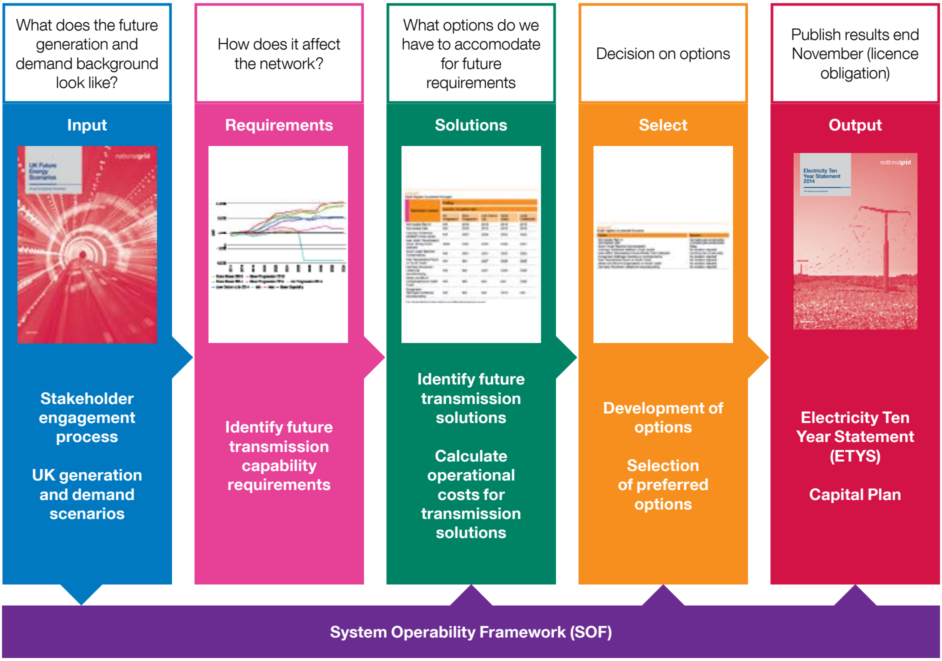


The Electricity Ten Year Statement (ETYS) is produced every year by National Grid in its role as Transmission Owner (TO) and System Operator (SO).

Its purpose is to illustrate what the future National Electricity Transmission System (NETS) could look like, and describe how it could operate, under a range of plausible Future Energy Scenarios.

It is aimed at the energy industry and Transmission network customers to help inform their investment decisions. It does this by outlining the future investments needed on the NETS and future system operability.

Figure 1.1
Transmission and ETYS planning



The analysis underpinning the 2014 ETYS is based upon a set of credible Future Energy Scenarios (figure 1.2) which were developed following engagement with a wide range of stakeholders. We take these and apply the various network requirements and changes that would be needed to respond in each scenario. We then take a strategic view on these, add in sensitivities around the local contracted positions and publish them in the ETYS. This process can be seen in figure 1.1.

Executive Summary

Figure 1.2
2014 Future Energy Scenarios

Affordability
More money available

Low Carbon Life

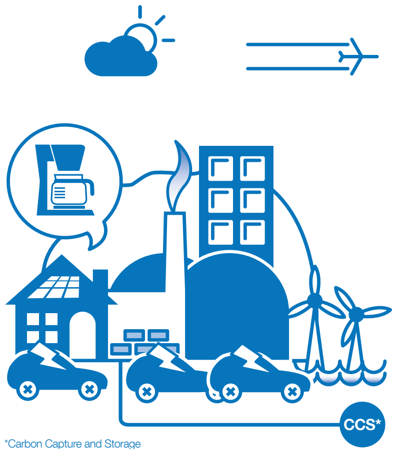
Economic – Growing UK economy.

Political – Short-term political volatility but long-term consensus around decarbonisation.

Technological – Renewable generation at a local level. High innovation in the energy sector.

Social – High uptake of electric vehicles but consumers not focused on energy efficiency. ‘Going green’ is a by-product of purchasing desirable items.

Environmental – Carbon target hit. No new environmental targets introduced.



No Progression

Economic – Slow UK economic recovery.

Political – Inconsistent political statements within Government, resulting in investor uncertainty.

Technological – Gas is the preferred choice for generation over renewables. Little technological innovation occurs in the energy sector.

Social – Consumers not engaged with energy efficiency. Low uptake of electric vehicles and heat pumps.

Environmental – Targets are missed, no new environmental targets introduced.

Affordability
Less money available

Sustainability
Less emphasis

Gone Green

Economic – Growing UK economy.

Political – Domestic and European policy harmonisation, with long-term certainty provided.

Technological – High levels of renewable generation with high innovation in the energy sector.

Social – Engaged consumers focused on drive for energy efficiency. This results in high uptake of electric vehicles and heat pumps.

Environmental – All targets hit, including new European targets post-2020.

Slow Progression

Economic – Slow UK economic recovery.

Political – Political will for sustainability but financial constraints prevent delivery of policies.

Technological – Renewable generation chosen over low carbon generation. Low levels of innovation in the energy sector.

Social – Engaged consumers focused on drive for energy efficiency but with low uptake of electric vehicles and heat pumps due to affordability.

Environmental – Environmental targets missed but hit later. New European targets introduced.

Sustainability
More emphasis

Executive Summary

We are currently going through a period of radical change in the energy landscape with 10GW of intermittent renewable generation capacity presently connected to the NETS, with a peak recorded output of 7.2GW. The location of this generation and intermittency has required progressive development of our system operation and required levels of network development.

Ensuring that the NETS is developed in an economic and efficient manner is a key requirement of all the TOs. The solutions available to the transmission companies to deliver significant capacity changes to the NETS include onshore construction, integrated offshore developments and commercial solutions such as commercial intertripping of generation. Within the ETYS this year over 150 potential reinforcements were reviewed to determine an optimal strategy for future development.

There remains significant uncertainty in the market. The Network Development Policy analysis undertaken, for England and Wales, demonstrates that the investments that are in construction phase should continue as scheduled and a number of minor schemes should progress. However, we do not see a need for any other large scale investments to start now other than the Hinckley Point to Seabank route. Our analysis also shows that we should progress pre-construction for a number of major projects to ensure that the lead times are maintained to meet future uncertain requirements. With respect to Scotland there are a significant number of major investments that have been agreed with Ofgem and this analysis has confirmed the need to progress. In examining the future requirements of the NETS the analysis has shown the continued benefit of Integrated Offshore to the development of a coordinated NETS.

The ongoing investments such as series and shunt compensation and the Western HVDC Link associated with the Anglo-Scottish boundary should be continued as planned. The Hinkley Point to Seabank route should commence construction to deliver to the required dates. We also need to progress pre-construction engineering on projects such as Eastern HVDC and Wylfa to Pentir options to respond to the future uncertainty. The output recommendations from the Network Development Policy and suggested investment dates for each scenario are shown in Table 1.1.

Table 1.1
Network development projects

Critical Schemes	Network Area	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	Decision
Western HVDC Link	Scotland to England border	2016	2016	2016	2016	2016	Complete construction
Series and Shunt Compensation	Scotland to England border	2015	2015	2015	2015	2015	Complete construction
Wylfa–Pentir	North Wales	N/A	N/A	2027	2028	2025	Complete pre-construction consenting
Pentir–Trawsfynndd	North Wales	N/A	2022	2027	2021	2021	Delay
Wymondley Turn-in	South East	N/A	2019	2019	2019	2019	Complete pre-construction
Wymondley QBs	South East	N/A	2019	2019	2019	2019	Complete pre-construction
South Coast Reactive Compensation	South Coast	N/A	2021	2021	2020	2020	Delay
Bramford–Twinstead New Overhead Lines	East Anglia	N/A	2025	2023	2023	2023	Delay
Hinkley–Seabank	South West	2029	2027	2025	2026	2021	Complete pre-construction
Integrated Offshore Transmission Project (East)	Offshore	N/A	N/A	2026	2027	2025	

Executive Summary

With the continued delay of the offshore wind developments and new nuclear fleet this has deferred the need for many of the projects identified. However, based on the balance of the scenarios, there is still a significant investment plan required to meet the scenario needs beyond 2020.

Cost-benefit analysis for the reinforcements in this document ensures value for money for the consumer. Each transmission solution is evaluated to compare the cost of providing transmission capacity, through new assets or contracts to control generation at times of stress, with the expected constraint cost for if the capacity was not available. Without the building of the GB transmission capacity identified in this report the total constraints across the system could exceed £10 billion per annum by 2025 if the Gone Green scenario was to develop and £5 billion per annum if the Slow Progression scenario developed. This is compared with a constraint cost of £200m for 2013/14.

Given the significant changes in generation scenarios it leads to a change in operating requirements. A System Operability Framework (SOF) has been developed to study in-depth, year-round impact of the FES on system operability. The scenarios show a significant range in the possible future operability challenges.

By assessing existing network performance, identifying the root causes of incidents and constraints observed on the system, new challenges in system dynamics are identified by system studies using the FES. SOF highlights new opportunities for more innovative ways to design and operate the system in future years. In doing so, we engage with our stakeholders to seek their views on what new capabilities they can offer and how we can work together to deliver an economic and efficient solution for future grid development.

We are committed to ensuring that the Electricity Ten Year Statement continues to evolve and each year our stakeholders have the opportunity to shape the development of this document. We would welcome any views on the content and scope of year's document and whether you would like to see any changes made to future versions. We are happy to receive feedback of any kind through the following means:

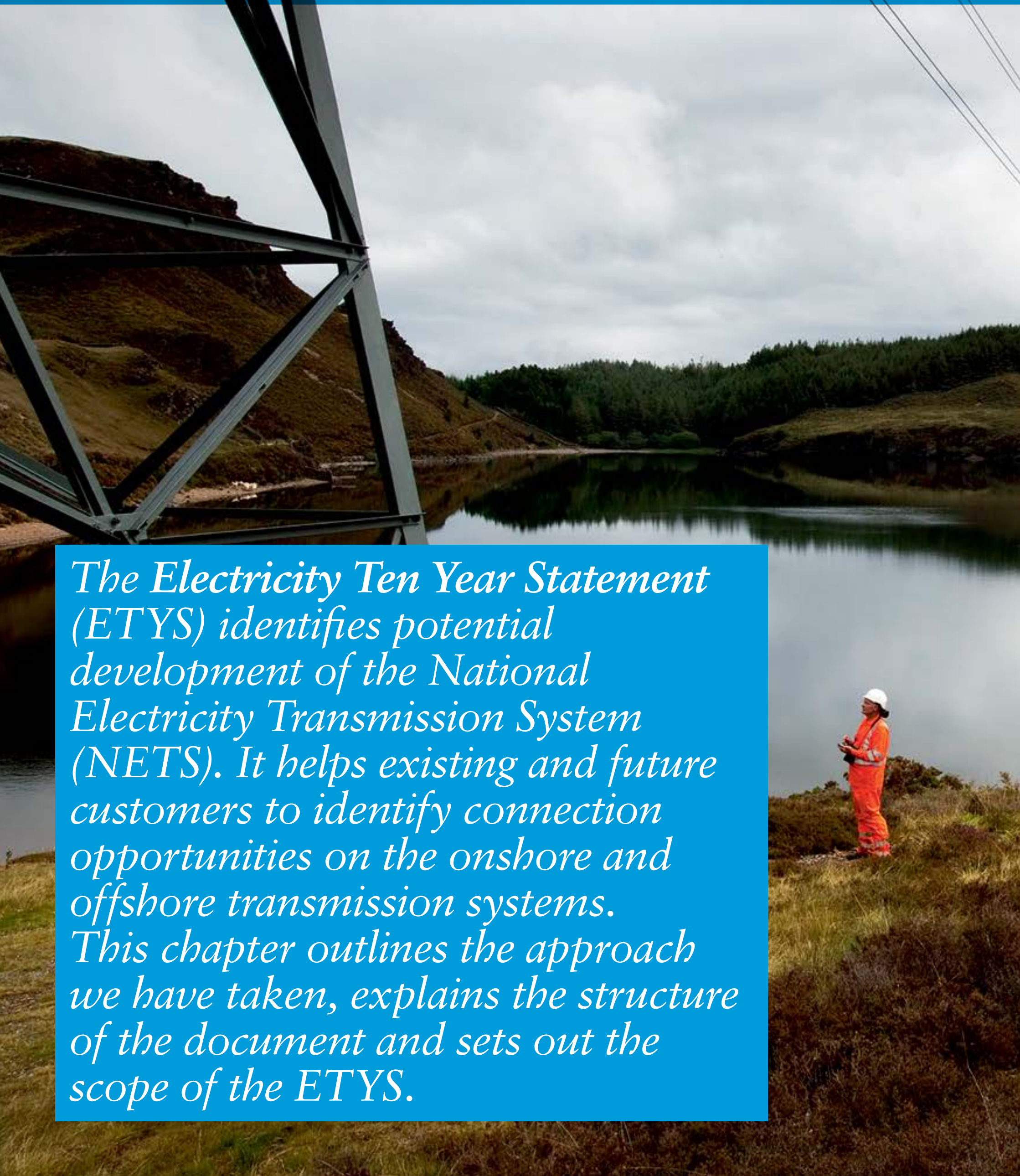
- At customer seminars
- At operational forums
- Through responses to the ETYS email: **transmission.etys@nationalgrid.com**
- At bilateral stakeholder meetings.

Contents

Contents

Contents

Chapter 1
Introduction



The ***Electricity Ten Year Statement*** *(ETYS) identifies potential development of the National Electricity Transmission System (NETS). It helps existing and future customers to identify connection opportunities on the onshore and offshore transmission systems. This chapter outlines the approach we have taken, explains the structure of the document and sets out the scope of the ETYS.*

1.1 Background

The 2014 ETYS is the third GB Electricity Ten Year Statement to be published. It is produced for you, our stakeholders, and we want it to develop as a result of what you tell us.

The document is part of a suite of publications that is underpinned by our Future Energy Scenarios. This means that the analysis in both the ETYS and its sister publications – the Gas Ten Year Statement (GTYS) and the System Operability Framework (SOF) – have a consistent base when assessing the potential development of both the gas and electricity transmission networks.

The ETYS was developed through engagement with you to harmonise several of our previous publications, including the SYS and ODIS. The result is a single document containing relevant and timely information about the onshore, offshore and interconnected networks.

In April 2014 we consulted with you on the development of the ETYS publication. We received feedback on how you would like the ETYS to develop, mainly through face-to-face meetings at the electricity customer seminars and also through our written consultation.

The feedback received from our customers and the output from the process in our 'ETYS Consultation 2014' can be found in Chapter 6, 'Way Forward'. The main elements addressed in this year's edition are rationalisation to avoid duplication with the sister publications, greater data provision and changes to the way network development proposals are presented.

Following the publication of this edition of the document, we will gather your views so we can continually evolve the document and incorporate your opinions. Section 1.4 outlines how we aim to give your views more emphasis as we develop the document.

1.2 Methodology

The document will focus on the potential development of the NETS using analysis of the four energy scenarios and any related sensitivities, while ensuring that the network is developed to meet customer connection dates. The energy scenarios are detailed in our Future Energy Scenarios publication, which can also be found on our website. An overview of these scenarios, and how we use them as inputs for our wider system planning, can also be found in Chapter 2.

Figure 1.1
Network development process

Network development process

The network development process associated with NETS development is shown above. It starts with the inputs to transmission planning, the Future Energy Scenarios that provide a plausible range of future outcomes. The scenarios are analysed in the different areas of the transmission system to show what they mean for the future system. These requirements are turned into a set of potential network reinforcement solutions. Finally, these options are analysed and decisions are made on the preferred course of action to develop the network in the most economic and efficient way. This process is shown in Figure 1.1 above and is the basis for the structure of the document discussed in section 1.3, Navigation of the document.

Future Energy Scenarios

As well as the four scenarios, we have analysed locally contracted backgrounds, which include any existing or future project that has a signed connection agreement with us. This ensures that our solutions are consistent with our wider licence obligations and that we can meet all contracted connection dates.

The use of energy scenarios, rather than focusing purely on the contracted generation background, is one of the key developments of the ETYS. The current contracted position is for 256 projects totalling 83GW of capacity. By using scenarios, we can explore a range of more credible outcomes than if we used the contracted background alone. Our scenarios have been developed via a full, wide-ranging industry consultation. With them, we can assess the development of the transmission network against a range of plausible generation and demand backgrounds.

To help align the ETYS with other National Grid publications and to provide a longer-term view, the analysis in the document covers a detailed ten-year study period, with less detailed analysis of the period from 2024 to 2035.

Transmission system planning

The principle of transmission system planning is common across all GB transmission owners (TO) as we seek to build an economic and efficient level of transmission to manage future transmission requirements and to connect new customers to the energy market. However, the approach of TOs will vary depending on each company's resources; challenges such as volumes of connection; transmission system capacity and age; and their regulatory requirements.

The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) sets out criteria and methodologies that transmission licensees (both onshore and offshore) use in the planning and operation of the National Electricity Transmission System.

This ETYS document explains how the TOs are planning their networks over the next 20 years. The scenario inputs to network planning are analysed using the NETS SQSS criteria to determine the future requirements. Based on these requirements, best options are chosen to solve the identified system boundary constraints.

1.2 continued
Methodology

Network Development Policy

The Network Development Policy (NDP[1]) is an approach to assessing wider works on the NETS system, in England and Wales only. The analysis and decisions that National Grid has made about NETS reinforcements can be seen in this ETYS document, in Chapter 4. We are keen to engage with industry stakeholders in this key area as we plan an economic and efficient level of transmission.

The NDP allows NGET to manage one of the most significant uncertainties facing the electricity transmission system: the quantity, type and location of connected generation and the extent and location of new interconnection to other systems. The lead-time for reinforcement of the wider transmission network can often be longer than the lead-time for the development and construction of new generation projects.

The TOs need to balance the risks of investing too early in wider transmission reinforcements – which includes the risks of inefficient financing costs and an increased stranding risk – with the risks of investing too late, which includes the risks of inefficient congestion costs. Given this significant amount of uncertainty, the process to choose the preferred combination of transmission solutions must be well structured and transparent. This transparency will allow stakeholders to understand our rationale to build, or not to build. We believe this allows for greater stakeholder engagement in our process and outputs.

The NDP defines how National Grid will assess the need to progress wider transmission system reinforcements to meet our customers' requirements economically and efficiently, based on forecast future generation and demand scenarios.

Following their assessment of National Grid's NDP proposals, Ofgem concluded that they "consider the decision-making framework and process in National Grid's proposed NDP to be a proactive, prudent and flexible approach." Ofgem continued "that by applying this approach, National Grid would have a reasonable basis to take decisions on network investment in a manner that is compatible with its overall duty to develop and maintain an efficient, co-ordinated and economical system of transmission." Therefore "based upon our assessment, and in consideration of our statutory duties, we support the implementation of National Grid's proposed NDP and are minded to not direct any changes to the proposed NDP, subject to stakeholders not raising any significant concerns about it." Ofgem's full response can be read on their website.[2]

The NDP network modelling and analysis in the ETYS uses the Future Energy Scenarios (FES). The detailed cost benefit analysis is undertaken using all of the scenarios and case studies with equal weight. The NDP output recommends the projects that will be progressed over the next twelve months.

[1] http://www.nationalgrid.com/NR/rdonlyres/034CF928-2052-41CD-90FF-A2623B375FF2/60854/2012_NGET_Network_Development_Policy_Resubmissionproposedver41_HR.pdf
[2] https://www.ofgem.gov.uk/ofgem-publications/53478/final-con-letter-nget-ndp-may-2013.pdf

Ten-Year Network Development Plan (TYNDP)

The TYNDP is a European development plan for pan-European electricity transmission investments. It supports decision-making processes at regional and European levels. The ETYS is designed to be more GB-focused, giving readers a clear picture of all GB investments, while complementing the TYNDP in areas of pan-European interest.

ENTSO-E created the working group (WG) TYNDP to lead the development and publication of the TYNDP. The first pilot TYNDP was published in June 2010 and the second official TYNDP was released for consultation in July 2014, with final publication in December 2014. The TYNDP was based on the most up-to-date and accurate information available on planned or envisaged transmission investment projects of European importance.

1.3 Navigation Through the Document

The form of the document has been broadly kept the same as last year following positive comments from the ETYS consultation. We hope this ETYS will help us bring clarity to the development of the NETS and integrate the NDP in to the body of the document. The overall structure of the ETYS document for 2014 is shown below in Figure 1.2 and described in the following text.

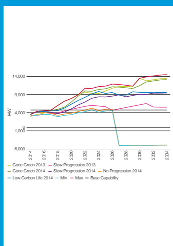
Figure 1.2
ETYS structure

Network Development Inputs

Stakeholder engagement process

UK generation and demand scenarios

Network Capability and Requirements



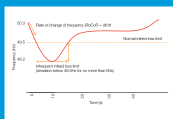
Identify future transmission capability requirements

Network Development & Opportunities

Identify future transmission solutions

Selection of preferred option

System Operation



Operational chapter

Articulation of key operational challenges today and in the future

Stakeholder Engagement

“We require more information on the system such as demand to assess connection opportunities.”

ETYS 2014 engagement timeline

Summary of ETYS 2013 engagement

Network development inputs

This chapter describes the key inputs to the development of the network, such as the FES and the cost assumptions of curtailing generation. It outlines the elements behind each scenario of the FES and gives an overview of the contracted background. It also includes details of the transmission demand projections in the FES and explains how we turn these inputs into generation backgrounds for development and operability studies. It includes an overview of the inputs for the constraint analysis section of the NDP for England and Wales.

Network capability and future requirements

This section builds on the previous chapter and illustrates the impact of the FES inputs on the NETS. It also shows the current capability limits of each NETS boundary for reference. It maps future network requirements relevant to each of the scenarios against all boundaries on the NETS.

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 discusses each of these boundaries, and enclosed regions. There is a description of each boundary, details of the generation background, demand backgrounds and the limiting factors.

Network development and opportunities

Given the earlier identified future NETS requirements, this chapter assesses the reinforcement solutions for each region of the network and analyses their merits.

The chapter outlines our NDP methodology. It also defines how we will assess the need to progress wider transmission system reinforcements to meet the requirements of our customers economically.

The chapter looks at the network reinforcement options available including onshore, offshore and commercial. It discusses the potential development of an integrated offshore network and the impact of increased interconnection on the network.

Potential system reinforcements are analysed across all the energy scenarios and a potential future boundary capability and opportunities are identified. Most importantly, this chapter captures the decisions that will be made on the NETS in the next year. This analysis forms the bulk of the document.

There’s also illustration of the NETS, including detailed system maps of the onshore and offshore areas.

1.3 continued
Navigation Through the Document

System operation
Following the identification of how the network might look in the future, this chapter focuses on our evolving operational strategy. The focus is on how network operation will need to change given the changing generation mix and increased renewable generation. This section also highlights where there might be opportunities for customers to provide services to support system operation such as balancing or ancillary services.

Way forward
We want the ETYS to evolve each year and our stakeholders to help shape its development. This chapter details the engagement process for producing the 2015 ETYS.

Appendices
In addition to the main ETYS document, there are also several data appendices on our website. The appendices contain all the relevant technical and numerical data supporting 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 that 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 that will enable linking of study zones to boundaries
- Technology – in conjunction with key manufacturers and suppliers we have produced a series of technology sheets that look at the present and future technologies associated with the development of both the onshore and offshore transmission system.

1.4 Stakeholder Engagement

We are committed to stakeholder engagement and ensuring that your views are central to developing this document. We have embedded stakeholder engagement prompts throughout the document and highlighted areas in each section where we'd like your views. Please see the stakeholder engagement box below – this shows the format you will find in other key areas of the document.

Stakeholder engagement
We'd appreciate the industry's views on the availability assumptions of these generation types to further enhance our constraint modelling analysis.

Throughout the document you will see areas where your engagement and industry experience could help us enhance this statement. However, feedback is not limited to those questions: we would be delighted to receive all feedback by any means appropriate. We are also keen to know how you'd prefer to engage with us to develop the ETYS.

We plan to engage with stakeholders:

- At consultation events as part of the customer seminars
- Through responses to the ETYS mailbox
- By organising bilateral stakeholder meetings depending on the feedback.

Engagments across all of National Grid on the future of energy works is shown below in figure 1.3.

In preparation for next year's statement a 'way forward' section, Chapter 6, at the end of this document, summarises our next steps in the engagement process for the ETYS 2015.

This stakeholder engagement helps us to understand your views. We would very much like to know how you use this document and how our work affects others, so we can incorporate these views into our decision-making processes.

If you have feedback on any of the content of this document please send it to transmission.etys@nationalgrid.com, catch up with us at one of our consultation events or visit us at National Grid House, Warwick.

1.4 continued
Stakeholder Engagement

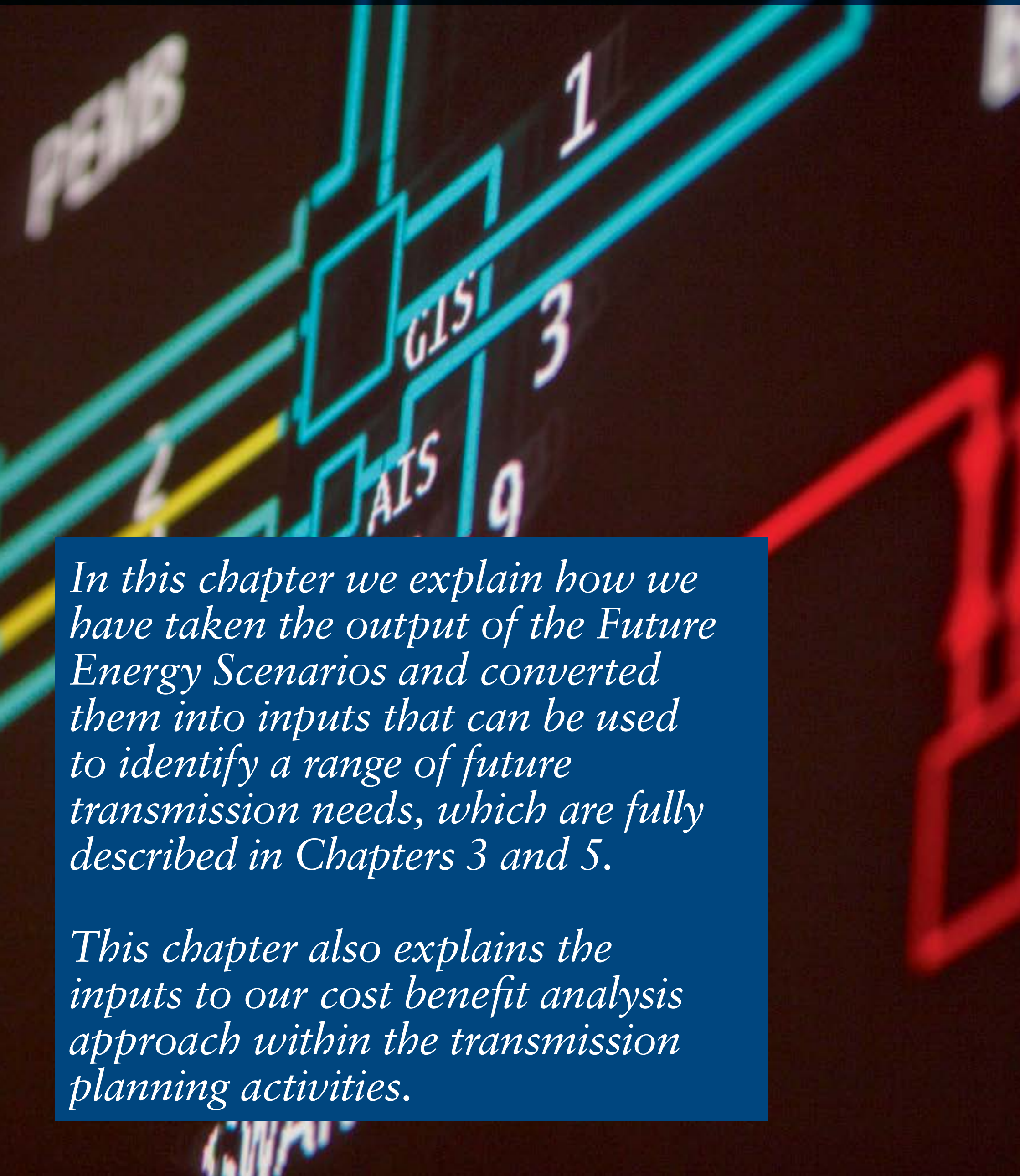
Figure 1.3
Stakeholder engagement

This business process diagram shows the areas of stakeholder involvement

		Commercial frameworks				
Our stakeholders' journey	Identify future energy scenarios*	Customer connection applications	Establish impact on network	Build the network	Maintain the network	Operate the network
Examples of output based on consultation events	Future Energy Scenarios	Connection processes that meet customers' needs	Gas and Electricity Ten Year Statements	Highways diversions and major infrastructure solutions	Individual landowner liaison	Market information development and balancing services
Examples of consultation events	Future Energy Scenarios workshops and conference	Customer seminars and bilateral meetings	Consultation and round tables at customer seminars	Community town hall meetings	Letters to landowners with pylons and pipes on their land	Seminars for new market entrants and operational forums

***Identify Future Energy Scenarios –** Providing a forum for the exchange of ideas and data that informs our view of how the energy landscape will look in the future.

Chapter 2
Network Development Inputs



In this chapter we explain how we have taken the output of the Future Energy Scenarios and converted them into inputs that can be used to identify a range of future transmission needs, which are fully described in Chapters 3 and 5.

This chapter also explains the inputs to our cost benefit analysis approach within the transmission planning activities.

2.1 Introduction

To establish what investment will be needed in the future and to describe the effect that changes in the future make-up of the transmission system have on the framework of future system operation, we must understand the demand for generation (both in terms of active and reactive power supply) together with its variability across the year. This chapter discusses the basis of future scenarios that are used in Chapter 3 and the additional inputs to those Future Energy Scenarios which support our analysis of the future system operation (SO) challenge.

In this chapter we explain the methodology used to convert the scenarios to generation ranking orders. We also describe how these ranking orders and associated inputs are used to determine the operational costs of a given network. We also describe the process by which year-round analysis of the system is conducted and how this and the post-event examination of the experience and trends evidenced in actual system events derive future network understanding in network investment and operability. This data is collectively used as inputs into the Network Development Policy, which is further described in Chapter 4.

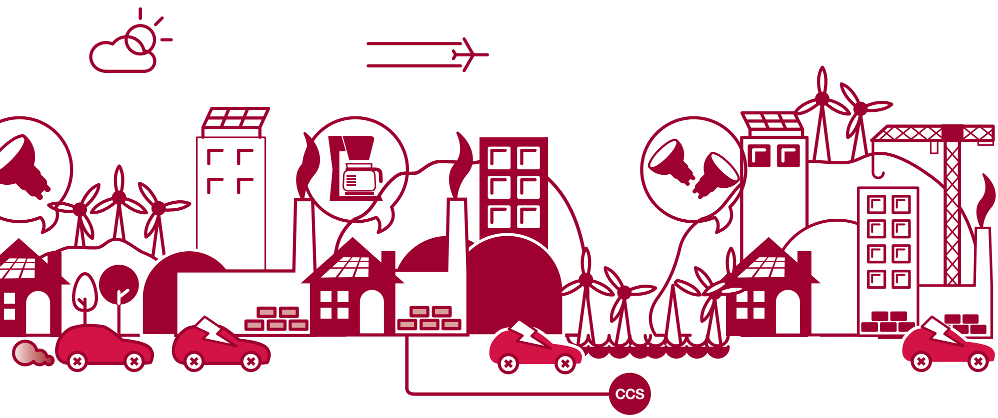
In presenting this chapter, we'd like your views on the input assumptions we have used to determine future investment needs. We would also draw your attention to the consultation related to our first publication of our System Operability Framework accessible by the link below, where we would further welcome your feedback:

http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

2.2 Future Energy Scenarios

We produce our energy scenarios annually after an extensive industry consultation that is designed to encourage debate and help shape the assumptions that underpin the final scenarios. After this year's stakeholder engagement programme, the latest scenarios were published in National Grid's **UK Future Energy Scenarios** document in July 2014. As described in the introduction, this document uses these scenarios as the basis of the network analysis.

The analysis carried out within our Electricity Ten Year Statement (ETYS) is based on the Future Energy Scenarios, which provide a range of potential reinforcements and outcomes. There is information on electricity demand and generation within the 2014 UK Future Energy Scenarios document in Chapter 4.



2.3 ETYS Background and Scenarios

This year our range of scenarios is based on the energy trilemma of security of supply, affordability and sustainability. Based on stakeholder feedback, we've introduced two new scenarios this year: No Progression and Low Carbon Life. We now have four scenarios and a wider range of potential future outcomes, so we feel there's no need for extra case studies and sensitivities on the main scenarios as we had for the last publication of the ETYS. The matrix below shows the four scenarios and how these are flexed against the variables of the trilemma. It also shows the key economical, political, technological, social and environmental messages around each of the scenarios. Security of supply is assumed in all the scenarios.

To illustrate the generation backgrounds for each scenario in this chapter, the data is shown at a transmission level (excluding embedded and micro generation) but the analysis and studies carried out for ETYS consider GB-level analysis. Later in this chapter there's more detailed information on the key messages in terms of installed capacity levels in each generation mix.

For more information on the narrative and the assumptions that underpin each of the Future Energy Scenario backgrounds please refer to the UK Future Energy Scenarios document.

We also use the contracted background for comparison and it refers to all generation projects that have a signed connection agreement with National Grid. We have made assumptions about closures only where we have received notification of a reduction in Transmission Entry Capacity (TEC) or where there is a known closure date driven by binding legislation such as the Large Combustion Plant Directive (LCPD).

Figure 2.1
2014 Scenario Matrix

LOW CARBON LIFE
is a world of high affordability and low sustainability. More money is available due to higher economic growth and society has more disposable income. There is short-term volatility regarding energy policy and no additional targets are introduced. Government policy is focused on the long term with consensus around decarbonisation, which is delivered through purchasing power and macro policy.

GONE GREEN
is a world of high affordability and sustainability. The economy is growing, with strong policy and regulation and new environmental targets, all of which are met on time. Sustainability is not restrained by financial limitations as more money is available at both an investment level for energy infrastructure and at a domestic level via disposable income.

NO PROGRESSION
is a world of low affordability and low sustainability. There is slow economic recovery in this scenario, meaning less money is available at both a government and consumer level. There is less emphasis on policy and regulation which remains the same as today, and no new targets are introduced. Financial pressures result in political volatility, and government policy that is focused on short-term affordability measures.

SLOW PROGRESSION
is a world of high affordability and low sustainability. Less money is available compared to Gone Green, but with similar strong focus on policy and regulation and new targets. Economic recovery is slower, resulting in some uncertainty, and financial constraints lead to difficult political decisions. Although there is political will and market intervention, slower economic recovery delays delivery against environmental targets.

2.4 Demand

In this section we describe the electricity demand assumptions for each of the four scenarios.

Demand definition
For the purposes of the ETYS, demand is shown at its assumed peak day level. The assessment of electricity network adequacy uses as a base the transmission system peak day demand because this is often the most onerous demand condition for the network and will therefore drive many of the required reinforcements. Year-round demand is also used for analysis of system operation and investment planning.

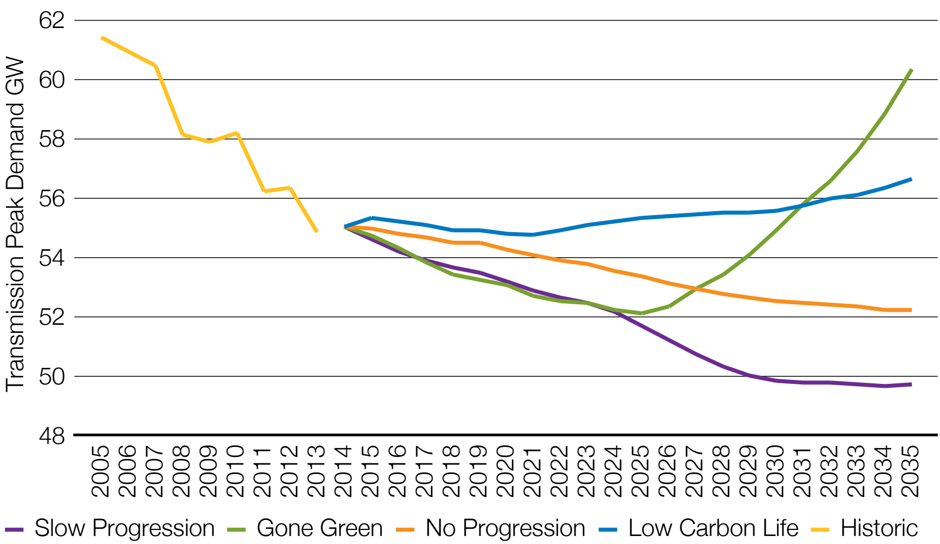
The ETYS peak transmission demand includes losses but excludes station demand, exports and Demand Side Response (DSR). We assume there's no pumping demand at peak, so it doesn't contribute to demand[1]. Small embedded generation is included as part of the assessment of peak demand.

The demand scenarios are derived from annual electricity consumption – which is driven by historic electricity consumption – extensive stakeholder engagement and analysis of the drivers of demand. Further to the GB views of demand shown in the UK Future Energy Scenarios document, there has been analysis of the effects of regional demand, including the roll-out of electric vehicles and electric heat pumps.

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 2014 UK Future Energy Scenarios document.

Peak transmission ACS demand history and projections for all four scenarios are shown in Figure 2.2.

Figure 2.2
Peak Outturn and Scenarios



Note that the peak transmission demand has been reducing in recent years. This is due to factors including economic downturn and an increase in energy efficiency.

Here is a brief overview of the demand assumptions in the four scenarios.

Gone Green

The Gone Green scenario has high economic growth and a strong emphasis on energy efficiency in the residential and industrial and commercial sectors. Electricity consumers are engaged in SMART technologies and there is widespread use of time-of-use tariffs. There's also high uptake of heat pumps and electric vehicles in this scenario. This leads to a fall in demand in the short to medium term, as energy efficiency is the key driver. After this, the uptake of heat pumps and electric vehicles drives demand upwards.

Slow Progression

The Slow Progression scenario has low economic growth and a strong emphasis on energy efficiency across residential and industrial and commercial sectors. Electricity consumers are not as engaged in SMART technologies as in the Gone Green scenario. There's also less interest in heat pumps and electric vehicles. The result is a fall in demand.

No Progression

The No Progression scenario has low economic growth and less emphasis on energy efficiency across residential and industrial and commercial sectors than Gone Green or Slow Progression. Electricity consumers are not as engaged in SMART technologies as in the Gone Green scenario and there's a lower uptake of heat pumps and electric vehicles. This leads to a fall in demand over the scenario period, although the fall is less than in the Slow Progression scenario because fewer energy efficiency measures are used.

Low Carbon Life

The Low Carbon Life scenario has high economic growth and less emphasis on energy efficiency across residential and industrial and commercial sectors than the Gone Green or Slow Progression scenarios. Electricity consumers are not as engaged in SMART technologies as in the Gone Green scenario, with a lower uptake of heat pumps than in Gone Green but a high uptake of electric vehicles. This leads to a rise in demand over the scenario period, as economic growth and less energy efficiency measures are the key drivers.

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

Reactive demand

The above narrative relates to the peak active demand assumptions within the FES. In addition to active power, the same scenarios are also used to calculate the reactive power demand in future years. For illustration, figure 2.3 below highlights for the Gone Green Scenario, how active and reactive demand compares.

Reactive power demand as described at the transmission network interface relates to three factors:

- The characteristics of the demand supplied at lower voltages within the distribution network supported by the Transmission system at the Grid Supply Point
- The reactive power exchanges across the distribution network
- The effect that embedded generation has upon the above.

[1] Please note that other related documents may have different definitions of peak demand (e.g. National Grid's Winter Outlook Report quotes restricted demands and UK Future Energy Scenarios quotes GB peak demand (including demand at a distribution network level as well as transmission network demand). Therefore, care should be exercised when making comparisons between these demand forecasts.

2.4 continued
Demand

Across the scenarios the following comments on reactive power may be made:

Gone Green

The Gone Green scenario has high economic growth and a strong emphasis on energy efficiency in the residential and industrial and commercial sectors. As such many of the power factors associated with demand will be seen to decline. Electricity consumers are engaged in SMART technologies and there is widespread use of time-of-use tariffs; these are expected to lead to the dual effects of increasing use of power factor correction devices on the demands supplied and together with the impact of heat pumps would lead to a general reduction in the levels of power active and reactive supplied across the distribution networks affected. The effect of the growth in electric vehicle usage would provide new power demand, however this is expected to be power factor correcting and as such provides limited effect in increasing reactive power demand.

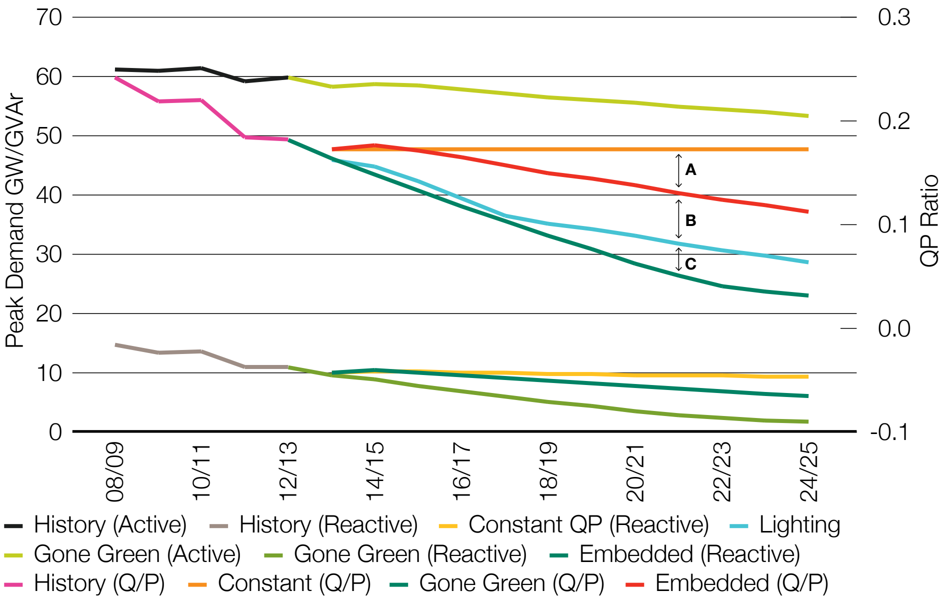
Slow Progression

The Slow Progression scenario has low economic growth and a strong emphasis on energy efficiency across residential and industrial and commercial sectors. Given there is less interest in heat pumps and electric vehicles a greater fall in reactive power demand is therefore anticipated.

No Progression

The No Progression scenario has low economic growth and less emphasis on energy efficiency across residential and industrial and commercial sectors than Gone Green or Slow Progression. Growth in embedded generation in this scenario is however proportionately higher to the lower

Figure 2.3
National reactive power forecast illustration for Gone Green



A Embedded (29% in 2019/20) **B** Lighting* (51% in 2019/20) **C** Additional historic effect subject to further examination demand and as such the extent of power supplied across the network is further reduced.

Low Carbon Life

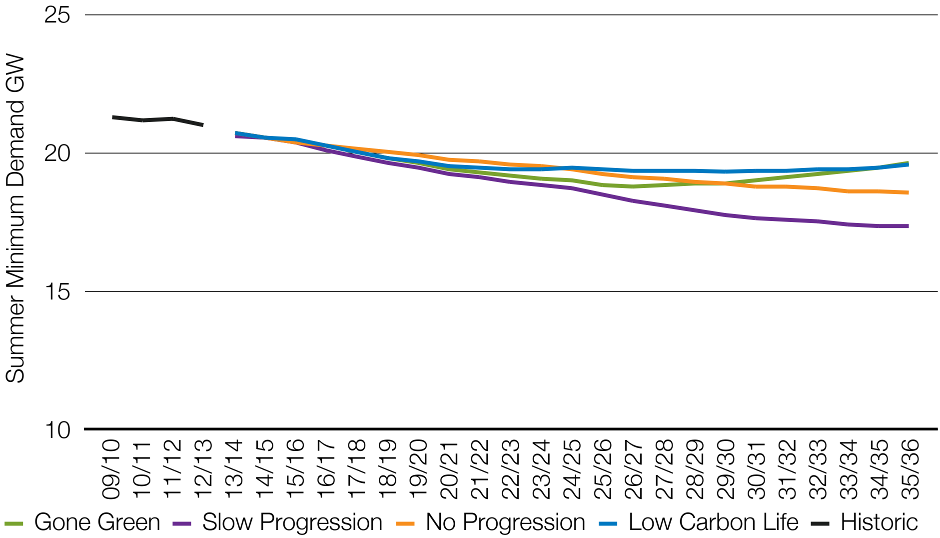
The Low Carbon Life scenario has high economic growth and less emphasis on energy efficiency across residential and industrial and commercial sectors than the Gone Green or Slow Progression scenarios with higher uptake of electric vehicles to scenarios above. In this scenario decline in reactive power would be expected to be predominantly driven by the effect of embedded generation reducing overall supply levels.

Within figure 2.3 it can be noted that there is significant effect related to embedded generation which can be further visualised in figure 2.4. By 2020 some 29% of the effect change in the ratio between reactive power (Q) and active power (P) forecast by Gone Green, based on expected levels of embedded generation presence at peak is expected to be due to embedded generation.

This however represents in FES an average position as indicated in existing levels of embedded generation penetration as extrapolated to the levels of embedded generation in each Future Energy Scenario. National Grid has in consultation with the industry progressed a Grid Code Modification (GC046) to enable the onshore TOs and SO to be provided with additional data specific to embedded generation which will aid in future planning and background estimation in future years, and next year's week 24 returns from DNOs shall enable future FES construction to be richer in this area of consideration.

Figure 2.3 also notes the historic effect of Q/P decline is as yet not fully captured between DNOs and ourselves. As Our System Operability Framework notes, the Q/P ratio has declined consistently across the period 2005–2013. Figure 23 of the System Operability Framework is repeated as figure 2.4 below for further information on this trend.

Figure 2.4
National historic Q/P ratios



2.4 continued
Demand

Figure 2.5 shows historic reactive demand at peak and projections for the four scenarios.

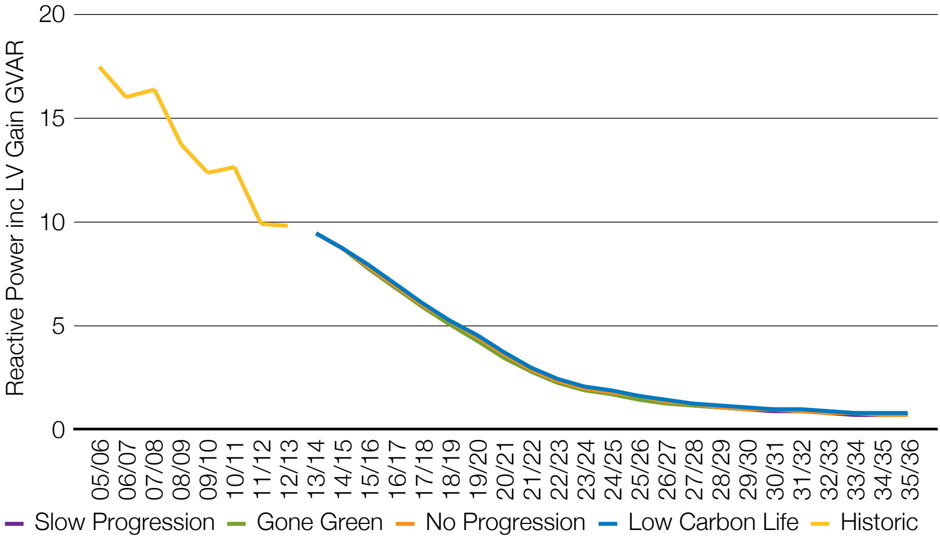
Demand for reactive power from the transmission network has been falling since 2005/06. The peak reactive power/active power ratio (Q/P), which has historically remained constant at ~0.43, has fallen by ~5% per year. This means that reactive power demand has been falling faster than active power demand.

There could be many explanations for this fall in reactive power and it is likely to be a combination of factors. National Grid is involved in the REACT project (Reactive Power Exchange and CharacTerisation), an industry study that is attempting to understand the causes and potential solutions. You can find details of the project at **http://www.manchester.ac.uk/research/luis.ochoa/research**.

For the purposes of the 2014 scenarios it has been assumed that reactive demand on the transmission system will continue to fall and that reactive power will not be exported from the distribution networks to the transmission networks.

QUESTION
What do you think are the drivers behind the reductions in reactive power demand and the Q/P ratio?

Figure 2.5
Reactive power including LV gain: outturn and scenarios



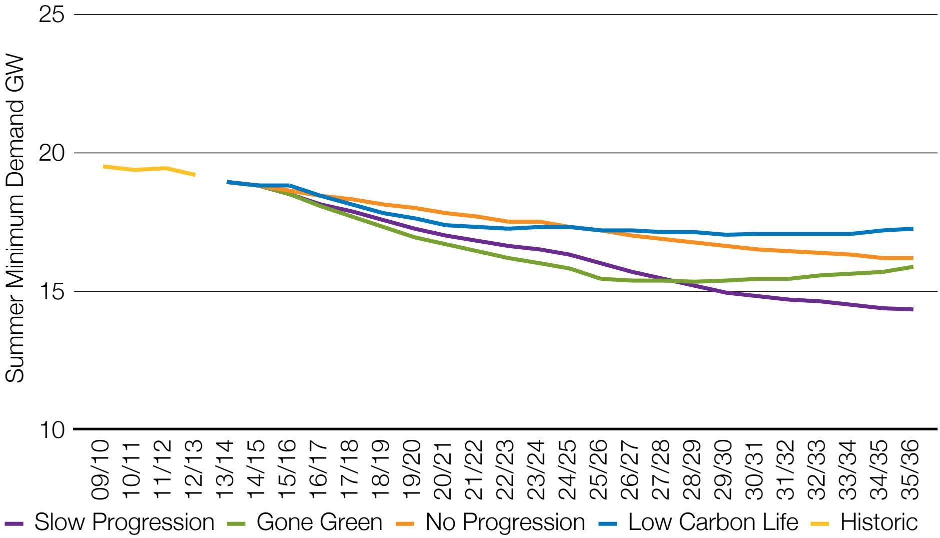
The decrease in reactive power and scale of the graph has led to the masking of the variation between the four scenarios.

Summer demand

Summer minimum history and projections for all four scenarios are shown in Figure 2.6.

Summer minimum demands are projected to fall slowly for two reasons. Firstly, as more distributed generation is installed, it will reduce the demands on the transmission system. Secondly, the energy efficiency of appliances is also expected to improve at different rates in the four scenarios, which will also reduce demand.

Figure 2.6
Summer minimum outturn and scenarios



2.5 Generating Capacity

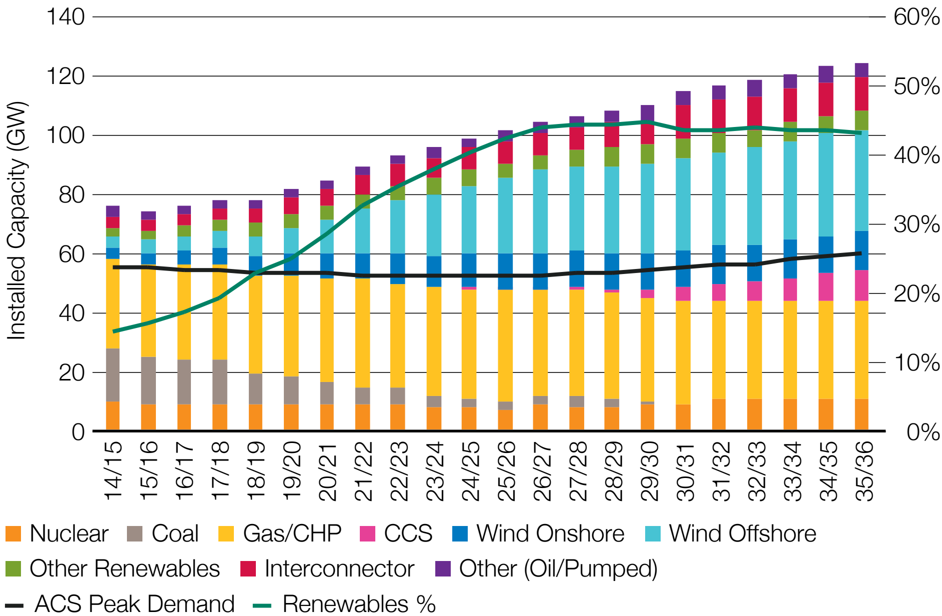
This section provides more detail about the generation capacity backgrounds for the scenarios and outlines the key changes in each case until 2035. For the purposes of the ETYS and associated commentary, the analysis period starts in 2014/15 and ends in 2035/36.

Generating capacity definition

The values shown within this section are only for installed capacity that is classed as 'transmission capacity'. This is generally generation capacity that is classified as 'large'[2] and therefore does not include any small and medium embedded generation. Embedded generation not included in these values is accounted for in the assessment of transmission demand. This is important to note as these figures cannot be directly compared with values shown in the UK Future Energy Scenarios document, which are for total capacity, including all embedded and micro generation.

For information on security of supply and data on embedded generation that no longer form part of this chapter, please see Chapter 4 of the UK Future Energy Scenarios document. This section describes in detail the embedded assumptions and generation capacity mix for each of the scenarios.

Figure 2.7
Gone Green (transmission) generation mix



Gone Green

In the Gone Green scenario, the generation mix has been developed to achieve the climate change targets. Some of the key messages from this generation background, and how it develops in terms of installed capacity, are:

- Wind reaches approximately 20GW of capacity by 2020 (just under 12GW of this being offshore) and 47GW by 2035 (35.5GW of this being offshore)
- Other renewables – excluding wind and including hydro, biomass and marine – increase by 1.4GW (the vast majority of this being biomass) to 2020 and by 3.6GW over the full period to 2035
- Gas/CHP increases slightly over the period and peaks between 2023 and 2025, taking into account closures of existing plant and future openings. It reaches 32GW by 2035, a net increase of just 2GW
- Coal capacity decreases dramatically over the period to 2035, with the steepest drop between now and 2020. From a starting point of 18GW it decreases to just over 7GW by 2020 and to 0GW by 2030. This is due to LCPD and Industrial Emissions Directive (IED) legislation
- In this scenario, it's assumed that carbon capture and storage (CCS) technology is introduced into the generation capacity mix from 2024 onwards. The scenario assumes that 11GW of plant will be fitted with both coal and gas CCS by the end of the period
- Nuclear capacity remains relatively flat over the full period increasing by only 1.2GW by 2035, taking into account closures of existing plant and openings of new plant
- Interconnector capacity reaches 6GW by 2020 and 11.4GW by the end of the period, showing a 7.4GW increase in capacity to 2035
- The level of renewables (as a percentage of installed capacity and not generation output) at the start of the period in this scenario is 14 per cent, rising to 29 per cent in 2020 and to 43 per cent in 2035.

Figure 2.7 illustrates the capacity mix for the Gone Green background over the study period.

Slow Progression

This scenario is shaped by the switch from traditional generation technology to a supply mix with more renewable generation, introduced to meet environmental legislation and to reduce greenhouse gas emissions. The key messages for this scenario are:

- Gas/CHP capacity increases from 30GW to 2020 and to a total installed capacity of 35GW by 2035, an increase of 5GW
- Growth in wind capacity is less in Slow Progression than in the Gone Green scenario, reaching 10GW by 2020 and 35GW by 2035 (24GW being offshore wind), an increase of approximately 27GW
- Other renewables, excluding wind, remain fairly static over the period, showing only a 1GW increase
- As seen in the other generation backgrounds, coal capacity shows a steep decline to 2020. In the Slow Progression scenario there is a 10GW decrease in coal capacity by 2020, leaving 8GW. By 2030 there is just 2GW of coal capacity remaining on the system, which is assumed to comply with IED legislation, resulting in a total decrease of 28GW of the period
- Nuclear capacity decreases over the period with existing nuclear plant closing and a moderate amount of new nuclear plant connecting. The total decrease over the period is 1.6GW

[2] National Grid: What size is my power station classed as? http://www2.nationalgrid.com/uk/services/gas-distribution-connections/frequently-asked-questions/

2.5 continued
Generating Capacity

- Interconnector capacity reaches 6GW by 2020 and 11.4GW by the end of the period, showing a 7.4GW increase in capacity to 2035
- The level of renewables (as a percentage of installed capacity and not generation output) at the start of the period is 14%, rising to 21% in 2020 and to 39% in 2035.

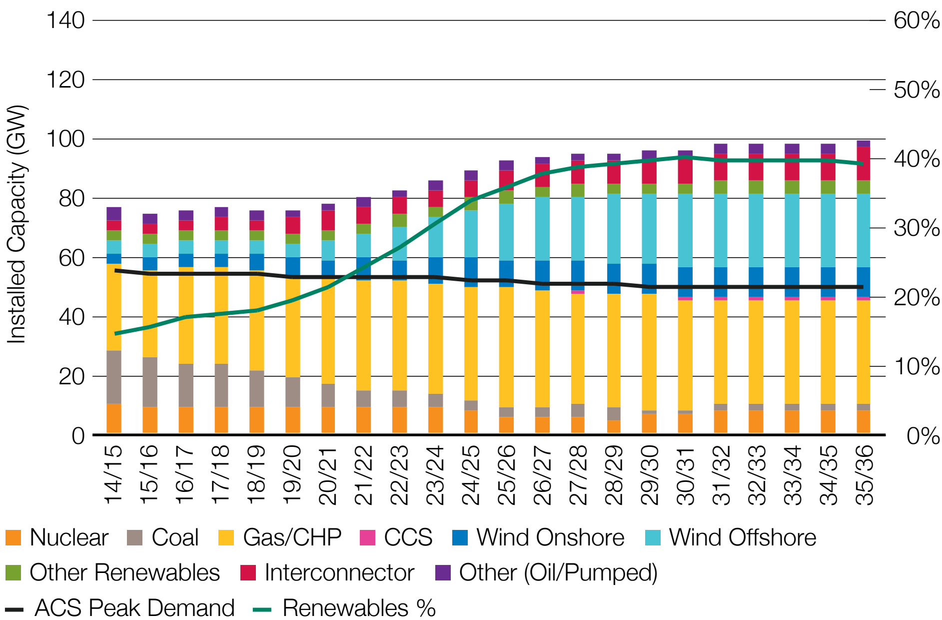
Figure 2.8 illustrates the capacity mix for Slow Progression.

No Progression

This is a new scenario for 2014 with the emphasis on cheaper and more traditional forms of generation, such as gas, rather than more expensive renewable technologies. The key messages in terms of installed capacity for this scenario are:

- Gas/CHP capacity steadily increases over the period, increasing by 5.7GW to 2020 and reaching 44GW by 2035; a total increase over the period of 14GW
- There is very little growth in wind capacity within this generation mix reaching just 8GW by 2020 and 15.6GW by 2035, showing a total increase over the full period of approximately 8GW
- Other renewables, excluding wind, remain static over the period showing just a 0.7GW increase

Figure 2.8
Slow Progression (transmission) generation mix



- As with all the 2014 scenarios, coal capacity shows a rapid decline which sees installed capacity drop from 18GW to 10GW in 2020 and to just 2GW by the end of the period
- Nuclear capacity falls across the period because of closure of existing plant and limited new build. Installed capacity drops from 9.4GW to 4.5GW by 2035, showing a 5GW decrease in total
- Interconnector capacity reaches 5GW by 2020 and 7.4GW by the end of the period, showing only a 3.4GW increase in capacity to 2035
- The level of renewables (as a percentage of installed capacity and not generation output) at the start of the period in this scenario is 14%, rising to 18% in 2020 and to 24% in 2035.

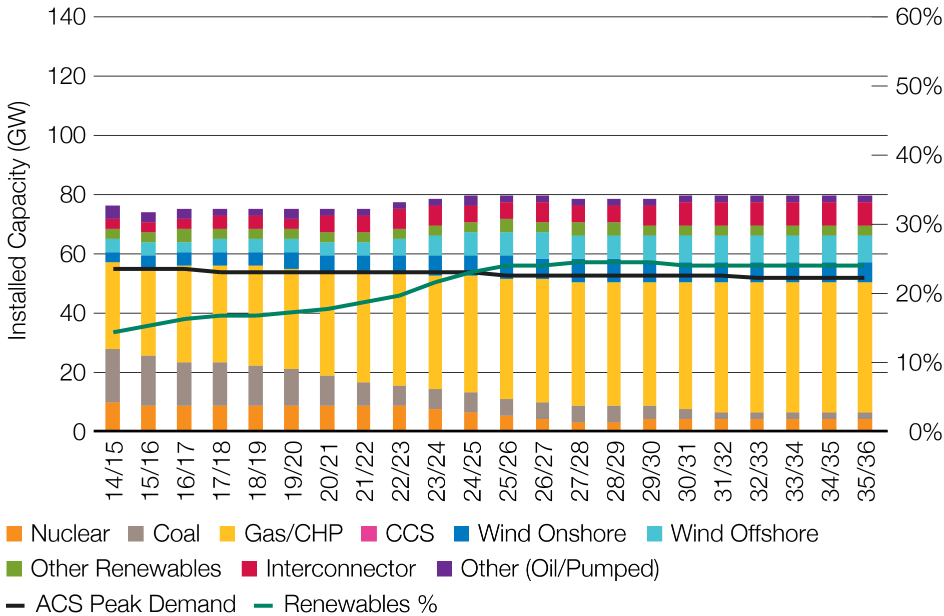
Figure 2.9 illustrates the capacity mix for No Progression.

Low Carbon Life

This scenario, which is new for 2014, is characterised by the switch from traditional technology to a supply mix dominated by low carbon forms of generation. This is as a result of the enduring focus on decarbonising energy that drives the type of technology connecting to the electricity system. The key messages for this scenario are:

- Gas/CHP capacity decreases over the full period to 2035 by approximately 5GW. This is the only scenario that shows a decrease in gas capacity over the period because the emphasis in this scenario is on nuclear and CCS

Figure 2.9
No Progression (transmission) generation mix

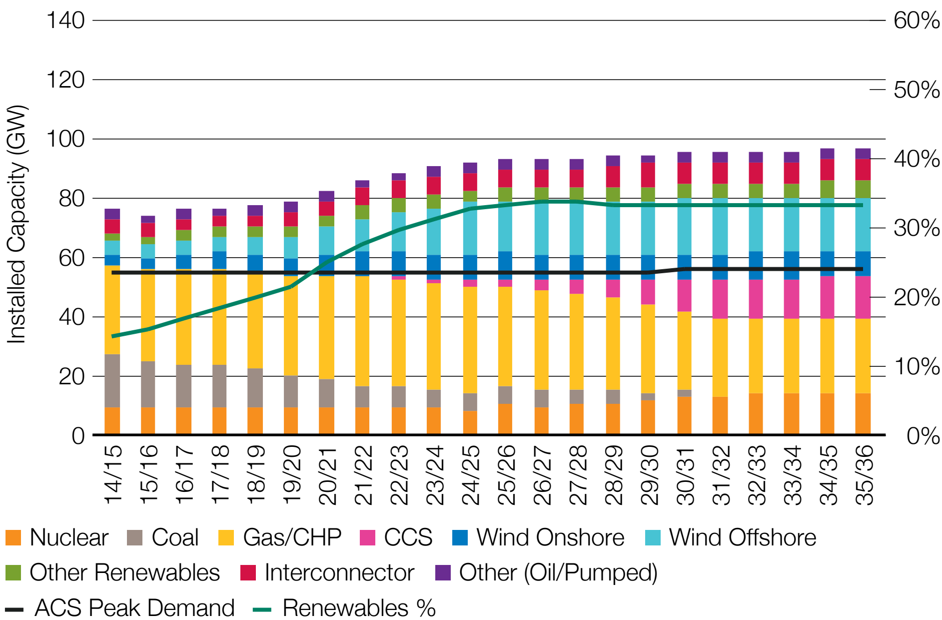


2.5 continued
Generating Capacity

- Growth in wind capacity to 2020 is broadly similar to the levels shown in the Gone Green scenario, with wind reaching 16.5GW by this point. There is considerably less focus on wind than in Gone Green after 2020 with an increase of just 10.5GW from 2020 to 2035, and a total wind capacity by the end of the period of 26.9GW, in comparison to the 47GW shown in Gone Green in 2035
- Other renewables, excluding wind, increase by 2GW over the full period, which includes an increase in marine generation
- Coal capacity shows a decline with an 8GW decrease by 2020 to 10GW. By 2031 there is no remaining coal capacity on the system resulting in a total decrease to this point of just over 18GW
- Low Carbon Life shows the largest increase in nuclear capacity across the scenarios with a 4.5GW increase over the period reflecting both closure and replacement of existing plant and a high level of openings
- Interconnector capacity reaches 5GW by 2020 and 7.4GW by the end of the period, showing only a 3.4GW increase in capacity to 2035
- The level of renewables (as a percentage of installed capacity and not generation output) at the start of the period in this scenario is 14%, rising to 25% in 2020 and to 33% in 2035.

Figure 2.10 illustrates the capacity mix for Low Carbon Life.

Figure 2.10
Low Carbon Life (transmission) generation mix



Contracted background

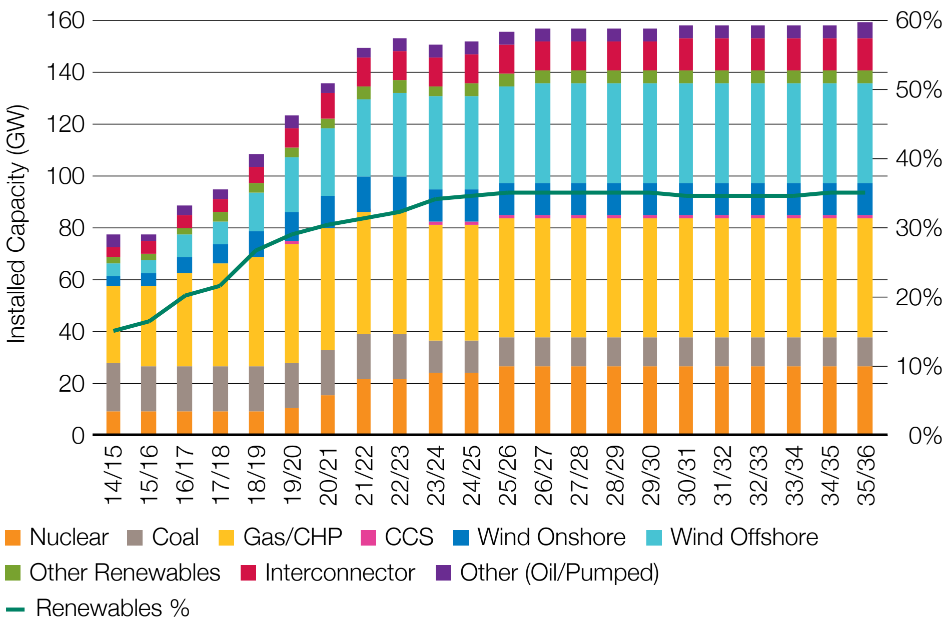
The dataset for the contracted background, shown in Figure 2.11, used in this document was taken at the end of June 2014, so please note that there will have been updates since then. For the most recent contracted background analysis please refer to the latest **Transmission Entry Capacity register**. Note 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, starting at an existing level of approximately 4GW rising to a total of 38GW of generation that currently has a signed connection agreement by the end of the period
- A decrease in coal generation amounting to around 6.5GW over the period to 2022/23, reflecting closure assumptions included for LCPD and IED closures
- There is also a total of 26GW of new nuclear plant that has a signed connection agreement.

Figure 2.11 illustrates the capacity mix for the contracted background.

Figure 2.11
Contracted background capacity mix



2.6 Contracted Background

This section looks at various elements of the scenario generation backgrounds and compares them to the contracted background that has been split into stages: existing, under construction, awaiting consents and scoping.

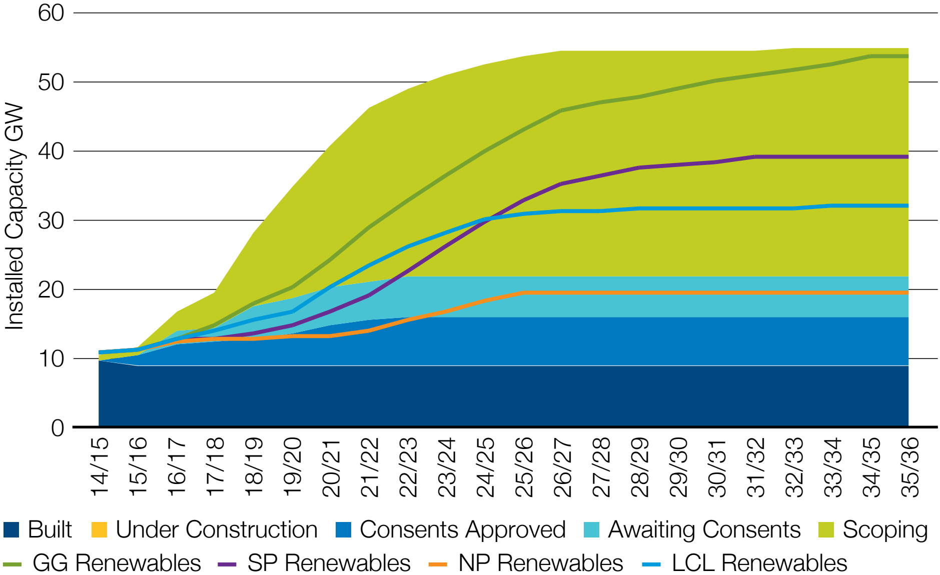
- **Existing** – this is the level of generation capacity already built and commercially generating
- **Under construction** – the level of generation capacity that is currently being built
- **Consents approved** – generation projects that have the relevant consents to proceed
- **Awaiting consents** – generation projects that have applied for the relevant consents to proceed but are waiting for a decision
- **Scoping** – these are projects that have a signed connection agreement only but have not yet applied for any consents.

Renewables (transmission) generation

Figure 2.12 shows the amount of renewable generation (both existing and future) that is contracted to be connected to the NETS. The contracted position is then compared to the amount included in each scenario. The following renewables technologies are considered:

- Biomass (including conversions)
- Wind (both onshore and offshore)
- Marine (tidal and wave)
- Hydro.

Figure 2.12
Renewables contracted background by stage



The graph shows that there is around 11GW of renewable generating capacity, with the Gone Green needing approximately 24GW by 2020. To meet the Gone Green scenario a further 13GW of renewable generation (out of a total 33GW of renewable contracted future generation with completion dates before 2020), will need to connect to the transmission system by 2020.

There are currently around 5.8GW of projects (with connections dates before 2020) that have consent. So to meet the levels of renewables needed for the Gone Green scenario in 2020, 7.2GW of contracted projects that currently fall into the 'awaiting consents' or 'scoping' category will have to be connected.

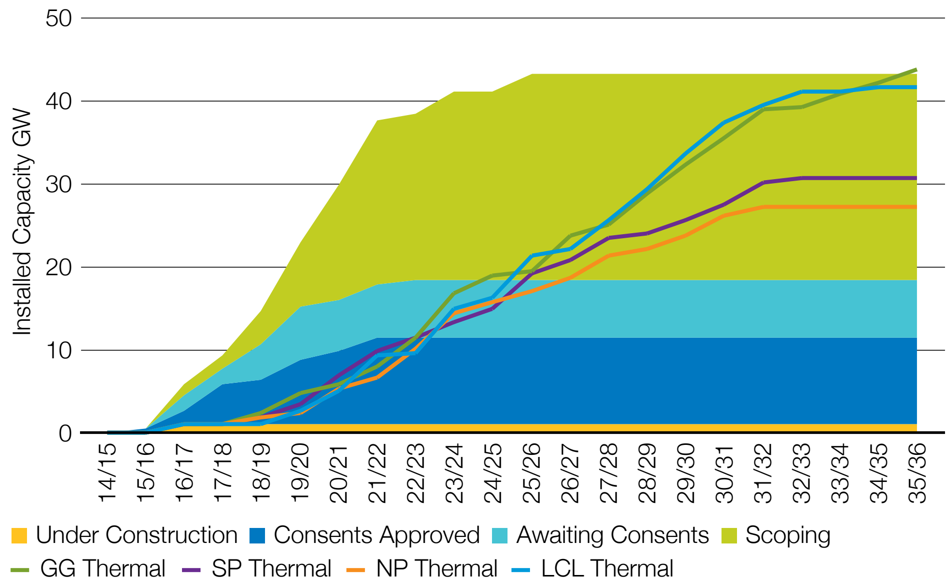
At the lower end of the renewables scale, No Progression requires 13.5GW of renewable generation capacity to be connected to the transmission system by 2020, an increase of only 2.5GW from the start of the period.

Renewable generation plays a large part in the scenarios, with even No Progression showing an 8.5GW increase over the period to 2035. Figure 2.8 shows that there is enough contracted generation capacity to meet the levels required under all of the scenarios, but some of these generation projects are in the 'scoping' or 'without consents' phases and they may not all be completed

Transmission connected thermal generation

Figure 2.13 shows the contracted position versus the required scenario position for future thermal plant. Please note that the existing plant has been removed from this analysis and Figure 2.13 does

Figure 2.13
Thermal contracted background by stage (opening only)



2.6 continued
Contracted Background

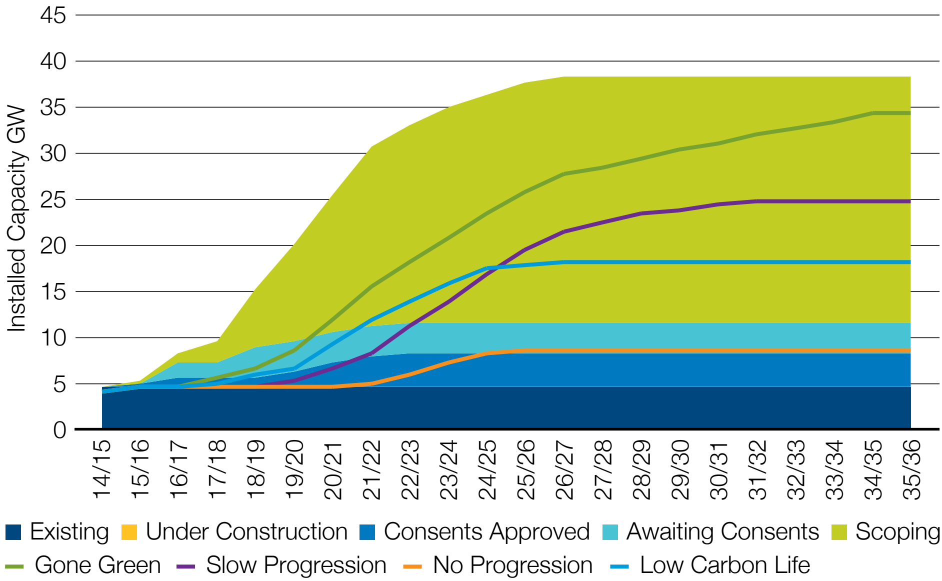
not account for closures of existing thermal plant; it purely focuses on the openings of future plant.

The graph shows that up to 2020 there is 30GW of generation contracted at various stages of consent. Under the scenarios up to the same point, the increase required in thermal plant is relatively similar between the four backgrounds, requiring an average increase of around 5.7GW. Most of this is gas plant required to compensate for the steep decline in coal within this period. Of the 5.7GW required under the scenario generation backgrounds, 0.9GW is under construction and the rest has consents.

Looking further out, the spread between the scenarios becomes wider with Gone Green and Low Carbon Life requiring approximately a further 37GW, on top of that required for 2020 levels. Only 11GW of this is under construction or has consents. At the lower end of the scale, No Progression requires an increase of 22GW by 2035 on top of 2020 levels. This split is because the Gone Green and Low Carbon Life scenarios have more closures of existing plant so need more new capacity; these are also the two backgrounds with the larger nuclear ramp-up.

For all four scenarios from 2025/26 onwards, the required generation currently lies in the scoping phase. Both Gone Green and Low Carbon Life rise to a level that is very close to the total amount of currently contracted thermal generation.

Figure 2.14
Offshore wind contracted vs scenarios



Wind (transmission) generation

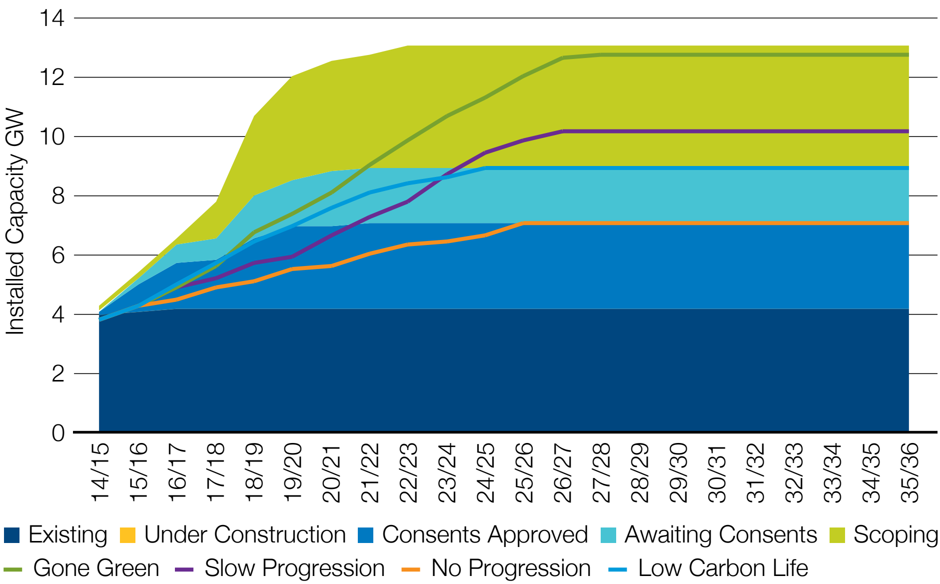
Figures 2.14 and 2.15 show the offshore and onshore wind scenario requirements compared to the contracted background. Wind in particular has been split out as it could have a significant impact on the future development of the transmission network. It also plays a significant role in the future energy mix and the ability to meet environmental targets.

Figure 2.14 focuses on the offshore wind element and shows that an increase of 7.8GW is needed in the Gone Green scenario by 2020. Currently, 2.7GW of this required increase has consents, which leaves 5.1GW of contracted but not consented generation to connect by this point. By the end of the period, the Gone Green scenario shows an offshore wind installed capacity of 34GW. No Progression, which shows the slowest ramp-up in offshore wind, requires an increase of just 0.4GW by 2020.

Figure 2.15 is shown below and focuses on the onshore wind element.

The graph shows that there is currently 3.8GW of connected onshore wind generation. The Gone Green scenario will need an increase of around 4.3GW by 2020. Of this required increase, 2.7GW has consents, leaving a further 1.6GW of contracted but not consented generation to connect by this point. By the end of the period the Gone Green scenario shows an onshore wind installed capacity of 12.7GW, which is very close to the total amount that is currently contracted. No Progression, which shows the slowest ramp-up in offshore wind, requires an increase of just 1.8GW by 2020, all of which currently has consents.

Figure 2.15
Onshore wind contracted vs scenarios



2.7 Application of the Future Energy Scenarios in System Planning

The earlier section of this chapter discussed the content of the scenarios at a high level, summarised by the types, size and timing of generation and the level of background demand. To perform network analysis, the scenario data must be applied to NETS network models so performance can be assessed. The FES generation backgrounds are created at an individual generator unit level and demand by zone. Within each scenario, assumptions about connection timescales for future plant are made against a list of criteria including consenting milestones, contractual connection dates and up-to-date market intelligence gleaned through our stakeholder engagement programme, journals and press releases.

Ranking order

Once the generation backgrounds are finalised, units are arranged in order of their perceived likelihood of operation and a ranking order is created. For existing generation, this means looking at the unit operation experienced over the previous two winter periods, from the beginning of December to the end of January. For future plant, the generation is ordered according to fuel type, with low carbon plant assumed to be more likely to operate as baseload. New thermal plant is likely to be more efficient than existing thermal generation so it is higher in the ranking order. The ranking order used to determine the operation of future plant is shown in Table 2.1.

Table 2.1
Ranking Order

Rank	Fuel type
1	Offshore wind
2	Tidal / wave
3	Hydro tranche 1
4	New nuclear
5	Hydro tranche 2
6	Onshore wind
7	Hydro tranche 3
8	Existing nuclear
9	New coal and gas with CCS
10	Biomass
11	New gas
12	Existing plant as per operation calculation and hydro tranche 4
13	Pumped storage
14	Open cycle gas turbine

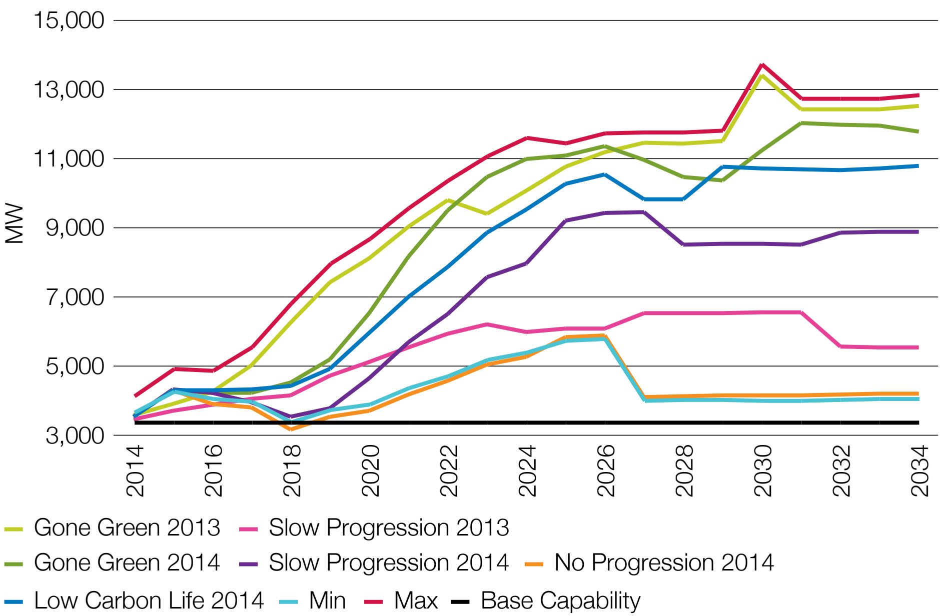
The methodology described for ordering plant in terms of operation is a general rule and is applied in a pragmatic way, supported by judgement and market intelligence. For example, a plant may have achieved a low ranking based on the previous winter's operational data but it may be recognised that this was due to a unique set of circumstances that are unlikely to be repeated. For instance, the plant may have been 'mothballed' but market intelligence suggests that it will be returning for future years.

NETS SQSS
The NETS SQSS standard specifies the output level that should be applied for each generator type for planning the future system requirements. For example, the SQSS Chapter 4 economy standards suggests that at winter peak, wind farm output should be considered at 70% of capacity, nuclear power stations at 85% and most other thermal plant variably scaled according to the remaining plant margin. Application of the NETS SQSS economy standards allows initial inspection of where a transmission solution might be economic to develop. These initial transmission requirements are shown in detail for the transmission system in Chapter 3.

The FES scenarios are used to calculate the requirement on a particular boundary on the system below as shown in Figure 2.16.

The studies are carried out over the 10 + 10 year period by varying the given generation and demand present appropriately relative to the boundary location. This is carried out to find the maximum capability of this area of the network to transfer power in each given year. If the capability is less than the requirements in the scenario there is a need to re-calculate the boundary capability with a range of reinforcements.

Figure 2.16
Sample boundary requirement chart



2.8 Operational Cost Assessment Inputs

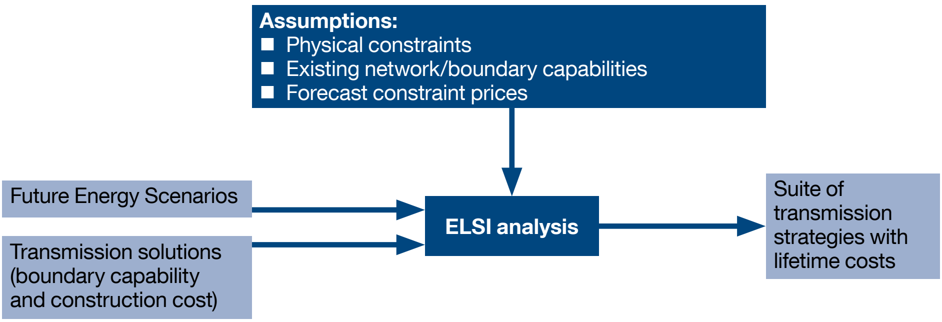
2.8.1 Introduction

Operational costs occur when the desired power transfer across a transmission system boundary exceeds the boundary's maximum operational capability. When this happens, it is necessary to pay generation behind that network boundary not to operate (i.e. constrain their output) and replace this energy with generation located in an unconstrained area of the network. Operational cost assessment is one of our key inputs to the transmission investment decision-making process, when assessing wider works. The fundamental trade-off is between the risk of undertaking an investment too early and the risk of congestion costs because network capacity has been added too late. The optimum combination of transmission solutions for each of the demand and generation scenarios and sensitivities needs to be established. This is achieved with detailed cost benefit analysis.

The Electricity Scenario Illustrator (ELSI) is a tool used to simulate the operation of generation and storage resources to meet consumer requirements. Its output, the forecast costs of network constraints, form a key input to the cost benefit analysis of the NDP. The constraint costs are a key part of the full cost benefit analysis, used to determine the best course of action for the next year, considering all of the Future Energy Scenarios discussed above.

The ELSI model was developed by National Grid to model future constraints on the GB system. The electricity transmission system in ELSI is represented by a series of zones, separated by boundaries. The total level of generation and demand is modelled so that each zone contains a total installed generation capacity by fuel types (CCGT, coal, nuclear etc.) and a percentage of overall demand. For a system to balance, generation must equal demand. The level of zonal connectivity is defined in ELSI to allow the system to balance as a whole. The boundaries, which represent the actual transmission circuits facilitating this connectivity, have a maximum capability that

Figure 2.17
ELSI tool inputs



restricts the amount of power that can be securely transferred across them. This capability may be an N-1 or N-D capability, according to the operational standards applied to the boundary.

ELSI was released to industry to support the stakeholder engagement process for the purposes of our RIIO-T1 submission. We have given our stakeholders the tool and information so they can perform their own analysis on the possible development of wider works.

The ELSI tool uses various inputs as shown in Figure 2.17, and later in this section many of these inputs are discussed in more detail.

As demonstrated in the figure above, the model requires inputs in terms of existing boundary capabilities and their future development.

The capabilities are calculated in a separate power system analysis package. Neither their dependence on generation and demand, nor the power sharing across circuits, is modelled in ELSI. All of the option reinforcements are assessed against each one of the Future Energy Scenarios, discussed in the previous sections of Chapter 2.

ELSI uses the detailed Future Energy Scenarios to complete this analysis up to 2035. The values from 2035 are extrapolated to estimate full lifetime costs. Lifetime cost analysis will be undertaken against various transmission strategies, combinations and timings of transmission solutions, until the optimum cost benefit is found for each of the scenarios and sensitivities.

Like industry benchmark tools for constraint cost forecasts, ELSI includes various input data such as fuel cost forecasts; renewable subsidies; plant availability by fuel type and seasons; and forecasts for base load energy prices in interconnected European member states. The rest of section 2.8 outlines the key assumptions adopted within ELSI.

2.8 continued
Operational Cost Assessment Inputs

2.8.2
Generation modelling assumptions in ELSI

A key input assumption within ELSI is the availability factors of all generation types. Table 2.2 below shows the availability factors of the generation types within ELSI, which are aligned with the assumptions adopted for the production of the FES 2014. These are the factors that have been used for transmission planning.

Table 2.2
Generation Availability Assumptions

Fuel Type	Fuel Grouping	Winter Availability	Spring Availability	Summer Availability	Autumn Availability
Hydro	Renewables	100%	100%	100%	100%
Offshore Wind[3]	Renewables	100%	100%	100%	100%
Onshore Wind	Renewables	100%	100%	100%	100%
Wave	Renewables	100%	100%	100%	100%
Nuclear	Nuclear	81%	76%	70%	76%
Nuclear New	Nuclear	90%	80%	70%	80%
Biomass – Conversion	Renewables	80%	75%	70%	75%
CHP	Gas	80%	75%	70%	75%
CHP New	Gas	80%	75%	70%	75%
CCGT CCS	Gas	85%	78%	69%	78%
Clean Coal CCS	Coal	88%	79%	70%	79%
Wave – Enhanced	Renewables	100%	100%	100%	100%
Tidal	Renewables	31%	31%	31%	31%
Tidal – Enhanced	Renewables	31%	31%	31%	31%
Base Gas	Gas	85%	78%	69%	78%
Mid Gas	Gas	85%	78%	69%	78%
Marg Gas	Gas	85%	78%	69%	78%
Interconnector Europe	Interconnector	95%	95%	95%	95%
Biomass – New	Renewables	80%	75%	70%	75%
Base Coal	Coal	88%	79%	70%	79%
Mid Coal	Coal	80%	69%	56%	69%
Marg Coal	Coal	80%	69%	56%	69%

Fuel Type	Fuel Grouping	Winter Availability	Spring Availability	Summer Availability	Autumn Availability
Interconnector Ireland	Interconnector	95%	95%	95%	95%
Pumped Storage Pump	Pumped Storage	99%	89%	88%	89%
Pumped Storage Gen	Pumped Storage	99%	89%	88%	89%
Pumped Storage Float	Pumped Storage	99%	89%	88%	89%
Oil	Peaking	74%	51%	41%	51%
Open cycle gas turbine	Peaking	91%	84%	84%	84%

With respect to the development of a merit order of generation, ELSI uses a layered model approach – a model where classifications of generators have marginal costs based on observed industry behaviours. This is to say that the fuel types above, although they may have the same availability factors, will have different marginal costs (or level of subsidy for renewable fuel types) affecting the merit order of the plant[4]. Further details regarding the marginal costs are presented later in this chapter.

However, it is worth noting that there are a number of further modifications to these base availability assumptions. In particular, onshore wind, offshore wind, wave and wave (enhanced) all have 100% availability as they have an additional model that uses historic data[5] to determine availability for each time period. The model randomly selects historic data from the appropriate season and assigns this value to each of the four fuel types. Further details on wind modelling are presented later in this chapter.

Hydro availability assumptions are shown in the table below. The availability of this fuel type varies both by season and period within the day. The daily periods are as follows:

P1 – Peak
P2 – Plateau
P3 – Pickup/drop off
P4 – Night trough

Table 2.2
Generation Availability Assumptions

Season/Period	P1	P2	P3	P4
Winter	62%	47%	33%	26%
Spring/Autumn	38%	32%	21%	18%
Summer	27%	18%	12%	9%

In addition to availability assumptions outlined in this section, modelling of interconnectors within ELSI is driven by price-based interactions between GB and the interconnected member states.

Stakeholder engagement
We'd appreciate your views on the availability assumptions of these generation types to help with our constraint modelling analysis.

[3] Although availability of certain intermittent renewables such as onshore and offshore wind have been presented as full capacity in Table 2.2, their output is determined using load factors, which are presented later in this section.

[4] Coal and gas generators have particularly been categorised as 'base', mid' or 'marg' plant. This is based on the age, efficiency and level of carbon emissions, which impact the SRMCs of these fuel types. Wave and tidal fuel types have an 'enhanced' category. The generators classified as enhanced will receive a greater level of renewable subsidy due to their location.

[5] Due to the nascent nature of technology and subsequently limited availability of output data for wave generation, the availability of these generators is based on a Monte-Carlo simulation of wind availability.

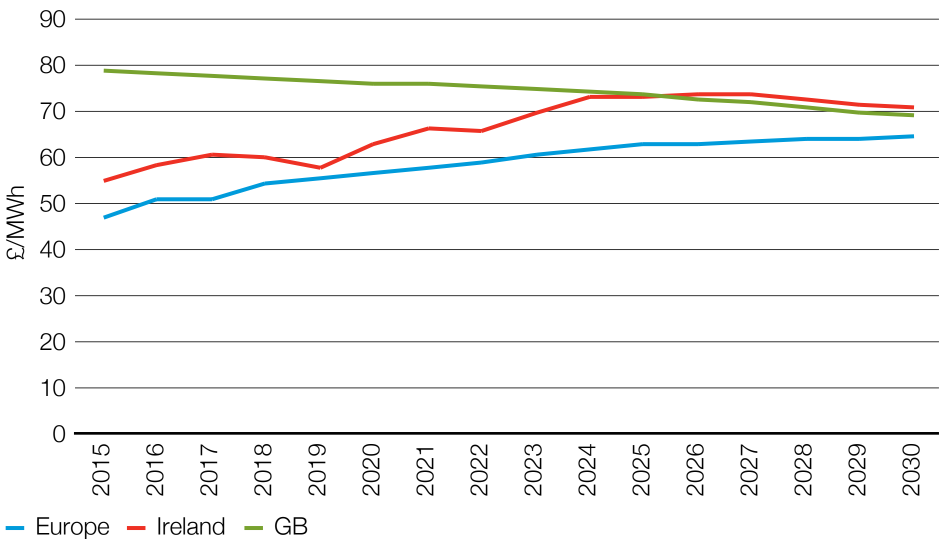
2.8 continued
Operational Cost Assessment Inputs

Treatment of interconnectors
In undertaking the cost benefit analysis in ELSI, interconnectors are treated via an entry in the merit order, each with two prices quoted, which are driven by the forecast base load energy prices in the interconnected member states.

ELSI calculates system marginal prices for every day by periods. If the GB system price for a particular period in the day is below the lower price, then it is assumed that the links export power, i.e. the receiving country takes advantage of low power prices in GB. Between the lower and upper price, there is assumed to be no power flow (i.e. the interconnectors are at float). If the GB system marginal price is above the upper price, the interconnectors import power, i.e. the GB system benefits from lower power prices abroad.

At present only interconnectors to Ireland and mainland Europe are modelled in ELSI and the forecast power prices in £/MWh for both of these regions are shown in Figure 2.18. Forecasts for GB system marginal price using ELSI are scenario dependent. However, for the purpose of comparison, base load energy price forecasts for GB are also presented in the figure.

Figure 2.18
Forecast power prices for Ireland and mainland Europe

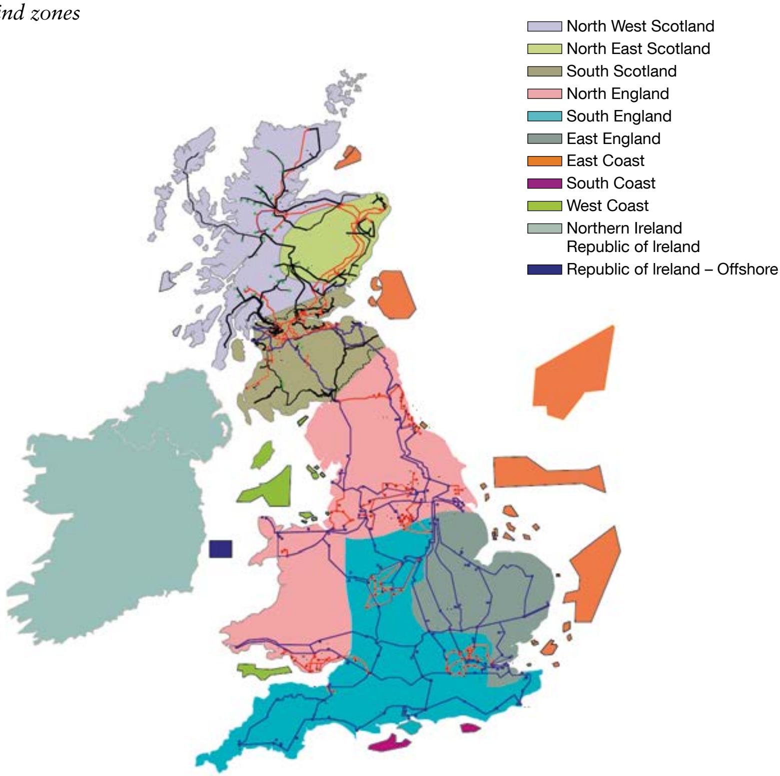


Wind modelling in ELSI

Wind output is represented by sampling (Monte Carlo) of historic daily wind speed data, for twelve discrete zones listed in Figure 2.19 below. Notably, three Irish zones are included along with disaggregation of onshore and offshore zones in GB. This is a modification on last year's model, which included only four wind regions. Each of the zones has a ten-year historical representation of wind generation load factor, based on wind speed source data by different locations from the Meteorological Office. This, by its nature, includes a seasonal variation. This wind speed data was applied to a benchmark wind turbine power curve to establish corresponding wind generation load factors.

The base wind speed data available allows further disaggregation of zones if necessary. Indeed, National Grid has adopted this approach for specific projects where we need further locational granularity. However, for the purpose of analysis contained within this document, we think increasing the number of zones from four in 2013 to twelve in 2014 offers enough diversity of weather and location.

Figure 2.19
ELSI wind zones



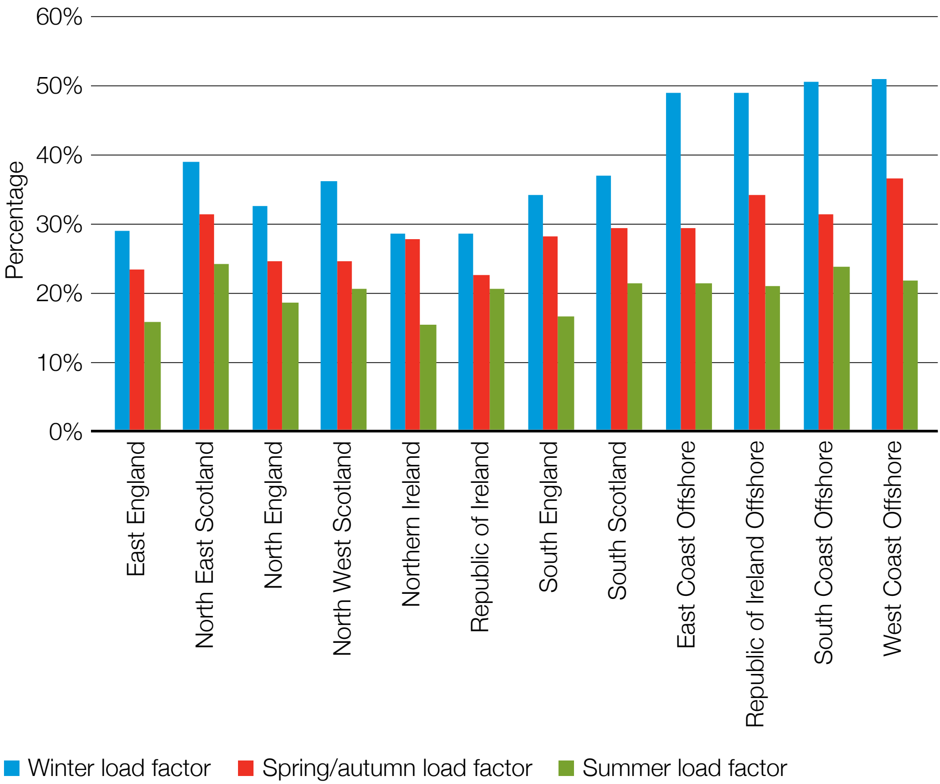
2.8 continued
Operational Cost Assessment Inputs

Statistical characteristics of the twelve zone data set are broadly as expected. Key characteristics include:

- There's a higher load factor in the winter season than spring/autumn, and summer has the lowest load factor of all
- Offshore wind has a higher annual load factor than onshore
- Northerly locations (Scotland) tend to have a higher annual load factor.

The seasonal and locational variations in load factor can be seen in Figure 2.20.

Figure 2.20
Seasonal average wind load factors by zones



We carried out correlation analysis to confirm that the wind generation data within ELSI is appropriate for simulating future onshore and offshore wind generation patterns.

Stakeholder engagement
We would welcome engagement on the modelling of wind and future interconnector flow assumptions.

Constraint management option costs

In seeking to deliver the optimum investment at the correct time we are seeking to balance investment cost with operational cost, taking into account those costs that we would occur if investment did not take place, i.e. investment costs versus the operational costs before and after investments. To allow us to undertake this assessment we need to first calculate constraint volume and then determine costs.

ELSI, our long-term constraint forecast tool, models the electricity market in two main steps. The first step looks at the short run marginal cost (SRMC[6]) of each zonal fuel type and dispatches available generation from the cheapest through to the most expensive one, until the total level of GB demand is met. This is referred to as the 'unconstrained dispatch'. At this point, the network (boundaries) is assumed to have infinite capacity.

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

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

The SRMC forecast assumptions for all types of synchronous generation, excluding nuclear, are derived using fuel price forecasts from the Department of Energy and Climate Change[7] and carbon price forecasts from Wood Mackenzie, our economic data providers Future Energy Scenario 2014. The SRMC forecast for nuclear generation is from Wood Mackenzie.

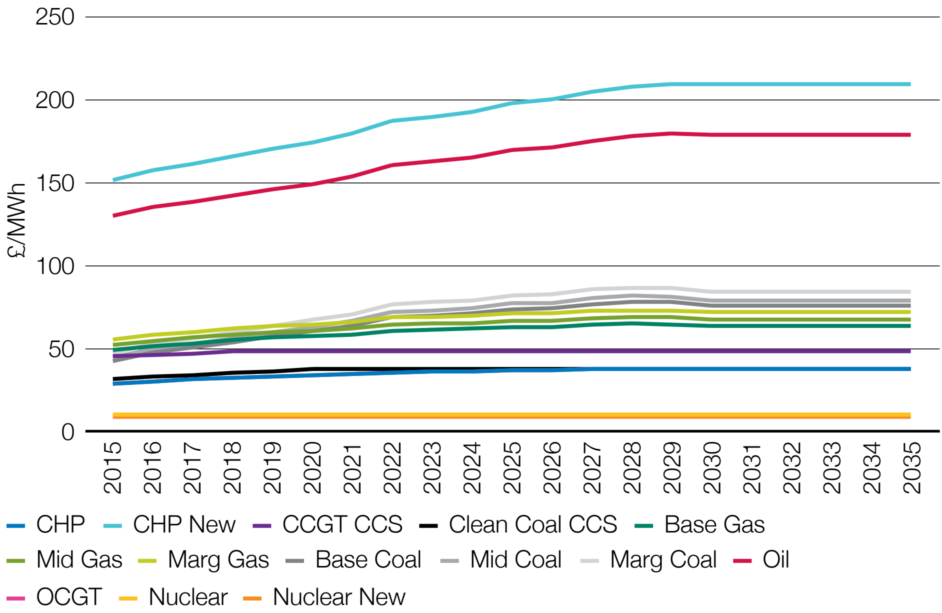
The forecasts for SRMCs for synchronous generators under the Future Energy Scenarios are presented in the figures 2.21 and 2.22. The forecasts suggest that increasing carbon prices under these scenarios will mean very high SRMCs for conventional coal- and gas-based generators. SRMCs for oil and OCGT generators will continue to be higher and increase. SRMCs for alternative technologies such as clean coal, new CHP and CCGT, will remain comparatively low. Nuclear continues to be the most efficient type of synchronous generation.

[6] Note that ELSI models SRMC (£/MWh) = Production (£/MWh) + Carbon emissions (£/MWh) + zonal adjuster (£/MWh)

[7] Source: DECC Fossil Fuel Price Projections, Dec 2013

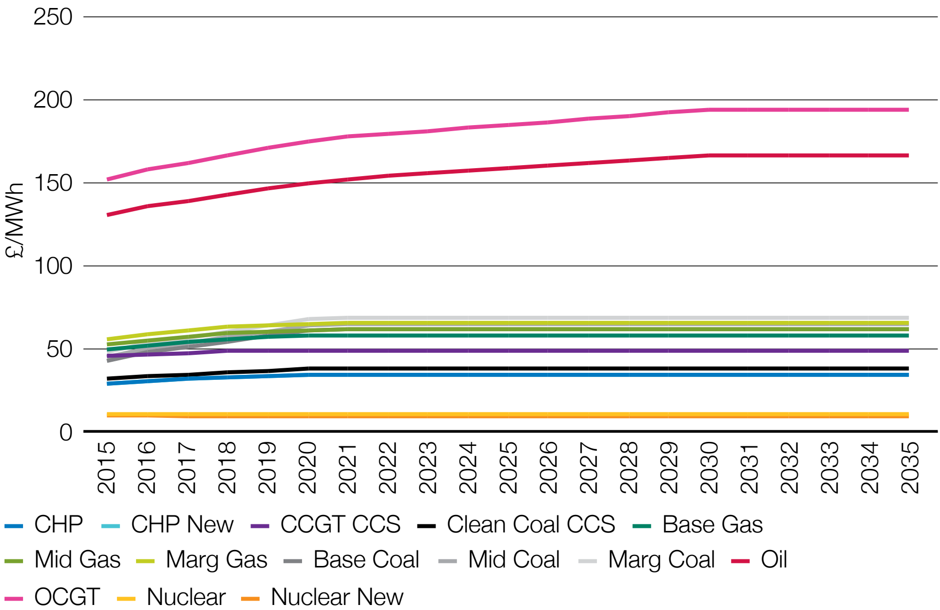
2.8 continued
Operational Cost Assessment Inputs

Figure 2.21
SRMC forecasts for synchronous generation for Gone Green and Low Carbon Life scenarios



The forecasts for SRMCs for synchronous generators under the Slow Progression and No Progression scenarios are presented in the figures below. The forecasts suggest that, as carbon prices increase sluggishly, the increase in SRMCs for conventional coal- and gas-based generators is nominal. However, SRMCs for oil and OCGT generators will continue to be higher and increase. SRMCs for alternative technologies such as clean coal, new CHP and CCGT will be also be comparatively low. Nuclear generators are forecasted to continue as the most efficient type of synchronous generation for these scenarios as well.

Figure 2.22
SRMC forecasts for synchronous generation for Slow Progression and No Progression scenarios



The SRMCs for all renewable generators are assumed to be nil. Their relative position in the merit order is based on the assumptions about renewable subsidy available per unit of energy generated. The forecast for the level of support available for different types of renewable generators, measured in terms of Renewable Obligation Certificates (ROCs), is sourced from the ROC (to Contracts for Difference or CfD) Bandings Review undertaken by DECC and Ofgem. The referenced review confirmed that support for each fuel type will be reviewed every five years. As we have no other information, our current assumptions about future support are consistent with the 2019 estimates.

2.8 continued
Operational Cost Assessment Inputs

Table 2.4
Renewable support forecast in terms of ROCs: all scenarios

ROC to CfD banding	2015	2016	2017	2018	2019
Hydro	0.70	0.70	0.70	0.70	0.70
Offshore Wind	1.90	1.80	1.80	1.80	1.80
Onshore Wind	0.90	0.90	0.90	0.90	0.90
Wave	2.00	2.00	2.00	2.00	2.00
Nuclear – Enhanced	5.00	5.00	5.00	5.00	5.00
Tidal	2.00	2.00	2.00	2.00	2.00
Tidal – Enhanced	3.00	3.00	3.00	3.00	3.00
Biomass – Conversion	1.25	1.25	1.25	1.25	1.25
Biomass – New	1.77	1.67	1.67	1.67	1.67

The monetary forecasts for ROCs from Wood Mackenzie are projected to grow linearly from approximately £47 per ROC in 2014/15 to £52 per ROC in 2029/30.

The total constraint cost used to solve a transmission congestion issue is associated with bid and offer components within the balancing mechanism. The 'bid' is a volume of energy at a £/MWh to reduce generation in an area and the 'offer' is the associated £/MWh to replace the energy, in another area of the system. The bid prices are technology dependent. For synchronous generation, evidence from the National Grid Economic Database (NED) confirms that the bid prices represent a proportional saving achieved by generators. For renewable generators, or any other generators receiving subsidies through the CfD framework, such as new nuclear, the bid prices represent the opportunity cost associated with constrained generation. Hence, these are valued at the level of subsidy available by technology type outlined earlier in this section.

In areas where there is no generation available to constrain on or off, the only option is to turn down demand; we have assumed £6,000 per MWh for the system 'value of lost load'. This figure has been recommended by Ofgem and DECC in the recently published Reliability Standard Methodology.

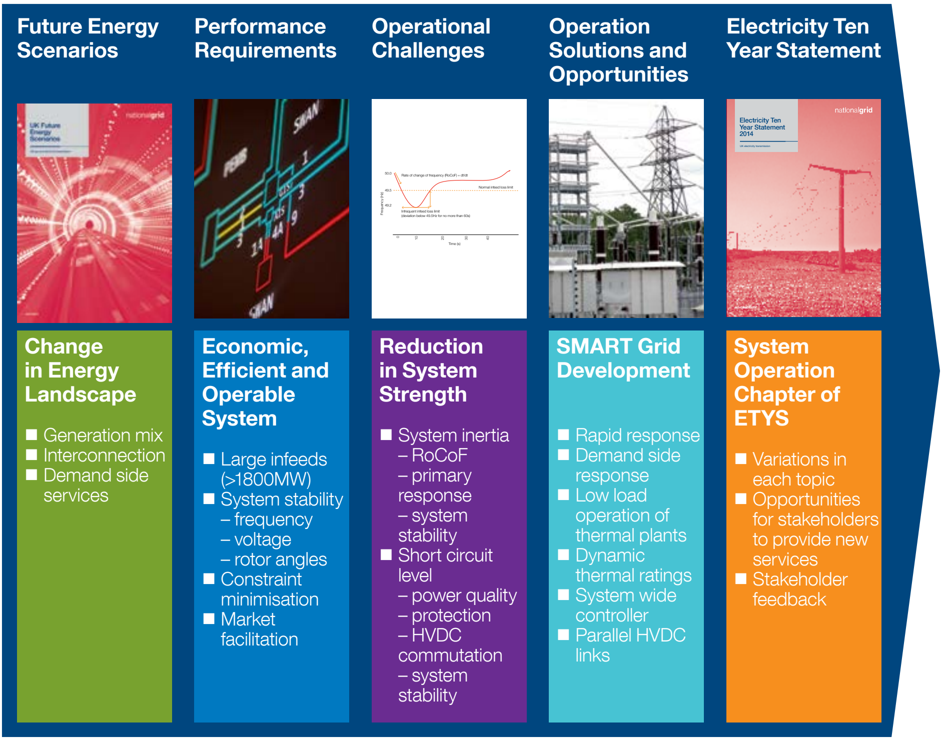
2.9 Application of the Scenarios in the System Operability Framework

National Grid's System Operability Framework (SOF) – published for the first time in 2014 – draws upon both the real-time experience of the system operator and the outlook of the Future Energy Scenarios (FES) for the period up to 2035, as recently published.

System operability is maintaining system stability and all of the asset ratings and operational parameters within pre-defined limits, safely, economically and sustainably. By combining knowledge and experience with detailed system analysis, it is possible to extrapolate the current experience of operating the network into these future years, across multiple future scenarios. This makes it possible to identify common themes where factors influencing the operability of the network may change, and to evaluate different approaches when changes happen. The full document was published on 10 September, together with a consultation document. The main messages are summarised in Chapter 5.

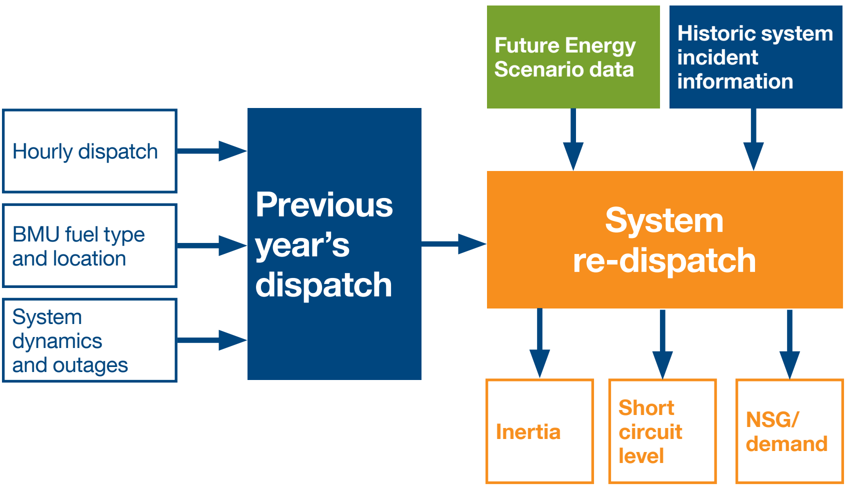
Figure 2.23 below highlights the process underpinning the SOF.

Figure 2.23
Overview of SOF considerations



2.9 continued
Application of the Scenarios in the System Operability Framework

Figure 2.24
Methodology of SOF



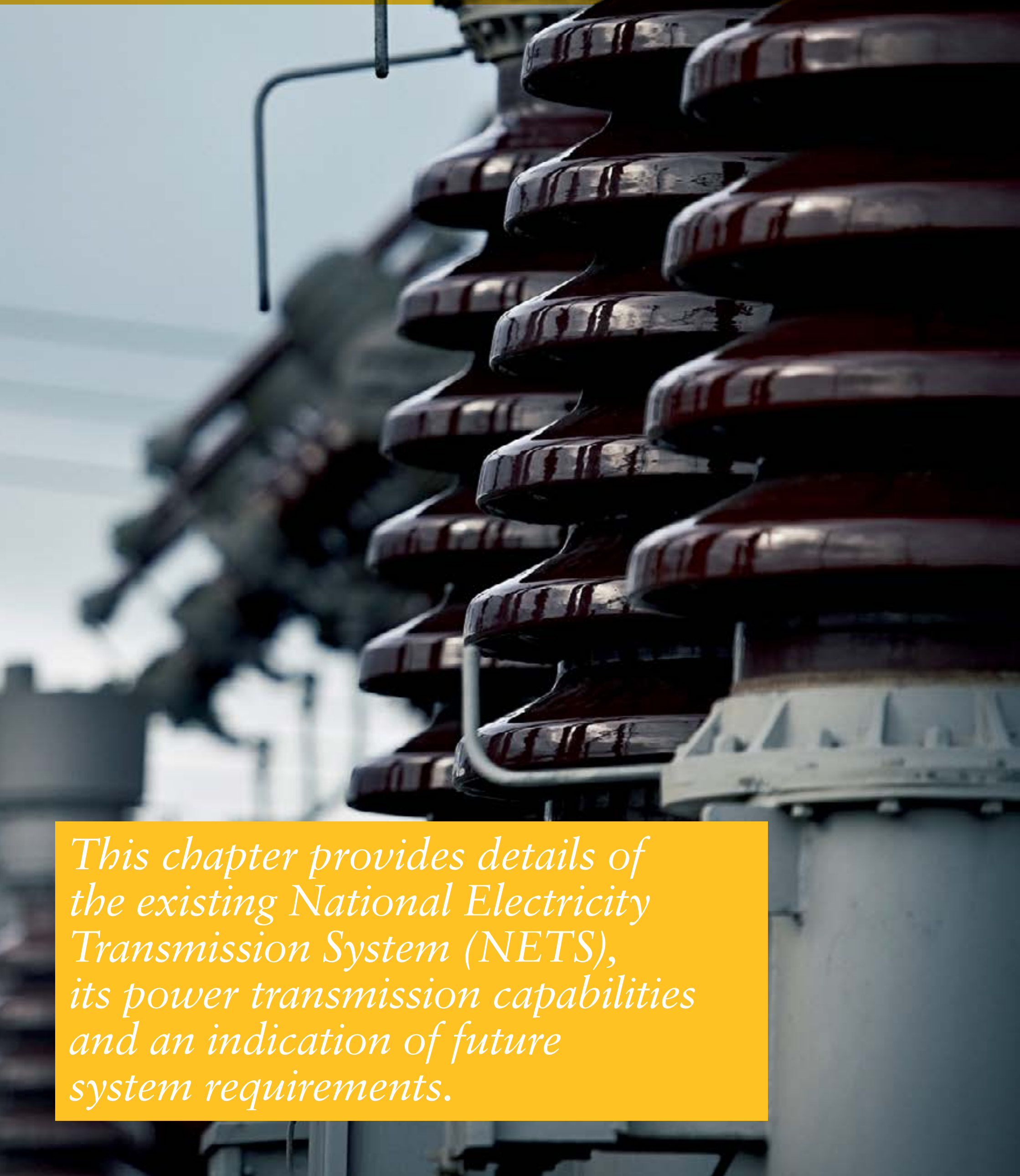
System Operability Framework has been developed to study in-depth, year-round impact of FES on system operability. The process begins by assessing existing network performance, identifying the root causes of incidents and constraints observed on the system in recent years, examining trends and highlighting potential new changes in system dynamics in future years based on system studies.

FES demand and generation data is then used together with consideration of previous year's actual hourly generation and demand information in order to extrapolate system behaviour for future years, highlighting the key variances in system operability parameters and assuring that risks associated with future system operability are identified. These are fully considered in section 5. The SOF approach then analyses across the entire year of each future year of forecasts the duration and scale of the technical challenges envisaged, and considers in detail its potential consequence relative to that FES background at that given point of day in a given point of the year. This is achieved by a combination of routine thermal voltage and stability assessment methodologies being combined with more specialised network simulations relating to the frequency, voltage and control dynamics of the transmission network at a given point of time and its quality of end supply and regulation.

This approach ensures the full characteristics of future challenges may be quantified such that mitigating measures may developed early enough to allow for full economic assessment across a range potential solutions and allow timely implementation of such measures which may include development of new market opportunities. The SOF is an organic process and in each year, evolving realtime network experience, combining with potential changes in FES may combine to illustrate changed or additional areas of operational challenge going forward and we undertake to annually update the industry in our assessments relative to these changes.

The System Operability Framework will support future FES and Electricity Ten Year Statement (ETYS) documents. We hope it will promote a common understanding across the industry of the factors driving network innovation, and how technical codes established in Europe will be implemented in the UK.

Chapter 3
Network Capability and Requirements



This chapter provides details of the existing National Electricity Transmission System (NETS), its power transmission capabilities and an indication of future system requirements.

3.1 Introduction

The transmission system is split by boundaries that cross key power flow paths where we anticipate that additional transmission capacity may be required[1]. The requirements are derived from the application of the NETS Security and Quality of Supply Standard (SQSS).

In assessing future requirements, we need to bear in mind that we have more than 80GW of signed contracts for new generation to connect to the NETS.

It is unlikely that they will all connect within the current timescales and some will probably not connect. Because we do not yet know when the existing generation will close, we use the Future Energy Scenarios (FES) document discussed in Chapter 2 to determine credible ranges of future transmission requirements. We use the system boundaries concept to provide clarity and transparency on NETS capabilities and future power transfer requirements.

This chapter describes the characteristics of each boundary. We have grouped a number of interactive boundaries together as regions, to help the reader gain an overview of the total requirement within each region.

Under a fully contracted position, there would be little to no opportunity for further generation development in many of the regions. However, by presenting an estimate of the future requirements of the boundaries against the FES, combined with the current system capabilities and opportunities outlined in Chapter 4, we are able to provide a more realistic assessment of potential future connection options in a given region.

In this chapter we map system areas to affected boundaries, which will be useful when interpreting the boundary sections and graphs.

[1] Please note that these boundaries will be reviewed annually and updated as appropriate.

3.2 Background

The NETS consists predominantly of 400kV, 275kV and 132kV assets connecting separately owned generation and distribution systems.

The 'transmission' classification applies in Scotland or offshore to assets at 132kV or above, and in England and Wales to assets at 275kV or above.

The transmission network in Scotland is owned by two separate transmission companies. The offshore transmission systems are also separately owned. National Grid owns the transmission network in England and Wales and is system operator for the NETS.

Nine licensed offshore transmission owners (OFTOs) have been appointed through the transitional tendering process. They connect operational offshore wind farms that obtained Crown Estate seabed leases from allocation rounds 1 and 2. Further OFTO appointments will be made through the enduring tender process.

Assets at lower voltage levels are part of the six regional distribution companies supplying customers down to domestic level.

The generators and interconnectors are separately owned and operated. The NETS peak demand is approximately 60GW and transmission-connected generation is dispersed across the country, with large groups of generation clustered around fuel sources including coal mines, oil and gas terminals, transport corridors and sea access.

With the expected growth in nuclear power and wind as primary sources of energy, generation is moving towards the periphery of the system, away from the demand centres. This means we have to move power over longer distances.

Wind power is mainly being developed to the north and east of the system, particularly within Scotland. This has increased power transfers from north to south, triggering associated reinforcement requirements.

To manage these challenges, in developing future transmission capacity we use a flexible approach that allows us to respond to future requirements while also minimising the risk of asset stranding.

The National Electricity Transmission System Operator (NETSO) and the transmission owners (TOs) deal with this uncertainty about the timing and location of future generation by considering a number of credible future scenarios and case studies. In areas of the system where there is a high level of risk, we also consider a contracted background. These are all described in Chapter 2.

A range of system actions and reinforcement options emerges from the scenarios. Chapter 4 describes how the appropriate options and their associated risks are assessed.

Fault level information is provided in Appendix D. It includes an explanation of the calculations as well as the fault levels for the most onerous system conditions at the time of peak winter demand.

3.3 Offshore Transmission

In order to support the connection of new offshore generators, the Department of Energy & Climate Change (DECC) and Ofgem developed a new offshore regulatory regime to offer competitive tendering for the development of new offshore transmission.

The regime was launched in 2009 and comprised two parts for tendering: transitional – for projects already built or in construction; and enduring – for future projects. Details of the offshore regime are available on the Ofgem website[2].

With more than 30GW of offshore generation being developed, there is a potential associated need for large-scale offshore transmission capacity. The offshore transmission is developed as part of the generation connection between the generator developer, OFTO (if appointed), the distribution company (if used), the affected onshore TO and National Grid as the NETSO. The connection and infrastructure options note (CION) records the different options considered to form the connection offer.

The CION process was initially established to help coordinate design activities between TOs where a developer's location meant that connection to different TO-owned networks was possible. With the arrival of offshore generation, the CION process was adapted to facilitate optioneering and coordination when designing connections for offshore developments to the onshore transmission network.

The CION process enables different connection options to be evaluated between all affected TOs and the NETSO, so that an agreement can be reached on the most economic and efficient option. It also helps to identify and facilitate the coordination of offshore connections in the event that there are additional developments in a similar location and there is a potential benefit to be realised.

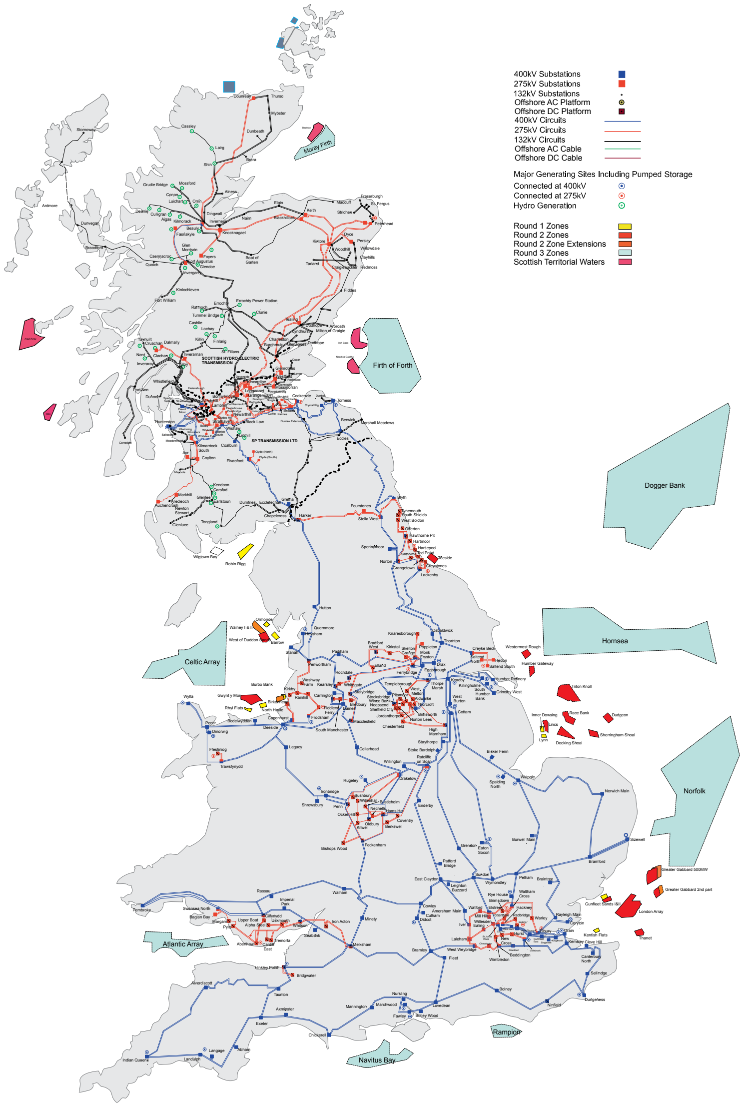
The CION document can be complex, involving the analysis of a number of different connection options. Achieving the required level of detail within the three-month connection process is challenging, so we have been reviewing the CION process to ensure that we meet the needs of developers, TOs and the NETSO. As part of this, in early 2014 we ran a stakeholder engagment workshop, which resulted in valuable feedback for use in developing guidance material. The System Operator Transmission Owner Code (STC) contains a procedure detailing the assessment and subsequent provision of a connection offer (STCP18-1). Taking into account stakeholder feedback, STCP18-1 was reissued in October 2014. Timescales for communication and data exchange, along with the clarity of the CION process, are all areas of concern. A sub-group of the joint planning committee of all the TOs facilitates interaction on issues like this.

Stakeholder engagement
We welcome your views on the representation of offshore and onshore connections.

[2] www.ofgem.gov.uk//electricity/transmission-networks/offshore-transmission

3.3 continued
Offshore Transmission

Figure 3.1
Seabed lease zones



3.4 European Interconnection

Increased interconnectivity between European member states will play a role in the security of the system, facilitating competition and supporting the efficient integration of renewable generation.

Current and planned interconnection

1. There are four existing interconnectors between Great Britain (GB) and other markets:
   a. IFA (1986) – 2000MW interconnector between France and GB, jointly owned by National Grid Interconnector Limited (NGIL)[3] and French transmission company Réseau de Transport d'Electricité (RTE)
   b. Moyle[4] (2002) – 450MW interconnector from Scotland to Northern Ireland, 295MW into Scotland owned by Northern Ireland Energy Holdings and operated by the System Operator for Northern Ireland (SONI)
   c. BritNed (2011) – 1200MW interconnector between the Netherlands and GB, jointly owned by NGIL and Dutch transmission company TenneT
   d. EWIC (2012) – 500MW interconnector from Ireland to GB, owned by the Irish System Operator, EirGrid.
2. There are seven more interconnectors with signed connection agreements that are contracted to commission before or around 2020:
   a. NEMO (2018) – 1000MW interconnector between Belgium and GB, jointly owned by NGIL and Belgian transmission company Elia
   b. ElecLink (staged connection 2016) – 1050MW, to UK, and 1000MW, to France, interconnector between France and GB, owned by ElecLink Ltd
   c. IFA2 (2019) – 1000MW interconnector between France and GB, jointly owned by NGIL and RTE
   d. NSN (2019) – 1400MW interconnector between Norway and GB, jointly owned by NGIL and Norwegian transmission company Statnett, connecting at Blyth on the NGET network
   e. NorthConnect (2021) – 1400MW interconnector between Norway and GB, connecting at Peterhead on the Scottish Hydro Electric network. It is jointly owned by four partners: AgderEnergi, E-CO, Lyse and Vattenfall AB
   f. Viking Link (2020) – 1000MW interconnector between Denmark and GB, connecting at Bicker Fen on the NGET network. It is owned by National Grid Interconnector Holdings Ltd.
   g. FABLink (2020) – 1400MW interconnector between France, Alderney and GB owned by FABLink Ltd.
   For up-to-date details of transmission contracted interconnectors please see the Interconnector TEC Register http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/
3. There are further projects that have applied for Projects of Common Interest (PCI)[5] status under the EU's Trans-European Networks (Energy) (TEN-E) regulations, and other projects that are already in the public domain, such as in the Ten-Year Network Development Plan (TYNDP). These are set out in table 3.1 below. There may be others of which we are currently unaware.
4. How interconnector requirements are reflected as part of wider network planning is under review. This will be influenced by European processes such as the TYNDP, and by Ofgem-led projects to review the current regulatory arrangements within GB.
5. We have also initiated a NETS SQSS working group to conclude on the future requirements for interconnectors. The Grid System Review (GSR) 012 has reached conclusions about local requirements and is currently addressing wider system impacts of Interconnectors. The review is scheduled for completion in Q1 2015.

[3] A wholly owned subsidiary of National Grid Plc.
[4] Presently operating at part load due to known cable faults but anticipated to return to full load by 2017
[5] http://ec.europa.eu/energy/infrastructure/pci/doc/2013_pci_projects_country.pdf

3.4 continued
European Interconnection

Integrated Transmission Planning and Regulation project

The Ofgem-led Integrated Transmission Planning and Regulation (ITPR) project is considering if and what changes may be required to the planning and regulatory regime. High volumes of renewable generation require closer coordination of transmission system planning to ensure that optimum solutions are developed. Additionally, the increasing integration with Europe through the interconnection and coordination of Transmission System Operators (TSO) activities requires greater cooperation with European TSOs. The ITPR project is exploring whether the current regulatory regime is appropriate to deliver an efficient, integrated transmission network – onshore, offshore and cross-border – given these new challenges.

Ofgem published ITPR's Draft Conclusions[6] document in September 2014. It includes a set of proposals to facilitate efficient and coordinated planning in electricity transmission and efficient delivery of assets. A consultation period ran until November and conclusions are expected in spring 2015.

In the document, Ofgem proposes that the system operator will have an enhanced role in planning the network, and we set out a more consistent approach to the delivery and regulation of different types of transmission assets. This includes increasing the role of competitive tendering to drive efficiency, and clarifying where different regulatory regimes will apply.

Ten-Year Network Development Plan (TYNDP)

The 2014 Ten-Year Network Development Plan (TYNDP) is published in accordance with Regulation (EC) 714/2009. It requests European Network of Transmission System Operators for Electricity (ENTSO-E) to adopt a non-binding community-wide TYNDP in order to ensure greater transparency regarding the entire electricity transmission network in the community and to support the decision-making process at regional and European levels.

The TYNDP 2014 was published for stakeholder engagement on 10 July 2014. Once this feedback has been incorporated into the plan, it will be finalised in December 2014. The complete TYNDP package consists of eight documents. The pan-European TYNDP 2014 report presents a synthetic overview of the studies, supported by six detailed regional investment plans and the Scenario Outlook and Adequacy Forecast (SO&AF) 2014–2030[7]. The North Sea area is the relevant regional investment plan for the GB network.

The TYNDP assesses projects that meet criteria in the Cost Benefit Methodology document – projects must increase the boundary capability, connect <500MW of renewable energy and increase the security of demand supply. It uses key indicators such as security of supply, social-economic welfare, renewable energy integration, impact on transmission losses and CO_2 emissions. The benefit assessment of all projects is detailed in the TYNDP and the regional investment plans.

In the light of Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure, which came into force on 15 May 2013, the TYNDP plays a double role:

- It ensures greater transparency of the entire European electricity transmission network and supports the decision-making process at regional and European levels
- It is the only selection base for projects of common interest (PCIs).

The list of TYNDP and PCI projects associated with the UK is published in Table 3.1 below.

[6] https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-draft-conclusions

[7] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

What's the difference between TYNDP and ETYS?

The TYNDP document is produced every two years whereas the ETYS is produced annually. The TYNDP is focused on pan-European projects and the analysis is conducted by regional groups. NGET, SP TRANSMISSION and SHET are members or corresponding members of the TYNDP group and the North Sea regional group. This information will be updated every two years in line with the process to update the TYNDP. However, given the time required to carry out the analysis and publish the plan, there will be a two-year time lag in respect of scenario data. For example, the 2014 TYNDP will be based on 2012 Future Energy Scenario data and system reinforcement options considered for ETYS 2012.

In addition to the timing differences of ETYS and TYNDP there are also different projects that qualify for inclusion within each document. In the TYNDP, the projects included are only for the chosen preferred option from the ETYS and additional ones which meet the criteria of TYNDP. For example the London Power Tunnels investment is not shown in ETYS but is included within the TYNDP (because it meets the security of supply criteria).

Projects that are associated wholly with GB and meet the ENTSO-E cost-benefit analysis criteria have been included within the TYNDP, which lays down specific rules on the clustering of projects. GB has five clusters of individual projects: the Anglo-Scottish cluster, East Coast cluster, East Anglia cluster, Wales cluster and the London cluster.

In contrast within the ETYS, the analysis focuses on the Network Development Policy application in England and Wales, where we show many options for reinforcements of each boundary and the chosen option. The same principle is applied to projects in the Scottish Hydro Electric Transmission (SHE Transmission) and Scottish Power Transmission (SP Transmission) areas, which are reported in ETYS. The main investments shown in the ETYS are those which add boundary capacity on the NETS system in the UK. We do not show individual generation connections or any asset replacement schemes that are needed for the security of demand.

Offshore grid initiative

We expect that an increase in intermittent renewable generation across Europe will require stronger connections between countries. The extension of the electrical transmission infrastructure into the seas around European countries to connect offshore generation presents opportunities to further extend that infrastructure to join the countries together.

In December 2010 the 10 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 coordinated strategic development path for an offshore transmission network in the North Sea. The North Seas Countries' Offshore Grid Initiative (NSCOGI) is seeking to establish a strategic and cooperative approach to improve current and future energy infrastructure development. This initiative is now progressing the work that ENTSO-E published in February 2011, which concluded that there are benefits in developing an integrated offshore grid, but only if both of the following conditions apply:

- A requirement for increased cross-border trading capacity, driven by the markets
- Significant and increasing volumes of offshore renewables between 2020 and 2030.

3.4 continued
European Interconnection

Table 3.1
Interconnectors

Name	Owner(s)	Connects to	Capacity	Key dates
Operational interconnectors				
IFA	NGIL and RTE	France	2000MW	Operational 1986
Moyle	NI Energy Holdings	Northern Ireland	450MW to NI 295MW from NI	Operational 2002
BritNed	NG and TenneT	The Netherlands	1200MW	Operational 2011
EWIC	Eirgrid	Ireland	500MW	Operational 2012
Contracted interconnectors				
ElecLink	ElecLink Ltd	France	1000MW	Contracted 2016
Nemo	NGIL and Elia	Belgium	1000MW	Contracted 2018
NSN	NGIL and Statnett	Norway	1400MW	Contracted 2019
IFA 2	NGIL and RTE	France	1000MW	Contracted 2019
NorthConnect	Agder Energi, E-CO, Lyse, & Vattenfall AB	Norway	1400MW	Contracted 2021
FABLink	FabLink Ltd	France via Alderney	1400MW	Contracted 2020
Viking Link	NGI Holdings	Denmark	1000MW	Contracted 2020

Projects of Common Interest or TYNDP Projects (applied for PCI status or pre-feasibility studies announced)				
Name	**TYNDP Project**	**PCI Ref**	**Capacity**	**Connect to**
Nemo	74	1.1	1000MW	Belgium
Belgium-GB 2	121	1.2	1000MW	Belgium
IFA 2	25	1.7.2	1000MW	France
FABLink	153	1.7.1	1400MW	France
ElecLink	172	1.7.3	1000MW	France
Interco Iceland-UK	214		1000MW	Iceland
Ireland-GB Interconnector	106		500MW	Ireland
Greenwire	185	1.91	3000MW	Ireland
Codling Park	N/A	1.9.2 and 1.9.3	500–1000MW	Ireland
Energy Bridge	N/A	1.9.4, 1.9.5 and 1.9.6	5000MW	Ireland
Marex	228	1.11	1200MW	Ireland
Irish-Scottish Isles	189	2.13	1200MW	Northern Ireland
NSN (Norway-UK)	110	1.10	1400MW	Norway
NorthConnect	190		1400MW	Norway
Viking Link	167		1000MW	Denmark
BritIB	182		1000MW	France and Spain
Larne Storage	N/A	1.12	550GWh p.a.	Ireland

3.5
Boundaries Introduction

Boundaries

The transmission network is designed to ensure that there is enough transmission capacity to send power from areas of generation to areas of demand.

To provide an overview of existing and future transmission requirements, and report the restrictions, we developed the concept of boundaries.

A boundary splits the system into two adjacent parts, crossing critical circuit paths that carry power between the areas where power flow limitations may be encountered.

Limiting factors on transmission capacity include thermal circuit rating, voltage constraints and/or dynamic stability. Each factor is assessed to determine the network capability. In preparing this year's ETYS document, the main focus of our analysis is thermal and voltage issues. Where there are known stability issues, these are reflected in the analysis presented in this report.

The maximum power transfers sustainable across a boundary have been determined against existing and future potential network topologies, to assess adequacy against a range of future requirements.

Defining the boundaries has taken many years of operation and planning experience of the transmission system. The NETS and boundaries have developed around major sources of generation, significant route corridors and major demand centres. A number of recognised boundaries (B0 to B17) are regularly reported for consistency and comparison purposes. When significant transmission system changes occur, new boundaries may be defined and some existing boundaries either removed or amended (an explanation will be given for any changes).

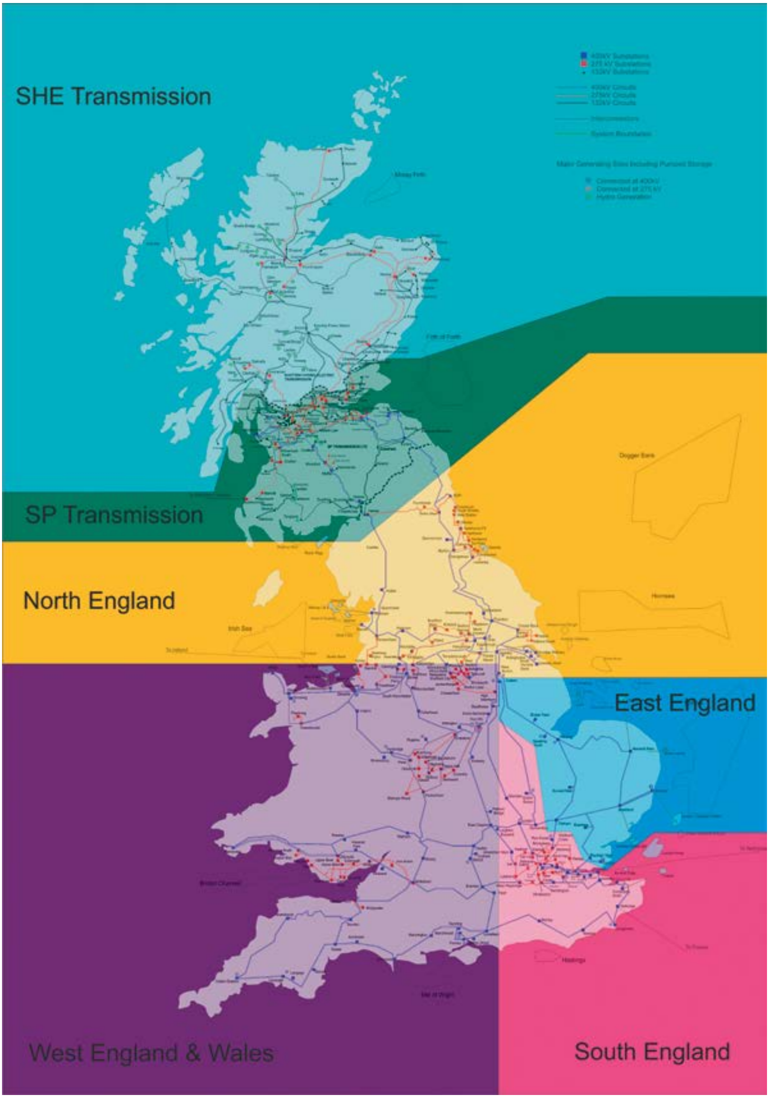
In recent years, many new boundaries have been added as the future generation seeks to connect to new, non-traditional locations. So transmission reinforcements have been required in areas not previously considered.

Many boundaries cross the same circuits and cover the same parts of the network, so we have grouped them into six regions (see Figure 3.2).

Planning future systems needs must also take into account the different conditions that can typically occur during a full year's operation. Many of the technical system operational characteristics have been discussed in the previous chapter. The standard specifies that the NETS must be secure for year-round operation during conditions that should be reasonably expected. The differences from peak conditions that can limit the NETS capability include:

- **Seasonal circuit ratings –** the current-carrying capability of circuits typically reduces during the warmer seasons as the circuit's capability to dissipate heat is reduced. The rating of a typical 400kV overhead line may be 20 per cent lower in the summer than in winter. As mentioned in the previous chapter, the use of dynamic circuit ratings is being considered to actively change circuit ratings based on monitored conditions
- **Voltage management –** at times of low demand – especially low reactive power demand – the voltages on the NETS can increase naturally due to capacitive gain. High voltages need to be controlled in order to avoid damaging the equipment. There must be enough reactive compensation and switching options to allow effective voltage control
- **System stability –** with reduced power demand and a tendency for higher system voltages during the summer months, fewer generators will operate (and those that do could be at reduced power factor output). This condition has a tendency to reduce the dynamic stability of the NETS, so we usually analyse network stability for summer minimum demand conditions, because this would normally represent the most onerous condition.

Figure 3.2
Regional map



3.5 continued
Boundaries Introduction

- **Network access –** maintenance and system access is typically undertaken during the spring, summer and autumn seasons. Planning outages and system operations is carefully controlled to ensure that system security is maintained
- **Generation profiles –** the winter peak is when the greatest number of generators are operational – at other times of the year the number of generators running can be greatly reduced. Variation of generator operation can be much higher in the summer because generators undergo maintenance, demand is reduced and intermittent generation becomes more sporadic. We ensure that all regions are adequately supported at all times.

Boundary map
Figure 3.3 shows the boundaries considered.

Security standard requirements and determination of capability
The NETS SQSS specifies methodologies for assessing local generator boundaries and wider system boundaries. The differences lie primarily in the level of generation and demand modelled, which in turn directly affects the level of boundary transfer to be accommodated:

- **Local boundaries –** for all the local boundaries selected in this statement there is more generation than demand within the group under consideration, so they are all net power export boundaries. In such areas, the generation is set at its transmission entry capacity (TEC) or at a level that may reasonably be expected to arise during the course of a year of operation
- **Wider boundaries –** in the case of wider system boundaries the overall generation is selected and scaled according to the security and economy criteria defined in the NETS SQSS and described below. The demand level is set at national peak, which results in a 'planned transfer' level. Furthermore, for each system boundary an extra interconnection or boundary allowance is calculated and added to the planned transfer level to give a required transfer level. In this way the standard seeks to ensure that peak demand will be met, allowing for generator unavailability and system variations.

For wider boundary studies, the security and economy criteria are both applied to the generation background, and in any given year the required transfer is the highest value.

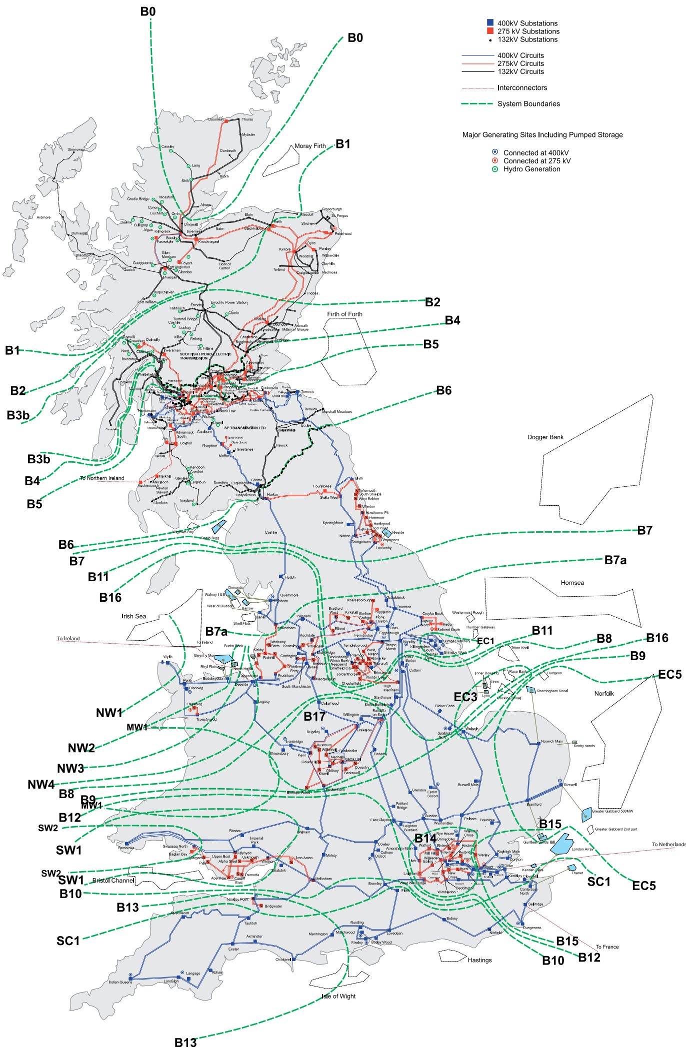
The security criterion – aims to ensure that demand can be supplied securely, without reliance on intermittent generators or imports from interconnectors. The background is established by:

- Setting the output from intermittent generators and interconnectors to zero
- Using a ranking order to determine the conventional generation required to meet 120 per cent average cold spell (ACS) demand, based on the TEC of the generators
- Uniformly scaling the output of these generators to meet demand.

The economy criterion – as increasing volumes of intermittent generation connect to the GB system, the security criterion will become less representative of year-round operating conditions. The economy criterion emulates a year-round cost-benefit analysis. To achieve this, a single background condition is specified for analysis and the appropriate agreed direct and variable scaling factors are applied to all generation so that the generation output meets the ACS peak demand. The chosen scaling factors are those that will enable the plant to run with the lowest marginal cost, while taking into account that intermittent generation is not likely to operate consistently at 100 per cent output.

Further explanation can be found in Chapter 4 and Appendices C, D and E of the NETS SQSS.

Figure 3.3
ETYS GB boundaries



3.5 continued
Boundaries Introduction

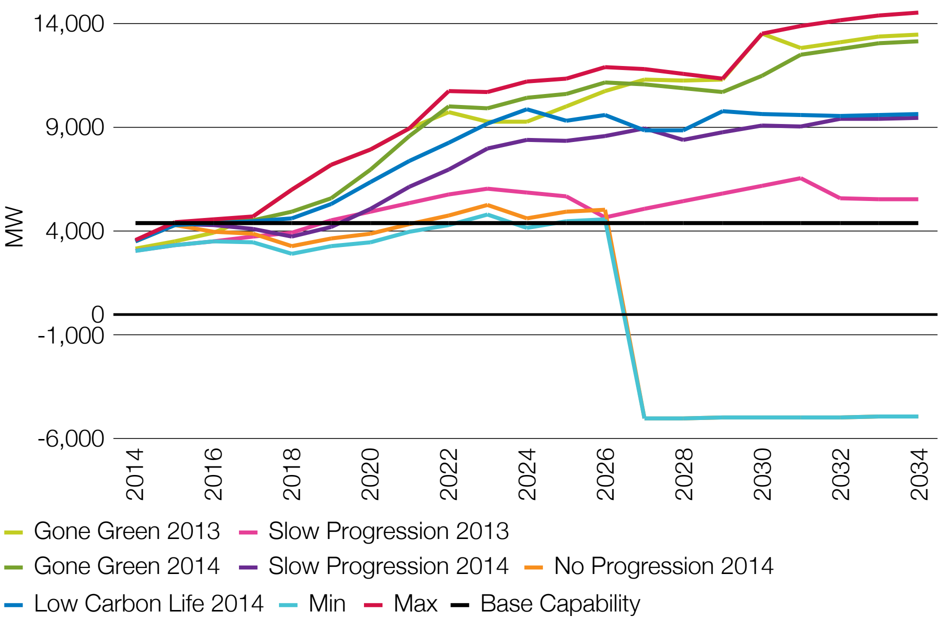
Interpreting the boundary graphs
When presenting the scenarios and sensitivities for the boundaries, it is not possible to show everything at once. This is because there would be extensive overlapping of results and far more information than could be displayed clearly. So we have simplified the boundary graphs using the style shown in Figure 3.4.

For England and Wales we have shown a maximum and minimum line that represents the highest and lowest requirements of the four case studies for each boundary.

For the local and Scottish boundaries we have also shown a plot of the contracted background.

Stakeholder engagement
We welcome your feedback on using boundaries as a means of representing transmission network capability and requirements.

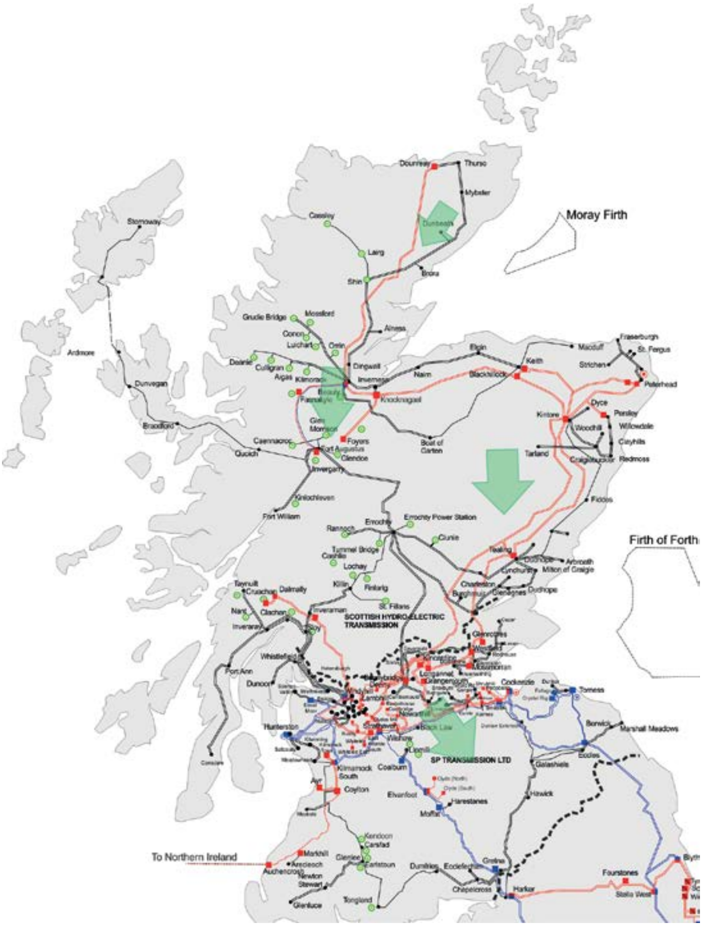
Figure 3.4
Example of required transfer and base capability for boundary B7



On the x-axis the year refers to the winter peak of that year. For example 2014 represents December 2014 – February 2015.

3.6 Scottish Boundaries

Introduction
The following section describes the Scottish transmission networks up to the transmission ownership boundary with the England and Wales transmission network. The onshore transmission network in Scotland is owned by SHE Transmission and SP Transmission but is operated by National Grid as NETSO. The following boundary information has been provided by the two Scottish transmission owners.



3.6 continued
Scottish Boundaries

Primary challenge statement:
Scotland is experiencing massive growth in renewable generation capacity in remote locations, with required connection to a relatively low-capacity and sparse-transmission network.

The restrictions of the Scottish boundaries are often caused by the rapidly increasing generation capacity, mostly from renewable sources, connecting within Scotland. The need to transport this generation through the Scottish networks to southerly demand centres in England provides drivers for network development in this region.

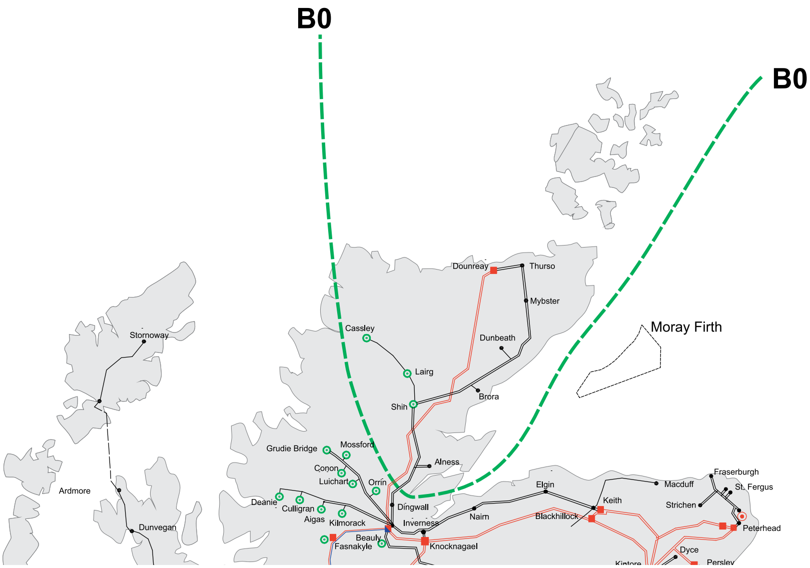
Regional drivers

The forecast increase in generation in Scotland will result in the following:

- Limitation on power transfer from generation in remote locations to the main transmission routes (B0, B1)
- Argyll and the Kintyre peninsula is an area with significant renewable generation activity. A local boundary assessment is needed, to show potential for high generation output and network limitations to power flow
- Limitation on power transfer from north to south of Scotland (B1, B2, B4, B5):
  - Generation in the north of Scotland is increasing over time because of the high volume of new contracted renewable generation seeking connection in the SHE transmission area. So boundary transfers across B1, B2, B4 and B5 are also increasing
  - The current capability of some of these boundaries is insufficient to satisfy the boundary transfer requirements for the first few years under some scenarios. This is because of generation being connected ahead of the required reinforcement, in accordance with the Connect and Manage access framework. The increase in the required transfer capability of these boundaries over the ETYS period clearly indicates the need to reinforce the transmission system in order to create the extra capacity for power transfer from the north to the south of Scotland
- Limitation on exporting power through Scotland and into England (B2, B4, B5, B6):
  - The high volume of new contracted renewable generation seeking connection throughout Scotland is expected to create significant power flows through the Scottish networks to reach demand in England. Renewable generation connection throughout Scotland is expected to increase across all ETYS scenarios, so the increase in the required transfer capabilities over the ETYS period clearly indicates the need to reinforce the transmission system in order to create the extra capacity for exporting power from Scotland to England.

3.6.1
Boundary B0 – Upper North SHE Transmission

Figure B0.1
Geographic representation of boundary B0



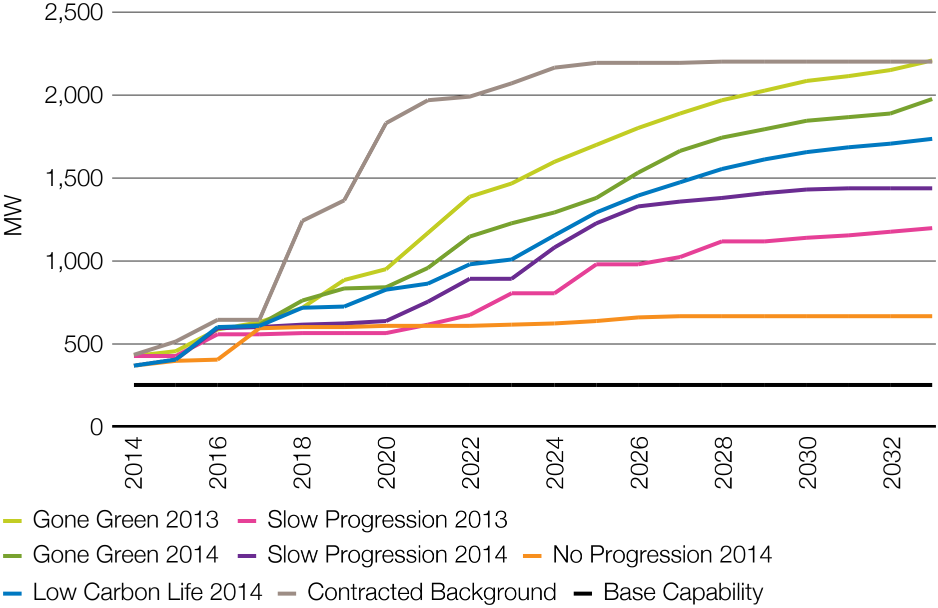
Boundary B0 separates the area north of Beauly, comprising north Highland, Caithness, Sutherland and Orkney. The existing transmission infrastructure north of Beauly is relatively sparse.

The boundary cuts across the existing 275kV double circuit and 132kV double circuits extending north from Beauly. The 275kV overhead line takes a direct route north from Beauly to Dounreay, while the 132kV overhead line takes a longer route along the east coast and serves the local grid supply points at Alness, Shin, Brora, Mybster and Thurso. The Orkney demand is fed via a 33kV subsea link from Thurso.

Reinforcement works in this area, referred to as Beauly–Dounreay Phase 1, were completed in March 2013. These works included the installation of the second circuit on the 275kV line between Beauly and Dounreay and an upgrade of the Dounreay substation.

3.6 continued
Scottish Boundaries

Figure B0.2
Required transfer and base capability for boundary B0



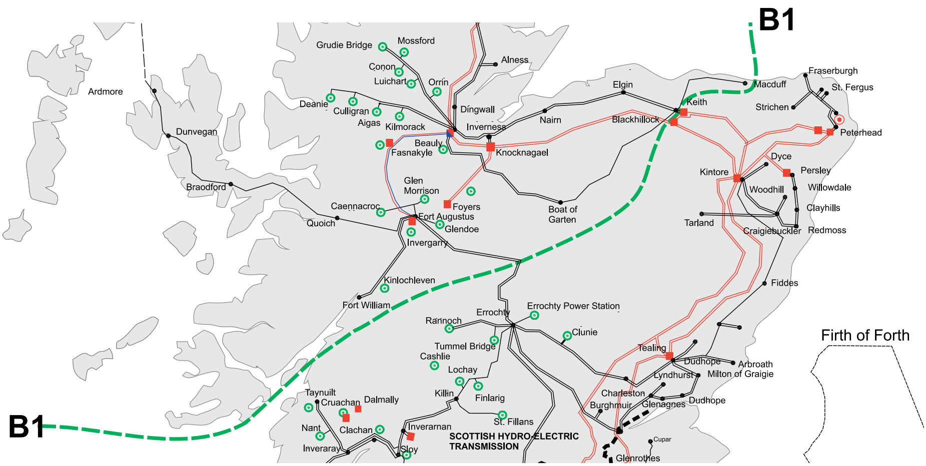
Boundary requirements and capability
Figure B0.2 above shows required boundary transfers for B0 from 2014 to 2034. The boundary capability is currently 0.25GW.

The power transfer through B0 is increasing due to the substantial growth of renewable generation north of the boundary. This generation is primarily onshore wind, with the prospect of significant marine generation resource in the Pentland Firth and Orkney waters in the longer term.

Reinforcement of boundary B0 is required and the Caithness–Moray reinforcement project has been proposed to achieve this. It is due for completion in 2018 and comprises an HVDC link between a new substation at Spittal in Caithness and Blackhillock in Moray, along with associated onshore reinforcement works. The onshore works include rebuilding the 132kV double circuit line between Dounreay and Spittal at 275kV, a short section of new 132kV line between Spittal and Mybster, new 275/132kV substations at Fyrish (near Alness), Loch Buidhe (to the east of Shin), Spittal (5km north of Mybster) and Thurso.

3.6.2
Boundary B1 – North West SHE Transmission

Figure B1.1
Geographic representation of boundary B1



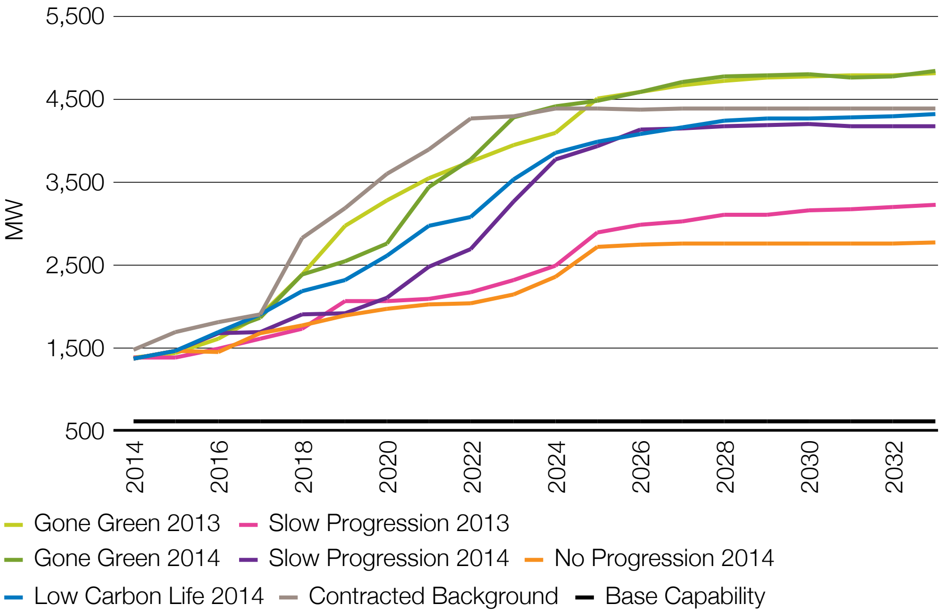
Boundary B1 runs from the Moray coast near Macduff to the west coast near Oban, separating the north-west of Scotland from the southern and eastern regions. The area to the north and west of boundary B1 includes Moray, north Highland, Caithness, Sutherland, Western Isles, Skye, Mull and Orkney. The boundary crosses the 275kV double circuit running eastwards from Beauly, the 275/132kV interface at Keith and the double circuit running south from Fort Augustus.

The existing transmission infrastructure in this area comprises 275 kV and 132 kV assets. Some of the large new generation projects are 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.

In all 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 (see Figure B1.2). Although this is primarily onshore wind and hydro, there is the prospect of significant additional wind, wave and tidal generation resources being connected in the longer term. The contracted generation behind boundary B1 includes the renewable generation on the Western Isles, Orkney and the Shetland Isles as well as a considerable volume of large and small onshore wind developments. A large new pump storage generator is also planned in the Fort Augustus area. Some marine generation is also expected to connect in this region during the ETYS time period. This is supplemented by existing generation, which comprises around 800MW of hydro and 300MW of pumped storage at Foyers.

3.6 continued
Scottish Boundaries

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



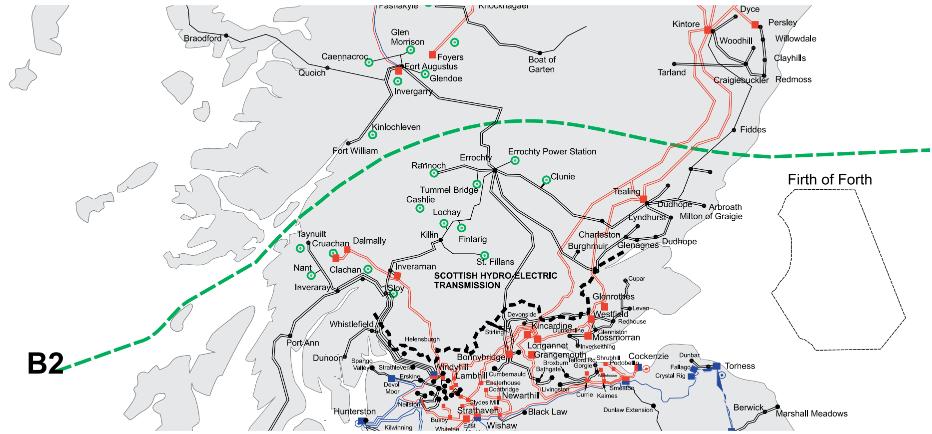
Boundary requirements and capability
Figure B1.2 above shows required boundary transfers for B1 from 2014 to 2034. The boundary capability is currently 0.6GW.

New renewable generation connections north of the boundary are expected to result in a massive increase in export requirements across the boundary (see Figure B1.2). All generation north of boundary B0 also lies behind boundary B1.

Two key reinforcement projects are currently being constructed to allow for the increasing requirement to export power across boundary B1. The Beauly to Denny reinforcement due for completion in 2015 extends from Beauly in the north to Denny in the south, providing additional capability for boundary B1 as well as boundaries B2 and B4. The second project comprises the replacement of conductors on the 275kV line between Beauly, Blackhillock and Kintore and also completes in 2015.

3.6.3
Boundary B2 – North to South SHE Transmission

Figure B2.1
Geographic representation of boundary B2



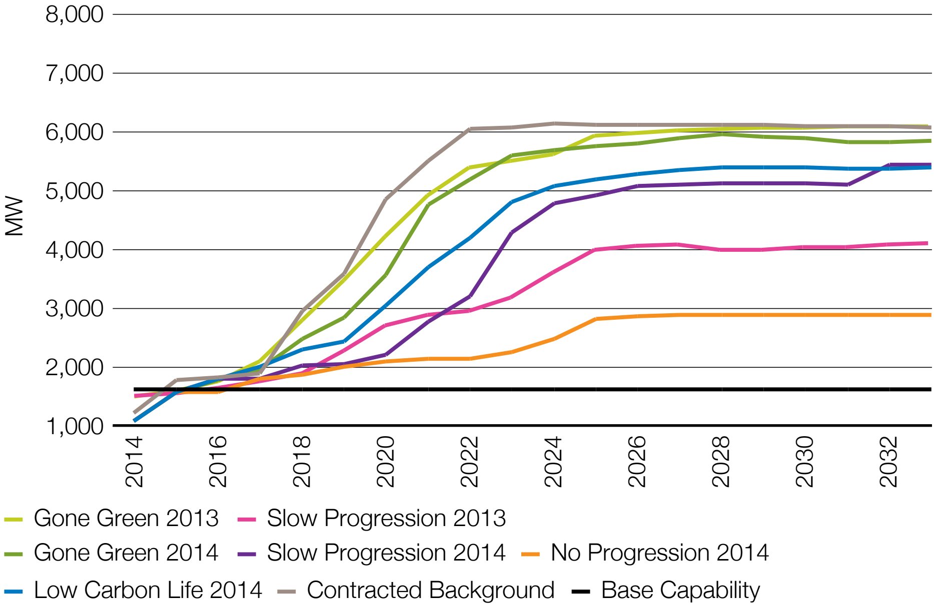
Boundary B2 cuts across the Scottish mainland from the east coast between Aberdeen and Dundee to near Oban on the west coast. The boundary cuts across the two 275 kV double circuits and a 132 kV single circuit in the east as well as the double circuit running southwards from Fort Augustus. As a result it crosses all the main north–south transmission routes from the north of Scotland.

As described in boundary B1, the Beauly–Denny project is a key reinforcement that increases the capability across boundaries B1, B2 and B4. This project is currently under construction and is due for completion in 2015.

The generation behind boundary B2 includes both onshore and offshore wind, with the prospect of significant marine generation resource being connected in the longer term. There is also the potential for additional pumped storage plant to be located in the Fort Augustus area. The thermal generation at Peterhead lies between boundaries B1 and B2, as do several offshore windfarms and the proposed future NorthConnect interconnector with Norway.

3.6 continued
Scottish Boundaries

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



Boundary requirements and capability

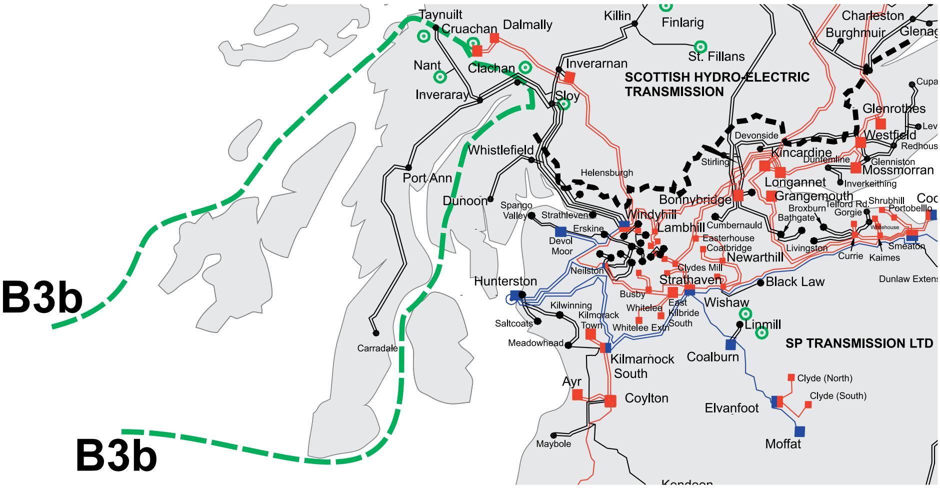
Figure B2.2 above shows required boundary transfers for B2 from 2014 to 2034. The boundary capacity is currently 1.6GW.

The forecast boundary transfers for boundary B2 are increasing at a significant rate because of the high volume of contracted renewable generation seeking connection to the north of the boundary.

The increase in the required transfer capability for this boundary across all generation scenarios indicates the need to reinforce the transmission system. The Beauly to Denny reinforcement, which is due for completion in 2015, provides significant additional network capacity and increases boundary B2's north–south capability.

3.6.4
Boundary B3b – Argyll and Kintyre

Figure B3b.1
Geographic and single-line representation of boundary B3b

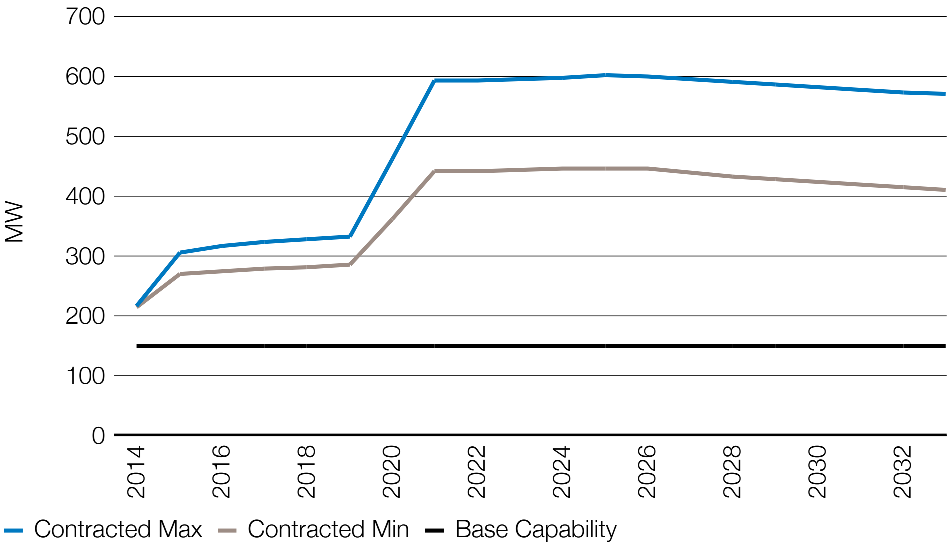


In the Argyll and Kintyre area the 132kV network is relatively weak with a low capacity, so a local boundary assessment is used to show limitations to generation power flow. Boundary B3b encompasses the Argyll and the Kintyre peninsula, cutting across the existing 132kV circuits between Inveraray and Sloy substations.

A key reinforcement is under construction in the Kintyre area, comprising two 220kV AC subsea cables between a new substation at Crossaig (to the north of Carradale) on Kintyre and Hunterston in Ayrshire. A 15km section of existing 132kV double circuit line between Crossaig and Carradale is also being rebuilt.

3.6 continued
Scottish Boundaries

Figure B3b.2
Required transfer and base capability for boundary B3b

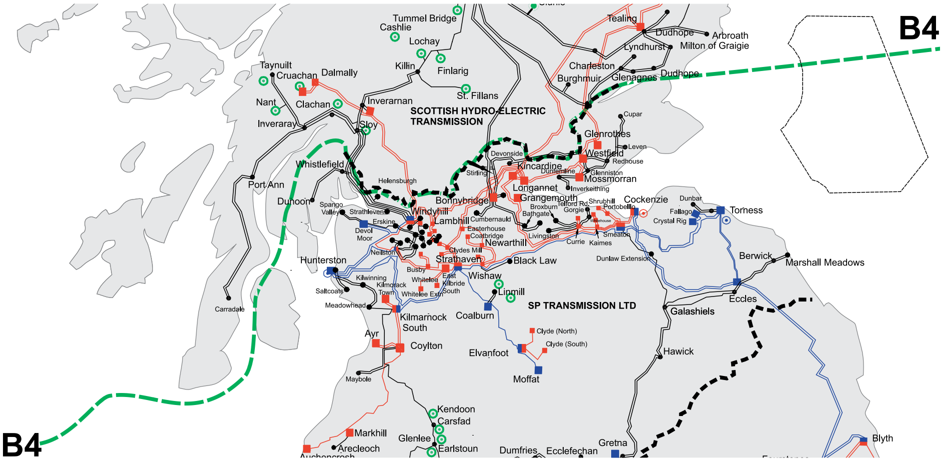


Boundary requirements and capability
Figure B3b.2 above gives the capability of the B3b local boundary and a view of the maximum and minimum transfer requirements from 2014 to 2034. The boundary capability is 0.15GW.

The forecast power transfers across boundary B3b are increasing at a significant rate because of the high volume of connected and contracted renewable generation seeking connection in Argyll and Kintyre. The present boundary capability is around 150MW, rising to around 400MW on completion of the Kintyre–Hunterston link (due in 2015). There is still significant interest and proposed connection activity in the area, and it is likely that further reinforcement of this network will be required in the future.

3.6.5
Boundary B4 – SHE Transmission to SP Transmission

Figure B4.1
Geographic representation of boundary B4



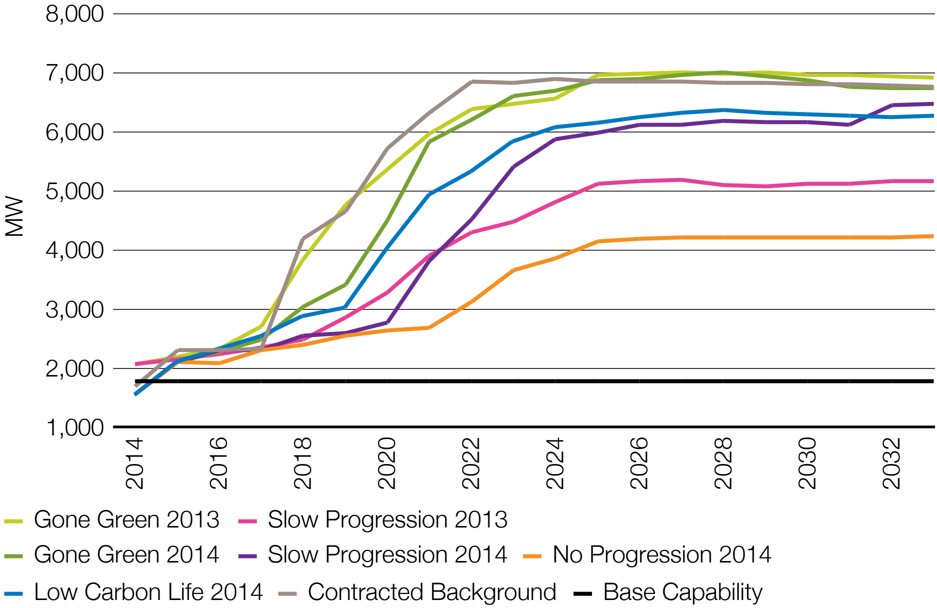
Boundary B4 separates the transmission network at the SP transmission and SHE Transmission interface running from the Firth of Tay in the east to near the head of Loch Long in the west. With increasing generation in the SHE transmission area for all generation scenarios, the required transfer across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

The boundary is crossed by 275 kV double circuits to Kincardine and Westfield in the east; a 132kV double circuit to Bonnybridge, near Denny; and two 132kV double circuits from Sloy to Windyhill in the west. A major reinforcement across boundary B4 is under construction. The Beauly to Denny upgrade involves the replacement of the existing 132kV 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.

The prospective generation behind boundary B4 includes around 2.7GW from rounds 1–3 offshore wind located off the east coast of Scotland.

3.6 continued
Scottish Boundaries

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



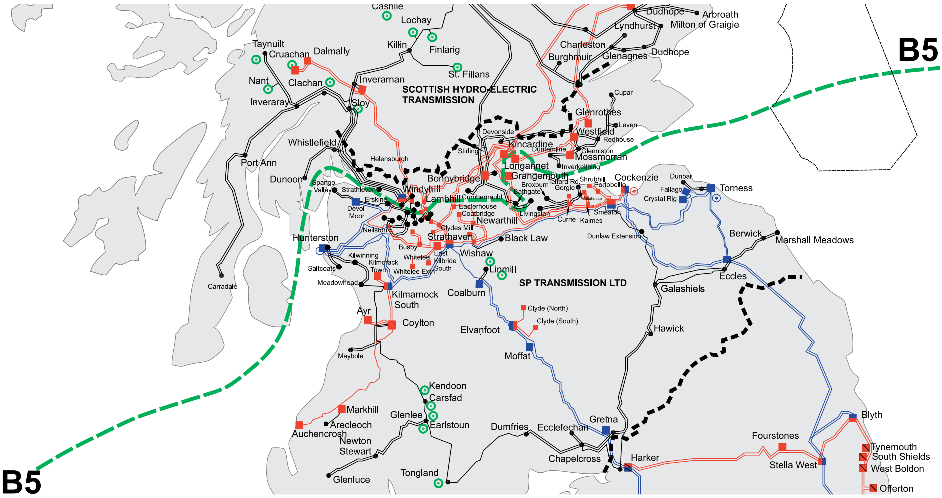
Boundary requirements and capability
Figure B4.2 above shows required boundary transfers for B4 from 2014 to 2034. The boundary capability is currently 1.75GW.

In all of the ETYS generation scenarios, the power transfer through boundary B4 increases because of the significant volumes of generation connecting north of the boundary, including all generation above boundaries B0, B1 and B2. This is primarily onshore and offshore wind generation, with the prospect of significant marine generation resource being connected in the longer term. The contracted generation behind boundary B4 includes around 2.7GW of offshore and 5.2GW of large onshore wind generation.

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

3.6.6
Boundary B5 – North to South SP TRANSMISSION

Figure B5.1
Geographic representation of boundary B5

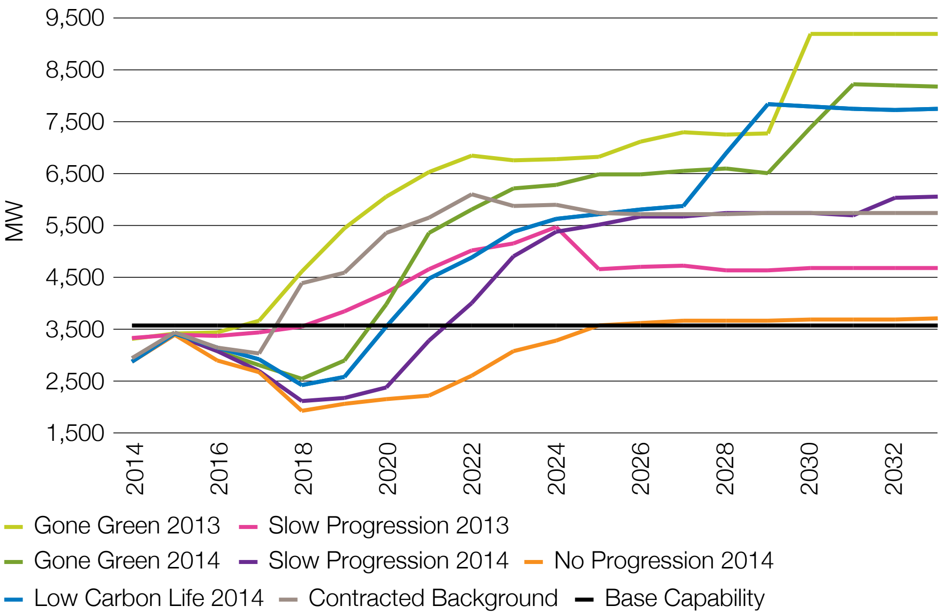


Boundary B5 is internal to the SP Transmission system and runs from the Firth of Clyde in the west to the Firth of Forth in the east. The generating stations at Longannet and Cruachan, together with the demand groups served from Windyhill, Lambhill and Bonnybridge 275kV substations, are located to the north of boundary 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 boundary B5 typically contains excess generation and the predominant direction of power flow across the boundary is from north to south.

3.6 continued
Scottish Boundaries

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



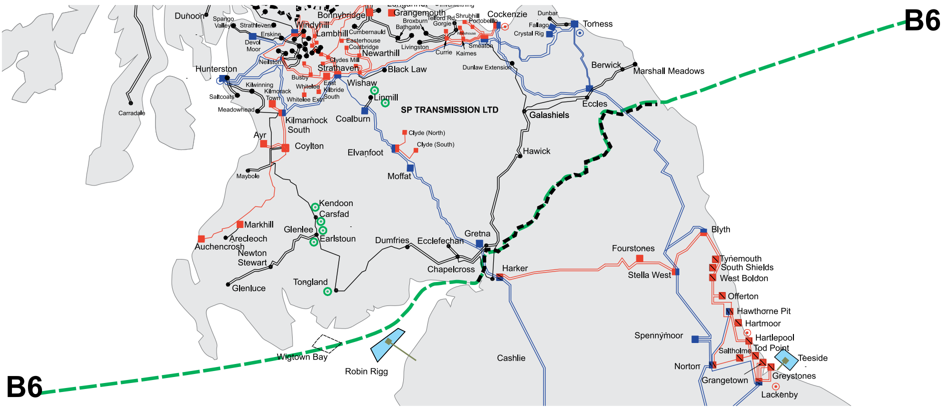
Boundary requirements and capability
Figure B5.2 above shows required boundary transfers for B5 from 2014 to 2034.

In all of the ETYS scenarios (except No Progression), there is an increase in the export requirement across boundary B5 over time. This is because of a large volume of generation connections throughout the north of Scotland, primarily on and offshore wind. This potentially large generation increase is supplemented by marine and CCS projects and is only partially offset, to varying degrees, by closure of ageing plant in earlier years.

The capability of the boundary is presently limited by thermal considerations to around 3.6GW. The boundary capability is required to grow as generation increases to the north of boundary B5.

3.6.7
Boundary B6 – SP Transmission to NGET

Figure B6.1
Geographic representation of boundary B6



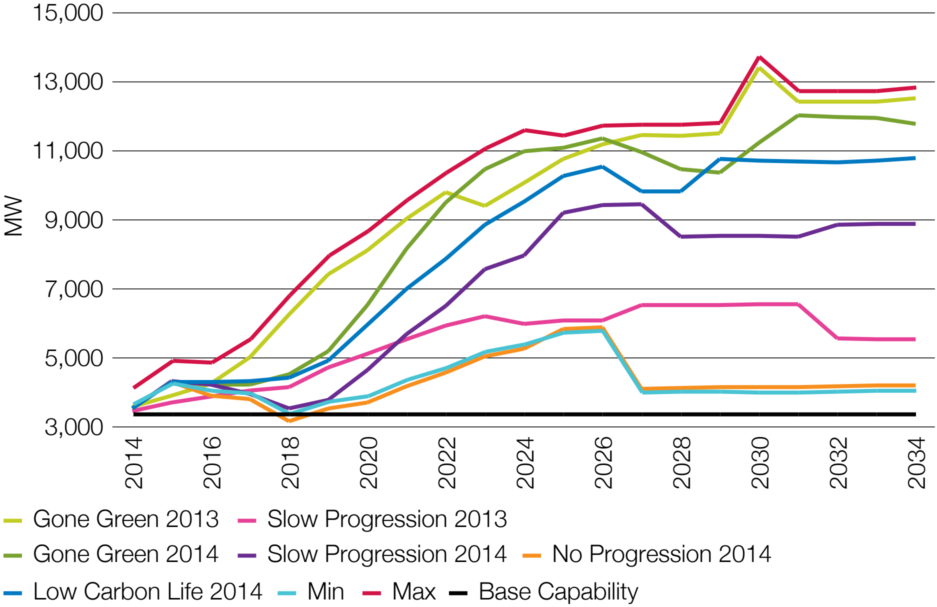
Boundary B6 separates the SP transmission and the National Grid electricity transmission (NGET) systems. The existing transmission network across the boundary primarily consists of two double-circuit 400kV routes. There are also some 132kV circuits across the boundary, which are of limited capacity. The key 400kV routes are from Gretna to Harker and from Eccles to Stella West. Scotland contains an excess of generation, so north–south power flows are considered as the most likely operating condition.

Large thermal and nuclear plants in Scotland still play a vital role in managing security of supply issues across Scotland. To secure the peak demand in Scotland at times of low wind generation output, approximately 3GW of generation will be required in Scotland. This generation could be provided by a variety of sites such as Torness, Hunterston, various pump storage and hydro schemes, Longannet and Peterhead. After the Western HVDC link is completed in 2016, this generation requirement is expected to fall to approximately 1.5GW.

Small embedded generation within Scotland can make a significant change to the boundary requirements. There is more than 2000MW of small embedded wind generation capacity that could be installed by 2030 – this could increase the required boundary capability for B6 by up to 1400MW (see section 2.4 for definitions of small embedded generation).

3.6 continued
Scottish Boundaries

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



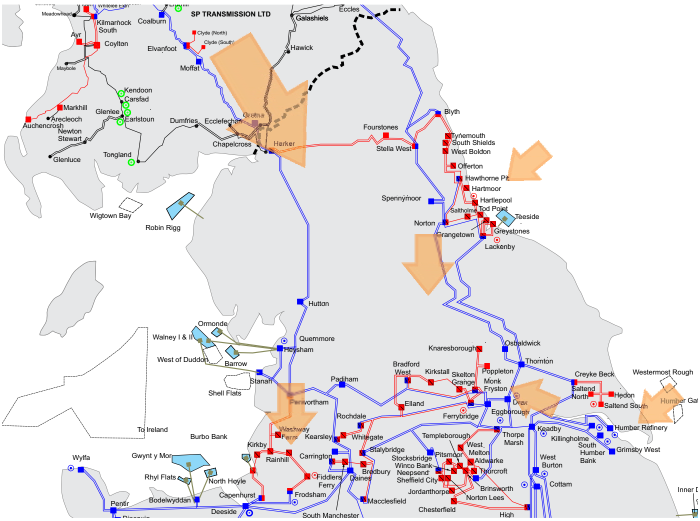
Boundary requirements and capability
Figure B6.2 above shows required transfers for boundary B6 from 2014 to 2034. The capability of boundary B6 is currently a stability limit at around 3.3GW but will increase to around 4.4GW when the series compensation and Torness–Eccles cable upgrade schemes are completed.

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 ageing coal, gas and nuclear plants, the timing of which varies in each scenario. The requirement for very large transfers (above 5GW) is delayed until 2019 in all scenarios.

3.7 Northern Boundaries

Introduction

The following section describes the transmission network between Scotland and the north Midlands. Upper North includes boundaries B7, B7a, B11, B16 and, enclosing the Humber region, boundary EC1.



3.7 continued
Northern Boundaries

Primary challenge statement:
Rapidly growing north to south power flows, greatly exceeding existing system capability, driven by renewable generation connections.

The restrictions of the northern boundaries are often caused by the rapidly increasing generation connected to Scotland, Humber and North East England. The need to transport this generation from Scotland through north England to the demand centre located further south provides the network development drivers for this region.

Regional drivers
The forecast increase in generation from Scotland and East Coast will see:

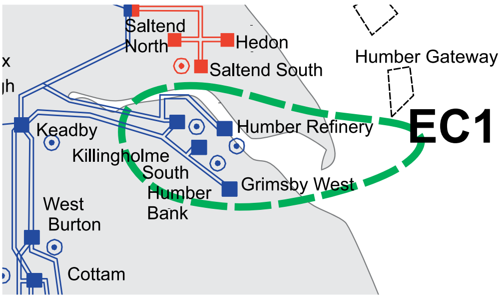
- Limitation on power transfer from Scotland to England (boundaries B7, B11, B16)
  - The restriction of boundary B6 also limits the capability of the downstream boundaries B7, B11 and B16. Boundary B6 is currently limited by low voltage compliance and system stability at 3.3GW. With the vast amount of renewables that will potentially connect in Scotland over the next 10 years, there is a driver to increase the transfer capability across the Scotland to England boundaries
  - The network in Scotland is connected to England via two sets of 400kV double circuits: Harker–Elvanfoot/Gretna and Stella West–Eccles, which are overhead line routes each over 100km long. There are also some smaller 132kV circuits with limited capacity. There are high reactive power losses due to the long routes having high impedance. As the power flow increases, the reactive power loss in the circuits also increases. So at a high transfer level, if the losses are not compensated they will eventually lead to voltage depression at the receiving end – which in this case is the English side of the circuits
  - A stability issue arises when a fault appears on one of the two double-circuit routes, because the Scottish system may be left with only one double-circuits connection to the English system. This significantly increases the impedance in the connection between the two systems and exposes the system to instability at high transfer levels
  - Previous analysis has led to the construction of the Anglo-Scottish compensation. If the works continue and are commissioned in 2015, the voltage and stability capability of boundary B6 will be improved because it will be limited at 4.4GW by thermal restriction. As generation continues to connect in Scotland, the increasing transfer will reach this thermal restriction in the next couple of years
  - So there is a driver to develop the network in order to maintain the voltage at the receiving end on the English side at compliance level, and to increase the thermal capability of the circuits connecting Scotland and England to cope with the forecasted increase in generation connecting in Scotland.
- Limitation on power transfer out of North East England (boundary B7)
  - Once the power flows through the Scottish to English boundaries, on the east side it enters the network in North-East England and continues to flow south via two sets of 400kV double circuits – Norton–Osbaldwick–Thornton and Lackenby–Thornton. As the generation forecast to connect to North East England increases, adding to the flow through generation from Scotland, the circuits exporting power to the south will be increasingly stressed and will eventually reach their thermal limit
  - This means there is a driver to develop the network to increase the thermal capability of the circuits exporting power from North East England to the south of the country.

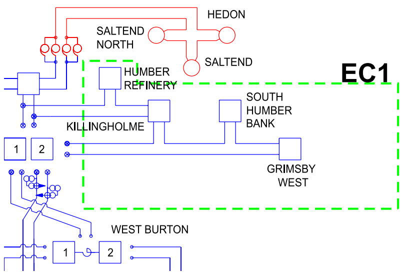
- Limitation on power transfer from Cumbria to Lancashire (boundary B7a)
  – On the west side of the network, south of the Scotland to England boundaries, power flows from North Midlands to West Midlands via two branches of circuits: a 400kV branch of Penwortham–Padiham/Daines and a 275kV branch of Penwortham–Kirkby to Deeside. As the power flow increases in the future, the two branches will be stressed to their thermal limit; in particular the 275kV branch may require an upgrade to operate at higher voltage level so that its thermal capability can be increased
  – So there is a driver to develop the network in order to increase the thermal capability of the circuits exporting power from North Midlands to the south of the country
  – Limitation on power transfer out of Humber (EC1)
  – There is currently around 4GW of generation connected to the network in Humber. This large group of generation is exported out of Humber via two sets of 400kV double circuits: Keadby–Killingholme/Grimsby West and Keadby/Creyke Beck–Humber Refinery/Killingholme. Further increases in generation in Humber will place additional stress on the thermal capability of these exporting circuits
  – So there is a driver to develop the network in order to increase the thermal capability of the circuits exporting power out of Humber.

3.7 continued
Northern Boundaries

3.7.1
Boundary EC1 – Humber

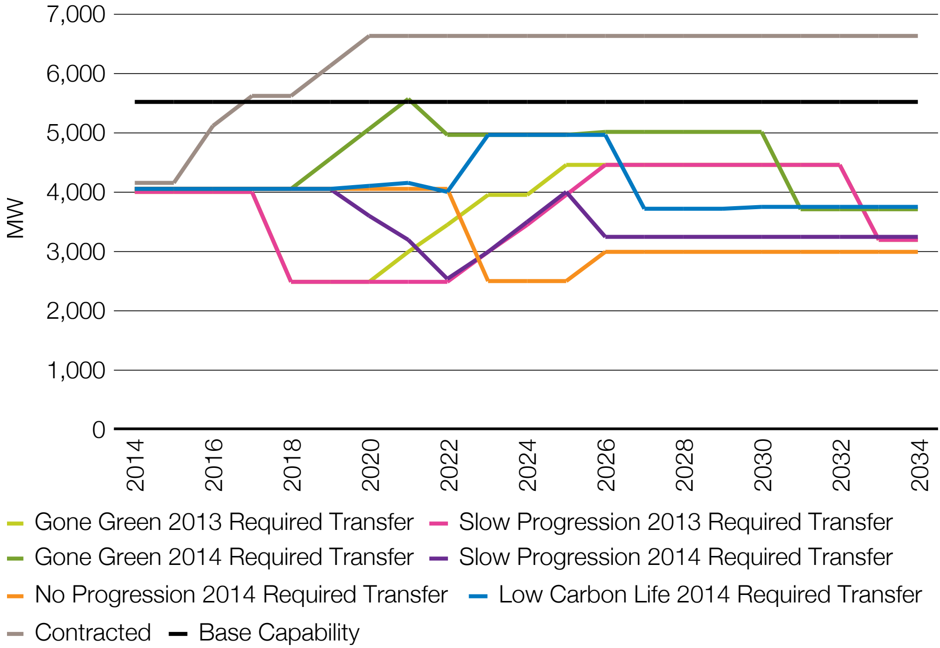
Figure EC1.1
Geographic and single-line representation of boundary EC1





Boundary EC1 is an enclosed local boundary consisting of four 400kV circuits that export power to the Keadby substation. Killingholme is the only substation within the boundary that is connected by more than two transmission circuits.

Figure EC1.2
Boundary export and base capability for boundary EC1



Boundary requirements and capability

Figure EC1.2 above shows required transfers for boundary EC1 from 2014 to 2034. The boundary capability is currently a voltage compliance and thermal limit at 5.65GW for a double circuit fault on the Creyke Beck–Keadby–Killingholme and Creyke Beck–Keadby–Humber Refinery overloading the Keadby–Killingholme circuit.

The region is a congested area of the transmission system, with 4GW of Combined Cycle Gas Turbine (CCGT) generation connected. Our scenarios consider the potential for new offshore wind farm connections, as well as closures across the existing conventional plant.

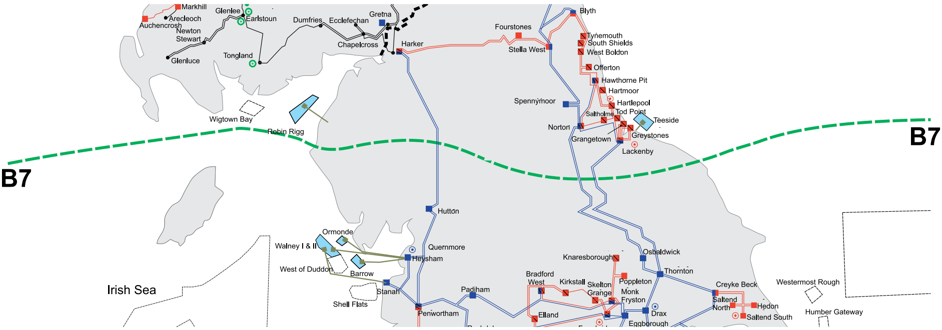
The Slow Progression and No Progression scenarios show a reduced required transfer after 2020, compared to the current level. This is because of the closure of existing conventional plant combined with a lack of offshore renewable connection. The Gone Green and Low Carbon Life scenarios initially show an increased required transfer after 2020 as renewable offshore generation connects. However, this is offset in later years with the closure of conventional plant.

Potential reinforcement within the region includes constructing a new substation at Killingholme South and a new double-circuit overhead line out of the region (to West Burton).

3.7 continued
Northern Boundaries

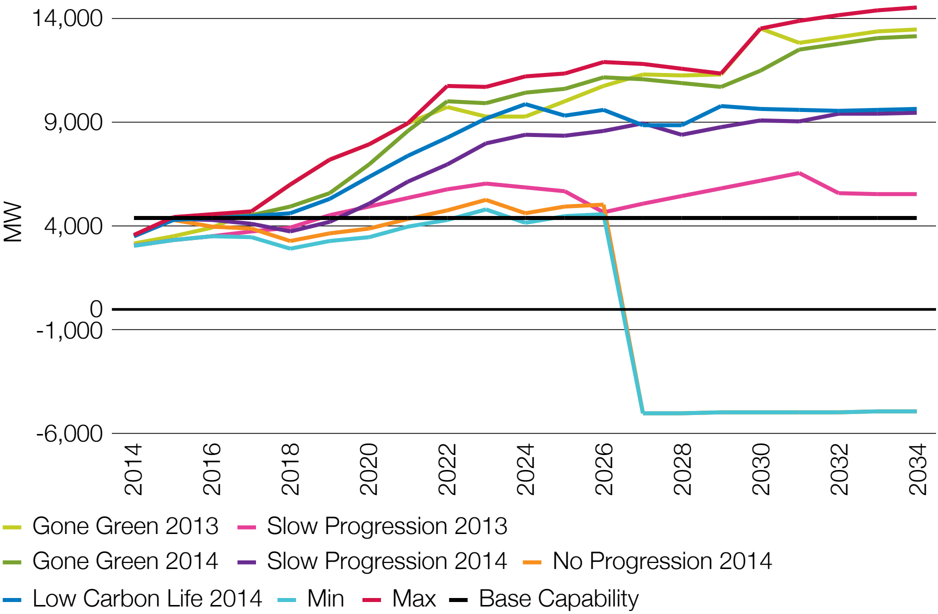
3.7.7
Boundary B7 – Upper North

Figure B7.1
Geographic 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 boundaries B6 and B7 used to have a surplus of generation so exported power – when added to the exported power from Scotland, this was putting significant requirements on boundary B7. However, since Teesside generation has closed, the surplus in the area between boundaries B6 and B7 has disappeared. Although boundary B7's requirement has reduced, it is still exposed to large Scottish exports. In the future large amounts of onshore and offshore wind will be connecting north of this boundary, increasing the transfer requirements.

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



Boundary requirements and capability

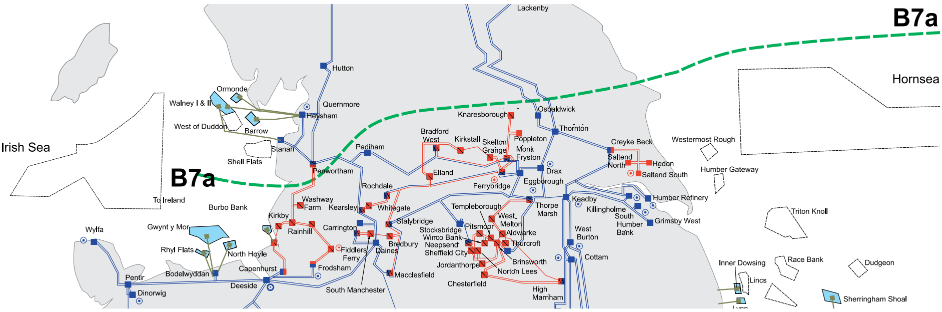
Figure B7.2 above shows the required transfers for boundary B7 from 2014 to 2034. The boundary capability is currently a voltage compliance at 4.4GW for a double circuit fault on the Heysham–Hutton–Penwortham circuits causing low volts at Stella West 400kV. When the series and shunt compensation and the Western HVDC link are introduced by 2016 the boundary capability increases significantly to 7.4GW.

As with 2013 scenarios, three scenarios are experiencing an increase of capability requirements due to the increase of generation north of boundary B7. Although ageing coal, gas and nuclear plants are closing north of the boundary across these three scenarios, this is offset by the vast amount of onshore and offshore wind. The only scenario not showing a similar trend is No Progression – this is mainly due to the lack of new offshore and onshore wind connections after 2019. The Gone Green and Low Carbon Life scenarios show that the requirement for transfers above 5GW is delayed until 2019 (and until 2020 for Slow Progression). However, this trend does not apply to the No Progression scenario.

3.7 continued
Northern Boundaries

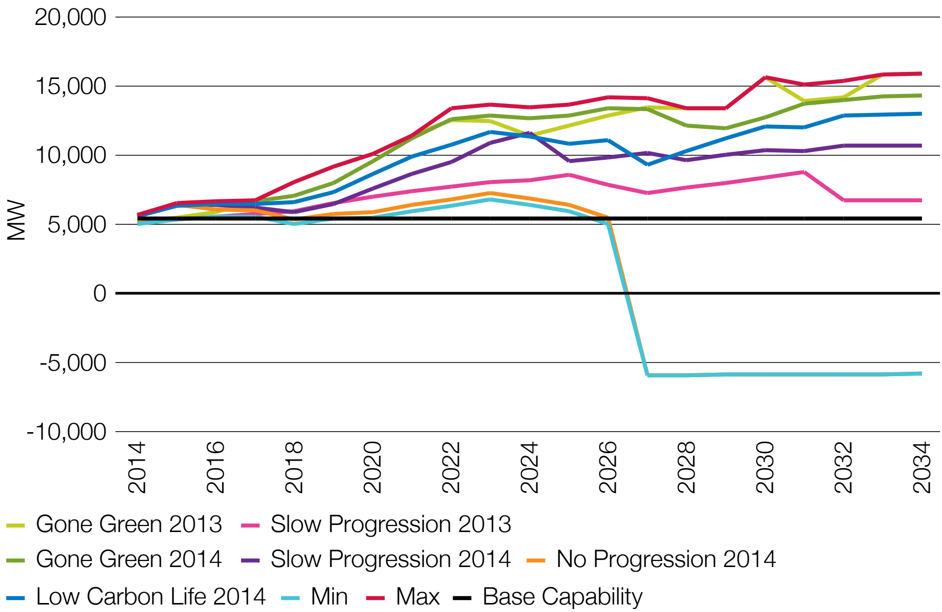
3.7.7a
Boundary B7a – Upper North

Figure B7a.1
Geographic representation of boundary B7a



Boundary B7a bisects England south of Teesside and into the Mersey Ring area. It is characterised by three 400kV double circuits (two in the east, one in the west) and one 275kV circuit. Between boundaries B6 and B7a was traditionally an exporting area with a surplus of generation – when added to the exported power from Scotland this puts significant requirements on boundary B7a. With the closure of generation at Teesside the surplus of generation in the area between boundaries B6 and B7a has disappeared. Boundary B7a's requirement is reduced but is still exposed to large Scottish exports. In the future large amounts of onshore and offshore wind will be connecting north of this boundary, increasing the transfer requirements.

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



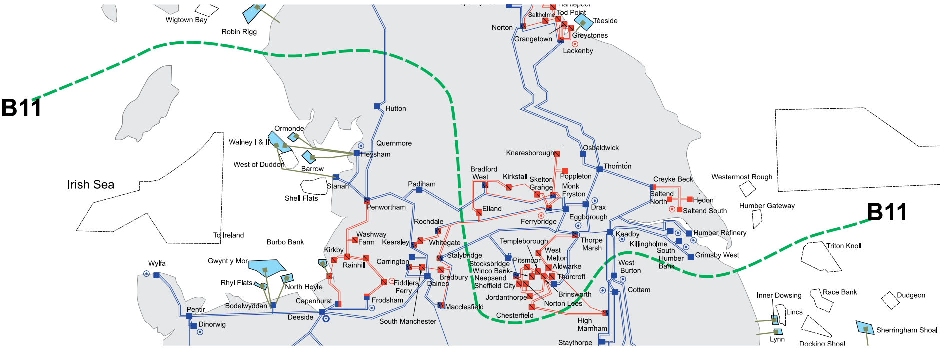
Boundary requirements and capability
Figure B7a.2 above shows the required transfers for boundary B7a from 2014 to 2034. The boundary capability is currently a thermal limit at 5.3GW for a double circuit fault on the Padiham–Penwortham and Daines–Carrington–Penwortham circuits overloading one of the Kirby to Lister Drive circuits. The introduction of the Western HVDC link will increase the boundary limit to around 8.7GW (a thermal limit for a fault on the Western HVDC link and the Penwortham–Carrington circuit overloading the Padiham–Penwortham circuit).

Across all scenarios the required transfer remains fairly static until 2018 when there is a rapid increase in the Gone Green, Low Carbon Life and Slow Progression scenarios. The increase in the No Progression scenario is less pronounced. The rapid increase results from a number of new onshore and offshore wind farm connections in England and Scotland (there are fewer of these in the No Progression scenario).

3.7 continued
Northern Boundaries

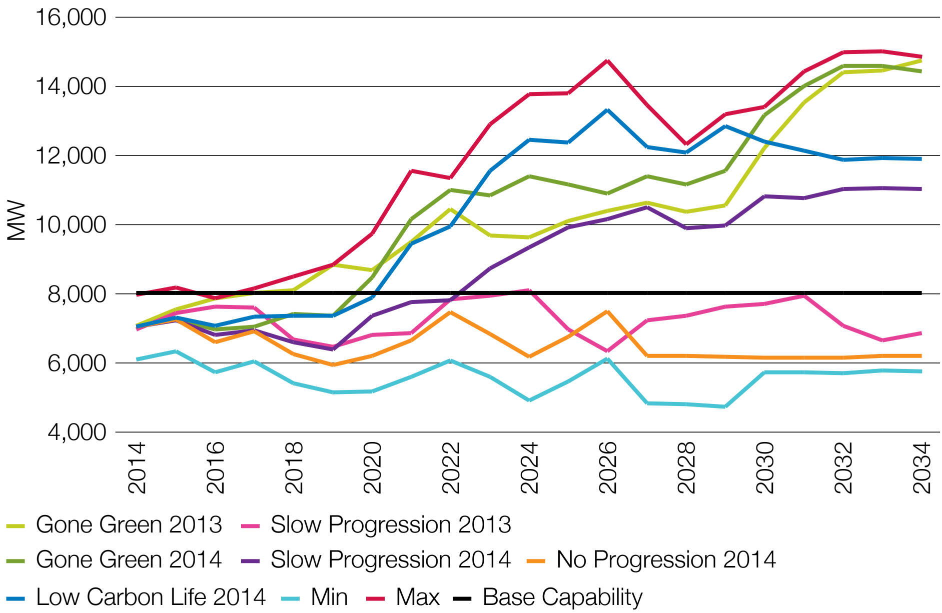
3.7.11
Boundary B11 – North East and Yorkshire

Figure B11.1
Geographic representation 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. This boundary is significant to the NETS system because along with boundary B7 it allows us to focus on east-west flows and the effects of generation in the Aire Valley and Humber areas.

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



Boundary requirements and capability

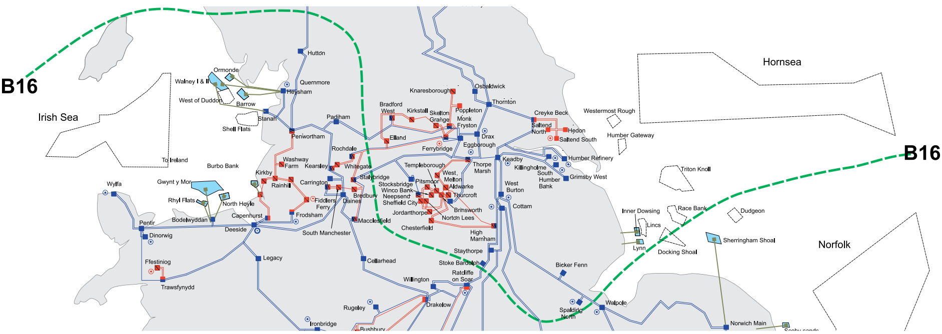
Figure B11.2 above shows the required transfers for boundary B11 from 2014 to 2034. The boundary capability is currently 8GW.

The Slow Progression scenario does not show any significant increase in boundary requirements but the Gone Green scenario suggests increasing requirements beyond 2018. The drive behind this is increasing generation north of the boundary, mostly from renewables.

3.7 continued
Northern Boundaries

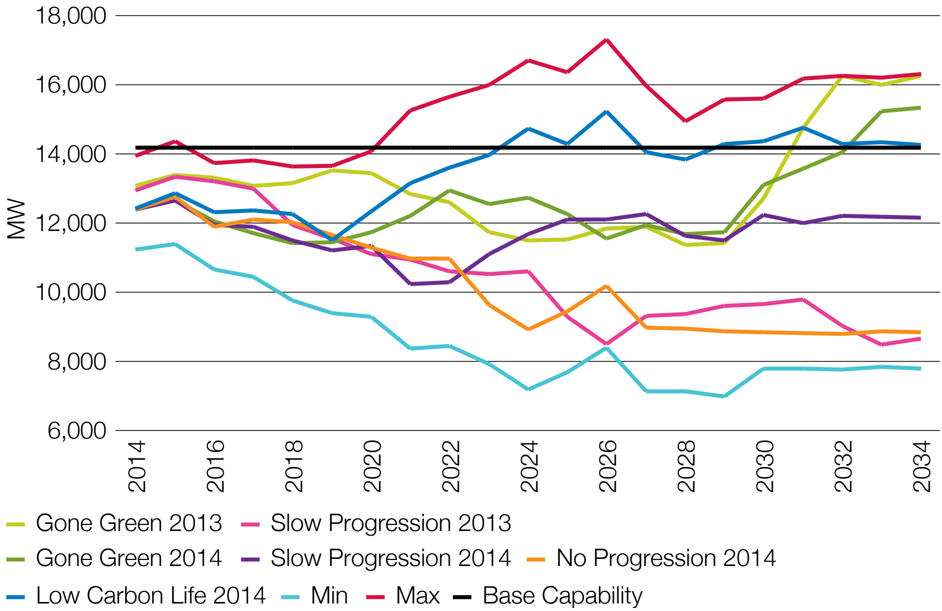
3.7.16
Boundary B16 – North East, Trent and Yorkshire

Figure B16.1
Geographic and single-line representation of boundary B16



Boundary B16 follows the same path of boundary B11 in the west. In the east it also encompasses the areas of Nottinghamshire and Lincolnshire, so incorporates additional generation from these regions. It crosses the four double circuits running south from Nottinghamshire (West Burton/Cottam), instead of the two circuit pairs south of Keadby. Like boundary B11, boundary B16 is considered to carry power from north to south.

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



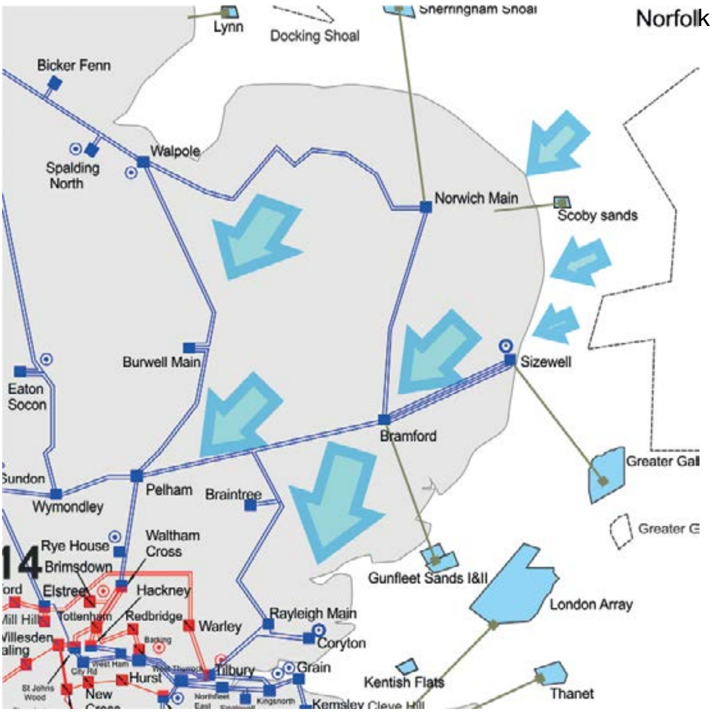
Boundary requirements and capability
Figure B16.2 above shows the required transfers for boundary B16 from 2014 to 2034. The boundary capability is currently 14.2GW.

The required transfer starts to decrease as conventional thermal generation closes or reduces output. All of the prospective new nuclear generation lies to the south of boundary B16. Given its benign nature over the next few years and the fact that we do not generally see east–west flows, we have not studied boundary B16 in detail for this year's ETYS. The key issues are covered in the sections concerning boundaries B6 to B9.

3.8 Eastern Boundaries

Introduction

The East England region includes the counties of Norfolk and Suffolk. The transmission boundaries EC3 and EC5 cover the transmission network in the area. Both boundaries are considered local, based on the generation and demand currently connected.



Primary challenge statement:
With a large amount of generation to be connected, mainly offshore wind and nuclear, which exceeds local demand significantly so will cause heavy circuit loading and voltage depressions.

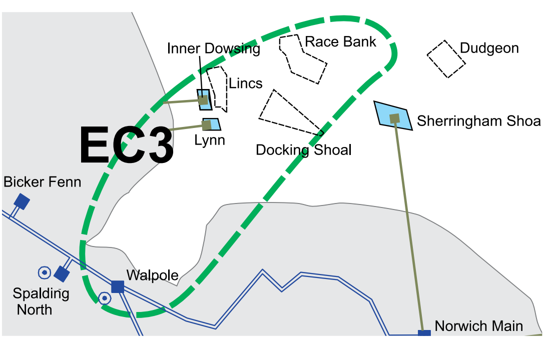
Regional drivers
The forecast increase in generation within East Anglia will see:

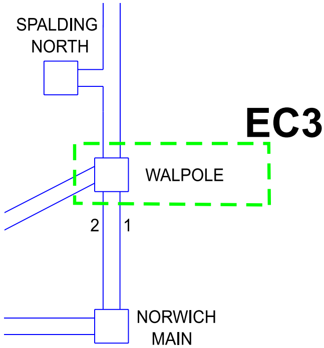
- Limitation from East Anglia to Greater London and South East England (boundaries EC3 and EC5)
  – The East England region is connected by several sets of long 400kV double circuits, including Bramford–Pelham/Braintree, Walpole–Spalding North/Bicker Fen and Walpole–Burwell Main. When a fault happens on one set of these circuits, some of the power has to flow a long distance to reach the rest of the network and continue to flow into Greater London and South East England
  – As the power flow increases because of new generation connection in East Anglia, the reactive power loss in these high impedance routes also increases. So at a high transfer level, if the losses are not compensated they will eventually lead to voltage depression at the receiving end of the routes
  – Stability becomes an additional concern when some of the large generators connect, further increasing the size of the generation group in the area. Losing a set of double circuits when a fault happens will lead to significant increases in the impedance of the connection between this large generation group and the remainder of the system. As a result, the system may be exposed to risk of instability as transfer increases
  – It is also important to ensure that all the transmission route in the area will have sufficient thermal capacity to cope with the export requirement under post-fault condition.

So there is a driver to develop the network in the East England region, in order to ensure that it has sufficient capability to export the power safely and securely to the rest of the system.

3.8.EC3
Boundary EC3 – Wash

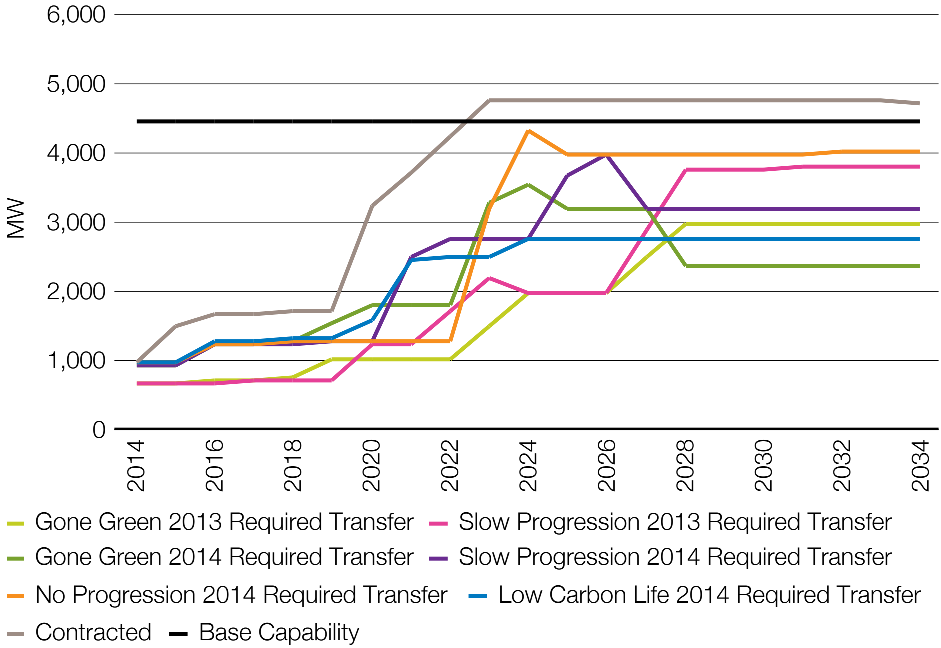
Figure EC3.1
Geographic and single-line representation of boundary EC3





Boundary EC3 is a local boundary surrounding the Walpole substation. It includes six 400kV circuits out of Walpole; two single circuits (Walpole–Bicker Fen and Walpole–Spalding North); and two double circuits (Walpole–Norwich and Walpole–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.

Figure EC3.2
Boundary export and base capability for boundary EC3



Boundary requirements and capability
Figure EC3.2 above shows the required transfers for boundary EC3 from 2014 to 2034. The boundary capability is currently a thermal limit at 4.5GW for a double circuit fault on the Burwell–Walpole circuits overloading a Bramford–Norwich main circuit.

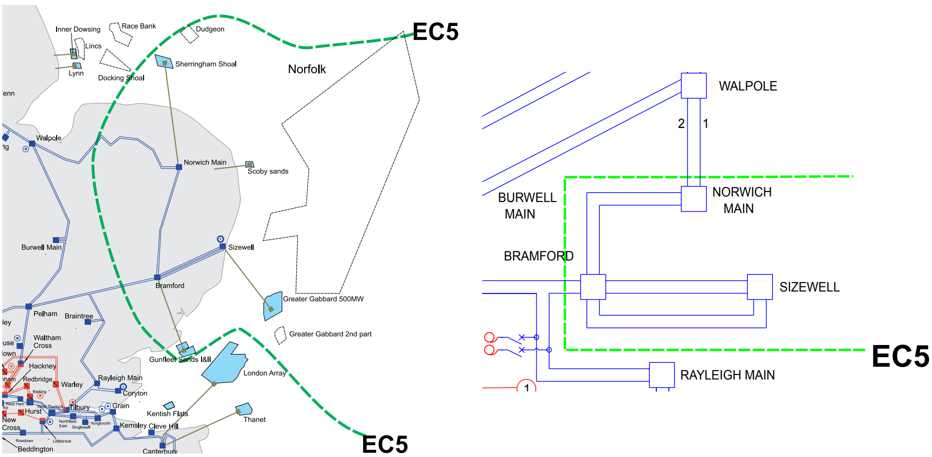
The plots show that the export requirements of the boundary increase across all scenarios but that the present capability should be sufficient for at least the next few years.

In the last 12 months two reinforcements have been completed in the East Anglia area: Bramford substation work and Norwich–Walpole. Both reinforcements added 1650MW to the boundary.

3.8 continued
Eastern Boundaries

3.8.EC5
Boundary EC5 – East Anglia

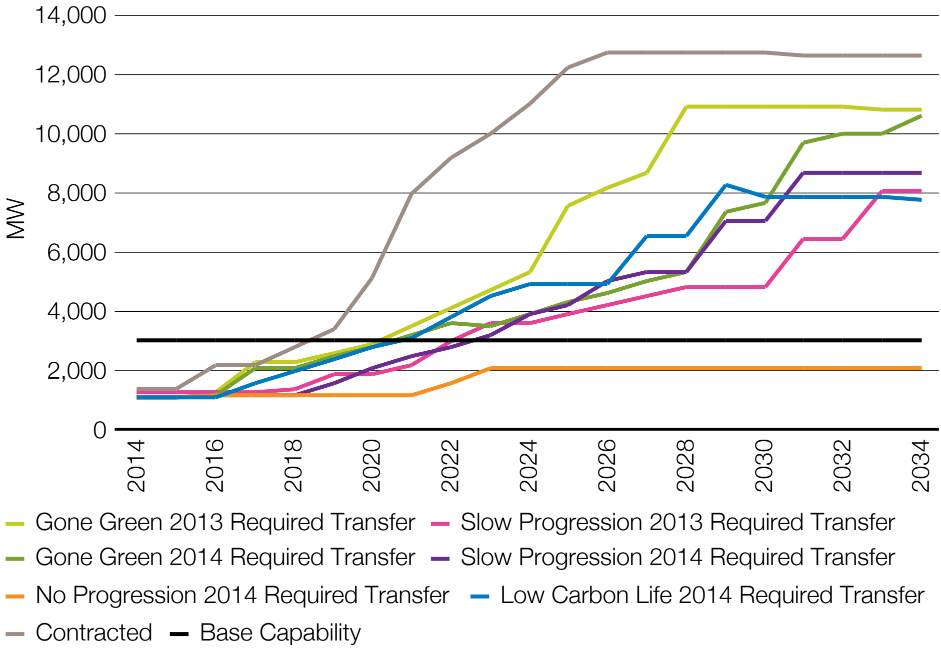
Figure EC5.1
Geographic and single-line representation of boundary EC5



Boundary EC5 is a local boundary enclosing most of East Anglia with 400kV substations at Norwich, Sizewell and Bramford. It crosses four 400kV circuits that mainly export power towards London.

The coastline and waters around East Anglia are attractive for the connection of offshore wind projects including the large East Anglia Round 3 offshore zone that lies directly to the east. The existing nuclear generation site at Sizewell is one of the approved sites selected for new nuclear generation development.

Figure EC5.2
Boundary export and base capability for boundary EC5



Boundary requirements and capability
Figure EC5.2 above shows the required transfers for boundary EC5 from 2014 to 2034. The boundary capability is currently a thermal limit at 3.4GW for a double circuit fault on the Bramford–Pelham and Bramford–Braintree–Rayleigh Main circuits overloading a Bramford–Norwich Main circuit.

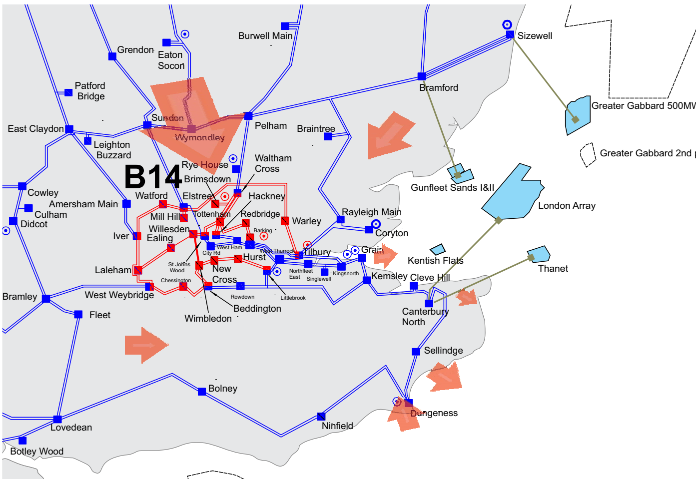
The growth in offshore wind and nuclear generation capacities connecting behind this boundary greatly increase the transfer capability requirements. This is particularly prominent with the contracted background.

In the last 12 months two reinforcements have been completed in the East Anglia area: Bramford substation and Norwich–Walpole. Both reinforcements added 600MW to the boundary.

3.9 South-eastern Boundaries

Introduction

The South East region has a high concentration of power demand and generation, with much of the demand found in London and generation in the Thames Estuary. Interconnection to central Europe occurs along the south-east coast and influences power flows in the region by being able to import and export power with Europe. The South East region includes boundaries B14, B14E, SC1 and B15.



Primary challenge statement:
High demand in London and possible coincidental interconnector exports drive power through north London and the Thames Estuary, causing heavy circuit loading and voltage depressions.

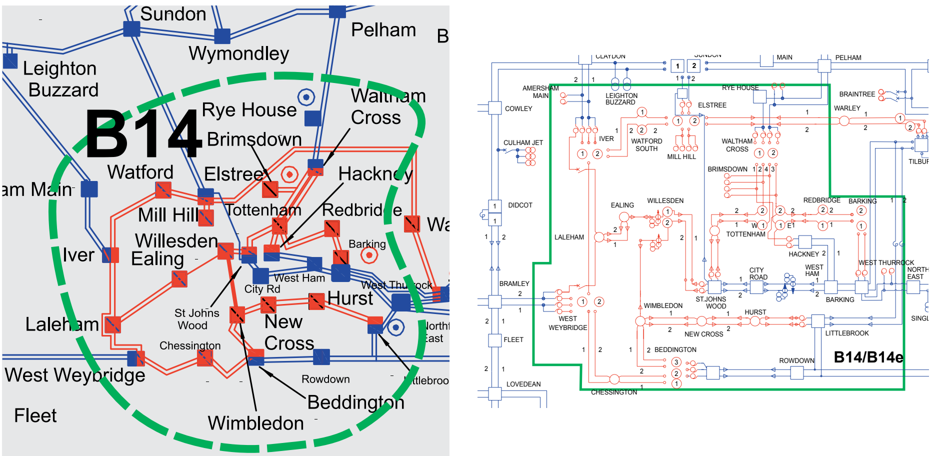
Regional drivers
As generation increases in the north of the country, and the interconnectors in the South East region are put onto export operation, the region's network will see:

- Limitation from the Midlands into South England (boundaries B14, B14e and B15)
  – High demand in London traditionally drives the heavy north to south flows through the GB network. This has always put the transmission routes connecting the Midlands and South England on heavy loading conditions during the GB system peak
  – With more interconnectors over the next 10 years, an increased draw of power is seen through the major Midlands to South routes and through London when the interconnectors export
  – This will put these major transmission route and the circuits connecting the Greater London area close to the thermal capacity limits
  – Most transmission networks within Greater London are currently operating at 275kV. As the power that flows through London to the interconnector connection points in the south coast continues to increase, the network will have to be developed in order to improve the use of existing transmission capacity or to create new capacity within the area
- Limitation in the South Coast (SC1)
  – The South Coast is connected to the rest of the system by only one set of 400kV double circuits of over 200km long stretching from Kemsley to Lovedean. In the next 10 years the capacity of interconnectors connecting along this transmission route is forecast to reach 4GW, with a further 1GW capacity connecting near Grain
  – If a fault happens on one end of this transmission route, power will be forced to flow a very long distance to reach the interconnector connection points. Combining the South Coast's high demand with these interconnector exports drives a high power flow through this route – the only one in post-fault condition
  – At a high transfer level, if the losses in these long circuits with high impedance are not compensated, they will eventually lead to voltage depression along the route
  – As the amount of interconnector capacity increases over time, it is important to ensure that the thermal capability of the transmission route is high enough to sustain the growth in requirement
  – So there is a driver to develop the network in order to maintain the voltage in the South Coast at compliance level, and to increase the thermal capability of the circuits connecting the region so that they can cope with the forecasted increase in interconnectors.

3.9 continued
South-eastern Boundaries

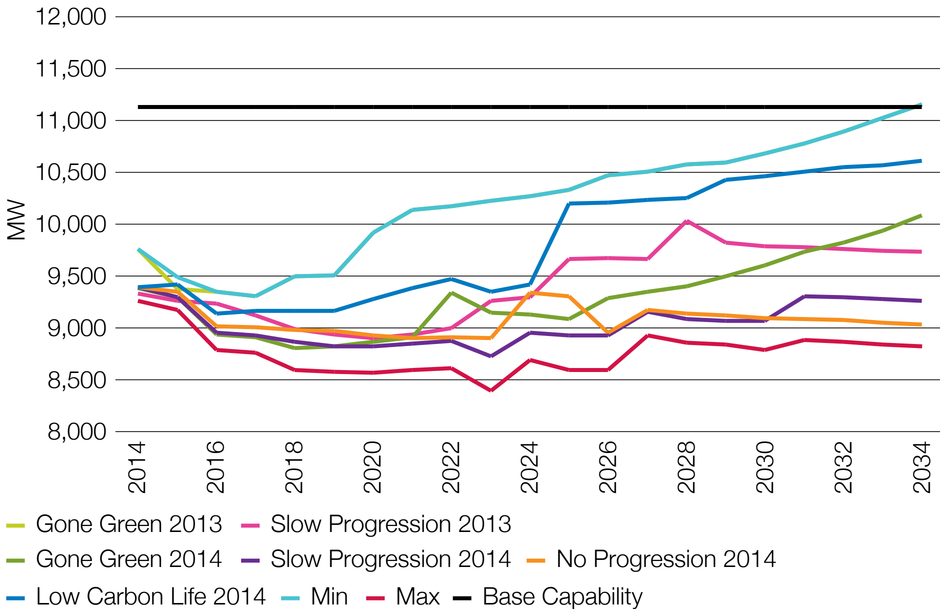
3.9.14
Boundary B14 – London

Figure B14.1
Geographic and single-line representation of boundary B14



Boundary B14 encloses London and is characterised by high local demand and a small amount of generation. London's energy import relies heavily on surrounding 400kV and 275kV circuits. The circuits entering from the north can be particularly heavily loaded at 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 as power is down through London north to south.

Figure B14.2
Required transfer and base capability for boundary B14



Boundary requirements and capability

Figure B14.2 above shows the required transfers for boundary B14 from 2014 to 2034. The boundary capability is currently a voltage collapse limit at 11.4GW for a double circuit fault on the Elstree–Sundon circuits.

As this transfer is mostly dictated by the contained demand, the future requirements mostly follow the demand in the scenarios with little deviation due to generation changes.

The Slow Progression scenario shows a lower boundary requirement than the Gone Green scenario as the few conventional-type generators within the boundary are expected to continue operation in that scenario.

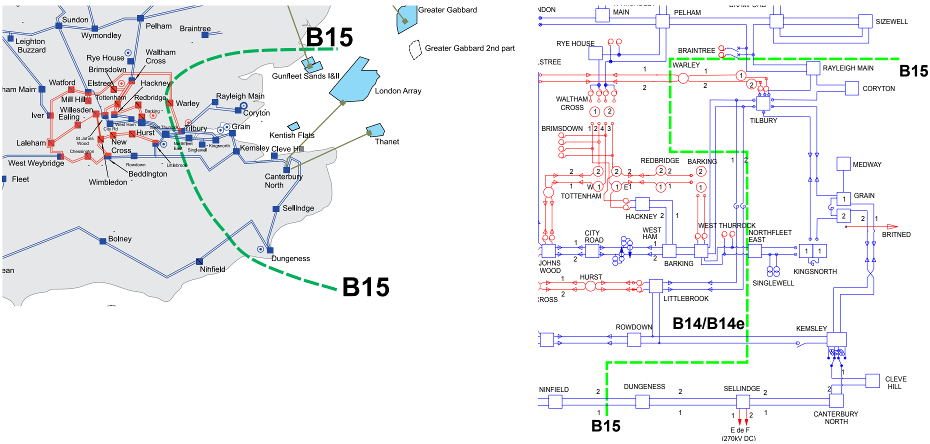
The capability of boundary B14 can depend on power flows cutting across London to the Thames Estuary and south Kent. To account for this a second capability has been produced and analysed with the European interconnectors set to export from GB. This cross-London power flow to feed the export does not increase the planned transfer within B14, but removes support for London demand from the Thames Estuary area and puts additional stress on the north London circuits. The interconnectors are set to export from 3GW to 5GW.

This year's capability has increased as a result of the local reactive demand within London falling, thereby alleviating a previous voltage constraint.

3.9 continued
South-eastern Boundaries

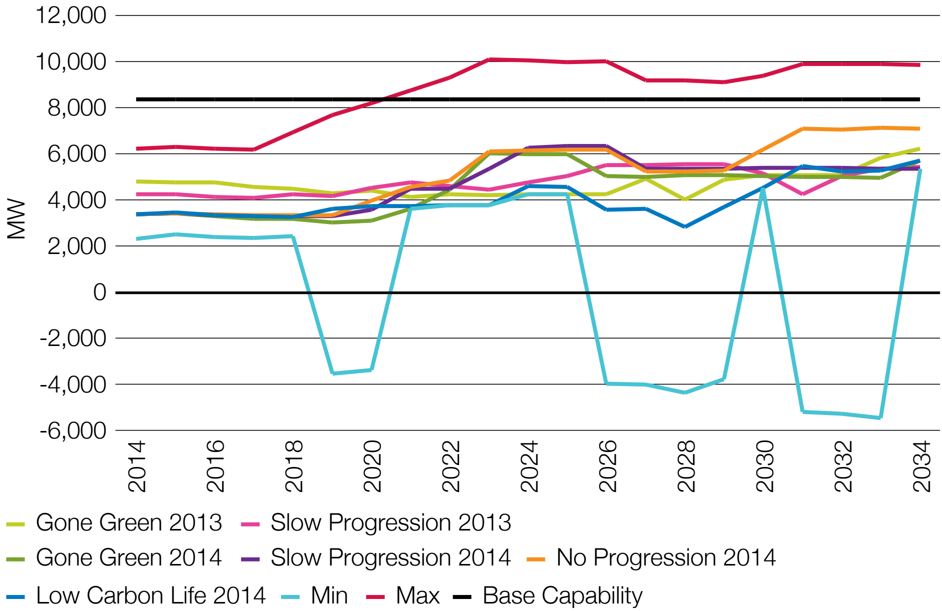
3.9.15
Boundary B15 – Thames Estuary

Figure B15.1
Geographic and single-line representation of boundary B15



Boundary B15 is the Thames Estuary boundary, enclosing the south-east corner of England. It has significant thermal generation capacity and some large offshore wind farms to the east. With its large generation base the boundary normally exports power out to London. With large interconnectors at Sellindge and Grain connecting to France and the Netherlands, boundary B15's power flow is greatly influenced by their power flows. With agreements in place for new interconnectors to France and Belgium within boundary B15, the boundary power flows will become dominated by the interconnector activity.

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



Boundary requirements and capability

Figure B15.2 above shows the required transfers for boundary B15 from 2014 to 2034. The boundary capability is currently a voltage collapse limit at 8.4GW for a double circuit fault on the Canterbury North–Kemsley and Cleve Hill–Kemsley circuits.

The large differences from the core scenarios to the minimum and maximum requirements result from the sensitivities of interconnectors importing and exporting.

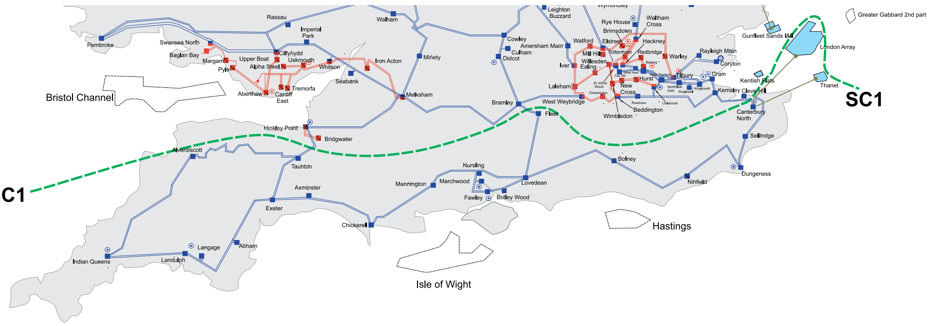
The interconnectors are at float position in the Slow Progression and Gone Green scenarios. This leads to the boundary exporting. The planned transfers across this boundary are fairly constant between the Gone Green and Slow Progression scenarios 2014, and begin to deviate post-2020 as assumptions on gas plants and timings are reflected.

The boundary capability is primarily for interconnector importing. With sensitivities for the interconnectors exporting to Europe, the boundary can switch to an importing state – but only when new interconnectors connect.

3.9 continued
South-eastern Boundaries

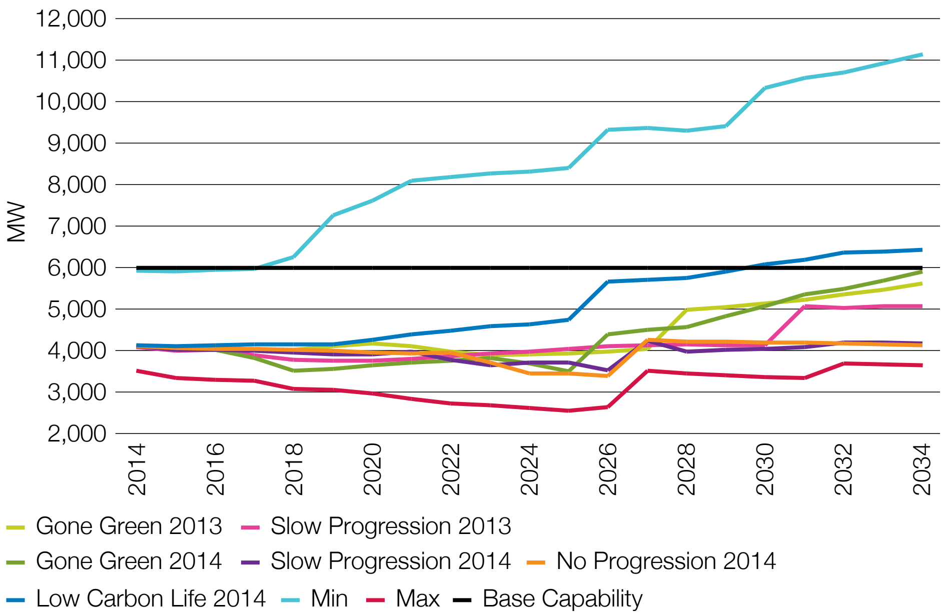
3.9.SC1
Boundary SC1 – South Coast

Figure BSC.1
Geographic representation of boundary SC1



The South Coast boundary SC1 runs parallel with the south coast of England between the Severn and Thames Estuaries. At times of peak winter GB demand the power flow is typically north to south across the boundary, with more demand enclosed in the south of the boundary than supporting generation. Interconnector activity can significantly influence the boundary power flow. The current interconnectors to France and the Netherlands connect at Sellindge and Grain respectively. Crossing the boundary are three 400kV double circuits with one in the east, one west and one in the middle between Fleet and Bramley.

Figure BSC.2
Required transfer and base capability for boundary SC1



Boundary requirements and capability

Figure BSC.2 above shows the required transfers for boundary SC1 from 2014 to 2034. The boundary capability is currently a voltage collapse limit at 6GW for a double circuit fault on the Canterbury North–Kemsley and Cleve Hill–Kemsley circuits.

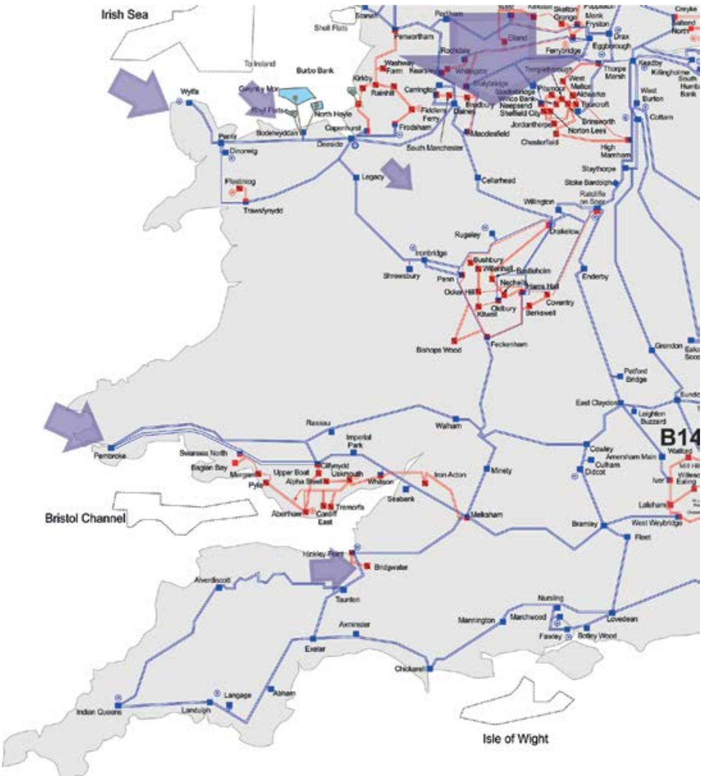
In the base scenarios all interconnectors are assumed to not transfer power.

In the 2014 Gone Green scenario the generation in this region remains fairly constant. This is similar for the Slow Progression scenario. However, the demand decreases as the years progress, which gives rise to a higher transfer. In comparison to last year's Gone Green scenario there is an average drop in transfer of around 550MW, which is attributed to IFA1 interconnector not transferring power (last year the interconnector was on import: 750MW for all years). The most important scenario for this boundary is the scenario sensitivities associated with interconnector operation, as this greatly affects the boundary capability. These sensitivities are shown as the maximum and minimum requirements of the boundary.

3.10
Western Boundaries

Introduction

The Western region covers the remaining boundaries on the system including Wales, the Midlands and the south west. Some of the the boundaries are closely related, such as those for north Wales, but the region also covers large wider boundaries such as B9 and B12.



Primary challenge statement:

Rapidly growing north to south power flows, increasing generation in Wales and new nuclear generation in the south west drive power through Midlands (where various plant closures happen) and the south coast, causing heavy circuit loading and voltage depressions.

Regional drivers

As the generation continues to increase in the north, and wind and nuclear generation connect to West England and Wales, the network in this region will see:

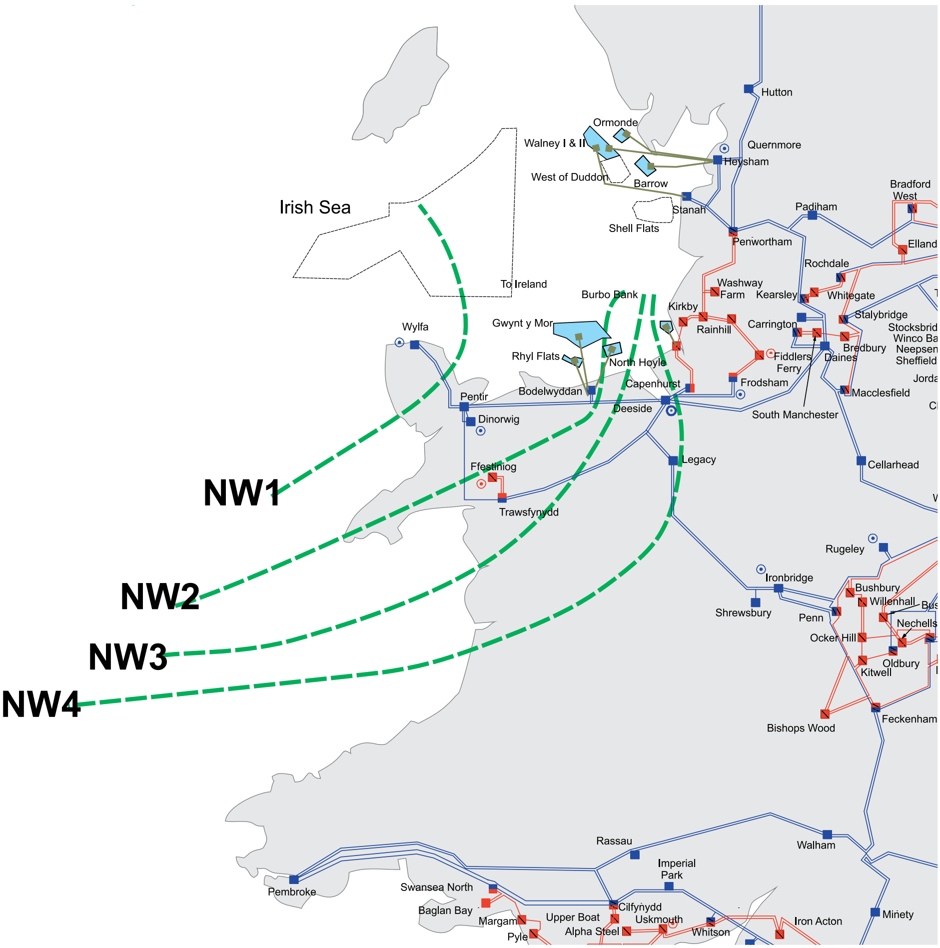
- Limitation on power transfer through the Midlands (boundaries B7a, B8, B17)
  - As generation increases in the north, the large demand in the Midlands and further south of the country creates the increasingly high north to south power flows through the networks around the Midlands. These heavy power flows will stress the transmission routes in the future and could push these routes close to their thermal capability
  - This leads to the need to develop the network around the Midlands to ensure there will be enough thermal capability to sustain the future increase in power flows through the region
- Limitation on power export from North Wales (boundaries NW1, NW2, NW3, NW4)
  - A large amount of generation, mainly wind and nuclear, is expected to connect to North Wales. The transmission network in the area is connected by only a few 400kV circuits with limited capacity
  - Further increase in generation in the area will require network development in order to create new transmission capacity for exporting excess generation to the rest of the system
- Limitation on power transfer from South West England to South East England (boundaries B12, B13)
  - As wind and nuclear generation connects to South West England, the generation in the area may exceed the amount of demand at time of GB system peak and result in increasing power flows towards the high demand area in South East England
  - As the two areas are only connected by a few long transmission routes, it is important to ensure that future network development in the area will create the thermal capacity required for west to east power flow during interconnectors' export operation.

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 400kV 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. Most of this circuitry is of double-circuit tower construction. However, Pentir and Trawsfynydd within the Snowdonia National Park are connected by a single 400kV circuit, which is the main limiting factor for capacity in this area.

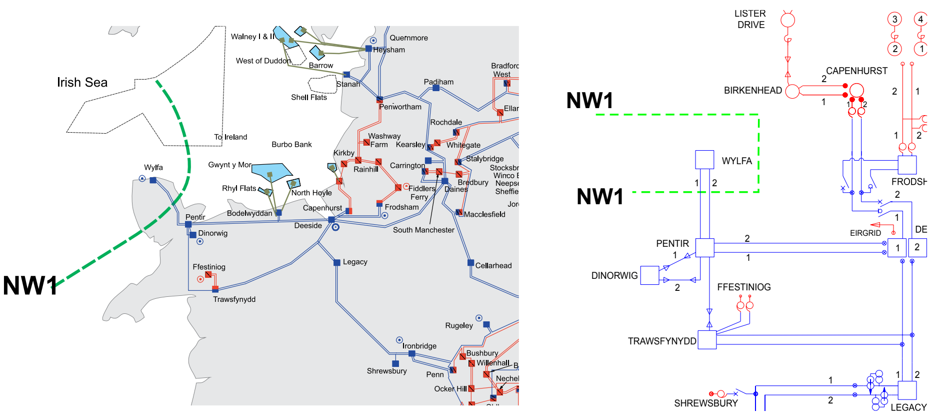
3.10 continued
Western Boundaries

Figure NW1
Geographic representation of North Wales boundaries



3.10.NW1
Boundary NW1 – Anglesey

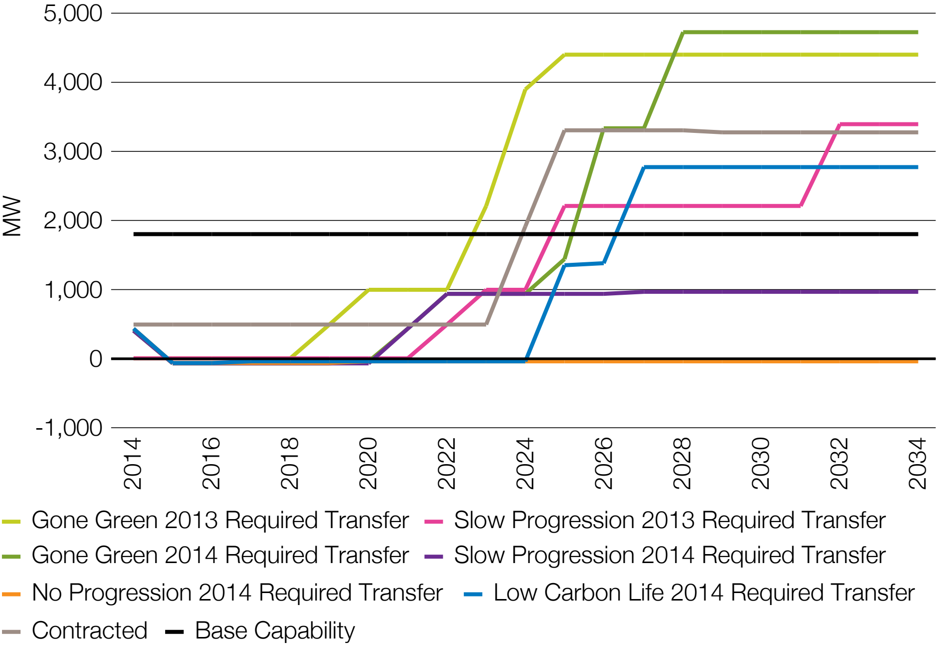
Figure NW1.1
Geographic and single-line representation of boundary NW1



Boundary NW1 is a local boundary crossing the 400kV double circuit that runs along Anglesey between Wylfa and Pentir substations.

3.10 continued
Western Boundaries

Figure NW1.2
Boundary export and base capability for boundary NW1

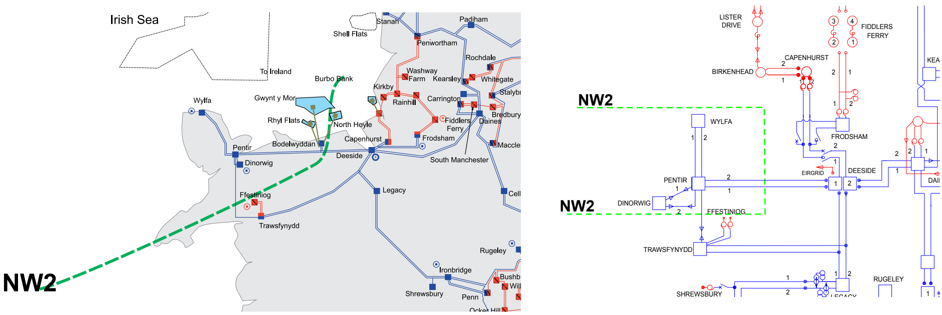


Boundary requirements and capability
Figure NW1.2 above shows the required transfers for boundary NW1 from 2014 to 2034. Transfer capability is limited by the infeed loss risk criterion set in the standard, which is currently 1,800MW. If the infeed loss risk criterion is exceeded, the boundary will need to be reinforced by adding a new transmission route across the boundary.

The scenarios all show a similar requirement until 2020 where they diverge due to different assumptions of when wind and nuclear generation will connect.

3.10.NW2
Boundary NW2 – Anglesey and Caernarvonshire

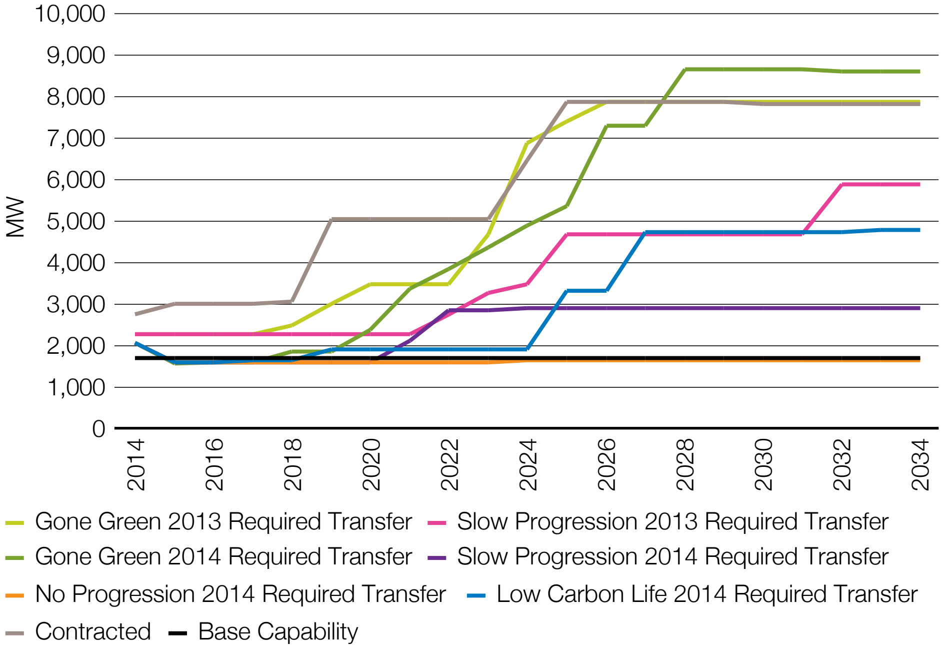
Figure NW2.1
Geographic and single-line representation of boundary NW2



This local boundary bisects the North Wales mainland close to Anglesey. As shown in Figure NW2.1 above, it crosses through the Pentir to the Deeside 400kV double circuit and the Trawsfynydd 400kV single circuit.

3.10 continued
Western Boundaries

Figure NW2.2
Boundary export and base capability for boundary NW2

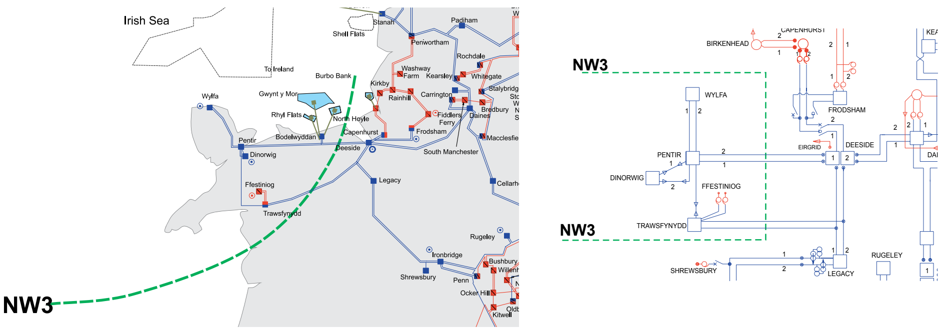


Boundary requirements and capability
Figure NW2.2 above shows the required transfers for boundary NW2 from 2014 to 2034. The boundary capability is a thermal limit at 1.7 GW for a double circuit fault on the Deeside–Bodelwyddan–Pentir circuits overloading the Pentir–Trawsfynydd circuit.

The scenarios all show a similar requirement until 2018 where they diverge due to different assumptions of when wind and nuclear generation will connect.

3.10.NW3
Boundary NW3 – Anglesey and Caernarvonshire and Merionethshire

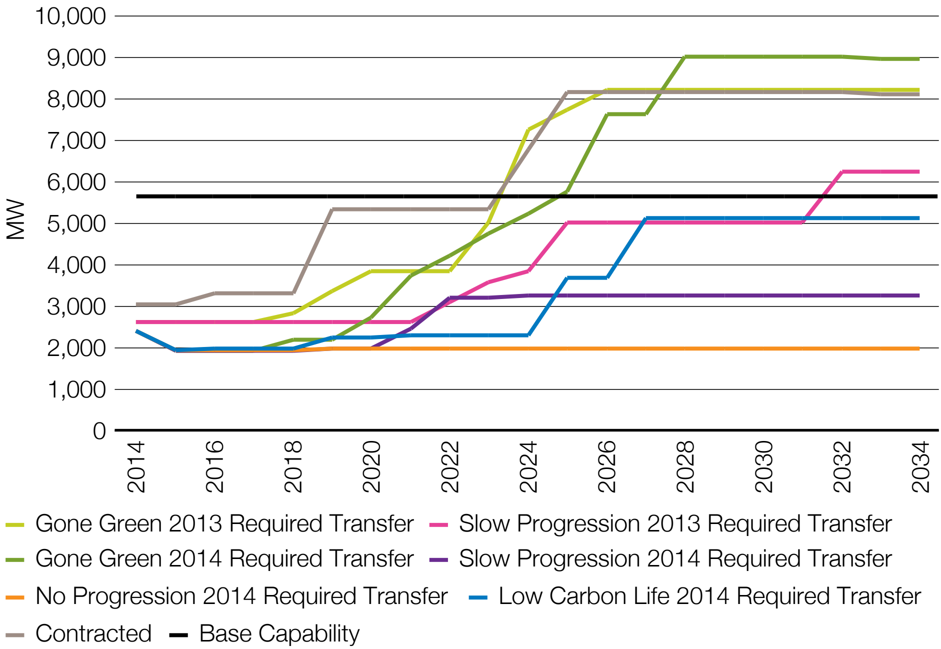
Figure NW3.1
Geographic and single-line representation of boundary NW3



Boundary NW3 (see Figure NW3.1) provides capacity for further generation connections in addition to those behind boundaries NW1 and NW2. It is defined by a pair of 400kV double circuits from Pentir to Deeside and Trawsfynydd to the Treuddyn Tee.

3.10 continued
Western Boundaries

Figure NW3.2
Boundary export and base capability for boundary NW3

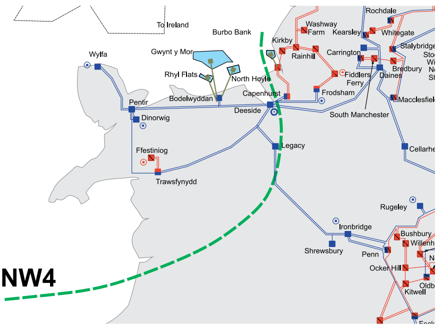


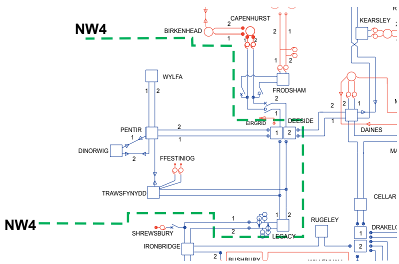
Boundary requirements and capability
Figure NW3.2 above shows the required transfers for boundary NW3 from 2014 to 2034. The boundary capability is thermal limit at 3.5GW for a double circuit fault on Deeside–Bodelwyddan –Pentir circuits overloading one of the Deeside–Trawsfynydd–Legacy circuits.

The scenarios all show a similar requirement until 2018 where they diverge due to different assumptions of when wind and nuclear generation will connect.

3.10.NW4
Boundary NW4 – North Wales

Figure NW4.1
Geographic and single-line representation of boundary NW4

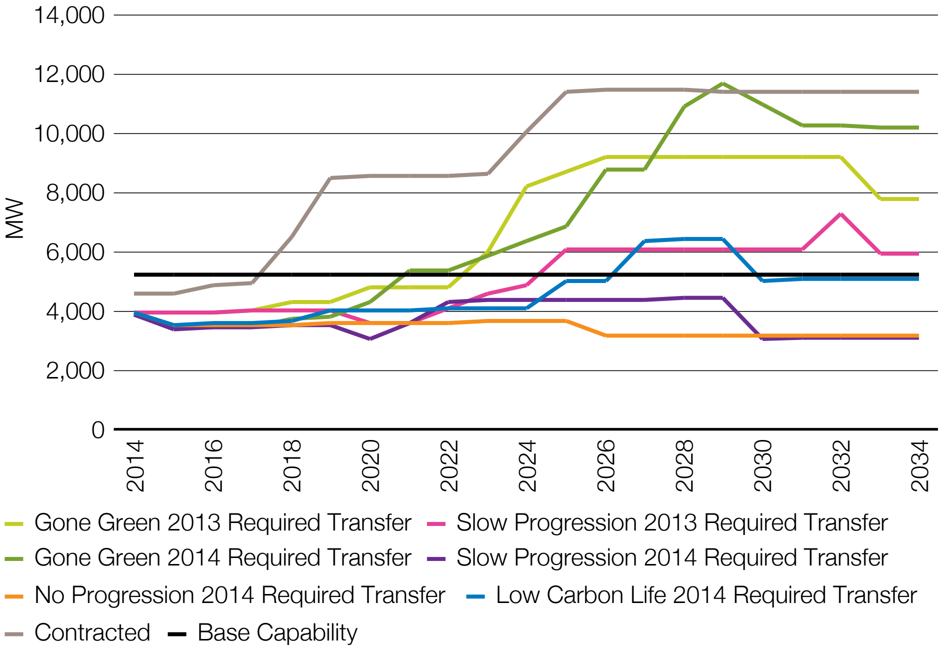




Boundary NW4 covers most of North Wales. Given that it contains fairly low generation and demand, it is currently considered as a local boundary, although it is on the threshold of becoming a wider boundary. As the developments in the enclosed area happen, it may well become a wider system boundary.

3.10 continued
Western Boundaries

Figure NW4.2
Boundary export and base capability for boundary NW4

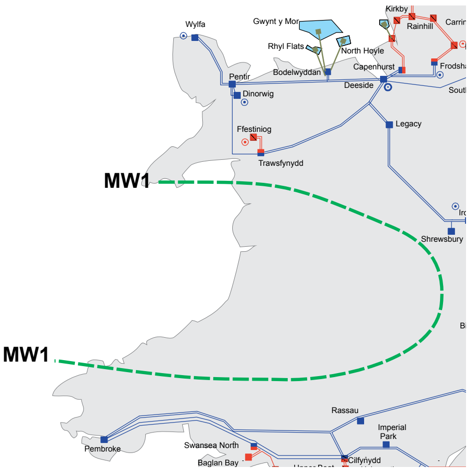


Boundary requirements and capability
Figure NW4.2 above shows the required transfers for boundary NW4 from 2014 to 2034. The boundary capability is voltage compliance limit at 5.2GW for a double circuit fault on Connahs Quay–Daines circuits.

The scenarios all show a similar requirement until 2018 where they diverge due to different assumptions of when wind and nuclear generation will connect.

3.10.MW1
Boundary MW1 – Mid Wales

Figure MW1.1
Geographic representation of boundary MW1



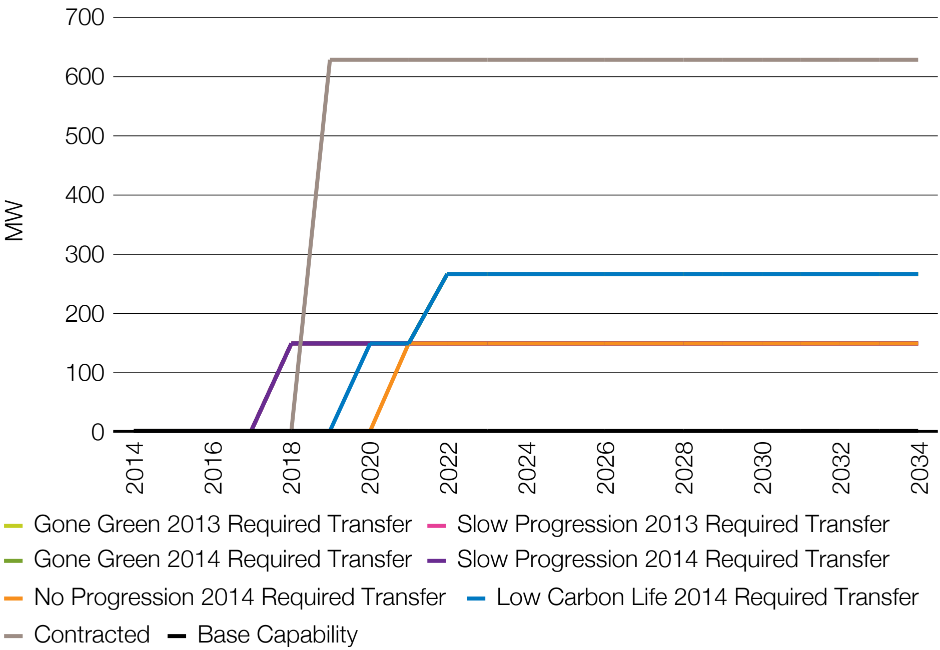
Boundary MW1 is a new local boundary, representing an area in which new wind farm capacity intends to connect to the NETS. Presently there are no transmission circuits crossing central Wales for this new generation to connect to, because there are no large generators or demand points requiring them. The prospective new wind farm capacity is beyond the capability of the current distribution network so will require new circuit capacity to enable its connection.

At the time of writing, a preferred substation location and route for the wind farm connections have been identified, although consultation is on-going. Additional details on this project are available on the project website[8].

[8] http://www.midwalesconnection.com/

3.10 continued
Western Boundaries

Figure MW1.2
Boundary export and base capability for boundary MW1

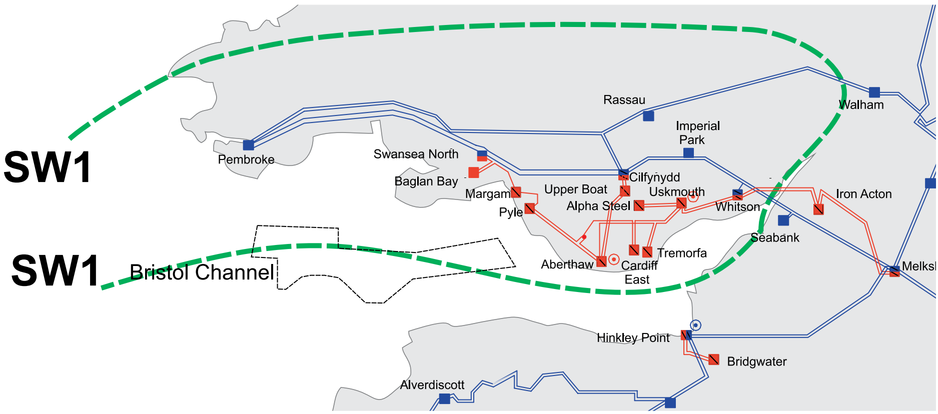


Boundary requirements and capability

Figure MW1.2 above shows the required transfers for boundary MW1 from 2014 to 2034. As there are currently no transmission circuits to Mid Wales there is no existing transmission capability out of the area and across the boundary.

3.10.SW1
Boundary SW1 – South Wales

Figure SW1.1
Geographic representation of boundary SW1

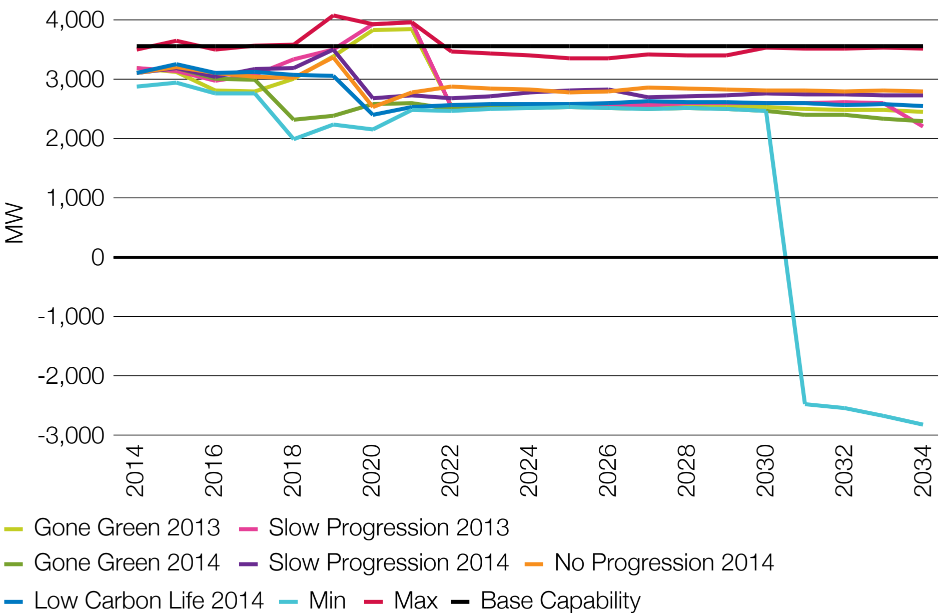


Boundary SW1 encloses south Wales and is considered a local boundary. Within the boundary are a number of thermal generators including Pembroke and Severn Power powered by gas, and Aberthaw powered by coal. Some of the older power stations may be expected to close in the future but new generation capacity is expected to connect, including generators powered by wind and gas.

South Wales includes demand consumptions from the major cities, including Swansea and Cardiff, and the surrounding industry.

3.10 continued
Western Boundaries

Figure SW1.2
Boundary export and base capability for boundary SW1



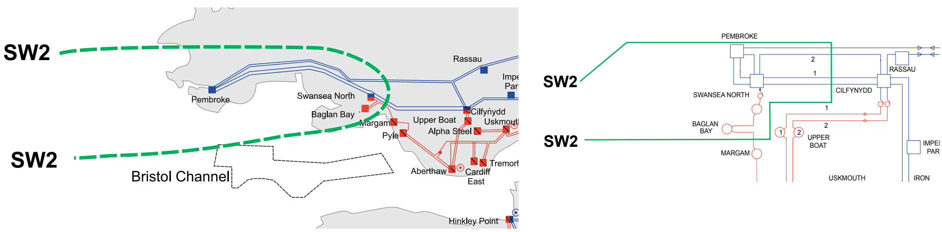
Boundary requirements and capability
Figure SW1.2 above shows the required transfers for boundary SW1 from 2014 to 2034. The boundary capability is a thermal limit at 3.6GW for a double circuit fault on Rassau–Walham and Iron Acton–Whitson circuits overloading the remaining Iron Acton–Whitson circuit.

The boundary required transfer graph for the scenarios and case studies shows a short-term increase in requirements out of South Wales, but this decays beyond 2021.

The Slow Progression scenario assumes that generation remains fairly constant around the region, with a spike in transfer at 2019 due to new wind and CHP plant connections. However, this is counterbalanced as coal plants close. This is also seen in the Gone Green scenario, which assumes an earlier closure of the coal plants, leading to a lower transfer in 2018/19. Once the new generation connects, a reasonable comparison can be made between the Gone Green and Slow Progression scenarios.

3.10.SW2
Boundary SW2 – Pembrokeshire and Carmarthenshire

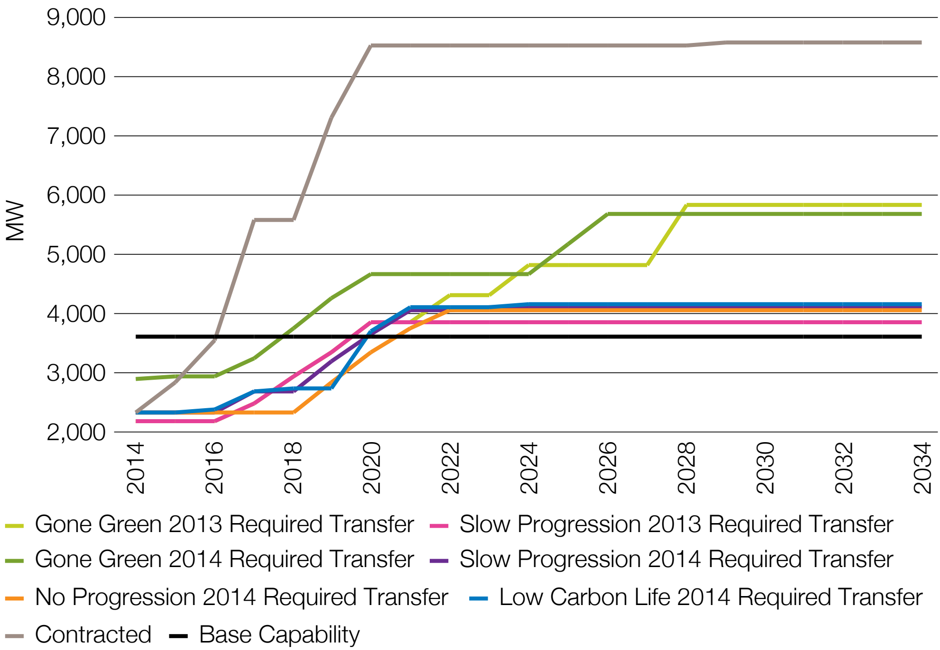
Figure SW2.1
Geographic and single-line representation of boundary SW2



SW2 is a small local boundary enclosing Pembrokeshire in south Wales. There are four 400kV circuits crossing the boundary going to Pembroke and Swansea, and a single 275kV circuit east of Baglan Bay.

3.10 continued
Western Boundaries

Figure SW2.2
Boundary export and base capability for boundary SW2

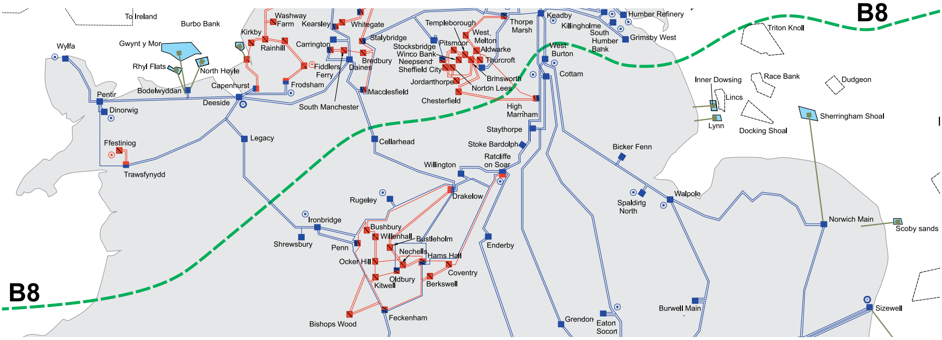


Boundary requirements and capability
Figure SW2.2 above shows the required transfers for boundary SW2 from 2014 to 2034. The boundary capability is a voltage compliance limited at 4.3GW for the double circuit fault on Pembroke–Walham and Cilfynydd–Rassau circuits. Restrictions with SW1 will not allow that capability to be achieved.

In all scenarios additional generation is connecting, the timing of which varies between the scenarios.

3.10.8
Boundary B8 – North to Midlands

Figure B8.1
Geographic representation of boundary B8



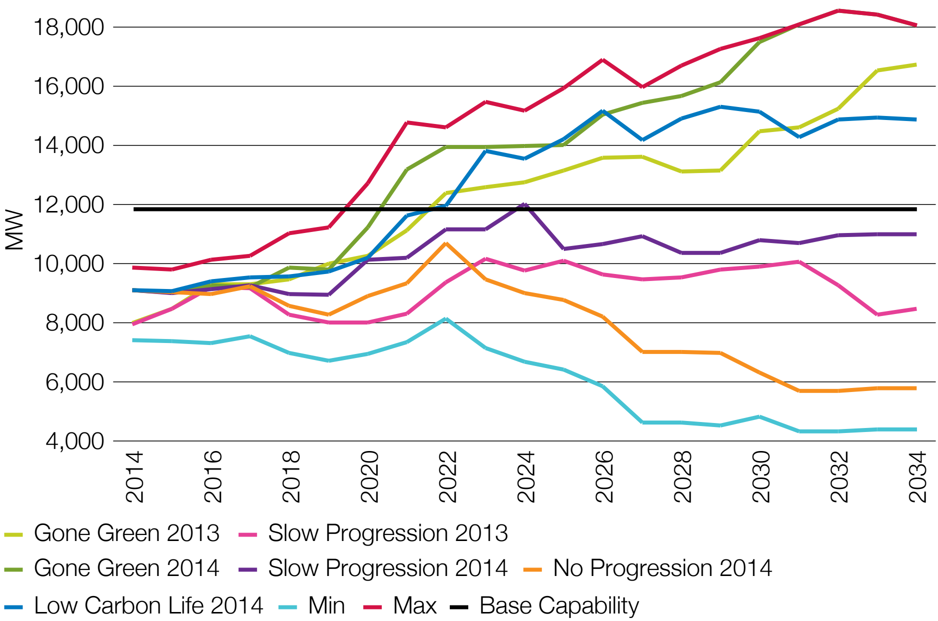
The North to Midlands boundary B8 is one of the wider boundaries that intersects the centre of GB, separating the northern generation zones including Scotland, Northern England and Northern Wales from the Midlands and southern demand centres. The boundary crosses four major 400kV double circuits, with 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 constrain the running arrangements of several substations in the area.

3.10 continued
Western Boundaries

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

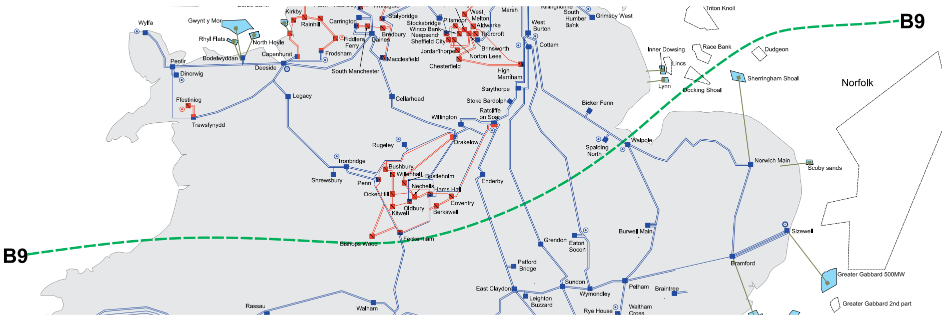


Boundary requirements and capability
Figure B8.2 above shows the required transfers for boundary B8 from 2014 to 2034. The boundary capability is a thermal and voltage compliance limit at 11.9GW for a double-circuit fault on the Deeside–Legacy–Trwsfynydd circuits overloading the Cellarhead–Drakelow circuits and low voltage at Daines 400kV.

Across all scenarios there is a steady increase in the generation behind boundary B8 until 2022, when the No Progression and Slow Progression scenarios decrease or flatten out. Gone Green 2014 has a more rapid increase than Gone Green 2013 because of an increased amount of embedded wind.

3.10.9
Boundary B9 – Midlands to South

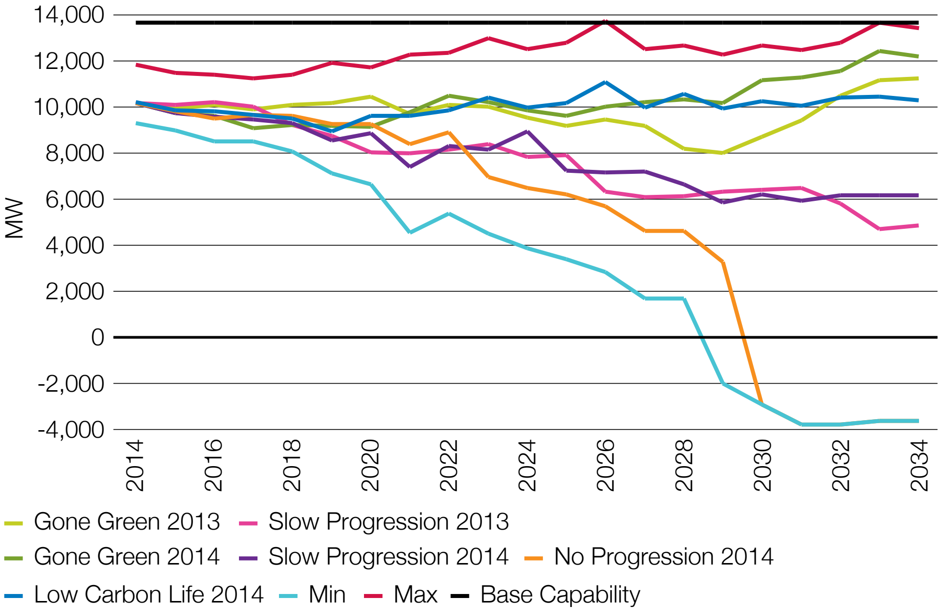
Figure B9.1
Geographic representation of boundary B9



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 typically heavily loaded circuits present voltage compliance challenges, so delivering reactive compensation support in the right area is 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 the transfer requirement and capability of boundary B9.

3.10 continued
Western Boundaries

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



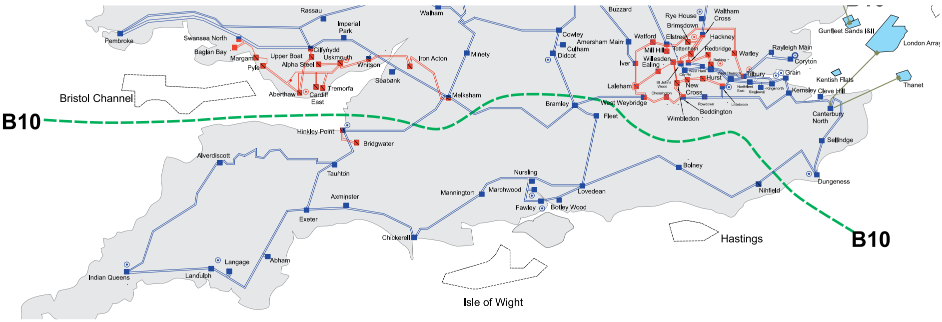
Boundary requirements and capability

Figure B9.2 above shows the required transfers for boundary B9 from 2014 to 2034. The boundary capability is a voltage collapse limited at 13.5GW for a double circuit fault the Splading North–Bicker Fen–Westburton and Walpole–Bicker Fen–West Burton circuits.

The Gone Green scenario remains quite steady as onshore and offshore wind replaces conventional coal and gas plant. In the Slow Progression scenario the conventional plant is closing more quickly than it is being replaced by wind.

3.10.10
Boundary B10 – South Coast

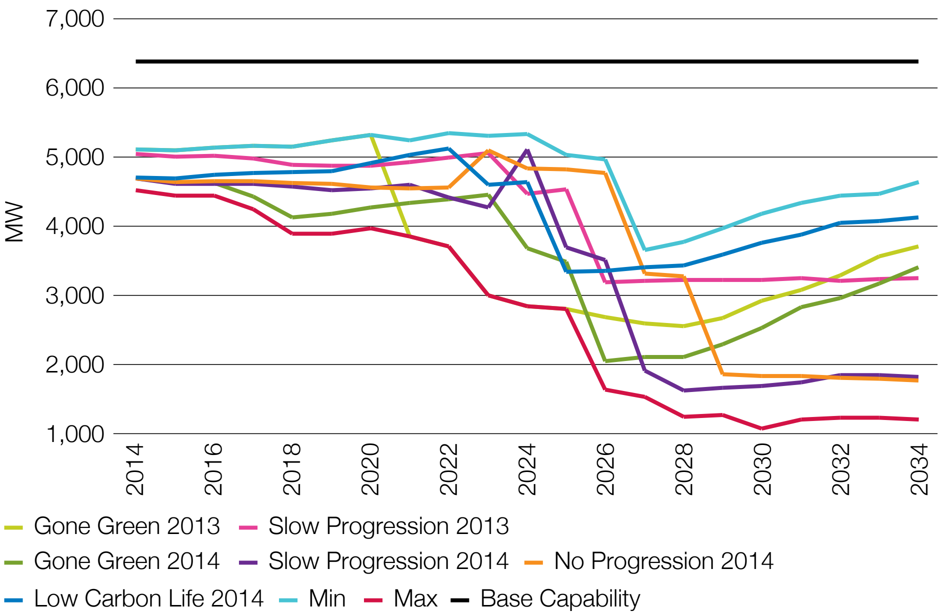
Figure B10.1
Geographic representation of boundary B10



Boundary B10 encompasses the south-west peninsula and the South Coast. It cuts the four 400kV double circuits from Hinkley Point to Melksham, Ninfield to Dungeness, Bramley to Didcot and Bramley to West Weybridge. It is traditionally a heavily importing boundary, with demand enclosed in the South Coast higher than available generation.

3.10 continued
Western Boundaries

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



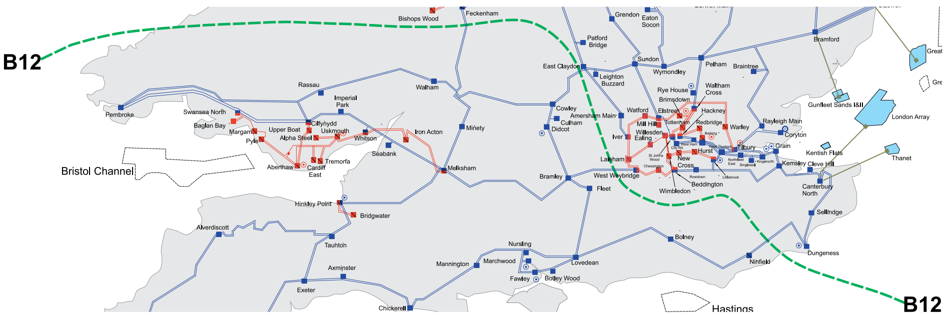
Boundary requirements and capability
Figure B10.2 above shows the required transfers for boundary B10 from 2014 to 2034. The boundary capability is a voltage collapse limited at 6.4GW for a double circuit fault on the Bramley–Fleet circuits.

As a predominantly importing boundary with new generation expected to connect, the boundary requirements fall once the generation connects. So there is no need for this boundary to change the current network.

This boundary is not affected by interconnector flow as much as the other southern boundaries as the French, Belgian and Netherlands interconnectors are outside this boundary.

3.10.12
Boundary B12 – South Wales and South West

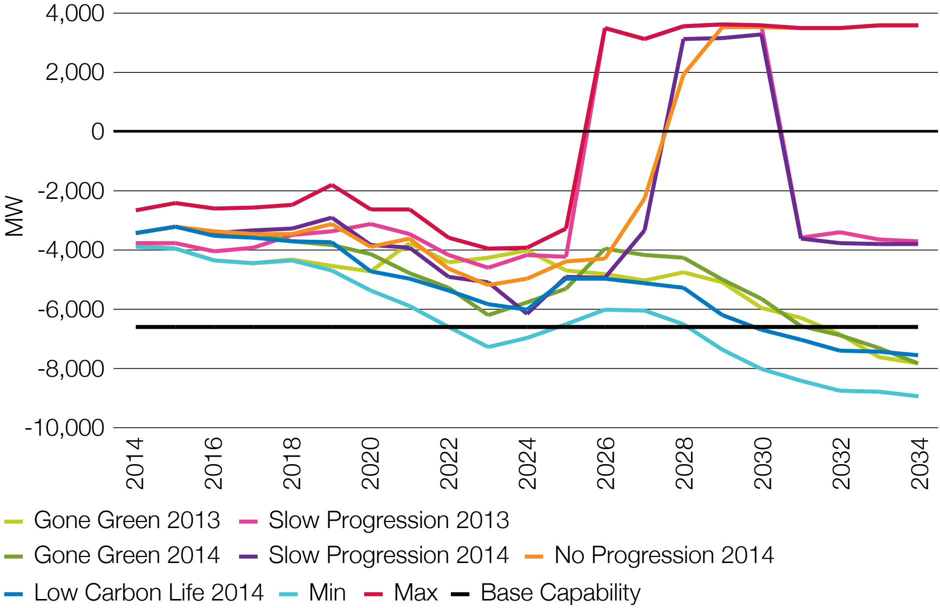
Figure B12.1
Geographic representation of boundary B12



Boundary B12 encompasses South Wales, the South West and a large section of the South Coast. Four 400kV double circuits cross the boundary: Feckenham–Walham, Cowley–Sundon and Cowley–East Claydon, Bramley–West Weybridge and Dungeness–Ninfield. The boundary contains a large volume of demand and generation. Existing generation is mostly thermal, at locations such as Pembroke, Fawley and Didcot and large nuclear units at Hinkley Point. The boundary is generally assumed to import in winter peak conditions.

3.10 continued
Western Boundaries

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



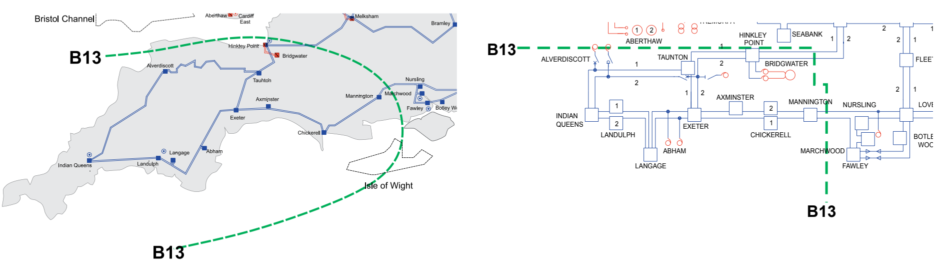
Boundary requirements and capability
Figure B12.2 above shows the required transfers for boundary B12 from 2014 to 2034. The boundary capability is a voltage compliance limited to 6.6GW for a double circuit fault on the Melksham–Minety circuits.

The plots show that over the next few years the importing nature of the boundary persists, with very little deviation in requirement across the scenarios and sensitivity cases.

The Gone Green and Slow Progression scenarios are similar in the earlier years, but begin to deviate beyond 2026 as the gas and wind assumptions for each scenario are realised. Under the Slow Progression scenario boundary B12 moves from importing boundary to exporting as more gas plants connect within the South West and Wales region.

3.10.13
Boundary B13 – South West

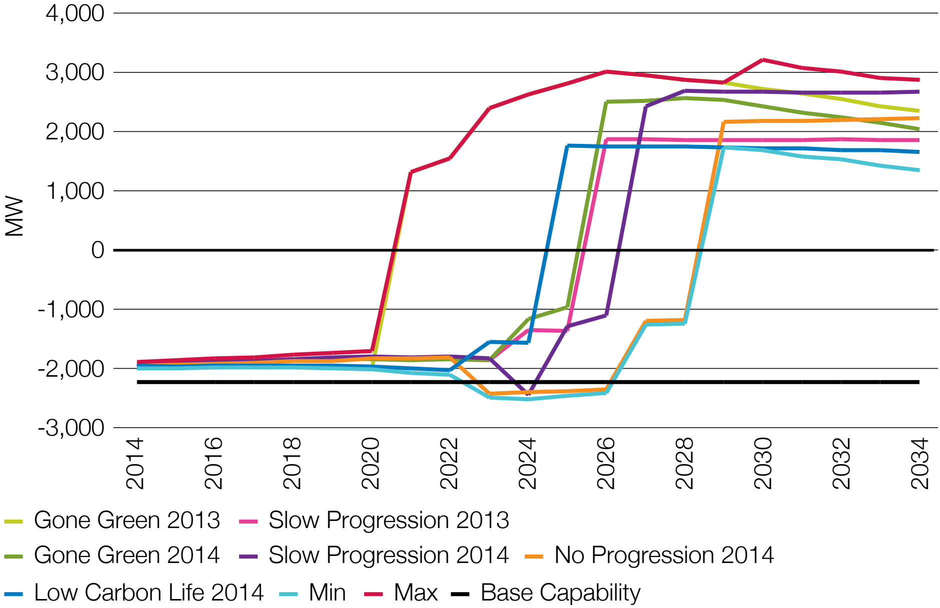
Figure B13.1
Geographic and single-line representation of boundary B13



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 zone demand. The boundary is currently an importing boundary, with the demand being higher than the generation at peak conditions. With the potential connection 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.

3.10 continued
Western Boundaries

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



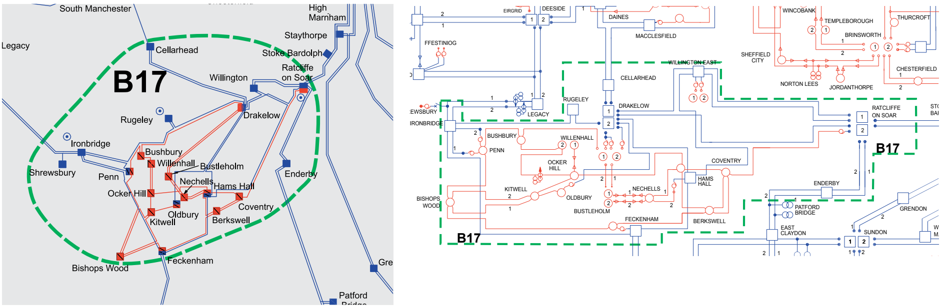
Boundary requirements and capability
Figure B13.2 above shows the required transfers for boundary B13 from 2014 to 2034. The boundary capability is a voltage collapse limited at 2.2GW for a double circuit fault on the Chickerell–Exeter and Axminster–Exeter circuits.

It can be seen that until new generation connects there is very little variation in boundary importing requirements and the current importing boundary capability is sufficient to meet the short-term needs.

The large size of the potential new generators wishing to connect close to boundary B13 is likely to push it to large exports and require additional boundary capacity.

3.10.17
Boundary B17 – West Midlands

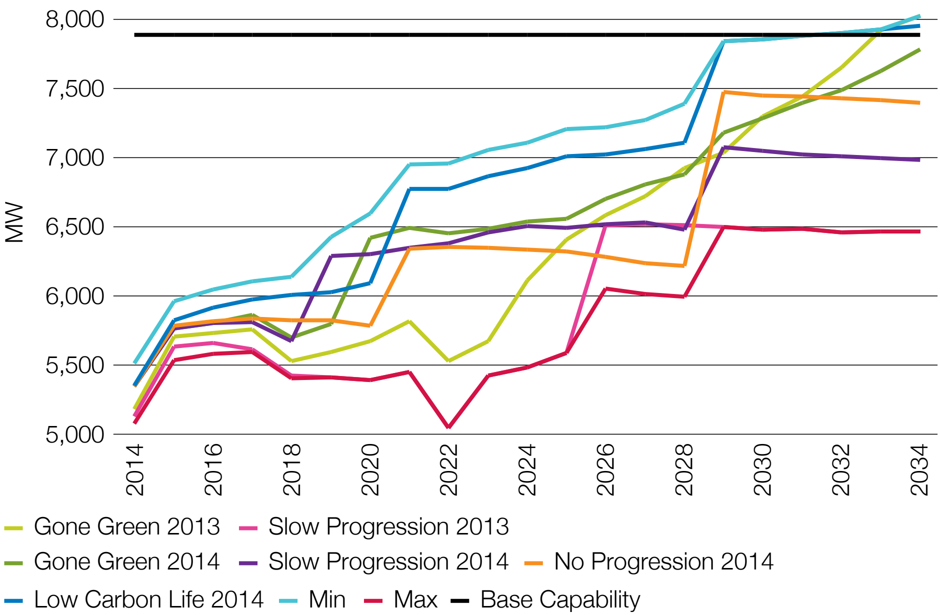
Figure B17.1
Geographic and single-line representation of boundary B17



Enclosing the West Midlands, boundary B17 is heavily dependent on importing power from the north because local generation is insufficient. 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 boundary B17, putting significant loading on these circuits that is not apparent on this boundary's requirements.

3.10 continued
Western Boundaries

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



Boundary requirements and capability
Figure B17.2 above shows the required transfers for boundary B17 from 2014 to 2034. The boundary capability is currently 7.9GW.

The required transfers resulting from the scenarios suggest a general increase in importing boundary requirements after 2021 – this is because of reducing output from the enclosed thermal generation, rather than a significant increase in local demand.

Reduced availability of local thermal generation causes problems for boundary B17. This is because reactive power support to maintain voltage compliance is also reduced, decreasing the boundary's capability to support local demand. At times of high demand, some relief to maintaining voltages is given by the gradual decline in reactive power demands seen by the system (see Chapter 2).

Increasing north to south power flows in the circuits crossing this boundary also work to reduce the boundary capability. Particularly limiting are the circuits entering Cellarhead from the north and the Shrewsbury circuits on the west.

3.11 Year-Round Capability

Introduction

The main presentation of the network capability in Chapter 3 focuses on the winter peak economic flows and winter peak capability. However, to ensure that the network is designed for full year-round capacity, further work is done on evaluating other key times of the year. This can include summer peak, summer minimum and other times such as autumn and spring peaks. The type of limit associated with the network will remain, such as thermal, voltage and stability. However, the absolute limits of the network would be expected to change.

There are many reasons why constraints manifest themselves at times other than winter peak including changes due to the network configuration, generation and demand patterns, transmission equipment outage patterns or the characteristics of transmission equipment related to ambient temperatures. Evaluating the system based on whole year-round planning conditions will allow a future network design to be the most economic and efficient based on expected full year-round operation.

A case study of the Anglo-Scottish boundary, which has recently been evaluated based on year-round capacity, is shown below.

Case study: Anglo-Scottish boundary

As well as assessments at winter peak (highlighted in section 3.6–3.10), each boundary will be assessed for different points during the year where the capacity of the system is important.

This case study considers the Anglo-Scottish boundary of the system on an importing condition, which is sending power from England to Scotland. The analysis takes into account different periods of the year and associated generation and demand backgrounds. In Scotland the generation background considers times of the year when there may be little output from wind farms.

Large thermal and nuclear plants in Scotland still play a vital role in managing security of supply issues across Scotland. Securing the peak demand in Scotland at times of low wind generation output requires around 3GW of generation, which could be provided by a variety of sites, including Torness, Hunterston, various pump storage and hydro schemes, Longannet and Peterhead. After the Western HVDC link is completed in 2016, this requirement should reduce to approximately 1.5GWs of generation at winter peak demand.

3.11 continued
Year-Round Capability

Figure 3.5
Anglo-Scottish boundary curves for 2012/13

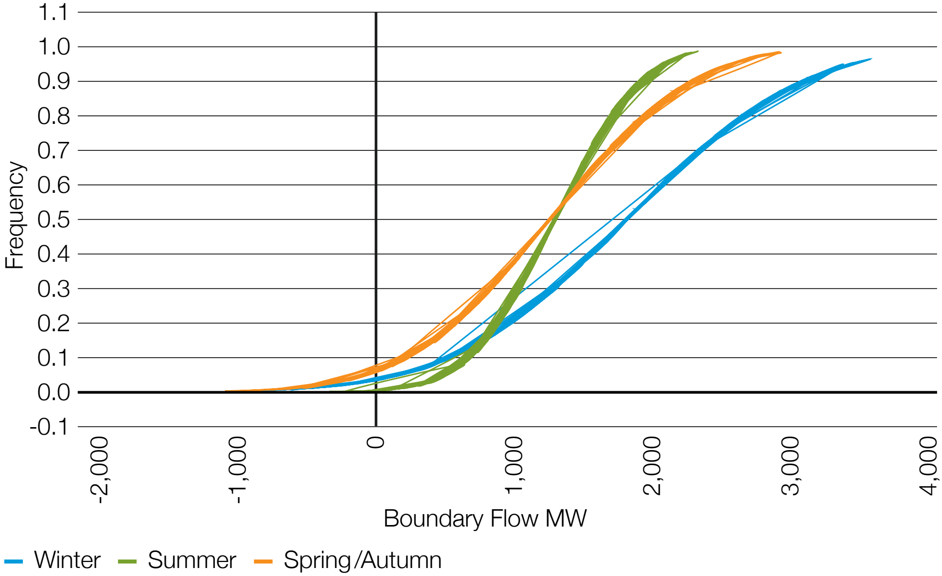


Figure 3.4 shows how the transmission system flows vary with the seasons and the differences even within season. The boundary flows above are constrained boundary flows, following actions by the system operator for constraints above the boundary. Although the highest flow in winter 2012/13 was around 3.5GW, Scotland to England, the system also had to be capable of sending some power in the opposite direction. The constrained spring peak flow was 3GW, Scotland to England, and the constrained summer peak flow was 2.4GW, Scotland to England.

The capability of the system at different times of the year is shown in the Table 3.11 below.

Table 3.11
Anglo-Scotland Scottish import limits

Year	Boundary	Summer capability	Winter capability
2014/15	Anglo-Scottish	2GW	2.55GW
2016/17	Anglo-Scottish	3.6GW	4.1GW

The current capability of the system is 2GW and 2.55GW, increasing to 3.6GW and 4.1GW in 2016/17, mainly because the Western Link will have been completed. The capability of the transmission system will be sufficient to manage whole year-round conditions in the future and particularly times of low wind generation within Scotland.

3.12
System Constraints

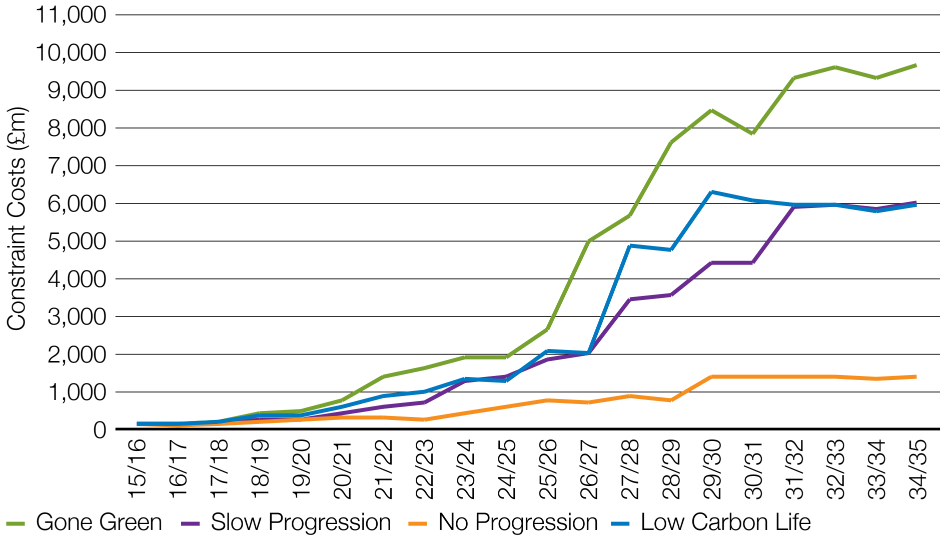
To ensure that the transmission system remains within safe operating limits at all times, including times of system constraint, the system operator takes actions to work around the constraints. Actions include entering into a Transmission Constraint Agreement, trading or taking actions in Balancing Mechanism with generators, suppliers and large customers.

To minimise the cost impact of constraint actions National Grid carefully plans and applies strategies such as aligning network outages with those of its connected customers. Some constraint expenditure for managing the system is however unavoidable. A completely constraint-free system would be uneconomic due to additional transmission infrastructure that would be required.

Last year over £200m was spent on constraints within Scotland and on the Anglo-Scottish boundary making this the highest spending area. Other areas have also incurred constraint costs but there is no other area with constraints above £20m.

Projections of future constraint spend without system reinforcement have been produced using the four future energy scenarios and are shown in figure 3.6 below.

Figure 3.6
Projected constraint costs



The analysis above shows that in the near future the system is not expected to suffer high constraint, but if it is unreinforced the constraint costs could grow to more than £1bn a year. The Gone Green scenario shows the largest potential impact to constraint costs.

3.13
Stakeholder Engagement

In this chapter we explore how the transmission system requirements may need to develop over the next 20 years.

If you wish to discuss this further, please contact us at: **transmission.etys@nationalgrid.com**

Stakeholder engagement
We welcome your views on the representation of offshore and onshore connections.

Stakeholder engagement
We welcome feedback on the use of boundaries as a means of representing transmission network capability and requirements.

Chapter 4

Network Development and Opportunities

This chapter focuses on how the National Electricity Transmission System (NETS) can be developed in response to the drivers presented in the previous chapter. Potential solutions are presented and we consider possible opportunities for current and future users of the electricity transmission system.

4.1 Introduction

We have identified potential asset, operational and commercial solutions that could meet future transmission requirements and have highlighted opportunities for stakeholders. Delivering some of these reinforcement solutions could mean significant lead-times because of consents, system access and construction coordination.

The responsibility to determine which transmission developments to progress lies with the relevant transmission owner. The decision to invest, however, is made with input from the many stakeholders, including the National Electricity Transmission System Operator (NETSO), customers and government departments.

The decision to progress transmission works that directly relate to individual customer connections is less complex compared to wider works. The single user enabling works must progress to allow that user to connect to the NETS in time to meet the agreed connection date. When multiple connections are involved, as with wider transmission works, the decision to invest is more complex. The triggering events coinciding become less certain with more parties developing projects in a given area. To support investment decisions for wider works, National Grid, as the England and Wales onshore transmission owner, has developed the Network Development Policy (NDP).

This policy, approved by Ofgem, applies only to England and Wales and is described later in this chapter. Similar principles are also applied by the other transmission owners in delivering need and timing for reinforcement in their areas.

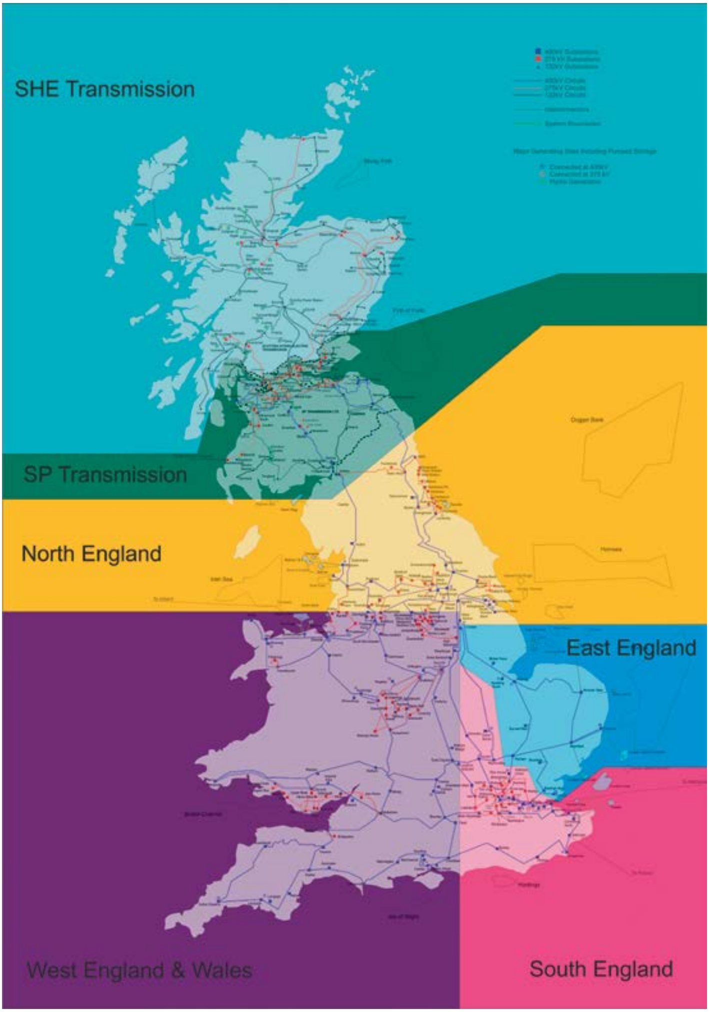
In this chapter, the potential physical onshore and offshore transmission reinforcements have been split into six regional groups, with related projects grouped into the same region. There are, however, some large reinforcements that span multiple regions. In these cases, reinforcements have been highlighted and we have shown the benefits provided to the multiple regions. The regions used in this chapter relate to the geographically grouped boundaries from the previous chapter.

See Figure 4.1, below, for a geographical representation of the six regions (Scotland SHE Transmission, Scotland SP Transmission, North England, West England & Wales, South England and East England).

The colour codes applied to various regions, as shown in Figure 4.1, are applied throughout this chapter to help identify information relevant to the respective regions.

4.1 continued
Introduction

Figure 4.1
Region map



4.2 Overview of Transmission Solution Options

The following sections help describe some of the important factors in making investment decisions.

4.2.1 Transmission solution options

So that economic and efficient investment decisions are made, a range of credible solutions is identified. Solutions are then developed to a stage where the information needed to support the investment decision is available when needed. This first stage of the process is to identify credible potential transmission solutions that provide additional transmission network capability across the transmission boundaries being considered. In undertaking this review, we not only consider new schemes but review in-flight schemes, so that we make the most economic and efficient decisions.

We consider commercial, operational and asset solutions (either onshore, offshore or a combination of both). Individual solutions and a combination of solutions are considered when testing if boundary capability constraints are reduced.

The range of solutions should include both small-scale reinforcements with short lead-times and large-scale reinforcements that may have longer lead-times. An important factor of the reinforcement considered is the increase in incremental network capability and cost. Transmission solutions are presented in Table 4.1 in order of increasing likely cost.

4.2 continued
Overview of Transmission Solution Options

Table 4.1
Potential transmission solutions

Category	Transmission Solution	Nature of Constraint			
		Thermal	Voltage	Stability	Fault Levels
Low Cost Investment (Operational)	Coordinated quadrature booster schemes	✓	✓		
	Automatic switching schemes for alternative running arrangements	✓	✓	✓	✓
	Dynamic ratings	✓			
	Enhanced generator reactive range through reactive markets		✓	✓	
	Fast switching reactive compensation		✓	✓	
Commercial	Availability contract	✓	✓	✓	
	Inter-tripping	✓	✓	✓	
	Reactive demand reduction		✓		
	Generation advanced control systems	✓	✓	✓	
Asset Investment (Onshore/ Offshore)	Hot-wiring overhead lines	✓			
	Overhead line reconductoring or cable replacement	✓			
	Reactive compensation (MSC, SVC, Reactors)		✓	✓	
	Switchgear replacement	✓	✓	✓	✓
	New build (HVAC/HVDC)	✓	✓	✓	✓

Operational options
Changes to operational policies and procedures may provide additional capability to the transmission system. An example would be a move to provide significantly increased quadrature booster actions following a fault. This would allow power to be redistributed more effectively after a fault to mitigate circuit overloading. Changes to operational policies and procedures will be developed in response to system requirements.

If you would like to learn more about these potential options, please see Chapter 5 of this document.

Commercial options
In order to provide a more economic and efficient electricity transmission system, National Grid, as the NETSO, explores commercial, non-build transmission solutions to help resolve potential transmission system issues.

Examples of non-build transmission solutions include demand side management, inter-trips and reactive power services. These commercial, non-build options could negate the need for asset investment and construction. As we continue to develop opportunities in this area, we will discuss options with our stakeholders.

If you would like to learn more about these potential opportunities, or can offer such a service to National Grid, please see Section 4.3 later in this chapter.

Onshore options
We could increase the capability of the transmission system by building major new

infrastructure, by reinforcing existing routes, using new technologies or developing new routes. We carry out robust analysis of all options and the analysis is presented to the public and other stakeholders in the local communities.

In carrying out the options analysis, we apply two primary principles set out in the Electricity Act 1989 and the transmission licences:

- To develop an economic, efficient and coordinated transmission system
- To have due regard to the environment.

With regard to the second of these principles, National Grid maintains a stakeholder, community and amenity policy which defines the commitments when undertaking works. In accordance with this policy, construction of electricity lines along new routes, or above ground installations in new locations, will only be pursued as an option where:

- The existing infrastructure cannot be technically or economically upgraded to meet system security standards and regulatory obligations
- Forecast increases in demand for electricity will not be satisfied by other means
- New customer connections are required.

All reinforcement needs are assessed using these criteria, which leads to the following approach for considering high-level network options.

Figure 4.2
High-level network options considerations

Figure 4.2, which presents our logic chain for the selection of network options, shows that the first option we consider is using existing assets to meet the needs of customers. If this is not possible, we consider upgrading existing assets, using techniques such as 'hot-wiring' circuits or employing SMART technologies. Beyond that, we consider replacing existing assets with assets of a higher capability, such as reconductoring an existing overhead line with higher-rated conductor, or replacing a transformer with a higher-rated model. The construction of any major new infrastructure will be taken forward only if, after careful consideration, it is the only viable option to meet future network requirements.

Where there is a defined need case to improve the transmission system beyond the capability of existing assets, so new assets need to be installed, the various options for resolving the limitation are considered in detail. Stakeholders are consulted widely over what options have been considered as part of the planning process.

In developing these solutions, the replacement priority of any existing transmission assets are considered and aligned if possible. 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, is calculated.

4.2 continued
Overview of Transmission Solution Options

Offshore options

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

- Radial – a point-to-point connection from the offshore substation to a suitable onshore collector substation, using currently available transmission technology
- Coordinated – a coordinated onshore and offshore design approach, with AC cables and HVDC interconnection between offshore platforms and development zones. This is optimised for an economic and efficient holistic design.

Figure 4.3 shows how the different design strategies affect the design of an illustrative 4GW offshore windfarm development. The network design is developed to be delivered in stages to aid timely investment and minimise stranding risk. Interconnection between the offshore platforms occurs at a later stage (shown as stage two in Figure 4.3) of the coordinated design strategy.

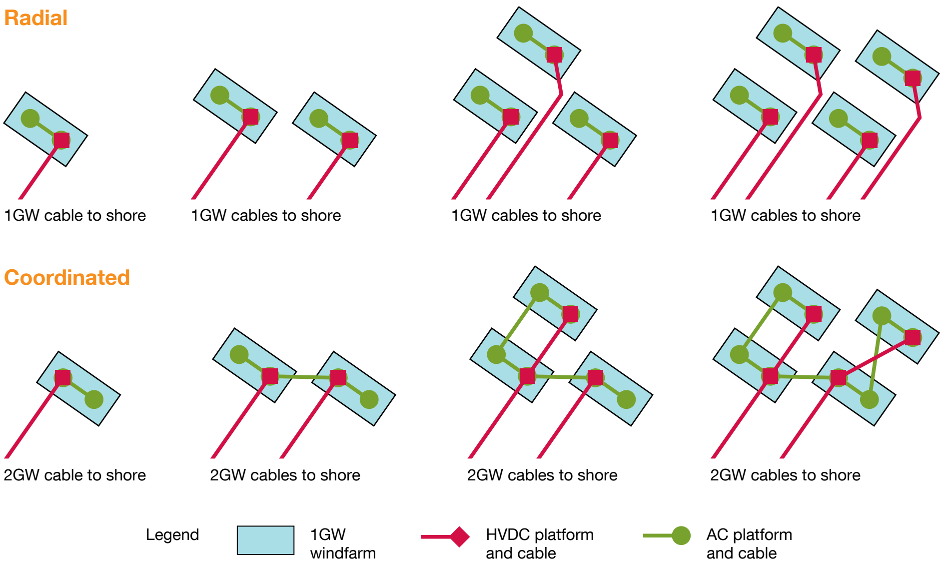
In the event of the loss of any single offshore cable, the coordinated design strategy provides an alternative path for the power to the onshore collector substation. While there may not be sufficient transmission capacity to accommodate the full generation output following an outage, there should be sufficient capacity to cover the majority of the output. If the onshore connection points are separate, then interconnection offshore by the coordinated design provides a new 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, thus providing additional resilience which is not catered for in radial designs.

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.

HVDC systems, particularly the modern VSC designs, allow for direct active control of the power passing from one end to the other of DC circuits. When combined with offshore interconnection and the parallel operation with the onshore system, this can 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 more traditionally passive AC circuits.

Various Round 3 offshore wind zones present opportunities to develop coordinated offshore connection. These opportunities are discussed further in section 4.2.2.

Figure 4.3
Radial and coordinated offshore connection



General consideration for transmission solution options

When we develop and implement any transmission strategy, we run an inclusive and robust optioneering process to evaluate each transmission option and agree an optimum solution. This assessment balances the conflicting priorities of network benefit, cost and build programme with their associated risks. Co-operative work between all the parties is the key to ensuring the timely delivery of an economic and efficient network solution for consumers.

Strategic optioneering

In looking for solutions to develop the NETS we consider both onshore and offshore transmission solutions – and we recognise that there are different considerations with offshore options. Many of the technologies required for wider works are new and developing rapidly. Voltage Sourced Converter (VSC) HVDC technology was introduced in 1997 and has been characterised by continuously increasing power transfer capabilities. There have been significant developments in the area of DC cables including the introduction of extruded and mass impregnated polypropylene paper laminate (MI PPL) insulation technologies. New devices are emerging, such as the HVDC circuit-breaker. This document aims to anticipate how the capability of the key technology areas for wider works might develop and indicate expected technology availability, by year, in order to inform investment decisions.

4.2 continued
Overview of Transmission Solution Options

Matrices are presented, in Appendix E, for each of the key technology areas we have considered in developing wider work options. These tables show the expected timelines in which the technology will be available for in service use.

In the 'generator connection offer' phase for an offshore connection we will base our design and costs on the information available in Appendix E. Once the agreement is signed, we will work with that developer through the CION to further develop these assumptions. We will continue to evaluate the need for the wider works options via the NDP.

Future generation connections, especially in the form of nuclear and renewables, are likely to trigger major network reinforcements in some regions, either onshore or offshore, and there may be extensive planning and construction programmes. A significant amount of strategic pre-construction work may be required to deliver an overall efficient transmission strategy. It is also important that this ability to deliver the overall strategy is not compromised while progressing the local connection for individual projects.

Under Connect and Manage (C&M), generation projects may connect to the transmission system before completion of the wider transmission reinforcement works. Wherever possible, operational and commercial options will be taken forward to manage the increasing requirements in network capability. This should be consistent with the strategies identified.

As well as identifying the most economic and efficient solution, the following factors are also identified for each transmission solution to provide a consistent basis for the cost benefit analysis.

Outputs: the calculated impact of the transmission solution on all affected transmission boundary capabilities, the impact on network security and the forecast impact on transmission losses.

Lead-time: 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. It includes an assessment of the opportunity to advance and the risks of delay. It is recognised that there can be significant lead-time risk for some major infrastructure projects (e.g. new overhead lines that require planning consents). In managing these projects, it may be necessary to commit to pre-construction engineering to minimise lead-time when there is sufficient confidence to proceed with a major investment.

Cost: the forecast total cost for delivering the project, split to reflect the pre-construction and construction phases. The risk of over spend, for example due to the 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 overspend is significantly reduced.

Stage: a transmission solution passes through several stages in the development and delivery process. The stages[1] are as follows:

- **Pre-construction: Scoping:** the identification of a broad needs case and consideration of a number of design and reinforcement options to solve boundary constraint issues
- **Pre-construction: Optioneering:** the needs case is firm and a number of design options have been provided for public consultation if needed so that a preferred design solution can be identified
- **Pre-construction: Design:** the preferred solution is designed in greater levels of detail and, if needed, preparation begins for the planning process
- **Pre-construction: Planning:** continuing with public consultation and adjusting the design as required all the way through the planning application process if needed
- **Construction:** planning consent has been granted when needed and the chosen solution is under construction.

In addition, it is possible that some alternative investments will be identified during each investment review. Updates to developments, backgrounds and economics are part of subsequent iterations.

The following sections describe the range of solutions that have been considered for the wider system investment review.

[1] Defined as part of the Electricity Network Strategy Group (ENSG) process and published by the Department of Energy and Climate Change (DECC)

4.2.2
Potential development of a coordinated offshore network

The Round 3 offshore wind programme represents the potential of approximately 37GW of additional offshore generation. A coordinated design approach for these large Round 3 zones, depending on the timing of volumes of offshore generation, could provide alternative transmission solutions to onshore reinforcement. This section looks at the potential development of a co-ordinated offshore network in Round 3 zones.

Dogger Bank zone

There is potential for some 9–12.8GW of offshore wind generation from the Dogger Bank zone, of which 6GW is contracted to connect between 2017 and 2021. There could be more offshore generation from the Dogger Bank zone along the east coast, but this would need additional transmission capacity across the northern boundaries such as B7 and B7a. The boundaries needing reinforcement would depend on how far north the connection was made. This could be achieved by either onshore or offshore reinforcement. However, by providing an offshore link between distant onshore connection points via the Dogger Bank zone, it would be possible to provide both transmission capacity to connect the offshore wind and reinforce the main interconnected transmission system. In addition, under onshore or offshore outage conditions, it would be possible to divert power between connection points, thus mitigating the need for further reinforcement in either of these regions. Depending on the timing of volumes of offshore generation in the Dogger Bank zone, the integrated offshore network could offer a more economic and environmentally acceptable solution than some of the onshore options described later in this chapter.

Hornsea zone

Around 4GW of offshore wind generation could come from the Hornsea zone, of which 2GW is presently contracted to connect from 2020, south of the Humber region, with the remaining 2GW of capacity contracted to connect in the Wash region by 2023. Additional transmission capacity may be required out of both the EC1 and EC3 group and boundary B8. This could be provided by either onshore or offshore reinforcement. Providing an offshore link between EC1 and EC3 via Hornsea, would provide transmission capacity to connect the offshore wind to the main interconnected transmission system, as well as reinforcing boundary B8. Also, if there was an outage in region EC1 or EC3, power could be diverted to EC3 or EC1 respectively. This would mitigate the need for further reinforcement in either of these zones. Depending on the timing and volumes of offshore generation in the Hornsea region, the integrated offshore network could also offer alternative solution and benefits that will be evaluated as part of the on-going NDP assessments.

Dogger Bank and Hornsea zones

As described above, there is potential for some 13–16.8GW of offshore wind generation in the Round 3 Dogger Bank and Hornsea zones. Considering these zones in isolation could lead to significantly more investment than if they were considered in an integrated way. There are potential solutions, both onshore and offshore, that can increase the transmission capability across B7, B7a and B8. As this onshore and offshore generation develops, the network solutions will be developed, so the proposed solution can be developed incrementally alongside the generators. This will minimise redundancy risk while facilitating future development.

East Anglia zone

The Round 3 East Anglia zone has the potential for 7.2GW of offshore wind generation capacity. Connection contracts are in place for the full 7.2GW, with staged connection dates between 2018 and 2026 to connection points in East Anglia, within the EC5 boundary. Offshore coordination within the East Anglia zone can result in increased supply security. The addition of a coordinated connection with Hornsea or Dogger Bank would provide additional boundary capability across the B8 and B9 boundaries. The offshore zone could also be considered for coordination with the Belgian or Dutch projects to provide additional interconnection between the countries.

Integrated Offshore Transmission Project (IOTP)

The Integrated Offshore Transmission Project (IOTP) is a joint project between National Grid and the developers of the Dogger Bank, Hornsea and East Anglia projects. This project is considering system requirements, technology and commercial frameworks.

The benefits of integrated and coordinated offshore designs are being evaluated. Advantages include improving transmission boundary capability while incorporating flexibility into the existing transmission network, and providing offshore options to avoid potential delays usually associated with onshore reinforcements. The aim is for efficient reinforcement of the wider (B7, B7a, B8 and B9) and local system boundaries (EC1, EC3 and EC5) for timely connection of offshore projects.

The main purpose of the Integrated Offshore Transmission project was to provide a visionary and transparent prediction of integrated offshore development from now up to 2030. In addition to the 2013 FES generation backgrounds of Gone Green and Slow Progression scenarios, the two backgrounds case studies used were scenario 1 (generation build-up scenario based on TEC) and scenario 2 (represents generation build-up scenario agreed with developers). These scenarios give alternative, plausible generation mixes to provide a wider representation of offshore integrated network development.

The system requirements work stream produced 83 designs that were classified into four design groups: onshore designs, bootstrap, hybrid designs (bootstrap & offshore) and offshore integrated design. Together with offshore developers, 12 designs were agreed to proceed to cost benefit analysis (CBA). Once the CBA sensitivity studies are complete, the IOTP project will go into industry consultation process.

South Coast zone

The two Round 3 projects off the south coast and south west peninsula of England are Rampion, to the south of Brighton, and Navitus Bay, to the south west of the Isle of Wight. There is the potential for some 1.5–1.9GW combined offshore wind generation from these two zones. As the affected boundaries, B10 and SC1, are generally net importers, this generation can be probably be accommodated within the zone.

Both of these Round 3 generating zones are close to the coastline. The indicative capacity for each zone is small enough that the use of AC technology is expected to be the most cost-effective solution for transmission connection. Connections to existing substations are likely to be the most straightforward option. The low level of existing generation in the area, coupled with local demand requirements, results in only small impacts on load flows so only minor local reinforcements should be needed to facilitate these connections.

4.2 continued
Overview of Transmission Solution Options

Due to the large geographic split between these two offshore zones and the pattern of predicted network flows on the south coast circuits, it is unlikely that offshore links between these zones will provide any cost-effective options to meet any network reinforcement requirements. However, there are other offshore contracted connections from outside these zones that are due to connect to similar regions onshore. These further connections will use DC technologies due to the long distance from the coastline.

Bristol Channel zone

There is a single Round 3 zone in the Bristol Channel area with the potential for some 1.5GW of offshore wind generation.

In November 2013, Atlantic Array terminated their development agreement for this zone with the Crown Estate.

Scotland zone

There are two Round 3 zones in the Scotland area: Moray Firth and Firth of Forth, with the potential for some 4.7–5.2GW of offshore wind generation. There are also smaller Scottish Territorial Water (STW) sites with contracted capacity of 1.7GW in total, as well as 1.6GW split across 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. These zones may necessitate a requirement for HVDC technology, although the parts of the zones closest to the coastline may only require AC connections. However, a significant requirement for HVDC would present an opportunity for within-zone interconnection. This would offset the number of offshore to onshore links, with selected re-optimisation of the rating of some of these links in comparison with 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, a pressing requirement to accommodate renewable generation output from Caithness will be addressed by an HVDC reinforcement planned by SHE Transmission across the Firth between Caithness and Blackhillock in Moray. There may be potential for the offshore windfarms to share their connections to shore but any integration with SHE Transmission's HVDC circuit would be subject to technology compatibility, commercial considerations and timing. There would also need to be clarification of roles and responsibilities under the evolving transmission licensing arrangements for offshore and onshore transmission.

Initial wave and tidal generation projects in the Pentland Firth and Orkney waters are planned to be connected over AC reinforcements, with the Caithness–Moray HVDC link assumed to have been installed. Further outline HVDC development options integrating with that circuit, technology permitting, would accommodate later stages of wave and tidal generation. Because the proposed generating sites in the North Scotland zone are widespread, a DC switching station could be established that could connect the mainland network to the Moray Firth, Orkney and Shetland developments, although this would require significant technological innovation and development.

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 the potential for some 4.2GW of offshore wind generation in total. In July 2014, Celtic Array terminated their development agreement for this zone with the Crown Estate.

Should another developer be granted a lease sometime in the future, an integrated design within the zone could give additional transfer capability across boundary B7a, either mitigating or deferring the need for additional onshore reinforcement.

Ireland and Irish territorial waters

There is significant interest in connecting wind generation both from Irish territorial waters and from the Irish mainland itself. This is despite the failure of the GB and Irish Governments to conclude an agreement for renewable energy trading within 2020 timescales. Contractually, this now totals 4GW from two different developers. The distances involved will require HVDC technology and the indicative capacities will require multiple links to the onshore network, most likely to north and south Wales.

There is a range of potential network design solutions, depending on the rate of growth and timing of the generation. A coordinated and integrated design solution is contracted and would allow incremental development, minimising redundancy risk while facilitating development that can incorporate further generation connections. By integrating at the source of these links, it is expected that network transfer can be achieved with the benefit of mitigating major onshore reinforcements compared to a radial approach.

Connection of these network design solutions to the Irish transmission system has also been progressed with EirGrid. The respective TSOs have jointly investigated the benefits of coordinating the infrastructure associated with these renewable wind energy projects. The benefits examined include:

- increased capacity for cross-border trade
- increased sharing of response and reserve
- reduced total generation capacity required to maintain security of supply
- reduction in overall capital costs and environmental impact
- future flexibility for network evolution and further integration.

For additional information, please see the joint study conducted with EirGrid, available on the National Grid website at the following address:

http://www.nationalgrid.com/uk/Electricity/OffshoreTransmission/Joint+Study+with+EirGrid/

Following this study, National Grid and EirGrid have undertaken a joint high-level technical study to explore how infrastructure associated with onshore Irish wind could be developed in the best way for all stakeholders. The report details the main analysis presented to an Energy Trading Grid Group (consisting of DECC and Ofgem and their Irish equivalents DCENR and CER) and is available on the National Grid website:

http://www2.nationalgrid.com/UK/Industry-information/Europe/Publications/

4.2.3
Technology

It is possible to improve network performance using methods ranging from dynamic ratings to new HVDC circuits, depending on the output requirements cost and risks. National Grid's strategy is to prioritise optimising existing assets before considering major new infrastructure construction.

Appendix E summarises the key features, development status and issues for a range of technologies that may be used to meet network capacity requirements.

For marginal or temporary increases in thermal capacity, asset performance can be enhanced using coordinated asset intelligence and condition monitoring to either improve the capability of circuits or defer the need for replacement. This could include overhead line hot-wiring, cable and transformer cyclic ratings, transformer and switchgear life extension.

Network reinforcement is not just about new capacity but can also mean releasing the latent capability of the system. This is achieved by enabling technologies, which do not deliver capacity alone, but as part of a network will improve transfer capacity or improve stability, which will allow higher boundary transfers. Where network parameters such as voltage, fault tolerance or stability are the limiting factors then reactive compensation can be used to improve regulation and thereby regional power capacity (shunt capacitor and reactor banks). Static VAR compensators (SVCs) and STATCOMs are used to retain voltage stability during fault conditions. In marginal cases, this can avoid the need for new circuits for security of supply.

Power flow control in AC, particularly meshed systems like the GB one, is difficult, but devices such as phase shifting transformers, quad boosters and series compensation can be strategically installed to compensate circuits to make the active power flow into lesser utilised circuits. This delivers more net power across the boundary. Series compensation is also being installed to increase the transfer capability on the Anglo-Scottish transmission boundary by improving the transient stability during fault conditions.

The series compensation case study shows how this is being used on the transmission system.

Too much generation in one region can result in unacceptable fault levels, requiring the system to be run split with reduced system security. Series reactors enable the system to be run fully intact, improving security of supply by controlling fault current to safe levels so customer and transmission plant is not overstressed or damaged.

A stage is reached where enhancing asset performance is not enough and a more permanent upgrade is needed. Refurbishment and up-rating involves the replacement of key components such as conductors (overhead lines) or new switchgear to increase the asset capability to achieve the higher rating on a permanent basis. This involves longer service outages and a more onerous impact on the network during the construction work, which can be minimised through coordinated planning and system operation.

Once all the existing asset options have been exhausted or proved insufficient, a new transmission circuit or substation may be required. Geographical, amenity and technical parameters will determine the viability of some technologies. Where multiple options remain, a cost-benefit analysis is necessary to consider the costs and the enduring asset management and network resilience measures. HVDC is playing an emerging role in the connection of renewable generation, particularly as an embedded solution within the AC network. While it provides controllable capacity, the coordination with the existing network raises significant challenges. This scenario is further described in the HVDC case study.

Network resilience

Network access and flexibility is a balance between enhancing the capability of existing infrastructure and installing more controllable technology to manage new operational conditions. The downside to lower-cost smarter solutions is the extra complexity, control and analysis needed. This becomes progressively more difficult and risky where smart solutions and FACTS devices are used in preference to building new circuits. Chapter 5 reports on the changes in system parameters concerning voltage, inertia, harmonics, control interactions and frequency response etc. which arise due to more renewable and embedded generation connecting to the system. Much of this new technology incorporates power electronics and advanced control systems. It is very important that these do not negatively impact with the other systems on the transmission system, such as generator AVRs or flexible AC transmission system (FACTS) devices. This requires on-going study, analysis and review of settings to recognise network changes. Security and dependability is paramount for critical national infrastructure such as the electricity networks. Cyber security becomes key as external services such as communication, information systems and software platforms increasingly play a significant role in delivering energy.

Asset management

Providing a secure and reliable network is not easy. The backbone of the 400kV transmission network was constructed in the 1950s and 60s and has been developing ever since. Unsurprisingly, it is made up of equipment of different technologies and age. Transmission assets tend to have very long operational lifetimes, many in excess of 50 years. Although much of the equipment is obsolete, it is in good condition with many years of service left, so integrating new modern high-tech solutions into the existing network requires a very good understanding of all the technologies. It also needs careful management, particularly around ratings, spares and maintenance.

Transmission technology, and especially its application, must be understood so that the utility can be confident that it can maintain security of supply for any credible planned or unplanned activity. This can be achieved through an effective combination of:

- modelling and monitoring of the interactions and dependencies between assets and the system
- specifications and testing to demonstrate the solution is fit for purpose
- coordinated ratings to avoid unnecessary asset stress and investment
- operational and control regimes to cater for all credible contingencies
- planning and commissioning of the asset to seamlessly introduce it into the operational network
- maintenance strategy to ensure critical equipment is safe and operational, meeting availability and reliability targets
- change control management to ensure protection and control systems have the correct settings to provide flexible operation and revised ratings.

4.2 continued
Overview of Transmission Solution Options

Opportunities for innovation

The transmission network has a high degree of control and intelligence, already making it a 'smart' grid. Automation is widely used to improve circuit availability, such as delayed circuit auto reclose following weather-induced non-permanent faults such as lightning strikes. It is also used to manage substation voltage through transformer tap-changer control and reactive device switching. Operational tripping supports 'connect and manage', allowing more capacity onto the network during 'system intact' conditions.

Making the grid smarter requires a deeper understanding of the relationship between asset performance, complex control systems and the resilience of support services such as communication services and information systems.

New technology solutions are continually being considered to facilitate more capacity from the existing network, to improve security or to reduce the size and footprint of equipment. Examples of this are new composite conductors being installed to increase the capacity of overhead lines, and new tower designs that will reduce the size and improve visual amenity around new transmission lines. There is also a lot of development in the field of HVDC to improve understanding and integrate it into AC networks to work efficiently with renewable sources of generation, particularly offshore wind.

In the field of asset management, improved techniques to incorporate condition monitoring, remote sensing and automation are being explored to improve inspection and maintenance without needing to take the circuit out of operation.

Increasing complexity drives a need for more detailed modelling and monitoring to validate the findings and conclusions. There are some big challenges to overcome when introducing new technology into a mature transmission system:

- Modelling and intimate system knowledge to specify and assess the equipment performance suitability for the application
- Comprehensive testing programme to ensure the technology is fit for purpose
- Commissioning programme to modify the adjacent equipment to safely integrate the new equipment into the system
- Knowledge of the operational risks and impact on reliability and availability
- Asset management strategy – benchmark performance, risk mitigation measures, return to service times, resource and skills.

Case study

This illustrates the deep network understanding and analysis required to reinforce the Anglo Scottish boundary integrating Series Compensation and HVDC to increase the export capability from Scotland.

The challenge

The volume of renewable generation installed in Scotland over recent years means that the export limit between England and Scotland is insufficient. Because of constraint costs and technical limitations, no single solution will address all the issues.

- Additional new permanent capacity is required to connect deep into the load centres in the English network, a distance of approximately 400km
- Transient stability restricts the B6 boundary to 3.3GW. The existing circuits between England and Scotland are long at approximately 100km each. A minimum of two new separate AC circuits would be required.

Options

Series compensation

Series compensation is a flexible AC transmission system (FACTS) device, which compensates the circuit inductance using capacitance, allowing the full line rating to be utilised.

Four series capacitors, each equipped with passive (SSR) bypass filters are being installed in Scotland; two units at Eccles 400kV Substation in the Stella West/ Blyth circuits; one unit at Moffat 400kV Substation in the Harker circuit and one unit at Gretna 400kV Substation in the Elvanfoot circuit.

Two thyristor controlled series capacitor (TCSC) units providing 35% compensation of the overhead line reactance are being installed at Hutton 400kV substation in the Harker circuits.

The (TCSC) and passive bypass filter technologies were chosen for their ability to prevent the production of sub-synchronous (SSR) capacitive frequencies. The series compensation will improve the transient stability and enable the transmission lines to be operated to their thermal limit, increasing the boundary transfer limit by 35%.

Integrated HVDC

The Western HVDC Link will operate at a world leading 600kV and rating of 2200MW. It is a mixed submarine and underground HVDC cable connection with a total route length of approximately 420 km (385 km submarine and 37 km underground), between Hunterston in Scotland and Connor's Quay, Cheshire.

This solution was chosen because installing a long-distance HVDC submarine cable in parallel with the onshore network could be achieved much more quickly than new onshore circuits. Also, the efficiency and reactive compensation requirements of an underground AC connection are too onerous and technically unviable for a 400km circuit (see appendix E12 and E13). It is the first HVDC circuit that will be an integral part of the GB electricity transmission system, since it will operate in parallel to the existing AC circuits.

HVDC can also provide value-adding ancillary services such as power oscillation damping and sub-synchronous resonance mitigation for the adjacent heavy-loaded and series-compensated HVAC overhead lines, potentially increasing the net transfer margin.

Innovation, risks and issues

These case studies are both very technically challenging projects. Detailed system and asset studies were carried out before specifications or orders could be prepared. In addition to the typical studies carried out for new projects (load-flow, voltage, insulation coordination and environmental amenity) the following were also required:

Sub-Synchronous Resonance (SSR) is a key risk aspect of Series Compensation schemes, as generator shafts' natural frequencies can be excited by network frequencies introduced with network series capacitance and damage the generator units. Studies were required to understand and quantify the SSR risk for generic series compensation designs in the Anglo-Scottish transmission circuits and affected generating units. Solution specific studies establish effective SSR damping or mitigation, and show that for a range of torsional frequencies, the SSR condition is effectively removed.

Transient Recovery Voltage (TRV) and Rate of Rise of Recovery Voltage (RRRV) studies identify any requirements to modify or upgrade switchgear impacted by the installation of the series compensation.

4.2 continued
Overview of Transmission Solution Options

Protection and control coordination studies of all adjacent circuits to ensure safe, correct and reliable operation in a series compensated network. This helps avoid the risk of mal- or mis-operation as a result of the series compensation installation. Studies identify a comprehensive testing regime using real time digital simulators to make sure the control systems will correctly respond to all the onerous contingencies identified during the study phase.

Harmonic assessment using modelling and network analysis tools provides the details of harmonic currents and voltages the design could introduce. Excessive harmonic content, exacerbated by any nearby power electronic installations (HVDC terminal or SVC) can cause overheating conditions in operational equipment (particularly of inductive components). Establish mitigation and compliant harmonic filter designs to control the incremental distortion to compliant levels.

Control interaction studies between the respective control schemes of TCSC, local generation, SVCs and the HVDC link that could cause mal operation of equipment that in isolation would function perfectly.

Studies to specify significant steady state and dynamic reactive compensation will be required to support and control the voltage at the HVDC terminals during normal operation or in the event of disturbances or contingencies.

Table of the Appendix E Sections:

E1	Overhead lines
E2	Cables
E3	Onshore cable installation
E4	Switchgear
E5	Transformers
E6	Shunt reactors
E7	Shunt capacitor banks
E8	Static VAR compensators
E9	Static compensation (STATCOM)
E10	Series compensation
E11	Quadrature boosters
E12	Submarine cables (3 core)
E13	Submarine cables (1 core)
E14	Subsea cable installation
E15	Offshore structures
E16	HVDC Current source
E17	HVDC Voltage source
E18	HVDC extruded cabes
E19	HVDC mass impregnated cables
E20	HVDC overhead lines
E21	HVDC switchgear
E22	Technology availability
E23	Unit Costs

Reference & additional information

Achenbach, S., Barry, V., Bayfield, C.H., Coventry, P.F., Increasing the GB electricity transmission network's power transfer capability between North and South–The Western HVDC Link, [Online], [Accessed: August 11, 2014]. http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6521238&sortType%3Dasc_p_Sequence%26filter%3DAND%28p_IS_Number%3A6521235%29

Electricity Networks Strategy Group, Our Electricity Transmission Network: A Vision for 2020, [Online], [Accessed: August 11, 2014]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48274/4263-ensgFull.pdf

Alstom Grid, High Voltage Direct Current (HVDC) Technology, [Online], [Accessed: August 11, 2014]. Available: http://www.alstom.com/Global/Group/Resources/Documents/Investors%20document/Investor%20events/Analysts%20presentation/Analyst%20Day%20-%20HVDC%20technology.pdf

4.2.4
Planning consents

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

England and Wales

In England and Wales, the consenting process for nationally significant infrastructure projects (NSIPs) is defined in the Planning Act 2008[2]. The Planning Inspectorate[3] 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 stations (onshore: more than 50MW capacity; offshore: more than 100MW capacity) and electric lines above ground over certain thresholds. UK national policy for NSIPs is set out in a series of National Policy Statements (NPSs).[4]

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 that includes notification, consultation and publicity requirements. 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 and Amenity Policy[5] that also outlines how we seek to meet our statutory responsibilities under Schedule 9 of the Electricity Act 1989[6]: to have regard to the preservation of amenity. 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[7].

[2] www.legislation.gov.uk/ukpga/2008/29/contents

[3] http://infrastructure.planningportal.gov.uk/

[4] infrastructure.independent.gov.uk/legislation-and-advice/national-policy-statements/www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/nps_en_infra/nps_en_infra.aspx

[5] www.nationalgrid.com/NR/rdonlyres/21448661-909B-428D-86F0-2C4B9554C30E/39991/SCADocument_2_Final_24_2_13.pdf

[6] www.nationalgrid.com/uk/LandandDevelopment/SC/Responsibilities/

[7] www.nationalgrid.com/NR/rdonlyres/E9F96A2A-C987-403F-AE7D-BDA07821F2C8/55465/OurApproach.pdf

4.2 continued
Overview of Transmission Solution Options

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

Scotland

In Scotland, new major energy infrastructure is consented through the Scottish Government. Applications to construct and operate offshore renewable generation of any capacity are made to Marine Scotland[8] which grants a marine licence for the works under the Marine (Scotland) Act 2010[9]. Marine Scotland then makes a recommendation to Scottish Ministers who grant Section 36 consent under the Electricity Act 1989[10].

Marine planning

The Marine and Coastal Access Act 2009[11] and the Marine (Scotland) Act 2010[12] establish 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.

An overarching UK Marine Policy Statement (March 2011)[13] 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[14] and will be implemented through marine plans in England, Scotland, Wales and Northern Ireland. Where there is no marine plan in place, the MPS sets the direction for decisions that affect the marine areas, such as granting licences for all public bodies.

For marine planning purposes, UK waters are 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)[15], Marine Scotland[16], the Welsh Government[17] and the Department of the Environment for Northern Ireland[18] are responsible for the marine planning systems in their authority areas.

[8] scotland.gov.uk/About/Directorates/marinescotland

[9] www.legislation.gov.uk/asp/2010/5/contents

[10] www.legislation.hmso.gov.uk/acts/acts1989/Ukpga_19890029_en_2.htm
www.legislation.gov.uk/ukpga/1989/29/section/36

[11] www.legislation.gov.uk/ukpga/2009/23/contents

[12] www.scotland.gov.uk/Topics/marine/seamanagement/marineact

[13] www.defra.gov.uk/environment/marine/protect/planning/archive.defra.gov.uk/environment/marine/documents/interim2/marine-policy-statement.pdf

[14] archive.defra.gov.uk/environment/marine/documents/ourseas-2009update.pdf

[15] www.marinemanagement.org.uk/

[16] www.scotland.gov.uk/About/People/Directorates/marinescotland

[17] wales.gov.uk/?lang=en

[18] www.doeni.gov.uk/

Marine licensing

New legislation has changed the system for marine consenting and licensing. Rather than multiple consents being required under multiple Acts, the new streamlined system now requires a single 'marine licence'[19].

In the past, multiple licensing regimes and authorities regulated marine development and this included consent under the Coast Protection Act 1949[20] (CPA consent) and a licence under the Food and Environment Protection Act 1985[21] (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, Natural Resources Wales (on behalf of the 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 Secretary of State will determine applications for offshore generation development projects greater than 100MW in size. Any associated infrastructure including cabling, collector stations and converter stations would require consent under the Marine and Coastal Access Act 2009[22], in England, the developer may apply for this to be consented by the Secretary of State as 'associated development' and a marine licence will be issued as part of the (DCO)[23] in consultation with the marine bodies.

[19] marinemanagement.org.uk/licensing/index.htmmarinemanagement.org.uk/licensing/marine.htm

[20] www.legislation.gov.uk/ukpga/Geo6/12-13-14/74

[21] www.legislation.gov.uk/ukpga/1985/48

[22] www.legislation.gov.uk/ukpga/2009/23/contents

[23] www.communities.gov.uk/publications/planningandbuilding/dcosimpactassessment

4.2 continued
Overview of Transmission Solution Options

Table 4.2
Indicative timeline for the offshore planning process for an offshore generation project (larger than 100MW of installed generation capacity) connecting to or using the NETS

Stage	Time	Activity	Consulted/Responsible Party
Project Development		Strategic Environmental Assessment (SEA) Zones for tender Site identification and selection	DECC Planning Inspectorate The Crown Estate Offshore Developers
		Site awarded	The Crown Estate
		Agreement for lease	The Crown Estate
	6 months	Connection application to National Grid Electricity Transmission (NGET)	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 Statement	Planning Inspectorate Marine Management Organisation (MMO) Scottish Government Marine Scotland Welsh Government Local 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 Section 36 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/ TO

4.3 Commercial and Non-Build Options

When it comes to providing boundary capacity, commercial and non-build solutions can complement or offer an alternative to asset solutions. National Grid would like to explore further with stakeholders the possibility and benefits of commercial, non-build solutions to meet transmission capacity requirements. At this stage we are keen to learn how our stakeholders would like to be more involved in meeting future network requirements through initiatives such as:

- Demand side response
- Generation and demand curtailment (e.g. inter-trips)
- Third parties to consider asset investment at specific locations to provide system support (e.g. reactive power services).

Stakeholder engagement
We welcome views on the assumptions that we have used for onshore and offshore NETS developments in the ETYS.

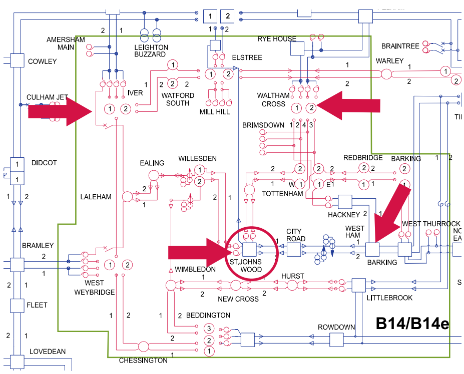
4.3.1 Commercial options: Demand side response

Customers and stakeholders can participate in offering ancillary services such as demand management by curtailing their demand to alleviate constraints. This could be by way of the end energy consumer taking action in reducing the level of energy that they take from the electricity transmission system when required. There are two types of demand side response: one is local to a grid supply point (GSP) and sufficient to reduce constraints at an individual substation; and the other another type would require a larger action involving a conglomerate of potential suppliers reducing demand across a wider region. An example is illustrated below.

The area circled by the green line in Figure 4.4 indicates the possibility of reducing demand at a single GSP, such as St. Johns Wood, to reduce constraints at that local substation. In comparison, the area encompassed by the green line indicates the possibility of reducing demand at a number of sites across a region. For example, if we could identify a number of sites (arbitrarily shown below by the arrows) that could collectively reduce their demand at the same time, this would have a positive impact on the nearest electricity transmission system boundary.

In specifying the duration of both demand side response types, enough time would need to be allowed for National Grid to re-optimise the transmission system.

Figure 4.4
An example of potential demand side response opportunities in and around London



4.3 continued
Commercial and Non-Build Options

Demand side response services could therefore be contracted out to third parties or suppliers to switch off their highly loaded plants at certain periods of time, such as winter peak, under planned outage conditions, or under fault conditions. This would reduce the loading on specific GSPs or potentially entire regional areas.

4.3.2 Commercial options: Generation and demand curtailment: inter-trips

An inter-trip will automatically disconnect a generator or demand from the electricity transmission system when a specific event occurs. There are two types of inter-trip service: commercial inter-trips and system-to-generator operational inter-trips. In this section we will consider only the commercial inter-trip option.[24]

The automatic operation of an inter-trip typically requires the monitoring of all transmission circuits within a localised zone that are linked with system protection arrangements. Should a selected circuit trip, the logic process will trigger activation of a scheme to disconnect generation and/or demand.

Inter-trip services may be required as an automatic control arrangement where generation or demand may be reduced or disconnected following a system fault event to relieve localised network overloads, maintain system stability, manage system voltages and/or ensure the quick restoration of the electricity transmission system following its possible collapse. We may use these commercial inter-trips for planning scenarios on all of the boundaries discussed in Chapter 3. If you believe that you could offer an inter-trip service where a current reinforcement is planned, please contact us (the opportunities for these areas are highlighted in Chapter 4, Section 4.9).

4.3.3 Commercial options: Reactive power services

National Grid is required to maintain the reactive power balance on the electricity transmission system. Reactive power can only be managed locally, so without the appropriate injections of reactive power at the correct locations, electricity transmission system voltages could breach statutory planning and operational limits. National Grid controls reactive power through two balancing services: obligatory reactive power services and enhanced reactive power services.

As we look to plan the future transmission system, reactive compensation requirements will be identified in certain areas. Rather than only looking at installing new transmission assets in these areas, we would like to establish if there is opportunity for agreement with local customers who may have the facilities available as a suitable alternative. The reactive service that we would be interested in is a guaranteed obligatory service or

[24] Where generators are 100% effective against the constraint any necessary operational inter trips are detailed in Appendix F3 of the customer offer and are treated under CAP 076.

an enhanced reactive service provision. This might be in the form of agreeing a service to provide reactive power as required.

The obligatory reactive power service is the provision of varying reactive power output. At any given output, generators may be required to produce or absorb reactive power in order to help manage system voltages close to their point of connection. All generators covered by the Grid Code must have the capability to provide reactive power.

The enhanced reactive power service is the provision of voltage support that exceeds the minimum technical requirement of the obligatory reactive power service.

We would expect these opportunities to be available to owners of any plant or apparatus that can generate or absorb reactive power, including static compensation equipment.

Stakeholder engagement
We welcome your views on what would incentivise users to make more reactive power available to the NETSO.

4.3.4 Non-build options: Running arrangements/switch events

The operation of substations in the UK varies from site to site, but the most common running arrangements are solid, two-way and three-way splits. The running arrangements are usually dictated by the fault level of the site. As more non-synchronous plants connect to the system, the fault level of many sites will fall, which will allow the system operator more flexibility in managing the system while maintaining system security. There are two main benefits for the operator: the load sharing between circuits can be arranged so that they are at the desired optimal (therefore further utilising the assets) and post fault switching for a change in running arrangement under a secured event. This allows greater flexibility to the operator in managing constraints on the system while maintaining system security.

4.3.5 Non-build options: Transmission equipment inter-trips

National Grid is responsible for system security as a whole and for ensuring a safe, reliable and economical transmission system for all its customers. System security is the main constraint throughout the year, so a failure to secure the system against faults or plant loss after an outage has started could cause possible network effects, such as secondary overloads, consumer interruptions and frequency deviations. If the latter is shown to be non-existent, secondary overloads on transmission equipment can be inter-tripped, provided that it adheres to internal operational and security standards. This methodology allows the automatic isolation of lower-rated assets that are prone to overloads, and could be a cost-effective solution in comparison to asset replacement/reinforced solutions.

4.3 continued
Commercial and Non-Build Options

4.3.6 Non-build options: Interconnector ramping/power reversal

As Europe becomes more interconnected, it is likely that the UK will have further interconnection with neighbouring EU countries.

The UK currently has four interconnectors in operation, with more being contracted to connect in the next 10 years. Most of them are based on HVDC technology, which has advantages over conventional AC technology – a good example of this is the rapid control of active power and the independent control of reactive power (assuming that voltage source converter technology is used).

The features and benefits of HVDC depend on the technology used, the size, the specification and the system requirements. This provides many advantages to the transmission system because the rapid response of active power control via ramping down/power reversal facilities can minimise or prevent overloads on transmission assets. This is also true in terms of voltage support for regions prone to voltage compliance or instability issues, where additional reactive support from an interconnector may provide a good alternative to otherwise required reactive compensation devices.

4.3.7 Non-build options: Dynamic thermal ratings

The dynamic thermal ratings technique fully optimises existing transmission assets based on astute, real-time system monitoring. Various sensors measure the condition of the asset in terms of key characteristics such as temperature, heat loss and conductor sag. Monitoring the data from the sensors gives the operator an insight into the operation of the asset, without the need for detailed calculations or calibration. This can lead to optimal short-term current rating enhancements, which would otherwise be qualitatively assessed via historical data.

4.3.8 Non-build options: **QB coordination**

For the last 20 years, quadrature boosters (QBs) have been used to increase or alleviate flows on given circuits across the country. However, larger power flows are now experienced across the country and are travelling further distances. A coordinated approach to all the QBs would ensure that the power sent from the source to the load centres is managed in an efficient and economical way with minimal constraints. This would require a sophisticated monitoring and control system that would help the operator to coordinate tapping activities at minimal time along with a strategy for the given situation.

4.3.9 Non-build options: **Further work and contact details**

We hope that a combination of network investment and the use of commercial or ancillary services such as those previously described will reduce costs to consumers, enhance security of supply and contribute to sustainable development. National Grid is developing a process to explore the potential for third-party suppliers to offer commercial or ancillary services that could negate or delay the need for system reinforcement. We will be sharing this information with stakeholders during 2015.

Stakeholder engagement
To help deliver our engagement strategy for developing and procuring non-build reinforcement options, we would like to know what information third-party suppliers need from National Grid, and in what timescale. We would very much welcome your input. Please contact us via:
.box.transmission.etys@nationalgrid.com

4.4
Asset Reinforcement Options

This section of the statement presents a number of potential reinforcement options to satisfy the need for wider NETS capability as part of network planning. The reinforcement options in England and Wales are considered as part of the NDP.

An earliest in-service date (EISD) is provided for each potential reinforcement. It suggests the earliest date when the project could be delivered and put into service, if investment into the project were started immediately.

Options that reinforce the network across multiple regions are only referenced once in this section. For example, although the Western HVDC link will provide benefits for three regions (Scotland – SHE Transmission, Scotland – SP Transmission and North England), the link is only referenced in Section 4.4.2 Scotland – SP Transmission.

We have again used colour codes (see Figure 4.1) to help identify the information relating to a particular region.

4.4.1
Scotland – SHE Transmission

1. Beauly to Denny Reinforcement **EISD 2015**

Replace the existing Beauly–Fort Augustus–Errochty–Bonnybridge 132kV overhead lines with a new 400kV tower construction which terminates at a new substation near Denny in SP Transmission's area, and carry out associated AC substation works. One of the circuits will be operated at 400kV and the other at 275kV. The Beauly to Denny reinforcement extends from Beauly in the north to Denny in the south, providing additional capability for boundary B1 as well as boundaries B2 and B4.

Current Status	In construction	Primary boundary capability increase	B4	1150MW

2. Beauly–Blackhillock–Kintore 275kV Uprate **EISD 2015**

Replace the existing conductors on the existing 275kV double circuits between Beauly, Knocknagael, Blackhillock and Kintore with new high capacity conductors.

Current Status	In construction	Primary boundary capability increase	B1	500MW

3. Beauly–Mossford 132kV Reinforcement **EISD 2015**

Replace the existing 132kV overhead line with a new high capacity 132kV overhead line. A new 132kV substation at Corriemoillie near Mossford was completed in October 2013.

Current Status	In construction	Primary boundary capability increase	Radial	250MW

4. Kintyre to Hunterston Subsea Link **EISD 2015**

Install two 220kV subsea cables from Crossaig, 13km north of Carradale, to Hunterston in Ayrshire, and reinforce the existing 132kV double circuit overhead line from Crossaig to Carradale.

Current Status	In construction	Primary boundary capability increase	B3	150MW

5. Caithness–Moray Reinforcement Strategy — EISD 2018

Construct an HVDC link between a new substation at Spittal in Caithness and Blackhillock in Moray, along with associated onshore reinforcement works. The onshore works include the rebuild of the 132kV double circuit line between Dounreay and Spittal at 275kV, a short section of new 132kV overhead line between Spittal and Mybster, new 275/132kV substations at Fyrish (near Alness), Loch Buidhe (to the east of Shin), Spittal (5km north of Mybster) and Thurso. This will be designed with a multi-terminal capability to allow a third HVDC link from Shetland or Orkney to be connected if needed.

Current Status	In construction	Primary boundary capability increase	B0	800MW
			B1	850MW

6. Gravir on Lewis to Beauly HVDC Link — EISD 2020

Install a new HVDC transmission link from a new substation at Gravir on Lewis to Beauly substation. The HVDC cable route will be partly subsea and partly overland.

Current Status	Design	Primary boundary capability increase	Radial	450MW

7. Shetland to Mainland HVDC Link — EISD 2020

Install a subsea HVDC transmission link from a new substation at Kergord on Shetland to a DC bussing point at Sinclairs Bay in Caithness to integrate with the main Caithness–Moray HVDC link as described above. This will form a three-ended multi-terminal HVDC link arrangement.

Current Status	Design	Primary boundary capability increase	Radial	600MW

8. Orkney–Dounreay AC Subsea Connection — EISD 2018

Construct an AC subsea cable link from Bay of Skaill, on the western side of Orkney, to the existing 275kV substation at Dounreay.

Current Status	Design	Primary boundary capability increase	Radial	200MW

9. East Coast 400kV Upgrade — EISD 2020

A joint SHE Transmission and SP Transmission project to upgrade the existing east coast overhead line between Blackhillock and Kincardine to 400kV, using existing infrastructure that is currently operated at 275kV but which was constructed ready for 400kV. Includes new substations at Rothienorman, Alyth and an extension of the existing substations at Kintore and Kincardine. The existing overhead line between Rothienorman and Peterhead will also be re-insulated to 400kV with associated interface works required at Peterhead substation.

Current Status	Planning	Primary boundary capability increase	B4	850MW

10. Tealing–Westfield–Longannet 275kV Uprate — EISD 2018

Part of East Coast 400kV upgrade strategy. This is a joint SHE Transmission and SP Transmission project to re-profile the existing double circuit overhead line between Tealing–Westfield–Longannet to 65 deg C, with associated works to increase the circuit ratings. This project must follow the East Coast 400kV upgrade in order to achieve the stated boundary capability increase.

Current Status	Design	Primary boundary capability increase	B4	300MW

4.4 continued
Asset Reinforcement Options

11. Eastern HVDC One **EISD 2023**

A new ~2GW subsea HVDC cable link from Peterhead to Hawthorn Pit with associated AC network reinforcement works at both ends. The scope of Eastern HVDC Link One shown here is valid at the time of publication. The three onshore transmission owners will continue to work together during 2015 to review the most economic and efficient design solution and time for delivery of the Eastern HVDC link.

Current Status	Optioneering	Primary boundary capability increase	B4	2200MW
			B6	2200MW

12. Eastern HVDC Three **EISD 2025**

A potential new ~2GW subsea HVDC cable link between Peterhead and North East England with associated AC network reinforcement works on both ends.

Current Status	Optioneering	Primary boundary capability increase	B4	2200MW
			B6	2200MW

13. Foyers to Knocknagael 275kV Uprate **EISD 2015**

Replace the existing conductors on the 275kV overhead line between Knocknagael and Foyers with high capacity conductors.

Current Status	Planning	Primary boundary capability increase	Radial	650MW

14. Lairg to Loch Buidhe 275kV Reinforcement **EISD 2019**

Investigate the installation of a 275kV overhead line between Lairg and a new substation at Loch Buidhe to harvest generation in the Lairg area.

Current Status	Design	Primary boundary capability increase	Radial	700MW

15. Beauly to Tomatin 275kV Reinforcement **EISD 2018**

Investigate the installation of a 275kV overhead line between Beauly and a new substation at Tomatin to harvest generation in the area.

Current Status	Design	Primary boundary capability increase	Radial	500MW

16. Beauly to Blackhillock Reinforcement **EISD 2024**

Investigate construction of a new high capacity 400kV or 275kV overhead line between Beauly and Blackhillock to reinforce the B1 boundary.

Current Status	Scoping	Primary boundary capability increase	B1	1000MW

17. Skye Second 132kV Circuit **EISD 2021**

Investigate the installation of a second 132kV overhead line between Fort Augustus and the north west of Skye to harvest generation in the area.

Current Status	Scoping	Primary boundary capability increase	Radial	160MW

4.4.2
Scotland – SP Transmission

18. B6 Series and Shunt Compensation — EISD 2016

Install series compensation in the Harker–Hutton, Eccles–Stella West and Strathaven–Harker routes. Two 225MVar MSCs to be installed at Harker, one at Hutton, two at Stella West and one at Cockenzie. Uprate the Strathaven–Smeaton route to 400kV and uprate the cables at Torness. This effectively reduces the impedance of the Anglo-Scottish circuits improving their loading capability. The English stage of works can be completed in 2015 ahead of those in Scotland.

Current Status	In construction	Primary boundary capability increase	B6	10 00MW

19. Western HVDC Link — EISD 2016

This is 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. At the northern end it will include construction of a Hunterston East 400kV GIS substation. Reconfiguration of the associated 400kV network will facilitate the decommissioning of Inverkip 400kV substation and the future rationalisation of the local overhead line network.

Current Status	In construction	Primary boundary capability increase	B6	2200MW

20. Central 400kV Uprate — EISD 2021

The Central 400kV Uprate uses existing infrastructure between Denny and Bonnybridge, Wishaw and Newarthill along with 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 reinforcement will create two new north to south circuits through the central belt: a 275kV Denny/Wishaw circuit and a 400kV Denny/Wishaw circuit, thereby significantly increasing B5 capability.

Current Status	Design	Primary boundary capability increase	B5	1900MW

21. Harker–Strathaven Reconductoring and Series Compensation — EISD 2019

Reconductor the existing double circuit overhead line which runs from Harker to Strathaven with higher rated conductor and additional series compensation.

Current Status	Scoping	Primary boundary capability increase	B6	500MW

22. Eastern HVDC Two — EISD 2024

A new second ~2GW submarine HVDC cable route between Torness and North East England with associated AC network reinforcement works on both ends.

Current Status	Scoping	Primary boundary capability increase	B6	2200MW

23. South West Scotland Connections Project — EISD 2015

Extend the 275kV overhead line network in Ayrshire from the Coylton 275kV substation to the west of New Cumnock. Construct a New Cumnock 275/132kV substation, the New Cumnock 132kV substation will form a ‘collector’ substation for renewable generation in south and east Ayrshire. The 480MW capacity of the initial stage of development will be capable of phased development, as required to accommodate renewable generation development in the area.

4.4 continued
Asset Reinforcement Options

	Current Status	Scoping	Primary boundary capability increase	Radial	480MW

24. Kilmarnock South–Coylton 275kV Uprating **EISD 2016**

Reconductor the existing double circuit overhead line route from Kilmarnock South to Coylton with higher rated conductor and address an existing 275kV cable restriction. This will help make sure that the circuits provide sufficient thermal capacity to transport generation output from South West Scotland, as wind generation increases.

	Current Status	Design	Primary boundary capability increase	Radial	350MW

25. Coylton–Mark Hill 275kV Uprating **EISD 2016**

Reconductor the existing single circuit overhead line route from Coylton to Mark Hill with higher rated conductor. This will help ensure that the circuit provides sufficient thermal capacity to transport generation output from the Mark Hill 275kV group as wind generation increases over time.

	Current Status	Design	Primary boundary capability increase	Radial	350MW

26. Kilmarnock South 400/275kV Substation Uprating **EISD 2018**

Replace the Kilmarnock South 275kV Substation to increase thermal rating. Install a third 400/275kV 1000MVA transformer and reconfigure Kilmarnock South 400kV substation. This will help ensure the substation provides sufficient thermal capacity to transport generation output from South West Scotland to the 400kV system, as wind generation increases over time.

	Current Status	Optioneering	Primary boundary capability increase	Radial	510MW

27. Kilmarnock South–Coylton 275kV Reinforcement **EISD 2022**

Construct a new (second) 275kV double circuit overhead line from Kilmarnock South 275kV substation to Coylton 275kV substation. This will ensure the provision of sufficient thermal capacity to transport generation output from Coylton and South West Scotland to the 400kV system, as the amount of wind generation increases over time.

	Current Status	Optioneering	Primary boundary capability increase	Radial	500MW

28. Dumfries and Galloway Reinforcement **EISD 2023**

The transmission network in the Dumfries and Galloway Region is provided by an interconnected single 132kV circuit between Dumfries and Coylton. This circuit has a summer rating of 106MVA and was constructed in 1936 to connect the Galloway Hydro scheme.

Investigate construction of a new overhead line to serve the main demand blocks, existing generation portfolios and facilitate the connection of new renewable generation in the Dumfries and Galloway region.

	Current Status	Scoping	Primary boundary capability increase		TBC

4.4.3 North England

29. New 400kV Transmission Route between Torness and Lackenby — EISD 2027

Establish a new 400kV transmission route between Torness and Lackenby. This reinforcement involves reconductoring a number of spans for the existing 275kV circuit between Tod Point and Hartlepool. The new transmission route provides capacity for flows, mainly on the east side of the B6 boundary, following faults of any of the circuits crossing the boundary. This reinforcement will provide additional thermal, voltage and transient capability.

Current Status	Scoping	Primary boundary capability increase	B6	4380MW

30. New 400kV Transmission Route between Harker–Heysham — EISD 2027

Construct a new 400 kV transmission route between Harker and Heysham via new substations located within the vicinity of Middleton, Moorside, Roosecote and Stainburn.

Current Status	Scoping	Primary boundary capability increase	B7	300MW

31. Mersey Ring Uprate — EISD 2021

Uprate the existing 275kV double circuits from Penwortham to Kirkby to operate at 400kV. Associated work includes constructing a new Kirkby 400kV substation and a new Washway Farm 400/132kV substation with two 400/132kV 240MVA SGTs adjacent to the existing site. This reinforcement will help to improve power sharing capability across the Western circuits by reducing stress on the Penwortham–Padiham circuit and increasing the power flow on Kirkby–Lister Drive–Birkenhead circuits.

Current Status	Scoping	Primary boundary capability increase	B7a	760MW

32. Reconductor Penwortham–Padiham & Penwortham–Carrington and Upgrade Kirkby–Penwortham — EISD 2020

Uprate the Penwortham–Padiham and Penwortham Carrington circuits and uprate the existing 275kV double circuits from Penwortham to Kirkby to operate at 400kV. Associated work includes constructing a new Kirkby 400kV substation and a new Washway Farm 400/132kV substation with two 400/132kV 240MVA SGTs adjacent to the existing site. This work will improve the capability of the network to handle the heavy north to south power flows due to the large amount of expected generation connection in Scotland.

Current Status	Scoping	Primary boundary capability increase	B7a	2070MW

33. Kirkby and Rainhill Substation Upgrade — EISD 2017

Replace circuit breakers and equipment at Rainhill so the running arrangements at Kirkby and Rainhill can be changed to a two-way split configuration. This change to the running arrangement will divert more power to flow into the Kirkby–Rainhill–Fiddlers Ferry route from the Kirkby–Lister Drive–Birkenhead route; as a result, loading on the Kirkby to Lister Drive circuits will be better shared and the stress on them will be relieved. Accordingly, the power flows around the 275kV Mersey ring and hence the capability of the network to handle north to south power flows will be improved significantly.

Current Status	Scoping	Primary boundary capability increase	B7a	100MW

4.4 continued
Asset Reinforcement Options

34. New 400kV Transmission Route between Norton–Padiham — EISD 2025

Construction of a new 400kV transmission route between Norton and Padiham will provide additional thermal and voltage capability to the northern boundaries by better sharing the load across the Western and Eastern circuits.

Current Status	Scoping	Primary boundary capability increase	B7a	700MW

35. Lackenby–Stella West New 400 kV Transmission Route — EISD 2025

Construct a new 400kV transmission route between the Lackenby to Stella West substations. This extra transmission route will improve the capability of the network to export power from north to south. Shown below is the current status and accumulative boundary capability increase for above mentioned reinforcements in conjunction with Reconductoring of Penwortham–Padiham & Penwortham–Carrington and upgrading Kirkby–Penwortham.

Current Status	Scoping	Primary boundary capability increase	B7	1860MW

36. Norton–Osbaldwick circuits Hotwiring and Reconductoring — EISD 2020

Hotwire to higher operating temperature and reconductor the remaining sections of the existing 400kV double circuits which run from Norton to Osbaldwick to achieve higher circuit ratings.

Current Status	Scoping	Primary boundary capability increase	B7	730MW

37. Reconductor Lackenby–Norton Circuit — EISD 2018

Reconductor sections of the Lackenby – 400kV circuit with higher rated conductor, and uprate the cross-site cable at Lackenby 400kV substation to higher rating. This will help ensure the circuits will provide sufficient thermal capacity to transport the excess generation from Scotland to southern demand.

Current Status	Scoping	Primary boundary capability increase	B7	380MW

38. Uprate Harker–Stella West circuits — EISD 2025

Uprate the 275kV circuit between Harker and Stella West (via Fourstones) to 400kV. This reinforcement will improve the thermal capacity of the network around northern boundaries and will enable more generation to be transported from Scotland to England.

Current Status	Scoping	Primary boundary capability increase	B7a	340MW

39. Killingholme South–West Burton New Transmission Route — EISD 2023

Construct a new 400kV substation at Killingholme South and a new transmission route between the new substation and West Burton. This extra transmission route will improve the capability of the network to export excess generation from the Humber area in the future.

Current Status	Scoping	Primary boundary capability increase	EC1	4150MW

40. East Coast Integration Stage One — EISD 2026

The integration of Dogger Bank Round 3 offshore windfarm projects 1 and 12 by AC links will provide boundary capability across B7 and B7a. This is because the connecting onshore locations of the projects situated at the north and south of both boundaries B7 and B7a respectively. This will help improve the ability of the network to handle the heavy north to south power flows across these boundaries.

Current Status	Scoping	Primary boundary capability increase	B7	1500MW
			B7a	400MW

4.4.4 East England

41. Hotwire Bramford–Braintree–Rayleigh Main and Switch Gear upgrade at Pelham — EISD 2018

Increase the thermal capability of the existing circuit between Bramford, Braintree and Rayleigh Main by increasing the operating temperature. This reinforcement also includes switchgear upgrade on the Bramford–Pelham circuit at the Pelham substation. This will help ensure the circuits will provide sufficient thermal capacity to transport the excess generation in the East Anglia area to South East England, as an increasing amount of wind and nuclear generation is expected to connect in the area in the future.

Current Status	Scoping	Primary boundary capability increase	EC5	500MW

42. Bramford–Twinstead New Overhead Lines — EISD 2018

Reconductor the existing circuit which runs between Pelham, Braintree and Rayleigh Main, and construct a new transmission route from Bramford to the Twinstead tee-point. This will create double circuits that runs between Bramford–Pelham and Bramford–Braintree–Rayleigh Main. These works will result in two transmission routes for power to flow south from the East Anglia area thereby significantly increasing the network's capability to export excess generation from the area.

Current Status	Scoping	Primary boundary capability increase	EC5	1950MW

43. Norwich–Bramford Reconductoring — EISD 2016

Reconductor the existing double circuits that run from Norwich to Bramford with higher rated conductor. This will help make sure that the circuits provide sufficient thermal capacity to transport the excess generation in the East Anglia area, as an increasing amount of wind and nuclear generation is expected to connect in the area in the future.

Current Status	Scoping	Primary boundary capability increase	EC5	270MW

44. Rayleigh–Coryton South–Tilbury Reconductoring — EISD 2018

Reconductor the existing circuits that run between Rayleigh Main–Coryton South–Tilbury with higher rated conductor. This will help ensure the circuits will provide sufficient thermal capacity to transport the excess generation from the East Anglia area to the south east demand, as an increasing amount of wind and nuclear generation is expected to connect in the area in the future. This reinforcement when taken in conjunction with Bramford-Twinstead above provides more than 3GW of capability (depending on the scenario).

Current Status	In Construction	Primary boundary capability increase	EC5	100MW

45. New Transmission Route and QBs on East Anglia — EISD 2025

Construct two new 400kV transmission routes one from the East Anglia to North London and other from East Anglia to the East Coast. This reinforcement also includes a pair of QB on the Bramford–Tilbury circuit to control the flow across the Bramford–Tilbury and Bramford–Pelham circuit. These works will help to ensure the circuits will provide enough thermal capacity to transport excess generation out from East Anglia.

Current Status	Scoping	Primary boundary capability increase	EC5	c. 4200MW

4.4 continued
Asset Reinforcement Options

46. Rayleigh Main Series Reactor — EISD 2019

Install a pair of 3000MVA series reactors at the Rayleigh Main substation on the Braintree–Rayleigh Main circuits. Following completion of the Bramford–Twinstead project, for a double circuit outage on the newly formed Bramford–Pelham double circuit, significant flows will be encouraged by the low impedances on the newly formed Bramford–Braintree–Rayleigh double circuit to go south towards Rayleigh Main 400kV substation. This will potentially cause further overloads on the circuit south of Rayleigh Main even after they are reconductored with higher rated conductor.

Current Status	Scoping	Primary boundary capability increase	EC5	580MW

47. Reconductor Bramford–Braintree–Rayleigh Main circuits — EISD 2018

This reinforcement is also planned to deliver after the Bramford–Twinstead project. In this solution the newly formed Bramford–Braintree–Rayleigh Main 400kV circuits will be reconductored with triple Araucaria conductor.

48. Reconductor Bramford–Pelham double circuit — EISD 2018

This reinforcement is planned to deliver after Bramford–Twinstead project. In this solution the newly formed Bramford–Pelham 400kV circuits is designed to reconductor with triple Araucaria conductor. This will further increase the thermal capacity of the line and will assist to export more power from East Anglia.

49. East Anglia MSC — EISD 2017

Install a 225MVAr MSC to provide voltage support to the East Anglia area. The MSC will help maintain voltage compliance when there is a fault around the area, leading to diversion of power flowing through a longer transmission route.

Current Status	Scoping	Primary boundary capability increase	EC5	190MW

50. East Coast Integration Stage Two — EISD 2022

Once enough offshore transmission platforms are built and connected to the Wash, it will be possible to integrate them together with platforms connected to other areas by AC interconnection circuits. This will help to improve the network's ability to handle the heavy north-to-south power flows across multiple boundaries including boundaries B8, B9, B11 and B16

Current Status	Scoping	Primary boundary capability increase	B8	2000MW
			B9	2100MW

51. Reconductor West Burton–High Marnham Circuit — EISD 2017

Complete reconductoring of the remaining section of existing West Burton–High Marnham 400kV circuit.

Current Status	Scoping	Primary boundary capability increase	EC5	870MW

4.4.5
South England

52. Wymondley Turn-in — EISD 2019

Modify the existing circuit that runs from Pelham to Sundon. Turn in the circuit at Wymondley to create two separate circuits that run from Pelham to Wymondley and from Wymondley to Sundon. This work will improve the balance of the power flows on the North London circuits, and increase the networks capability to import power into London from the north transmission routes.

Current Status	Scoping	Primary boundary capability increase	B14	300MW
			B14e	1020MW

53. Hackney–Tottenham–Waltham Cross Uprate — EISD 2019

Uprate and reconductor the existing 275kV transmission route which runs between Hackney–Tottenham–Brimsdown–Waltham Cross with higher rated conductor to operate at 400kV, and reconductor the existing double circuits running from Pelham to Rye House with higher rated conductor. Also, carry out the associated work including constructing a new Waltham Cross 400kV substation, modifying the Tottenham substation and installing two new transformers at the Brimsdown substation. This work will increase the London B14 boundary capability and facilitate future East Anglia, Thames Estuary generation and also Interconnectors on the South Coast.

Current Status	Planning	Primary boundary capability increase	B14e	370MW
			EC5	520MW

54. Wymondley QBs — EISD 2019

Install a pair of 2750MVA QBs on the double circuits running from Wymondley to Pelham at the Wymondley 400kV substation. The pair of QBs will improve the capability to control the power flows on the North London circuits, and improve the capability of the network to import power into London from the north transmission routes significantly.

Current Status	Scoping	Primary boundary capability increase	B14e	730MW
			EC5	500MW

55. Dungeness–Sellindge–Canterbury North Reconductoring — EISD 2017

Reconductor the existing double circuits that run between Dungeness–Sellindge–Canterbury North with higher rated conductor. This will help ensure the circuits will provide sufficient thermal capacity to transport the power along the south coast during time with high interconnector flows.

Current Status	Design	Primary boundary capability increase	B15	2140MW

56. Reconductor Kemsley–Rowdown–Littlebrook double circuits — EISD 2018

Reconductor the 400kV circuits running through Kemsley–Rowdown and Littlebrook substation with higher rated conductor.

Current Status	Scoping	Primary boundary capability increase	SC1	2400MW

4.4 continued
Asset Reinforcement Options

57. New Transmission Route on South Coast — EISD 2025

Construct a 400kV transmission route from the south coast to south London and carry out associated work. These works will provide a new transmission route connecting south of London and the south coast circuits between Kemsley and Lovedean, resulting in a strong network connection for the south coast area. This reinforcement would require completion of Kemsley–Rowdown–Littlebrook reconductoring first to provide incremental capability.

Current Status	Scoping	Primary boundary capability increase	SC1	2160MW

58. Rye House Shunt Capacitor — EISD 2020

Install two 225MVAr shunt capacitors at Rye House 400kV substation to improve the overall voltage across the boundary.

Current Status	Scoping	Primary boundary capability increase	B14e	200MW

59. Series and Shunt Compensation on south coast — EISD 2019

Install series compensation at six locations on the South Coast. This reinforcement also requires three 200MVar shunt reactors to control high voltage during summer minimum condition and four 225Mvar MSC to support post-fault low voltage during interconnector export (to Europe) conditions.

Current Status	Scoping	Primary boundary capability increase	SC1	650MW

60. South Coast Reactive Compensation — EISD 2019

This is an alternative solution to the series and shunt compensation mentioned above. Install one SVC and one 225MVAr MSC each at Bolney, Ninfield and Richborough substation. These MSCs and SVCs will prevent voltage instability issues when there is a fault around the area during interconnector exporting (to Europe) conditions.

Current Status	Scoping	Primary boundary capability increase	B15	500MW
			SC1	440MW

61. Hinkley Point–Seabank new Transmission Route — EISD 2020

Establish a new 400kV transmission route between Hinkley Point and Seabank. The new transmission route provides capacity for flows, following faults of any of the circuits in that area. This reinforcement will provide additional thermal, voltage and transient capability.

Current Status	Planning	Primary boundary capability increase	B13	4130MW

4.4.6
West England and Wales

62. Wylfa–Pembroke HVDC Link — EISD 2022

Construct a new subsea HVDC circuit rated at 2–2.5GW connecting from Wylfa/Irish Sea to Pembroke. The reinforcement work includes extending both Wylfa and Pembroke 400kV substations. This link is driven by the new generation at Wylfa and the Irish Sea Round 3 offshore wind farm. It increases the transfer capacity across several boundaries.

Current Status	Scoping	Primary boundary capability increase	B8	3190MW

63. Wylfa–Pentir Second Transmission Route — EISD 2023

Construct a second 400kV transmission route from Wylfa to Pentir and carry out associated work including modifying Wylfa400kV substation and extending the Pentir 400kV substation. This extra transmission route will allow the connection of generation at Wylfa beyond the infeed loss risk criterion, which is 1800MW. As a result, the capability of the network to export power from Wylfa into the main transmission system will be significantly improved.

Current Status	Scoping	Primary boundary capability increase	NW1	3800MW

64. Pentir–Trawsfynydd Second Circuit — EISD 2019

Create a second circuit by using the other side of the route which is currently occupied by a SP-MANWEB 132kV circuit. A large single core per phase cable section is required across Glaslyn where no overhead line currently exists. A single 400/132kV transformer is teed off the new circuit to provide a connection to SP-MANWEB at Four Crosses to replace its circuit.

Current Status	Scoping	Primary boundary capability increase	NW2	1600MW

65. Pentir–Deeside and Pentir–Trawsfynydd Reconductoring — EISD 2018

Reconductor the existing double circuits which run from Pentir to Deeside and Pentir to Trawsfynydd with triple Araucaria conductor. The boundary capability will improve once both routes are reconductored. This will help to ensure the circuits will provide sufficient thermal capacity to export the excess generation from North Wales to the rest of the system, as an increasing amount of wind and nuclear generation is expected to connect in the area in the future.

Current Status	Scoping	Primary boundary capability increase	NW2	690MW
			NW3	880MW

66. Trawsfynydd–Treuddyn Tee Reconductoring 1 — EISD 2015

The route was constructed in 1961 and uprated to 400kV in 1976. The latest proposal to reconductor the double circuit to GAP 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 nuclear and wind farm generation connecting in North Wales. It is planned in 2014 as a result of asset condition drivers rather than boundary capability drivers.

Current Status	Planning	Primary boundary capability increase	NW3	2130MW

4.4 continued
Asset Reinforcement Options

67. Pentir–Trawsfynydd 1 Single Core per Phase — EISD 2021

The existing cable sections of the Pentir–Trawsfynydd 1 circuit replaced by large single core per phase cable sections.

Current Status	Scoping	Primary boundary capability increase	NW2	400MW

68. Pentir–Trawsfynydd Second Cable Core per Phase — EISD 2021

Add a second core per phase to both the both the existing Pentir–Trawsfynydd 400kV circuit and the new circuit including the long sections across the Glaslyn. The OHL will become the limiting component after this reinforcement is constructed.

Current Status	Scoping	Primary boundary capability increase	NW2	1500MW

69. New Transmission Route in Mid Wales — EISD 2019

Establish a new 400/132kV substation near Cefn Coch and connect the substation to the main interconnected system via a double circuit connecting into the existing Legacy–Ironbridge and Legacy–Shrewsbury–Ironbridge circuits. Make modifications at Shrewsbury substation to conform to circuit complexity requirements.

Current Status	Scoping	Primary boundary capability increase	MW1	Generation Connection

70. Legacy–Iron Bridge Reconductoring and Legacy Quad Boosters upgrading — EISD 2019

Reconductor the Legacy–Iron Bridge circuit and upgrade the Legacy QBs to increase the capacity of this circuit and across the boundary

Current Status	Scoping	Primary boundary capability increase	NW4	1070MW

71. Reconductor Daines–Macclesfield circuit — EISD 2020

Reconductor the overhead section and uprate the cable section of the Daines–Macclesfield circuit will increase thermal capacity of the network to export power from the North Wales significantly.

Current Status	Scoping	Primary boundary capability increase	B8	470MW

72. Reconductor Bramley–Melksham double circuits — EISD 2016

Reconductor the existing 400kV circuits which run from the Melksham to Bramley 400kV substations with higher rated conductor. The reinforcement will resolves the thermal overloading encountered on this circuit and will help to export excess power generation from the south west.

Current Status	Scoping	Primary boundary capability increase	B13	910MW

73. Local Generation Connection Works in the South West — EISD 2019

Local works (substation and transmission capacity) to accommodate local generation before commissioning the new Hinkley–Seabank circuit.

Current Status	Scoping	Primary boundary capability increase		Local

4.5 Network Development Policy

4.5.1 Identification of schemes for progression

The following describes how National Grid applies its Network Development Policy (NDP) in making investment decisions about wider transmission works. Similar principles are applied by the Scottish TOs. The first stage of the process is to determine future transmission capacity requirements, as presented in chapter 3. Once requirements have been identified, a range of potential solutions are proposed, as in section 4.4.

While identifying potential solutions a high-level assessment is made of the potential benefits provided and the requirements to realise those benefits. An initial ranking of the solutions takes account of any restrictions on the ability to deliver investments to optimum timescales. For example; outage availability may delay the commissioning timescale of a reinforcement due to other planned outages in the same period.

Following the identification of a range of possible transmission network solutions, the next stage of the NDP is to determine the total lifetime costs including operational costs against each of the scenarios, case studies and sensitivities considered. Potential reinforcements are considered both in isolation and in combination with the other reinforcements, to determine if the sequential order is robust. Given the required in service date and lead time of each individual project, it is determined which solution should progress to the next stage of NDP analysis.

The Electricity Scenarios Illustrator (ELSI) analysis tool, as mentioned in Chapter 2, is used to determine forecast constraint costs and transmission losses for the range of transmission network solutions identified against each of the future energy scenarios (FES).

Full lifetime costs are used in the analysis including forecast transmission investment costs and constraint costs. The constraint costs are based on observed prices in the Balancing Mechanism and the cost of transmission losses are based on anticipated energy prices.

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.

4.5.2 Progression of transmission solutions

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 each stage progresses.

This allows regret minimising options to be developed. For example; the option to complete pre-construction maintains the ability to complete the project to the earliest commissioning date for any scenario in which the reinforcement is required. It also allows work to cease with minimal regret against a scenario in which it is not required.

4.5 continued
Network Development Policy

4.5.3
Selection of preferred option – Least Regret analysis

Given the range of uncertainty we face, the NDP has been developed so we take forward the preferred option.

The regret associated with any potential reinforcement being progressed is calculated against each of the scenarios.The regret is defined as the difference in cost (both investment and operational costs) between the option being considered and the best possible transmission option for that scenario. This means that we consider all options against a scenario. The option that provides the minimum cost solution (investment and operational costs) is treated as base (zero cost) and all other options are compared against the base option.

This analysis is repeated for all scenarios. It should be noted that different options could be selected as base in different scenarios. The worst regret for each option is identified against the range of scenarios considered.

The preferred option is selected based on the least regret approach. This is illustrated in Table 4.3 below, where Option 1 is selected as the preferred solution for the following year.

Table 4.3
Least Regret Analysis Example

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

For the example above, Option 1 is selected because across all of the scenarios it has the least ‘worst regret’ of only £40m compared to all the other options.

4.5.4
Testing selected transmission strategy

Against NETS SQSS Security Criterion:
Once a transmission solution has been selected with a delivery date consistent with the ‘least worst’ regret analysis, it will be reviewed against the requirements of the security criterion in the NETS SQSS. 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 captured in the ELSI treatment (i.e. ideal curtailment of demand and immediate restoration))
- Cost of reduced security on the system.

If the economic implications of these considerations outweigh the cost of reinforcement to meet the security criterion, then the reinforcement will be taken forward.

4.5.5
Delaying a transmission project

So that the least regret solution is progressed, we will annually review the NDP against the latest scenarios and contracted position as updated by the user. It is possible that a transmission reinforcement solution selected in a prior year will no longer be the least regret option identified in the current year. If so, the transmission strategy will be reviewed in detail to understand the committed cost to date and the cost of cancellation. It will then be progressed in a way that ensures minimum cost and risk to the consumer. The options to achieve this outcome will range from continuing a project, delaying and at the extreme may mean the project is cancelled.

4.5.6
Strategic Wider Works (SWW) process

Some high-value future schemes under the Ofgem RIIO regulatory settlement will fall outside the remit of NDP and be classified as a Strategic Wider Work (SWW). There is a separate process for these schemes as described below. In England and Wales, a scheme is classified as SWW if any of the following criteria are met:

- The project has a forecast cost of more than £500m[25]
- The project has a forecast cost of less than £100m but consent is required for the project and it is supported by only one customer and is not required under the majority of scenarios
- The project has a forecast cost between £100m and £500m, is supported by only one customer and is not required under the majority of scenarios.

This is summarised in Figure 4.5 shown below. For Scotland a different set of criteria with lower expenditure limits are used to determine SWW schemes. In Scotland, a project must satisfy the following materiality criteria to be classed as SWW:

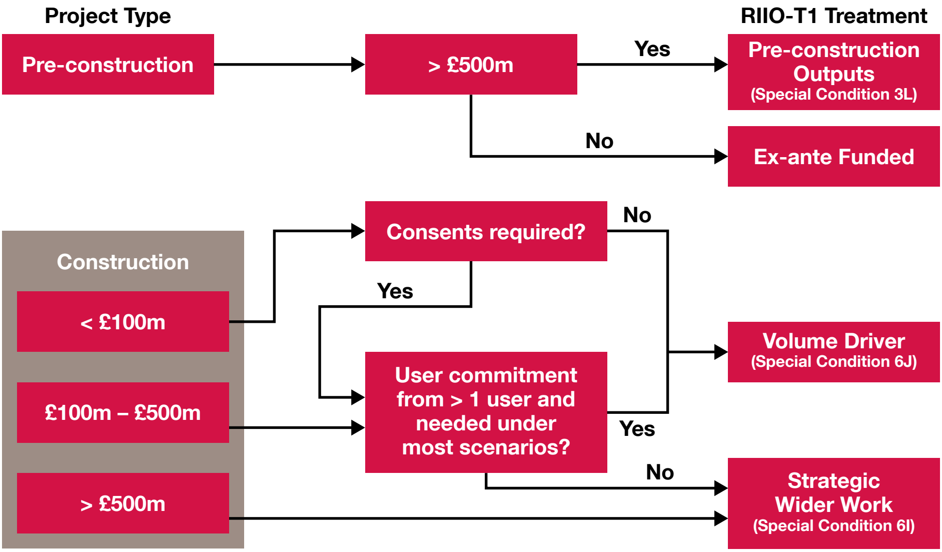
- Total delivery costs will be greater than £100 million
- The output will deliver cross boundary (or sub boundary) capacity or wider system benefits
- Costs cannot be recovered under any other provision of this license.

At present, the following projects are treated as Strategic Wider Works, namely:

[25] In 2009/10 prices.

4.5 continued
Network Development Policy

Figure 4.5
Definition of Strategic Wider Work (SWW) Schemes for England and Wales

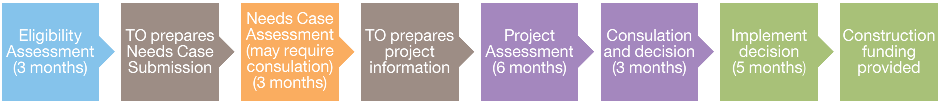


England and Wales
- Eastern HVDC Link
- Wylfa–Pembroke HVDC Link
- Hinkley–Seabank New Transmission Route

Scotland
- Eastern HVDC Link
- Kintyre to Hunterston Subsea Link
- Beauly–Mossford 132kV OHL Rebuild
- Western Isles HVDC Link
- Caithness–Moray Reinforcement
- Shetland to Mainland HVDC Link
- Orkney–Dounreay AC Link
- East Coast 400kV Reinforcement
- Tealing–Westfield–Longannet Uprate
- Beauly–Blackhillock 400kV
- Dumfries and Galloway
- Central 400kV upgrade (Denny–Wishaw)

Strategic Wider Works funding process
A process has been defined to allow the transmission owners to propose new SWW outputs and to be able to request funding to deliver these outputs. The SWW process consists of four main stages: Eligibility Assessment, Needs Case Assessment, Project Assessment and Implementing Decision. This is summarised in Figure 4.6.

Figure 4.6
Strategic Wider Works Assessment Process



It should be noted that these assessment stages are interactive and can overlap. The timescales defined are indicative only and can be changed to accommodate the need of the project, with agreement from Ofgem.

Table 4.4 below illustrates the responsibilities of the transmission owner and Ofgem at each stage of the Strategic Wider Works process.

Table 4.4
Strategic Wider Works: Roles and Responsibilities

Stages	Objective	Transmission Owner (TO)	Ofgem
Eligibility Assessment	Determine eligibility for assessment under SWW mechanism.	Advises Ofgem of its intention to submit a request for SWW and provides evidence of the scheme meeting the pre-defined eligibility criteria.	Assesses whether scheme is eligible. If appropriate, agrees with TO the timetable for assessment.
Needs Case Assessment	Assess needs case for the project including the scope of proposed works and timing.	Submits details of needs case including justification of proposed timing and explanation of how proposed project would meet the required need.	Assesses the needs case, scope of the project and timing of the project to determine if the project is economically efficient.
Project Assessment	Justify proposals against technical readiness and cost effectiveness; determine funding allowances, outputs and criteria for any future adjustments to costs or outputs.	Submits detailed information about design, costs and risks for project.	Assesses construction costs and deliverables to ensure efficiency and value for money for consumers and consults on initial findings.
Implementing Decision	Provide allowances of delivering the output where needs case is justified.		Publishes decisions. Consults on licence changes. Issues licence changes.

4.6 Investment Recommendations

This section of the chapter takes the potential transmission solutions, which include a variety of offshore, conventional, operational and commercial solutions, as input to perform a regional cost-benefit analysis. The result gives the best cost-benefit strategy for each scenario, and enables the conclusion to a current year recommendation for works required in a region.

Colour codes are used in this section as discussed earlier in the Introduction of this chapter to help identify information about the relevant region.

4.6.1 Scotland

Table 4.5 summarises the regional drivers for Scotland and the corresponding potential transmission solutions suggested for the region.

Table 4.5
Scottish Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation on power transfer from generation in remote locations to the main transmission routes	Asset	Gravir on Lewis to Beauly HVDC Link	2020
		Shetland to Mainland HVDC Link	2020
		Orkney–Dounreay AC Subsea Connection	2018
		Beauly-Mossford 132kV Reinforcement	2015
		Beauly-Tomatin 275kV Reinforcement	2018
		Foyers-Knocknagael 275kV Upgrade	2015
		Lairg-Loch Buidhe 275kV Reinforcement	2019
		Skye 132kV Second Circuit	2021
		South West Scotland Connections Project	2015
		Kilmarnock South–Coylton 275kV Uprating	2016
		Coylton–Mark Hill 275kV Uprating	2016
		Kilmarnock South 400/275kV Substation Uprating	2018
		Dumfries and Galloway Reinforcement	2023
Limitation on exporting power from Argyll and the Kintyre peninsula	Asset	Kintyre to Hunterston Subsea Link	2015
Limitation on power transfer from north to south of Scotland	Asset	Beauly to Denny Reinforcement	2015
		Beauly–Blackhillock–Kintore Uprate	2015
		Caithness–Moray Reinforcement Strategy	2018
		East Coast 400kV Uprate	2020
		Central 400kV Uprate	2019
Limitation on exporting power from Scotland to England	Asset	B6 Series and Shunt Compensation	2015
		Harker–Strathaven Reconductoring and Series Compensation	2019
		Western HVDC Link	2016
		Eastern HVDC One	2023
		Eastern HVDC Two	2024
		Eastern HVDC Three	2025

The timing of the reinforcement projects reflect the later of the required reinforcement year and the earliest possible implementation date.

4.6 continued
Investment Recommendations

Table 4.6
SHE Transmission Investment Recommendation by Scenario

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
Crossaig to Hunterston Subsea Cable	2015	2015	2015	2015	2015
Beauly to Denny Reinforcement	2015	2015	2015	2015	2015
Beauly–Blackhillock–Kintore Uprate	2015	2015	2015	2015	2015
Gravir on Lewis to Beauly HVDC Link	2020	2020	2020	2020	2020
Shetland to Mainland HVDC Link	2020	2020	2020	2020	2020
Orkney–Dounreay AC Subsea Connection	2018	2018	2018	2018	2018
Caithness–Moray Reinforcement Strategy	2018	2018	2018	2018	2018
East Coast 400kV Uprate	2023	2022	2021	2020	2020
Beauly–Loch Buidhe 275kV uprate	2030	2028	2024	2020	2019
Eastern HVDC Link One	N/A	2023	2023	2023	2023
Eastern HVDC Link Three	N/A	N/A	N/A	N/A	2025

* N/A indicates that transmission solution is not justified against respective scenario

The Slow Progression, Gone Green and Contracted scenarios predict continual growth in renewable generation that requires reinforcement of the SHE Transmission network.

Three key reinforcement projects are currently being constructed–: Beauly to Denny reinforcement, the Beauly–Blackhillock–Kintore Upgrade and the Kintyre to Hunterston subsea link, all of which are due for completion in 2015.

Against this background of rapidly increasing renewable generation, a number of reinforcement strategies have been proposed and are being investigated to maintain compliance with the NETS SQSS. Examples of these are the proposed Caithness–Moray reinforcement and the East Coast 400kV reinforcement projects. A project to install a subsea HVDC link between Peterhead and Hawthorne Pit, known as Eastern HVDC, is also being investigated to address higher transfer requirements from North Scotland to England.

Additional reinforcement projects that, in the main, are radial extensions of the Main Interconnected Transmission System (MITS) are required to harvest generation in remote areas. An example of these is the Beauly to Mossford project which is currently under construction and due for completion in 2015. Further proposed projects include Beauly to Tomatin, Knocknagael to Foyers upgrades.

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 bussing point at Sinclairs Bay in Caithness. The growth of small onshore renewable generation on mainland Orkney together with the potential significant growth in marine generation around Orkney and the Pentland Firth requires a transmission connection to Orkney. It is currently proposed to install an AC subsea cable from Orkney to Dounreay.

Table 4.7
SP Transmission Investment Recommendation by Scenario

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
B6 Series and Shunt Compensation	2015	2015	2015	2015	2015
Western HVDC Link	2016	2016	2016	2016	2016
Central 400kV Upgrade		2021		2019	2019
South West Scotland Connections Project		2015		2015	2015
Kilmarnock South–Coylton 275kV Uprating		2016		2016	2016
Coylton–Mark Hill 275kV Uprating		2016		2016	2016
Kilmarnock South 400/275kV Substation Uprating		2018		2018	2018
Dumfries and Galloway Reinforcement		2023		2023	2023
Harker–Strathaven Reconductoring and Series Compensation		2023		2020	2020
Eastern HVDC Link Two		N/A		2024	2024

* N/A indicates that transmission solution is not justified against respective scenario

4.6 continued
Investment Recommendations

A number of schemes have already been delivered to improve the capability of cross Scotland–England power transfer, 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 2016.

Beyond this, taking account of the potential generation in the period up to and beyond 2020, SHE Transmission, SP Transmission and NGET are carrying out pre-construction design and engineering work of an offshore HVDC link between Peterhead, Torness and Hawthorne Pit in the north of England (Eastern HVDC Link One). Undertaking pre-construction design and engineering work positions the delivery of the Eastern HVDC project such that construction can commence at the appropriate time when there is confidence that the reinforcement will be required. For the Gone Green scenario and contracted background this may be around 2023, however under Slow Progression a later delivery date may be more suitable.

SP Transmission is also undertaking pre-construction design and engineering work on prospective upgrades specific to cope with the increasingly high north to south power flows through the Scottish networks. Reinforcement works are programmed for 2018 by SHE Transmission and SP Transmission which involve the upgrade of the existing 275kV tower line between Tealing and Longannet via Westfield and Glenrothes.

The Gone Green scenario may also require further reinforcement around 2029 due to the level of offshore wind generation and assumed CCS generation connecting in the later part of the period.

For Gone Green the reinforcements identified represent a significant challenge if they are to be delivered by the dates specified. In the latter part of the period, the required transfer levels for the Gone Green scenario in some boundaries 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 once there is sufficient confidence that it is required.

For the contracted background, there is a far greater pace of wind farm connection in the early years, with the required transfer peaking around 2023 after which point it remains relatively static, primarily due to the high volume of contracted generation connections in England and Wales.

For Slow Progression, there is little growth in the required transfer after 2025, predominantly due to a reduced amount of generation in the Round 3 and Scottish Territorial Waters windfarm zones, and no assumed CCGT generation connecting in the later part of the period. Accordingly, no further reinforcements are required.

4.6.2 North England

Table 4.8 below summarises the regional drivers for North England and the corresponding potential transmission solutions suggested for the region.

Table 4.8
North England Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation on power transfer from Scotland to England	Asset	Western HVDC Link Eastern HVDC Link One Eastern HVDC Link Two Eastern HVDC Link Three Uprate Harker–Stella West circuits Torness-Lackenby New 400kV Transmission Route	2016 2023 2024 2025 2025 2027
Limitation on power transfer out of North East England Offshore	Asset	Lackenby–Norton Reconductoring Norton–Osbaldwick Hotwiring and Reconductoring Lackenby-Stella West New 400kV Transmission Route	2018 2020 2025
	Offshore	East Coast Offshore Integration Stage One	2026
Limitation on power transfer from North Midlands to West Midlands	Asset	Kirkby–Rainhill Substation Upgrade Penwortham–Padiham & Penwortham–Carrington Reconductoring and Kirkby–Penwortham Upgrade Mersey Ring Uprate Norton–Padiham New 400kV Transmission Route Harker–Heysham New 400kV Transmission Route	2017 2020 2021 2025 2027
Limitation on power transfer out of Humber	Asset	Killingholme South–West Burton New Transmission Route	2023

4.6 continued
Investment Recommendations

There are a multitude of options for this region that provide significant capability to the boundary. These options include offshore integration through to new onshore circuits that can give boundary capability to the NETS.

The current status of these projects varies from initial feasibility scoping through to nearing completion. Where the time to deliver these projects is relatively short in comparison to its determined optimum implementation date, no decision is required within the twelve next months.

Reinforcement selection by scenario

Cost-benefit analysis was completed for different combinations and timings of transmission solutions until the most economic strategy was found for each scenario, as shown in Table 4.9 below.

Table 4.9
North England Investment Strategies

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
Series & Shunt Reactive Compensation	2015	2015	2015	2015	2015
Western HVDC Link	2016	2016	2016	2016	2016
Kirkby–Rainhill Substation Upgrade	2022	2021	2021	2020	2020
Eastern HVDC Link One	N/A	2023	2023	2023	2023
Eastern HVDC Link Two	N/A	2024	2024	2024	2024
Penwortham–Padiham & Penwortham–Carrington Reconductoring and Kirkby–Penwortham Upgrade	N/A	2020	2020	2020	2020
Lackenby–Norton Reconductoring	N/A	2023	2023	2023	2023
Norton–Osbaldwick Hotwiring and Reconductoring	N/A	2025	2025	2025	2025
East Coast Offshore Integration Stage 1	N/A	2028	N/A	2026	2026
Uprate Harker–Stella West circuits	N/A	N/A	2030	N/A	N/A

* N/A indicates that transmission solution is not justified against respective scenario

The early years of the scenarios are similar; therefore projects which justify in these early years, such as the Western HVDC project, typically have the same year of delivery across each of the scenarios. Given the near completion of the project, the recommendation is to continue this project to completion.

Given the divergence in scenarios in later years, we see a difference in required in service dates for the subsequent projects for each scenario.

There are several projects that are not required in the No Progression & Slow Progression scenarios because the respective transfer volumes within these scenarios would never see a need for this reinforcement.

Development of options

Considering the most economic strategy for each scenario and taking into account the lead times and boundary benefit of each of the above reinforcements, the key decision for the North England region least regret analysis is the potential development of the Western HVDC link and/or Kirkby–Rainhill Substation Upgrade

Selection of the preferred option

The regret associated with any potential reinforcement being progressed is calculated against each of the scenarios. The regret is defined as the difference in cost (which includes both investment and operational costs) between the option being considered and the best possible transmission option for that scenario.

The worst regret for each option is identified against the range of scenarios considered. The preferred option is selected based on the least regret approach.

The worst regret for each of the current year options considered against each of the scenarios is shown in Table 4.10.

The NDP investment decisions for North England resulting from this analysis are shown in Table 4.11.

Table 4.10
North England Investment Options and Regrets

Scenario	2014 (current year) option			
	Western HVDC Link	Kirkby–Rainhill Substation Upgrade	Proceed Both	Do Nothing
No Progression	£0m	£20.3m	£0.05m	£20.3m
Slow Progression	£0m	£39.0m	£0.03m	£38.9m
Low Carbon Life	£0m	£46.4m	£0.03m	£46.4m
Gone Green	£0m	£57.6m	£0.02m	£57.6m
Local Contracted	£0m	£69.7m	£0.02m	£69.7m
Worst regrets	£0m	£69.7m	£0.05m	£57.6m

The optimum current year solution, in terms of balancing investment cost versus constraint cost, is the Western HVDC link project; hence it is assigned a current year regret of zero.

The Do Nothing regret cost is incurred constraint costs as result of not investing in the existing network. The largest constraints are seen with the local contracted scenario which has the highest volumes of connections as compared with the No Progression scenario which has the lowest build-up of generation and therefore lowest constraints.

The significant potential regret shown against investing in the Kirkby–Rainhill Substation Upgrade project alone is produced by a combination of investment cost for a scheme that is not immediately needed and constraint cost by investing in a scheme that does not alleviate the cause of the constraints. The potential regret in investing in both schemes is small suggesting that investing in the Kirkby–Rainhill upgrade is getting close to being efficient, but not now.

4.6 continued
Investment Recommendations

Table 4.11
North England Investment Decisions

Option	Decision
Series & Shunt Reactive Compensation	Complete construction
Western HVDC Link	Complete construction
Kirkby-Rainhill Substation Upgrade	Delay
Eastern HVDC Link 1	Continue pre-construction scoping
Norton–Osbaldwick Hotwiring and Reconductoring	No decision required
Lackenby–Norton Reconductoring	No decision required
Penwortham–Padiham & Penwortham–Carrington Reconductoring and Kirkby–Penwortham Upgrade	No decision required
Uprate Harker–Stella West circuits	No decision required
Eastern HVDC Link 2	Evaluation On-going
Eastern HVDC Link 3	Evaluation On-going
East Coast Offshore Integration Stage 1	Evaluation On-going

NDP Recommendations

The present least worst regret NDP recommendation is to only proceed with construction of the Western HVDC project. The Kirkby–Rainhill upgrade contains significant risk if developed now; therefore it is recommended not to proceed at present.

Last year's NDP inputs contained the options of completion of Anglo Scottish Series and Shunt compensation and Penwortham QBs.

The recommendation last year was to continue with these projects as they were near completion with little expenditure left and good network benefits. Now the projects are nearly fully complete it is recommended that any final works are completed on them.

To maintain the optionality of the Eastern HVDC link it is recommended to continue with the pre-construction scoping phase, with the project being reviewed again in next year's NDP.

4.6.3 East England

The table below summarises the regional drivers for East England and the corresponding potential transmission solutions suggested for the region.

Table 4.12
East England Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation from East Anglia to Greater London and South East England	Asset	Norwich–Bramford Reconductoring	2016
		West Burton–High Marnham reconductoring	2017
		East Anglia MSC at Burwell Main	2017
		Bramford–Braintree–Rayleigh Main Reconductoring	2017
		Bramford–Braintree–Rayleigh Main Hotwiring and switchgear upgrade at Pelham	2018
		Complete Rayleigh–Coryton South–Tilbury Reconductoring	2018
		Bramford–Twinstead New Overhead Lines	2018
		Bramford-Pelham Double Circuit Reconductoring	2018
		Rayleigh Main Series Reactor	2019
		New Transmission Route and Quad Boosters in East Anglia	2025

Reinforcement selection by scenario
Cost-benefit analysis was completed with consideration of different combinations and timings of transmission solutions until the lowest cost strategies were found for each of the scenarios. These optimised strategies were shown in Table 4.13.

4.6 continued
Investment Recommendations

Table 4.13
East England Investment Strategies

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
Bramford–Twinstead New Overhead Lines (requires Rayleigh–Coryton South–Tilbury Reconductoring)	N/A	2025	2023	2023	2023
Complete Rayleigh–Coryton South–Tilbury Reconductoring (requires Bramford–Twinstead New Overhead Lines)	N/A	2025	2023	2023	2023
Bramford–Braintree–Rayleigh Main Reconductoring (requires Bramford–Pelham reconductoring and East Anglia MSC at Burwell Main)	N/A	2026	2024	2024	2023
Bramford–Pelham reconductoring	N/A	2026	2024	2024	2023
Rayleigh Main Series Reactor	N/A	2024	2024	2024	2023
New Transmission Route and Quad Boosters in East Anglia	N/A	2029	2027	2029	2025

* N/A indicates that transmission solution is not justified against respective scenario

There is limited divergence within the Slow Progression, Low Carbon Life and Gone Green scenarios over the next 15 years, hence the majority of the considered projects within the East region trigger for the same delivery year.

Potential project delivery restrictions arising from lack of network access (i.e. outage availability) and the potential interaction of projects within the same region are considered in the establishment of the optimum strategy. For example, lack of network access within the initial desired year of implementation will see the project instead recommended for delivery in the best available year.

A number of the projects considered for the East region are interlinked with neighbouring projects. For example, the full benefit (i.e. network capacity uplift) from the Bramford–Twinstead New Overhead Lines would not be realised until reconductoring the Rayleigh–Coryton South–Tilbury circuit is also completed. In these particular instances, these projects are typically recommended for delivery in the same year, where possible.

Development options

Considering the most economic strategy for each scenario and taking into account the lead times and boundary benefit of each of the above reinforcements; the key decision for the least regret analysis is the potential development of new Bramford to Twinstead circuits.

Selection of preferred current year option

The regret associated with any potential reinforcement being progressed is calculated against each of the scenarios. The regret is defined as the difference in cost (which includes both investment and operational costs) between the option being considered and the best possible transmission option for that scenario. The worst regret for each option is identified against the range of scenarios considered.

The preferred option is selected based on the least regret approach.

The worst regret for each of the current year options considered against each of the scenarios is shown in Table 4.14.

The NDP investment decisions for East England resulting from this analysis are shown in Table 4.15.

Table 4.14
East England Investment Options and Regrets

Scenario	2014 (current year) option	
	Bramford–Twinstead New Overhead Lines	Do Nothing
No Progression	£204.1m	£0m
Slow Progression	£25.8m	£0m
Low Carbon Life	£25.8m	£0m
Gone Green	£25.8m	£0m
Local Contracted	£2.8m	£0m
Worst regrets	£204.1m	£0m

Proceeding with the Bramford–Twinstead New Overhead Lines has been assessed as not required in the next twelve months to resolve constraints on the network. Hence, the optimum investment strategy with minimum attached regret is to Do Nothing–; it is therefore awarded a regret figure of zero. The project is however required in all the scenarios before 2025 with the exception of No Progression, but no work is required on the project in the next twelve months to achieve these dates. This decision is consistent with the decision we made last year to delay the progress on this investment given the delay in the associated contracted background and scenarios.

4.6 continued
Investment Recommendations

Table 4.15
East England Investment Decisions

Option	Decision
Bramford–Twinstead New Overhead Lines	Delay
Complete Rayleigh–Coryton South–Tilbury Reconductoring	Delay
Bramford–Braintree–Rayleigh Main Reconductoring	No decision required
Bramford–Pelham reconductoring	No decision required
Rayleigh Main Series Reactor	No decision required
New Transmission Route and Quad Boosters in East Anglia	No decision required

NDP Recommendation
The current least worst regret NDP recommendation is to delay construction of the new Bramford to Twinstead overhead lines. This is a result of the current year regret cost associated with developing the project further far outweighing the network benefit of delivering the project. The same recommendation was produced as part of last year's NDP for this project.

Last year's NDP inputs also contained the option of completing works forming the Rayleigh Main–Coryton-South-Tilbury reondсуctoring project.

The resulting recommendation last year was to continue with this project. In the period since last year's NDP, the Rayleigh–Coryton section of these works have been completed, however the remaining works (Coryton–Tilbury reconductoring) have been removed following de-scoping of the overall project.

This year's NDP recommendation is therefore to delay the completion of the remaining works associated with the Rayleigh–Coryton South–Tilbury Reconductoring project.

4.6.4 South England

The table below summarises the regional drivers for South England and the corresponding potential transmission solutions suggested for the region.

Table 4.16
South England Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation from Midlands into South England	Asset	Kelmsley–Rowdown–Littlebrook reconductoring Wymondley Turn-in Wymondley QBs Hackney–Tottenham–Waltham Cross Uprate Rye House Shunt Capacitor New 400kV Transmission Route Hinkley Point–Seabank	2018 2019 2019 2019 2020 2020
Limitation in the south coast	Asset	Dungeness–Sellindge–Canterbury North Reconductoring Series and Shunt Compensation on South Coast South Coast Reactive Compensation New Transmission Route on South Coast	2017 2019 2019 2025

Reinforcement selection by scenario
Cost-benefit analysis was completed with consideration of different combinations and timings of transmission solutions until the lowest cost strategies were found for each of the scenarios. These strategies are shown in Table 4.17.

4.6 continued
Investment Recommendations

Table 4.17
South England Investment Strategies

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
Wymondley Turn-in	N/A	2019	2019	2019	2019
Wymondley QBs	N/A	2019	2019	2019	2019
Hackney–Tottenham Waltham Cross Uprate	N/A	2031	2025	2022	2022
New 400kV Transmission Route Hinkley Point–Seabank	2029	2027	2025	2026	2021
South Coast Reactive Compensation	N/A	2021	2021	2020	2020
New Transmission Route on South Coast	N/A	N/A	2027	2026	2026
Kelmsley–Rowdown–Littlebrook reconductoring	N/A	N/A	2027	2026	2026
Series and Shunt Compensation on South Coast	N/A	N/A	N/A	N/A	2026
Dungeness–Sellindge–Canterbury reconductoring	N/A	N/A	N/A	2019	N/A

* N/A indicates that transmission solution is not justified against respective scenario

Development options
Across all scenarios, the Wymondley Turn-in and Wymondley Quad Boosters projects are required within the same year. Both projects can be constructed in conjunction during a single outage, therefore these works will therefore be considered as a single project for the purposes of an NDP assessment.

Taking into account the lead times and boundary benefit of each of the above reinforcements the key decision for the least regret analysis is the Wymondley (turn-in and quadrature boosters) projects and South Coast Reactive Compensation.

Selection of preferred current year option
The regret associated with any potential reinforcement being progressed is calculated against each of the scenarios. The regret is defined as the difference in cost (which includes both investment and operational costs) between the option being considered and the best possible transmission option for that scenario.
The worst regret for each option is identified against the range of scenarios considered. The preferred option is selected based on the least regret approach.

The regrets for each of the current year options considered against each of the scenarios are shown in Table 4.18.

The NDP investment decisions are shown in Table 4.19.

Table 4.18
South England Investment Options and Regrets

Scenario	2014 (current year) option			
	Wymondley Turn-in & Quad Boosters	South Coast Reactive Compensation	Proceed Both	Do Nothing
No Progression	£1.52m	£8.31m	£9.83m	£0m
Slow Progression	£0m	£10.2m	£8.31m	£1.84m
Low Carbon Life	£0m	£5.71m	£0.28m	£5.43m
Gone Green	£0m	£10.94m	£0.28m	£10.67m
Local Contracted	£0m	£10.9m	£0.28m	£10.62m
Worst regrets	£1.52m	£10.9m	£9.83m	£10.67m

The optimum current year solution, in terms of balancing investment cost versus constraint cost, is the Wymondley Turn-in & Quad Boosters project; hence it is assigned a current year regret of zero.

The Do Nothing regret cost is essentially attributable to incurred constraint costs as result of not investing in the existing network.

The significant regret provided against the South Coast Reactive Compensation project is driven by a combination of unnecessary investment cost and constraint cost, through investment in an ineffective solution. Proceeding with both solutions is evaluated as overinvestment to resolve the respective constraints triggering upon the network.

Table 4.19
South England Investment Decisions

Option	Decision
Wymondley Turn-in	Complete pre-construction
Wymondley QBs	Complete pre-construction
South Coast Reactive Compensation	Delay
Hackney–Tottenham Waltham Cross Uprate	No decision required
New 400kV Transmission Route Hinkley Point–Seabank	Continue pre-construction
Dungeness–Sellindge–Canterbury reconductoring	No decision required
New Transmission Route on South Coast	No decision required
Series and Shunt Compensation on South Coast	No decision required
Kelmsley–Rowdown–Littlebrook reconductoring	No decision required

4.6 continued
Investment Recommendations

Current year recommendation

The current year recommendation for South England is to commence pre-construction of the Wymondley Turn-in and Quadrature Boosters projects, which is consistent with last year's NDP recommentdation for the same project.
It is also recommended to delay pre-construction activities of the South Coast reactive compensation project as the regret of progressing this project within the current year exceeds that of delaying for a further year. This decision still maintains the feasibility of delivering the project for its optimum delivery year of 2021.

4.6.5
West England and Wales

The table below summarises the regional drivers for West England and Wales together with the proposed transmission solution options suggested for the region.

Table 4.20
West England and Wales Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation on power transfer through Midlands	Asset	New Transmission Route on Mid Wales Daines–Macclesfield circuit Reconductoring Wylfa–Pembroke HVDC Link	2019 2020 2022
Limitation on power export from North Wales	Asset	Pentir–Deeside and Pentir–Trawsfynydd Reconductoring Pentir–Trawsfynydd Second Circuit Legacy-Iron Bridge reconductoring and Legacy Quad Boosters uprating Pentir–Trawsfynydd 1 Single Core per Phase Pentir–Trawsfynydd 2 Second Core per Phase Wylfa–Pentir Second Transmission Route	2018 2019 2019 2021 2021 2023
	Offshore Offshore Offshore	East Coast Integrated Offshore Stage Two North Wales Offshore Integration Irish Offshore Integration	2022 2024 2025
Limitation on power transfer from South West England to South East England	Asset	Bramley–Melksham Reconductoring Local generation connection works in the South West	2016 2019

The key limitations are the North to Midlands transfer, North Wales exports and new connections in the South West. Given the number of drivers there are a significant number of potential solutions. A number of these potential solutions are complementary, solving several of these limitations.

Reinforcement selection by scenario

Cost-benefit analysis was completed with consideration of different combinations and timings of transmission solutions until the lowest cost strategies were found for each of the scenarios. These optimum strategies are shown in Table 4.21 below.

Table 4.21
West England and Wales Investment Strategies

Transmission Solution	Strategy				
	Scenario Completion date				
	No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted
Reconductor Daines–Macclesfield circuit	N/A	2026	N/A	2026	2024
Wylfa–Pembroke HVDC Link	N/A	2024	2024	2024	2024
Wylfa–Pentir Second Circuit	N/A	N/A	2027	2028	2025
Pentir–Trawsfynydd Second Circuit	N/A	2022	2027	2021	2021
Pentir–Deeside and Pentir–Trawsfynydd Reconductoring	N/A	N/A	N/A	2027	N/A
Pentir–Trawsfynydd 1 Single Core per Phase	N/A	N/A	N/A	2026	2025
Pentir–Trawsfynydd 2 Second Core per Phase	N/A	N/A	N/A	2026	2025
East Coast Integrated Offshore Stage Two	N/A	N/A	2025	2024	2024
North Wales Offshore Integration	N/A	N/A	N/A	2026	2025
Irish Offshore Integration	N/A	N/A	N/A	2026	N/A

* N/A indicates that transmission solution is not justified against respective scenario

4.6 continued
Investment Recommendations

There is a high degree of divergence across the range of scenarios for the West England & Wales region, hence why a number of the considered projects within the region trigger for different delivery years across the scenarios.

However, within the individual scenarios – Gone Green and Low Carbon Life in particular – a number of projects trigger for delivery in the same year. Potential project delivery restrictions arising from lack of network access (i.e. outage availability) and the potential interaction of such projects within the same region are considered in the establishment of the optimum strategy. For example, lack of network access within the initial desired year of implementation will see the project instead recommended for delivery in the best available year. Therefore, when a number of projects are highlighted for delivery in the same year, it has been confirmed that this is possible without any adverse impact upon the network.

Development of options
Taking into account the lead times and the optimum implementation date of each project, as identified in our strategy, there is no critical project which triggers current year regret analysis.

Selection of preferred current year option
The NDP recommendations for this region are shown in Table 4.22.

Table 4.22
North Wales Investment Decisions

Option	Decision
Wylfa–Pembroke HVDC link	Delay
Second Pentir –Trawsfynydd circuit	Delay
Second Wylfa–Pentir circuit	Complete pre-construction Planning
Pentir–Deeside and Pentir–Trawsfynydd Reconductoring	No decision required
Pentir–Trawsfynydd 1 Single Core per Phase	No decision required
Pentir–Trawsfynydd 2 Second Core per Phase	No decision required
Reconductor Daines–Macclesfield circuit	No decision required
East Coast Integrated Offshore Stage Two	No decision required
North Wales Offshore Integration	No decision required
Irish Offshore Integration	No decision required

NDP recommendation
The current year NDP recommendation is delay progression of the Wylfa–Pembroke HVDC link and Second Pentir–Trawsfynydd circuit projects. Doing so will minimise expenditure in the coming year without impacting the deliverability of the projects prior to their respective optimum implementation dates. These projects will be reviewed again as part of next year's NDP.

It is also recommended to progress with the pre-construction scoping of the 2nd Wylfa–Pentir circuit to maintain optionality ensuring the project can be delivered against its required in-service date.

Last year's NDP recommended completion of the Trawsfynydd–Treuddyn Tee reconductoring works, which been completed and are currently in service.

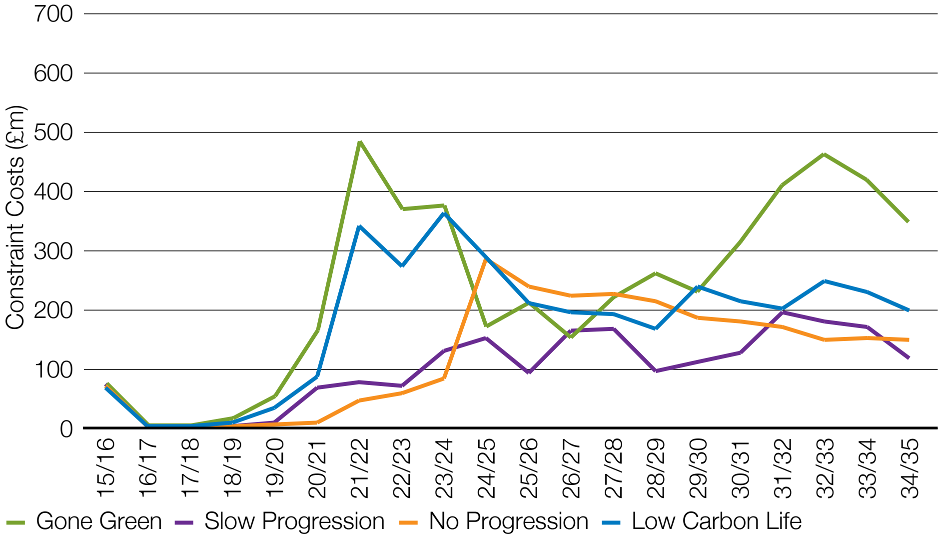
Stakeholder engagement
We would appreciate your view on how we presented the potential future development of the NETS. Have we explained to you clearly how development decisions were made to ensure an optimal, economic and efficient transmission strategy?

4.7
Reinforced System Constraints

Section 3.12 of this document presents forecast for system constraints without any new reinforcements. The analysis demonstrates that in the near future the network is not envisaged to suffer from high constraints. However, the analysis in Section 3.12 suggests that, in the absence of any new reinforcements, the constraint costs could grow to more than £1bn per annum by 2035 for all four scenarios. Furthermore, the analysis highlights that unreinforced network could result in nearly £10bn of annual constraints by 2035.

Based on the range of options appraised as part of the NDP analysis, this section presents the constraint cost forecasts for reinforced network states optimised by each scenario[26]. In particular, this analysis demonstrates the effectiveness of National Grid's investment decisions made to reinforce the network. The figure below suggests that constraint costs across most scenarios are forecast to be less than £300m per annum by 2035. With the identified wider works based reinforcements, the current constraint cost forecast for Gone Green and Low Carbon Life scenarios are estimated to be higher than £300m per annum between 2021 and 2023. In comparison, the constraint cost forecast for Slow Progression and No Progression for the same years is considerably lower. However the decision making for investment purposes is not made on any one of these scenarios but the least regret outcome across the whole suite of scenarios. That said to ensure value for money for GB consumers, National Grid will seek to optimise the network operation further through Connect and Manage Assessment and report any revisions in early 2015.

Figure 4.8
Constraint costs after wider work reinforcements against the 2014 FES



[26] These forecasts are based on assessment of major network boundaries. Actual outturns for early years are likely to be at least £100m per annum as a result of local issues and small boundaries which may not have been fully incorporated within constraint cost modelling.

4.8
Transmission Losses

Transmission losses introduction

Transmission losses can be generally classified into fixed losses and load related losses. Fixed losses are mostly independent from the loading of the circuits and typically come from such things as transformer iron losses and high voltage corona losses. Fixed losses vary slightly because of variations in system voltages and weather conditions. Load-related losses typically come from the resistance of circuits and depend on the square of the current carried (I^2R) so losses change significantly with the loading of the transmission system.

Reporting transmission losses

When examining transmission losses on the NETS, the total losses for the following transmission elements are considered:

- 400kV and 275kV circuits
- 132kV circuits in Scotland
- 400/275kV transformers
- 400kV or 275kV to 132kV transformers in Scotland
- HVDC transmission circuits and converters
- Offshore transmission cables of 132kV or above
- Offshore/onshore transmission interface transformer.

At winter peak the NETS losses are indicatively calculated to be as follows, assuming an intact system.

Table 4.23
Transmission Losses

Year	MW losses at GB peak
Year 1	830
Year 3	760
Year 5	800
Year 7	1,030
Year 10	1,380

The calculated losses for the first five years are similar, indicating that small changes in system operation are expected. After that, however, the calculated losses vary significantly even though the network has been reinforced to follow the changes in generation. These larger losses indicate that power flow within the NETS is travelling over longer distances. As more generation is connected at the periphery of the network, the losses are expected to increase. Load losses do not linearly change with circuit loading being proportional to the square of the current carried. A particularly heavily loaded circuit in one year contributing significantly to the total losses may be less loaded the next year and have a much smaller proportion of the total losses. Local reactive support for voltage management avoids the transmission of reactive power over distances that would otherwise increase system losses.

The total annual NETS losses accounts for approximately 2% of the energy supplied, and may rise. As generation and demand pattern change across the country, power flow volatility will mean more transmission losses.

4.9 Network Opportunities

This section focuses on opportunities for stakeholders when interacting with the NETS through new or existing connections. The NETS exists to carry power from sources of generation to areas of demand. National Grid has an obligation to coordinate in developing the NETS, including the services needed to operate the network.

Our customers and stakeholders are invited to suggest means in which they can help meet future system requirements. We'd welcome suggestions about planning capacity (Chapter 3) and managing the operation of the network (Chapter 5). We aim to explore all options that help satisfy the future network requirements and allow us to deliver network capability at lowest cost to the consumer.

4.9.1 Potential network opportunities

This section provides a very high-level indication of where opportunities lie. It will help developers, users and industry make informed decisions about how their investments will impact on the NETS, system reinforcement and system congestion. We have been working with stakeholders during 2014 to develop services that could reduce the need for system reinforcement and congestion. You can read about opportunities for new connections to the NETS in the Transmission Networks Quarterly Connections Update (TNQCU)[27]. This explains the contracted status of future and existing generation. The next chapter outlines opportunities around technical operational issues.

Generation

As well as supplying all of the power needed to meet the total NETS demand, generators play an important role in keeping the network operational by providing services such as:

- Voltage control
- Frequency response
- Emergency response
- Black start capability.

Providing a basic level of service is a condition of connection to the NETS. However, with the ever-changing NETS background, generators may be able to provide additional services. An example may be a generator offering enhanced voltage control that could remove the need for transmission connected reactive compensation. Reduced investment in the transmission network would then be reflected by a reduction in transmission usage charges.

Opportunity identification and boundary discussion

The following section presents the opportunities for connectees and the current system drivers for development associated with transmission connections. The table below maps areas of the transmission system to the affected boundaries. So, if you are connecting a new project above boundary B1, the connection will affect B1, B2, B3, B4, B5, B6, B7, B7a, B11 and B16. To make this clear, we have colour coordinated the developments in section 4.7 with opportunities in this section.

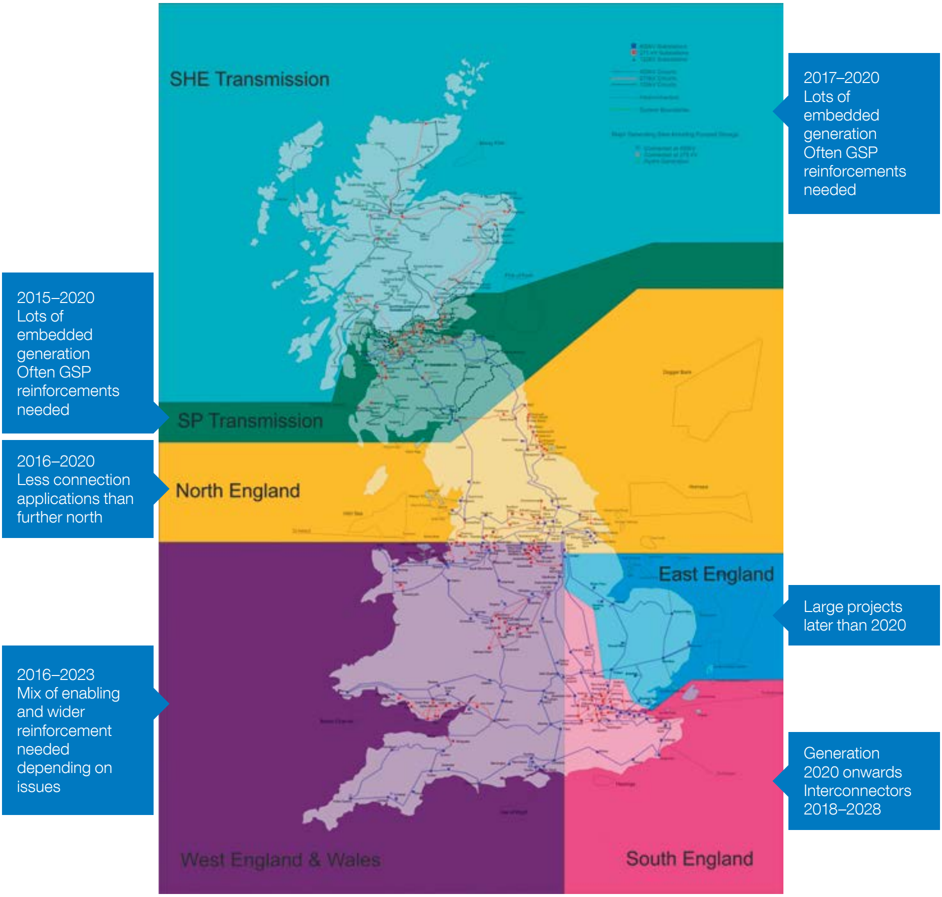
[27] http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/transmission-networks-quarterly-connections-updates/

4.9 continued
Network Opportunities

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

An overview of GB network main changes with likely timescales for new connections are shown on the following map:

Figure 4.9
GB new connection overview



4.9 continued
Network Opportunities

Demand

As shown in the FES, the trend appears to be for generation to be moving towards the periphery of the NETS away from the demand centres and for more intermittent generation. If demand could be shaped to reduce the congestion on the NETS, then less transmission investment may be required.

Stakeholders can offer services, such as demand management, by curtailing their demand during peak periods. This would alleviate boundary constraints and help us could meet future system requirements. This could be, for example, through demand-side response, where end-energy consumers reduce their demand to help maintain system balance. The combination of network investment and demand-side management could reduce costs to consumers, enhance security of supply, and contribute to sustainable development.

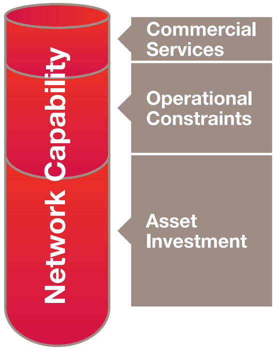
Demand-side management can be in the form of inter-trips, where an agreed automated disconnection of demand happens during times of system constraint. Where appropriate this could be part of a commercial service and combined with relatively low cost asset solutions. Such low cost investments could include circuit reconfiguration or hot-wiring[28]. This could provide a solution until the needs of the system become more certain, and it is clear that making a firm long-term large asset investment is economical and the right thing to do.

The reactive power support seen by the NETS from GSPs is changing due to a number of factors including:

- The reactive power demand seen by the NETS from GSPs is decreasing rapidly
- There are growing volumes of embedded generation connecting to GSPs
- Traditional generator reactive support is declining.

To help manage these changing circumstances, third parties could provide reactive power services locally. From the reinforcement options reported earlier in this chapter it can be seen where reactive compensation is required.

Innovation



We welcome and investigate new ideas that might aid the development of the electricity transmission network. Continued research and development into new ideas for processes, technology and resources will help the NETS remain economic and efficient.

Recent innovations being applied to the NETS include:

- first GB use of series reactive compensation
- design of the new T-pylon
- design of the Western HVDC link.

Innovation is constantly being applied by the customers of the NETS, such as new types of generators and changes to the distribution networks. Through regular engagement and our own research, the NETS is in a good position to innovate for the future.

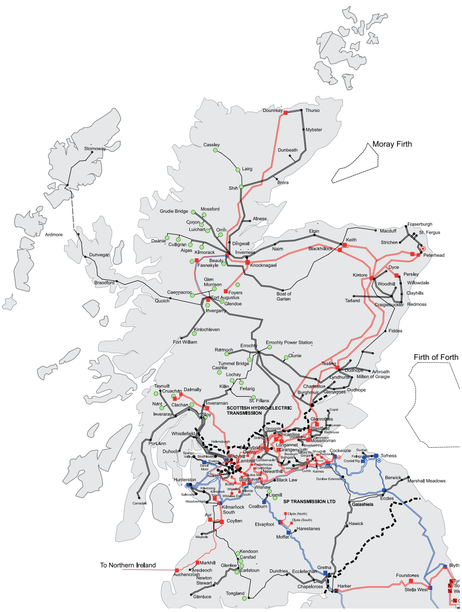
[28] Hot-wiring refers to operating existing overhead line circuits at higher temperatures to achieve higher thermal ratings. Operating at higher temperature may require minor works, for example, the re-tensioning of particular spans to ensure safety clearances.

4.9.2
Indication of regional opportunities

This section explores possible wider NETS-related opportunities split by regions across Scotland, England and Wales.

Colour codes are used in this section as discussed earlier in the Introduction of this chapter to help identify information for the relevant region.

Scotland



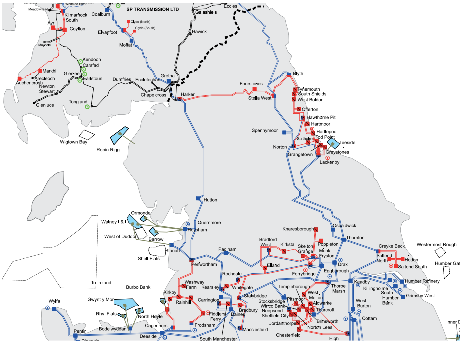
Region Type	High export of renewable energy
Limiting Factor	Circuit capacity and remoteness
Network Development	Major new infrastructure and upgrade of existing assets
Opportunity	Demand connections Reactive power services

Scotland has a growing excess of renewable generation capacity over demand. This can mean high north to south power flows, requiring significant circuit reinforcement. If demand increases towards the north of Scotland it could help to reduce the need for some of the transmission reinforcements.

Low renewable generation output could lead at times to power imports to Scotland from England and Northern Ireland. Coupled with the potential closure of large conventional generators, there could be a benefit in providing generation that could operate at the times of low intermittent renewable generation output. Additional voltage services may also be needed close to the main transmission routes and demand centres. There may be opportunities for third parties to provide this support.

4.9 continued
Network Opportunities

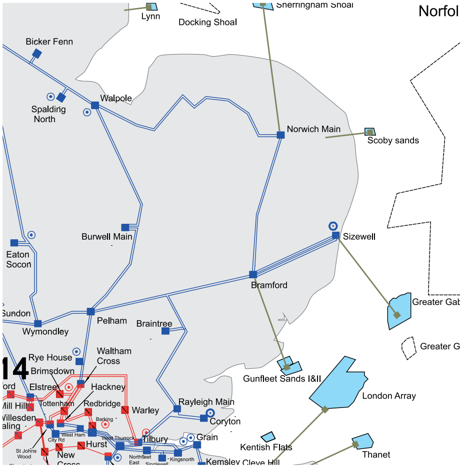
North England



Region Type	Through flow
Limiting Factor	Circuit capability and voltage
Network Development	Circuit upgrades and new offshore circuits
Opportunity	Demand connections Reactive power services

New connections will increase the north to south power flows across northern England. With contracted generation connections along the east and west coasts, there are opportunities for new generation towards Manchester and Sheffield. There is also opportunity for increased demand to the far north towards Scotland that could reduce the through flows on the network.

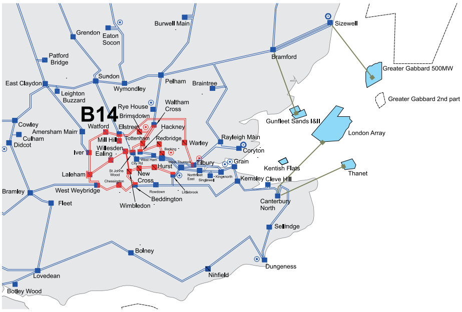
East England



Region Type	Exporting to the west and south
Limiting Factor	Circuit capability
Network Development	Reconductoring of existing circuits, new transmission route and voltage compensation
Opportunity	Demand connections near generation Reactive power services

With power flow south and west towards London, and many extra generation projects along the east coast, there is little opportunity for further generation connections along that coast without significant reinforcement. Further generation could be more easily accommodated closer to London.

South England

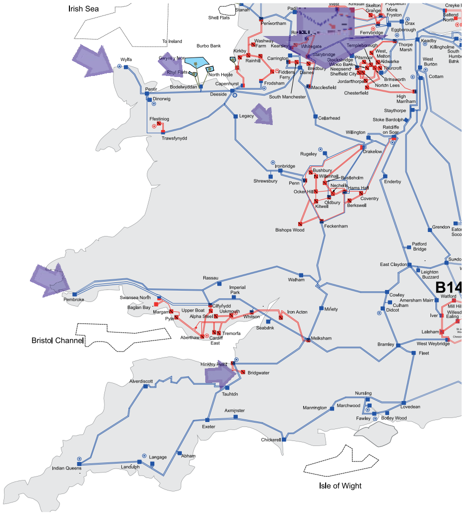


Region Type	High demand
Limiting Factor	Circuit capacity and voltage control
Network Development	Circuit uprating and voltage compensation
Opportunity	Local generation Demand-side response Demand curtailment (inter-trips) Reactive power services

London and the south are high demand regions, absorbing power from local generation and from surrounding areas. The continental interconnectors can further increase the flows by exporting power to the continent and drawing further power via London. Additional generation close to London or a way to reduce demand could be very beneficial. The circuits along the south coast between Kemsley and Lovedean connect a long chain of substations. This is sensitive to faults at either end, leaving a long radial spur where additional compensation is needed to maintain voltages. Reduced demand or extra voltage support could mean less transmission reinforcement would be needed in this area.

Stakeholder engagement
We would welcome your view on how we can improve the way we present network opportunities. What information would you like to see in the ETYS about network opportunities.

West England & Wales



Region Type	Increasing easterly export
Limiting Factor	Circuit capacity
Network Development	Circuit upgrades and new circuits
Opportunity	Local generation Demand-side response Demand curtailment (inter-trips)

The prospective connection of large new generators in the north west and south west corners of Wales and new generation in the south west peninsula of England will mean increasing power flows towards the east. New generation capacity at these points will need significant new transmission capacity. There is an opportunity for generation and demand towards the Midlands and south to help network management by providing commercial services.

4.10
Regional Summaries

Scotlandsummary

Inputs

- Increasing north to south power flows from Scotland.
- Increases in renewable generation across Scotland leading to growth in peak power exports from Scotland to England and limited by thermal circuit capability.

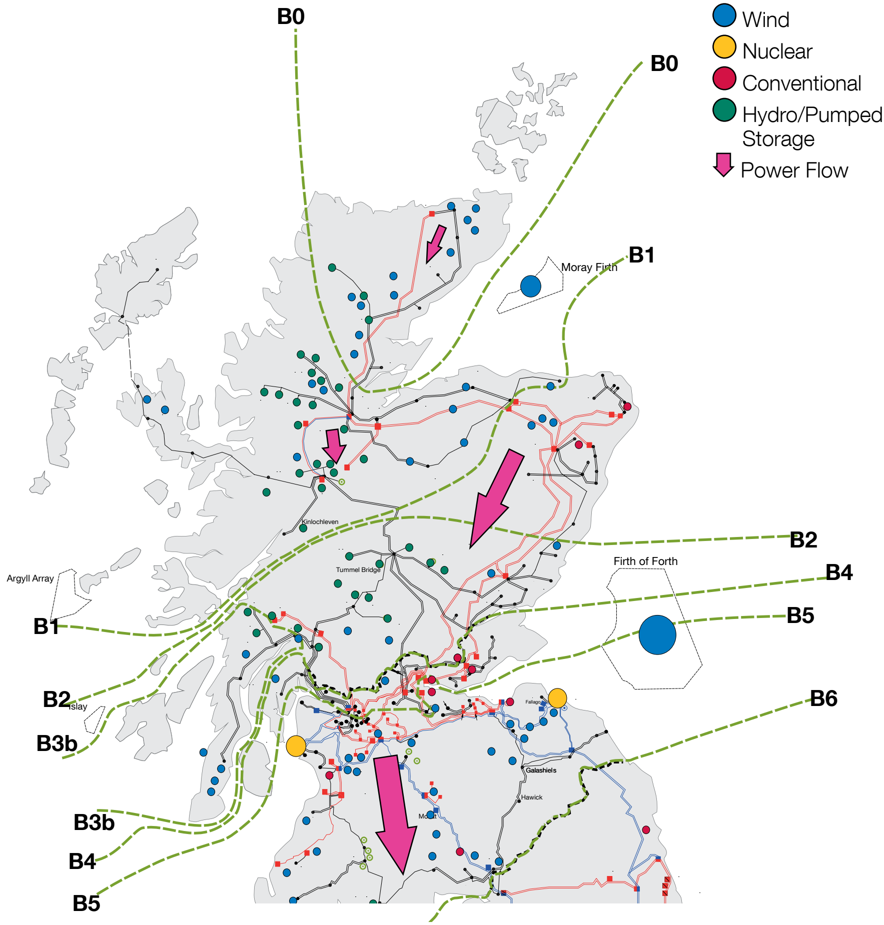


Table 4.24
Scotland Investment Strategies

Transmission Solution	Project Code	Strategic Scenario Completion date					Reinforces Boundary		
		No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	B2	B4	B5
Crossaig to Hunterston Subsea Cable		2015	2015	2015	2015	2015		✓	
Beauly to Denny Reinforcement		2015	2015	2015	2015	2015		✓	✓
Beauly–Blackhillock–Kintore Uprate		2015	2015	2015	2015	2015		✓	
Gravir on Lewis to Beauly HVDC Link		2020	2020	2020	2020	2020	✓		
Shetland to Mainland HVDC Link		2020	2020	2020	2020	2020			
Orkney–Dounreay AC Subsea Connection		2018	2018	2018	2018	2018			
Caithness–Moray Reinforcement Strategy		2018	2018	2018	2018	2018	✓	✓	
East Coast 400kV Uprate Blackhillock to Kincardine		2023	2022	2021	2020	2020		✓	
Beauly–Loch Buidhe 275kV uprate		2030	2028	2024	2020	2019		✓	
Eastern HVDC Link One		Not required	2023	2023	2023	2021		✓	✓
Eastern HVDC Link Three		Not required	Not required	Not required	Not required	2025		✓	✓
B6 Series and Shunt Compensation		2015	2015	2015	2015	2015			
Western HVDC Link		2016	2016	2016	2016	2016			✓
Central 400kV Upgrade			2021		2019	2019		✓	
South West Scotland Connections Project			2015		2015	2015			✓
Kilmarnock South–Coylton 275kV Uprating			2016		2016	2016		✓	
Coylton–Mark Hill 275kV Uprating			2016		2016	2016			
Kilmarnock South 400/275kV Substation Uprating			2018		2018	2018			
Dumfries and Galloway Reinforcement			2023		2023	2023			✓
Harker–Strathaven Reconductoring and Series Compensation			2023		2020	2020			✓
Eastern HVDC Link Two			Not required		2021	2019			✓

4.10 continued
Regional Summaries

Figure 4.10
B2 boundary capability with incremental reinforcements following the Gone Green Strategy

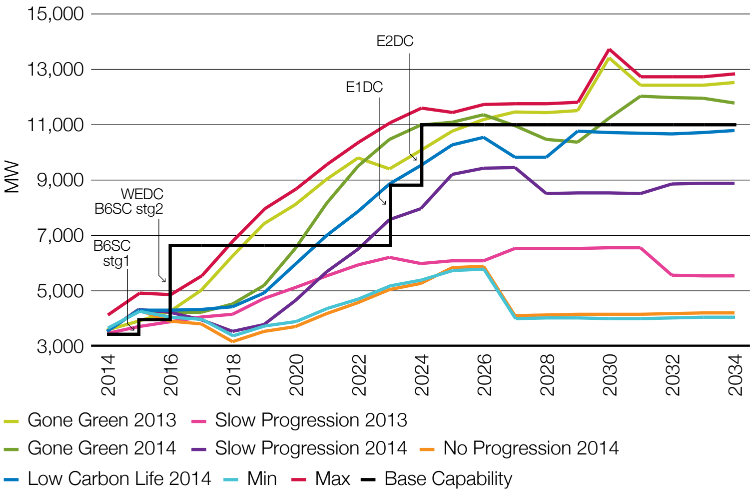


Figure 4.11
B4 boundary capability with incremental reinforcements following the Gone Green Strategy

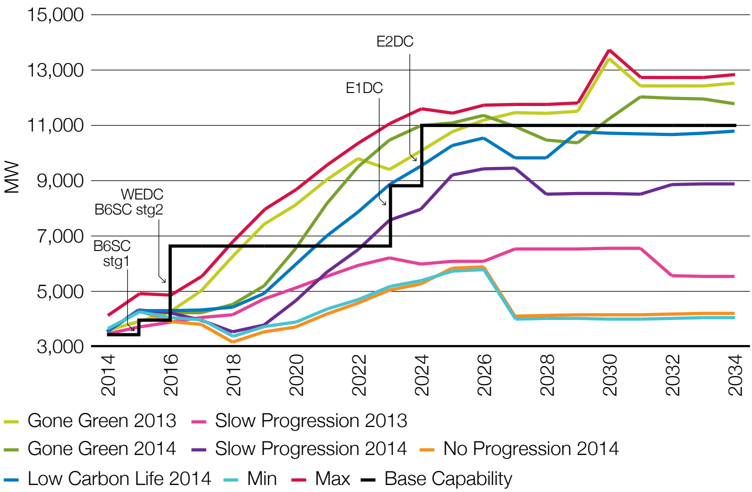
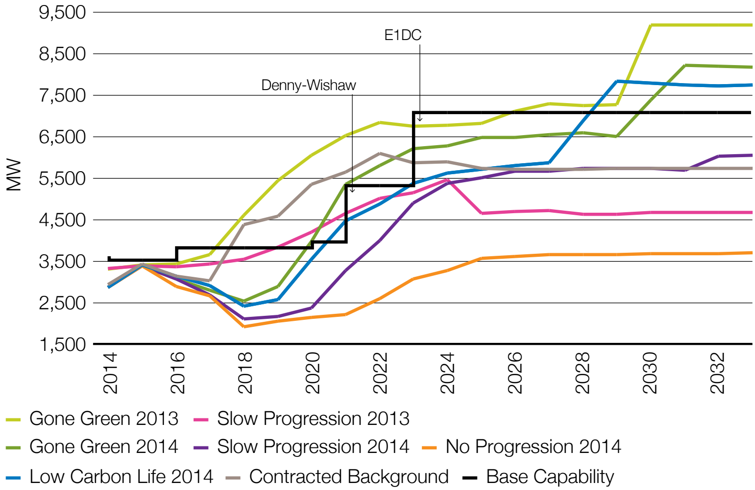


Figure 4.12
B5 boundary capability with incremental reinforcements following the Gone Green Strategy



4.10 continued
Regional Summaries

North England Summary

Inputs
- Increasing north to south peak power flows from Scotland. Driven by renewable generation connections
- Large Round 3 offshore wind farms connecting from the East and West and diminishing generation support towards the centre of the country.

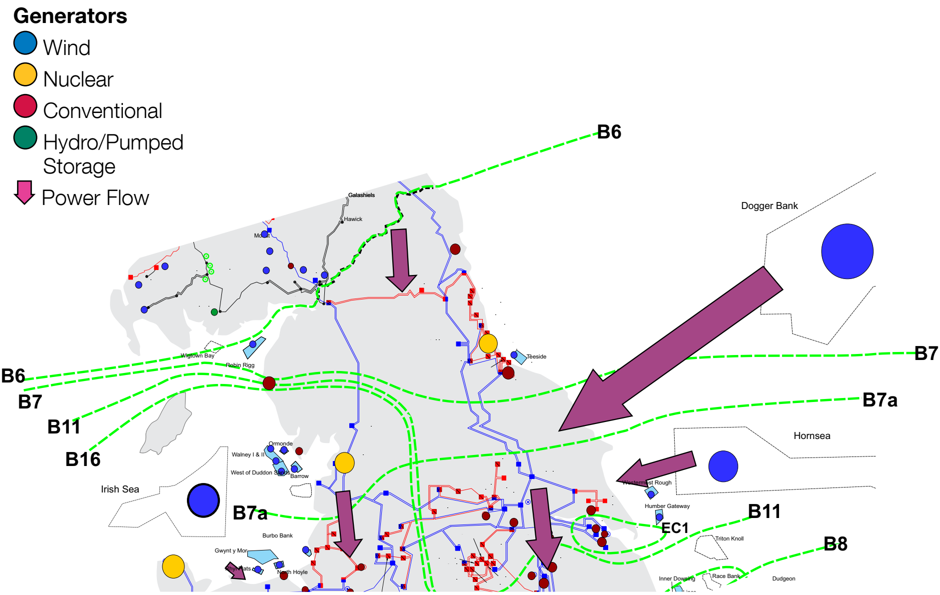


Table 4.25
North England Investment Strategies

Transmission Solution	Project Code	Strategic Scenario Completion date					Reinforces Boundary		
		No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	B6	B7	B7a
Series and Shunt compensation	B6SC	2015	2015	2015	2015	2015	✓	✓	
Western HVDC Link	WEDC	2016	2016	2016	2016	2016	✓	✓	✓
Kirkby–Rainhill Substation Upgrade	KREU	2022	2021	2021	2020	2020			✓
Eastern HVDC Link One	E1DC	N/A	2023	2023	2023	2023	✓	✓	✓
Eastern HVDC Link Two	E2DC	N/A	2024	2024	2024	2024	✓	✓	✓
Penwortham–Padiham & Penwortham–Carrington Reconductoring and Kirkby–Penwortham Upgrade	CPRE	N/A	2020	2020	2020	2020			✓
Lackenby–Norton Reconductoring	LNRE	N/A	2023	2023	2023	2023		✓	
Norton–Osbaldwick Hotwiring and Reconductoring	OYRE	N/A	2025	2025	2025	2025		✓	
East Coast Integration Stage 1	ECI1	N/A	2028	N/A	2026	2026		✓	✓
Uprate Harker–Stella West circuits	EWUP	N/A	N/A	2030	N/A	N/A			

4.10 continued
Regional Summaries

Figure 4.13
B6 boundary capability with incremental reinforcements following the Gone Green Strategy

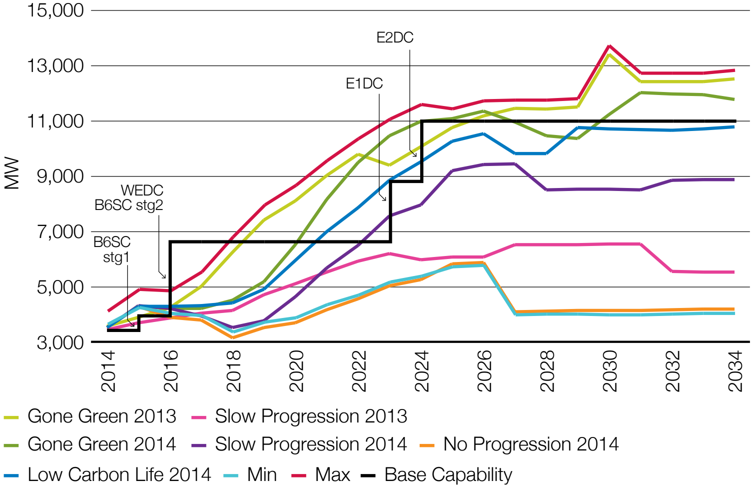


Figure 4.14
B7 boundary capability with incremental reinforcements following the Gone Green Strategy

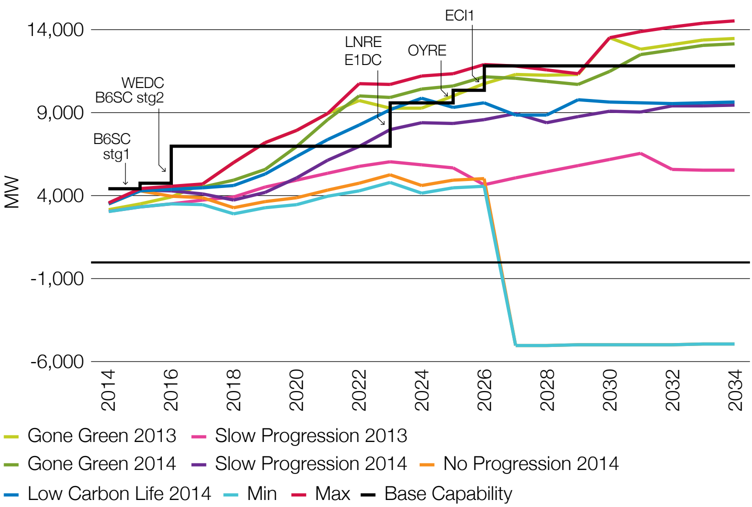


Figure 4.15
7a boundary capability with incremental reinforcements following the Gone Green Strategy

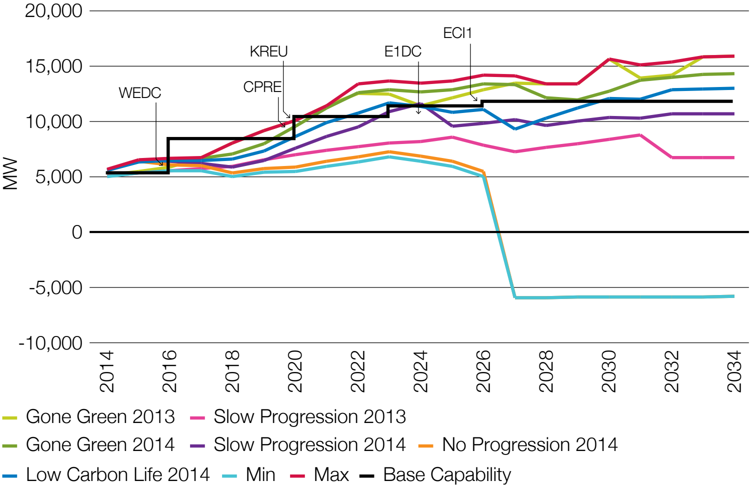


Table 4.26
North England NDP Investment Recommendations

Option	Decision
Series & Shunt Reactive Compensation	Progress construction
Western HVDC Link	Progress construction
Kirkby-Rainhill Substation Upgrade	Delay
Eastern HVDC Link 1	Continue pre-construction scoping
Norton–Osbaldwick Hotwiring and Reconductoring	
Lackenby–Norton Reconductoring	No decision required
Penwortham–Padiham & Penwortham–Carrington	No decision required
Reconductoring and Kirkby–Penwortham Upgrade	
Uprate Harker–Stella West circuits	No decision required
Eastern HVDC Link 2	No decision required
Eastern HVDC Link 3	Evaluation On-going
East Coast Offshore Integration Stage 1	Evaluation On-going
	Evaluation On-going

4.10 continued
Regional Summaries

East England summary

Inputs
- Prospect of increased wind generation off East Anglia coast and in the North Sea
- New nuclear connections and gas connections in certain scenarios
- Increasing east to south power flows.

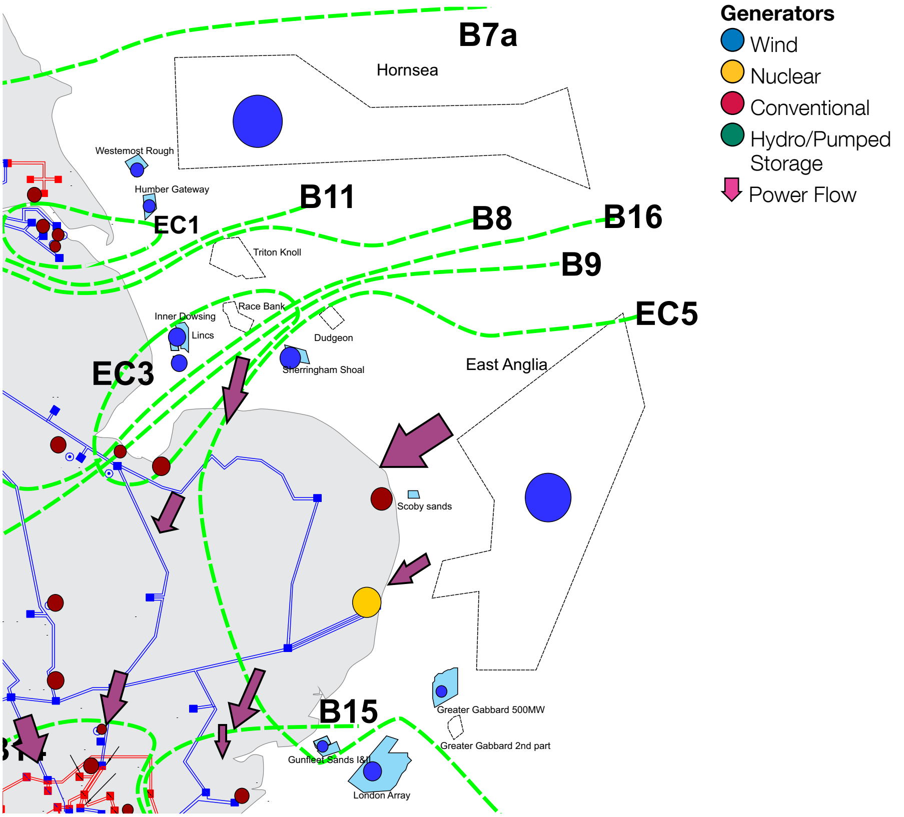


Table 4.27
East England Investment Strategies

Transmission Solution	Project Code	Strategic Scenario Completion date					Reinforces Boundary		
		No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	EC 1	EC 3	EC 5
Bramford–Twinstead New Overhead Lines (requires Rayleigh–Coryton South–Tilbury Reconductoring)	ETNO	N/A	2025	2023	2023	2023			✓
Complete Rayleigh–Coryton South–Tilbury Reconductoring (requires Bramford–Twinstead New Overhead Lines)	CTRE	N/A	2025	2023	2023	2023			✓
Bramford–Braintree–Rayleigh Main Reconductoring (requires Bramford–Pelham reconductoring and East Anglia MSC at Burwell Main)	BRRE	N/A	2026	2024	2024	2023			✓
Bramford–Pelham reconductoring	BPRE	N/A	2026	2024	2024	2023			✓
Rayleigh Main Series Reactor	RMSR	N/A	2024	2024	2024	2023			✓
New Transmission Route and Quad Boosters in East Anglia	ECNO	N/A	2029	2027	2029	2025			✓

4.10 continued
Regional Summaries

Figure 4.16
EC5 boundary capability with incremental reinforcements following the Gone Green Strategy

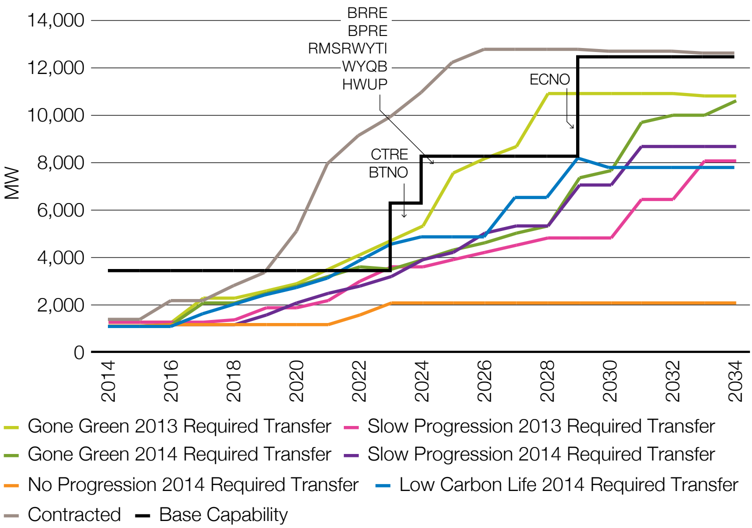


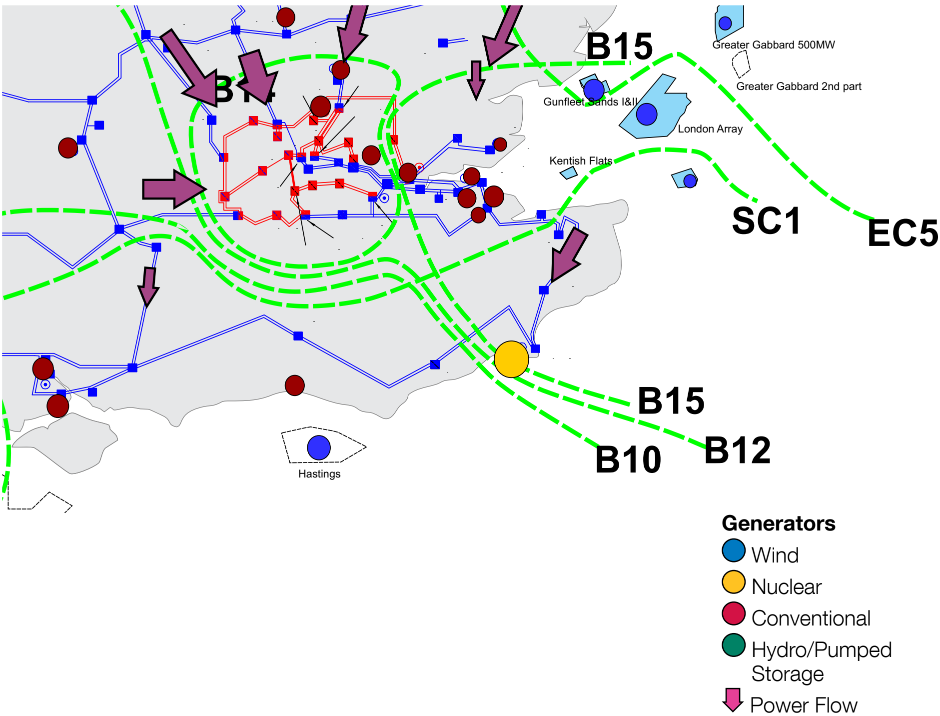
Table 4.28
East England NDP Investment Recommendations

Option	Decision
Bramford–Twinstead New Overhead Lines	Delay
Complete Rayleigh–Coryton South–Tilbury Reconductoring	Delay
Bramford–Braintree–Rayleigh Main Reconductoring	No decision required
Bramford–Pelham reconductoring	No decision required
East Anglia MSC at Burwell Main	No decision required
Rayleigh Main Series Reactor	No decision required
West Burton–High Marnam reconductoring	No decision required
New Transmission Route and Quad Boosters in East Anglia	No decision required

South England summary

Inputs

- High demand from London and the South
- European interconnectors have a large influence on power flows supporting demand supply when importing from Europe
- Interconnector export to Europe draws additional power through London and the surrounding areas.



4.10 continued
Regional Summaries

Table 4.29
South England Investment Strategies

Transmission Solution	Project Code	Strategic Scenario Completion date					Reinforces Boundary				
		No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	B 14	B 14 (e)	B 15	SC1	B13
Wymondley Turn-in	WYTI	N/A	2019	2019	2019	2019	✓	✓			
Wymondley QBs	WYQB	N/A	2019	2019	2019	2019	✓	✓			
Hackney–Tottenham Waltham Cross Uprate	HWUP	N/A	2031	2025	2022	2022		✓			
New 400kV Transmission Route Hinkley Point–Seabank	HSNO	2029	2027	2025	2026	2021					✓
South Coast Reactive Compensation	SCRC	N/A	2021	2021	2020	2020			✓	✓	
New Transmission Route on South Coast	SCNO	N/A	N/A	2027	2026	2026				✓	
Kelmsley–Rowdown–Littlebrook reconductoring	KLRE	N/A	N/A	2027	2026	2026			✓	✓	
Dungeness–Sellindge–Canterbury reconductoring	DCRE	N/A	N/A	N/A	2019	N/A			✓		
Series and Shunt Compensation on South Coast	SCSC	N/A	N/A	N/A	N/A	2026				✓	

Figure 4.17
B14 boundary capability with incremental reinforcements following the Gone Green Strategy

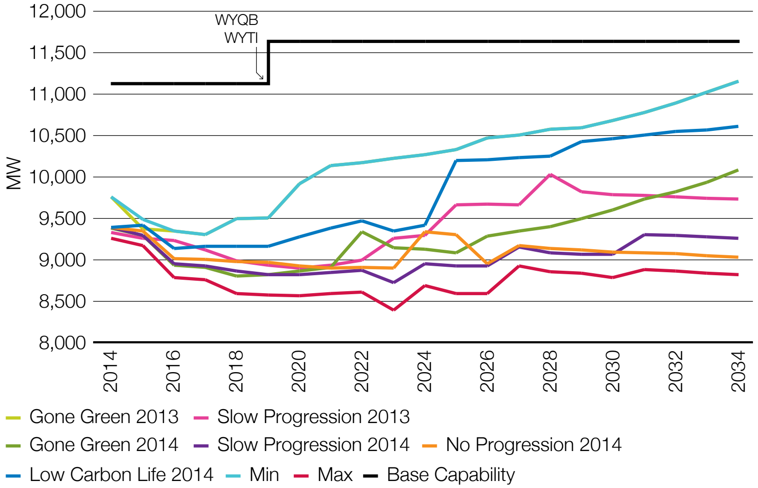
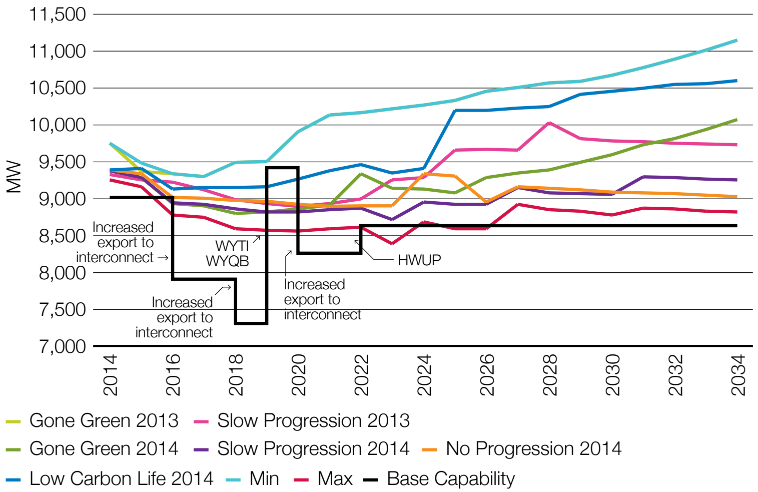


Figure 4.18
B14(e) boundary capability with incremental reinforcements following the Gone Green Strategy



4.10 continued
Regional Summaries

The capability of boundary B14(e) analysed with the European interconnectors set to export from South-East region. As shown in above Figure 4.18 reduction in boundary capability is due to increase in interconnector export condition.

Figure 4.19
B15 boundary capability with incremental reinforcements following the Gone Green Strategy

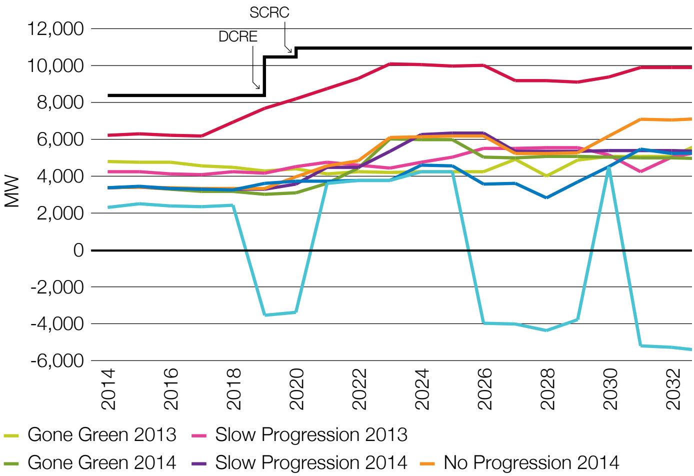


Figure 4.20
SC1 boundary reinforce capability with incremental reinforcement

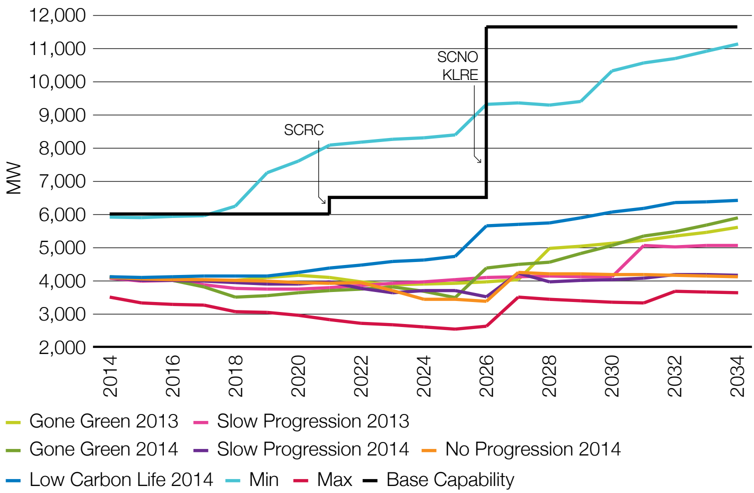


Table 4.30
South England NDP Investment Recommendations

Option	Decision
Wymondley Turn-in	Commence pre-construction
Wymondley QBs	Commence pre-construction
South Coast Reactive Compensation	Delay
Hackney–Tottenham Waltham Cross Uprate	No decision required
New 400kV Transmission Route Hinkley Point–Seabank	Continue pre-construction
Dungeness-Sellindge–Canterbury reconductoring	No decision required
New Transmission Route on South Coast	No decision required
Series and Shunt Compensation on South Coast	No decision required
Kelmsley–Rowdown–Littlebrook reconductoring	No decision required

4.10 continued
Regional Summaries

West England and Wales

Inputs

- Large capacity generation connections in Wales from 2016
- South west changes from importing to export with new large generation connections.

Generators

- Wind
- Nuclear
- Conventional
- Hydro/Pumped Storage
- Power Flow

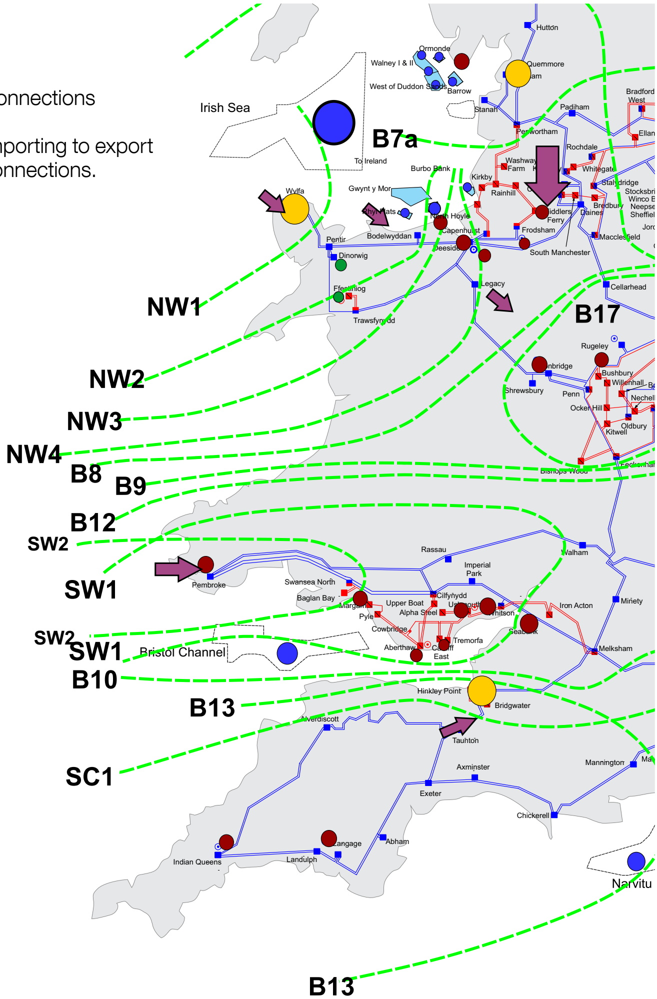


Table 4.31
West England Investment Strategies

Transmission Solution	Project Code	Strategic Scenario Completion date					Reinforces Boundary						
		No Progression	Slow Progression	Low Carbon Life	Gone Green	Local Contracted	NW1	NW2	NW3	NW4	B8	B9	SW1/SW2
Reconductor Daines–Macclesfield circuit	DMC1	N/A	2026	N/A	2026	2024					✓		
Wylfa–Pembroke HVDC Link	WPDC	N/A	2024	2024	2024	2024	✓	✓	✓	✓	✓		
Wylfa–Pentir Second Circuit	WPNO	N/A	N/A	2027	2028	2025	✓						
Pentir–Trawsfynydd Second Circuit	PTNO	N/A	2022	2027	2021	2021		✓					
Pentir–Deeside and Pentir–Trawsfynydd Reconducto-ring	PCRE	N/A	N/A	N/A	2027	N/A		✓	✓				
Pentir–Trawsfynydd 1 Single Core per Phase	PTC1	N/A	N/A	N/A	2026	2025		✓					
Pentir–Trawsfynydd 2 Second Core per Phase	PTC2	N/A	N/A	N/A	2026	2025		✓					
East Coast Integrated Offshore Stage Two	ECI2	N/A	N/A	2025	2024	2024					✓	✓	
North Wales Offshore Integration	NWOI	N/A	N/A	N/A	2026	2025	✓	✓	✓	✓			
Irish Offshore Integration	IROI	N/A	N/A	N/A	2026	N/A	✓	✓	✓	✓			✓

4.10 continued
Regional Summaries

Figure 4.21
NW1 boundary capability with incremental reinforcements following the Gone Green Strategy

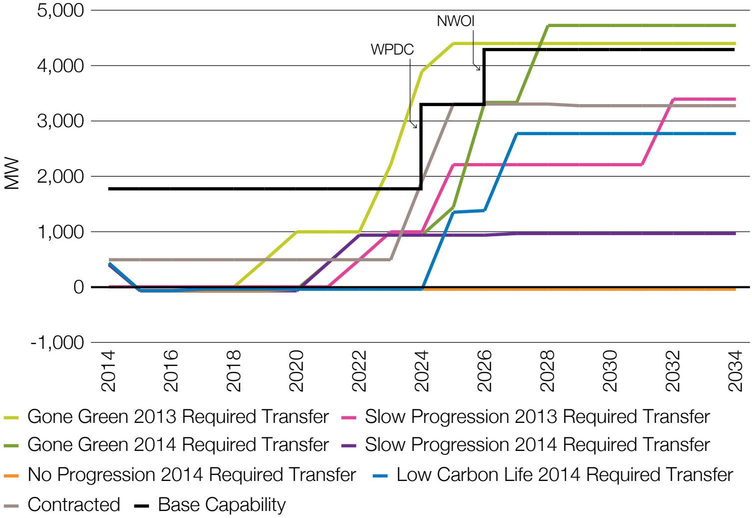


Figure 4.22
NW2 boundary capability with incremental reinforcements following the Gone Green Strategy

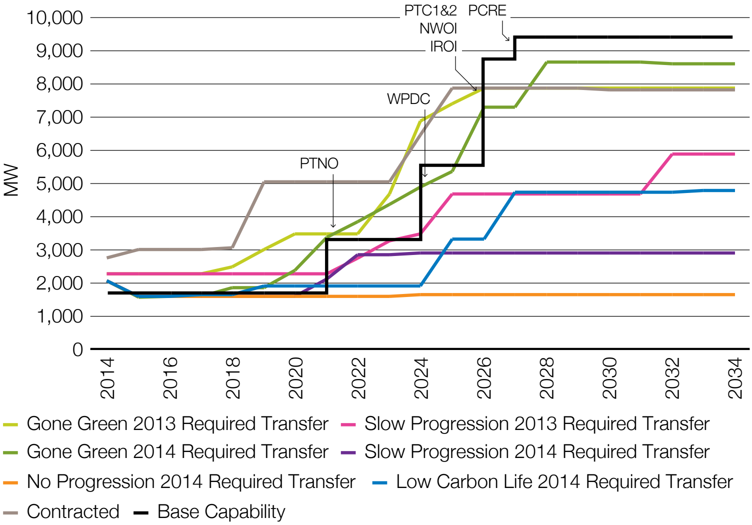


Figure 4.23
NW3 boundary capability with incremental reinforcements following the Gone Green Strategy

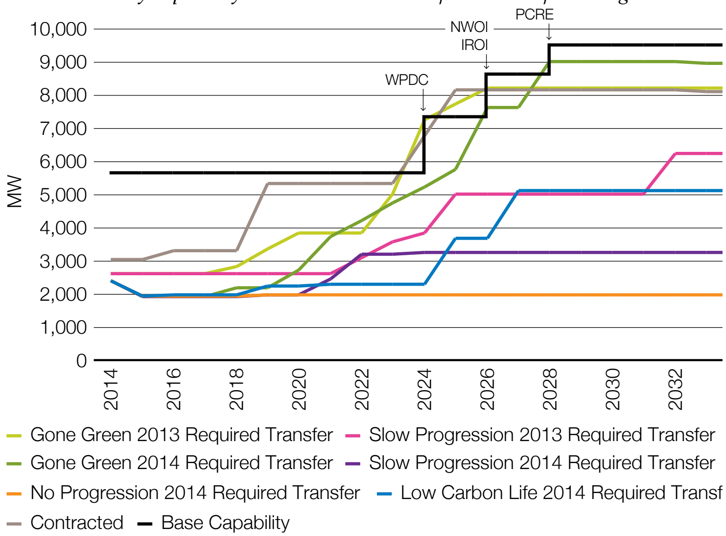
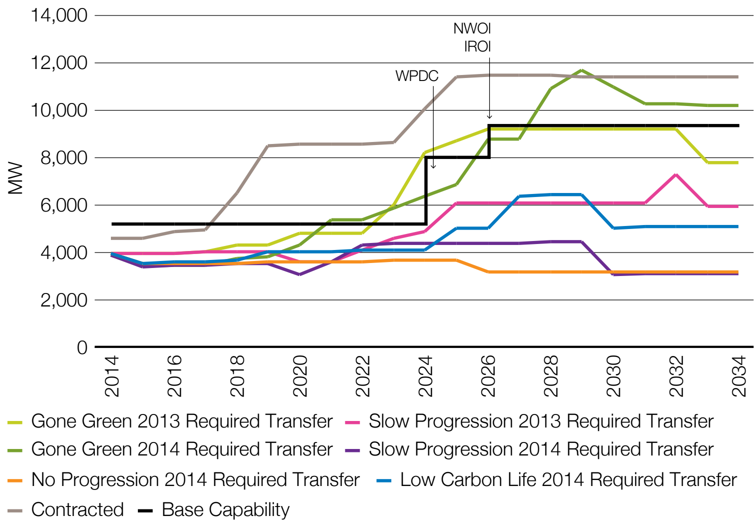


Figure 4.24
NW4 boundary capability with incremental reinforcements following the Gone Green Strategy



4.10 continued
Regional Summaries

Figure 4.25
B8 boundary capability with incremental reinforcements following the Gone Green Strategy

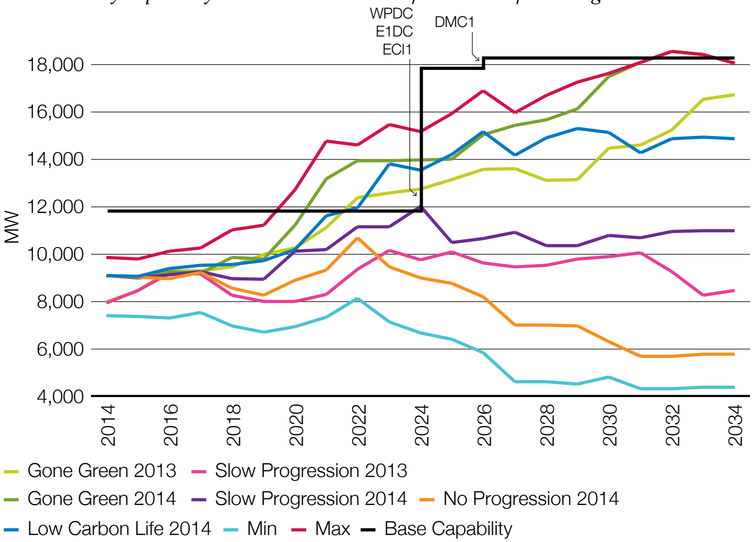


Figure 4.26
SW2 boundary capability with incremental reinforcements following the Gone Green Strategy

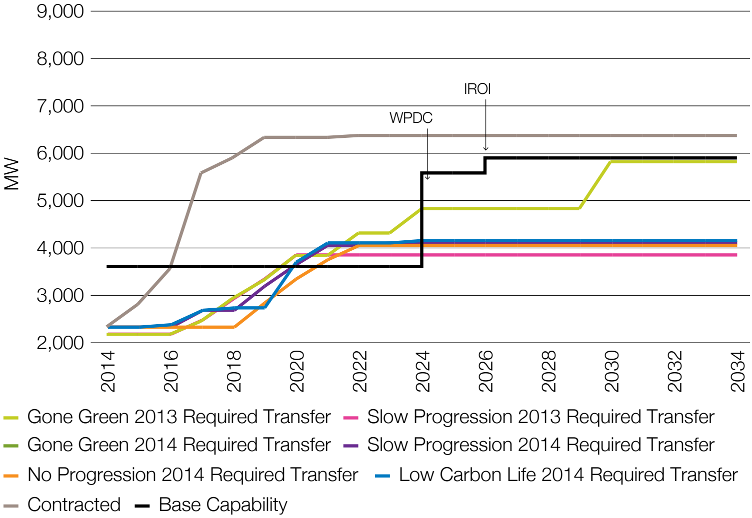


Table 4.32
West England & Wales NDP Investment Recommendations

Option	Decision
Wylfa–Pembroke HVDC link	Delay
Second Pentir–Trawsfynydd circuit	Delay
Second Wylfa–Pentir circuit	Complete pre-construction scoping
Pentir–Deeside and Pentir–Trawsfynydd Reconductoring	No decision required
Pentir–Trawsfynydd 1 Single Core per Phase	No decision required
Pentir–Trawsfynydd 2 Second Core per Phase	No decision required
Reconductor Daines–Macclesfield circuit	No decision required
East Coast Integrated Offshore Stage Two	No decision required
North Wales Offshore Integration	No decision required
Irish Offshore Integration	No decision required

4.11 Stakeholder Engagement

In this chapter we looked at how the transmission network could develop and opportunities for our stakeholders over the next twenty years.
Please contact us at:
transmission.etys@nationalgrid.com

Stakeholder engagement
We would like your view on how we could improve the information we provide in ETYS for offshore developers.

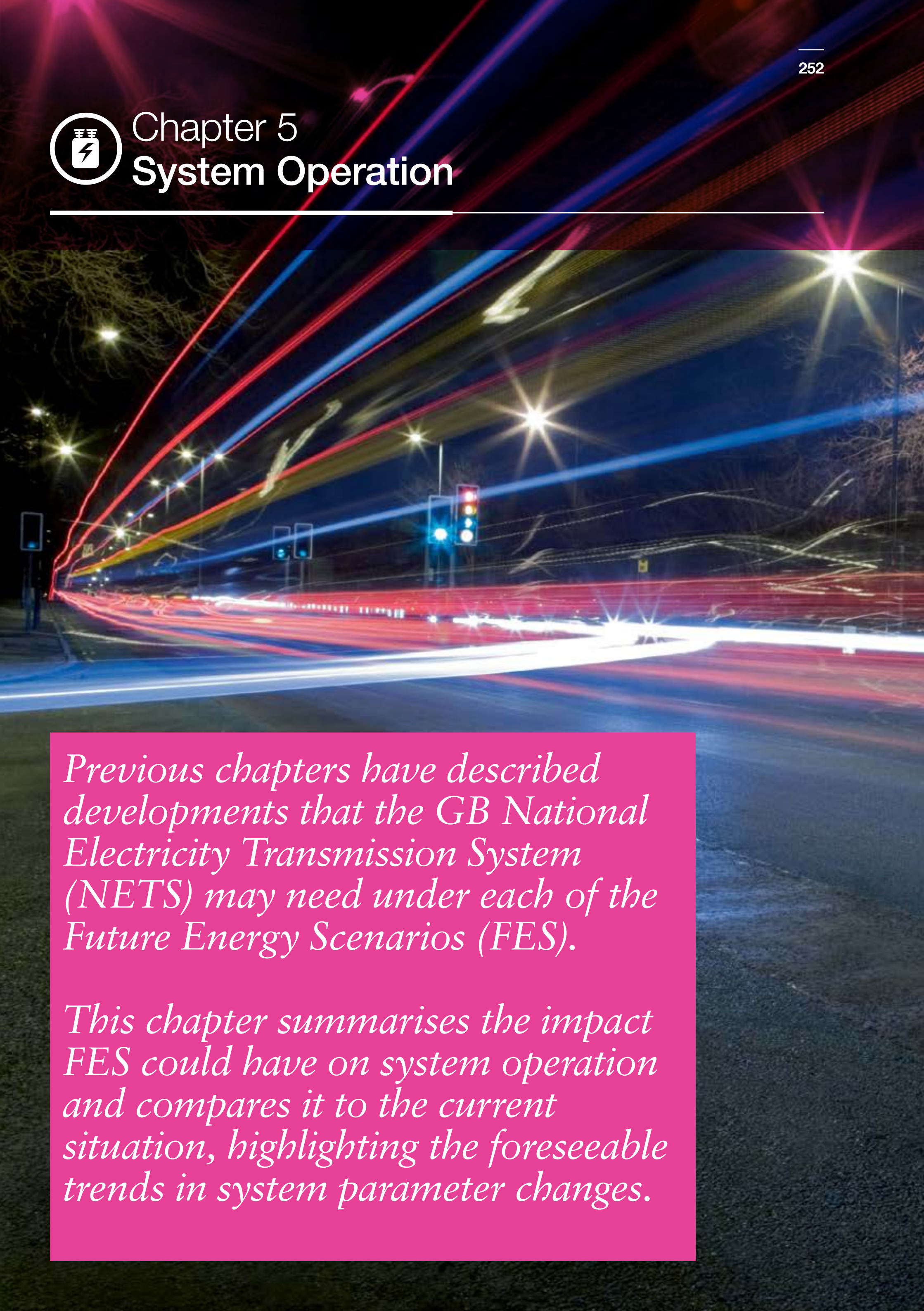
Stakeholder engagement
We would appreciate your view on the new ETYS section about non-build/commercial transmission solution options. What other commercial options would you like us to explore in the future?

Stakeholder engagement
We would welcome your view on what would incentivise an offshore generator/OFTO to make more reactive power available to the NETSO beyond Grid Code/STC requirements and rewarded as described in CUSC Schedule 3.

Stakeholder engagement
We would appreciate your view on how we presented the potential future development of the NETS. Have we explained to you clearly how development decisions were made to ensure an optimal, economic and efficient transmission strategy?

Stakeholder engagement
We would welcome your view on how we could improve the way network opportunities were presented. What information would you like to see in ETYS about network opportunities?

Chapter 5
System Operation



Previous chapters have described developments that the GB National Electricity Transmission System (NETS) may need under each of the Future Energy Scenarios (FES).

This chapter summarises the impact FES could have on system operation and compares it to the current situation, highlighting the foreseeable trends in system parameter changes.

5.1 Introduction

This chapter focuses on the long-term operation of the NETS; the short-term changes are discussed at the regular Electricity Transmission Operational Forum.[1]

Using the FES as the background for system studies means we can explore conditions that the system could experience. This gives us a wider view of possible additional system support and capabilities that could be needed. These could include developing new commercial services, technology and asset solutions and network codes, or improving the existing ones.

The gaps in performance and solution assessment have traditionally been related to the interfaces between different Transmission Owners (TOs) and between System Operator (SO), TOs, and Distribution Network Owners (DNOs). Ofgem's Integrated Transmission Planning and Regulation project, and various projects initiated by the Electricity Network Strategy Group, aim to bridge these gaps to implement the most beneficial solutions, where and when they are needed. We take part in these debates and engage with transmission customers and stakeholders to ensure very high levels of system reliability. At the same time, we aim to ensure that consumers receive the best value.

System operability

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. This stability is important to ensure the system remains operable and synchronised during disturbances such as loss of generation or 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 as described in the figure below.

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-system-operations/Electricity-Operational-Forum/

5.1 continued
Introduction

The figure illustrates the day-to-day stability challenges for almost any large power system. The three main classes consist of rotor angle, frequency and voltage stability. Networks have been designed to meet these challenges and they have also been the foundation of 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. For instance, as an island power system with no AC link to other large power systems, it is important that we maintain a balance between frequency stability, the size of the largest potential loss of infeed on the system, the costs of de-loading plant, and providing frequency control services.

System Operability Framework

This chapter complements the System Operability Framework (SOF) that has been developed to provide an in-depth assessment of future system operability. The first report describing the framework itself and the assessment under the 2014 Future Energy Scenarios was published in September 2014, along with a consultation document and a call for further feedback from the industry stakeholders[2]. This chapter occasionally refers to topics that are discussed in much greater detail in the SOF 2014 report.

The SOF report will describe only the framework itself and it will be updated as required in light of industry feedback, changes in legislation or changes to the framework methodology. Full assessment of system operation using the SOF methodology will continue to be published in the annual ETYS documents and feedback about results can be provided via the ETYS consultation and stakeholder engagement.

System characteristics

Table 5.1 illustrates the aspects of system operability that are affected by the changes described in the Future Energy Scenarios and that have been reviewed as part of the SOF 2014 assessment.

Figure 5.1
Power system stability classification

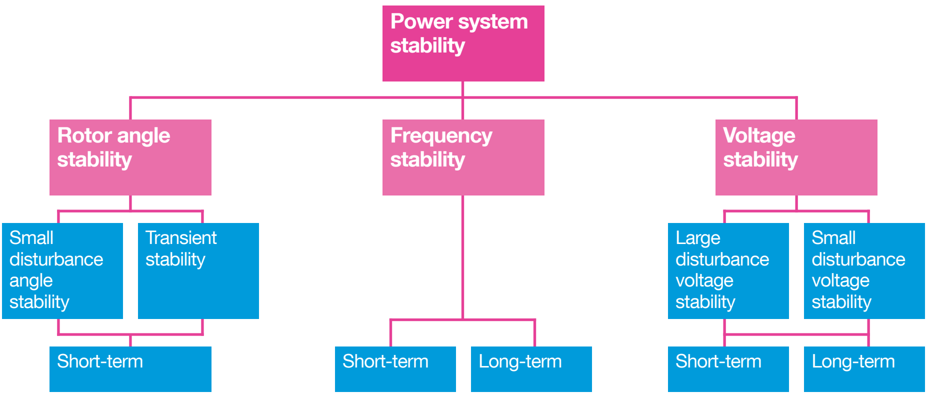


Table 5.1
System operability parameters

	Change	Affected subjects	Consequences
Change in generation mix	System inertia	RoCoF	Trip of embedded generation
		Frequency containment	Increase in volume of required response
		Generation withstand capability	Trip of larger units (i.e. flameout)
		System stability	Power oscillations
	Short circuit level	Protection	Faults not detected by protection systems
		Voltage dips	Trip of embedded generation without FRT capability
		Voltage management	Maintaining voltage within statutory limits
		Resonance and harmonics	Excessive harmonic voltage distortions
		CSC HVDC link commutation	Inability to import/export power across CSC HVDC links
	Conventional generator closures and increase in distributed generation	System inertia and short circuit level	New system study methodologies, services and asset investment
New technologies	Series compensation	Sub-synchronous resonance	Interaction with the mechanical shafts in thermal units and shaft fatigue
	New CSC HVDC links		
	New VSC HVDC links	Control systems	Adverse interaction with existing control systems (AVR/Govenors/SVCs/STATCOMS)

It's important to continuously reassess these operability aspects in light of the most recent and reliable industry and market intelligence. This will help us to maintain the more than 99.99% reliability of power supply that the GB system has seen in the past.

The system has always constantly grown and evolved in response to consumer needs and expectations, political and economic climate and technical capabilities. System planning and operation methods have therefore had to be adjusted so system safety and reliability are not compromised.

This continues today. However, the changes expected to take place in the energy industry in the next 20 to 30 years will have a much faster pace than the changes we have seen in the previous decades. Because of this, the considerations outlined in Table 5.1 above need to be continuously reviewed to ensure the priorities are clearly identified and communicated with the industry.

The real-time operation of the transmission system is largely dependent on the type and the amount of generation connected to it, and the nature of the loads connected to the network. Another important challenge is the increase in the number of embedded generators that have

[2] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

5.1 continued
Introduction

an impact on the transmission demand profile, flows on the transmission system and system performance aspects such as voltage, short circuit level and system inertia. Potential increases in the penetration of electric vehicles, electricity storage and a range of demand side management solutions may also change the demand profile and affect system operation.

The key changes to the system in response to the developments foreseen by the Future Energy Scenarios are expected to be:

- Reduction in system strength
- Change in the generation mix
- Change in the nature and the behaviour of the loads
- The evolution and growth of new technologies and services.

The challenges are likely to be most pronounced during periods of high non-synchronous generation output and low demand, because the installed capacity of wind generation and HVDC interconnectors connected at the transmission level may exceed the minimum demand in a few years. Future changes in the generation mix have an inherent effect on the Gas Transmission Network. For further information on these, please refer to Chapter 3 System operator of the Gas Ten Year Statement (GTYS).

The rest of this chapter sets the context for these changes and outlines the expected future trends of the related system operability parameters and possible solutions.

5.2 System Strength

The strength of a power system reflects its natural resilience against disturbances caused by system events such as switching, faults, loss of load or generation. System strength can be assessed by looking at the system inertia and the short circuit level.

The Gone Green background is generally the worst-case scenario for system strength in terms of system inertia reduction, stability constraints and short circuit level, while No Progression, being the closest to current background, is the best-case scenario. The differences between the four backgrounds are highlighted throughout this section and discussed in more detail in the System Operability Framework report.

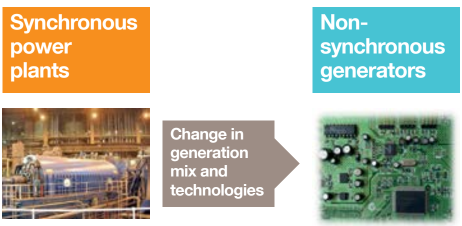
5.2.1 System strength

System inertia is a measure of how strong the system is in response to transient changes in frequency. By estimating and monitoring system inertia we can ensure that a sufficient level is always maintained to secure against the consequences of demand and generation imbalance.

Sources of system inertia

Transmission-connected synchronous generators have traditionally been the main source of system inertia, with some support from large industrial loads made up of heavy rotating elements. Conversely, most non-synchronous generators are de-coupled from the system; this typically prevents non-synchronous generators from contributing to system inertia.

Figure 5.2
Synchronous vs. non-synchronous generation



Non-synchronous generators connected to the system could in future contribute to the overall system inertia by providing 'synthetic inertia' – rapidly increasing the power output in response to a drop in system frequency, or decreasing power output in response to a rise in frequency.

Changes in system inertia

System inertia has a direct effect on:

- Rate of change of frequency (RoCoF)
- Frequency containment
- System stability.

The following figures describe the estimated effect on overall system inertia (H) changes for each of the scenarios. This is based on wind power output of 70% of the installed capacity (the load factor used in the economic analysis approach to boundary transfer planning). It can be seen that the system inertia is expected to decline most rapidly against the Gone Green background, but it also declines in the other scenarios.

5.2 continued
System Strength

Figure 5.3
System inertia (H) changes for Gone Green scenario at 70% wind power output

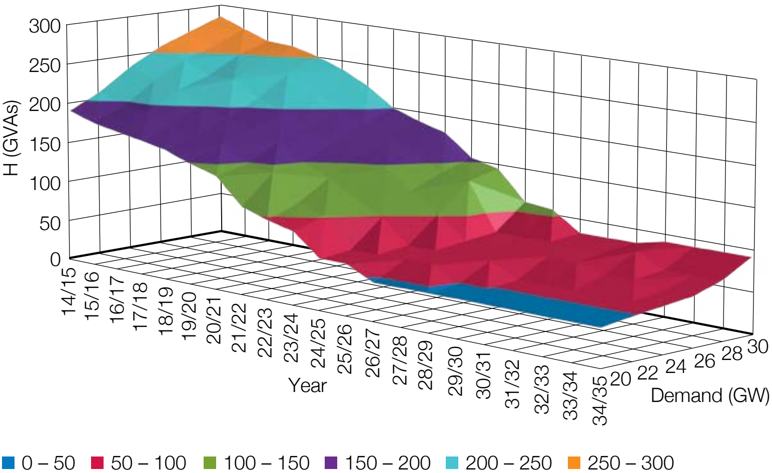


Figure 5.4
System inertia (H) changes for Slow Progression scenario at 70% wind power output

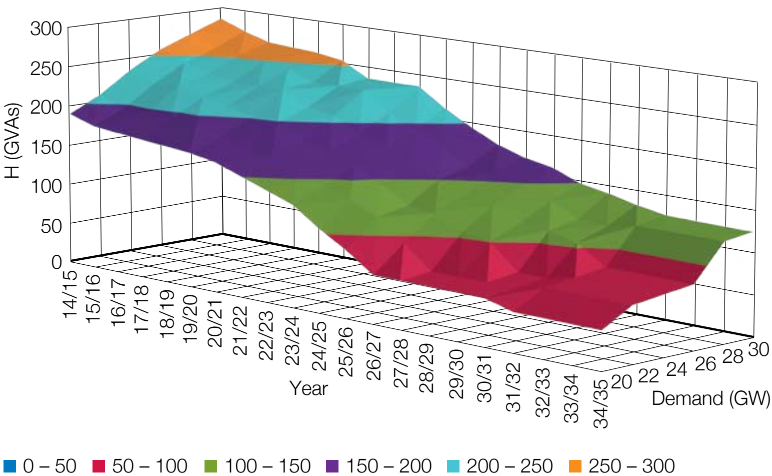
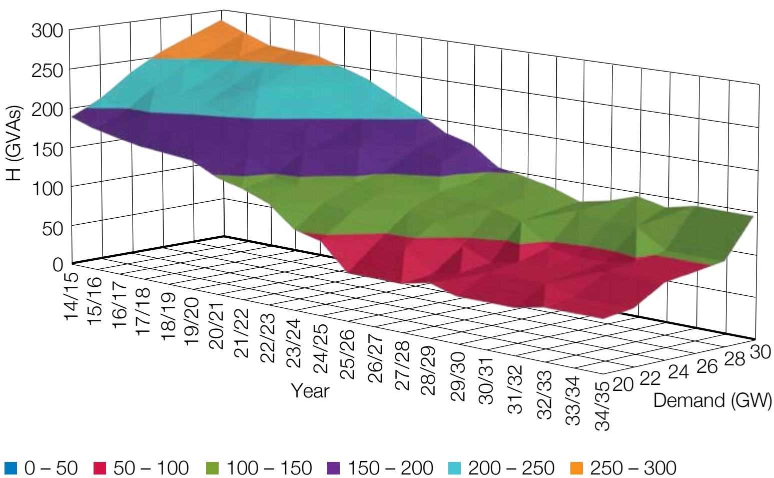
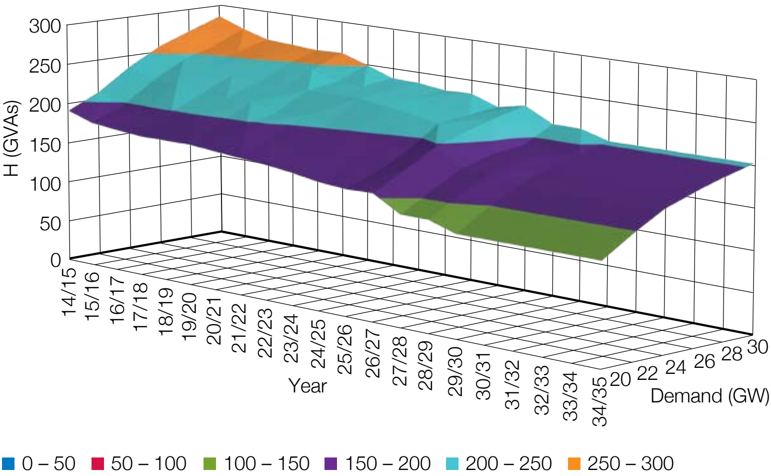


Figure 5.5
System inertia (H) changes for Low Carbon Life scenario at 70% wind power output



5.2 continued
System Strength

Figure 5.6
System inertia (H) changes for No Progression scenario at 70% wind power output



Embedded generation disconnection due to rate of change of frequency (RoCoF)
The consequence of generation and demand imbalance during times of low system inertia is an increase in the RoCoF, usually following the loss of a large infeed.

If the RoCoF during the initial period of disturbance is high enough to unnecessarily trigger the loss of mains protection RoCoF relays on embedded generation, this could lead to a cascading loss of large amounts of embedded generation connected against the existing forms of RoCoF protection.

The joint Grid Code and Distribution Code work group GC0035 has assessed this and has changed the threshold for future embedded generation from August 2016 onwards to be connected with RoCoF settings no lower than 0.5Hz/s for synchronous generators and 1Hz/s for non-synchronous generators above 5MW, a requirement now within Grid Code.

Level of exposure to high RoCoF
SOF 2014 report includes an assessment of the percentage of time that the system may be exposed to RoCoF above 0.125Hz/s and 0.5Hz/s and what impact that might have on system operation. This shows that if the typical setting remained at 0.125Hz/s, for example, in future there would be a requirement to either constrain the largest infeed or hold much greater amounts of frequency response for very long periods of time. For example, by 2024/25 the amount of time when there would need to be constraints would be:

- Over 90% in Gone Green
- Over 85% in Low Carbon Life
- Over 35% in Slow Progression
- Over 20% in No Progression.

Currently, constraints are required approximately 20% of the time across the year. This level of exposure is illustrated by the load duration curves in the figures below.

Figure 5.7
Exposure to high RoCoF – Gone Green

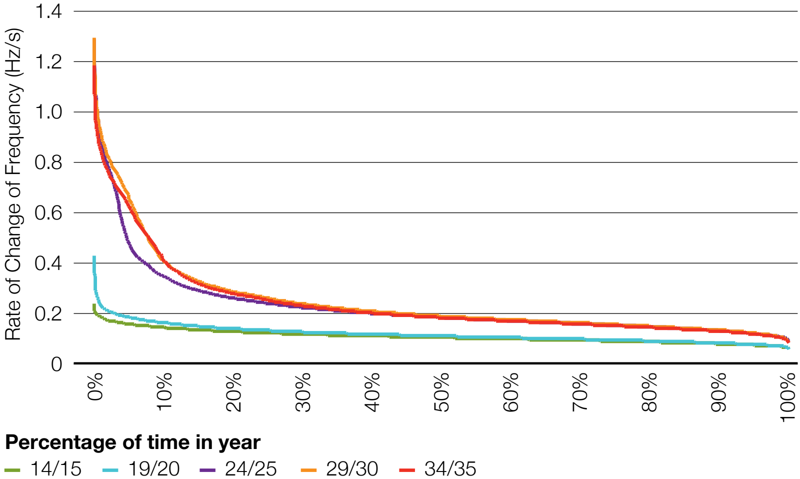
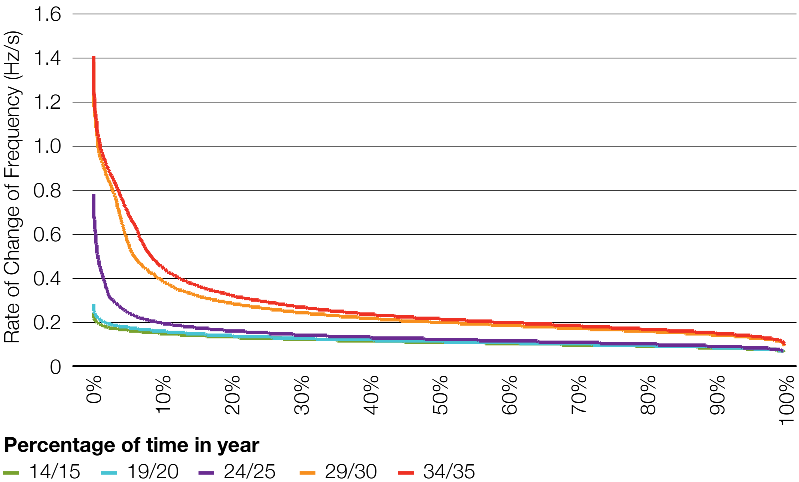


Figure 5.8
Exposure to high RoCoF – Slow Progression



5.2 continued
System Strength

Figure 5.9
Exposure to high RoCoF – Low Carbon Life

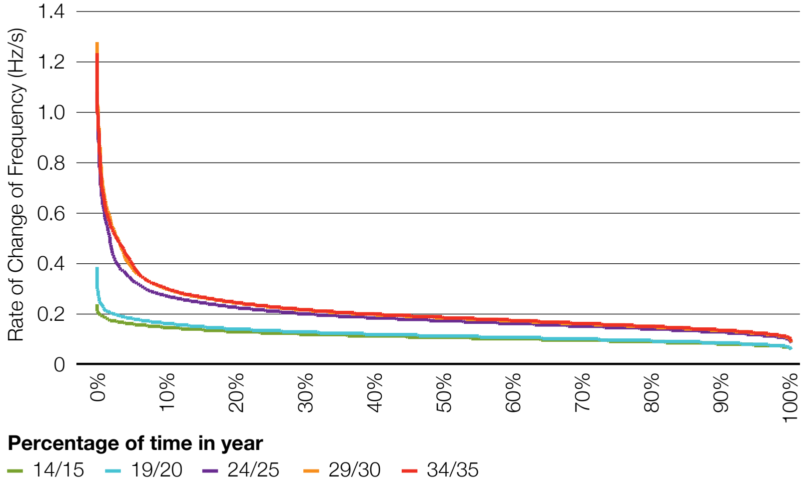
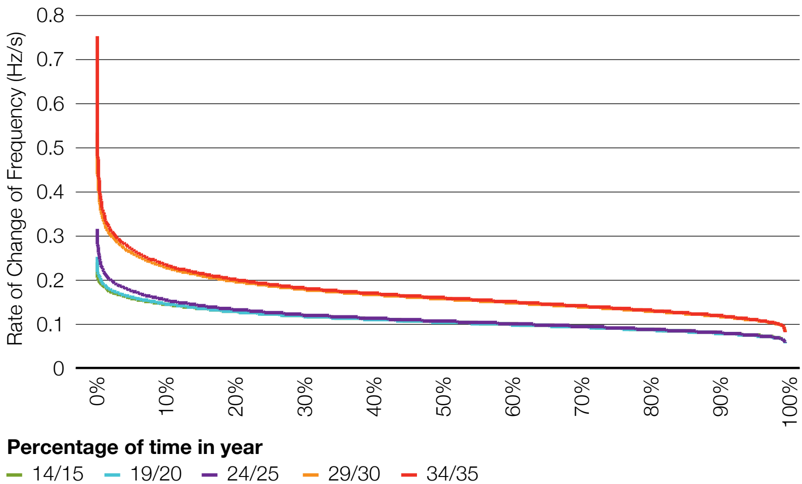


Figure 5.10
11Exposure to high RoCoF – No Progression



The investigation has demonstrated that 1Hz/s is expected to occur less than 1% of the time across all of these scenarios before 2034/35. The rate at which the challenge grows varies between the scenarios depending on the estimated connection timescales of large synchronous and non-synchronous generators.

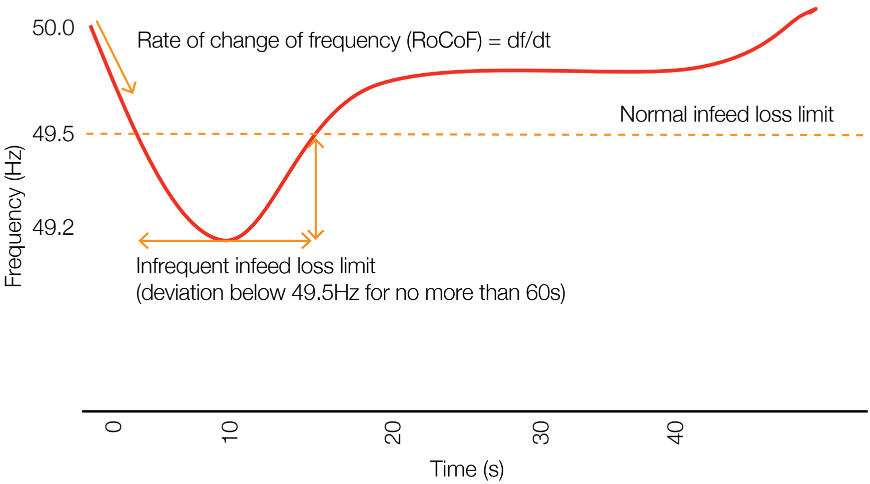
Stakeholder engagement
National Grid would welcome further discussion with members of the industry in all of the above areas. We would also like to further develop partnership proposals with stakeholders and with suppliers about potential implementation projects suitable for Network Innovation Competition funding.

Frequency containment

Frequency containment is a set of actions that ensures the changes in frequency following a loss of generation or demand are controlled, allowing the frequency to return to 50Hz as soon as possible and without exceeding the operational limits.

High RoCoF causes the frequency to change very quickly. When a large infeed is lost, the frequency may drop to the lower limit and below before sufficient response to the event can start.

Figure 5.11
12 Impact of high RoCoF on frequency containment



5.2 continued
System Strength

Rapid frequency response (RFR)

With increasing RoCoF, it is not only important to hold the appropriate level of response for credible system losses, but also to ensure that the response can be delivered quickly enough. The minimum requirements of this frequency response capability are described in the Grid Code.

Typical frequency response units have so far operated with an aggregated ramp rate of 250MW/s that can be sustained for six seconds following a 1320MW infeed loss. The infrequent infeed loss, as defined by the NETS SQSS, has recently increased to 1800MW and several units of this size are expected to connect to the system.

This requires the response units to be capable of contributing to a 400MW/s aggregated ramp rate in order to arrest the frequency before it has reached the statutory limit of 49.2Hz following an 1800MW loss.

The required ramp rates for the units responding to a 1800MW infeed loss limit, when and for what proportion of time across a year this response would be required are summarised in the table below and further illustrated by the load duration curves in figures below.

Table 5.3
Required response rate for 0.125 to 0.3Hz RoCoF and the year it is required (for a 1800MW infeed loss).

Inertia (GWs)	RoCoF[3] seen on the system (Hz/s)	Time[4] (to reach 49.2 Hz)	Response rate (MW/s)		Requirement			
					Gone Green	Slow Progression	Low Carbon Life	No Progression
360	0.1	11	185		2014/15	2014/15	2014/15	2014/15
225	0.2	6	400	Currently Not Available	2019/20	2024/25	2024/25	2029/30
150	0.3	3.2	1148	Currently Not Available	2024/25	2024/25	2024/25	2034/35

[3] The actions currently taken to protect against RoCoF removes such high df/dt as a challenge for frequency containment

[4] This includes a 2s delay between detection/response activation time

Figure 5.12
Response ramp rate requirement – Gone Green

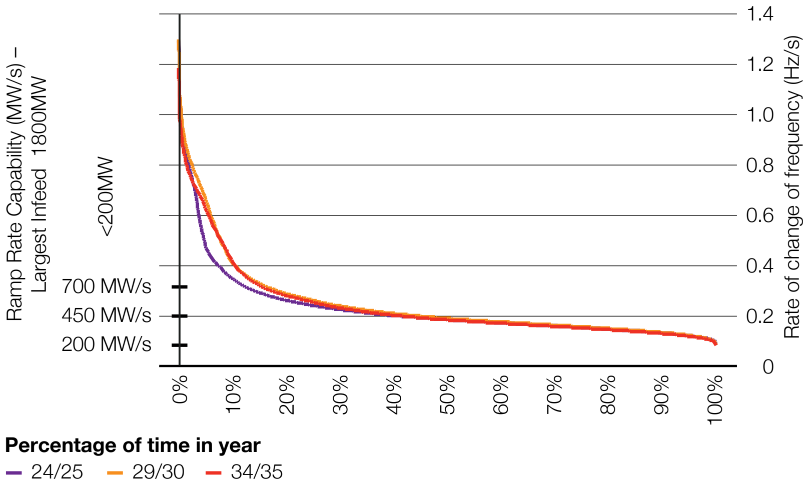
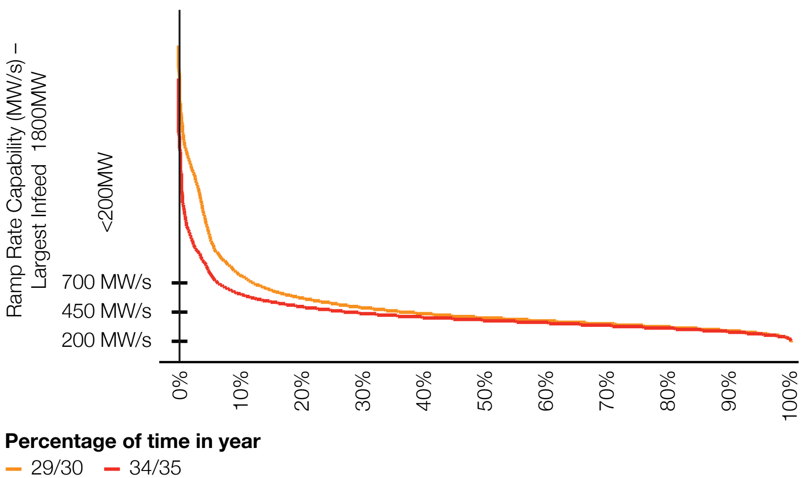


Figure 5.13
Response ramp rate requirement – Slow Progression



5.2 continued
System Strength

Figure 5.14
Response ramp rate requirement – Low Carbon Life

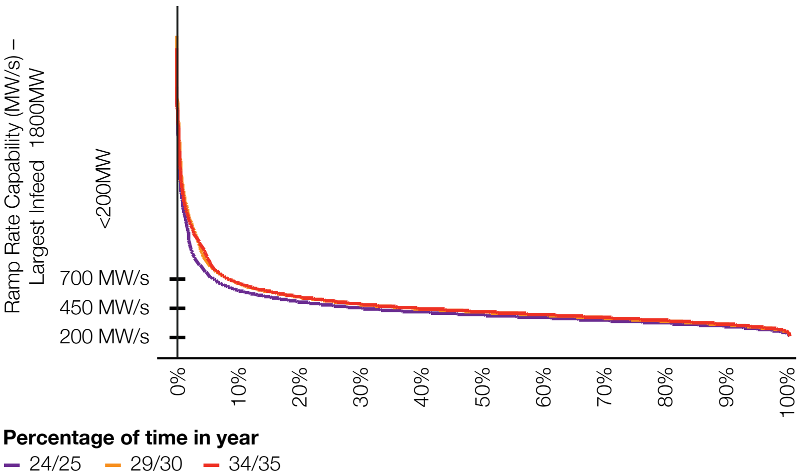
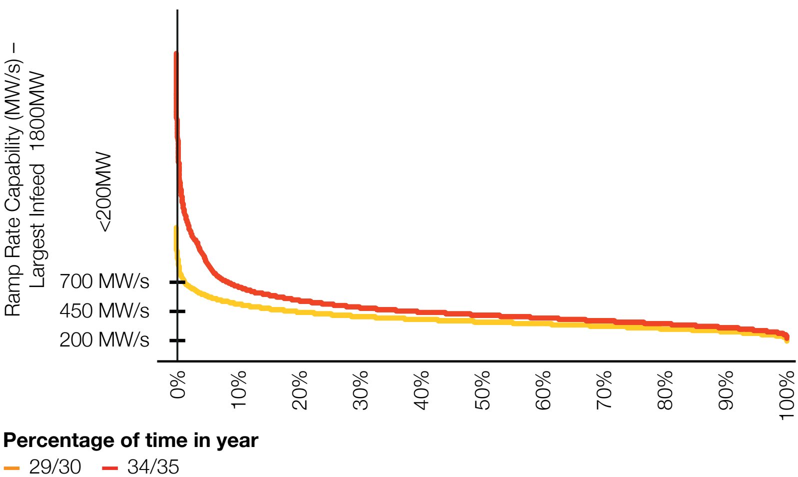


Figure 5.15
Response ramp rate requirement – No Progression



Rapid frequency response (RFR) sources

Achieving a higher amount of response within a much shorter time is likely to require new rapid frequency response (RFR) services and changes to current network codes and frameworks. RFR can be delivered via:

- Converter connected infeeds such as HVDC interconnectors and wind turbine generators
- Fast demand side response
- Energy storage.

Grid Code working group GC0022 was set up to evaluate the feasibility of rapid response from non-synchronous generation. A number of R&D projects have also been investigating this, e.g. RFR from:

- HVDC sources
- Demand side customers
- Offshore wind turbine generators.

Other possible solutions, such as voltage modulation, are at very early stages of feasibility analysis and will need in-depth assessment before they are considered.

Generator RoCoF withstand capability

Generator turbine control is designed to withstand load rejection. The ability to withstand load rejection from base load is usually tested during commissioning. In a system with low inertia and high RoCoF, however, the generator turbine may trip because of rapid acceleration of the turbine generator (for steam turbines) and rapid reduction in the fuel-air ratio (flame-out). This is more often reported for gas turbines. Generator part-load or full-load rejection can result in a significant and almost instantaneous loss of power infeed.

Existing turbine generators are tested against the requirements set out in the Grid Code. Their capability to withstand such conditions in a real system operation scenario is uncertain. Although the flame-out condition at high RoCoF has been reported in gas turbine generators, other generators, including non-synchronous generators, are not known to have this risk. Feedback received so far from generators and manufacturers suggests this should not be a risk for RoCoF lower than 1Hz/s. As shown above, this level of RoCoF is not expected to occur for more than 1% of the time over a year until at least 2034/35.

The Grid Code working group GC0035 plans to investigate generator RoCoF withstand. Also, further discussions with manufacturers will establish if this could be an operability risk.

Solutions to inertia and RoCoF constraints

The inertia and RoCoF risk is currently managed by:

- Constraining down the power output of the largest infeed if the loss of this infeed would trigger large amounts of RoCoF relays
- Constraining other synchronous plants into service in order to increase the level of inertia where it is possible to do so without incurring negative reserve-active power margin (NRAPM).

The increase in embedded generation RoCoF protection relay setting threshold and the above actions deal with the consequence of inertia reduction in the short term; however they are not sustainable long-term solutions dealing with the root cause of inertia reduction. Other possible approaches to deal with the declining system inertia are being considered. These include:

- Discussing the market and technical opportunities surrounding the de-clutched operation of synchronous generators to increase system inertia
- Examining the market and technical opportunities for new synchronous compensation units
- Examining the ability to use stored energy or enhanced control settings on non-synchronous generation sources to simulate an inertia-like response
- Examining the ability to incentivise higher demand on the system during periods of high non-synchronous generation availability and otherwise low system inertia to support greater levels of synchronous generation in these periods

5.2 continued
System Strength

- Examining how energy storage could minimise the effective non-synchronous generation on the network by increasing system demand at those times.

Regional stability

On a regional level, the displacement of conventional synchronous generation (in the absence of similar support from non-synchronous generation or other sources) can also make instability more likely after a disturbance. This is due to the lack of post-fault voltage support provided from current non-synchronous generation as compared to the synchronous generation.

Due to the nature of the GB power system, different regions of the system will inherently have different tolerances to the level of inertia needed to maintain stability within the required limits.

Stability is achieved not merely by the rapid provision of power and frequency dependent behaviour discussed above, but also by ensuring that sufficiently dynamic reactive power reserves, dispatched from the available providers, stabilise and recover the voltage in the area. This prevents large power angle swings that could complicate generation return to normal operation following a fault. Much of the analysis in this area focuses on the behaviours of synchronous generators and loads.

Regional stability will be analysed in four regions, based on the scale of non-synchronous generation already connected and anticipated to connect in these areas, and how this might impact existing transient stability management considerations. These regions are Scotland, South West, South East and North Wales.

Supporting regional stability

The support needed and when it would be required is being assessed, but it is clear that most of the limitations associated with the capability to accommodate additional non-synchronous generation capacity are due to insufficient pre-and post-fault dynamic reactive power support. The mitigation options should therefore look to increase capacitive reactive power response from a range of sources:

- New and existing synchronous generators
- New and existing non-synchronous generators
- VSC HVDC links
- Dynamic reactive power compensation devices.

Table 5.4
Enablers for increasing the non-synchronous generation accommodation capability

Region	Enablers for increasing the capability (to reach 49.2 Hz)
Scotland	■ Additional dynamic capacitive reactive power support near the Anglo-Scottish boundary ■ Sufficient level of inertia locally (regional inertia) ■ Improved power oscillation damping (POD) capability
North Wales	■ Additional inductive and capacitive dynamic reactive power support
South East	■ Additional capacitive dynamic reactive power support
South West	■ Additional dynamic capacitive and inductive reactive power support

5.2.2 Short circuit level

Short circuit level describes the magnitude of fault current that can be seen on the system during a fault. Maximum short circuit level is calculated to establish the highest stress condition that equipment needs to withstand during a fault and thereby to establish equipment ratings. Minimum short circuit level is used to determine the lowest signal that protection devices must detect to be able to operate correctly.

As highlighted above, short circuit level is one of the traditional measures of AC power system strength and it relates to aspects of power quality and voltage management. A high short circuit level indicates that the system is strong due to the concentration of generation and demand in the area being highly interconnected.

Voltage management

Voltage behaviour is the principal indicator of power quality. Voltage management relates to:

- The steady state behaviour of the voltage
- The extent to which deviations are contained within a region
- The ability of the system to contain the effects of any disturbance in steady state conditions.

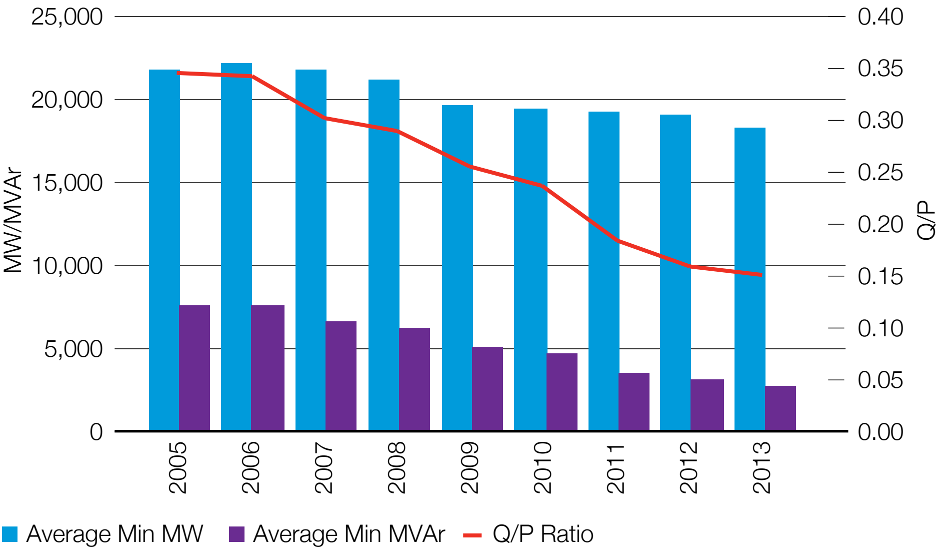
During peak demand periods across all scenarios, the network continues to operate within the norms for voltage step change. Voltage regulation for particular high boundary transfer conditions is achieved using shunt-connected capacitors.

When there is low system demand, however, reactive power demand, as seen at the Grid Supply Points (GSPs), has been reducing significantly recently, causing the voltage seen on the transmission system to rise rapidly during these periods. Figure 5.17 illustrates the shift in averaged minimum (average of three minimum values) active and reactive power demand, and the ratio between the two (Q/P ratio, where Q is the reactive power demand and P is the active power demand). As the reduction in this ratio is proportional to the rise in voltage seen on the system, this trend indicates that the requirement for high voltage management actions will grow until reactive power demand reduction is mitigated.

The Future Energy Scenario view of the minimum reactive power demand future trend is that there will be a significant reduction in reactive power demand under all of the scenarios, while active power demand is expected to reduce much more slowly. This means that the Q/P ratio will decrease rapidly and may become negative around 2018/19 if no additional actions are taken.

5.2 continued
System Strength

Figure 5.16
Historic Q/P ratio trend



There are several factors that might contribute to a reduction in reactive power demand:

- Increasing use of cables in distribution network owner (DNO) and transmission networks
- Changes in line loading patterns due to increase in embedded generation
- Voltage control asset capability in certain areas
- Energy efficiency measures such as a switch to energy efficient lighting
- Changes in load characteristics such as shifts between industrial and domestic loads.

It is important that this exposure to high voltage is minimised as it can increase the likelihood of flashover risk. It can also cause asset overstressing, inductive iron core equipment over-fluxing and circuit breaker re-striking during de-energisation.

Voltage management solutions
The system operator manages the above issues mainly by keeping the system voltage close to the lower limit during the day to allow a bigger head room for the rising voltage overnight; switching out lightly loaded cable circuits in key areas; optimising the use of reactive power compensation equipment and contracting synchronous generators near problem areas to absorb reactive power overnight. New potential providers of reactive power support are being investigated and may include:

- New and existing reactive power compensation devices on transmission and distribution networks
- Offshore transmission and offshore generator assets
- Tap-staggering on existing quadrature boosters (QBs) and some super grid transformers (SGTs)

- Wide area monitoring together with automated control systems and auto-switching by the TOs.

The principles of operating the above technologies are explained in more detail in Chapter 4.

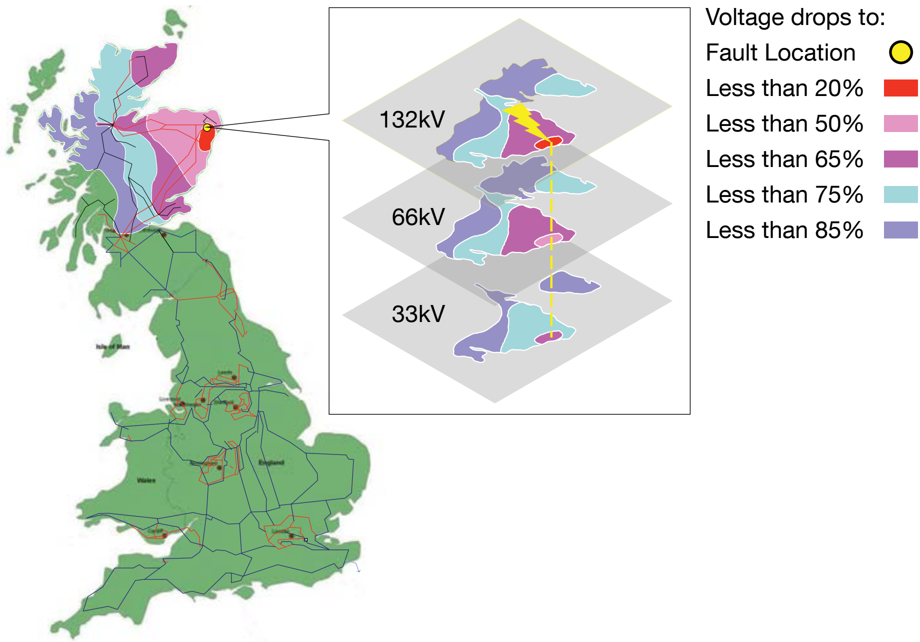
As well as improved modelling and study work, several research projects are identifying the cause of such rapid reactive power demand reduction and optimal mitigation solutions. An example of this is the REACT project between National Grid and DNO companies that will include more detailed DNO network modelling to complement transmission level studies.

Voltage dips

A transient voltage dip is a short-term reduction in system voltage (0 to 140 milliseconds, after which local generators seeing a severe dip can disconnect as specified in the Grid Code). The dip is usually caused by a short circuit, large machine start-up or transformer energisation. The extent and the duration of voltage dips need to be minimised because they are detrimental to generators and loads experiencing the dip.

As the short circuit level decreases, the size of the area affected by a voltage dip will increase, as shown in the 2012 and 2013 editions of the ETYS. The effects of transmission voltage dips, however, are seen across the transmission network, and also on distribution networks near the fault (the effects are 'three-dimensional') as shown below for an example fault (for illustrative purposes only).

Figure 5.17
Three-dimensional spread of voltage depression



5.2 continued
System Strength

Fault ride-through (FRT) requirements for microgeneration

The installed capacity of distribution level micro generation (e.g. domestic solar PV) is expected to grow rapidly as per FES. These small generators do not have a strict FRT requirement. They must have FRT capability with respect to voltage dips only if this is defined in the Connection Agreement between the DNO and the generator in accordance with the Distribution Planning Code (DPC 7.4.3.3).

The installed capacity of micro generation nationally is around 10GW, but that could double in the next decade, so FRT requirements may need to be defined for these units to ensure there are adequate economic and efficient reserves and that there is support after a fault.

Grid Code working group GC0062 aims to provide further clarity on the requirements for generators to remain connected during long-lasting faults. This will give consistency across all users connected to the transmission system and ensure the connection design philosophy does not exacerbate real network voltage dip conditions.

Voltage dip support

It's clear that the system needs greater transient voltage support. This support could include:

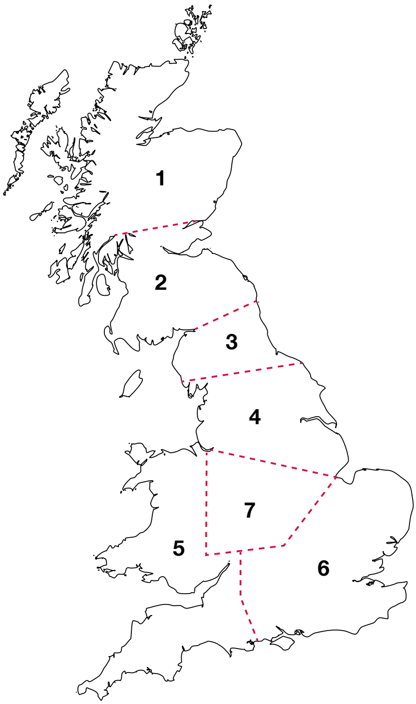
- Higher transient voltage support requirement from synchronous and non-synchronous transmission-connected generators
- Fast dynamic reactive power support from flexible AC transmission system devices
- Changes to transmission and distribution equipment design
- Changes in the Distribution Code
- FRT capability for all generators connected at the distribution level.

Minimum short circuit level

As explained above, the minimum short circuit level is a crucial factor in power system protection device design and operation. This is because it describes the weakest fault signal that the devices need to detect, if there's a fault, to be able to isolate the affected equipment.

Minimum short circuit level variation has been evaluated for seven regions as shown below. The studies have been performed for low short circuit level conditions, i.e. for minimum system demand periods. This illustrates the strength of each of the areas relative to one another.

Figure 5.18
Short circuit level calculation areas

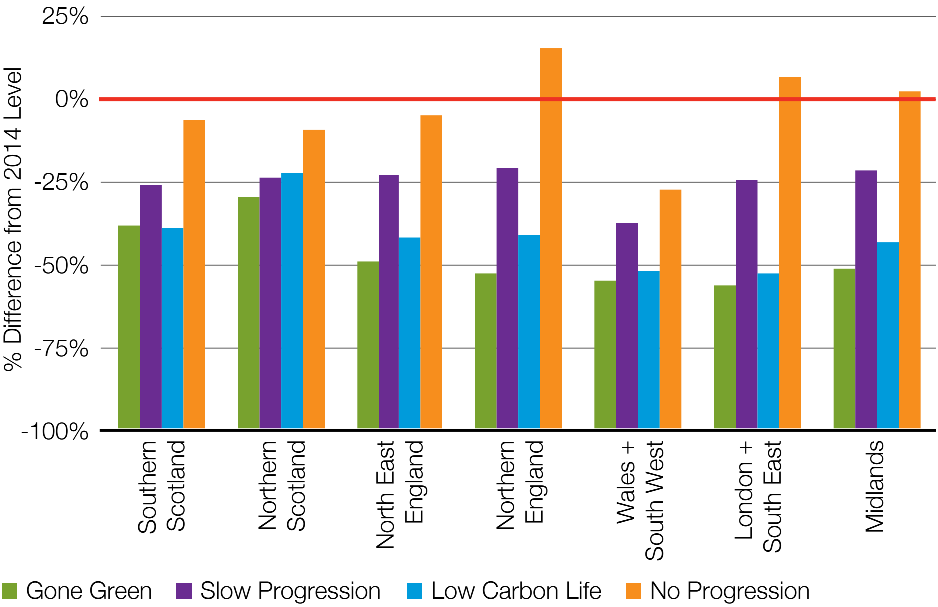


1 North Scotland
2 South Scotland
3 North East England
4 Northern England
5 Wales and South West England
6 London and South East England
7 Midlands

5.2 continued
System Strength

Figures 5.19 and 5.20 show the relative change in 2024/25 and 2034/35 minimum short circuit levels compared to the 2014/15 level (indicated by 0% on the Y axis). It is clear that in the next 10 years, Gone Green and Low Carbon Life present the worst-case scenarios in most regions, while by 2034/35 the short circuit level in Slow Progression background falls below that of Gone Green and Low Carbon Life.

Figure 5.19
Minimum short circuit level relative to 2014/15 level (2024/25)



Short circuit level impact on protection
Protection systems are designed to have a very high degree of reliability, but they depend on the short circuit current infeed being high enough to trigger protection relay operation.

The impact of low short circuit levels on protection depends on the type of the protection scheme and the characteristics of the lower short circuit level used for protection relay operation early in the fault. The most common protection schemes used on the GB system are summarised in Table 5.5.

Figure 5.20
Minimum short circuit level relative to 2014/15 level (2034/35)

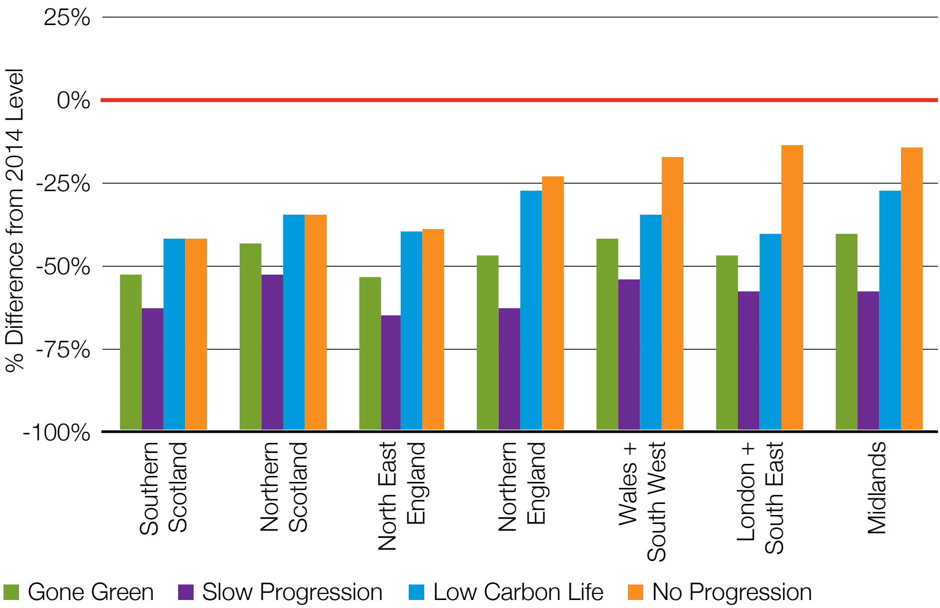


Table 5.5
Short circuit level impact on protection

Protection scheme	Operating principle	Impact of low short circuit level
Differential protection	Compares the current infeed and output from the equipment; if the difference between the two is greater than a set current, the relay trips	If the difference between the currents is very small, it may not be detected by the relay
Distance protection	Calculates the impedance at the relay point and compares it with the reach impedance; if the measured impedance is lower than the reach impedance, the relay trips	It may not be affected if the ratio of voltage to current decreases following the short circuit
Over-current protection	The operating time of the relay is inversely proportional to the magnitude of the short circuit current	This type of protection is the most likely to be affected by low short circuit levels, however these schemes are mainly used for back-up protection and therefore the consequences may not be severe, provided that main protection schemes are not compromised

5.2 continued
System Strength

There is a well-defined process to evaluate short circuit level and to assess the suitable protection settings. The reduction in minimum short circuit levels is considered to be within the limits to be mitigated as part of the business-as-usual approach. New protection approaches are being developed that would be less sensitive to the reduction in the observed system short circuit level.

Harmonics

Harmonics are waveforms of higher frequencies than the 50Hz fundamental frequency. They superimpose the original waveform, thereby creating an impure waveform (non-sinusoidal) compared to the original 50Hz sine wave. Harmonics are unavoidably created when power is converted from DC to AC via power electronic converters.

Harmonics have an impact on a range of operational aspects:

- Conductor heating
- Increase in losses
- Voltage distortion (quality of supply)
- Over-voltage under resonant conditions
- Electromagnetic interference with communication circuits
- Protection relay malfunction.

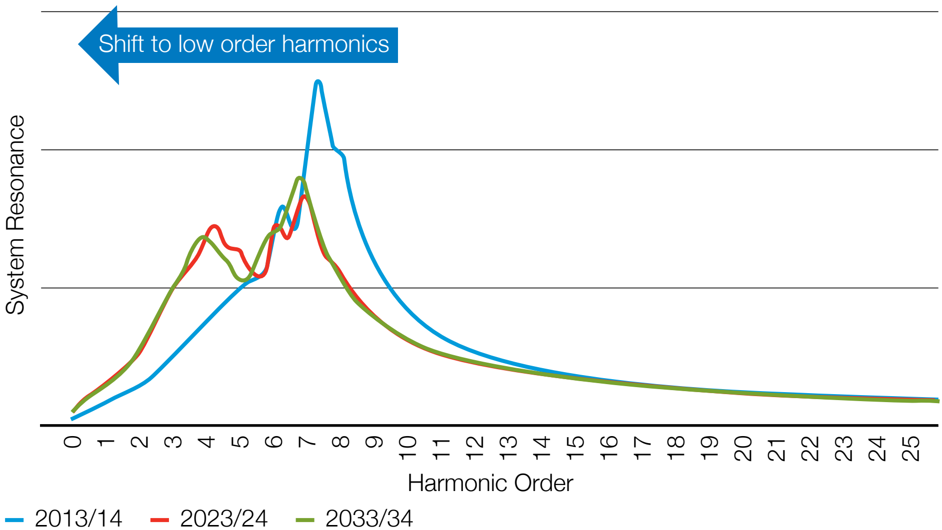
Solutions to harmonic elimination

Harmonic content is generally limited by using filters tuned to damp harmonics in a particular frequency band. These shift the spectra of emission seen close to the device and transfer it to other pertinent points of examination.

Over time there is a danger that there will be so many filters installed on the network that they lead to issues that can't be solved using standard solutions; rather more flexible (dynamic) filter solutions will be needed.

There is a more in-depth analysis on the trend in the harmonic shift in the ETYS 2013 and SOF 2014 reports. This analysis highlighted the trend of harmonic order shift to lower order, illustrated below. This analysis, and the studies performed at the connection design stage as 'business as usual', will be further complemented in England and Wales by using power system monitor devices that measure existing voltage distortions at specific locations, allowing the network owner to ascertain the margin between existing level of distortion and the engineering recommendation G5/4 (soon to be superseded by G5/5) planning limits. The power system monitor installation scheme is expected to deliver 75 permanent monitors and 25 portable monitors by 2015/16, providing coverage for half the substations in England and Wales. Monitoring devices are also being installed in Scotland on key areas of the network so system parameters can be observed and measured.

Figure 5.21
Harmonic shift



Although the FES considers the current approach of harmonic content studying and elimination during the connection design stage as suitable, rapid developments are expected on the network in the future. They may require existing harmonic filter designs to be revised and upgraded as more customers are connected.

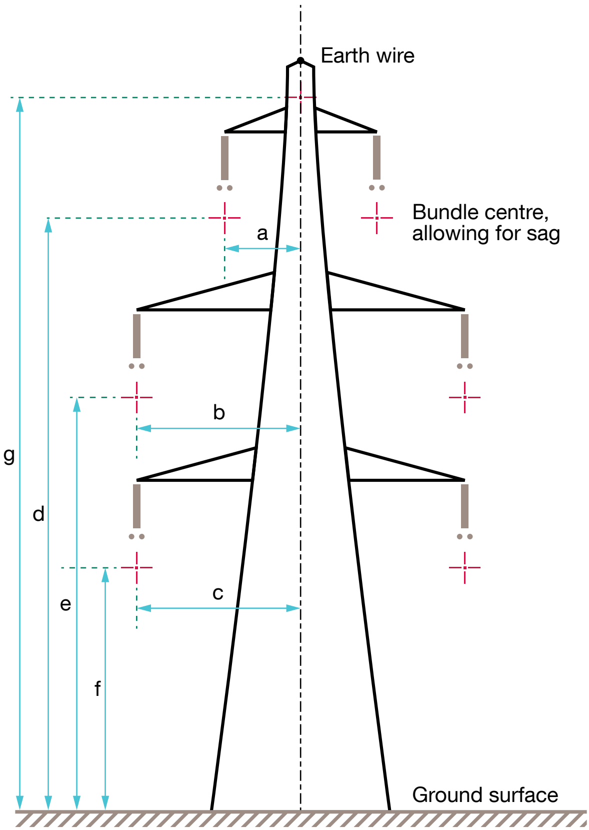
Negative phase sequence (NPS)

An AC sinusoidal power supply can be broken down mathematically into synchronous components of positive phase sequence aligned to the current phasor of power transmission; negative phase sequence (NPS) inverted 180 degrees from the current phasor; and zero sequence components represented as a rotational vector that is the same in each phase. This approach helps assess unbalanced currents within the transmission system during both fault and steady state conditions.

5.2 continued
System Strength

NPS physically manifests due to the inherent non-ideal symmetry of transmission assets supporting power flow. For example, an overhead line design will inherently display impedance relationships between phase conductors, the earthwire and ground (a to g in the figure below) that in turn lead to differing levels of induced current on these conductors and some unbalance in the characteristic of the transmitted power. NPS may also be produced or exaggerated by the design or nature of generation or load connected to the transmission system or their associated control systems.

Figure 5.22
Overhead line impedances



NPS limits

Under Grid Code conditions C.C. 6.1.5 b and CC. 6.16 the maximum phase voltage unbalance on the transmission system should remain below 1% or – for infrequent short duration peaks – below 2% in England and Wales and below 2% in Scotland unless there are abnormal conditions. Additional guidance on the assessment and management of NPS is provided within engineering recommendation P24.

As a system operator, NGET will ensure that the connections made to the transmission include appropriate measures where NPS is created by an unbalanced supply (for example those of traction supplies, which are frequently two-phase supplies) or exaggerated in control to limit or mitigate these effects, resulting in additional technical requirements or assets. Study of NPS mitigation by TO and SO requires highly detailed modelling of the user, transmission and distribution networks, complemented by network monitoring.

The effect of such unbalances can be inversely proportional to the system strength of the area of the network it interfaces. As the effect of declining short circuit level impacts other areas of power quality, control and protection as described above, it also increases the system vulnerability to the effects of unbalanced power injection:

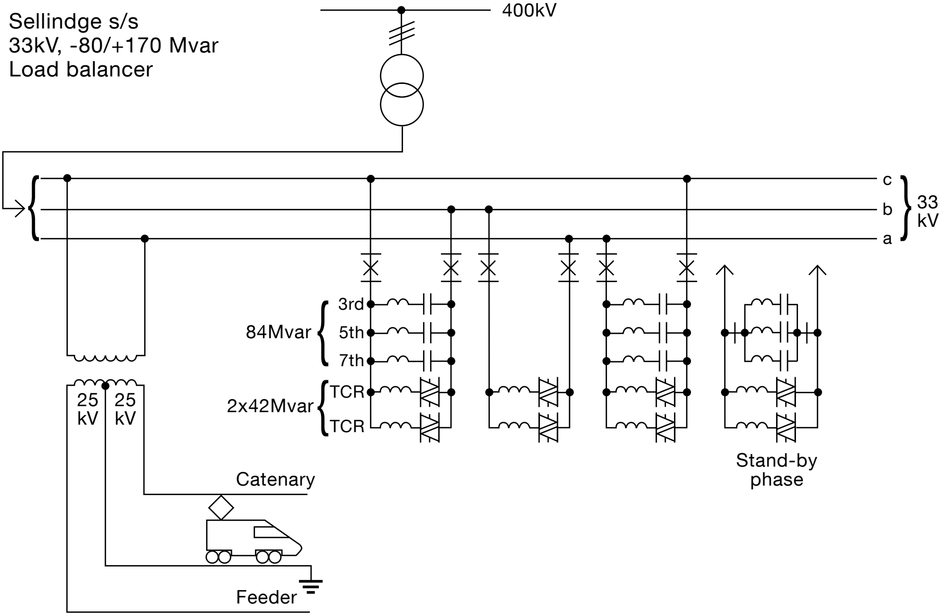
NPS mitigation

NPS arising from unbalanced connections can be mitigated by considering the optimal manner in which unbalanced supply and injection manifest on the system and specifying phase connections or additional devices accordingly. These might include particular transformer designs or additional equipment providing a phase balancing and/or short circuit level increasing effect to mitigate. Solutions must be robust across a range of locations within the transmission network and against scenarios of year-round system operation, planned system depletion and both intact and post-fault network operational conditions, in line with the NETSSQSS and the Grid Code considerations. Conventional Generator connections provide significant levels of fault current to increase the system strength and also reduce the levels of overall NPS by balancing current supplied.
A phase balancing arrangement supporting the cross-channel HVDC interconnector has been demonstrated at Sellindge where a two-phase load is supported by a three-phase supply. The control system re-distributes the loading across the three phases to limit phase unbalance. Similar approaches could be considered for other power-electronic based sources and non-synchronous generation.

$$V_{NPS} = \frac{\text{phase-phase load}}{\text{short-circuit level (MVA) at interface}} \times 100\%$$

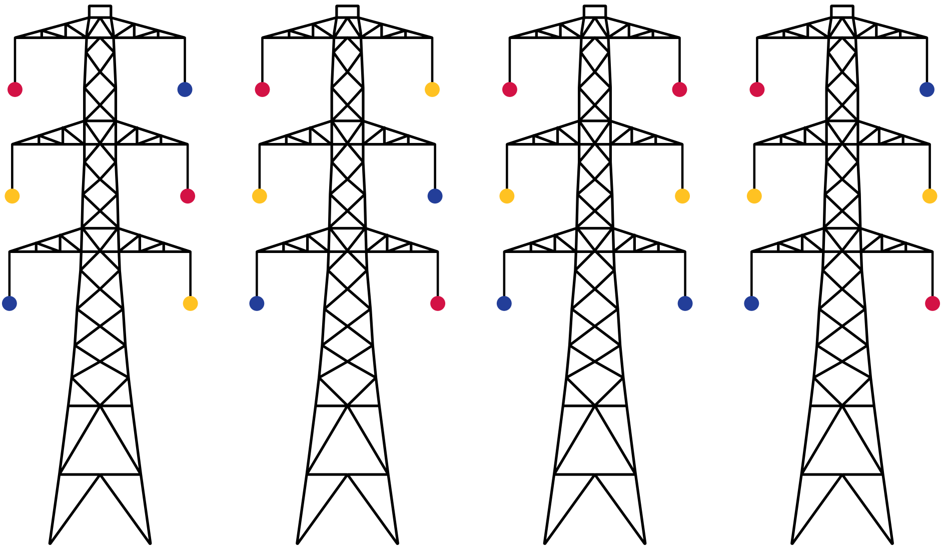
5.2 continued
System Strength

Figure 5.23
Single-line representation of the phase balancing arrangement at Sellindge



Background NPS levels are normally contained by the transmission owners' phase alignment selections upon their transmission corridors (illustrated in the figure below). Background levels of NPS relate to the topology of the network and the levels of power flow in areas of that network. Long or heavily loaded overhead line routes may need additional phase transposition or re-selection.

Figure 5.24
Overhead line phasing standard configurations



As the new generation disposition forecast within the FES manifests, this can lead to longer electrical distances of transmission, subject to lower damping factors relating to inherent or injected unbalanced current. So far, we have not seen the level of issue that this risk might suggest, so the subject is not under SOF consideration. It will, however, be kept under review.

5.3
Impact of New Technologies and Services

The evolving use of new technologies should help achieve increased capacities and efficiencies from GB transmission assets. These new technologies can also allow the development of new services and market arrangements that will help meet changes in the generation mix and demand. However as highlighted in Chapter 4, connecting new equipment to the system will always have an impact on the operation of the existing equipment and the overall system. For this reason, co-ordination and a wider understanding of the impact of integrating different assets together is essential in the design and operation of these assets and the transmission system.

5.3.1
Sub-synchronous resonance (SSR) and sub-synchronous torsional interactions (SSTI)

SSR happens when series compensation is added onto the system. SSTI are due to the addition of HVDC sources. Both SSR and SSTI can interact with generator shafts, and in severe cases they can both cause shaft fatigue and failure. There are other types of sub-synchronous interactions between control systems and the transmission network, and between control systems at particular complementary control frequencies. Both types will become increasingly relevant as regional levels of non-synchronous generation increase.

In the case of the series capacitor, SSR can take place, with the potential for shaft oscillations, depending on the level of mechanical damping in the shaft to restrict oscillatory behaviour. If not damped out in good time, SSR can damage the turbine-generator shaft, resulting in loss of generation.

In HVDC installations, there is a risk of a similar interaction – SSTI – this time between the current/active power feedback loop of the HVDC control system and the turbine-generator shafts of neighbouring synchronous generators. This can also result in damaging shaft oscillations, but on a smaller scale than the series capacitor interaction.

Preliminary studies and mitigating measures early in the design stages can eliminate restrictions on using these technologies, including series capacitors and HVDC links. The complex system models needed must be continuously improved and updated.

More information on the subject and current mitigating approaches is available in the System Operability Framework Report.

5.3.2
Power electronic control system interaction

With the increasing number of non-synchronous generation, compensation devices and HVDC converters connected electrically very closely together, all with control systems that share the same values as inputs, not studying such behaviours collectively could lead to undesirable control interactions.

Some key areas that will see an increase in the connection of highly sophisticated control systems are identified below. The interactions of these control systems need to be studied as soon as connection possibilities are perceived and early in the design stage.

The table below summarises the impact of each of the scenarios on the aspects associated with control system interaction.

Table 5.6
Control system coordination requirements

Region	Gone Green	Slow Progression	Low Carbon Life	No Progression
South East	Greater need for co-ordination expected in 2018/19	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected until 2020/21	No additional mitigation requirement expected until 2021/22
North Wales	Potential for more extensive control coordination after 2016			
East Coast	Triggering events expected in 2019-2023	No additional mitigation requirement expected until 2024/25	No additional mitigation requirement expected until 2019/20	No additional mitigation requirement expected before 2035/36

With more grid connected users employing sophisticated control systems, there is an opportunity for the SO to coordinate the response of these devices to ensure economic and efficient operation. The initial step is the modelling, and without representative models, control coordination has been very difficult. Using phasor measurement units (PMU) is recommended to help the SO validate the dynamic models with system parameters for optimal coordination of control systems on the network.

5.3 continued
Impact of New Technologies and Services

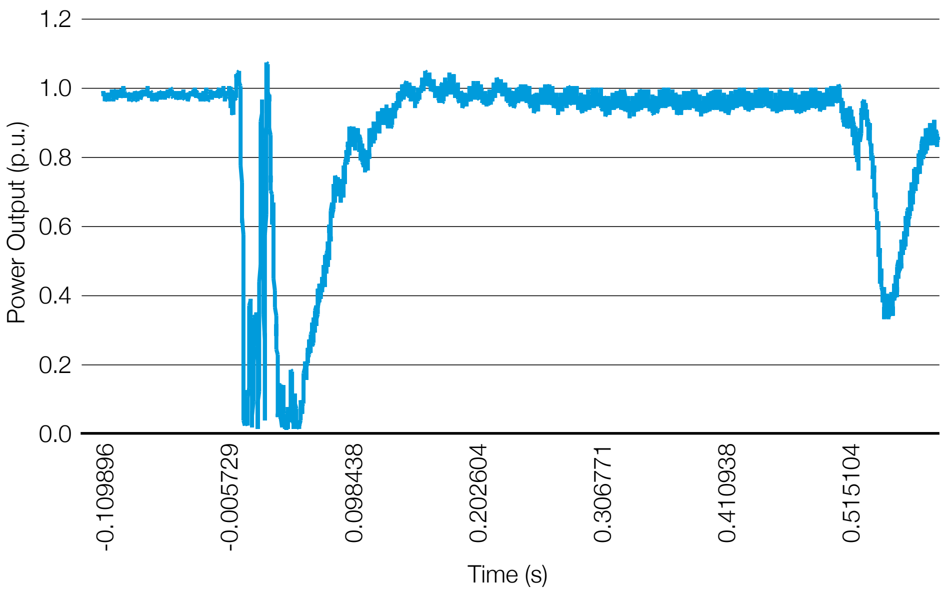
5.3.3
Commutation failure

The interaction between the AC network and HVDC links is one of the major concerns in hybrid AC/DC power systems.

Commutation failure happens if the commutation of current from one current source converter (CSC) valve to another is not complete before the commutating voltage reverses across the ongoing valve. This results in a short circuit across the valve group. AC system faults affect the commutation margin by voltage magnitude reduction, increased overlap due to higher DC current and phase angle shifts.

The above can be caused by AC voltage faults and disturbances, transformer inrush current, capacitor inrush current, harmonic pollution and/or instability and system-induced resonances.

Figure 5.25
Commutation failure event



Exposure to commutation failure

Only the HVDC links based on CSC technology are susceptible to commutation failure. The HVDC links that may be exposed and are therefore assessed against this risk are Moyle, Britned, cross-Channel link Interconnexion France Angleterre (IFA) and the Western HVDC link. The East West HVDC interconnector and most of future HVDC links will probably be based on voltage source converter (VSC) technology and will not be affected by commutation failure.

Minimum short circuit levels are established at the design stage of current CSC HVDC links to avoid commutation failure.

Opportunities to mitigate commutation failure

Reactive power compensation is widely used to improve voltage stability in the steady state and the transient state of power systems. Ways to regulate voltage include the synchronous condenser (SC), the static VAr compensator (SVC) and a static synchronous compensator (STATCOM).

Using power-electronics-based compensators such as SVCs and STATCOMs increases the ability to maintain the converter bus voltage. However, as these devices are not rotating machines they do not increase the short circuit level at the converter bus. The STATCOM provides both the necessary commutation voltage to the HVDC inverter and the reactive power compensation to the AC network during steady state and dynamic conditions.

5.4
Solutions and Opportunities

As highlighted throughout this chapter, the solutions to the operability challenges that the system operator faces can be in the form of additional assets or the operation of the existing assets and resources (generation units and loads, for example) in a new, optimal and coordinated way. This section describes some of these solutions and their potential applications. We welcome feedback on the assumptions made in this section and other possible solutions that should be considered. Some of the proposed solutions and brief commentary are given below.

Table 5.7
Solutions matrix

		External actions							Internal actions				
		RoCoF setting change	Infeed constraint	Rapid frequency response	Synchronous compensation	Demand side response	Distribution system operator (DSO)	Technical code changes	HVDC constraint	System monitoring	Improved study capability	Reactive compensation	Damping controllers
Before 2020	RoCoF	■	■	■	■	■	■						
	Voltage management				■		■	■			■	■	■
	SSI								■	■	■		
After 2020	Frequency containment		■	■	■	■	■						
	Generator RoCoF withstand		■	■	■		■	■		■			
	Regional stability			■	■	■	■	■		■	■	■	■
	Protection						■	■					
	Voltage dips				■		■	■			■	■	
	Harmonics						■			■			■
	HVDC commutation				■			■	■		■	■	
	Control system interaction					■				■	■		■

5.4.1 RoCoF setting change

As explained in the system inertia section, the RoCoF protection relay setting change on embedded generators can offset the RoCoF constraint issue for a few years. While this is not a sustainable long-term solution, it will give the system operator and the rest of the industry time to develop and implement new capabilities and services, such as rapid frequency response, that can mitigate the constraint in the long term.

5.4.2 Infeed constraint

In terms of RoCoF and frequency containment, generation infeed constraint can reduce the output of the largest infeed if its sudden disconnection would trigger a high RoCoF constraint. Or it can increase the output of other infeeds from synchronous generation sources to increase the overall system inertia so that the loss of the largest infeed would not trigger a high RoCoF constraint. Both of these actions are costly and are a last resort only when other actions are unavailable or even more expensive. So it's important to have other solutions in place to avoid generator infeed constraints as much as possible.

5.4.3 Rapid frequency response

As explained in the system inertia section, increase in the RoCoF after loss of infeed events means that there is less time for the generators and demand side response customers to respond to the event and stabilise the system before the frequency reaches the lower limit.

Frequency response units have a two-second delay before starting to ramp up. This means that the ramp-up time, together with the delay, will be more than the time available to arrest the frequency fall in the future. The rapid frequency response service therefore aims to reduce or eliminate this limit altogether, as well as allow a faster ramp rate.

5.4.4
Synchronous compensation

Synchronous compensators, or synchronous condensers, provide the same inertia effect to the system as synchronous generators, but do not provide active power. Synchronous compensation can be provided by new and existing synchronous generator units that have an additional clutch system installed. De-clutching allows these units to switch from generation mode to synchronous compensation mode where the unit is spinning and providing system inertia and reactive power support without providing active power.

5.4.5
Demand side response (DSR)

The concept of DSR is a deliberate modification in the consumer electricity demand in response to a specific signal (by the user or third party). This may be either a shift in demand in a flexible timescale or a permanent change in electrical power usage. It may be executed by managing electrical load or by the self-supply of electrical load from local generation sources enabled by direct control and/or market signals. Under this definition, DSR happens only because the consumer pro-actively chooses to take part in a DSR programme and does not include planned load shifting to avoid price differential periods[5].

The figure below illustrates the relevant parties in DSR delivery. National Grid, as a GB system operator, would need to procure the service from DSR providers (or aggregators[6]) while the aggregators would contract loads (from the commercial industrial or public sectors) that can deliver deliberate change in demand on single or multiple sites.

As previously described, demand side response can reduce power imbalance and rapid frequency response. DSR provides firm frequency response and frequency control by demand management services. As the volume of the available response grows and diversifies, it may become an important tool in managing the RoCoF and frequency containment issues. At the same time, it defers asset investment by optimally using resources that are already available on the demand side.

[5] Demand Side Response Shared Services Framework Concept Paper For Industry Consultation – April 2014

[6] For more information on aggregation please visit http://www2.nationalgrid.com/UK/Services/Balancing-services/Demand-Side-Aggregators/

Figure 5.27
DSR parties

5.4.6 Distribution system operator (DSO)

The scope of the DSO role, as well as the technical, commercial and regulatory arrangements, is being discussed at European and national levels. The most notable of these fora is the Department of Energy and Climate Change (DECC) and Ofgem Smart Grid Forum. Work stream 7 in particular has been set up to analyse the future power system, focusing on the distribution networks.

The DSO role is expected to be active distribution network operation with the aim of helping technically and economically optimal overall electricity system operation. This would include facilitating more active demand side participation in energy balancing and network constraint management, either from commercial customers or domestic customers via smart meters and enabled domestic appliances and embedded generation units. This would alleviate some of the constraints and challenges that would otherwise have to be solved by more transmission-level investment.

The evolution of these active DSOs is not expected until the end of the DNO price control RIIO-ED1 that ends in March 2023. Until then, many of these solutions will probably be delivered in a similar way as they are currently, unless otherwise mandated by any of the network codes.

5.4 continued
Solutions and Opportunities

5.4.7
Active network management (ANM)

ANM schemes aim to maximise network capacity by monitoring the available capacity (within the thermal limits) and automatically allocating it to the customers connected to the local ANM scheme. ANM allows best use of unutilised network capacity and quicker customer connections. This could allow new users to connect before all wider reinforcements are complete.

This is achieved using extensive real-time monitoring systems and control systems that can differentiate between capacity availability due to actual headroom on the network and capacity reduction due to constraint actions taken by the system operator.

There are several ANM trial schemes operating in Scotland and England that have demonstrated these principles and gained support from the Ofgem Low Carbon Network Fund and the System Operator. These schemes are efficiently connecting growing amounts of embedded generation to the distribution networks and acting as a first step towards establishing DSOs.

5.4.8
Technical code changes

Many of the units connected to the transmission and distribution systems have capabilities above the minimum requirements set out in the Grid Code, Distribution Code and other technical codes. They may not be providing this response because it is not mandated by the codes or facilitated by the existing commercial frameworks. In many cases, technical code change could allow accessing more of the capability and resources that already exist, which would reduce the need for additional investments and system constraint costs. One such example is the fault ride-through requirements for embedded generators described in more detail in the previous sections. The European network codes coming into force over the next few years will take precedence over the national network codes and may set out new or enhanced requirements.

5.4.9 HVDC constraint

Constraining HVDC links naturally limits exposure to commutation failure and sub-synchronous interaction (SSI) risks. However, this is not a sustainable mitigation option that would be economic and efficient as a 'business as usual' approach and is used only when other options are not available or are not effective enough.

5.4.10 System monitoring and improved study capability

In real-time, system monitoring provides a close view of the system parameters, allowing better system operation, including optimised power flows and generation dispatch that can reduce voltage, frequency and stability constraints.

Ahead of real-time, system monitoring data can be used to calibrate and validate the system models used in power system studies. It can improve these models and study methodology to accurately represent system performance and parameters for the various system events. This may be of interest when studying system performance limits and evaluating the requirements for new capabilities and services.

There are several high-resolution monitoring devices (phasor measurement units) installed on the network in England and Wales and more are to be installed in Scotland as part of the VISOR project (as part of Ofgem Network Innovation Competition).

5.4.11 Reactive compensation devices

Reactive power compensation devices provide voltage support when voltage needs to be increased or decreased. This might be during the minimum demand periods when voltage is often too high, or after a fault when there is rapid and significant voltage depression that needs reactive power injection to recover the voltage level as quickly as possible.

This response can be provided by a range of devices, such as capacitors, reactors, static VAr compensators (SVCs), static synchronous compensators (STATCOMs), or generation assets. These devices have various capabilities and the best solution is chosen based on the type of voltage management required and the local system parameters.

5.4 continued
Solutions and Opportunities

5.4.12
Energy storage case study

Given the anticipated changes in the future performance of the transmission system, one of the possible solutions being investigated is for more energy storage to provide balancing and ancillary services.

Currently, pumped hydroelectric energy storage plants in Wales and Scotland provide balancing services such as frequency response, reserve services and voltage support. There have been more small-scale projects at the distribution system level recently comprising a range of battery storage technologies.

Energy storage case study in FES

The 2014 Future Energy Scenarios publication includes storage projects constructed and under construction, but does not assume any further growth in energy storage. A case study in the FES on the potential for energy storage (section 4.2.2) considers the business case for storage purely in relation to two of our balancing services. The case study finds that, in general, providing short-term operating reserve (STOR) or fast reserve alone would not ensure that new storage projects are economically viable. The exception is compressed air energy storage (CAES), which has the potential for profitability as it offers fast reserve across all scenarios.

The case study highlights the need to assess the viability of energy storage technologies with access to multiple revenue streams. We are therefore assessing the potential value of energy storage when a range of revenue streams and benefits to the system are considered.

Potential benefits of energy storage

It's expected that energy storage plants would be built under the assumption that a large amount of revenue would be made through price arbitrage on the balancing mechanism and day-ahead or other longer-term energy markets. Depending on the flexibility, volume capacity, power rating and location of the plant, energy storage technologies could help system operation in several ways:

- Frequency response
- Reserve
- Voltage support
- Inertia support
- Black start
- Network reinforcement deferral.

Providing some or all of these via established balancing and ancillary services or appropriately tailored contract markets could defer network reinforcements and open up supplementary revenue streams to an energy storage plant.

Value of energy storage under the FES

An important factor in the potential role of energy storage is how energy prices and the value of balancing and ancillary services could change. The following table shows a qualitative assessment of the potential impact of each FES on the value of energy storage. Under the Gone Green scenario, energy storage has the most revenue potential and would be most valuable for system support, while the large increase in gas generation under No Progression may decrease the value of storage compared to today.

Table 5.8
Future Energy Scenario potential impact on the value of energy storage

Factors affecting the value of energy storage	Impact of increasing each factor	Impact on need for services[7]						Expected level by 2035 of each factor by FES scenario			
		Frequency response	Reserve	Voltage support	Inertia support	Black start	Network reinforcement	No Progression	Slow Progression	Low Carbon Life	Gone Green
Flexible generation	Greater competition – lower BM and service availability prices	↓	↓	↓	↓	↓	-	High	Medium	Low	Low
Inflexible generation	Greater demand for services – higher prices	↑	↑	↑	↑	↑	↑	Low	Very high	Medium	Very high
Interconnectors	Greater need for voltage support, currently counts as inflexible generation	↑	↑	↑	↑	↑	↑	Medium	Medium	Low	Low
Electric vehicles	Increase off-peak demand, may raise charging prices for storage	↓	↓	↓	-	-	-	Very low	Low	High	High
Energy efficient appliances	Increase reactive power in the system – greater voltage support needed	↑	↑	↑	↑	-	-	Low	Low	Medium	High

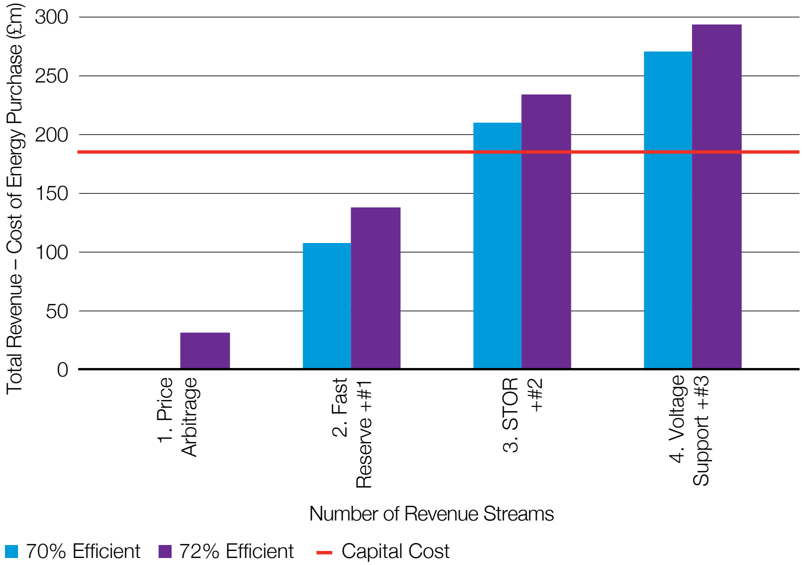
[7] Arrow direction indicates an increase or decrease in the need for each service. The size of the arrow represents a relatively large or small increase or decrease. A '-' indicates that an increase in the factor has no significant impact on the need for the service.

5.4 continued
Solutions and Opportunities

Provision of multiple services
Many studies consider the value of price arbitrage or single service provision only when estimating the potential economic viability of energy storage. We are undertaking a more comprehensive study that considers the value of energy storage when multiple services can be contracted simultaneously, coupled to the revenue derived from price arbitrage outside of those services. Our analysis will consider many different types of energy storage, from batteries and flywheels to compressed air energy storage and pumped hydroelectric storage.

As an example of our preliminary results, consider the following study that investigates the potential value of compressed-air energy storage (CAES) plant[8] over its 40-year lifetime, assuming a 6% discounting rate. With price arbitrage alone, assuming a yearly average sell price of £50/Mwh and buy price of £35/Mwh, the CAES plant is not economically viable. However by combining revenue from price arbitrage, fast reserve, short-term operating reserve (STOR) and voltage support, the storage recovers its capital costs within its lifetime and makes a profit. The same methodology can be applied to any type of energy storage, depending on the capabilities of the plant.

Figure 5.28
Revenue during the lifetime of a 441MW CAES plant through price arbitrage and service contracts



[8] Plant characteristics are taken from Table B-13 in the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA by Akhil A.A. et al. The plant chosen is the largest example in the table.

We are working to expand the combinations of services considered and extending the study to other types of energy storage including batteries and flywheels.

We welcome discussion with industry on the opportunities for energy storage and viability for energy storage to contribute to system balancing and support.

Stakeholder engagement

Which developments in commercial arrangements are needed to increase the number of balancing and ancillary providers, which may include energy storage?

Do you see potential for growth in the energy storage sector under any of the FES scenarios? If so, in what technologies or range of technologies?

Do you see any ways in which energy storage could benefit the system operator in addition to those mentioned above?

5.5 Conclusions

Provision of multiple services

The shift from a generation mix dominated by synchronous generators to one dominated by non-synchronous generation changes the way the SO needs to operate the system.

The expected total transmission-connected non-synchronous generation capacity for each of the scenarios highlights the potential for developing and making available new or enhanced capabilities and services from new and existing sources. These could provide valuable system operability support, provided that the enablers are put in place either by support from existing and future synchronous and non-synchronous generators, asset investment, demand side services or a combination of the above.

A number of new approaches and recommendations have been highlighted throughout the System Operability Framework report published earlier this year. The key points to note are:

- The rapid frequency response delivery from non-synchronous generators that can provide fast response may require new services to attract potential providers
- The contribution of non-synchronous generators to system stability is very limited as some requirements applicable to synchronous power plants are not yet provided/maintained by non-synchronous generators
- Improving the study capability is one of the key recommendations of SOF in many topics. This includes the use of new tools such as advanced monitoring using phasor measurement units (PMU), new modelling tools for transmission and distribution interface issues to ensure better assessment of the impact of change in energy landscape in the whole system.

Stakeholder engagement

We welcome further feedback and your views on the content of this chapter and the System Operability Framework report that is available online at **http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/**.

Please contact us at box.transmission.sof@nationalgrid.com

Chapter 6
Way Forward

This is the third edition of the ETYS and we really hope that we are getting closer to what all of our stakeholders are looking for from this document. In the past 12 months we have been at a variey of stakeholder events including the FES workshops, customer seminar events and the FES launch, as well as running a written consultation in July and taking feedback via the ETYS mailbox throughout the year.

6.1 Introduction

We encourage you to provide feedback and comments on this document and help us improve it in the future. Please participate in our stakeholder engagement programme in 2015 so we may better understand and respond to your future needs.

Please provide any feedback on all aspects of the 2014 ETYS via e-mail:
transmission.etys@nationalgrid.com

6.1 continued
Introduction

2013/14 Engagement

Stakeholder emails

32

Consultation response

1

5

Presentations at FES workshops and customer seminars

ofgem

5

Consultation responses to Ofgem licence

6.2 Continuous Development

We will ensure that we have adopted the following principles to enable the ETYS to continue to add value:

- seek to identify and understand the views and opinions of all our stakeholders
- to provide opportunities for engagement throughout the process to enable constructive debate
- to create open and two-way communication processes around assumptions, drivers and outputs with our stakeholders
- respond to all stakeholder feedback on the ETYS document within five working days
- to provide feedback on how stakeholder views have been considered and the outcomes of any engagement process.

The ETYS annual review process will facilitate the continuous development of the statement, encouraging participation from all interested parties with the view of enhancing future versions of the document.

6.3 Feedback from 2014 Stakeholder Engagement

Where we received our feedback:
The ETYS 2014 consultation took place through a variety of channels; the majority of feedback was received at National Grid Future Energy Scenarios and Customer Seminar workshops. We also undertook a formal consultation via the National Grid ETYS website which was sent to key stakeholders. The written consultation only provided one response. We have picked up on other feedback on the ETYS content through Ofgem's consultation on ETYS licence obligations. We are committed to getting more feedback and making the document a richer source of industry information without saturating the industry.

We would like to have the demand data made available so that we can look for embedded opportunities.

You told us:
To enable analysis of embedded generation connection and demand opportunities more information on the demand data is required similar to that of generation and networks.

> **We require more information on the system such as demand to assess connection opportunities.**

Our response:
We will be including more system information in the appendices to meet this request and to facilitate customers' ability to assess future opportunities. It will be based on the data that we are sent by Distribution Owners.

We are concerned that merging the future system operation issues with network development loses focus on these important issues.

You told us:
That there was a need to make sure that the system operation is not lost in the detail of the network evolution.

> **...there is a risk that an operational section in the ETYS is superficial and it does not encompass the SO expertise or engage the relevant stakeholder inputs.**

Our response:
The system operation (SO) issues are of key concern to the future development of the National Grid and we absolutely feel that it is the right place to have this information.

In the ETYS we are trying to highlight future operational challenges that will allow manufacturers and developers to explore options and opportunities in the next 10 years. It is also our intention to spark industry debate in these areas and create thought piecies of how we belive they can be solved. Operational Forums discuss the here and now of the network issues and also the nearer term i.e. one to two years.

We will demonstrate in this year's ETYS that the SO issues are very much integral to understanding the future network operation. We will encompass SO expertise and stakeholder views through the System Operability Framework to make sure this is the case.

Detailed system maps are no longer available showing the future system and power flows.

You told us:
To be able to develop timely connections and to understand what is happening on the future you require the future power flows following investment.

The power system diagrams showing the impact of future system reinforcements has been changed to remove network connections and only show bubbles in some areas.

Our response:
We understand that many groups are looking to understand the system performance in the future and the power system flow diagrams can help in this regard. The reason that we show bubbles and do not include flows are where we expect there to be much further consultation with all stakeholders regarding the future solution.

It is difficult to make sense of the outcome of chapter 4 given that there is no cost information of schemes.

You told us:
While it was useful to see the decisions that National Grid have made, more information is required for readers to understand the conclusions.

While we welcome the increased transparency associated with chapter 4 decisions, further information such as costs and greater explanation of the conclusions is required.
…there is a large regret of £44m for the local contracted sensitivity considering the Wylfa-Pembroke however this is not well explained.

Our response:
We welcome the feedback on greater transparency and understand the need for a greater explanation of our results. We will be looking to update how we present the NDP results in chapter 4 to make it much clearer for stakeholders to understand why we are undertaking future network development.

In previous versions of the ETYS there was greater visibility of the reinforcements in certain areas and how they relieve bottlenecks on the system.

You told us:
The link between the individual network development and the requirements of the network which were clearly shown in ETYS 2012 have been broken.

The 2012 ETYS provided better views of future potential reinforcements than the 2013 ETYS because it looked further ahead and with more development.

Our response:
We did try to present the requirements and network development in a different way last year. In responding to this feedback we will be integrating the pull-out section that was an appendix in the document. We will do this by moving the pull-out sections in to the main body of chapter 4, Network Development and Opportunities.

It would be useful to understand how ETYS impacts on the wider work in customers' agreements.

You told us:
There are many customer agreements that contain wider works requirements but within ETYS these can be subject to change.

6.3 continued
Feedback from 2014 Stakeholder Engagement

> **We would like to see the Transmission Reinforcement Reference Numbers used in Construction Agreements and in the Transmission Works Register explained in more detail, referenced and tracked in the ETYS.**

Our response:
We hope to tie up this issue in this document and will be at the customer seminar in early March with proposals for ETYS and scheme linkages.

Links to other industry information are required such as the ENTSO-e's TYNDP.

You told us:
It would be useful to see how this document links to other National Grid and Industry publications.

> **...we need much greater information on how this document links to the European Grid plans.**

Our response:
In the ETYS this year we will be explaining the relationship between the ETYS and the TYNDP. We will also ensure that we provide key links to other relevant documents.

NDP input data is useful to understand the assumptions that are being made that may result in future network development.

You told us:
You welcome the inclusion of more information on the cost benefit inputs of the Network Development Policy.

> **Section 2.11 is a necessarily brief introduction to cost-benefit methods and data. The concept of Base Gas/ Mid Gas/Marg Gas is not even explained – arguably, you should disclose the volumes of each.**

Our response:
We are glad that our readership feel this information is valuable to understanding our network development. In certain areas where inputs are not explained we will seek to make this clearer.

NDP input data is useful to understand the assumptions that are being made that may result in future network development.

You told us:
It was important that National Grid reviewed alternatives to developing asset solutions in every area of the network.

> **It is good that National Grid are looking at alternatives to network development and more information on opportunites in greater detail would be very useful as it can be hard given our current project status to understand if this is an opportunity worth going after.**

Our response:
It is our intention in this year's ETYS chapter 4 to include more information on these commercial and network opportunites. We hope that this will yield greater interest in this key area of nework development.

6.4 Stakeholder Engagement

The ETYS is subject to an annual review process, facilitated by National Grid, and involving all stakeholders who use the publication. The purpose of this review is to ensure the ETYS evolves alongside industry developments. Some of the areas to consider are:

- Does the ETYS:
  - illustrate the future development of the transmission system in a co-ordinated and efficient way?
  - provide 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.

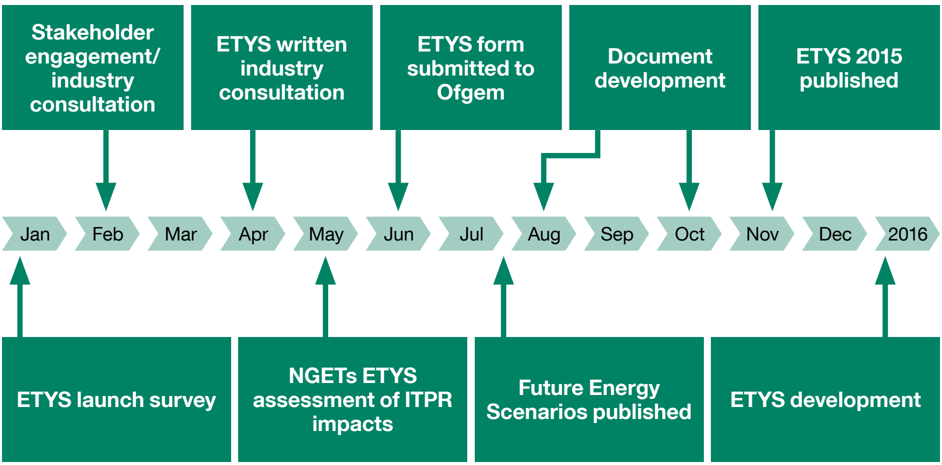
We are happy to receive engagement of any kind through the following means and of course at any other opportunities we get to meet:

- Responses to the short launch survey
- At consultation events as part of the customer seminars
- At Operational Forums
- Through responses to the ETYS email **transmission.etys@nationalgrid.com**
- Organising bilateral stakeholder meetings.

6.5
Timetable for 2015 Engagement

Our indicative timetable for the 2015 ETYS engagement programme is shown below:

Figure 6.1
ETYS engagement timeline 2015



Glossary

Term	Definition
Average Cold Spell (ACS) Peak Demand	The estimated unrestricted winter peak demand (MW and MVAr) on the NETS for the average cold spell (ACS) condition. This represents the demand to be met by large power stations (directly connected or embedded), medium power stations and small power stations which are directly connected to the national electricity transmission system and by electricity imported into the onshore transmission system from external systems across external interconnections (and which is not adjusted to take into account demand management or other techniques that could modify demand).
Boundary Allowance	An allowance in MW to be added in whole or in part to transfers arising out of the NETS SQSS economy planned transfer condition to take some account of year-round variations in levels of generation and demand. This allowance is calculated by an empirical method described in Appendix F of the security and quality of supply standards (SQSS).
Boundary Transfer Capacity	The maximum pre-fault power that the transmission system can carry from the region on one side of a boundary to the region on the other side of the boundary while ensuring acceptable transmission system operating conditions will exist following one of a range of different faults.
Bus coupler	The term used to reference a device which is used to switch from one bus to another without any interruption in power supply or arcing. Bus couplers are often comprised of circuit breakers and isolators.
Bus Section	Part of a busbar that can be isolated from another part of the same busbar.
Busbar	The common connection point of two or more transmission circuits.
Carbon Capture and Storage (CCS)	The process of trapping carbon dioxide produced by burning fossil fuels or other chemical or biological processes and storing it in such a way that it is unable to affect the atmosphere.

Term	Definition
Combined Heat and Power (CHP)	CHP plants generate electricity while also capturing the usable heat that is produced as a result of this process. Using this method, plant efficiencies are often higher than those of conventional generating technologies.
Combined Cycle Gas Turbine (CCGT)	A type of thermal generation that uses a two-stage process. Natural gas is fed into a jet engine which then drives an electrical generator. The exhaust gases from this process are then used to drive a secondary set of turbines and in turn, a second electrical generator.
Contracted Generation	A term used to reference any generator who has entered into a contract to connect with the National Electricity Transmission System (NETS) on a given date while having a transmission entry capacity (TEC) figure as a requirement of said contract.
Cost Benefit Analysis (CBA)	A method of assessing the benefits of a given project in comparison to the costs. This tool can help to provide a comparative base for all projects considered.
Crown Estate	A property business that manages the UK seabed out to a distance of 12 nautical miles. Since 2000, the Crown Estate has run six rounds of offshore wind leasing activities which involve the waters surrounding England, Scotland, Wales and Northern Ireland.
DC Converter	Any apparatus used as part of the National Electricity Transmission System to convert alternating current electricity to direct current electricity, or vice versa. A DC converter is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion. In a bipolar arrangement, a DC converter represents the bipolar configuration.
Delayed Auto Reclose	This term is used to refer to a sequence of events that occur after a transient fault. Protection and control systems on an overhead line may automatically re-close circuit breakers if a fault is identified to be of a transient nature, thus re-energising the circuit.

Glossary

Term	Definition
Double Circuit Overhead Line	In the case of the onshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span in SHE Transmission's system or NGET's transmission system or for at least two miles in SP Transmission system. In the case of an offshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span.
Embedded Generation	A term used to refer to any generation that is not directly connected to the National Electricity Transmission System (NETS). This can typically include solar panels on domestic properties along with Combined Heat and Power Plants that may supply industrial facilities.
ENTSO-E	ENTSO-E is a Europe-wide organisation that is responsible for representing all Electricity Transmission System Operators and others connecting to their network. It addresses all their technical and market issues as well as coordinating planning and operations across Europe.
External Interconnection	Apparatus for the transmission of electricity to or from the onshore transmission system into or out of an external system.
External System	A transmission or distribution system located outside the national electricity transmission system operator area, which is electrically connected to the onshore transmission system by an external interconnection.
First Onshore Substation	The first onshore substation defines the onshore limit of an offshore transmission system. An offshore transmission system cannot extend beyond the first onshore substation. Accordingly, the security criteria relating to an offshore transmission system extend from the offshore (GEP) up to the interface point or user system interface point (as the case may be), which is located at the first onshore substation. The security criteria relating to the onshore transmission system extend from the interface point located at the first onshore substation and extend across the remainder of the onshore transmission system. The security criteria relating to an onshore

Term	Definition
	user system extend from the user system interface point located at the first onshore substation and extend across the remainder of the relevant user system. The first onshore substation will comprise, inter alia, facilities for the connection between, or isolation of, transmission circuits and/or distribution circuits. These facilities will include at least one busbar to which the offshore transmission system connects and one or more circuit breakers and disconnectors. For the avoidance of doubt, if the substation does not include these elements, then it does not constitute the first onshore substation. The first onshore substation may be owned by the offshore transmission owner, the onshore transmission owner or onshore user system owner as determined by the relevant transmission licensee and/or distribution licensee as the case may be. Normally, in the case of there being transformation facilities at the first onshore substation and unless otherwise agreed, if the offshore transmission owner owns the first onshore substation, the interface point would be on the HV busbars and, if the first onshore substation is owned by the onshore transmission owner or onshore user system owner, the interface point or user system interface point (as the case may be) would be on the LV busbars.
Generating Units	An onshore generating unit or an offshore generating unit.
Generation Circuits	The sole electrical connection between one or more onshore generating units and the Main Interconnected Transmission System i.e. a radial circuit which if removed would disconnect the onshore generating units.
Generation Profiles	At winter peak it can be assumed that the greatest number of generators will be operational but at other times of the year the number of generators running can be greatly reduced. Variation of generator operation can be much greater in the summer as generators undertake maintenance, demand is reduced and intermittent generation become more sporadic. Care is taken to ensure adequate support is maintained in all regions at all times.

Glossary

Term	Definition
Gone Green	A Future Energy Scenario. This scenario has been designed to meet the nation's environmental targets; 15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting the carbon budgets out to 2027, and an 80% reduction in greenhouse gas emissions by 2050. There are two case studies to test uncertainty in the Gone Green generation background: one with high offshore wind; and the other with high onshore wind.
Grid Entry Point (GEP)	A point at which a generating unit directly connects to the national electricity transmission system. The default point of connection is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, or equivalent point as may be determined by the relevant transmission licensees for new types of substation. When offshore, the GEP is defined as the low voltage busbar on the platform substation.
Grid Supply Point (GSP)	A point of supply from the GB transmission system to a distribution network or transmission-connected load. Typically only large industrial loads are directly connected to the transmission system.
High Voltage Alternating Current (AC)	Electric power transmission in which the voltage varies in a sinusoidal fashion, resulting in a current flow that periodically reverses direction. HVAC is presently the most common form of electricity transmission and distribution, since it allows the voltage level to be raised or lowered using a transformer.
High Voltage Direct Current (HVDC)	The transmission of power using continuous voltage and current as opposed to alternating current. HVDC is commonly used for point to point long-distance and/or subsea connections. HVDC offers various advantages over HVAC transmission, but requires the use of costly power electronic converters at each end to change the voltage level and convert it to/from AC.
Industrial Emissions Directive (IED)	Launched on 21st September 2007, the IED involved the amalgamation of seven existing directives into one. These were namely the Large Combustion Plant Directive (LCPD), the Integrated Pollution Prevention and Control Directive (IPPCD), the Waste Incineration

Term	Definition
	Directive (WID), the Solvent Emissions Directive (SED) and the three existing directives on titanium dioxide on (i) Disposal (78/176/EEC), (ii) Monitoring and Surveillance (82/883/EEC) and (iii) programms for the Reduction of Pollution (92/112/EEC).
Interface Point	A point at which an offshore transmission system, which is directly connected to an onshore transmission system, connects to the onshore transmission system. The interface point is located at the first onshore substation which the offshore transmission circuits reach onshore. The default point of connection, within the first onshore substation, is taken to be the busbar clamp in the case of an air insulated substation, gas zone separator in the case of a gas insulated substation, on either the lower voltage (LV) busbars or the higher voltage (HV) busbars as may be determined by the relevant transmission licensees. Normally, and unless otherwise agreed, if the offshore transmission owner owns the first onshore substation, the interface point would be on the HV busbars and, if the first onshore substation is owned by the onshore transmission owner, the interface point would be on the LV busbars.
Large Combustion Plant Directive (LCPD)	The revised Large Combustion Plant Directive (LCPD, 2001/80/EC) applies to combustion plants with a thermal output of 50 MW or more. Its primary purpose is to reduce acidification, ground level ozone and particles throughout Europe.
Main Interconnected Transmission System (MITS)	This comprises all the 400kV and 275kV elements of the onshore transmission system and, in Scotland, the132kV elements of the onshore transmission system operated in parallel with the supergrid, and any elements of an offshore transmission system operated in parallel with the supergrid, but excludes generation circuits, transformer connections to lower voltage systems, external interconnections between the onshore transmission system and external systems, and any offshore transmission systems radially connected to the onshore transmission system via single interface points.
Merit Order	An ordered list of generators, sorted by margin cost.

Glossary

Term	Definition
National Electricity Transmission System (NETS)	The national electricity transmission system comprises the onshore and offshore transmission systems of England, Wales and Scotland.
National Electricity Transmission System Operator (NETSO)	National Grid acts as the NETSO for the whole of Great Britain while only owning the transmission assets in England and Wales. In Scotland, transmission assets are owned by Scottish Hydro Electricty Transmission Ltd (SHE Transmission) in the North of the country and Scottish Power Transmission SP Transmission in the South.
National Peak	The point at which electricity generation is at its highest in order to meet the nation's peak demand. This often occurs during the coldest winter days.
National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS)	A set of standards used in the planning and operation of the national electricity transmission system of Great Britain. For the avoidance of doubt the national electricity transmission system is made up of both the onshore transmission system and the offshore transmission systems.
Network Access	Maintenance and system access is typically undertaken during the spring, summer and autumn seasons when the system is less heavily loaded and access is favourable. With circuits and equipment unavailable the integrity of the system is reduced. The planning of the system access is carefully controlled to ensure system security is maintained.
NGET	National Grid Electricity Transmission plc (No.2366977) whose registered office is 1-3 Strand, London WC2N 5EH
Offshore	This term means wholly or partly in offshore waters.
Offshore Generating Unit	Any apparatus, which produces electricity including, a synchronous offshore generating unit and non-synchronous offshore generating unit and which is located in offshore waters.
Offshore Power Park Module	A collection of one or more offshore power park strings, located in offshore waters, registered as an offshore power park module under the provisions of the Grid Code. There is no limit to the number of

Term	Definition
	offshore power park strings within the offshore power park module, so long as they either: a) connect to the same busbar which cannot be electrically split; or b) connect to a collection of directly electrically connected busbars of the same nominal voltage and are configured in accordance with the operating arrangements set.
Offshore Power Park Strings	A collection of non-synchronous offshore generating units, located in offshore waters that are powered by an intermittent power source joined together by cables with a single point of connection to an offshore transmission system.
Offshore Power Station	An installation, located in offshore waters, comprising one or more offshore generating units or offshore power park modules or offshore gas turbines (even where sited separately) owned and/or controlled by the same generator, which may reasonably be considered as being managed as one offshore power station.
Offshore Transmission Circuit	Part of an offshore transmission system between two or more circuit breakers which includes, for example, transformers, reactors, cables, overhead lines and DC converters but excludes busbars and onshore transmission circuits.
Offshore Waters	Has the meaning given to "offshore waters" in Section 90(9) of the Energy Act 2004.
Onshore	This term refers to assets that are wholly on land.
Onshore Generating Unit	Any apparatus which produces electricity including a synchronous generating unit and non-synchronous generating unit but excluding an offshore generating unit.
Onshore Power Station	An installation comprising one or more onshore generating units or onshore power park module (even where sited separately) owned and/or controlled by the same generator, which may reasonably be considered as being managed as one onshore power station.

Glossary

Term	Definition
Onshore Transmission Circuit	Part of the onshore transmission system between two or more circuit-breakers which includes, for example, transformers, reactors, cables and overhead lines but excludes busbars, generation circuits and offshore transmission circuits.
Onshore Transmission Licensees	NGET, SP Transmission and SHE Transmission
Onshore Transmission System	The system consisting (wholly or mainly) of high voltage electric lines owned or operated by onshore transmission licensees and used for the transmission of electricity from one power station to a substation or to another power station or between substations or to or from offshore transmission systems or to or from any external interconnections and includes any plant and apparatus and meters owned or operated by onshore transmission licensees within Great Britain in connection with the transmission of electricity. The onshore transmission system does not include any remote transmission assets. For the avoidance of doubt, the onshore transmission system, together with the offshore transmission systems form the national electricity transmission system.
Planned Transfer	A term to describe a point at which demand is set to the National Peak when analysing boundary capability.
Power Station	Means an onshore power station or an offshore power station.
Ranking Order	A list of generators sorted in order of likelihood of operation at time of winter peak and used by the NETS SQSS.
Reactive Power	Reactive power is a concept used by engineers to describe the background energy movement in an alternating current (AC) system arising from the production of electric and magnetic fields. These fields store energy which changes through each AC cycle. Devices which store energy by virtue of a magnetic field produced by a flow of current are said to absorb reactive power; those which store energy by virtue of electric fields are said to generate reactive power.

Term	Definition
Real Power	This term (sometimes referred to as "Active Power") provides the useful energy to a load. In an AC system, real power is accompanied by reactive power for any Power Factor other than 1.
Seasonal Circuit Ratings	The current carrying capability of circuits. Typically, this reduces during the warmer seasons as the circuit's capability to dissipate heat is reduced. The rating of a typical 400kV overhead line may be 20% less in the summer than in winter.
SHE Transmission	Scottish Hydro-Electric Transmission (No.SC213461) whose registered office is situated at Inveralmond HS, 200 Dunkeld Road, Perth, Perthshire PH1 3AQ.
Slow Progression	A Future Energy Scenario. This is where developments in renewable and low carbon energy are comparatively slow and the renewable energy target for 2020 is not met. The carbon reduction target for 2020 is achieved but not the indicative target for 2030. Again, there are two case studies to explore some of the uncertainty seen in fuel prices. At the moment coal is significantly cheaper to burn than gas, so one case study is based on high coal generation and the other flips the fuel price dynamic and examines a high gas generation case.
SP Transmission	Scottish Power Transmission Limited (No. SC189126) whose registered office is situated at 1 Atlantic Quay, Robertson Street, Glasgow G2 8SP.
Station Demand	The demand drawn by power stations to operate ancillary services which prior to and after synchronisation to the NETS, support the process of electricity generation.
Summer Minimum Demand	The point at which electricity generation is at its lowest due to low demand. This is often attributed to longer daylight hours, lack of lighting demand and reduced heating demand.
Supergrid	That part of the national electricity transmission system operated at a nominal voltage of 275kV and above.

Glossary

Term	Definition
Supergrid Transformers (SGTs)	A term used to describe transformers on the NETS that operate in the 275–400kV range.
Switchgear	The term used to describe components of a substation that can be used to carry out switching activities. This can include, but is not limited to, isolators/disconnectors and circuit breakers.
System Operator (SO)	The System Operator (SO) is responsible for control of the electricity transmission network including controlling system switching, frequency and voltage.
System Stability	With reduced power demand and a tendency for higher system voltages during the summer months fewer generators will operate and those that do run could be at reduced power factor output. This condition has a tendency to reduce the dynamic stability of the NETS. Therefore network stability analysis is usually performed for summer minimum demand conditions as this represents the limiting period.
Transient Fault	A term used to describe a temporary fault on the network which will often clear before the Delayed Auto Reclose (DAR) operates.
Transmission Capacity	The ability of a network to transmit electricity.
Transmission Circuit	This is either an onshore transmission circuit or an offshore transmission circuit.
Transmission Entry Capacity (TEC)	The maximum amount of active power deliverable by a power station at its grid entry point (which can be onshore and offshore). This will be the maximum power deliverable simultaneously by all of the generating units that connect to the GEP, minus any auxiliary loads.

Term	Definition
Transmission Owners	A collective term used to describe the three transmission asset owners within Great Britain, namely National Grid Electricity Transmission, Scottish Hydro-Electric Transmission Limited and SP Transmission Limited.
UK Future Energy Scenarios (FES)	A term used to describe the range of scenarios used by NGET to provide a plausible and credible projection for the future of UK Energy.
Voltage Management	At times of low demand and particularly low reactive power demand, the voltages on the NETS can naturally increase due to capacitive gain. High voltages need to be controlled to avoid equipment damage. Sufficient reactive compensation and switching options must be available to allow effective voltage control.

Meet the Team

Electricity Network Development Team
Electricity Compliance, Modelling and Policy Team
Transmission Strategy Team

We would like to take this opportunity to introduce the Electricity Network Development Team, the Electricity Compliance, Modelling and Policy Team and the Transmission Strategy Team.

The **Electricity Network Development** Team is responsible for developing a holistic strategy for the electricity transmission system based upon a variety of forecast future generation and demand scenarios. The team manages and implements the Network Development Policy (NDP) which assesses the need to progress wider transmission system reinforcements; is responsible for all technical activities relating to offshore electricity network design and is also there to ensure that we can facilitate system access for our capital and maintenance plans while ensuring the system can be operated both securely and economically.

The **Electricity Compliance, Modelling and Policy** Team is responsible for a variety of power system issues including generator and HVDC compliance; providing accurate power system models and datasets for analysis and the management of the system Security and Quality of Supply Standards (SQSS). The team also manages the technical aspects of the GB and European electricity frameworks that are applicable to network development.

The **Transmission Strategy Team** considers and directs strategic and policy options that will maintain and enhance our current system operator and transmission owner roles for both gas and electricity, while working with a broad spectrum of stakeholders. Current projects include the role of the system operator, the role of interconnection, strategic network development within the North Sea basin and new concepts such as the frameworks to connect wind based in Ireland.

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Meet the Team

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We have won Business in the Community's highest award, Responsible Business of the Year 2014. This accolade acknowledges all of our efforts in getting involved with the things that really matter to us and to society, and doing the right things in the right way.