CLEVE HILL SOLAR PARK

OTHER DEADLINE 2 SUBMISSIONS RESPONSE TO ADDITIONAL SUBMISSION BY GREAT DATED 16 APRIL 2019 (ANSWERING THE STATEMENT OF NEED FOR CLEVE HILL SOLAR PARK) (AS-012) - Appendices
Appendix 5 - Network Options Assessment 2018/19

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Network Options Assessment 2018/19

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Foreword

From our *Future Energy Scenarios (FES)* publication, it can clearly be seen that we are in the midst of an energy revolution. Our *Network Options Assessment (NOA)* publication, along with our other Electricity System Operator (ESO) publications, aims to help our industry ensure a secure, sustainable and affordable energy future.

We publish the *NOA* as part of our ESO role. The *NOA* describes the major projects considered to meet the future needs of GB's electricity transmission system as outlined in the *Electricity Ten Year Statement (ETYS)* 2018, and recommends which investments in the year ahead would best manage the capability of the GB transmission networks against the uncertainty of the future.

This is the 4th *NOA* report and process we have run. To be transparent in our processes, and to ensure that the ESO is impartial throughout, we follow the NOA methodology, consult with our stakeholders and gain approval from Ofgem on an annual basis. This methodology sets out how we base our recommendations on the data and analysis of the 2018 *FES* and *ETYS*. Our latest methodology was approved by Ofgem in October 2018.

The separation between the ESO and National Grid Electricity Transmission is to be completed this April. This will not change the *NOA* itself although the changing roles and responsibilities of different parties will be reflected in future methodologies.

We published the Network Development Roadmap in 2018 and highlighted the steps that we are to take for the development of the NOA process in the coming years. We are now undertaking a number of pathfinding projects to explore how we can use the *NOA* to address broader system needs together with wider industry participants. We believe these will create additional value for GB's consumers. More information and the results of these pathfinding projects will be released throughout the coming years.

Investment decision

We considered the investment options proposed by the Transmission Owners (TOs). A couple of the highlights are:

- Recommendation for investment of £59.8m in 2019/20 across 25 projects to potentially deliver projects worth almost £5.4bn.
- Analysis suggests a total interconnection capacity range of between 18.4 GW to 21.4 GW between GB and European markets by 2031 would provide optimal benefit.

This *NOA* is also the first in which we've included ESO-led commercial solutions[1] in a similar way to the asset-based options proposed by the TOs. We found that commercial solutions can provide significant consumer benefit, especially in the period before asset-based options are yet to be delivered. Therefore, we will continue developing them for our future assessments.

- ESO-led commercial solutions identified in this *NOA* can make consumer savings up to £1.1bn between 2020 and 2028.

[1] See Chapter 4 – 'Proposed options' for more information about commercial solutions

The *NOA* represents a balance between asset investment and network management to achieve the best use of consumers' money. How the future energy landscape could look is uncertain, and the ESO's recommendations are there to help make sure the GB transmission network is fit for the future. In producing this year's *NOA* we have listened to and acted on your feedback.

We are making more changes and enhancements to the NOA process to drive greater and greater consumer value. I would welcome your thoughts as to how we can push the *NOA* even further to drive value for consumers whilst ensuring a safe and secure GB transmission system.

Julian Leslie
Head of Networks, ESO

Executive summary

Using the *FES* 2018, *ETYS* 2018 and following the latest *NOA* methodology approved by Ofgem, we recommend the reinforcement projects that should be invested in for the upcoming year.

Below, we present a summary of the key points of the *NOA* 2018/19.

Key points

- We recommend an investment of £59.8m in 2019/20 across 25 asset-based projects to maintain the option to deliver projects costing almost £5.4bn. This will allow us to manage the future capability of the GB transmission network against an uncertain energy landscape over the coming decades, and support the future development of the networks in an efficient, economical and coordinated way.
- We included 115 different reinforcement options in this *NOA*. Forty-one options are given either a 'Stop' or 'Do not start' recommendation as they are currently not optimal. We also recommend 45 optimal options to be put on hold where investment decisions can be delayed until there is greater certainty in the future. This ensures that a recommendation for investment is made at the most efficient time. Where a decision cannot be delayed any further, we investigate the cost impact of not investing in the coming financial year. Based on this, we recommend deferring the spend of £111k on two options in 2019/20.
- From the *NOA* 2017/18, we introduced the NOA Committee and the utilisation of implied probability for scrutinising our analysis results and investment recommendations. We continue to apply them in this *NOA* to ensure our final recommendations are robust and minimise the potential of them being 'false-positive'. Table 0.1 is an overview of our investment recommendations, including all the options where decisions must be made this year, and some key changes to last year's.
- The recommended investment spend is higher this year, primarily due to two factors. While reinforcing the Kemsley–Littlebrook circuits reconductoring advances to the delivery stage, its spend this year will be significantly higher. We also recommended a number of newly proposed options, such as power flow control devices, to be delivered as early as 2020. Their short lead time means a relatively higher spend for the next couple of years.
- We identified a need for a least two Anglo-Scottish reinforcements (eastern HVDC links and/or onshore circuits, each with a capacity of around 2 GW) from as early as 2027 to accommodate the high north-to-south flows. We assessed seven options (four new) in different combinations and found the HVDC links from Torness to Hawthorn Pit and from Peterhead to Drax will deliver the maximum benefit. We also recognised that the results are highly sensitive to the deliverability of these options and their associated onshore works. The final recommendations for these reinforcements are subject to the Strategic Wider Works (SWW) assessment, where a wider range of sensitivities are being investigated.
- The south coast is anticipated to have a growing volume of interconnection capacity in the next a few decades. The increasing flows between GB and other countries trigger a need for a new transmission route between South London and the south coast. We improved our modelling of network capabilities in this assessment so they are interconnector-flow-dependent. This further confirmed the need and we recommend this be investigated as an SWW with other available options.
- In addition to the asset-based reinforcements proposed by the TOs, we considered six ESO-led options, including four commercial solutions in this assessment. For the commercial solutions, we made generic assumptions on their effectiveness, costs, and service durations to ensure a fair comparison to the asset-based reinforcements. Based on our results, we believe there is a significant benefit of pursuing these commercial solutions. We are planning to refine these options via market testing this year.

ESO-led commercial solutions can deliver up to £1.1bn of additional consumer benefits between 2020 and 2028. We recommend developing two of the commercial solutions in 2019/20.

- This year's interconnection analysis suggests that a total interconnection capacity range of between 18.4 GW to 21.4 GW between GB and European markets by 2031 would provide optimal consumer benefit. Many other factors outside the scope of this analysis will influence the outcome for GB interconnection over the next decade and beyond.

It is important to recognise that these recommendations represent the best view at a snap-shot in time. Investment decisions taken by any business should always consider these recommendations in the light of subsequent events and developments in the energy sector.

This *NOA* also identifies which of the options we recommend to proceed are likely to meet Ofgem's criteria for onshore competition. We also expand this assessment to any new or modified contracted connection projects for generator and demand connections. The competition assessment is in accordance with the Ofgem agreed methodology and the outcomes are described in Chapter 5.

We are waiting on the final outcome of the EU-Exit negotiations and what this will mean for trading arrangements for interconnectors. We expect interconnectors to continue playing a long-term role as part of the UK's diverse energy mix. While some of the trading arrangements for interconnectors may need to change in a no deal scenario, the systems and processes can be amended to cater for this eventuality, meaning power can still flow between the UK and Europe.

Table 0.1
Summary of investment recommendations

Option code	Description	Earliest In Service Date	Two Degrees[2]	Community Renewables[2]	Consumer Evolution[2]	Steady Progression[2]	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation	Reason[3]
CDRE	Cellarhead to Drakelow reconductoring	2022	2022	2022	2022	2023	Hold	Proceed	This reinforcement becomes critical under three scenarios
CPRE	Reconductor sections of the Penwortham to Padiham and Penwortham to Carrington circuits	2021	N/A	N/A	N/A	2024	Proceed	Hold	This reinforcement is no longer critical due to other new reinforcments
CS01	A commercial solution for Scotland and the north of England with a service duration of 40 years	2020	2020	2021	N/A	N/A	Not featured	Proceed	New reinforcement
DWNO	Denny to Wishaw 400kV reinforcement	2028	2028	2028	2029	2029	Proceed	Proceed	No change
E2DC	Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC	2027	2027	2027	2027	2027	Proceed	Proceed	No change
E4D3	Eastern Scotland to England link: Peterhead to Drax offshore HVDC	2029	2029	2029	2029	2029	Not featured	Proceed	This new reinforcment is an alternative to the Peterhead to Hawthorn Pit option (E4DC)
ECU2	East coast onshore 275kV upgrade	2023	2023	2023	2023	2023	Proceed	Proceed	No change
ECUP	East coast onshore 400kV incremental reinforcement	2026	2026	2026	2026	2026	Proceed	Proceed	No change

[2] See Chapter 2 – 'Methodology' for more information about the Future Energy Scenarios (FES) we use.

[3] See Chapter 5 – 'Investment recommendations' for more details.

Table 0.1
Summary of investment recommendations (continued)

Option code	Description	Earliest In Service Date	Two Degrees[2]	Community Renewables[2]	Consumer Evolution[2]	Steady Progression[2]	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation	Reason[3]
FSPC	Power control device along Fourstones to Stella West circuit	2020	2020	2020	2020	2020	Not featured	Proceed	New reinforcement
HAE2	Harker Supergrid Transformer 5 replacement	2022	2022	2022	2022	2022	Hold	Proceed	This reinforcement becomes critical under all scenarios
HAEU	Harker Supergrid Transformer 6 replacement	2021	2021	2021	2021	2021	Proceed	Proceed	No change
HNNO	Hunterston East–Neilston 400kV reinforcement	2023	2023	2023	2023	2023	Proceed	Proceed	No change
HSPC	Power control device along Harker to Stella West circuit	2020	2020	2020	2020	2020	Not featured	Proceed	New reinforcement
LDQB	Lister Drive quad booster	2020	2020	2020	2020	2020	Proceed	Proceed	No change
LNRE	Reconductor Lackenby to Norton single 400kV circuit	2022	2022	2022	2023	2022	Hold	Proceed	This reinforcement becomes critical under three scenarios
MRUP	Uprate the Penwortham to Washway Farm to Kirkby 275kV double circuit to 400kV	2023	N/A	N/A	N/A	N/A	Proceed	Stop	Generation mix changes
NEMS	225MVAr MSCs within the north east region	2022	2022	2022	2022	N/A	Not featured	Proceed	New reinforcement
NOR1	Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit	2021	2024	2024	N/A	N/A	Proceed	Hold	This reinforcement is no longer critical due to other new reinforcments
OENO	Central Yorkshire reinforcement	2027	2027	2027	N/A	2027	Hold	Proceed	This reinforcement becomes critical under three scenarios
THS1	Install series reactors at Thornton	2023	2023	2023	2023	2023	Hold	Proceed	This reinforcement becomes critical under all scenarios
WHTI	Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit	2021	2021	2021	2022	2022	Proceed	Proceed	No change
BMM2	225MVAr MSCs at Burwell Main	2022	2022	2022	2022	2022	Not featured	Proceed	New reinforcement
BMM3	225MVAr MSC at Burwell Main	2023	2023	2023	2023	2023	Not featured	Proceed	New reinforcement
BMMS	225MVAr MSCs at Burwell Main	2023	N/A	N/A	N/A	N/A	Proceed	Stop	This reinforcment is replaced by BMM2 and BMM3
BNRC	Bolney and Ninfield additional reactive compensation	2022	2022	2022	2022	2022	Proceed	Proceed	No change

[2] See Chapter 2 – 'Methodology' for more information about the Future Energy Scenarios (FES) we use.
[3] See Chapter 5 – 'Investment recommendations' for more details.

Table 0.1
Summary of investment recommendations (continued)

Option code	Description	Earliest In Service Date	Two Degrees[2]	Community Renewables[2]	Consumer Evolution[2]	Steady Progression[2]	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation	Reason[3]
BTNO	A new 400kV double circuit between Bramford and Twinstead	2026	2026	2026	2026	2026	Delay	Proceed	Generation mix changes
CS25	A commercial solution for the south coast with a service duration of 40 years	2020	2020	2020	2020	2020	Not featured	Proceed	New reinforcement
FLR2	Fleet to Lovedean reconductoring (with a different conductor type to FLRE)	2020	2025	2025	2025	N/A	Proceed	Hold	Outage limitations
KLRE	Kemsley to Littlebrook circuits uprating	2020	2020	2020	2020	2020	Proceed	Proceed	No change
RTRE	Reconductor remainder of Rayleigh to Tilbury circuit	2021	2021	2021	2021	2022	Hold	Proceed	This reinforcement becomes critical under three scenarios
SCN1	New 400kV transmission route between South London and the south coast	2026	2026	2026	2026	2026	Do not start[4]	Proceed	Generation mix changes
SEEU	Reactive compensation protective switching scheme	2021	2021	2021	2021	2021	Proceed	Proceed	No change
SER1	Elstree to Sundon reconductoring	2022	2025	2022	2024	2023	Hold	Delay	This reinforcement is only critical under one scenario
TKRE	Tilbury to Grain and Tilbury to Kingsnorth upgrade	2025	N/A	N/A	N/A	N/A	Proceed	Stop	Generation mix changes and model improvement
WYTI	Wymondley turn-in	2021	2022	2023	2029	2025	Proceed	Hold	Generation mix changes and model improvement
PTC1	Pentir to Trawsfynydd 1 cable replacement – single core per phase	2023	2024	2023	2035	2031	Hold	Delay[5]	This reinforcement is only critical under one scenario

[2] See Chapter 2 – ‘Methodology’ for more information about the Future Energy Scenarios (FES) we use.

[3] See Chapter 5 – ‘Investment recommendations’ for more details.

[4] The *NOA* 2017/18 recommended progressing with an alternative option (SCN2). This option has not been considered in this *NOA* due to access issues.

[5] This recommendation has changed from ‘Proceed’ to ‘Delay’ as a result of the NOA Committee.

We welcome your views

We want to continue to develop the *NOA* and we welcome your views on how to improve it. Chapter 7 – 'Stakeholder engagement' describes how you can contact us with your views.

Future energy publications

National Grid ESO has an important role to play in leading the energy debate across our industry and working with you to make sure that together we secure our shared energy future. The ESO is perfectly placed as an enabler, informer and facilitator. The ESO publications that we produce every year are intended to be a catalyst for debate, decision making and change.

The starting point for our flagship publications is the *Future Energy Scenarios (FES)*. The *FES* is published every year and involves input from stakeholders from across the energy industry. These scenarios are based on the energy trilemma (security of supply, sustainability and affordability) and provide supply and demand projections out to 2050. We use these scenarios to inform the energy industry about network analysis and the investment being planned, which will benefit our customers.

We build our long-term view of the electricity transmission capability in our *Future Energy Scenarios (FES)*, *Electricity Ten Year Statement (ETYS)*, and *Network Options Assessment (NOA)* publications. To help shape these publications, we seek your views and share information across the energy industry that can inform debate.

Chapter 1
Introduction

1.1 Introduction

This chapter introduces the *Network Options Assessment (NOA)* and summarises the new features in this publication.

The *NOA* 2018/19 is the fourth to be published. As ever, we welcome your feedback, which we will use to develop future editions.

We use the *NOA* to help us develop an efficient, coordinated and economic system of electricity transmission, consistent with the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS). We use it to identify and recommend the major NETS reinforcement projects for Great Britain's Transmission Owners (TOs) to proceed with to meet the future network requirements, as defined in the *Electricity Ten Year Statement* (*ETYS*). It also identifies which projects meet the criteria proposed by the Office of Gas and Electricity Markets (Ofgem) for onshore competition, providing relevant information to stakeholders. These projects include both major NETS reinforcements and future generator and demand connections to the transmission system[1]. This report is underpinned by the data in our *Future Energy Scenarios* (*FES*). This means that the *NOA* and the *ETYS* have a consistent base for assessing the potential development of the electricity transmission networks. Taken together, the *ETYS* and the *NOA* give a full picture of requirements and potential options for the NETS.

The *NOA* 2018/19 was published in January 2019 and is based on the *FES* 2018.

Chapter 6 includes our interconnection assessment (NOA IC). This informs the industry of the potential benefits of future interconnection, with the goal of encouraging the development of efficient levels of interconnector capacity between GB and other markets.

This year's NOA IC analysis includes additional improvements to the methodology. We have analysed the impact that interconnectors may have on operational costs such as ancillary services. Interconnectors have the potential to enhance system operability or lower the costs of providing system security, or conversely, their presence could worsen system operability or increase system security costs.

We have provided more context and explanation of the results, and highlighted how they differ from other analysis, such as the Ten-Year Network Development Plan[2] (TYNDP). These improvements have been driven by stakeholder feedback, and approved by Ofgem.

[1] Ofgem closed its informal consultation on changes to Standard Licence Condition C27 of electricity transmission in early 2018. The changes proposed new requirements for the ESO to assess projects recommended for further development in the *NOA* and projects for future generator and demand connections, for their eligibility for competition.

[2] https://tyndp.entsoe.eu/

1.2 How the *NOA* fits in with the *FES* and the *ETYS*

The ESO produces a suite of publications on the future of energy for Great Britain (see page 8). These publications inform the whole energy debate by addressing specific issues. The *FES*, *ETYS* and *NOA* provide an ever-evolving and consistent voice in the development of GB's electricity network.

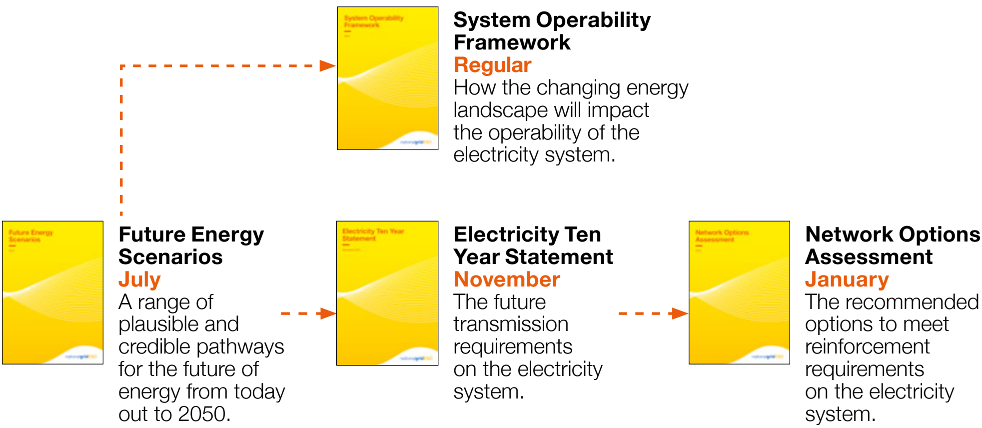
We use the *FES* to assess the network requirements for power transfers across the GB NETS. These requirements were published in the *ETYS* in November 2018, and the TOs responded with options for reinforcing the network. The *NOA* is based on our economic analysis of these options. Further explanation of this process can be found in Chapter 2 – 'Methodology'.

In the *NOA* we summarise our economic analysis of reinforcement options by region. An option may not appear in more than one region (to prevent an option being evaluated more than once, with the risk of different answers). Based on the economic analysis, we give our recommended option or options for each of the regions. For some options, we have included a summary of the Strategic Wider Works (SWW) analysis.

It is important to note that while we recommend options to meet system needs, the TOs or other relevant parties will ultimately decide on what, where and when to invest.

Some of the alternative options we have evaluated are reduced-build or operational options as explained in Chapter 4 – 'Proposed options'. We emphasise the need to reinforce the network through innovation.

Figure 1.1
NOA and ESO documents



1.3 What the *NOA* can do

- Recommend the most economic reinforcements, whether build or alternative options, to be invested in, over the coming years, to meet bulk power transfer requirements as outlined by the *ETYS*.
- Recommend when investments should be made under different Future Energy Scenarios to deliver an efficient, coordinated and economic future transmission system.
- Recommend whether the TOs should start, continue, delay or stop reinforcement projects to make sure they are completed at a time that will deliver the most benefit to consumers.
- Indicate to the market the optimum level of interconnections to other European electricity grids – as well as any necessary reinforcements.
- Highlight the potential benefits and disbenefits of interconnectors in terms of system operability.
- Indicate whether the TOs should begin developing the Needs Case for potential SWW options.
- Indicate to Ofgem and other relevant stakeholders which reinforcement options and works required for future generator and demand connection projects are eligible for onshore competition.

1.4 What the *NOA* cannot do

- Insist that reinforcement options are pursued. We can only recommend options based on our analysis. The TOs or other relevant parties are ultimately responsible for what, where and when they invest.
- Comment on the specific details of any specific option, such as how it could be planned or delivered. It is the TOs or other relevant parties who decide how they implement their options.
- Evaluate the specific designs of any option, such as the choice of equipment, route or environmental impacts. These types of decisions can only be made by the TOs or other relevant parties when the options are in a more advanced stage.
- Assess network asset replacement projects which do not increase network capability or individual customer connections.
- List all the options that the TOs develop. Some are discarded early. It is for the TOs to develop options and consult with stakeholders on variations on options.
- Forecast or recommend future interconnection levels. It indicates the optimum level of interconnection.

1.5 Evolution of the *NOA*

The electricity industry is fundamentally changing. New technologies and ways of working are bringing opportunities to deliver great value, for consumers and society. As the ESO, we have a crucial role in facilitating the transition to a low carbon electricity industry. Key to this success will be developing our planning tools – primarily the *ETYS* and *NOA*.

We launched our Network Development Roadmap Consultation[3] in May 2018, setting out our proposals on developing our network planning tools over the remainder of RIIO-T1. After engaging with the wider industry, including network companies, academics, and potential participants in the new process, we published our Network Development Roadmap[4] in July 2018 and confirmed our direction of travel over the next three years.

To make sure we can deliver these changes, we are committed to undertaking pathfinding projects and working closely with wider stakeholders. We summarised our ongoing pathfinding projects in this section.

1.5.1 Regional Development Programme (RDP) learnings

We have been working with the TOs and Distribution Network Operators (DNOs) on several RDPs over the past few years. These projects focus on regional network issues with the consideration of transmission and distribution network interactions.

The learnings from these projects are valuable as they formed the starting point for us to work with wider industry participants and to consider whole system solutions in future network development and investment planning. We have published the RDP learnings in the Energy Networks Association (ENA) Open Networks Workstream 1 Product 1 report.[5]

1.5.2 High voltage regions

Decarbonisation and decentralisation are two of the key aspects of our foreseeable future energy landscape. For the transmission network, this means lower demand levels and fewer synchronous power plants that could provide voltage support at certain periods of the year, such as during summer minimum demand. Because of this, voltage management, especially the upper limit, is becoming more challenging for the ESO. We currently spend over £150m annually on balancing services for reactive power to maintain the voltage levels within NETS SQSS operational limits. We envisage that the regional high voltage issues will become more prominent and costly to manage. Therefore, we are developing a process similar to the *NOA* to evaluate solutions to the regional high voltage issues. The aim is to find the best balance between investing in new solutions and using existing reactive support measures to deliver additional benefits for our consumers.

We have been working closely with National Grid Electricity Transmission (NGET) TO, Electricity North West Limited (ENWL), and Northern Powergrid (NPg) on high voltage issues in the north of England/Pennine region, assessing a range of solutions provided by the TO and DNOs, in conjunction with ESO measures, to meet an identified need for regional reactive support of up to 1000 MVAr from 2020. Our assessment indicates that 800 MVAr of reactive compensation was economically justified, comprising three transmission based solutions and one distribution based solution. This project is ongoing, and the next stage is to explore the opportunity to include commercial solutions for further comparisons.

[3] https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20consultation.pdf

[4] https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20-%20Confirming%20the%20direction%20July%202018.pdf

[5] http://www.energynetworks.org/assets/files/ON-PRJ-WS1-P1%20RDP%20Learnings%20vPublished.pdf

Apart from the above, we are also working with relevant TO and DNOs to expand the high voltage assessment to other regions of the network (Mersey and South Wales areas). We are developing a screening tool to help identify and prioritise areas for detailed studies on a consistent basis. We published our methodologies and processes, together with our findings and planned next steps, in the ENA Open Networks Workstream 1 Product 1 report[6].

Conducting pathfinding projects allows us to explore, experiment, and learn. It helps us refine our methodologies or frameworks for addressing other system needs with the inclusion of whole system solutions. Please let us know your views about these projects as your feedback is important to shape development in these areas.

For updates on our ongoing pathfinding projects and to find out how to get involved, please go to our Network Development Roadmap website[7].

1.5.3 Probabilistic approach

Our electricity energy industry is evolving rapidly with increasing levels of interconnection and renewable generation, which brings greater volatility to system flows and capability needs year-round. We are enhancing our study capability by developing a probabilistic approach to facilitate the year-round boundary analysis.

The probabilistic approach is aimed at providing a better understanding of system needs that may arise in conditions other than winter peak. This will lead to more informed investment and operational decisions, with clear cost/risk measures applied.

We have been working on a case study to demonstrate how the new probabilistic approach can be used and a report is to be published in the first quarter of 2019. We are engaging with the TOs and other stakeholders for the inclusion of this approach in the *NOA* 2019/20.

1.5.4 System stability

We are also exploring the benefits and practicalities of applying a NOA-type approach to stability aspects of system operability. In this context we are talking about stability of frequency, voltage and the ability of a network user to remain connected to the system during normal operation, during a fault and after a fault. Synchronous generation provides many benefits to system stability that will need to be replaced when this type of generation runs less frequently.

We are exploring how to articulate and quantify the properties synchronous generation gives us, the potential for these to be provided by alternative technologies, and the value of a NOA-type process for stability. We published some of our work on the impact of declining short circuit levels in our *System Operability Framework*[8] *(SOF)* document, and during 2019 we intend to invite technical and commercial solutions from across the industry to address needs in specific locations.

[6] http://www.energynetworks.org/assets/files/ON-WS1-P1%202018%20Investment%20Planning%20Processes%20-%20Approach%20vFinal.pdf

[7] https://www.nationalgrideso.com/insights/network-options-assessment-noa/network-development-roadmap

[8] HTTPS://WWW.NATIONALGRIDESO.COM/INSIGHTS/SYSTEM-OPERABILITY-FRAMEWORK-SOF

1.6 The *NOA* report methodology

The *NOA* report methodology sets out in detail how the NOA process should work. We started the *NOA* report methodology in early 2018, working with the onshore TOs and Ofgem. The initial draft of the methodology for the *NOA* 2018/19 was published for consultation in April 2018.

After more discussions and refinement, the methodology was submitted to Ofgem in July 2018, and then published on our website. The methodology was approved by Ofgem in October 2018.

We describe the methodology further in Chapter 2 – 'Methodology'.

1.7 Navigating through the document

We have structured the *NOA* document in a logical manner to help you understand how we have reached our recommendations and conclusions.

Chapter **two**

Methodology (page 21)
Chapter 2 describes the NOA process and the economic theory behind it. This is a good overview if you are unfamiliar with the *NOA*, or if you'd like to understand more about how we carry out the economic analysis of options.

Chapter **three**

Boundary descriptions (page 35)
Chapter 3 describes how we divide the GB network into boundaries and regions for analysis, and gives a description of each boundary, as well as an overview of the types of generation within each boundary. This is a good introduction to understanding the GB network.

Chapter **four**

Proposed options (page 59)
Chapter 4 describes the reinforcement options that can increase the NETS capability. This is a good description of the types of options being proposed for this year's assessment.

Chapter **five**

Investment recommendations (page 81)
Chapter 5 presents our investment recommendations for 2019/20. It also summarises the eligibility assessment for competition in onshore electricity transmission.

Chapter **six**

Interconnection analysis (page 103)
Chapter 6 presents our interconnection analysis results. We describe the optimum levels of interconnection between GB and European markets, and explain the economic theory behind the benefit of interconnectors to the consumer. This year, we also look at the impact of interconnectors on operational costs.

Chapter **seven**

Stakeholder engagement (page 139)
Chapter 7 discusses how you can give us your feedback to improve the *NOA* in future publications.

1.8 What's new?

In the *NOA* 2017/18, we achieved great success in strengthening the NOA process by introducing a NOA Committee to scrutinise our investment recommendations. This was supported by using implied probabilities to aid our decision making for options driven by a single factor or considered sensitive. Given the success of these, we continue to apply them this year. In addition, we have used our stakeholders' feedback, to improve the *NOA*. The following areas are new additions for the *NOA* 2018/19:

1.8.1 The expansion of eligibility assessment for onshore competition

Following Ofgem's informal consultation on changes to the electricity transmission Standard Licence Condition C27[9], we have expanded our eligibility assessment for onshore competition to new and modified future generator and demand connection projects. It builds on the existing process for major NETS reinforcements and uses the same criteria of high value, new and separable, which are detailed further in Ofgem's latest publications[10]. We've included a summary of our findings in Chapter 5 – 'Investment recommendations'.

1.8.2 The NOA pathfinding projects

In July 2018, we published our Network Development Roadmap[11] for the coming years, committing to conducting pathfinding projects to explore ways of including other system needs, such as regional reactive requirements; and a broader range of market participants for providing whole system solutions in the future NOA process. We've highlighted our ongoing pathfinding projects in Section 1.5 – 'Evolution of the *NOA*'. These new areas may be published separately to the *NOA* report in future.

[9] https://www.ofgem.gov.uk/publications-and-updates/consultation-changes-standard-licence-condition-c27

[10] https://www.ofgem.gov.uk/electricity/transmission-networks/competition-onshore-transmission

[11] https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20-%20Confirming%20the%20direction%20July%202018.pdf

1.8.3 Changes to the NOA economic analysis modelling

This is the first time we used four European Future Energy Scenarios in our economic models to make sure that our assumptions for GB and other European countries are aligned. We've also reviewed the way of modelling our network capabilities so that interconnector-flow-dependent capabilities could be used. These improvements made our models more accurate, which led to more informed results.

1.8.4 Changes to the NOA for Interconnectors

This year's *NOA* for Interconnectors analysis has been enhanced by not only focusing on Social Economic Welfare (SEW), capital costs and reinforcement costs, but by analysing the impact that interconnectors may have on other operational costs, specifically ancillary services.

We always want to hear suggestions on how we can continue improving the *NOA* so don't hesitate to let us know how we can further develop it to meet your needs.

1.9 Stakeholder engagement and feedback

Feedback isn't limited to the questions in this publication, and we'd be delighted to hear from you. We are also keen to know how you'd prefer to share your views and help us develop the *NOA*. Please see Chapter 7 – 'Stakeholder engagement' for more information.

To help encourage your feedback, we've included prompts throughout the publication and these highlight areas in each section where we'd like your views.

Chapter 2
Methodology

2.1 Introduction

This chapter highlights the methodology we use for the *NOA*, and explains the economic theory behind our analysis. It also explains how the *NOA* ties in with the SWW process.

2.2 The NOA process

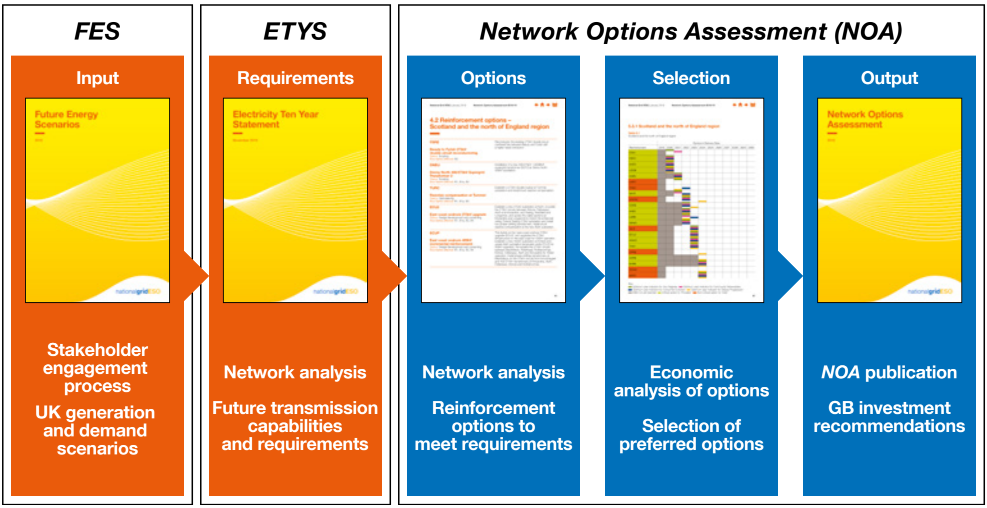
The *NOA* methodology describes how we assess Major National Electricity Transmission System (NETS) Reinforcements to meet the requirements identified from our analysis of the *Future Energy Scenarios* (*FES*). We have published this year's methodology on our website. It also includes the methodologies for interconnectors and SWW.

In accordance with our licence condition, Major National Electricity Transmission System Reinforcements are defined in Paragraph 1.28 of the *NOA* report methodology as: "a project or projects in development to deliver additional boundary capacity or alternative system benefits, as identified in the Electricity Ten Year Statement or equivalent document."

Some users' connection agreements have major reinforcements as their required works for connection. This means that the *NOA* may recommend a change to the delivery of these works. If this happens, we will inform and work with these users, but their connection dates remain the same.

Figure 2.1 shows the steps we take to produce the *NOA*. It follows the five stages of the *NOA* report process.

Figure 2.1
NOA process



2.2.1 *Future Energy Scenarios (FES)*

The NOA process for the NETS planning starts with the FES. They represent a credible range of future scenarios across the whole energy system and the electricity components form the foundation for our studies and economic analysis. The four scenarios are:

- Community Renewables
- Two Degrees
- Steady Progression
- Consumer Evolution.

The FES we used in this *NOA* were published in July 2018 and have evolved compared to previous years. The four scenarios above are still plotted in a 2×2 matrix against two axes, however the previous axes of ‘green ambition’ and ‘prosperity’ have been merged to form a ‘speed of decarbonisation’ axis and a new ‘speed of decentralisation’ axis has been included to reflect the increasing role of decentralisation in the energy industry.

The step changes in the latest FES may affect the NOA outcomes, as the drivers for the investments may no longer be the same as we anticipated in the past. For more information on how the *FES* is changing the *NOA* recommendations, see Chapter 5 – ‘Investment recommendations’.

For more information on our FES, see the *FES* 2018, which you can find at:

fes.nationalgrid.com
> *FES* document

2.2.2 *Electricity Ten Year Statement*

The ETYS is the second stage in the NOA process. We apply the FES to transmission system models and calculate the power flow requirements across the transmission network. To do this, we have developed the concept of boundaries. These are instead a virtual split of the network into two parts. As power transfers between these areas, we can see which parts of the network are under the most stress and where network reinforcement would be most needed.

The capability of the network and its future requirements are published in the *ETYS* 2018, which you can find at:

www.nationalgrid.com/etys

2.2.3 *Network Options Assessment*

To create an electricity transmission network fit for the future, we ask all TOs to propose options to meet the system capability requirements outlined by the *ETYS*. We encourage options that include upgrading existing assets or creating new assets to ensure we have a wide selection of options to assess.

With these options, we move onto the fourth stage of the NOA process, ‘Selection’. We use our understanding of constraint costs to carry out economic analysis of all the options. This gives us the ones we believe provide the most benefit for consumers. You can find the full list of our recommended options in Chapter 5 – ‘Investment recommendations’. How we perform economic analysis is described in greater detail in the following section.

As well as these build options, both the TOs and ESO can propose opportunities for alternative options. These are solutions requiring very little to no build and instead maximise use of existing assets, often in innovative ways. You can find a full list of the options we analysed in Chapter 4 – ‘Proposed options’.

2.3 Economic analysis

2.3.1 Theory

It is important to understand why we recommend that the TOs invest in their networks.

The transfer of energy across our network boundaries occurs because generation and demand are typically in different locations. When the power transfer across a transmission system boundary is above that boundary's capability, our control room must reduce the power transfer to avoid overloading the transmission assets. This is referred to as 'constraining' the network.

When this happens, we ask generators on the exporting side of the stressed boundaries to limit their output. To maintain an energy balance, we replace this energy with generation on the importing side. Balancing the network by switching generation on and off costs money, and if we are regularly constraining the network by large amounts, costs begin to accumulate.

Assessment of future constraint costs is an important factor in our decision-making process. It enables us to evaluate and recommend investments such as adding new overhead lines and underground cables to the transmission network. We call these potential investments 'options' and, although they cost money, they also raise the capability of the network, meaning that more power can be transferred across boundaries without the need to constrain. We work with the TOs to upgrade the transmission networks at the right time in the right places to give the best balance between investing in the network and constraining it.

2.3.2 Optimum years

To maximise benefit to consumers, we must recommend that the TOs invest in the right options at the right time. However, it takes time for the TOs to upgrade the network, with some options taking longer to implement than others. The earliest an option can be delivered is an important factor in our analysis. It's called the 'Earliest In Service Date' (EISD). We need to take this into account when considering the timing of options. We don't want to invest too early unnecessarily, or incur potentially high constraint costs by investing too late. Getting this balance right will achieve the best value for consumers. So each economically viable option has an optimum year of delivery to give the most benefit, and we aim to time an option to be delivered in its optimum year.

If an option's optimum year of delivery is later than its EISD, no recommendation on whether to proceed needs to be made yet. However, if an option's optimum year is the same year as its EISD, a recommendation cannot be delayed without the risk of missing its optimum year. Such an option is then considered 'critical'. All critical options are included in our single year least regret analysis, where we decide which options should be recommended to proceed for the next financial year.

2.3.3 Single year least regret analysis

Future uncertainty means an option's optimum year of delivery will likely not be the same for each of the energy scenarios. So we must balance the risk between recommending that the TOs proceed with a critical option to deliver on its EISD, or delaying its delivery until closer to its optimum year.

Table 2.1
Example of a critical option's optimum years of delivery

	EISD	Optimum year of delivery			
		Scenario A	Scenario B	Scenario C	Scenario D
Critical option	2019	2019	2019	2020	2021

In the above example, the earliest year the option can be delivered is 2019. The optimum year of delivery varies across the scenarios, but for scenarios A and B it's 2019, making it a critical option. For those scenarios, the right recommendation would be for the TOs to proceed with this option to maintain its EISD of 2019. However, for scenarios C and D, the right recommendation would be to not proceed with this option this year, and allow its EISD to slip back by one year to 2020. If an option's EISD cannot slip back by a year without carrying out some aspects of the work, a delay cost should be submitted for economic analysis. To make a recommendation to the TOs, we must analyse the potential 'regret' of making one recommendation and not the other.

As we are mostly interested in making investment recommendations for critical options, we use 'single year least regret' analysis. As each critical option can either be recommended to 'proceed' or 'delay', there are a number of courses of action we could recommend. For example, two critical options in the same region would produce four different possible courses of action, as shown in Table 2.2.

Table 2.2
Possible courses of action for two critical options in a region

Course of action 1	Proceed both Options X and Y
Course of action 2	Proceed Option X but delay Option Y
Course of action 3	Proceed Option Y but delay Option X
Course of action 4	Delay both Options X and Y

To balance the level of investment and exposure to risk, we use the concept of 'economic regret'.

Single year least regret analysis allows us to recommend to the TOs to invest just the right amount so an option can be progressed forward by one year and maintain its EISD. As our energy landscape is changing, our recommendation for an option may adapt accordingly. This means that an option we recommended to proceed last year may be recommended to be delayed this year and vice versa. Under the single year least regret analysis, an ongoing project is revaluated each year to ensure its planned completion date remains best for the consumer.

2.3.4 Economic regret

Once a reinforcement option is delivered, constraint costs decrease because of the capability it adds to the network. However, all options have a cost associated with their implementation, and the net benefit an option brings over its lifetime is the difference between the savings in constraint costs and the total cost of the option.

In the single year least regret analysis, we investigate all possible courses of action presented by critical options for the next investment year. These are treated as different investment strategies. Economic regrets are calculated under each scenario for different strategies to help us identify and quantify the maximum risk of each course of action across different scenarios. Selecting the strategy with the lowest maximum regret leaves consumers exposed to the least amount of risk. The following descriptions show how economic regrets are calculated in the single year least regret analysis.

Table 2.3
Example of the costs and benefits of different investment strategies under scenario A

	Strategy 1	Strategy 2	Strategy 3
Initial investment cost	£40m	£20m	£60m
Savings in constraint costs	£420m	£220m	£460m
Net benefit	£380m	£200m	**£400m**
Regret	£20m	£200m	**£0m**

In economic analysis, a strategy's 'regret' is the difference between the benefit of that strategy and the benefit of the best strategy. Therefore, the best strategy will have a regret of zero, and other strategies will have different levels of regret depending on how they compare to the best strategy. In Table 2.3, strategy 3 is the best strategy, so there is no regret in choosing it. If we were to select strategy 1, we would see a net benefit of £380 million, which is almost as good. But we would regret the decision as we didn't select strategy 3, which has a net benefit of £20 million more. Clearly, choosing the strategy with least regret makes economic sense.

However, as we face an uncertain future, we must consider the regret of our investments across each of the four energy scenarios. The same strategy won't always deliver the same value across every scenario; it will have more regret in some scenarios and less in others. The best strategy for one scenario might not be the best strategy for another scenario. Table 2.3's regret results were for just one scenario. We cannot predict the future, so we analyse a strategy's regret across all four credible scenarios and note the worst regret we could potentially incur by selecting that strategy.

Table 2.4
Example of net benefits from different strategies across multiple scenarios

		Strategy 1	Strategy 2	Strategy 3
Net benefit	Scenario A	£380m	£200m	**£400m**
	Scenario B	£120m	**£165m**	£125m
	Scenario C	**£350m**	£50m	£250m
	Scenario D	£160m	£150m	**£185m**

Table 2.5
Example of least regret analysis, with strategy 1 having the lowest worst regret

		Strategy 1	Strategy 2	Strategy 3
Regret	Scenario A	£20m	£200m	£0m
	Scenario B	**£45m**	£0m	£40m
	Scenario C	£0m	**£300m**	**£100m**
	Scenario D	£25m	£35m	£0m
Worst regret		**£45m**	**£300m**	**£100m**

We select the preferred strategy based on which has the lowest worst regret. In the above example, each scenario has a best and worst choice. Strategy 3 may be the best choice for scenarios A and D, but would be a much poorer choice under either of the other two scenarios. Least regret analysis shows that strategy 1 minimises risk across all four scenarios, as its regret will be no more than £45 million. This approach provides a more stable and robust decision against the range of uncertainties, and minimises exposure to significant regret.

2.3.5 Implied probability

The single year least regret analysis will always find the strategy that minimises the worst regret across different scenarios. However, in some circumstances, the approach may lead to 'false-positive' recommendations, especially when recommendations for the preferred strategy are driven by a single scenario with the highest level of congestion on the system. To mitigate the risks of giving 'false-positive' recommendations, we calculate implied probability weightings on scenarios to challenge the preferred strategy.
In this additional step, a priori probability weights are not directly applied to any scenarios; instead, we calculate the probability weights implied by the single year least regret decision. For the single year least regret chosen strategy to be preferred, the weighted net benefit of the chosen strategy must be greater than for any other. We can therefore compare each competing strategy against the single year least regret chosen strategy and calculate the probabilities, which would make us indifferent between the two. In the example shown in Table 2.5, we can see it is mainly scenarios B and C deciding the single year least regret analysis results. Scenario C produces the highest regret for strategies 2 and 3, and is the main driver behind strategy 1 being chosen. However, scenario B provides us with the largest regret for strategy 1 with respect to strategy 2 and 3. To make the same decision as the least regret decision under expected net benefit maximisation, the expected net benefit of strategy 1 must be greater than the expected net benefit of strategy 2 or 3. For example, to choose strategy 1 over strategy 2, it must be that:

$$350p+120(1-p) \geq 50p+165(1-p)$$

where p is the probability of scenario C, and 1-p is the probability of scenario B; the net benefit provided by strategy 1 is £350m and £120m under scenarios C and B respectively, as shown in Table 2.4; and the net benefit provided by strategy 2 is £50m and £165m under scenarios C and B respectively. Solving the inequality, we find that $p \geq 13.04\%$. This means that we need to believe that scenario C is greater than 13.04% likely to happen against scenario B for us to make the same decision as single year least regret analysis suggests. Conversely, we would need to believe that scenario B is less than 86.96% likely when compared with scenario C.

2.3.6 Economic tools

We use a constraint costs assessment tool to analyse and establish the benefits to consumers of the different options. Historically, we've used the Electricity Scenario Illustrator (ELSI) to determine these costs. In March 2016, we purchased a new economic tool, BID3, from Pöyry Management Consulting. We began using it from 2016/17 for econometric analysis work. It forecasts the costs of constraints, an important factor in the full cost-benefit analysis of the *NOA*. We use this information to help us identify the most economic investment strategies, taking into account all the Future Energy Scenarios described in Chapter 2 of the *ETYS* 2018.

To ensure a successful transition to BID3, the model has been extensively benchmarked against the ELSI, and we appointed two independent reviewers (Professor Keith Bell, University of Strathclyde, and Dr Iain Staffell, Imperial College London) to review our work, BID3 configuration and benchmarking.

The future energy landscape is uncertain, so the information we use in our cost-benefit analysis changes over time. We revisit our data, assumptions and analysis results every year to make sure that the preferred strategy is still the best solution. So, when we respond to market or policy-driven changes, this approach allows us to be flexible, while also keeping the cost associated with this flexibility to the minimum.

Figure 2.2
BID3 tool inputs

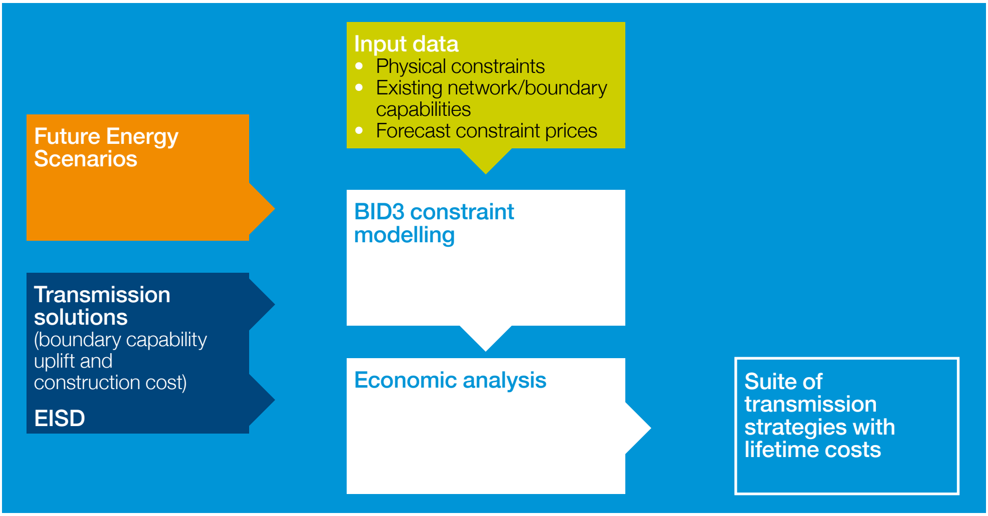


Figure 2.2 shows the inputs to BID3, which fall broadly into three categories:

Boundary capabilities and their future development – These were calculated using a separate power system analysis package. BID3 is the tool for calculating the market-driven flow across the boundaries, and takes capabilities as an input. The input to BID3 includes the increase in capability that the option provides, its EISD, and any associated operational costs.

Future Energy Scenarios – BID3 assesses all options for network reinforcements against each of the detailed scenarios. The resulting analysis takes us up to 2038 (the values from 2039 are extrapolated from 2038 forecasts so we can estimate full lifetime costs).

Assumptions – BID3's other input data takes account of fuel cost forecasts, plant availabilities and prices in interconnected European member states.

To find out more about BID3, see the resources our website. A copy of the independent reviewers' report is available, as well as our Long Term Market and Network Constraint Modelling Report, which provides further information on why we selected BID3, its use, and more detail on the inputs to BID3. The reports are available at the main NOA webpage.

www.nationalgrid.com/noa

2.4 The NOA Committee

Since the *NOA* 2017/18, we've operated the NOA Committee – consisting of ESO senior management – as an additional, transparent level of scrutiny to our *NOA* recommendations. In this final step, the investment recommendations from our economic analysis are presented to the NOA Committee, which focuses on marginal recommendations driven by a single scenario or driver, or recommendations which are considered to be sensitive, and challenges their single year least regret analysis with implied probabilities and other evidence.

The NOA Committee also provides holistic energy industry insight, and takes into account whole system needs to support or revise marginal investment recommendations. Ahead of the NOA Committee meeting, the ESO discusses the details of economic analysis results with both internal stakeholders and the TOs to make sure the final recommendations are robust. The TOs will be invited to present information at the NOA Committee if at least one of their options (or joint options) is to be discussed.

You can find the terms of reference of the NOA Committee and meeting minutes of our previous NOA Committee meetings on the NOA webpage.

nationalgrid.com

www.nationalgrid.com/noa

2.5 How the NOA connects to the SWW process

We use the NOA process to look at the costs and benefits of potential options, and put forward our recommended options. If a large infrastructure option is recommended that satisfies one of the criteria shown below, this option is referred to as Strategic Wider Works (SWW). SWWs are led by the TOs, with the support of the ESO, who develop the Needs Case for such an option.

An option in England and Wales needs to meet at least one of the criteria below to be considered as SWW. All costs are in 2009/10 prices:
- The option has a forecast cost of more than £500 million.
- The option has a forecast cost of between £100 million and £500 million, is supported by only one customer, and is not required in most scenarios.
- The option has a forecast cost of less than £100 million, is supported by only one customer, and is not required in most scenarios, but would require consents.

An option in Scotland needs to meet all the criteria shown below. Once again, all costs are in 2009/10 prices:
- The option has a forecast cost of more than £50 million for SHE Transmission and £100 million for SP Transmission.
- The output will deliver additional cross-boundary (or sub-boundary) capability, or wider system benefits.
- Costs cannot be recovered under any other provision of the TO's price control settlement.

It's important to note that the relevant TO leads on developing Needs Cases for SWW projects, but we support with the economic analysis. The TO initiates the Needs Case work for SWW projects depending on certain factors, including the forecast costs, and whether they trigger the SWW funding formula. Another important factor is the time needed to deliver the option.

This, combined with the date at which the option is needed, determines when to start building. The closer this date is, the sooner the TO needs to pursue the detailed analysis to justify the SWW funding.

We have published our methodology for the ESO process for input into TO-led SWW Needs Case submissions on our website.

www.nationalgrid.com/noa

2.5.1 Summary of SWW economic analysis methodology

When an option is deemed to be an SWW, cost-benefit analysis examines the economic benefit of a range of reinforcement options against the base network across their lifetimes. The base is usually 'do nothing' or 'do minimum', and usually has no associated capital costs. Constraint costs are forecast for the base and each network option across all scenarios.

We calculate the present value (PV) of constraint savings compared to the base for each network solution. These are subtracted from the PV of capital expenditure associated with each network option, giving a net present value (NPV) for each network option. Taking these NPVs, we use lifetime least regret analysis to determine a preferred network option and an optimal delivery year.

The results are analysed to determine how changing project capital costs and constraint savings would affect the recommendations.

The Joint Regulators Group on behalf of the UK's economic and competition regulators recommend discounting all costs (including financing costs as calculated based on a weighted average cost of capital or WACC) and benefits at HM Treasury's social time preference rate (STPR). This is known as the Spackman approach and is used for all our reinforcements.

We may vary the process where modelling the base network is not straightforward. These variations are assessed, case by case, with Ofgem.

2.6 Interaction between the NOA results and the FES

In the *NOA*, we set out our vision for the future of the electricity transmission networks and European interconnection. Chapter 5 – 'Investment recommendations' explains our recommended options for onshore reinforcements, based on providing the maximum benefit for GB consumers, and Chapter 6 – 'Interconnection analysis' describes the future optimum interconnection capacity between GB and European markets. Both sets of results will influence our *FES* 2019 analysis, and will contribute to the credible assumptions for the *ETYS* 2019/20 and *NOA*. We've described the methodology for interconnection analysis in Chapter 6 – 'Interconnection analysis'.

2.7 Other options

2.7.1 Excluded options

While this report looks at options that could help meet major NETS reinforcement needs, it doesn't include:

- projects with no boundary benefit (unless they are specifically included for another reason, such as links to the Scottish islands that trigger the SWW category).
- options that provide benefits, such as voltage control over the summer minimum, but no boundary capability improvement (this is published separately as part of our pathfinding projects).
- analysis of options where the costs for the expected benefits would be prohibitive.
- long-term conceptual options submitted by the TOs to support the analysis; this is explained in more detail in the next section.

The final Needs Cases of the Scottish islands SWW, including Orkney link, Western Isles link, and Shetland link, were submitted to Ofgem for approval in 2018. We included a summary of these SWWs in our previous *NOA* publications when they were being developed, even though they are reinforcements for radial connections and don't provide benefit to a particular boundary. As they advance to the approval stage, we no longer include them as potential SWWs. These projects, however, are included in our competition assessment for connections.

The SWW Final Needs Case for Hinkley–Seabank project was approved by Ofgem in early 2018. The project is considered in the base networks and not assessed for cost and benefit in this *NOA*.

Work on the Wylfa–Pentir second double circuit is solely driven by a local generator connection agreement. The project is excluded for assessment of its wider benefit in this *NOA*. However, we have included it in our competition assessment as it meets the proposed criteria of onshore competition for electricity transmission. The most recent market intelligence suggests there is considerable uncertainty over the project's future.

2.7.2 Long-term conceptual options

Through the NOA process, we recommend options for the upcoming investment year, and optimum delivery dates for options over the next few decades. This long-term strategy allows the TOs to constantly evolve and develop their electricity transmission networks to deliver the best value for consumers.

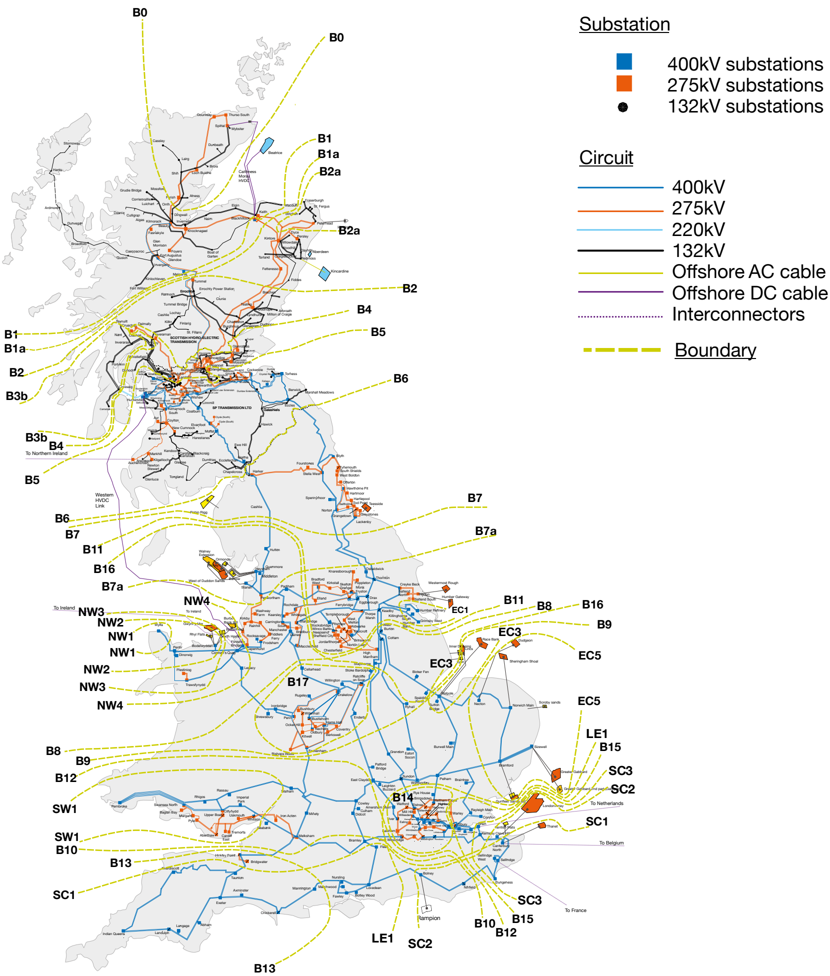
For this, we receive a wide range of options from the TOs for analysis and comparison, which we then assess for cost and benefit. However, development of reinforcement in the network will be a continuous process where the designs and costs for some option in the distant future are unknown. To represent these long-term eventual reinforcements in our economic analysis, the TOs also provide us with more conceptualised reinforcements to support the long-term future network.

Chapter 3
Boundary descriptions

3.1 Introduction

This section provides a short introduction to the boundaries on the NETS. You will find a fuller description in this year's *ETYS*. Figure 3.1 shows all the boundaries considered for this year's *NOA* analysis.

Figure 3.1
ETYS GB boundaries



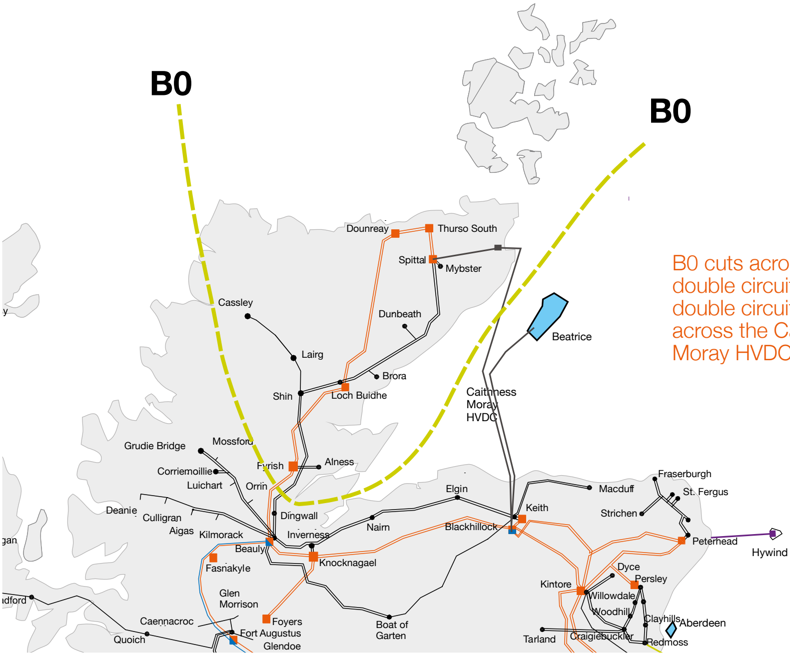
3.2 Scotland and the north of England region

3.2.1 Introduction

This section describes the NETS in Scotland and the north of England. The onshore transmission network in Scotland is owned by SHE Transmission and SP Transmission, but operated by National Grid as the electricity system operator.

3.2.2 Boundary B0 – Upper North SHE Transmission

Figure 3.2
Geographic representation of boundary B0

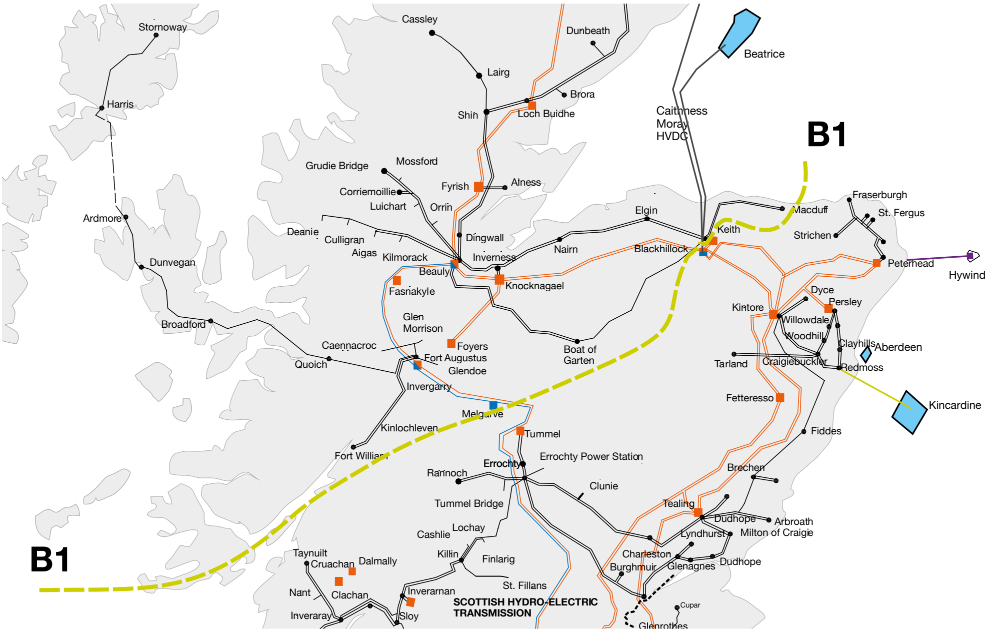


B0 cuts across a 275kV double circuit, a 132kV double circuit and across the Caithness–Moray HVDC cable.

Boundary B0 separates the area north of Beauly, comprising the north of the Highlands, Caithness, Sutherland and Orkney. The Caithness–Moray HVDC subsea cable, and associated onshore works, were completed in December 2018, and significantly strengthen the transmission network north of Beauly. Orkney is connected via a 33kV subsea link from Thurso. High renewables output causes high transfers across this boundary.

3.2.3 Boundary B1 – North West SHE Transmission

Figure 3.3
Geographic representation of boundary B1

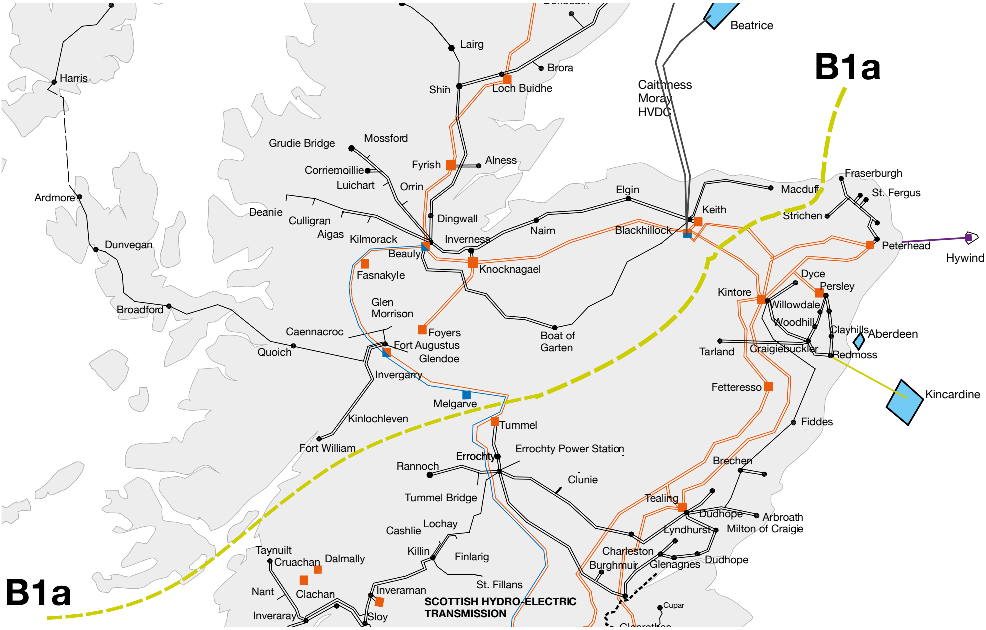


B1 crosses a 275kV double circuit, two 275/132kV auto-transformer circuits and a double circuit with one circuit at 400kV and the other at 275kV.

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. Because the boundary runs to the north of Blackhillock substation where the Caithness–Moray link connects, the link increases the boundary capability, allowing for increased power export. High renewables output causes high transfers across this boundary.

3.2.4 Boundary B1a – North West 1a SHE Transmission

Figure 3.4
Geographic representation of boundary B1a

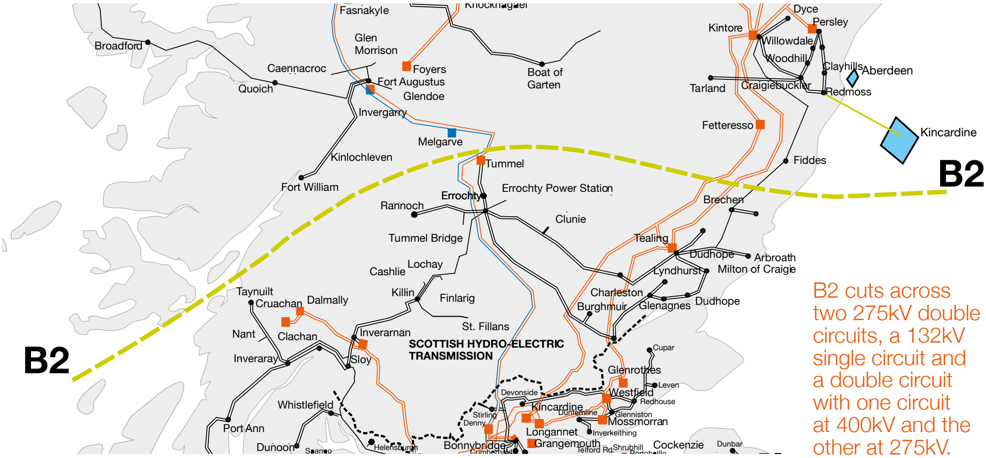


B1a crosses two 275kV double circuits and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B1a 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. High renewables output causes high transfers across this boundary. The difference from the B1 boundary is that Blackhillock substation is north of the B1a boundary.

3.2.5 Boundary B2 – North to South SHE Transmission

Figure 3.5
Geographic representation of boundary B2

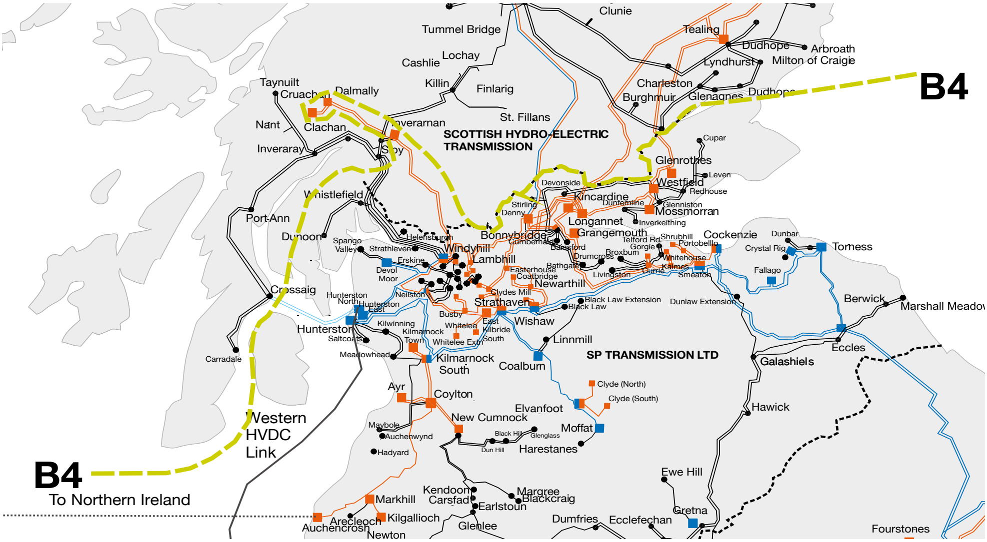


B2 cuts across two 275kV double circuits, a 132kV single circuit and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B2 cuts across the Scottish mainland from the east coast between Aberdeen and Dundee to near Oban on the west coast. It crosses all the main north-to-south transmission routes from the north of Scotland. As well as the wind and hydro renewable generation behind this boundary, the proposed North Connect interconnector with Norway will connect at Peterhead. This will affect loadings on the network as the interconnector transfers change between their extremes.

3.2.6 Boundary B4 – SHE Transmission to SP Transmission

Figure 3.6
Geographic representation of boundary B4

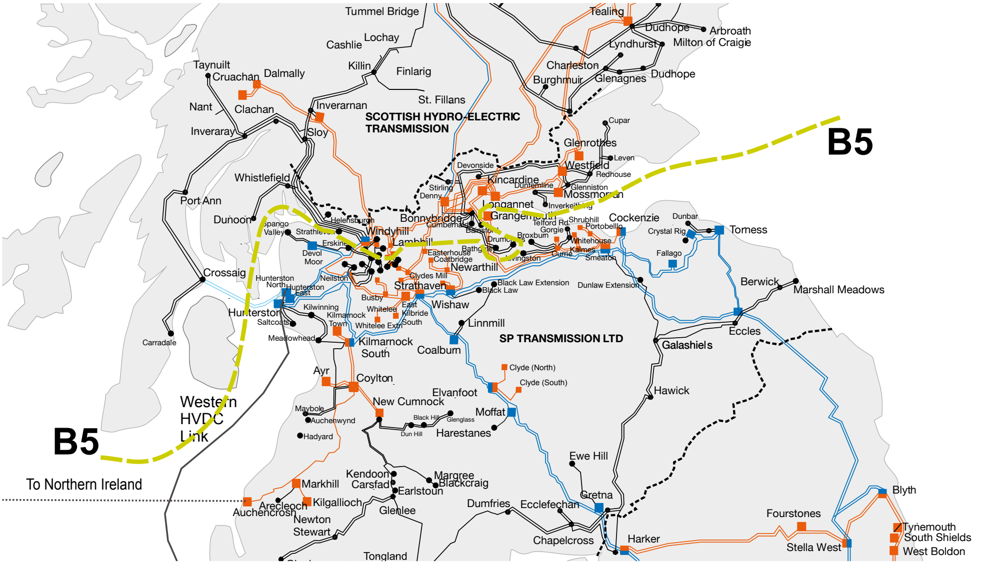


B4 cuts across two 275kV double circuits, two 132kV double circuits, two 275/132kV auto-transformer circuits, two 220kV subsea cables between Crossaig and Hunterston substations, and a double circuit with one circuit at 400kV and the other at 275kV.

Boundary B4 separates the transmission network at the SP Transmission and SHE Transmission interface, running from the Firth of Tay in the east to the Isle of Arran in the west. High renewables output causes high transfers across this boundary.

3.2.7 Boundary B5 – North to South SP Transmission

Figure 3.7
Geographic representation of boundary B5

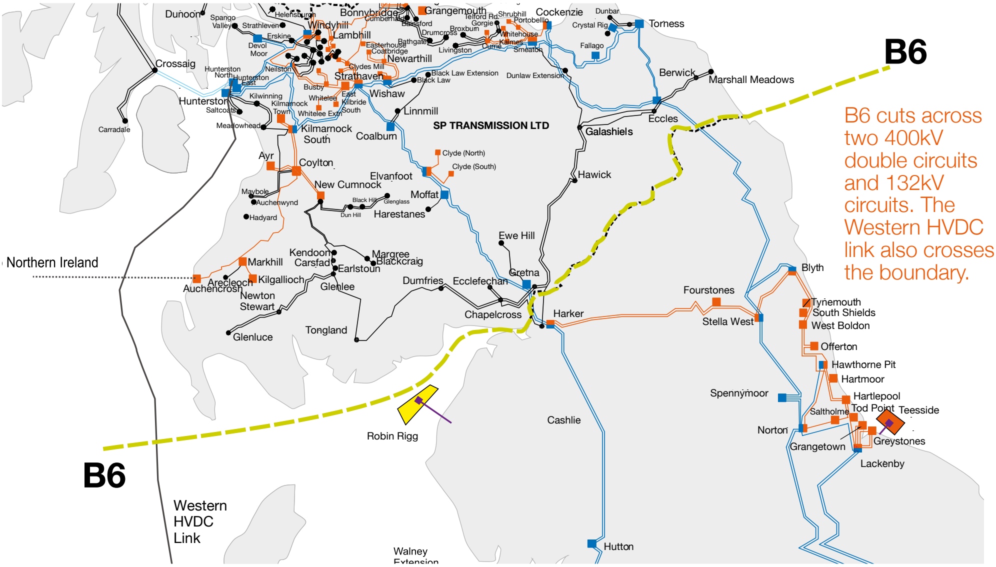


B5 cuts across three 275kV double circuits and a double circuit with one circuit at 400kV and the other at 275kV. The Kintyre–Hunterston subsea link provides two additional circuits crossing B5.

Boundary B5 is within the SP Transmission system and runs from the Firth of Clyde in the west to the Firth of Forth in the east. The pumped storage station at Cruachan, together with the demand groups served from Windyhill, Lambhill, Bonnybridge, Mossmorran and Westfield 275kV substations, are located north of boundary B5.

3.2.8 Boundary B6 – SP Transmission to National Grid Electricity Transmission (NGET)

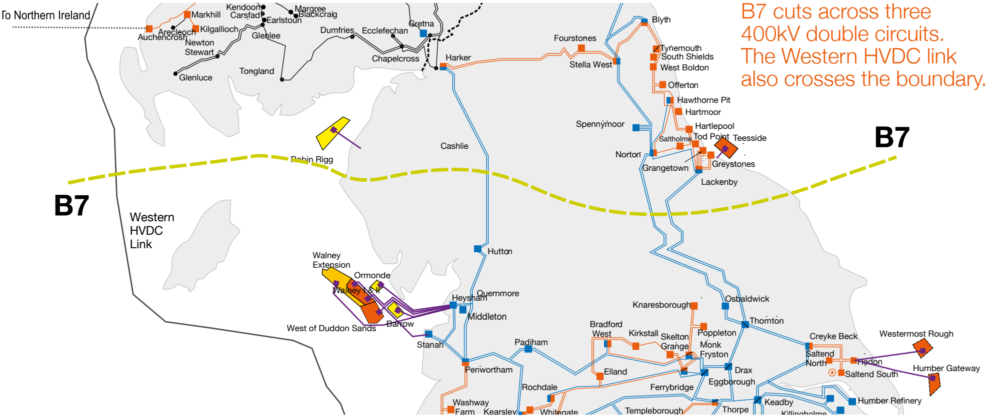
Figure 3.8
Geographic representation of boundary B6



Boundary B6 separates the SP Transmission and the National Grid Electricity Transmission (NGET) systems. Scotland has significantly more installed generation capacity than demand, increasingly from wind farms. Peak power flow requirements are typically from north to south at times of high renewable generation output, while large south-to-north power flows can happen during periods of low renewable generation output.

3.2.9 Boundary B7 – Upper North

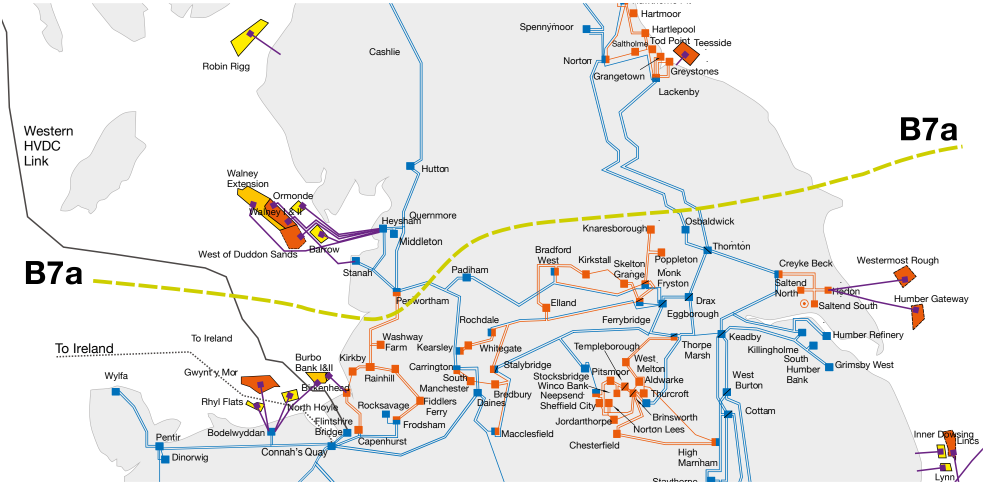
Figure 3.9
Geographic representation of boundary B7



Boundary B7 bisects England south of Teesside, cutting across Cumbria. The area between B6 and B7 has traditionally been an exporting area, constrained by power flowing through the region from Scotland towards the south including the generation surplus from this area.

3.2.10 Boundary B7a – Upper North

Figure 3.10
Geographic representation of boundary B7a

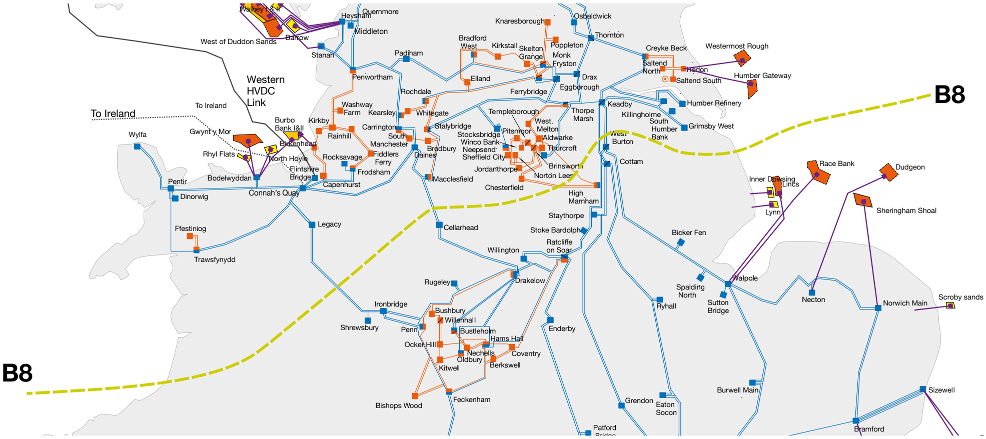


B7a cuts across three 400kV double circuits and one 275kV double circuit. The Western HVDC link also crosses the boundary.

Boundary B7a bisects England south of Teesside, across Lancashire and into the Mersey Ring area. It is used to capture network restrictions on the circuits feeding down through Liverpool, Manchester and Leeds.

3.2.11 Boundary B8 – North to Midlands

Figure 3.11
Geographic representation of boundary B8



B8 cuts across four 400kV double circuits and a limited 275kV connection to South Yorkshire.

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 North Wales, from the Midlands and southern demand centres.

3.3 The south and east of England region

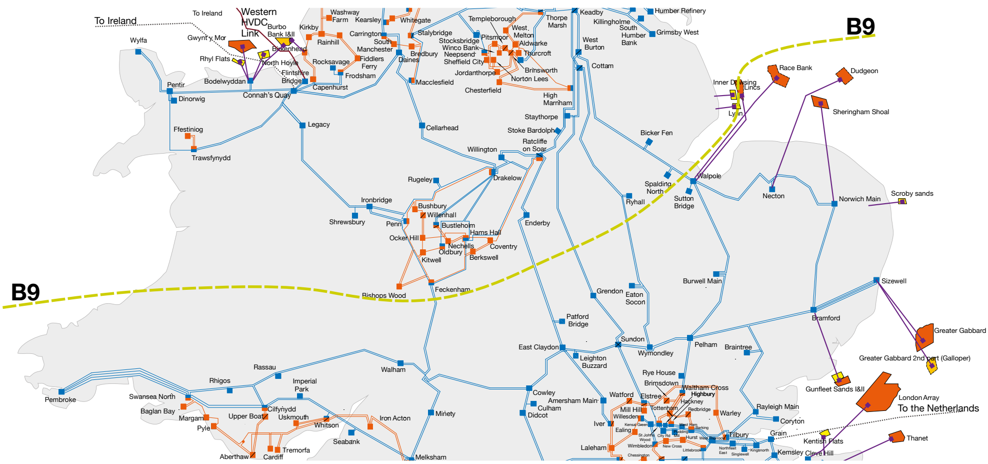
3.3.1 Introduction

The south and east region includes East Anglia and London, touches the Midlands and stretches along the south coast to Devon and Cornwall. It has a high concentration of power demand and generation, with much of the demand in London and generation in the Thames Estuary.

Interconnection to continental Europe is located on the south coast, and influences power flows in the region through the import and export of power with Europe.

3.3.2 Boundary B9 – Midlands to South

Figure 3.12
Geographic representation of boundary B9

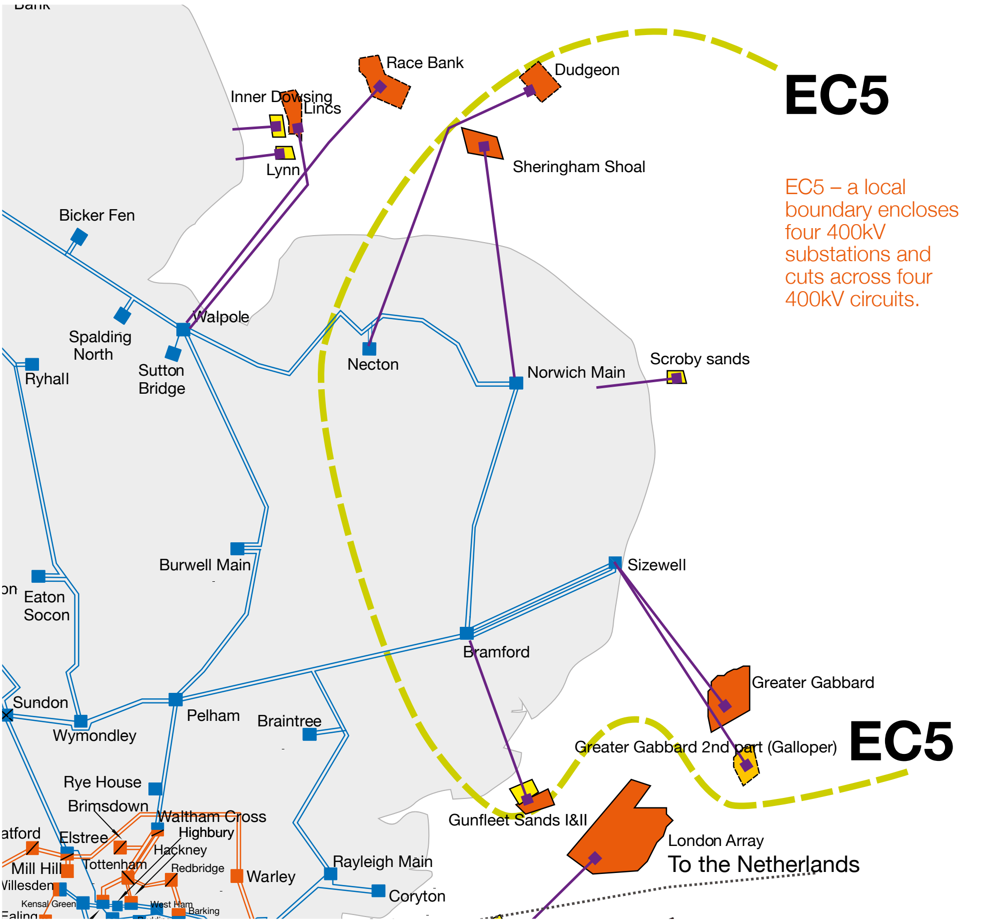


B9 cuts across five major 400kV double circuits transporting power over a long distance.

The Midlands-to-South boundary B9 separates the northern generation zones and the Midlands from the southern demand centres.

3.3.3 Boundary EC5 – East Anglia

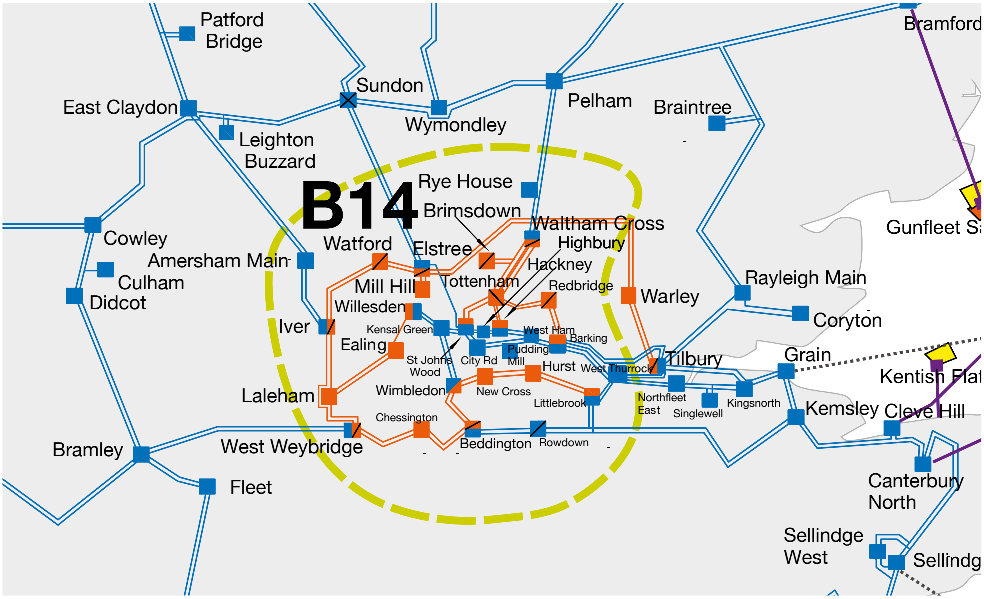
Figure 3.13
Geographic representation of boundary EC5



Boundary EC5 (East Coast 5) is a local boundary enclosing most of East Anglia. 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 for new nuclear generation development. Given the volume of possible generation, this boundary is likely to need reinforcement.

3.3.4 Boundary B14 – London

Figure 3.14
Geographic representation of boundary B14

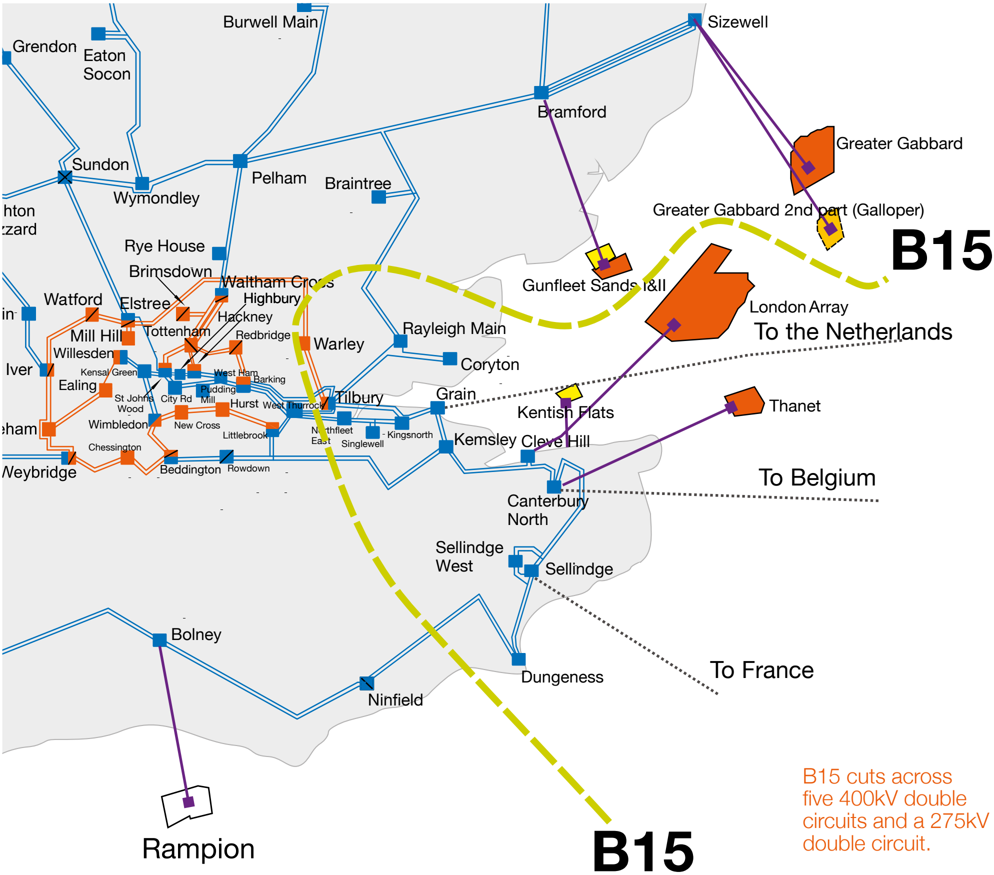


B14 cuts across eight 400kV double circuits and a 275kV double circuit.

Boundary B14 encloses London, and is characterised by high local demand and a small amount of generation. The circuits entering from the north can be heavily loaded during winter peak conditions. The circuits are further stressed when the European interconnectors export to the Continent.

3.3.5 Boundary B15 – Thames Estuary

Figure 3.15
Geographic representation of boundary B15

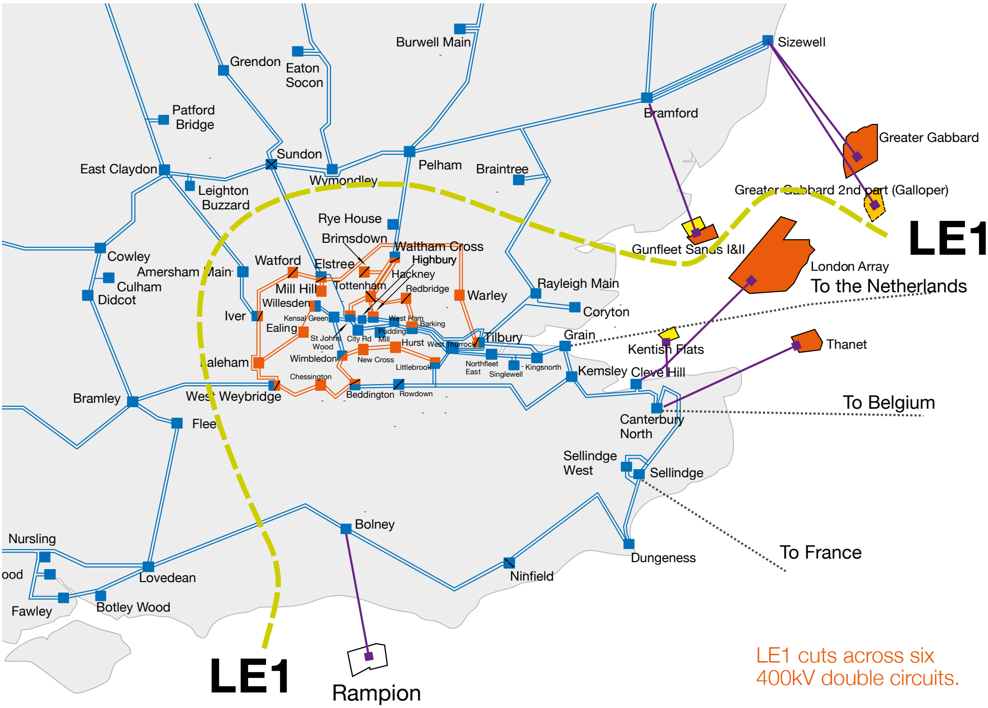


B15 cuts across five 400kV double circuits and a 275kV double circuit.

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 to London. The interconnectors greatly affect flows across boundary B15.

3.3.6 Boundary LE1 – South East

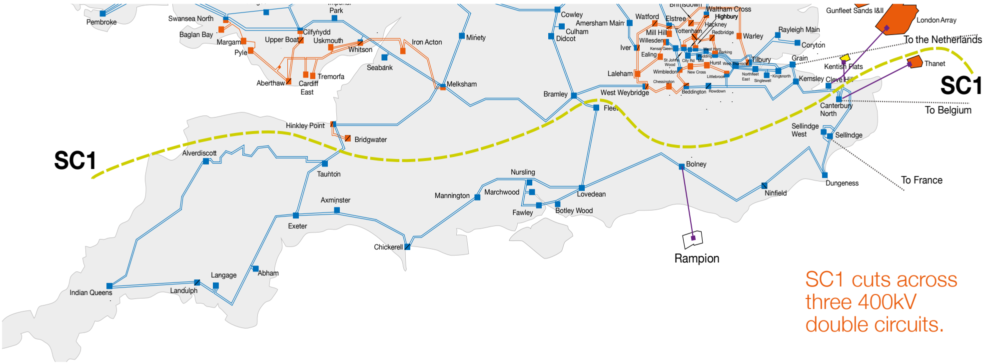
Figure 3.16
Geographic representation of boundary LE1



Boundary LE1 covers London and the areas to the south and east of it. Within London, there is high local demand and relatively small levels of generation. The south east part contains both high demand and relatively high levels of generation. There are also several current and potential future interconnectors to mainland Europe.

3.3.7 Boundary SC1 – South Coast

Figure 3.17
Geographic representation of boundary SC1

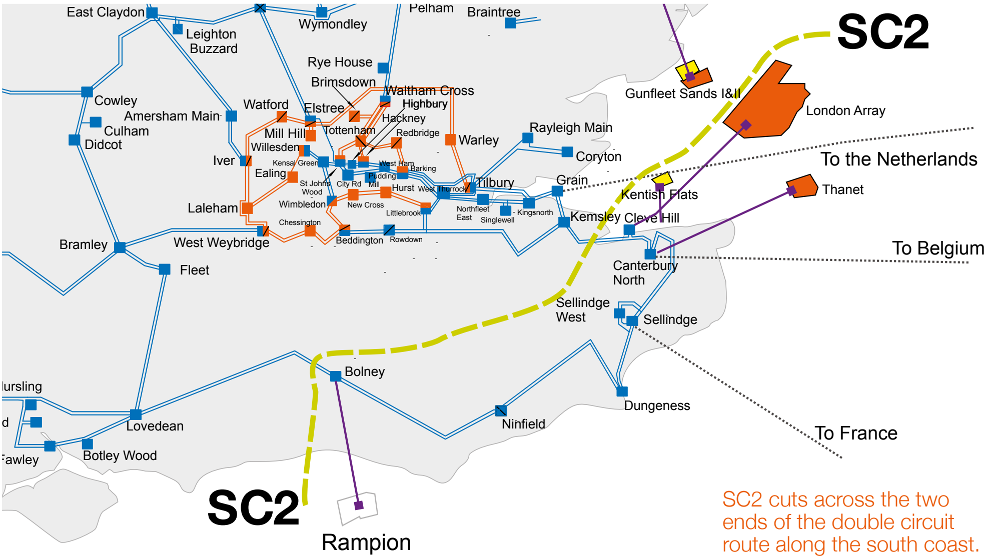


SC1 cuts across three 400kV double circuits.

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. Interconnector activity significantly influences boundary power flow.

3.3.8 Boundary SC2 – South East Coast

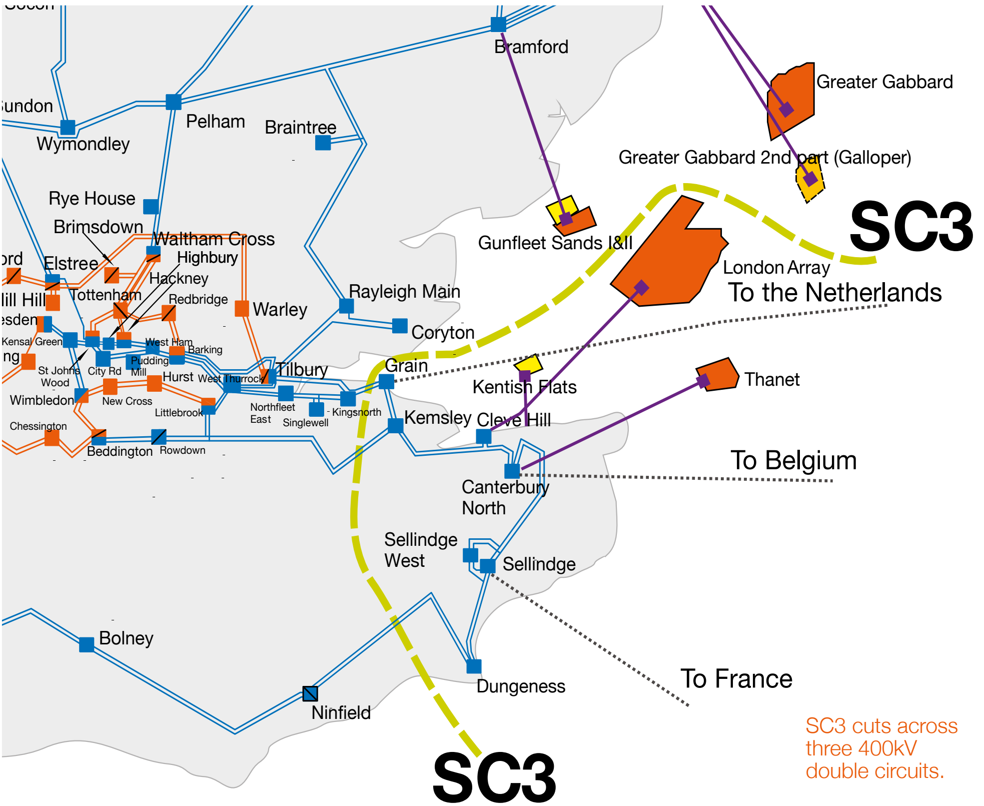
Figure 3.18
Geographic representation of boundary SC2



The south coast boundary SC2 takes in the relatively long 400kV route between Kemsley and Lovedean. It connects significant demand, and connects both large generators and interconnection to continental Europe.

3.3.9 Boundary SC3 – South Coast

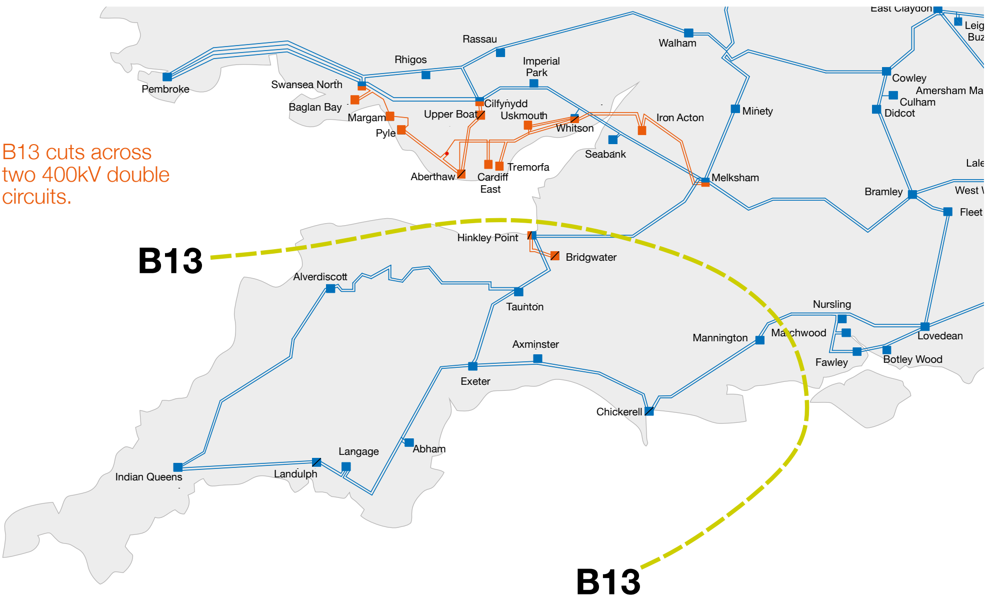
Figure 3.19
Geographic representation of boundary SC3



The south coast boundary SC3 captures transmission issues specifically in the south east part of the network. The current and future interconnectors to Europe have a massive impact on the power transfers across SC3. The current interconnectors to France and the Netherlands connect at Sellindge and Grain respectively.

3.3.10 Boundary B13 – South West

Figure 3.20
Geographic representation of boundary B13



Wider boundary B13 is defined as the southernmost tip of GB, below the Severn Estuary, encompassing Hinkley Point in the south west of England and stretching as far east as Mannington near Southampton. The South West Peninsula has a high level of localised generation and demand.

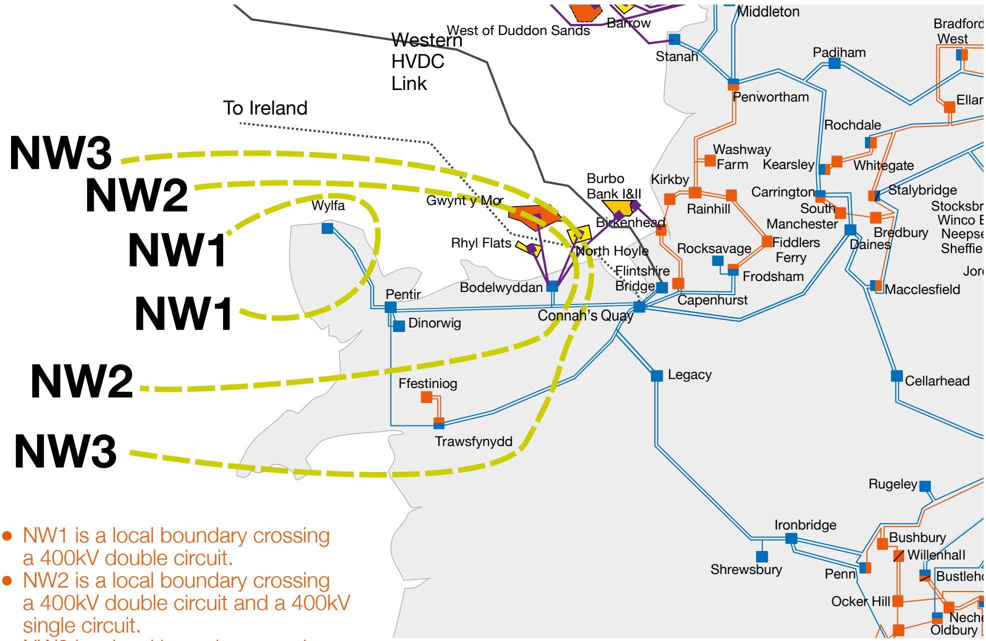
3.4 Wales and West Midlands region

3.3.1 Introduction

The Wales and West Midlands region is dominated by North Wales boundaries and a South Wales boundary, while other boundaries in the region aren't active.

3.4.2 Boundaries NW1, NW2 and NW3 – North Wales

Figure 3.21
Geographic representation of boundaries NW1, NW2 and NW3

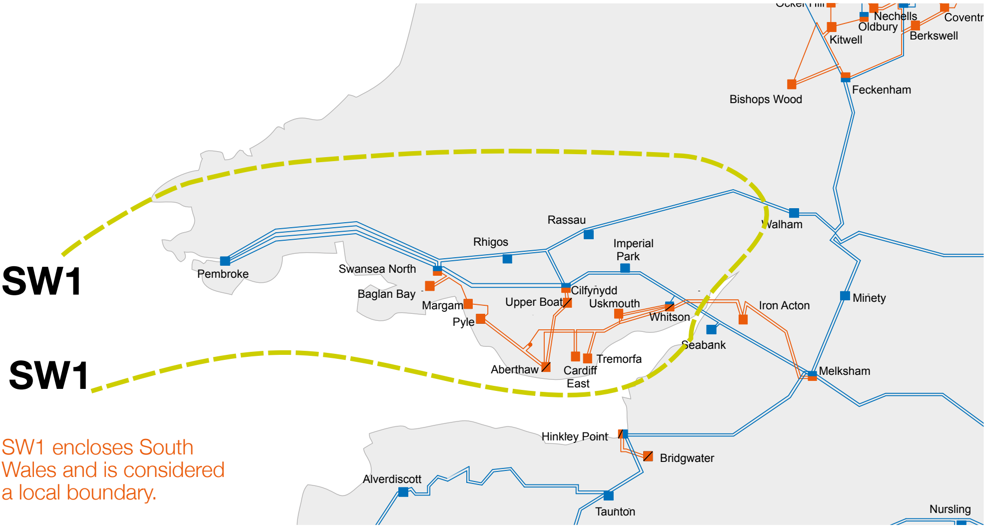


- NW1 is a local boundary crossing a 400kV double circuit.
- NW2 is a local boundary crossing a 400kV double circuit and a 400kV single circuit.
- NW3 is a local boundary crossing a pair of 400kV double circuits.

The onshore network in North Wales comprises a 400kV circuit ring that connects Pentir, Deeside/ Connah's Quay and Trawsfynydd substations. A short 400kV double-circuit cable spur from Pentir connects Dinorwig pumped-storage power station. Pentir and Trawsfynydd are in the Snowdonia National Park, and are connected by a single 400kV circuit, which is the main limiting factor for capacity in this area. The 'NW' boundaries are local boundaries.

3.4.3 Boundary SW1 – South Wales

Figure 3.22
Geographic representation of boundary SW1



SW1 encloses South Wales and is considered a local boundary.

Within the boundary are a number of thermal generators powered by coal. Some of the older power stations are expected to close in the future but significant amounts of new generation capacity are expected to connect, including generators powered by wind, gas and tidal. South Wales includes demand consumptions from the major cities, including Swansea and Cardiff, and the surrounding industry.

Chapter 4
Proposed options

4.1 Introduction

This chapter lists the reinforcement options that could increase the NETS boundary capability as part of network planning.

For the *NOA* 2018/19 we have carried out assessments to identify options that could benefit boundary transfers. We have included the status of each option, whether it is a build option or an alternative option, and some background. We've also included a summary of options that have started the SWW process in Appendix B.

The *NOA* methodology gives more details about alternative options, but these typically include reduced-build or operational options. Reduced-build options require little expenditure, and do not typically involve the addition or replacement of large assets. These can include overhead line conductor re-profiling to increase operating temperature limits, or additional cooling. Operational options usually provide additional transfer capabilities without physically uprating the network. This is normally achieved by operational measures (e.g. special running arrangements), sometimes together with commercial arrangements, to allow the network to operate at its full potential.

As the ESO, we also have a role in identifying offshore options that may provide an alternative solution to meet boundary transfer requirements. The feasibility of interconnection between offshore generation depends on their status and timing. Any additional offshore works (regardless of whether developer or non-developer associated) will require relevant current Offshore Transmission System Development User Works (OTSDUW) Users to take part, as it will affect their design and construction programme. In addition, the technology used in offshore connections is still developing, and there is a level of uncertainty in the design of the connection. This makes it harder to finalise the works required for the Offshore Wider Works (OWW). Establishing any OWW after generators have been connected incurs high cost and major modifications to the offshore transmission networks owned by multiple Offshore TOs (OFTOs). For these reasons, no offshore options have been identified this year. We are planning further consultations with relevant parties on potential offshore interconnected designs – based on cost-benefit analysis – as technology choices stabilise and integration opportunities arise.

Our methodology for the ESO's assessment of OWW is included in the *NOA* methodology.

4.2 Reinforcement options – Scotland and the north of England region

FBRE

Beauly to Fyrish 275kV double circuit reconductoring

Status: Scoping
Boundaries affected: B0

Reconductor the existing 275kV double circuit overhead line between Beauly and Fyrish with a higher rated conductor.

DNEU

Denny North 400/275kV Supergrid Transformer 2

Status: Scoping
Boundaries affected: B1, B1a, B2

Installation of a new 400/275kV 1,000MVA supergrid transformer (SGT2) at Denny North 400kV substation.

TURC

Reactive compensation at Tummel

Status: Optioneering
Boundaries affected: B1, B1a, B2

Establish a 275kV double busbar at Tummel substation and install shunt reactive compensation.

ECU2

East coast onshore 275kV upgrade

Status: Design/development and consenting
Boundaries affected: B1, B1a, B2, B4

Establish a new 275kV substation at Alyth, re-profile the 275kV circuits between Kintore, Fetteresso, Alyth and Kincardine, and Tealing, Westfield and Longannet, and uprate the cable sections at Kincardine and Longannet to match the enhanced rating. Extend Tealing 275kV substation and install two phase-shifting transformers. Install shunt reactive compensation at the new Alyth substation.

ECUP

East coast onshore 400kV incremental reinforcement

Status: Design/development and consenting
Boundaries affected: B1, B1a, B2, B4

This builds on the 'east coast onshore 275kV upgrade (ECU2)' and upgrades the 275kV infrastructure on the east coast for 400kV operation. Establish a new 400kV substation at Kintore and uprate Alyth substation (proposed under ECU2) for 400kV operation. Re-insulate the 275kV circuits between Blackhillock, Peterhead, Rothienorman, Kintore, Fetteresso, Alyth and Kincardine for 400kV operation. Install phase-shifting transformers at Blackhillock on the 275kV circuits from Knocknagael and 400/275kV transformers at Kincardine, Alyth, Fetteresso, Kintore and Rothienorman.

ECU4 **East coast onshore 400kV reinforcement** Status: Design/development and consenting Boundaries affected: B1, B1a, B2, B4	Upgrade the 275kV infrastructure on the east coast for 400kV operation by establishing new 400kV substations at Kintore and Alyth, and re-insulating the 275kV circuits between Blackhillock, Peterhead, Rothienorman, Kintore, Fetteresso, Alyth and Kincardine to 400kV. Install shunt reactive compensation at the new Alyth substation, phase-shifting transformers at Blackhillock on the 275kV circuits from Knocknagael, and 400/275kV transformers at Kincardine, Alyth, Fetteresso, Kintore and Rothienorman. Re-profile the 275kV circuits between Tealing, Westfield and Longannet, and uprate the cable sections at Longannet to match the enhanced rating.
E4DC **Eastern Scotland to England link: Peterhead to Hawthorn Pit offshore HVDC** Status: Design/development and consenting Boundaries affected: B1, B1a, B2, B4, B5, B6, B7, B7a	Construct a new offshore 2GW HVDC subsea link from Peterhead in the north east of Scotland to Hawthorn Pit in the north of England. The onshore works involve the construction of AC/DC converter stations and the associated AC works at Peterhead and Hawthorn Pit.
E4D2 **Eastern Scotland to England link: Peterhead to Cottam offshore HVDC** Status: Design/development and consenting Boundaries affected: B1, B1a, B2, B4, B5, B6, B7, B7a, B8	Construct a new offshore 2GW HVDC subsea link from Peterhead in the north east of Scotland to Cottam in north Nottinghamshire. The onshore works involve the construction of AC/DC converter stations and the associated AC works at Peterhead and Cottam.
E4D3 **Eastern Scotland to England link: Peterhead to Drax offshore HVDC** Status: Design/development and consenting Boundaries affected: B1, B1a, B2, B4, B5, B6, B7, B7a, B8	Construct a new offshore 2GW HVDC subsea link from Peterhead in the north east of Scotland to Drax in Yorkshire. The onshore works involve the construction of AC/DC converter stations and the associated AC works at Peterhead and Drax.
KBRE **Knocknagael to Blackhillock 275kV double circuit reconductoring** Status: Scoping Boundaries affected: B4	Reconductor the existing 275kV double circuit overhead line between Knocknagael and Blackhillock with a higher rated conductor.

DWNO **Denny to Wishaw 400kV reinforcement** Status: Design/development Boundaries affected: B4, B5, B6	Construct a new 400kV double circuit from Bonnybridge to Newarthill, and reconfigure associated sites to establish a fourth north-to-south double circuit supergrid route through the Scottish central belt. One side of the new double circuit will operate at 400kV, the other at 275kV. This reinforcement will establish Denny–Bonnybridge, Bonnybridge–Wishaw, Wishaw–Strathaven No.2 and Wishaw–Torness 400kV circuits, and a Denny–Newarthill–Easterhouse 275kV circuit.
HNNO **Hunterston East–Neilston 400kV reinforcement** Status: Design/development Boundaries affected: B5	Modification of the Hunterston East–Devol Moor 400kV circuit to become the Hunterston East–Neilston 400kV double circuit overhead line (OHL), and development of a new 400/275kV supergrid transformer (SGT4) at Neilston 400kV substation.
WLTI **Windyhill–Lambhill–Longannet 275kV circuit turn-in to Denny North 275kV substation** Status: Design/development Boundaries affected: B5	Turn the Windyhill–Lambhill–Longannet 275kV circuit into Denny North 275kV substation to create a 275kV Windyhill–Lambhill–Denny North circuit and a Denny North–Longannet No.2 275kV circuit.
E2D2 **Eastern Scotland to England link: Torness to Cottam offshore HVDC** Status: Scoping Boundaries affected: B5, B6, B7, B7a, B8	Construction of a new offshore 2 GW HVDC subsea link from Torness area to Cottam to provide additional transmission capacity. The onshore works involve the construction of AC/DC converter stations and associated AC works at Torness and Cottam.
E2D3 **Eastern Scotland to England link: Torness to Drax offshore HVDC** Status: Scoping Boundaries affected: B5, B6, B7, B7a, B8	Construction of a new offshore 2 GW HVDC subsea link from Torness area to Drax to provide additional transmission capacity. The onshore works involve the construction of AC/DC converter stations and associated AC works at Torness and Drax.
E2DC **Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC** Status: Scoping Boundaries affected: B5, B6, B7, B7a, B8	Construct a new offshore 2 GW HVDC subsea link from the Torness area to Hawthorn Pit to provide additional transmission capacity. The onshore works involve the construction of AC/DC converter stations and associated AC works at Torness and Hawthorn Pit.

HAMS **225MVAr MSC at Harker** Status: Project not started Boundaries affected: B6	Install a 225MVAr MSC at Harker 400kV substation. This would provide voltage support under a number of fault conditions due to high power flow from Scotland.
ECVC **Eccles SVCs and real-time rating system** Status: Scoping Boundaries affected: B6	Installation of two SVCs at Eccles 400kV substation, and a real-time ratings system on the 400kV overhead line circuits between Moffat and Harker and Gretna and Harker and 400kV cable circuits between Crystal Rig and Torness.
EHRE **Elvanfoot to Harker reconductoring** Status: Scoping Boundaries affected: B6	Replace the double circuit conductors in the Elvanfoot to Harker circuits with a higher-rated conductor to increase their thermal ratings.
MHPC **Power control device along Harker to Gretna and Harker to Moffat** Status: Project not started Boundaries affected: B6	Install a power control device along the Harker to Gretna and Harker to Moffat 400kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.
NEMS **225MVAr MSCs within the north east region** Status: Project not started Boundaries affected: B6, B7, B7a	Three new 225MVAr switched capacitors (MSCs) at Norton, Osbaldwick and Stella West 400kV substations would provide voltage support to the east side of the transmission network as future system flows increase.
HAE2 **Harker Supergrid Transformer 5 replacement** Status: Project not started Boundaries affected: B6, B7, B7a	Replacing an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.
HAEU **Harker Supergrid Transformer 6 replacement** Status: Scoping Boundaries affected: B6, B7, B7a	Replacing an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.

HSIT

Harker to Stella West circuit intertrip

Status: Project not started
Operational option
Boundaries affected: B6, B7, B7a

Disconnect the Harker to Stella West 275kV circuits following faults on Stella West 400kV circuits to avoid overloading the 275kV circuits.

STSC

Series capacitors at Stella West

Status: Project not started
Boundaries affected: B6, B7, B7a

Install 2 new series reactors on north feeder circuits at Stella West 400kV substation. This would increase the voltage stability when the circuits are highly loaded.

SSHW

Spennymoor to Stella West circuits thermal uprating

Status: Project not started
Boundaries affected: B6, B7, B7a

Thermal upgrade of the Spennymoor to Stella West circuits to allow them to operate at higher temperatures, and increase their thermal rating.

WHTI

Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit

Status: Scoping
Boundaries affected: B6, B7, B7a

Turn-in the West Boldon to Hartlepool circuit, to connect to the Hawthorn Pit site it currently passes. This would create new West Boldon to Hawthorn Pit and Hawthorn Pit to Hartlepool circuits and ensure better load flow sharing and increased connectivity in the north east 275kV ring.

NEPC

Power control device along Blyth to Tynemouth and Blyth to South Shields

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Blyth to Tynemouth and Blyth to South Shields 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

HFPC

Power control device along Fourstones to Harker

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Fourstones to Harker 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

HSS1

Power control device along Fourstones to Harker to Stella West

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Fourstones to Harker to Stella West 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

HSS2

Power control device along Fourstones to Harker to Stella West

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Fourstones to Harker to Stella West 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

FSPC

Power control device along Fourstones to Stella West

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Fourstones to Stella West 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

HSPC

Power control device along Harker to Stella West

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Harker to Stella West 275kV overhead line route. This would improve the capability to control the power flows from north to south of the transmission network.

LNPC

Power control device along Lackenby to Norton

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Lackenby to Norton 400kV circuit overhead line route. This would improve the capability to control the power flows across the east and west of the transmission network.

NOPC

Power control device along Norton to Osbaldwick

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Norton to Osbaldwick 400kV circuit overhead line route. This would improve the capability to control the power flows across the east and west of the transmission network.

MRPC

Power control device along Penwortham to Kirkby

Status: Project not started
Reduced-build option
Boundaries affected: B6, B7, B7a, B8

Install a power control device along the Penwortham to Kirkby 275kV circuit overhead line route. This would improve the capability to control the power flows across the east and west of the transmission network.

TLNO

Torness to north east England AC reinforcement

Status: Project not started
Boundaries affected: B6, B7, B7a, B8

This option provides additional transmission capacity by installing a double circuit from a new 400kV substation in the Torness area to a suitable connection point in north east England.

HSRE

Reconductor Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuit

Status: Project not started
Boundaries affected: B6, B7, B7a, B8, B9

Replace the conductors from Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuits with higher-rated conductors to increase the circuits' thermal ratings.

SPDC

Stella West to Padiham HVDC link

Status: Project not started
Boundaries affected: B6, B7, B7a, B8, B9

Construct a new onshore 1 GW HVDC Link from Stella West to Padiham to improve power flow around the eastern side of the network. The works involve the construction of AC/DC converter stations and reconfiguration of Stella West and Padiham substations.

LTR3

Lackenby to Thornton 1 circuit thermal upgrade

Status: Project not started
Boundaries affected: B7, B7a

Thermal upgrade of the Lackenby to Thornton 1 circuit to allow it to operate at higher temperatures and increase its thermal rating.

OTHW

Osbaldwick to Thornton 1 circuit thermal upgrade

Status: Project not started
Reduced-build option
Boundaries affected: B7, B7a

Thermal upgrade of the Osbaldwick to Thornton 1 circuit to allow it to operate at higher temperatures and increase its thermal rating.

NOR1

Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit

Status: Scoping
Boundaries affected: B7, B7a

Replace some of the conductors in the Norton to Osbaldwick double circuit with higher-rated conductors to increase the circuits' thermal ratings.

NOR2

Reconductor 13.75km of Norton to Osbaldwick 1 400kV circuit

Status: Project not started
Boundaries affected: B7, B7a

Replace some of the conductors in Norton to Osbaldwick 1 circuit with higher-rated conductors to increase the circuit's thermal rating.

NOR4

Reconductor 13.75km of Norton to Osbaldwick 2 400kV circuit

Status: Project not started
Boundaries affected: B7, B7a

Replace some of the conductors in Norton to Osbaldwick 2 circuit with higher-rated conductors to increase the circuit's thermal rating.

LNRE

Reconductor Lackenby to Norton single 400kV circuit

Status: Design
Boundaries affected: B7, B7a

Replace the conductors in the Lackenby to Norton single circuit with higher-rated conductors, and replace the cable with one with higher rating to increase the circuit's thermal rating. The two options have different conductor types that provide different ratings.

NOHW

Thermal uprate 55km of the Norton to Osbaldwick 400kV double circuit

Status: Project not started
Boundaries affected: B7, B7a

Thermal upgrade of the Norton to Osbaldwick circuits to allow them to operate at higher temperatures and increase their thermal rating.

OENO

Central Yorkshire reinforcement

Status: Project not started
Boundaries affected: B7, B7a, B8

Construct a new 400kV double circuit in central Yorkshire to facilitate power transfer requirements across the relevant boundaries. Substation works might be required to accommodate the new circuits.

TDR2

Reconductor Drax to Thornton 1 circuit

Status: Project not started
Reduced-build option
Boundaries affected: B7, B7a, B8

Replace the conductors in the Drax to Thornton 1 circuit with higher-rated conductors to increase the circuit's thermal rating.

TDR1

Reconductor Drax to Thornton 2 circuit

Status: Project not started
Reduced-build option
Boundaries affected: B7, B7a, B8

Replace the conductors in the Drax to Thornton 2 circuit with higher-rated conductors to increase the circuit's thermal rating.

TDRE

Reconductor Drax to Thornton double circuit

Status: Project not started
Boundaries affected: B7, B7a, B8

Replace the conductors in the Drax to Thornton double circuit with higher-rated conductors to increase the circuits' thermal ratings.

GKRE

Reconductor the Garforth Tee to Keadby leg of the Creyke Beck to Keadby to Killingholme circuit

Status: Project not started
Boundaries affected: B7, B7a, B8

Replace the conductor on the Keadby leg of the Creyke Beck to Keadby to Killingholme three-ended circuit. This would raise the circuit's thermal rating.

DREU

Generator circuit breaker replacement to allow Thornton to run a two-way split circuit

Status: Project not started
Boundaries affected: B7, B7a, B8, B9

This reinforcement is to replace generator owned circuit breakers with higher-rated equivalents including substation equipment. This would allow higher fault levels, which improves load sharing on circuits connecting to the substation.

THS1

Install series reactors at Thornton

Status: Project not started
Boundaries affected: B7, B7a, B8, B9

Install series reactors at Thornton substation. These would connect the parts of the site at present being operated disconnected from one another to limit fault levels. The reactors would allow flow sharing between the different parts of the site and reduce thermal overloads on connected circuits.

LDQB

Lister Drive quad booster

Status: Design
Boundaries affected: B7a

Replace the series reactor at Lister Drive with a quad booster to allow better control of power flows through the single cable to Birkenhead and avoid thermal overloads in the Mersey Ring area.

CPRE

Reconductor sections of Penwortham to Padiham and Penwortham to Carrington

Status: Project not started
Boundaries affected: B7a

Replace some of the conductor sections in the Penwortham to Padiham and Penwortham to Carrington circuits with higher-rated conductors to increase the circuits' thermal ratings.

MRUP

Uprate the Penwortham to Washway Farm to Kirkby 275kV double circuit to 400kV

Status: Scoping
Boundaries affected: B7a

Reinsulate the Penwortham to Washway Farm to Kirkby double circuit to allow operation at 400kV. Other associated works at Kirkby substation are to transform voltage from 400kV to 275kV and replace the Washway Farm 275/132kV transformers with 400/132kV transformers. The option would prevent thermal overloads on these circuits.

DCCA

Cellarhead to Daines cable replacement

Status: Project not started
Boundaries affected: B8

Upgrade cable of the Cellarhead to Daines circuit with a larger cable section increasing the circuit's thermal rating.

CBEU **Creyke Beck to Keadby advance rating** Status: Project not started Reduced-build option Boundaries affected: B8	Using historical weather data, Creyke Beck to Keadby 400kV overhead line enhanced thermal rating is established to cope with high flows from the north east of the transmission network.
KWHW **Keadby to West Burton circuits thermal uprating** Status: Project not started Boundaries affected: B8	Thermal upgrade of the Keadby to West Burton circuits to allow them to operate at higher temperatures, and increase their thermal rating.
HPNO **New east–west circuit between the north east of England and Lancashire** Status: Project not started Boundaries affected: B8	Construct a new 400kV double circuit in the north of England to increase power export capability from the north of England into the rest of the transmission system. The exact landing points are to be determined. This is the first of two outline options.
NPNO **New east–west circuit between the north east and Lancashire** Status: Project not started Boundaries affected: B8	Construct a new 400kV double circuit in the north of England to increase power export capability from the north of England into the rest of the transmission system. The exact landing points are to be determined. This is the second of two outline options.
CDRE **Cellarhead to Drakelow reconductoring** Status: Project not started Boundaries affected: B8, B9	Replace the conductors on the existing double circuit from Cellarhead to Drakelow with higher-rated conductors to increase their thermal rating.

4.3 Reinforcement options – the south and east of England region

MBRE **Bramley to Melksham reconductoring** Status: Project not started Boundaries affected: B13	Replace the conductors in the Bramley to Melksham circuits with higher-rated conductors to increase their thermal ratings.
HMHW **Hinkley Point to Melksham circuits thermal uprating** Status: Scoping Reduced-build option Boundaries affected: B13	Thermal upgrade of the Hinkley Point to Melksham circuits to allow them to operate at higher temperatures, and increase their thermal rating.
THRE **Reconductor Hinkley Point to Taunton double circuit** Status: Project not started Boundaries affected: B13, SC1	Replace the conductors in the Hinkley Point to Taunton circuits with higher-rated conductors to increase the circuits' thermal ratings.
SER1 **Elstree to Sundon reconductoring** Status: Project not started Boundaries affected: B14, LE1	Replace the conductors from Elstree to Sundon circuit 1 with higher-rated conductors to increase their thermal rating.
SER2 **Elstree to Sundon 2 circuit turn-in and reconductoring** Status: Project not started Boundaries affected: B14, LE1	Turn-in the Elstree to Sundon circuit 2 to connect to the Elstree 400kV substation it currently passes and replace the conductor with a higher-rated conductor. This would ensure better load flow sharing and increase the thermal rating.
ESC1 **Second Elstree to St John's Wood 400kV circuit** Status: Project not started Boundaries affected: B14, LE1	New second 400kV cable transmission circuit in the tunnel from Elstree to St John's Wood and carry out associated work, including modifying Elstree 400kV and St John's Wood 400kV substations. This will improve the power flow into London.

HWUP

Uprate Hackney, Tottenham and Waltham Cross 275kV to 400kV

Status: Project not started
Boundaries affected: B14, LE1

Hackney, Tottenham and Waltham Cross substation uprate from 275kV to 400kV, and the double circuit route connecting them. This will strengthen the power flow into London, via Rye House, down to Hackney.

WYQB

Wymondley quad boosters

Status: Project not started
Boundaries affected: B14, LE1

Install a pair of quad boosters on the double circuits running from Wymondley to Pelham at the Wymondley 400kV substation. These would improve the capability to control the power flows on the North London circuits.

WYTI

Wymondley turn-in

Status: Scoping
Boundaries affected: B14, LE1

Modify the existing circuit that runs from Pelham to Sundon with a turn-in at Wymondley to create two separate circuits that run from Pelham to Wymondley and from Wymondley to Sundon. This will improve the balance of flows.

TKRE

Tilbury to Grain and Tilbury to Kingsnorth upgrade

Status: Scoping
Boundaries affected: B15

Replace the conductors in the Tilbury to Grain and Tilbury to Kingsnorth circuits with higher-rated conductors, and replace the associated cables with larger cables of a higher rating, including Tilbury, Grain and Kingsnorth substation equipment. This will increase the circuits' thermal ratings.

KLRE

Kemsley to Littlebrook circuits uprating

Status: Design/development
Boundaries affected: B15, SC1, B14

The 400kV circuits running from Kemsley via Longfield Tee to Littlebrook would be reconductored with higher-rated conductors.

BMMS

225MVAr MSCs at Burwell Main

Status: Scoping
Boundaries affected: EC5

Three new 225MVAr switched capacitors (MSCs) at Burwell Main would provide voltage support to the East Anglia area as future system flows increase.

BTNO

A new 400kV double circuit between Bramford and Twinstead

Status: Scoping
Boundaries affected: EC5

Construct a new 400kV double circuit between Bramford substation and Twinstead tee point to create double circuits between Bramford and Pelham and Bramford to Braintree to Rayleigh Main. It would increase power export capability from East Anglia into the rest of the transmission system.

NBRE

Reconductor Bramford to Norwich double circuit

Status: Project not started
Boundaries affected: EC5

The double circuit that runs from Norwich to Bramford would be reconductored with a higher-rated conductor.

BRRE

Reconductor remainder of Bramford to Braintree to Rayleigh route

Status: Project not started
Boundaries affected: EC5

Replace the conductors in the parts of the existing Bramford to Braintree to Rayleigh overhead line that have not already been reconductored, with higher-rated conductors, to increase the circuit's thermal rating.

CTRE

Reconductor remainder of Coryton South to Tilbury circuit

Status: Scoping
Boundaries affected: EC5

Replace the conductors on the remaining sections of the Coryton South to Tilbury circuit, which have not recently been reconductored, with higher-rated conductors. These would increase the circuit's thermal rating.

BPRE

Reconductor the newly formed second Bramford to Braintree to Rayleigh Main circuit

Status: Project not started
Boundaries affected: EC5

Replace the conductors of the newly formed second Bramford to Braintree to Rayleigh Main circuit, that has not already been reconductored, with higher-rated conductors. This would increase the circuit's thermal rating following the new 400kV double circuit between Bramford and Twinstead.

RRRE

Reconductor the newly formed second Bramford to Pelham circuit

Status: Project not started
Boundaries affected: EC5

Replace the conductors of the newly formed second Bramford to Pelham circuit, that has not already been reconductored, with higher-rated conductors. This would increase the circuit's thermal rating following the new 400kV double circuit between Bramford and Twinstead.

RTRE

Reconductor remainder of Rayleigh to Tilbury circuit

Status: Scoping
Boundaries affected: EC5, B15

Replace the conductors on the remaining sections of the Rayleigh to Tilbury circuit, which have not recently been reconductored, with higher-rated conductors. These would increase the circuit's thermal rating.

COVC

Two hybrid STATCOMS at Cottam

Status: Project not started
Boundaries affected: LE1

Install two hybrid STATCOMs at Cottam. This will increase the voltage stability when the circuits are highly loaded.

BMM3 **225MVAr MSC at Burwell Main** Status: Project not started Boundaries affected: LE1	One new 225MVAr switched capacitor (MSC) at Burwell Main would provide voltage support to the East Anglia area as future system flows increase.
BMM2 **225MVAr MSCs at Burwell Main** Status: Project not started Boundaries affected: LE1	Two new 225MVAr switched capacitors (MSCs) at Burwell Main would provide voltage support to the East Anglia area as future system flows increase.
EAMS **225MVAr MSCs at Eaton Socon** Status: Project not started Boundaries affected: LE1	Two new 225MVAr switched capacitors (MSCs) at Eaton Socon would provide voltage support to the East Anglia area as future system flows increase.
PEM1 **225MVAr MSC at Pelham** Status: Project not started Boundaries affected: LE1	One new 225MVAr switched capacitor (MSC) at Pelham would provide voltage support through East Anglia and North London as future system flows increase.
PEM2 **225MVAr MSC at Pelham** Status: Project not started Boundaries affected: LE1	One new 225MVAr switched capacitor (MSC) at Pelham would provide voltage support through East Anglia and North London as future system flows increase.
RHM1 **225MVAr MSC at Rye House** Status: Project not started Boundaries affected: LE1	One new 225MVAr switched capacitor (MSC) at Rye House would provide voltage support through East Anglia and North London as future system flows increase.
RHM2 **225MVAr MSC at Rye House** Status: Project not started Boundaries affected: LE1	One new 225MVAr switched capacitor (MSC) at Rye House would provide voltage support through East Anglia and North London as future system flows increase.
EWNO **Ealing to Willesden 275kV second circuit and quad booster** Status: Project not started Boundaries affected: LE1	Create a second Ealing to Willesden 275kV circuit and carry out associated work including modifying Ealing 275kV substation by rerouting Willesden to Wimbledon circuit with quad booster.

COSC

Series compensation south of Cottam

Status: Project not started
Boundaries affected: LE1

Install series capacitors at Cottam feeder circuits connecting to Grendon, Ryhall, and Staythorpe. This will increase the stability when the circuits are highly loaded.

BFHW

Bramley to Fleet circuits thermal uprating

Status: Project not started
Boundaries affected: SC1

Thermal upgrade of the Bramley to Fleet circuits to allow them to operate at higher temperatures, and increase their thermal rating.

BFRE

Bramley to Fleet reconductoring

Status: Project not started
Boundaries affected: SC1

Replace the conductors in the Bramley to Fleet circuits with higher-rated conductors to increase their thermal ratings.

IFHW

Feckenham to Ironbridge circuits thermal uprating

Status: Project not started
Boundaries affected: SC1

Thermal upgrade of the Feckenham to Ironbridge circuits to allow them to operate at higher temperatures, and increase their thermal ratings.

FMHW

Feckenham to Minety circuit thermal uprating

Status: Project not started
Boundaries affected: SC1

Thermal upgrade of the Feckenham to Minety single circuit to allow it to operate at higher temperatures, and increase its thermal rating.

FLPC

Power control device along Fleet to Lovedean route

Status: Project not started
Boundaries affected: SC1

Install a power control device along the Fleet to Lovedean 400kV circuit overhead line route. This would improve the capability to control the power flows south of the transmission network.

GKEU

Thermal upgrade for Grain and Kingsnorth 400kV substation

Status: Project not started
Boundaries affected: SC1, B15

Thermal upgrade of the 400kV Grain and Kingsnorth substation equipment to increase its thermal capacity, supporting future load flow within the area.

BNRC **Bolney and Ninfield additional reactive compensation** Status: Scoping Boundaries affected: SC1, SC2	Provide additional reactive compensation equipment at Bolney and Ninfield substations to maintain voltages within acceptable operational limits in future network operating conditions.
FLR2/FLRE **Fleet to Lovedean reconductoring** Status: Design/development Boundaries affected: SC1, SC2	Replace the conductors in the Fleet to Lovedean circuits with higher-rated conductors to increase their thermal ratings. The two options have different conductor types that provide different ratings.
SEEU **Reactive compensation protective switching scheme** Status: Design Boundaries affected: SC1, SC2	Provide a new communications system and other equipment to allow existing reactive equipment to be switched in or out of service very quickly following transmission system faults. This would allow better control of system voltages following faults.
SCN1 **New 400kV transmission route between South London and the south coast** Status: Scoping Boundaries affected: SC1, SC2, B15	Construct a new transmission route from the south coast to South London and carry out associated work. These works would provide additional transmission capacity between South London and the south coast.
BDEU **Bramley to Didcot circuits thermal uprating** Status: Project not started Boundaries affected: SW1	Thermal upgrade of the Bramley to Didcot circuits and construct a second single core per phase cable section on one circuit to allow them to operate at higher temperatures, and increase their thermal rating.
GRRA **Grain running arrangement change** Status: The status not applicable as it is an operational solution Operational option Boundaries affected: SC3	Change the running arrangement configuration at Grain 400kV substation so that is split into two sections. The circuit loading balance is improved following faults.

4.4 Reinforcement options – Wales and West Midlands region

PTC2

Pentir to Trawsfynydd 1 and 2 cables – second core per phase and reconductor of an overhead line section on the existing Pentir to Trawsfynydd circuit

Status: Scoping
Boundaries affected: NW2

Replace the conductors in part of the circuits between Pentir and Trawsfynydd with higher-rated conductors. Construct a second single core per phase cable section on these circuits. These two activities would increase the circuits' thermal ratings.

PTC1

Pentir to Trawsfynydd 1 cable replacement – single core per phase

Status: Scoping
Boundaries affected: NW2

Replacing cable sections of the Pentir to Trawsfynydd 1 circuit with large cable sections, increasing the circuit's thermal rating.

PTRE

Pentir to Trawsfynydd circuits – reconductor the remaining overhead line sections

Status: Scoping
Boundaries affected: NW2

Replace the conductors in the remaining parts of the circuits between Pentir and Trawsfynydd with higher-rated conductors to further increase the circuits' thermal ratings.

PTNO

Pentir to Trawsfynydd second circuit

Status: Scoping
Boundaries affected: NW2

Create a second Pentir to Trawsfynydd 400kV circuit by using the existing circuit infrastructure and corridor, including constructing new cable sections.

BCRE

Reconductor the Connah's Quay legs of the Pentir to Bodelwyddan to Connah's Quay 1 and 2 circuits

Status: Project not started
Boundaries affected: NW3

Replace the conductors in the sections between Bodelwyddan and Connah's Quay on the Pentir to Bodelwyddan to Connah's Quay double circuit with higher-rated conductors to increase the circuits' thermal ratings.

SWEU

South Wales (Cardiff to Bristol) region thermal uprating

Status: Project not started
Boundaries affected: SW1

Replace the conductors, transformers and quad boosters in the Cardiff to Bristol region to increase their thermal capability.

SWHW

South Wales (Cardiff to Swansea) region thermal uprating

Status: Project not started
Boundaries affected: SW1

Replace the 275kV conductors in the Cardiff to Swansea region with higher-rated conductors to increase their thermal capability.

4.5 Commercial solutions

Commercial solutions, such as generator intertrips and fast de-loading schemes, are able to relieve network constraints in certain conditions and therefore provide network benefits. We procure these as services from certain users of the network. Payment for the service is subject to the scale and competitiveness of the market.

In the *NOA* 2017/18, we studied commercial solutions at the end of our assessment as an interim option based on the optimal combinations of asset-based reinforcements identified. In this assessment, they are included in a similar way as the asset-based reinforcements and embedded into the final optimal paths, depending on where they are needed. We also consider a broader range of assumptions for the solutions including effectiveness, service durations, and costs. These improvements enhance the credibility of the results.

As commercial solutions can be contracted flexibly, they don't have a fixed 'asset life'. We consider each with two different service durations[1] – 15-year and 40-year for comparisons, also making them comparable to the asset life assumption we make on the asset-based reinforcements. We factor the availability and arming fee into the operational costs based on our historical data, while the actual usage fee is not included as it is low when discounted over 15 or 40 years (we assume the chances to use the services are low).

Commercial solutions are not free of capital costs, but only need minimal initial investment (mostly on communication and control systems). This, together with the flexibility of their contracts, makes commercial solutions a reasonable alternative option. We believe the commercial solutions will deliver additional value to GB consumers, even though these are still being developed. We propose to refine the details of these schemes once we have completed the market testing later this year.

CS01

A commercial solution for Scotland and the north of England with a 40-year service duration

Boundaries affected: B6 and B7a

This commercial solution has a duration of 40 years and provides boundary benefit across Anglo–Scottish border and further south.

CS03

A commercial solution for Scotland and the north of England with a 15-year service duration

Boundaries affected: B6 and B7a

This commercial solution has a duration of 15 years and provides boundary benefit across Anglo–Scottish border and further south.

CS21

A commercial solution for East Anglia with a 40-year service duration

Boundaries affected: EC5

This commercial solution has a duration of 40 years and provides boundary benefit across EC5 in the East Anglia region.

[1] Please note that a service duration of 15 or 40 years can be achieved by a single contract or multiple contracts. The exact forms of these contracts are not limited, but subject to the market testing results.

CS25

A commercial solution for the south coast with a 40-year service duration

Boundaries affected: SC1 and SC2

This commercial solution has a duration of 40 years and provides boundary benefit across SC1 and SC2 on the south coast.

Chapter 5
Investment recommendations

5.1 Introduction

Chapter 5 presents our investment recommendations from our economic analysis. The results give the most economic investment strategy for each scenario and enable us to identify our preferred options and the recommended next steps for works required in each region.

Key statistics
In 2019/20, the TOs are recommended to invest £59.84 million on reinforcement options with a total investment of almost £5.39 billion over their lifetime. We also recommend continuing the development of commercial solutions as they deliver additional consumer benefit. Of the 115 options submitted for evaluation, 27 options (including 25 asset-based options and two ESO-led commercial solutions) have a 'Proceed' recommendation. Our analysis considered what is truly necessary as the energy landscape changes and significant savings are possible from deferring expenditure.

We recommend deferring the delivery of two projects that may have committed over £111 thousand of spend this investment year. Our *NOA* 2018/19 recommendations are based on robust economic analysis, then subject to further scrutiny by our NOA Committee. This ensures that development of the GB transmission network will continue to support the transition to the future energy landscape in an efficient, economical and coordinated way.

£59.8m
Investing £59.84m this year

25
Through 25 asset-based options

£5.4bn
Total cost of £5.39bn

2
Develop 2 ESO-led commercial solutions

£1.1bn
Additional consumer benefits of up to £1.1bn[1]

[1] This is the additional savings in constraint cost driven by the ESO-led commercial solutions during 2020 to 2028.

Figure 5.1
How the options went through the process

115 options submitted for economic analysis (109 asset-based options and 6 ESO-led options)

75 options optimal under at least one scenario

40 options non-optimal

31 options' decisions considered critical

44 options' decisions considered non-critical

Stop progressing with 5 options that are non-optimal

Do not start with the remaining 35 non-optimal options

Proceed with the delivery of 27 options

44 options to be put on hold

Delay the delivery of 2 options

Hold the delivery of one option

Do not start the delivery of one option

5.2 Interpretation of the NOA outcomes

This section explains how to interpret the NOA outcomes including the economic analysis results and our investment recommendations.

5.2.1 Optimal path and optimum delivery date

Our cost-benefit analysis investigates the economic benefits of different combinations of reinforcement options across four Future Energy Scenarios. Under each scenario, we identified an optimal path to deliver a selection of options in a certain sequence to maximise the benefits for GB consumers. We consider an option to be optimal if it is included in the optimal path of at least one scenario. It is non-optimal if it does not appear in any optimal paths.

The optimal path not only shows the most economic options but also their optimum completion years. If an option's optimum delivery date is its current Earliest In Service Date (EISD) in at least one scenario, it is considered a critical option, as an investment decision must be made by the TOs and/or relevant parties this year to be able to meet the optimum delivery date. If under all scenarios, the optimum delivery date(s) of an option is later than its EISD, the option is non-critical and a decision can be put on hold until there is greater certainty.

5.2.2 Critical options' single year least regret analysis

A decision on each critical option must be made this year by the TOs and/or relevant parties, hence it is further assessed in our single year least regret analysis. This measures and compares the regret of delivering each critical option against the regret of not delivering it. If a region has multiple critical options, we compare the regret of delivering different combinations of critical options. We always recommend the option, or combination of options, that minimises the levels of regret across all scenarios. If an option is driven by a single scenario, we will further investigate the drivers to ensure we make the right recommendation.

Economic regret
In the economic analysis, the regret of an investment strategy is the net benefit difference between that strategy and the best strategy for that scenario. Therefore, under each scenario, the best strategy will have a regret of zero, and the other strategies will have different levels of regret depending on how they compare to the best strategy. We always choose the strategy with the least regret across all scenarios.

For more information, please see Chapter 2 – 'Methodology'.

5.2.3 Investment recommendations

Following the cost-benefit analysis and single year least regret analysis, we present the results to the NOA Committee for additional scrutiny. It focuses on the marginal options where recommendations indicated by the economic analysis are driven by a single scenario or factor, or are considered sensitive in terms of stakeholder engagement.

The NOA Committee brings expertise from across the ESO, including knowledge on operability challenges, network capability development, commercial operations and insight into future energy landscapes. It aims to provide a final set of recommendations for the marginal options. With the endorsement from the NOA Committee, we can recommend a decision for each option. All options will be allocated to one of the following outcomes:

- **Proceed:** Work should continue, or start, to maintain the EISD.
- **Delay:** The option is optimal and critical, but it is not economical to be delivered by its EISD. Delivery should be delayed by one year.
- **Hold:** The option is optimal but not critical and an investment decision should be put on hold. Delivery of this option should be delayed by at least one year.
- **Stop:** The option is currently non-optimal. Delivery should not be continued.
- **Do not start:** The option is currently non-optimal. Delivery should not begin.

An option we don't recommend to proceed with can (and would be expected to) still be considered in any relevant SWW assessment.

As our energy landscape is changing, our recommendations for an option may adapt accordingly. This means that an option that we recommended to proceed last year may be recommended to be delayed this year, and vice versa. The benefit of the single year least regret analysis is that an ongoing project is re-evaluated each year to ensure its planned completion date remains best for the consumer.

5.2.4 Eligibility for onshore competition

In November 2016, Ofgem published its decision on 'Extending Competition In Transmission' (ECIT[2]) which sets the future direction of travel for competition in onshore electricity transmission under the Competitively Appointed Transmission Owner (CATO) model. However, following Ofgem's update on ECIT in June 2017[3], development of the CATO regime has now been deferred due to a delay in introducing relevant legislation. Ofgem is pursuing competition in alternative forms during the RIIO-T1 period, but has indicated that it still intends to develop long-term arrangements for competition in onshore electricity transmission, along with other broader regulatory frameworks, for the RIIO-T2 period. In 2018, Ofgem launched an informal consultation on changes to Standard Licence Condition C27[4]. It proposed new requirements for the ESO to assess projects recommended for further development in the *NOA*, for their eligibility for competition, and to undertake the same competition suitability assessments on future generator and demand connections to the transmission system.

We believe it is sensible and pragmatic to continue to include an assessment for competition in this *NOA*.This includes options we recommend to proceed this year, SWW projects with Needs Case initiated, and contracted connections.

In the competition assessment, we use three criteria – 'new', 'separable' and 'high value' proposed by Ofgem in its latest guidance[5] as indicators that an option is eligible for onshore competition. The option must fulfil all criteria to be considered.

- To assess if the option meets the 'new' criterion, we test whether they involve the implementation of completely new assets or the complete replacement of an existing transmission asset.
- To assess if the option meets the 'separable' criterion, we test whether new assets can be clearly delineated from other (existing) assets.
- To assess if the option meets the 'high value' criterion, we assess whether the capital expenditure for the assets which meet the new and separable criteria is £100 million or more. We check costs provided by the TOs as part of our NOA process.

[2] https://www.ofgem.gov.uk/system/files/docs/2016/11/ecit_november_2016_decision.pdf

[3] https://www.ofgem.gov.uk/system/files/docs/2017/06/update_on_extending_competition_in_transmission.pdf

[4] https://www.ofgem.gov.uk/system/files/docs/2018/01/c27_consultation.pdf

[5] https://www.ofgem.gov.uk/system/files/docs/2018/01/draft_criteria_guidance.pdf

5.3 The NOA outcomes

This section presents the results of our economic analysis, investment recommendations, and eligibility for onshore competition.

In our economic analysis, we separated the GB network into three regions – Scotland and the north of England; the south and east of England; and Wales and West Midlands – where reinforcement options for one region have little or no impact on the other two. We present the economic analysis results on this basis.

For each region, we focus on the following aspects to identify our final investment recommendations:

- The optimal paths by scenario, which highlight optimal options and their delivery dates.
- Critical options from the optimal paths and single year least regret analysis, which produces the 'Proceed' and 'Delay' recommendations.
- Drivers such as system needs or changes to the energy landscape and network.

The main outputs of the economic analysis, including optimal paths and initial investment recommendations, are shown in Table 5.1 to 5.3 for the three regions. The optimal options are listed in four-letter codes (as detailed in Chapter 4) with the optimum delivery dates highlighted in different colours for different scenarios. If an option is not in the optimal path of a scenario, no optimum delivery year will be highlighted for that scenario.

Several critical options could be progressed this year, giving a number of combinations, one of which will have the lowest value of worst regret across all scenarios. The options that make up this combination will be recommended to proceed.

The initial recommendations are indicated by different shadings in Table 5.1 to 5.3. Forty options are currently not optimal under any of the scenarios and are not included in those tables. The initial recommendation for those is either 'Do not start' or 'Stop' depending on whether work is already in progress.

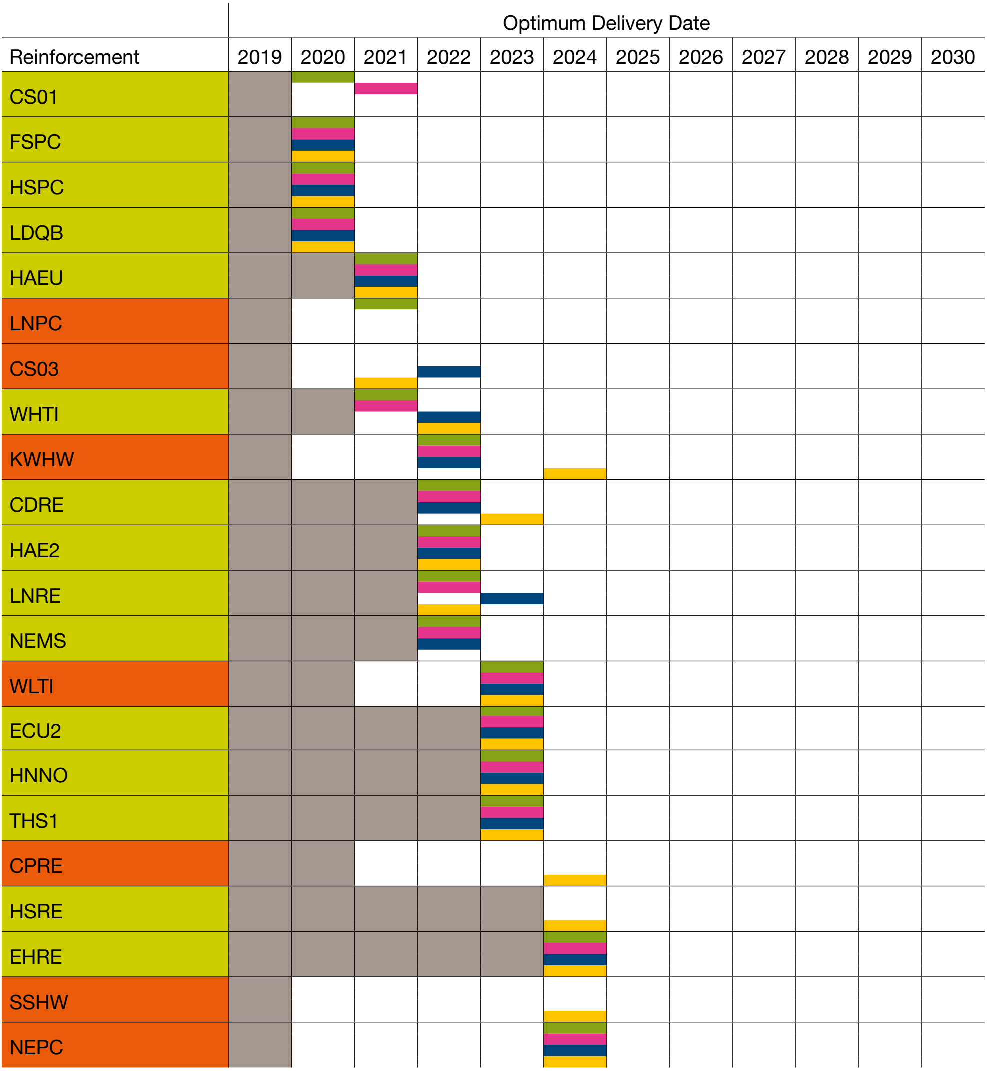
The economic analysis and initial recommendations were then further scrutinised by the NOA Committee and the final recommendation for each of the options is shown in Table 5.4 to 5.6. There are differences between initial and final recommendations for some options. Explanations for those are included as part of our regional narratives. In the interests of transparency, we will publish minutes from the NOA Committee meetings on our website.

A full list of optimal options for each region with descriptions and optimum delivery dates can be found in Appendix A.1-3. Critical options are in bold. Some options are marked as 'N/A' as they are not optimal under that particular scenario.

Results for the top performing combinations from our single year least regret analysis are in Appendix A.4-6. The worst regret for each combination is in bold and the combination with the smallest worst regret is highlighted in green.

5.3.1 Scotland and the north of England region

Table 5.1
Scotland and the north of England region



Key:
Optimum year indicator for Two Degrees; Optimum year indicator for Community Renewables
Optimum year indicator for Consumer Evolution; Optimum year indicator for Steady Progression
EISD not yet reached; Critical option to 'Proceed'; Non-critical option to 'Hold'

Table 5.1
Scotland and the north of England region (continued)

	Optimum Delivery Date											
Reinforcement	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NOR1												
NOR2												
NOR4												
NOHW												
CBEU												
ECUP												
TDRE												
DNEU												
ECVC												
E2DC												
OENO												
DWNO												
OTHW												
TDR2												
TURC												
E4D3												
KBRE												

Key:
Optimum year indicator for Two Degrees
Optimum year indicator for Community Renewables
Optimum year indicator for Consumer Evolution
Optimum year indicator for Steady Progression
EISD not yet reached
Critical option to 'Proceed'
Non-critical option to 'Hold'

For Scotland and the north of England region, we identified 39 optimal options as shown in Table 5.1. Their optimum delivery dates are highlighted in different colours for different scenarios.

Of the 39 optimal options, 20 are critical and they could present more than a million different possible combinations of 'Proceed' and 'Delay' recommendations. The optimum delivery years of the following options are the same as their EISDs across all four scenarios.

- **Power control device along Fourstones to Stella West** (FSPC).
- **Power control device along Harker to Stella West** (HSPC).
- **Lister Drive quad booster** (LDQB).
- **Harker SuperGrid Transformer 6 replacement** (HAEU).
- **Harker SuperGrid Transformer 5 replacement** (HAE2).
- **East coast onshore 275kV upgrade** (ECU2).
- **Hunterston East–Neilston 400kV reinforcement** (HNNO).
- **Install series reactors at Thornton** (THS1).
- **Elvanfoot to Harker reconducting** (EHRE).
- **East coast onshore 400kV incremental reinforcement** (ECUP).
- **Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC** (E2DC).
- **Eastern Scotland to England link: Peterhead to Drax offshore HVDC** (E4D3).

These 12 options don't need to be assessed in the single year least regret analysis, as progressing them to maintain their EISDs is the optimum course of action under all scenarios.

Having taken account of the options above, this leaves eight critical options and 256 different possible combinations of the following reinforcements:

- **A commercial solution for Scotland and the north of England with a 40-year service duration** (CS01).
- **Cellarhead to Drakelow reconductoring** (CDRE).
- **Denny to Wishaw 400kV reinforcement** (DWNO).
- **Reconductor Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuit** (HSRE).
- **Reconductor Lackenby to Norton single 400kV circuit** (LNRE).
- **225MVAr MSCs within the north east region** (NEMS).
- **Central Yorkshire reinforcement** (OENO).
- **Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit** (WHTI).

We performed the single year least regret analysis on all 256 combinations. The least regret strategy is to proceed with all critical options in Scotland and the north of England region. The 10 top performing combinations are listed in Appendix A.4.

The results explained in more detail:

For the first time, we included commercial solutions[6] in the assessment in the same way as the asset-based options. Commercial solutions are usually procured by the ESO from service providers, so they don't have a fixed 40-year asset life. We have considered two commercial solutions in Scotland and the north of England with different assumptions on their service durations (15 years and 40 years) for comparisons. They are aimed to relieve congestions around the Anglo-Scottish border and further south, especially when certain asset-based options are yet to be delivered. We found that both commercial solutions are needed under two of the four scenarios, where the one with a 40-year service duration (CS01) is required as soon as it can be delivered in the Two Degrees scenario. As no capital expenditure is associated with these commercial solutions[7], there is no regret in progressing them. Since these commercial solutions are still being developed by the ESO, there is a potential risk of consumer disbenefit if they are not delivered and other asset-based options have been delayed. We have carried out further analysis into the impact of commercial solutions on the optimal paths. We found their impact on the Two Degrees, Consumer Evolution, and Slow Progression paths is minimal, and the Community Renewables path isn't affected.

The only asset-based reinforcement, whose recommendation is affected by commercial solutions, is the Harker MSC (HAMS). This option is marginally required under the Steady Progression scenario when commercial solutions are excluded for consideration, but not required in any optimal paths with commercial solutions. We presented these to the NOA Committee for further scrutiny and agreed the development of commercial solutions should continue for its benefit, and the recommendation for HAMS should remain 'Do not start'.

[6] See Chapter 4 – 'Proposed options' about commercial solutions.

[7] Although we assumed no capital expenditure is associated with the commercial solutions, these options will actually require asset investment, but mostly on communication and protection systems. These costs are relatively low when compared to the service costs over their service durations.

We identified a need for at least two Anglo-Scottish reinforcements (each with a capacity of 2 GW) to alleviate constraints on the northern boundaries. This is driven by the increasing level of renewable generation in Scotland and is consistent with our findings in the *NOA* 2017/18. We considered two alternative landing points (Drax and Cottam), comprising six eastern HVDC link options (four new for this *NOA*). The landing points of these new options are further south than in the initial proposal. This means the new options are more expensive but are able to direct flows to a less constrained area, which can be more beneficial for consumers. We have assessed all available combinations of eastern HVDC link options. These, however, exclude two links connecting to the same location in north east England for several reasons, such as deliverability and negative impacts on nearby boundaries (i.e. this will double the power injection to one location from 2 to 4 GW and unnecessarily trigger additional reinforcements).

Results show that the first eastern HVDC link – Torness to Hawthorn Pit (E2DC) – is needed on its EISD (2027) across all scenarios. This is the most inexpensive option and the earliest that can be delivered. Therefore, there is a strong case for this option, and it is consistent with the *NOA* 2017/18 recommendation. The second eastern HVDC link – Peterhead to Drax (E4D3) – is recommended to be delivered on its EISD in 2029. It is also critical under all scenarios. The other option – Peterhead to Cottam (E4D2) – is non-optimal. Even though this option lands further south, the extra benefit is outweighed by its additional capital cost.

Central Yorkshire reinforcement (OENO) was recommended to be put on hold by the *NOA* 2017/18 so its delivery can be aligned with E2DC. For this assessment, its EISD is revised (from 2026 to 2027) as part of the 2017/18 Network Development Policy Output[8] (published by NGET TO) and is the same as E2DC's. The reinforcement is crucial for constraint management in north east England, especially after the eastern HVDC links are commissioned. In this assessment, it is found critical under all scenarios except Consumer Evolution. The constraints under the Consumer Evolution scenario are relatively low, which is not enough to justify its investment. Its benefits to the other three scenarios are mainly driven by constraints on the northern English boundaries between 2027 and 2029 when the second eastern HVDC link (E4D3) is not yet available. Our recommendation is to proceed with this option.

The recommendations for the eastern link options and associated onshore reinforcements are very much dependent on their deliverability. If E2DC or OENO cannot be delivered on time, the advantage of E2DC is greatly diminished. On the other hand, the alternative options (from Torness to Drax and Cottam) may be more efficient if they can be delivered earlier. Due to the complexity and scale of these options, they were discussed at the NOA Committee. The committee confirmed the needs of these east coast projects and agreed with the initial recommendations. The final recommendations will come from the SWW assessment, where a wider range of sensitivities are being investigated.

Elvanfoot to Harker reconductoring (EHRE) is needed on its EISD under all scenarios for its benefit across the Anglo-Scottish border. To meet its EISD, additional constraint costs during construction outages would be incurred in 2022 and 2023. Construction outages are currently not considered in the NOA process. Although we take into account the outage slot availabilities in timing the delivery for each option in the optimal path, the constraint costs associated with taking the outages are not included. To assess the additional financial impact of construction outages, a sensitivity study was conducted with reduced transfer capability on certain boundaries over the course of the two years prior to the option being commissioned. We found that the additional constraint costs associated with construction outages are likely to defer this option until other large infrastructure reinforcements, which increase boundary capability, are delivered. This option is considered sensitive and was referred to the NOA Committee for further scrutiny. The committee considered the evidence from the sensitivity studies and agreed with the recommendation that the delivery of EHRE should be put on hold to avoid excessive constraint costs during construction outages.

We recommended east coast onshore upgrades (ECU2 and ECUP) to proceed in the *NOA* 2017/18. Both options were critical in this assessment under all scenarios. They need to be delivered in 2023 and 2026 respectively, driven by the need for additional transfer capability across the border of SHE Transmission and SP Transmission networks. The alternative to this combination is the east coast onshore 400kV reinforcement (ECU4) which, as a single reinforcement, can be delivered as early as 2025.

[8] https://www.nationalgridet.com/sites/et/files/documents/NGET%202018%20NDP%20Outputs%20v4.pdf

We have carried out a sensitivity study to evaluate the impact of construction outages on constraint costs, as the delivery of ECUP could potentially set back the value created by ECU2. We applied a similar assumption to ECU4 for a fair comparison. The results indicate that delivering the east coast onshore upgrades as two separate reinforcements is still the best way forward. Therefore, a 'Proceed' recommendation for both ECU2 and ECUP should remain unchanged. These options were referred to the NOA Committee for discussion and they agreed with our conclusion. Final recommendations for these options will come from the east coast SWW Needs Case where a more thorough investigation will be carried out with the consideration of outage costs and impacts on other major projects.

Reconductor the Harker to Fourstones, Fourstones to Stella West, and Harker to Stella West 275kV circuits (HSRE) is an optimal option and required on its EISD in 2024. This is solely driven by the Slow Progression scenario where the level of east–west flows in the north of England is higher (mainly because of the extended running period of nearby nuclear generation) than in the other scenarios. The initial recommendation for this option is considered 'marginal' and we need to believe that the Slow Progression scenario or the conditions that would trigger this reinforcement are 12% likely to occur to support a 'Proceed' recommendation. Based on the analysis results and the latest market intelligence, the NOA Committee agreed the final recommendation for this option is 'Do not start'.

The *NOA* 2017/18 recommendation for Denny to Wishaw 400kV reinforcement (DWNO), Harker Supergrid Transformer 6 replacement (HAEU), Hunterston East–Neilston 400kV reinforcement (HNNO), and turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit (WHTI) was 'Proceed'. These options are critical in multiple scenarios in this assessment, so we recommend continuing progressing with these options. Cellarhead to Drakelow reconductoring (CDRE), Harker Supergrid Transformer 5 replacement (HAE2), and series reactors at Thornton (THS1) were recommended to be put on hold by the *NOA* 2017/18 and their EISDs slipped back by one year in this *NOA*. They are now critical in multiple scenarios and our recommendation for them is 'Proceed'.

In this assessment, we have included more reinforcements than in any previous *NOA*s. Together with the TOs, we embrace innovative ways of reinforcing the network and power flow control devices are one of the new options submitted by the TOs. They are much easier to deploy and relatively cheaper to install, while delivering comparable benefit to conventional network upgrades, such as circuit thermal uprates, in a more flexible way. Based on the options provided by the TOs, we've identified the need for two such devices as early as 2020. One along Fourstones to Stella West (FSPC) and one along Harker to Stella West (HSPC) to manage constraints in the north of England. These two options are critical under all scenarios and our recommendation is 'Proceed'. Further collaborative development of such schemes is ongoing between the TOs and ESO to fully understand the operability of multiple power flow control devices. The MSCs within the north east region (NEMS) is another new option we recommend to proceed. This option is critical under multiple scenarios with a relatively high regret of not progressing it.

Lister Drive quad booster (LDQB) was recommended to proceed by the *NOA* 2017/18 and we still see the need for the option in this assessment. An alternative to this option would be based on a power flow control device which could be easier to deploy. The NOA Committee endorsed the recommendation to proceed LDQB subject to the TO further investigating the alternative options, which may displace LDQB.

The recommendation for the option to reconductor Lackenby to Norton single 400kV circuit (LNRE) was 'Hold' in the *NOA* 2017/18 and it is critical under three of the four scenarios in this assessment. The alternative option – power control device along Lackenby to Norton (LNPC) – requires less capital investment and is more flexible to implement. As further work is required on the operability of multiple power flow control devices, the NOA Committee agreed with the recommendation to proceed LNRE subject to the TO investigating further the LNPC option, which could displace LNRE.

Reconductor sections of Penwortham to Padiham and Penwortham to Carrington (CPRE) was presented to the NOA Committee in the *NOA* 2017/18 as a marginal case (only supported by Two Degrees) and recommended to proceed as its first-year spend was much lower than the regret. This time, it is optimal in only one scenario – Steady Progression – and driven by similar network condition that triggers HSRE as mentioned before. This, together with the consideration of new options, such as power flow control devices and commercial solutions, makes the option no longer critical. Therefore, we recommend to put it on 'Hold' this year.

Uprate the Penwortham to Washway Farm to Kirkby 275kV double circuit to 400kV (MRUP) was found non-optimal in the last *NOA* but overruled by the NOA Committee with a final recommendation of 'Proceed'. This was because the option was very sensitive to the east–west flow balance (i.e. how much power goes down the west routes or the east routes) in the north of England and the condition to trigger it was marginal. In this assessment, the power flow direction in the early 2020s is predominantly west-to-east under all scenarios, and the option was again found non-optimal. Therefore, our recommendation this time is to 'Stop' the delivery of MRUP.

Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit (NOR1) was considered critical and recommended to proceed by the last two *NOA*s. This time, the option is still optimal but no longer needed on its EISD as the power flow control devices and commercial solutions are better alternatives in the early 2020s. Our recommendation is to put the option on 'Hold' this year.

In conclusion, we recommend progressing with the following reinforcements in Scotland and the north of England region.

CS01	to meet its EISD of 2020
FSPC	to meet its EISD of 2020
HSPC	to meet its EISD of 2020
LDQB	to meet its EISD of 2020
HAEU	to meet its EISD of 2021
WHTI	to meet its EISD of 2021
CDRE	to meet its EISD of 2022
HAE2	to meet its EISD of 2022
LNRE	to meet its EISD of 2022
NEMS	to meet its EISD of 2022
ECU2	to meet its EISD of 2023
HNNO	to meet its EISD of 2023
THS1	to meet its EISD of 2023
ECUP	to meet its EISD of 2026
E2DC	to meet its EISD of 2027
OENO	to meet its EISD of 2027
DWNO	to meet its EISD of 2028
E4D3	to meet its EISD of 2029

5.3.1.1 Competition assessment

Following the above, we conducted eligibility assessment for onshore competition for all reinforcements recommended to proceed this year in Scotland and the north of England. We identified the following options which meet the competition criteria proposed by Ofgem:

- Eastern Scotland to England link: Peterhead to Drax offshore HVDC (E4D3).
- Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC (E2DC).
- Central Yorkshire reinforcement (OENO).
- East coast onshore 275kV upgrade (ECU2).
- East coast onshore 400kV incremental reinforcement (ECUP).

The east coast onshore 400kV incremental reinforcement (ECUP) would have to be split to meet the competition criterion for separability. It also includes new assets that might be built earlier for one or more other projects. This could affect the value of ECUP and its eligibility for competition. We will review this as the plans for the network are developed.

We also assessed all new or modified contracted connection projects in this region and found the following projects meet the competition criteria proposed by Ofgem:

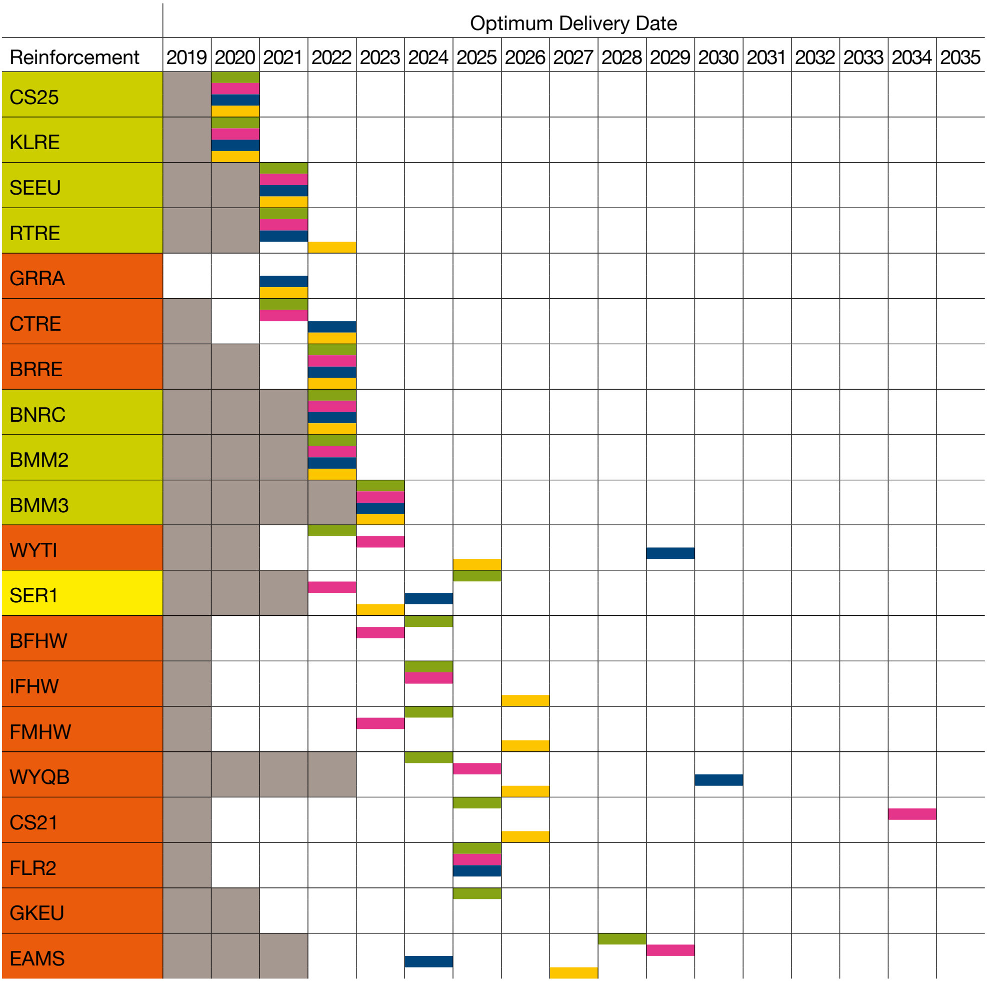
- Orkney link.
- Western Isles link.
- Shetland link.

The Orkney, Western Isles, and Shetland links are three SWW projects led by SHE Transmission. SHE Transmission submitted the Final Needs Cases to Ofgem for each of these projects during 2018. Please see Ofgem's website[9] for more information and updates on these projects.

[9] https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works/scottish-island-links

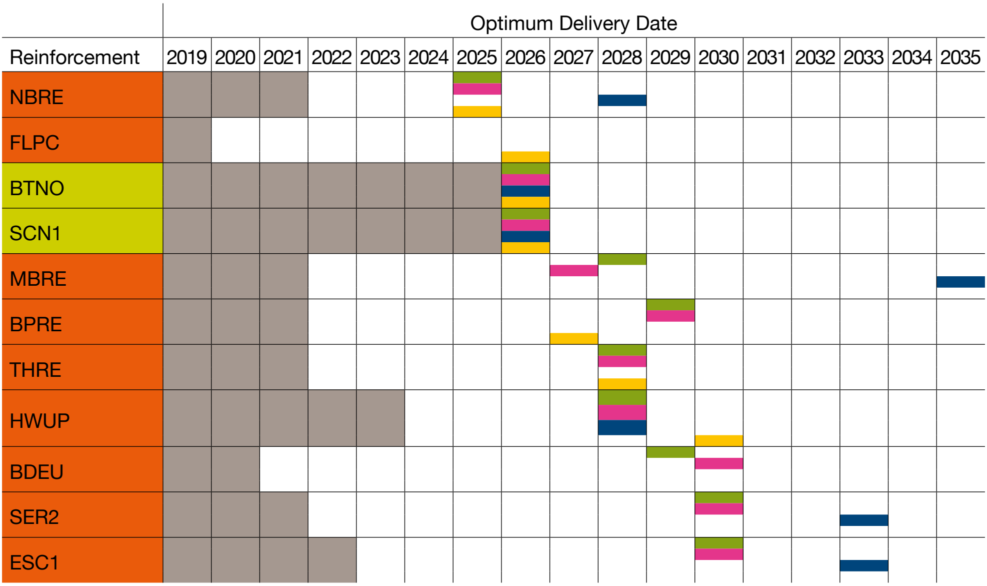
5.3.2 The south and east of England region

Table 5.2
The south and east of England region



Key:
Optimum year indicator for Two Degrees
Optimum year indicator for Community Renewables
Optimum year indicator for Consumer Evolution
Optimum year indicator for Steady Progression
EISD not yet reached
Critical option to 'Proceed'
Critical option to 'Delay'
Non-critical option to 'Hold'

Table 5.2
The south and east of England region (continued)



Key:
- Optimum year indicator for Two Degrees
- Optimum year indicator for Community Renewables
- Optimum year indicator for Consumer Evolution
- Optimum year indicator for Steady Progression
- EISD not yet reached
- Critical option to 'Proceed'
- Non-critical option to 'Hold'

For the south and east of England region, we identified 31 optimal options as shown in Table 5.2. Their optimum delivery dates are highlighted in different colours for different scenarios.

Of the 31 optimal options, 10 are critical and could present 1,024 different possible combinations of 'Proceed' and 'Delay' recommendations. The optimum delivery years of the following options are the same as their EISDs across all four scenarios.

- **A commercial solution for the south coast with a 40-year service duration** (CS25).
- **225MVAr MSCs at Burwell Main** (BMM2).
- **Bolney and Ninfield additional reactive compensation** (BNRC).
- **A new 400kV double circuit between Bramford and Twinstead** (BTNO).
- **Kemsley to Littlebrook circuits uprating** (KLRE).
- **Reactive compensation protective switching scheme** (SEEU).
- **225MVAr MSC at Burwell Main** (BMM3).
- **New 400kV transmission route between South London and the south coast** (SCN1).

This means there is no need for single year least regret analysis for these eight options; progressing them to maintain their EISDs is the optimum course of action under all scenarios.

This leaves two critical options and four different possible combinations of the following reinforcements:

- **Reconductor remainder of Rayleigh to Tilbury circuit** (RTRE).
- **Elstree to Sundon reconductoring** (SER1).

We performed the single year least regret analysis. The least regret strategy is to proceed with all critical options except SER1. The 10 top performing combinations for this region are listed in Appendix A.4.

The results explained in more detail:
This region has the largest interconnection capacity amongst the three we assessed. The capacity is also anticipated to grow in the next few decades, which brings even more volatility to the direction of power flows in this region. In the previous *NOA*s, we applied capabilities to the majority of the boundaries based on the winter-peak interconnector flow direction. In this assessment, we improved our modelling so that interconnector-flow-dependent boundary capabilities were used. This is really important, especially for the south coast where most of the future interconnectors are connecting to, as different interconnector conditions (importing, exporting, and at float) may trigger different reinforcements. This is also the reason why the optimal paths for this region are more diversified than the ones of the other two regions.

We considered a commercial solution (CS25) for the south coast where interconnection capacity between GB and other countries is high. We've seen a significant benefit of this option and recommend it to be delivered as soon as possible under all scenarios. This is mainly driven by importing conditions of the interconnectors. The commercial solution doesn't displace any asset-based reinforcements on the south coast, so there is little risk in proceeding.

The new 400kV double circuit between Bramford and Twinstead (BTNO) is optimal and critical under all scenarios in this assessment. In the *NOA* 2017/18, the NOA Committee recommended delaying the investment on this reinforcement as it was solely driven by a local contracted sensitivity. The *FES* 2018 suggested there will be more offshore wind generation and interconnection capacity connecting to East Anglia than there was in the *FES* 2017. These give rise to constraints on boundaries LE1 and EC5, making BTNO a crucial reinforcement for constraint management in East Anglia and North London under all scenarios. A sensitivity study was also conducted to examine whether the reinforcement is required if significant constraints only arise under the Two Degrees scenario. The results suggested BTNO is still needed because we only have to believe the Two Degrees scenario or similar network conditions are 2% likely to occur to support a 'Proceed' recommendation. Considering its sensitivity to the local generation mix assumptions and a relatively high first-year spend, we referred the option to the NOA Committee for discussion. The committee believed the driver for BTNO is clear and the recommendation is to 'Proceed'. This recommendation may only hold until the next round of CfD[9] auction and is subject to the auction results.

We assessed two alternative options (SCN1 and SCN2) between South London and the south coast in the *NOA* 2017/18 and recommended progressing SCN2 to SWW for further investigation. The TO has further studied the options and concluded that the SCN2 option is not feasible due to access issues, so only one option (SCN1) was submitted in this assessment. This option is critical under all scenarios this time due to its benefit on various southern boundaries. There is significant regret if it is not delivered on its EISD, particularly under the Consumer Evolution scenario. Due to the complexity and scale of this reinforcement, we referred it to the NOA Committee for discussion. The committee agreed that the evidence is clear and the final recommendation for SCN1 is 'Proceed'. This reinforcement will be further investigated as an SWW with other alternative options on the south coast.

We recommended progressing with the Burwell MSCs (BMMS) to meet its EISD of 2023 in the *NOA* 2017/18. In this assessment, alternative ways for delivering these are considered along with revised EISDs. The reinforcement can be delivered as two separate options (BMM2 and BMM3) in 2022 and 2023 respectively. We still see the need for these options and a greater benefit of them being delivered earlier. Therefore, we recommend continuing their delivery as two separate options.

Kemsley to Littlebrook circuits reconductoring (KLRE) is a reinforcement that provides benefit to multiple south coast boundaries. We recommend this to be delivered as soon it can be due to high constraints in the Thames Estuary area in the early 2020s.

[9] The Contracts for Difference (CfD) scheme is the government's main mechanism for supporting low-carbon electricity generation. Renewable generators located in the UK that meet the eligibility requirements can submit what is a form of 'sealed bid' to compete for a contract in a CfD auction or allocation round.

Fleet to Lovedean reconductoring (FLR2) was recommended to proceed in the *NOA* 2017/18. We still believe there is a benefit to continue progressing this option for its incremental capability on boundary SC1. However, the latest information indicates it may not be able to be delivered on its EISD. We are currently working with the TO, investigating the most optimised way of delivering these two options. We presented KLRE and FLR2 to the NOA Committee and they agreed that the recommendation for KLRE should remain 'Proceed' due to its greater benefit and significant regret of being deferred, while FLR2 should be put on hold this time unless a viable outage slot can be found.

The *NOA* 2017/18 recommendation for Bolney and Ninfield additional reactive compensation (BNRC) and reactive compensation protective switching scheme (SEEU) was 'Proceed'. These options are critical in multiple scenarios in this assessment and we recommend continuing progressing these options. The recommendation for reconductoring the remainder of Rayleigh to Tilbury circuit (RTRE) and Elstree to Sundon reconductoring (SER1) was 'Delay' in the *NOA* 2017/18 and their EISDs slipped back by one year in this *NOA*. They are now critical and further assessed in the single year least regret analysis. The results suggest proceeding with RTRE and delaying SER1.

Both Tilbury to Grain and Tilbury to Kingsnorth upgrade (TKRE) and Wymondley turn-in (WYTI) were given a 'Proceed' in the *NOA* 2017/18. We no longer recommend continuing the delivery of TKRE as its benefit to the south coast boundaries is limited, especially when SCN1 is built and the interconnectors are exporting. We also recommend putting WYTI on 'Hold' as it is only needed in later years under the interconnector exporting conditions and when some other reinforcements in East Anglia are delivered.

In conclusion, we recommend progressing with the following reinforcements in the south and east of England region.

CS25	to meet its EISD of 2020
KLRE	to meet its EISD of 2020
RTRE	to meet its EISD of 2021
SEEU	to meet its EISD of 2021
BMM2	to meet its EISD of 2022
BNRC	to meet its EISD of 2022
BMM3	to meet its EISD of 2023
BTNO	to meet its EISD of 2026
SCN1	to meet its EISD of 2026

5.3.2.1 Competition assessment

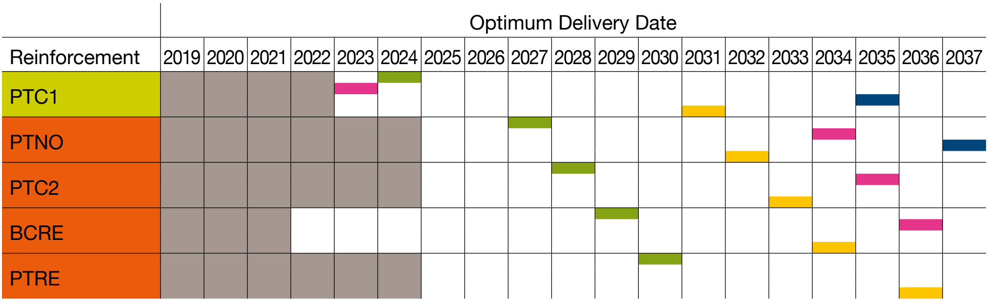
Following the above, we conducted eligibility assessment for onshore competition for all reinforcements recommended to proceed this year in the south and east of England region. We identified one option that meets the competition criteria proposed by Ofgem:

- New 400kV transmission route between South London and the south coast (SCN1).

There is no new or modified contracted connection project in this region to be assessed for onshore competition.

5.3.3 Wales and West Midlands region

Table 5.3
Wales and West Midlands region



Key:
Optimum year indicator for Two Degrees; Optimum year indicator for Community Renewables
Optimum year indicator for Consumer Evolution; Optimum year indicator for Steady Progression
EISD not yet reached; Critical option to 'Proceed'; Non-critical option to 'Hold'

For the Wales and West Midlands region, we identified five optimal options as shown in Table 5.3. Their optimum delivery dates are highlighted in different colours for different scenarios.

Pentir to Trawsfynydd 1 cable replacement – single core per phase (PTC1) is the only critical option in this region, whereas, in the *NOA* 2017/18, it was not beneficial until the Pentir to Trawsfynydd second circuit (PTNO) had been delivered. The latest information shows that the reinforcement, which crosses North Wales boundary NW2, could improve boundary transfer in the early 2020s without PTNO in place. Therefore, it is needed much earlier under the Two Degrees and Community Renewables scenarios, but is only critical in the Community Renewables optimal path. The single year least regret analysis result suggests proceeding with this option due to its low first-year spend but the regret of delaying it is only slightly higher. This result is considered marginal and was presented to the NOA Committee for further scrutiny. Additional evidence shows that the construction outages for PTC1 will adversely affect the ancillary services costs. Taking the points above, the committee agreed the final recommendation for PTC1 is 'Delay' due to its regret being low.

5.3.3.1 Competition assessment

We conducted eligibility assessment for onshore competition for all new or modified contracted connection projects in Wales and West Midlands region. We identified one connection project that meets the competition criteria proposed by Ofgem:

- Wylfa–Pentir second double circuit.

5.4 Recommendation for each option

This section presents the recommendation for each option assessed in the *NOA* 2018/19.

In addition, we present the recommendations from last year's *NOA* for comparison and to indicate whether an option could be an SWW. We also include cost bands for options with a 'Proceed' recommendation that satisfy the competition criteria. These options and their cost bands are highlighted in orange.

Table 5.4
Scotland and the north of England region

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
CBEU	Creyke Beck to Keadby advance rating		Not featured	Hold
CDRE	Cellarhead to Drakelow reconductoring		Hold	Proceed
CPRE	Reconductor sections of Penwortham to Padiham and Penwortham to Carrington		Proceed	Hold
CS01	A commercial solution for Scotland and the north of England with a service duration of 40 years		Not featured	Proceed
CS03	A commercial solution for Scotland and the north of England with a service duration of 15 years		Not featured	Hold
DCCA	Cellarhead to Daines cable replacement		Not featured	Do not start
DNEU	Denny North 400/275kV Supergrid Transformer 2		Hold	Hold
DREU	Generator circuit breaker replacement to allow Thornton to run a two-way split		Do not start	Do not start
DWNO	Denny to Wishaw 400kV reinforcement		Proceed	Proceed
E2D2	Eastern Scotland to England link: Torness to Cottam offshore HVDC		Not featured	Do not start
E2D3	Eastern Scotland to England link: Torness to Drax offshore HVDC		Not featured	Do not start
E2DC	Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC (cost band: [£1000m–£1500m])	Y	Proceed	Proceed
E4D2	Eastern Scotland to England link: Peterhead to Cottam offshore HVDC		Not featured	Do not start
E4D3	Eastern Scotland to England link: Peterhead to Drax offshore HVDC (cost band: [£1500m–£2000m])	Y	Not featured	Proceed
E4DC	Eastern Scotland to England link: Peterhead to Hawthorn Pit offshore HVDC		Proceed	Stop[10]
ECU2	East coast onshore 275kV upgrade (cost band: [£100m–£500m])	Y	Proceed	Proceed
ECU4	East coast onshore 400kV reinforcement		Do not start	Do not start[10]
ECUP	East coast onshore 400kV incremental reinforcement (cost band: [£100m–£500m])	Y	Proceed	Proceed
ECVC	Eccles SVCs and real-time rating system		Not featured	Hold
EHRE	Elvanfoot to Harker reconductoring		Hold	Hold
FBRE	Beauly to Fyrish 275kV double circuit reconductoring		Do not start	Do not start
FSPC	Power control device along Fourstones to Stella West		Not featured	Proceed
GKRE	Reconductor the Garforth Tee to Keadby leg of the Creyke Beck to Keadby to Killingholme circuit		Do not start	Do not start

[10] The NOA recommendations are based on our economic assessment of options to deliver boundary benefits. Some options assessed may be listed as enabling works in users' connection agreements. This may be for a number of reasons. An option not receiving a 'Proceed' recommendation could still be proceeded by the TO(s) if required for other reasons than delivering boundary benefits.

Table 5.4
Scotland and the north of England region (continued)

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
HAE2	Harker Supergrid Transformer 5 replacement		Hold	Proceed
HAEU	Harker Supergrid Transformer 6 replacement		Proceed	Proceed
HAMS	225MVAr MSC at Harker		Not featured	Do not start
HFPC	Power control device along Fourstones to Harker		Not featured	Do not start
HNNO	Hunterston East–Neilston 400kV reinforcement		Proceed	Proceed
HPNO	New east–west circuit between the north east and Lancashire		Hold	Do not start
HSIT	Harker to Stella West circuit intertrip		Not featured	Do not start
HSRE	Reconductor Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuit		Do not start	Do not start[11]
HSS1	Power control device along Fourstones to Harker to Stella West		Not featured	Do not start
HSS2	Power control device along Fourstones to Harker to Stella West		Not featured	Do not start
HSPC	Power control device along Harker to Stella West		Not featured	Proceed
KBRE	Knocknagael to Blackhillock 275kV double circuit reconductoring		Not featured	Hold
KWHW	Keadby to West Burton circuits thermal uprating		Not featured	Hold
LDQB	Lister Drive quad booster		Proceed	Proceed
LNRE	Reconductor Lackenby to Norton single 400kV circuit		Hold	Proceed
LNPC	Power control device along Lackenby to Norton		Not featured	Hold
LTR3	Lackenby to Thornton 1 circuit thermal upgrade		Do not start	Do not start
MHPC	Power control device along Harker to Gretna and Harker to Moffat		Not featured	Do not start
MRPC	Power control device along Penwortham to Kirkby		Not featured	Do not start
MRUP	Uprate the Penwortham to Washway Farm to Kirkby 275kV double circuit to 400kV		Proceed	Stop
NEMS	225MVAr MSCs within the north east region		Not featured	Proceed
NEPC	Power control device along Blyth to Tynemouth and Blyth to South Shields		Not featured	Hold
NOHW	Thermal uprate 55km of the Norton to Osbaldwick 400kV double circuit		Hold	Hold
NOR1	Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit		Proceed	Hold
NOR2	Reconductor 13.75km of Norton to Osbaldwick 1 400kV circuit		Do not start	Hold
NOR4	Reconductor 13.75km of Norton to Osbaldwick 2 400kV circuit		Do not start	Hold
NOPC	Power control device along Norton to Osbaldwick		Not featured	Do not start
NPNO	New east–west circuit between the north east and Lancashire		Do not start	Do not start
OENO	Central Yorkshire reinforcement (cost band: [£100m–£500m])		Hold	Proceed
OTHW	Osbaldwick to Thornton 1 circuit thermal upgrade		Do not start	Hold
SPDC	Stella West to Padiham HVDC link		Do not start	Do not start
SSHW	Spennymoor to Stella West circuits thermal uprating		Not featured	Hold
STSC	Series capacitors at Stella West		Not featured	Do not start
TDR1	Reconductor Drax to Thornton 2 circuit		Not featured	Do not start
TDR2	Reconductor Drax to Thornton 1 circuit		Hold	Hold
TDRE	Reconductor Drax to Thornton double circuit		Do not start	Hold
THS1	Install series reactors at Thornton		Hold	Proceed
TLNO	Torness to north east England AC reinforcement		Hold	Do not start

[11] This option's recommendation has changed as a result of the NOA Committee. See regional narratives for more information.

Table 5.4
Scotland and the north of England region (continued)

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
TURC	Reactive compensation at Tummel		Hold	Hold[10]
WHTI	Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit		Proceed	Proceed
WLTI	Windyhill–Lambhill–Longannet 275kV circuit turn-in to Denny North 275kV substation		Hold	Hold

Table 5.5
The south and east of England region

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
BDEU	Bramley to Didcot circuits thermal uprating		Not featured	Hold
BFHW	Bramley to Fleet circuits thermal uprating		Hold	Hold
BFRE	Bramley to Fleet reconductoring		Do not start	Do not start
BMM2	225MVAr MSCs at Burwell Main		Not featured	Proceed
BMM3	225MVAr MSC at Burwell Main		Not featured	Proceed
BMMS	225MVAr MSCs at Burwell Main		Proceed	Stop[10]
BNRC	Bolney and Ninfield additional reactive compensation		Proceed	Proceed
BPRE	Reconductor the newly formed second Bramford to Braintree to Rayleigh Main circuit		Not featured	Hold
BRRE	Reconductor remainder of Bramford to Braintree to Rayleigh route		Hold	Hold
BTNO	A new 400kV double circuit between Bramford and Twinstead		Delay	Proceed
COSC	Series compensation south of Cottam		Do not start	Do not start
COVC	Two hybrid STATCOMS at Cottam		Do not start	Do not start
CS21	A commercial solution for East Anglia with a service duration of 40 years		Not featured	Hold
CS25	A commercial solution for the south coast with a service duration of 40 years		Not featured	Proceed
CTRE	Reconductor remainder of Coryton South to Tilbury circuit		Hold	Hold
EAMS	225MVAr MSCs at Eaton Socon		Not featured	Hold
ESC1	Second Elstree to St John's Wood 400kV circuit		Delay	Hold
EWNO	Ealing to Willesden 275kV second circuit and quad booster		Not featured	Do not start
FLR2	Fleet to Lovedean reconductoring (with a different conductor type to FLRE)		Proceed	Hold
FLRE	Fleet to Lovedean reconductoring (with a different conductor type to FLR2)		Stop	Stop
FLPC	Power control device along Fleet to Lovedean		Not featured	Hold
FMHW	Feckenham to Minety circuits thermal uprating		Not featured	Hold
GKEU	Thermal upgrade for Grain and Kingsnorth 400kV substation		Hold	Hold
GRRA	Grain running arrangement change		Not featured	Hold
HMHW	Hinkley Point to Melksham circuits thermal uprating		Hold	Do not start
HWUP	Uprate Hackney, Tottenham and Waltham Cross 275kV to 400kV		Hold	Hold
IFHW	Feckenham to Ironbridge circuits thermal uprating		Not featured	Hold
KLRE	Kemsley to Littlebrook circuits uprating		Proceed	Proceed
MBRE	Bramley to Melksham reconductoring		Not featured	Hold

[10] The NOA recommendations are based on our economic assessment of options to deliver boundary benefits. Some options assessed may be listed as enabling works in users' connection agreements. This may be for a number of reasons. An option not receiving a 'Proceed' recommendation could still be proceeded by the TO(s) if required for other reasons than delivering boundary benefits.

Table 5.5
The south and east of England region (continued)

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
NBRE	Reconductor Bramford to Norwich double circuit		Hold	Hold
PEM1	225MVAr MSCs at Pelham		Not featured	Do not start[10]
PEM2	225MVAr MSCs at Pelham		Not featured	Do not start[10]
RHM1	225MVAr MSCs at Rye House		Not featured	Do not start
RHM2	225MVAr MSCs at Rye House		Not featured	Do not start
RRRE	Reconductor the newly formed second Bramford to Pelham circuit		Not featured	Do not start
RTRE	Reconductor remainder of Rayleigh to Tilbury circuit		Hold	Proceed
SCN1	New 400kV transmission route between South London and the south coast (cost band: [£100m–£500m])	Y	Do not start	Proceed
SEEU	Reactive compensation protective switching scheme		Proceed	Proceed
SER1	Elstree to Sundon reconductoring		Hold	Delay
SER2	Elstree–Sundon 2 circuit turn-in and reconductoring		Hold	Hold
THRE	Reconductor Hinkley Point to Taunton double circuit		Hold	Hold
TKRE	Tilbury to Grain and Tilbury to Kingsnorth upgrade		Proceed	Stop
WYQB	Wymondley quad boosters		Hold	Hold
WYTI	Wymondley turn-in		Proceed	Hold

Table 5.6
Wales and West Midlands region

Option four-letter code	Description (and cost band)	Potential SWW?	*NOA* 2017/18 recommendation	*NOA* 2018/19 recommendation
BCRE	Reconductor the Connah's Quay legs of the Pentir to Bodelwyddan to Connah's Quay 1 and 2 circuits		Hold	Hold
PTC1	Pentir to Trawsfynydd 1 cable replacement – single core per phase		Hold	Delay[11]
PTC2	Pentir to Trawsfynydd 1 and 2 cables – second core per phase and reconductor of an overhead line section on the existing Pentir to Trawsfynydd circuit		Hold	Hold
PTNO	Pentir to Trawsfynydd second circuit		Hold	Hold
PTRE	Pentir to Trawsfynydd circuits – reconductor the remaining overhead line sections		Hold	Hold
SWEU	South Wales (Cardiff to Bristol) region thermal uprating		Not featured	Do not start
SWHW	South Wales (Cardiff to Swansea) region thermal uprating		Not featured	Do not start

[10] The NOA recommendations are based on our economic assessment of options to deliver boundary benefits. Some options assessed may be listed as enabling works in users' connection agreements. This may be for a number of reasons. An option not receiving a 'Proceed' recommendation could still be proceeded by the TO(s) if required for other reasons than delivering boundary benefits.

[11] This option's recommendation has changed as a result of the NOA Committee. See regional narratives for more information.

Chapter 6
Interconnection analysis

NOA for Interconnectors at a glance

What is it?

The *NOA* for Interconnectors (*NOA* IC) is a market and network assessment of the optimal level of interconnection capacity to GB. It aims to provide a market signal by quantifying how much interconnection with GB would provide the most value to consumers and other interested parties.

How does it work?

It evaluates the potential benefit of additional interconnection. The benefit is calculated by considering three elements:

- Social economic welfare, that is the benefit to society.
- Constraint costs, that is the impact of the interconnector on the GB network.
- Capital expenditure costs of both the interconnector and any associated network reinforcements.

NOA IC calculates the optimal level of interconnection by evaluating these three elements for a range of interconnector options from GB to seven European countries for each future energy scenario.

What are the high level results?

- The analysis shows that there are still significant opportunities for additional GB interconnection to create value for GB and Europe, both economically and environmentally, over and above existing levels of interconnection and those projects with regulatory certainty.
- This year's analysis suggests that a total interconnection capacity of between 18.4 GW and 21.4 GW would provide the optimal benefit for GB consumers.
- This represents between 2.5 GW and 5.5 GW above the baseline level of interconnection of 15.9 GW.
- This is between four and five times the current level of GB interconnection of 4 GW.
- Many different interconnector options could be of benefit to GB and Europe.

Optimal interconnection for each future energy scenario

Scenario	Optimal interconnection
Consumer Evolution	19.4 GW
Community Renewables	18.4 GW
Steady Progression	18.9 GW
Two Degrees	21.4 GW

6.1 Introduction

Chapter 6 presents our latest interconnection analysis. It highlights the potential benefits of interconnection with the goal of encouraging the development of efficient levels of interconnector capacity between GB and other markets.

6.1.1 The purpose of this analysis

This analysis aims to provide stakeholders with a quantified assessment of the potential benefits of interconnection. The analysis provides an indication of the socio-economic benefits of interconnection by assessing the benefits of multiple parties, including consumers, generators and interconnector businesses.

What *NOA* IC is:

- The *NOA* for Interconnectors (*NOA* IC) is a market and network assessment of the optimal level of interconnection capacity to GB.
- It evaluates the social economic welfare (SEW), that is the overall benefit to society of a particular course of action, as well as constraint costs and capital expenditure costs of both the interconnection capacity and network reinforcements.

What *NOA* IC is not:

- It does not assess the viability of actual current or future projects: the final insights are largely independent of specific projects.
- It does not provide any project specific information.

Key insights

- This year's interconnection analysis suggests that there are still significant potential opportunities for additional GB interconnection to create value for GB and Europe, both economically and environmentally.
- The analysis shows that a total interconnection capacity in the range of 18.4 GW to 21.4 GW between GB and European markets by 2031 would provide the maximum benefit for GB consumers.
- The analysis demonstrates that the GB consumer can benefit from more interconnection beyond the Cap and Floor window 2 projects.
- Whilst the analysis highlights the optimal interconnector paths based on the *FES* 2018, the analysis shows that many of the interconnectors not in the optimal paths also add value.
- The effect of additional interconnection on system operability is complex: in certain situations additional interconnection may increase system security whilst in others it may decrease it.

We are waiting on the final outcome of the EU-Exit negotiations and what this will mean for trading arrangements for interconnectors. We expect interconnectors to continue playing a long-term role as part of the UK's diverse energy mix. While some of the trading arrangements for interconnectors may need to change in a no deal scenario, the systems and processes can be amended to cater for this eventuality, meaning power can still flow between the UK and Europe.

6.1.2 Improvements to this year's methodology

For this year's analysis we have undertaken further improvements to the methodology, which were approved by Ofgem.

- We have continued to use the output from this year's *NOA* as the baseline network reinforcement assumptions for the *NOA* IC analysis: this provides greater consistency between the *NOA* and *NOA* IC analysis.
- We have used broadly the same iterative method as last year. The studies involve a step-by-step process, where the market is modelled with a base level of interconnection, but unlike last year, there is no least worst regret calculation to assign one single additional interconnection option across all four scenarios. By excluding the least worst regret approach there are four distinct optimal solutions, one for each *FES*. This results in a range of solutions, which our stakeholders told us would be more beneficial than a single optimal solution.
- As well as focusing on SEW, capital costs and reinforcement costs, we have analysed the impact that interconnectors may have on other operational costs, specifically ancillary services. Interconnectors may enhance system operability or lower the costs of providing system security, or conversely their presence could worsen system operability or increase system security costs.
- We have analysed the effect of ancillary services as a sensitivity, separate to the main iterative methodology. We have focused on voltage control and stability.
- We have provided more context and explanation of the results, and how they differ from other analyses, such as the TYNDP.

6.2 Interconnection theory

Electricity interconnectors allow the transfer of electricity between nations. Currently GB has ~4 GW of interconnection with other European markets, however our *Future Energy Scenarios* (*FES*) 2018 sees an increase by 2030 to between 10 GW in Consumer Evolution and 20 GW in Two Degrees. Ofgem's Cap and Floor window 2 would take the total GB interconnection capacity to 15.9 GW by 2026.

Increases in interconnection can deliver benefits to both industry and consumers in a number of ways:

- **Greater security of supply** – both markets can access increased levels of generation to secure their energy needs.
- **Greater access to renewable energy** – increased access to intermittent renewable generation, consequently displacing domestic non-renewable generation.
- **Increased competition** – increased access to cheaper generation and more consumers leads to increased competition allowing some participants in both markets to benefit financially. These benefits are measured as social economic welfare (SEW).

SEW is a common indicator used in cost-benefit analysis of projects of public interest. It captures the overall benefit, in monetary terms, to society from a given course of action. It is an aggregate of multiple parties' benefits – so some groups within society may lose money because of the option taken. In this analysis, SEW captures the financial benefits and detriments seen by market participants due to increased interconnection. Increased SEW is primarily attained through the following benefits:

- **Reduced price for consumers in the higher priced market** – suppliers have increased access to cheap renewable generation.
- **Increased revenue for generators in the lower priced market** – generators can now access more customers.
- **Revenue for interconnector businesses** – income generated from selling capacity across their interconnectors.

In addition, SEW must also capture the associated detriments that some market participants will face:

- **Reduced revenue for generators in the higher priced market** – now competing against cheaper overseas generation.
- **Increased price for consumers in the cheaper market** – they now share their access to cheaper generation with more consumers.

The increase in SEW must also be balanced against the capital costs of the delivery of the increased interconnection capacity and any associated reinforcement costs. As capacity is increased between two suitable markets and SEW is consequently gained, prices between the two markets begin to converge until further interconnection brings no benefit. We then consider the interconnection capacity as optimised as the benefits derived from interconnection are at a maximum.

6.3 Current and potential interconnection

As stated within the *FES* 2018, interconnection capacity increases in all four scenarios. Table 6.1 shows the current and planned interconnection levels which have formed the basis for this study's base interconnection capacity. This included commissioned interconnectors, projects included within Ofgem's Cap and Floor (C&F) window 1, projects included within C&F window 2 that Ofgem are minded to grant a cap and floor regime to in principle, and projects with an approved exemption.

For this year's analysis we have continued to treat any Icelandic interconnection that appears within the *FES* as a generator. The unique properties of the Icelandic market, in particular plentiful renewable generation, result in a very low wholesale electricity price.

Further Icelandic interconnection was excluded from the process. It can be seen from Table 6.1 that if all the projects included within the base case do successfully connect on time, then this will represent roughly a quadrupling in GB interconnection capacity over the next eight years.

Table 6.1
Current interconnection capacities and 2026 base case

	Belgium	Denmark	France	Germany	Ireland	Netherlands	Norway	Total
2018 capacity (GW)	0	0	2	0	1	1	0	**4**[1]
2026 base case (GW)	1	1.4	6.8	1.4	1.5	1	2.8	**15.9**

[1] The Nemo Link interconnector connecting GB and Belgium will be operational from 31 January 2019.

6.4 Methodology

The methodology was developed in consultation with our stakeholders. The interconnection analysis aims to identify the optimal level of interconnection capacity across the seven European markets shown in Table 6.1 for a selection of study years. Details of the choice of markets, study years and further details of the methodology and the rationale for the approach taken are available on the *NOA* website[2].

6.4.1 Developments to methodology

Based on stakeholder feedback, we have continued to evolve the methodology.

- The iterative process remains broadly the same as last year, focusing on SEW, capital costs and reinforcement costs. The optimal paths will be based on SEW for GB and Europe.
- Last year's methodology used least worst regret after each iteration to identify which option should be taken forward across all future energy scenarios: this year, based on stakeholder feedback we have not used least worst regret and have produced the optimal interconnection development path for each future energy scenario. This results in four different optimal levels of interconnection: i.e. one for each *FES*. Stakeholders told us that they felt a range of results was more beneficial, due to the high levels of uncertainty regarding the future development of the European energy market.
- We have analysed the impact that interconnectors may have on system operability, where interconnectors may be able to provide services which enhance system operability or lower the cost of providing system security, as well as where their presence could worsen system operability and so increase the cost of system security. This has been analysed as a sensitivity following the main iterative methodology. This year we have focused on voltage control and stability.
- We have continued to use the recommendations from this year's *NOA* as the baseline network reinforcement assumptions for the *NOA* IC analysis: this provides greater consistency between the *NOA* and *NOA* IC analysis.

For this year's *NOA* IC, like last year, we modelled GB interconnection levels using studies within our electricity market modelling software BID3. The studies involved a step-by-step process, where the market was modelled with a base level of interconnection, including current interconnection levels and projects with regulatory certainty totalling 15.9 GW. An iterative process then directed where the additional interconnection should be implemented. Figure 6.1 provides a high-level overview of the process.

[2] https://www.nationalgrideso.com/sites/eso/files/documents/NOA-methodology-July-2018.pdf

Figure 6.1
Iterative process for interconnection optimisation

1. Set base level interconnection

2. Create study cases

3. Simulate European markets for all four scenarios, running each interconnector option sequentially

4. Calculate net benefit of each option: = SEW – capital costs + reduction in constraint costs

5. Identify optimal interconnector solution for each scenario

6. Update base level of interconnection in each scenario to include optimal interconnector and reinforcement (if included)

The selected method of arriving at a recommendation for capacity development is an iterative optimisation for each future energy scenario. This approach attempts to maximise the present value, equal to SEW less CAPEX less Constraint Costs. The iterative process is as follows:

1) Set base level of interconnection

The base level of interconnection was the total capacity GB has with each of the seven studied markets at the start of the iteration. This totalled 15.9 GW, as shown in Table 6.1. All interconnectors that are in the *NOA* IC base case are included in each scenario within the model[3].

2) Create study cases

To test the effect of additional capacity for each market, 1 GW of interconnection was added in each of the European markets (i.e. to each of the seven European connecting countries) to the base level of interconnection. For each country's additional interconnector, a number of zones and reinforcement combinations were studied. In total 30 study cases were considered, with different combinations of country, GB connection zone and reinforcement. In study cases where a reinforcement upgrade is selected, an additional 1 GW of capability is added to the relevant boundary. The 30 study cases are shown in Table 6.2. Additional interconnection is modelled to connect in 2026, 2028 and 2031, in order to understand the effects of varying commissioning dates on SEW and constraint costs.

[3] This results in the level of interconnection within the scenarios being different from the interconnector capacity projections originally used to develop them. Whilst this may make the scenarios used within the *NOA* IC analysis inconsistent with the initial assumptions and drivers, we believe they are acceptable for the purposes of *NOA* IC.

Table 6.2
Study cases, showing interconnector connecting country, zone and reinforcement options

Interconnected country	GB connection zone	Reinforcement on boundary
None (base)	None	None
Belgium	4	EC5
Belgium	4	None
Belgium	6	None
Belgium	6	SC1+B15
Denmark	4	EC5
Denmark	4	None
Denmark	7	None
France	5	None
France	5	SC1
France	6	SC1+B15
France	6	None
France	6	SC1
Germany	4	EC5
Germany	4	None
Germany	7	None
Ireland	1	None
Ireland	1	B6+B8
Ireland	2	None
Ireland	2	B8
Ireland	3	None
Ireland	3	SW1
Norway	1	None
Norway	1	B6+B8
Norway	2	None
Norway	2	B8
The Netherlands	4	None
The Netherlands	4	EC5
The Netherlands	6	None
The Netherlands	6	SC1+B15

3) Simulate European markets
Run all 30 study cases for each *FES* 2018 for all European countries then calculate SEW and constraint costs.

4) Calculate net benefit of each combination
Calculate PV = SEW – CAPEX – Constraint Costs for each option of country, GB connection zone, reinforcement and connecting year for each scenario.

5) Identify optimal solution
For each *FES* identify which option has the highest PV across three time periods (interconnectors commissioning in 2026, 2028 and 2031).

6) Update base level interconnection
Add optimal solution from step 5 to base level of interconnection for each *FES* and repeat steps 3 to 6.

The iterative process for each *FES* finishes when it is deemed to have converged, that is when 'None' (the base case) is the option with the highest present value. Once this result is achieved, the incremental capacity will be reduced to 500MW to analyse whether there is any benefit of a further 500MW of interconnection. The number of iterations necessary may vary across the future energy scenarios, depending on the level of potential additional benefit from interconnection relative to the base case for that scenario.

6.4.1.1 Estimation of interconnection construction costs

The cost of building interconnection capacity varies significantly between different projects, with key drivers including converter technology, cable length and capacity of cable. Estimating costs for generic interconnectors between European markets and GB is therefore challenging. The capital costs were derived from a publicly available ACER (Agency for the Cooperation of Energy Regulators) document[4], based on surveys carried out on a range of European projects, and approximations of median possible cable lengths. Costs were converted to 2018/19 prices.

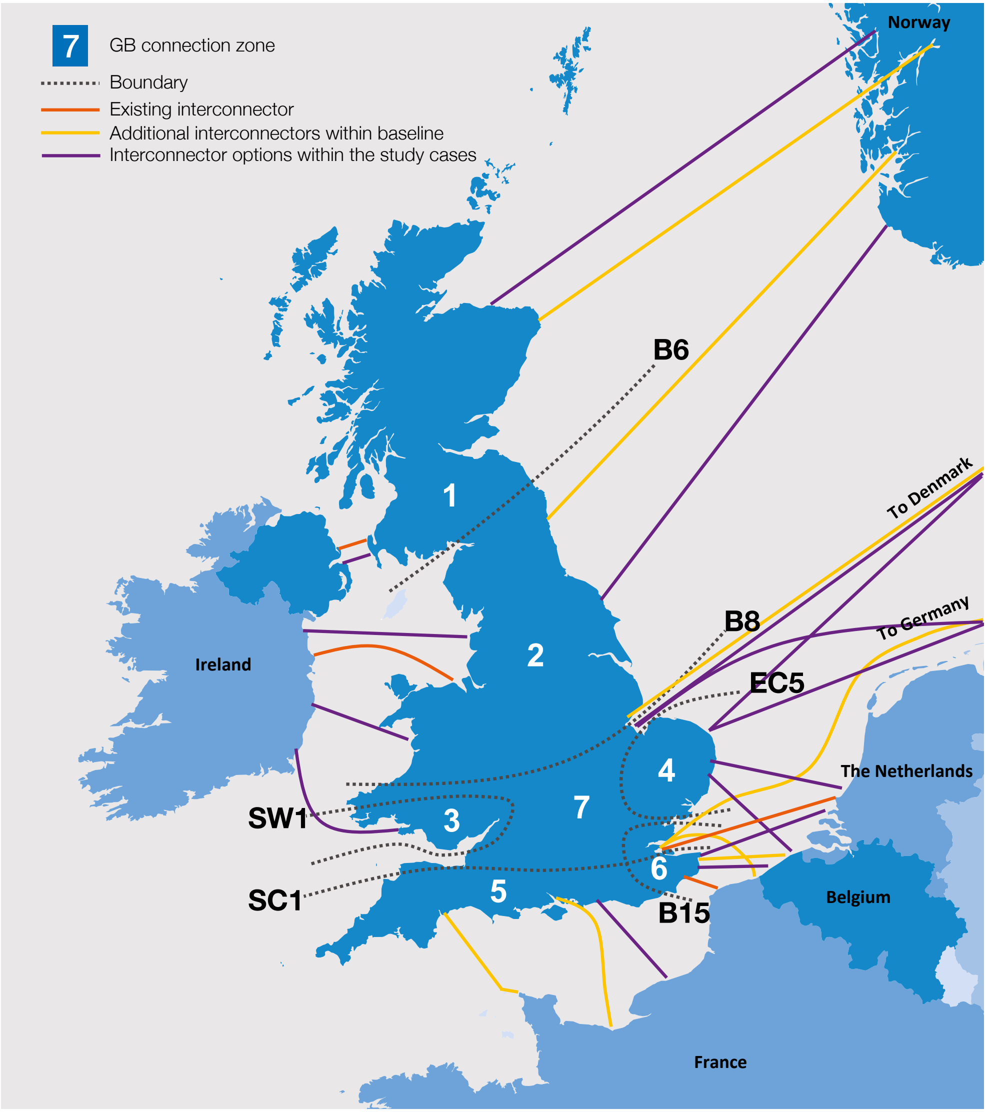
6.4.1.2 Estimation of network reinforcement costs

The network has been divided into seven high level zones which have been determined by areas of significant constraints on the network or areas of high interconnection.

Figure 6.2 highlights the GB connection zones, boundaries, interconnectors included within the base case and interconnector options modelled within the study cases.

[4] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/UIC%20Report%20%20-%20Electricity%20 infrastructure.pdf

Figure 6.2
GB network high level zones, boundaries and interconnector options



6.5 Outcome

The market studies that were undertaken generated SEW for each of the study cases that were analysed.

This section presents where future interconnection was a benefit to the GB and European consumers. The output is presented in four parts:

- Optimal Interconnection Range
- GB consumer benefit
- Interaction of interconnectors and constraints
- Benefits of overall increase in interconnection.

6.5.1 Optimal interconnection range

This section explores the optimal creation of European SEW through the development of interconnection. The final result shows, for each *FES*, the markets to connect to, whether reinforcement of the GB network was necessary, and the years to connect in, in order to maximise SEW. It is important to interpret the results in the context of the methodology undertaken:

- Projects to markets that are not in the optimal paths may well be beneficial, but simply not the most beneficial based on the assumptions made in this study.
- The attractiveness of different markets varies across the scenarios. Consequently there is uncertainty as to where the best opportunities lie, due to the uncertainty in future market conditions.
- The results should not be interpreted as a forecast: many other factors will influence the outcome for interconnection over the next decade and beyond.
- Variations in network constraint and construction costs will have a major impact on the attractiveness of projects.
- The optimal path for each *FES* is the most efficient way to optimise interconnection, but other pathways could result in a higher total level of interconnection and generate similar levels of SEW.
- Benefits of interconnection providing ancillary services to the GB network are not quantified within the main iterative analysis.

The starting interconnection capacities shown in Table 6.1 include projects that are already in operation or have a high level of regulatory certainty. This base case level of interconnection of 15.9 GW represents a near quadrupling of existing interconnection capacity, which causes considerable price convergence between GB and mainland Europe as seen within the modelling. As the SEW generated by additional interconnection depends on the price differential between GB and European markets, the interconnectors that form the base case potentially diminish the level of additional SEW further interconnection can bring.

The number of iterations within the iterative process varied across the future energy scenarios. The optimal level of interconnection between GB and European markets for each *FES*, including the baseline level of interconnection of 15.9 GW, is shown in Figure 6.3.

Figure 6.3
Optimal interconnection for each *FES* including the base case level

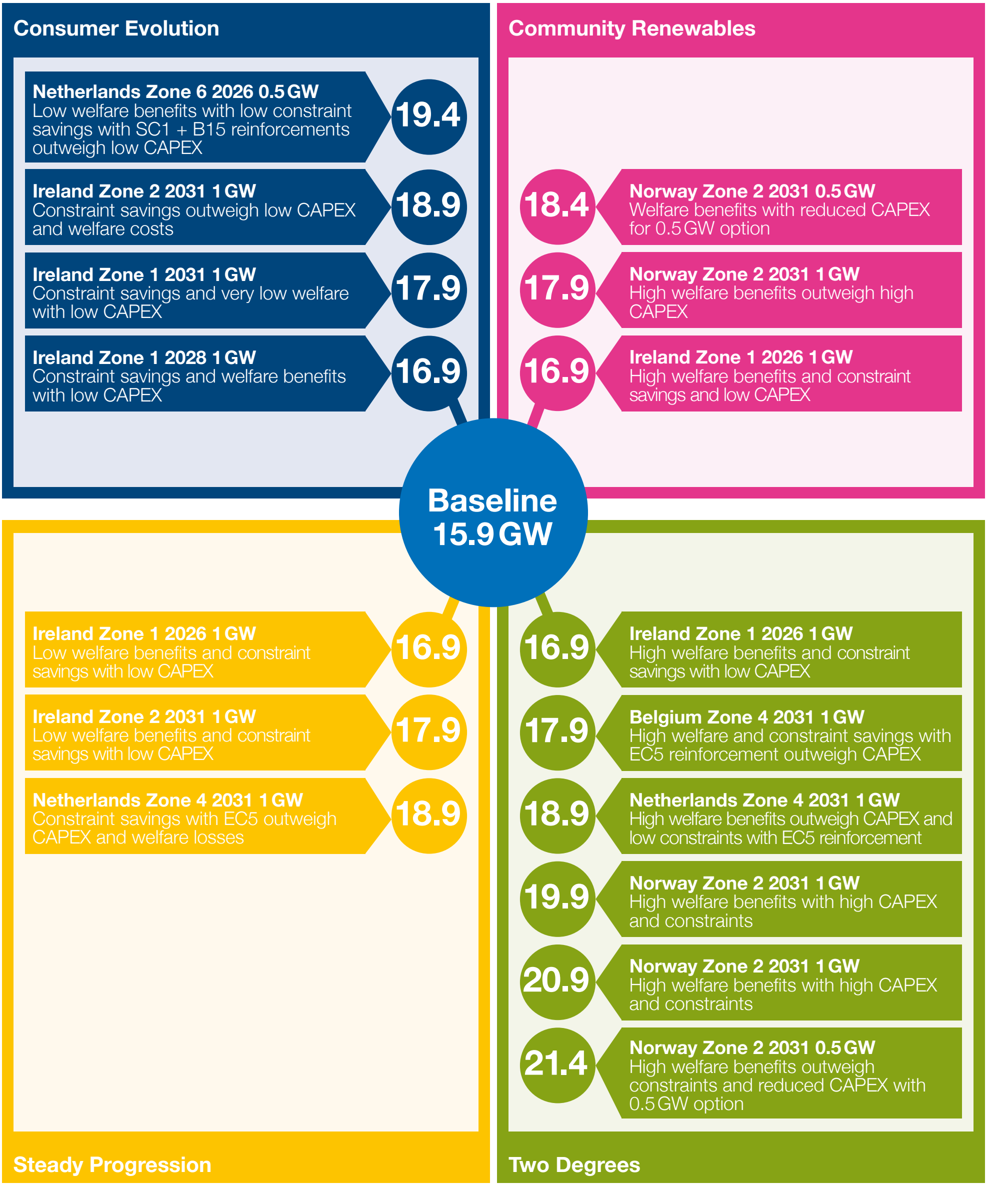
Scenario	Optimal interconnection
Consumer Evolution	19.4 GW
Community Renewables	18.4 GW
Steady Progression	18.9 GW
Two Degrees	21.4 GW

The four optimal levels of interconnection shown in Figure 6.3 result in a range of between 18.4 GW and 21.4 GW of interconnection capacity across the four *FES*.

Last year's *NOA* IC resulted in an additional 1.5 GW over and above the baseline level of 15.9 GW. This year's analysis has resulted in a maximum of 5.5 GW. The longer paths are likely the result of two factors. The first is the new *FES* 2018 scenarios, which have resulted in higher levels of welfare being generated within the scenarios, most noticeably within Two Degrees. The second is the removal of the least worst regret step, which may have resulted in a lower single optimal solution last year.

Figure 6.4 shows the results of the iterative analysis in graphical format. It shows the results in more detail, including the number of iterations, the level of additional interconnector capacity, the cumulative interconnection capacity, the connecting country, whether any additional reinforcement was associated with the option, the connecting zone and the connecting year for each option, as well as a brief description of why that study case was the optimal solution for that iteration.

Figure 6.4
Optimal interconnection paths for each *FES*



There is a range of optimal levels of interconnection across the different future energy scenarios. This is to be expected as a scenario such as Two Degrees, with high levels of intermittent generation and significant differences in wholesale prices between markets, provides greater levels of opportunity for welfare to be generated by additional interconnection.

Figure 6.5 presents the optimal level of interconnection to each European market for the four optimal paths.

Figure 6.5
Optimal level of interconnection to each European market

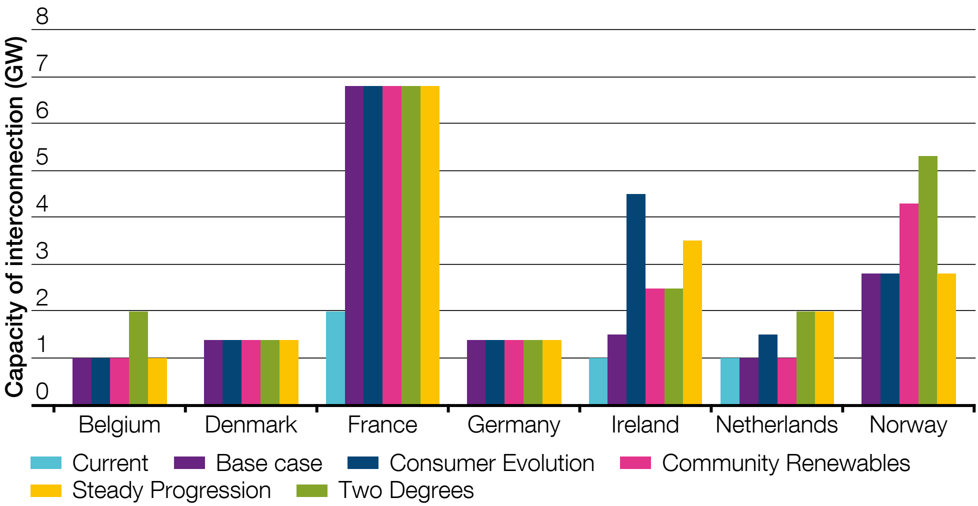


Figure 6.5 shows that all four scenarios result in additional interconnection to Ireland. The average Irish wholesale price is modelled as generally higher than GB resulting in welfare generation opportunities. A second mechanism which generates welfare is the alleviation of Ireland's synchronous generation constraint, where there is an imposed limit on the level of demand that can be met by wind. These two effects result in British exports to Ireland to exploit arbitrage and Irish exports to Britain to avoid wind curtailment. Both these sets of flows generate welfare.

Two of the four optimal paths also show additional interconnection above the base case level to Norway. Despite relatively high CAPEX costs, and in some instances higher constraint costs relative to the base case, these negatives are more than offset by the additional welfare benefits of additional interconnection to Norway, driven by Norway's lower wholesale prices.

Three of the four optimal paths also show additional interconnection above the base case level to the Netherlands. Two include the additional reinforcement to increase capability on the EC5 boundary.

Figure 6.6 shows the four optimal paths and the associated net present values relative to the base case for each iteration.

Figure 6.6
Net present value of each winning study case for the optimal path for each *FES*

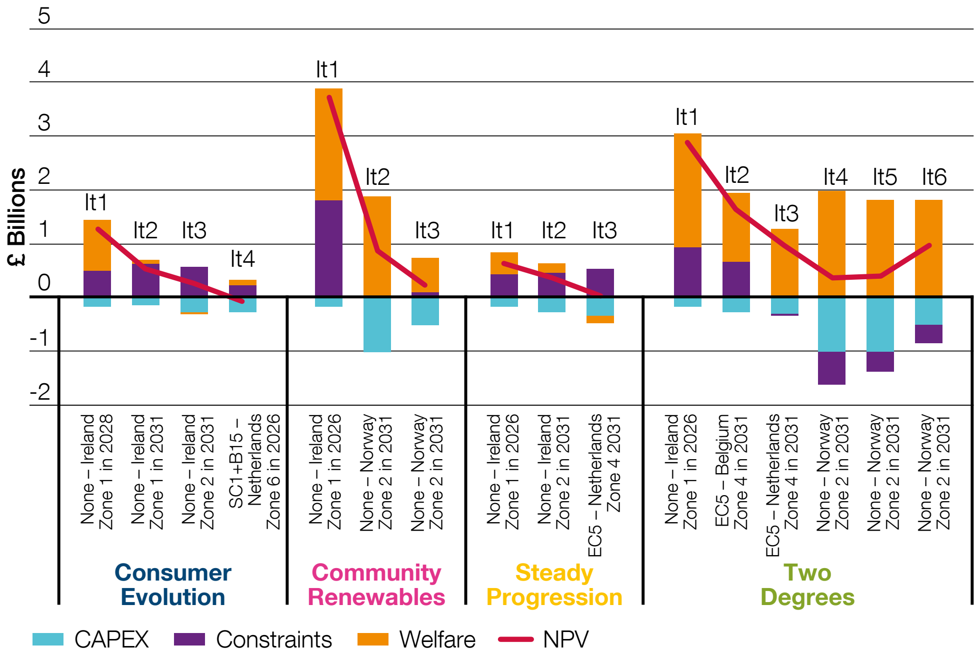


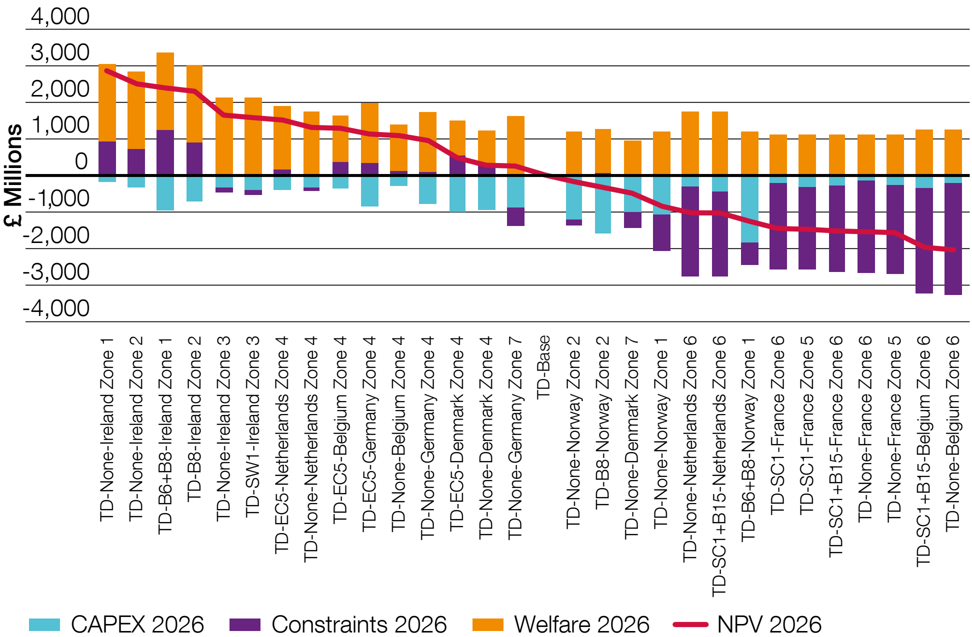
Figure 6.6 shows the variations in length of optimal path across the four *FES*, and the variations in net present value relative to the base case for each individual iteration. It also shows the composition of each NPV, broken down by welfare, CAPEX and constraints. Not surprisingly, CAPEX is always negative relative to the base case, but both welfare and constraints can result in both savings and additional costs (relative to the base case), depending on the study case. For example, the optimal interconnector solution (ie study case) for the fourth iteration for Two Degrees is 1 GW of interconnection to Norway connecting in zone 2, which results in high welfare benefits relative to the base case for that iteration which more than offset the negative constraint and CAPEX costs. The optimal interconnector solution for the first iteration for Community Renewables is 1 GW of interconnection to Ireland connecting in zone 1, which results in significant welfare benefits and constraint savings.

Figure 6.6 also shows how Two Degrees provides greater opportunities for welfare creation driven by the price difference between the GB and Norwegian markets, as shown by the optimal solution being interconnectors to Norway for iterations 4, 5 and 6.

Only four of the optimal solutions incorporate a boundary reinforcement. This is because the *NOA* IC analysis uses this year's *NOA* recommendations for network reinforcements, resulting in limited additional constraint savings from additional interconnection and associated boundary reinforcement. Three of the optimal solutions that do include a boundary reinforcement are for EC5, suggesting that additional interconnection in zone 4 may trigger more reinforcements in that area.

Figure 6.7 shows a sample of the results of iteration 1 for one scenario only, that is Two Degrees and for the interconnector options connecting in 2026.

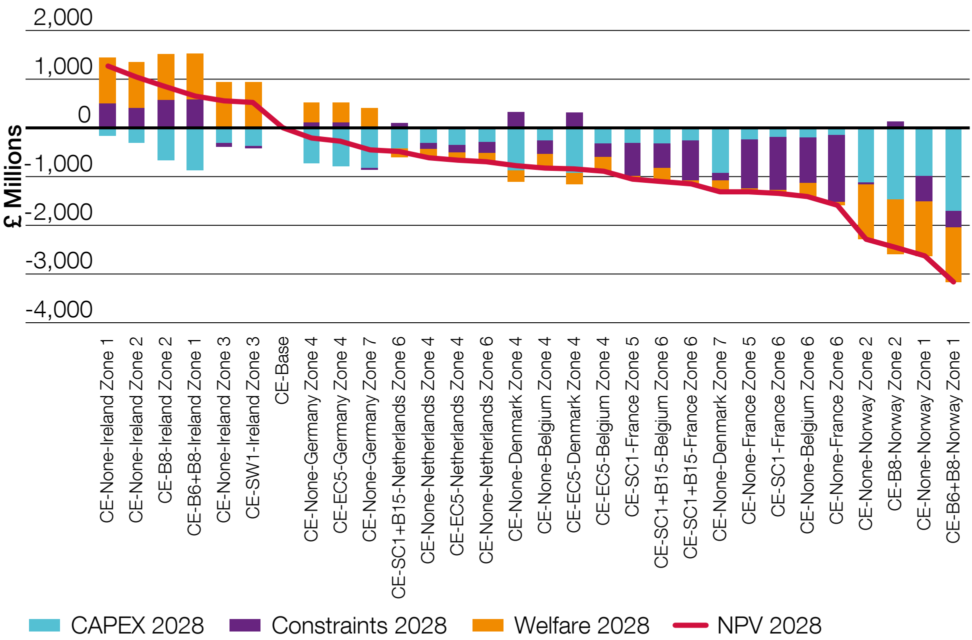
Figure 6.7
Net present value relative to base case for iteration 1, for Two Degrees scenario and interconnector options connecting in 2026



The results have been ordered by highest to lowest net present value for each study case. Roughly half of the study cases result in positive NPVs relative to the base case. Also of note is that all of the study cases result in positive welfare creation relative to the base case, due to the arbitrage opportunities, but constraints vary from savings of just over £1bn to additional costs of around £3bn, relative to the base case. It can also be seen that several different markets result in positive NPVs, including Ireland, the Netherlands, Belgium, Germany and Denmark, with all options to Ireland producing consistently high welfare and constraint savings benefits.

Figure 6.8 shows another sample of the results, this time for iteration 1 for Consumer Evolution and for the interconnector options connecting in 2028.

Figure 6.8
Net present value relative to base case for iteration 1, Consumer Evolution scenario and interconnector options connecting in 2028



The results have again been ordered by highest to lowest net present value for each study case. A fifth of the study cases result in positive NPVs relative to the base case, with the other three quarters resulting in negative NPVs. Also of note is that, compared to the results shown in Figure 6.7, the levels of NPV are considerably lower, the highest being roughly £1.3bn, compared to around £3bn in Figure 6.7. This is due to the Two Degrees scenario providing greater opportunities for arbitrage. Figure 6.8 also shows that only a third of the study cases result in positive welfare creation relative to the base case. The optimal interconnector solution with the highest NPV is for an interconnector to Ireland, with positive welfare benefits and constraint savings relative to the base case.

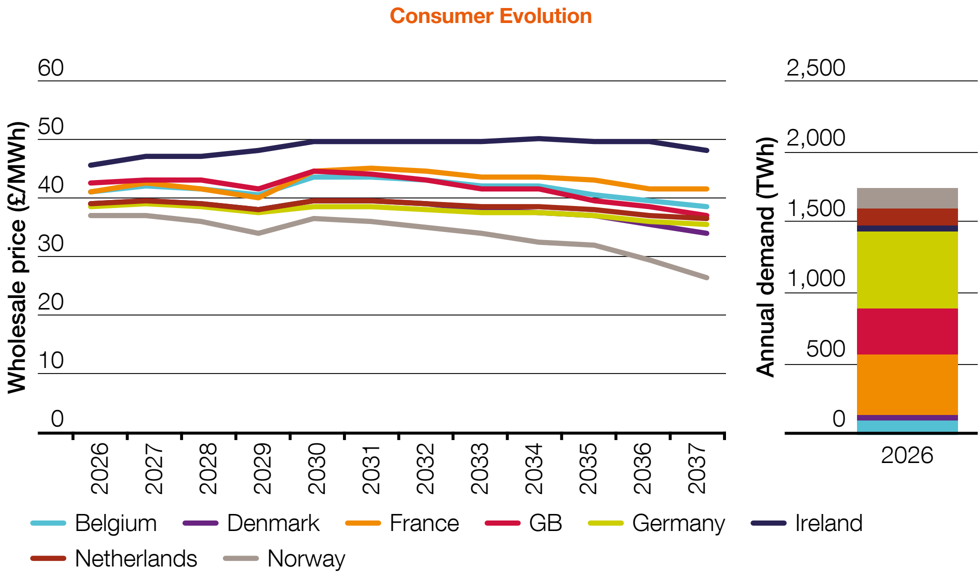
Apart from the study cases to Ireland, the constraint savings relative to the base case are often small, or in some instances negative. This is because we have used the recommendations of this year's NOA as the baseline network reinforcement assumptions, leading to lower additional constraint savings.

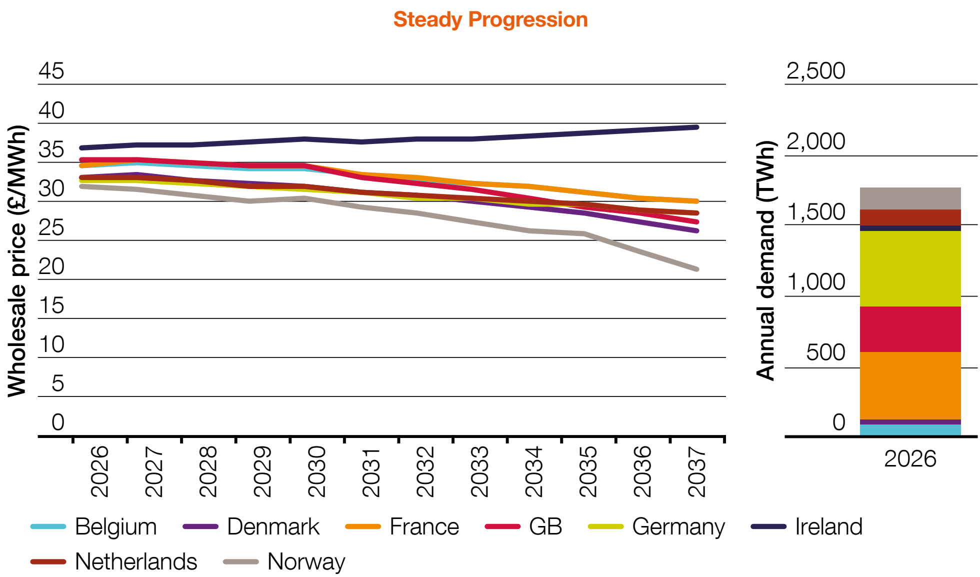
6.5.2 GB consumer benefit

The GB consumer gains from interconnection to cheaper wholesale electricity markets. Figure 6.9 below shows the average annual wholesale prices for GB and the seven European markets for the optimal interconnection paths for the four *FES*. The prices are not demand weighted. Figure 6.9 also shows annual demand for 2026 for GB and the European markets to provide an indication of the relative market size.

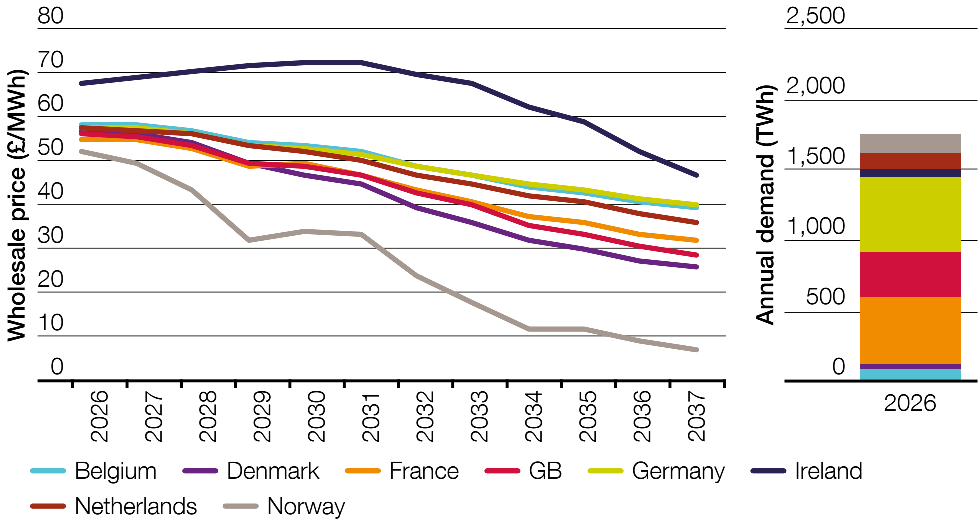
The trends in wholesale prices should not be used as an indicator for potential retail price trends, as many additional components such as transmission, distribution and account management costs, as well as costs from government policy mechanisms will affect retail prices.

Figure 6.9
Average annual wholesale prices difference for GB and European markets

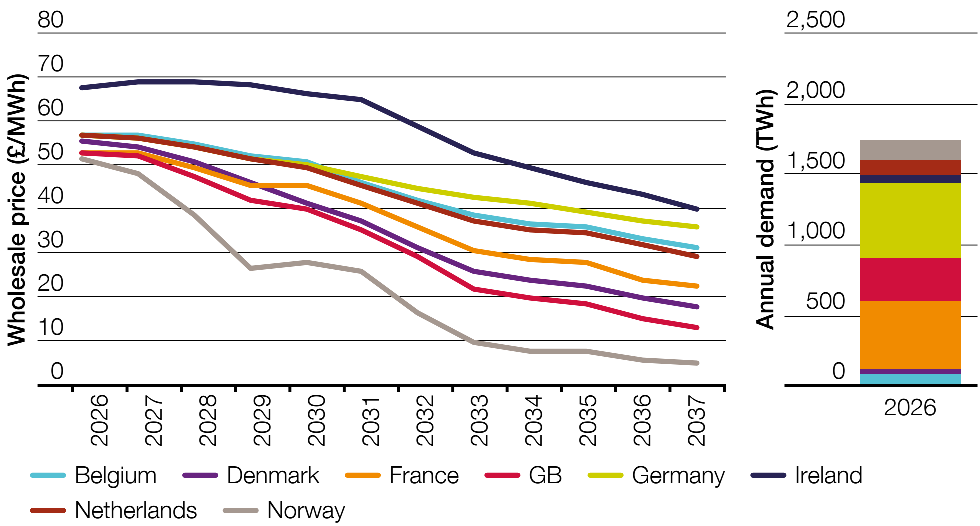




Community Renewables



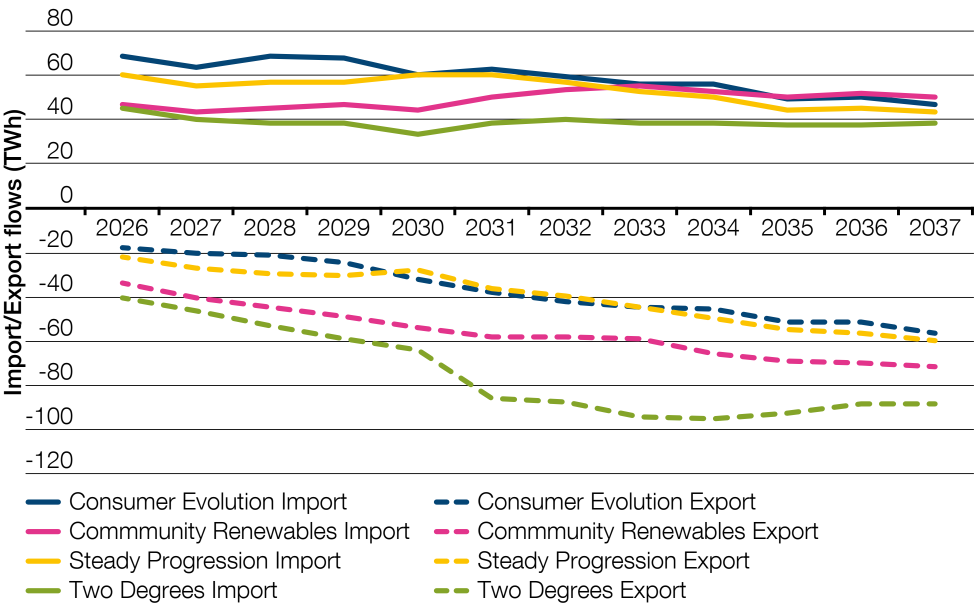
Two Degrees



Two Degrees shows a significant decline in GB and other European wholesale prices across the study period. The price decline is driven by increasing levels of renewable generation, and with the GB wholesale price lower than all other European markets in the study (with the exception of Norway), this provides significant opportunities for arbitrage resulting in high levels of exports from GB and increased welfare from additional interconnection. This is confirmed in Figure 6.10 which shows annual imports and exports for each of the optimal interconnection paths. Figure 6.10 shows that Two Degrees sees the highest levels of exports across interconnectors for all the FES. Figure 6.9 also shows that Community Renewables sees a decline in wholesale prices leading to opportunities for exports from GB to Europe, and this is confirmed in Figure 6.10. Figure 6.10 shows that all four scenarios show increasing levels of exports from 2026 to 2037 as arbitrage opportunities are exploited.

Figure 6.10 also shows Consumer Evolution and Steady Progression have the lowest levels of exports, coupled with the highest levels of imports. Figure 6.9 shows that all of the scenarios show arbitrage opportunities due to the relatively high wholesale prices in Ireland and the relatively low wholesale prices in Norway.

Figure 6.10
Annual imports and export flows



6.5.3 Interaction of interconnectors and constraints

The impact on GB constraints costs is dependent on the location of the interconnector on the GB network and the level of onshore reinforcement built to accommodate the interconnector. Constraint costs are incurred on the network when power within the merit order is limited from outputting due to network restrictions. In this event, the SO will incur balancing mechanism costs to turn down the generation which is not able to output and offer on generation elsewhere on the system to alleviate the constraint. Interconnection to different markets provides the SO with another balancing option. The inclusion of additional interconnection to GB may either help or hinder system balancing, as balancing mechanism costs increase or decrease as network boundaries are further strained or relieved. This can be seen in Figures 6.7 and 6.8 by the wide range of positive and negative attributable constraint costs relative to the base case. Flows across the GB network can be summarised as flowing from high levels of generation in the north to high levels of demand in the south. Interconnectors connected in the north may help alleviate constraints when exporting from GB and increase constraints when importing to GB. Conversely, interconnectors connected to the south of England may reduce network constraints when importing and exacerbate constraints when exporting.

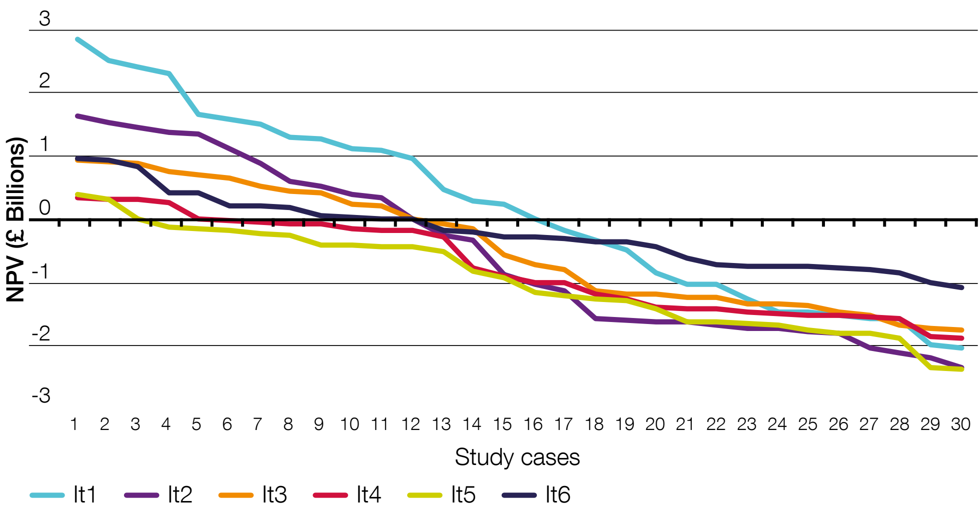
6.5.4 Benefits of overall increase in interconnection

Increased levels of interconnection bring significant benefits to GB and European consumers, both in terms of lower wholesale energy prices and greater use of renewable power.

6.5.4.1 Overall impact on wholesale prices

The additional interconnection drives down the average European price as cheaper generation is able to displace more expensive generation. These price changes drive increases in European welfare. However, as stated previously, as interconnection capacity is increased, prices between the two markets converge and additional SEW benefits are reduced. This is shown in Figure 6.11, which shows net present value relative to base case for all interconnector study cases for the six iterations within the Two Degrees optimal path.

Figure 6.11
Net Present Value for all six iterations within the Two Degrees optimal path



As in Figures 6.7 and 6.8, the study cases have been ordered by highest to lowest net present value for each iteration. Hence, study case 1 in iteration 1 may be different to study case 1 in iteration 2. The chart shows that as the iteration number increases, in general the maximum level of NPV relative to the base case decreases. In addition, the average level of positive NPV decreases and the number of study cases with positive NPV decreases, resulting in the lines tending to be lower and flatter.

As stated previously, for the Two Degrees scenario, the first iteration results in roughly half of the study cases producing positive NPVs relative to the base case. By iteration 5, this has reduced to only 2. While some options produce significant positive welfare relative to the base case, the majority produce less. This is a result of the high level of interconnection already included within the base case.

Iteration 6 bucks the trend of reducing NPV, as this iteration includes the 500 MW additional interconnector study cases, hence CAPEX costs will be lower and NPV relatively higher.

6.5.4.2 Environmental implications

Interconnectors can also increase access to renewable sources of power, resulting in reductions in CO_2. For the study period 2026 to 2037, the level of carbon dioxide output for GB is between 0.7 and 2.7 million tonnes of CO_2 lower for the optimal paths from the final iteration for each *FES* compared to the base case in iteration 1, which includes no additional interconnectors. For comparison, carbon dioxide emissions from UK power stations in 2017 was 72 million tonnes.

Interconnection allows surplus power from renewable generation to be exported, rather than curtailed. The exported power may also replace more expensive sources of generation, which may well use fossil fuels, resulting in a reduction in prices and reduced curtailment levels of renewable energy sources (RES). For Consumer Renewables, the interconnection optimal path results in a 4% reduction in RES curtailment in 2037 compared to that within the iteration 1 base case with no additional interconnection.

6.5.5 System operability analysis

This year, as part of our *NOA* for Interconnectors work we have expanded the scope of the analysis to begin to explore the impact interconnectors may have on our requirements for system operability, as discussed in our *SOF* reports, and operational costs in the future.

An attempt to quantify and detail the potential challenges in maintaining an operable electricity system over a decade in the future would be challenging and outside the scope of this report. This analysis focuses on whether the additional interconnection in the four optimal interconnections paths (over and above the 15.9 GW included within the base case) has an impact on operability.

In our role as ESO, we are responsible for maintaining the continuous balance of electricity generation and demand. Interconnectors are likely to have significant impact on future system operability.

Interconnectors may be able to provide ancillary services, providing the interconnector owner with additional income streams, and benefit the consumer by increasing system security or lowering the cost of providing system security. Equally, the net effect could be a cost to the consumer with the ESO being required to secure more services to facilitate operation of the interconnector. The interconnectors have been considered to perform in line with current technical standards, and we do not consider whether in future years new technical standards or capabilities beyond that would emerge.

There are a number of ancillary services that interconnectors can potentially contribute to including frequency control, voltage control, stability and restoration. These are summarised as follows.

Frequency control and system stability

The GB electricity transmission system is a high voltage, alternating current transmission system. It has a target operating frequency of 50Hz and part of the role of the ESO is to ensure that the system remains within strict limits to ensure safe and secure operation. Interconnectors have the potential to participate in future frequency markets. There is the possibility that interconnectors will increase the need for frequency response in certain periods by being the largest single loss on the system.

Stability is the ability of the system to quickly return to acceptable operation following a disturbance. Synchronous generation supports the stability of the system. Synchronous generation is generation where the waveform of the generated voltage is synchronized with the rotation of the generator. Without intervention, the system will become less stable when there is less synchronous generation running. To support the transition to a low carbon economy system we need to both decrease the reliance on fossil fuel generation to stabilise the system and learn to operate with a more dynamic system.

Voltage control

To maintain security and quality of electricity supply there are requirements to ensure the voltage of the network is maintained in strict limits. To maintain voltage control, reactive power is required. As GB transitions to a decentralised and decarbonised electricity system, new sources of reactive power will need to be accessed.

The requirements for reactive power will increase as network loading becomes more volatile and many conventional generators (which provide reactive power) run less predictably and less often. Conventional generators also provide short circuit current into the fault, as the network voltage and voltage angle changes. The higher the level of short circuit current on the transmission system, the less the voltage moves and the slower it moves at times where there is a surplus or deficit of reactive power on the system.

Restoration

Restoration refers to the wide process of restarting, and restoring networks, following a shutdown. There are a number of ways that providers can assist in different stages of restoration. A Black Start provider is a provider who can start up, energise the network and manage the supply of local demand without using external energy supplies from the transmission system.

As the level of Black Start services available from coal and less efficient gas stations declines, it is possible that interconnectors and other new types of providers will be able to supply Black Start services.

6.5.5.1 Methodology

We have taken the hourly output data from the base case and optimal interconnector path for each *FES* and input the data into a range of system operability tools. We then analysed the output focusing on any differences between the base case runs and the optimal interconnector path runs to see if they indicated any potential trends for operability.

This year we have focused on the potential impact of interconnectors on stability and voltage control.

6.5.5.2 Stability analysis: rate of change of frequency (RoCoF)

To investigate the potential impact of interconnectors on stability, we have analysed the impact of additional interconnection on the rate of change of frequency (RoCoF) on the system. In a less stable network, with less system inertia, the system frequency changes more quickly following an event. As levels of synchronous generation on the system are forecast to fall rapidly over the next decade, the reduced inertia results in increased system RoCoF during large system disturbances. An interconnector importing power may displace synchronous generation leading to increased system RoCoF, whereas an interconnector exporting power may result in additional synchronous generation on the system and therefore reduce system RoCoF.

The RoCoF analysis focused on the level of RoCoF that results from the optimal interconnection path in 2037 and the base case for each scenario in 2037. The results can be seen in Figure 6.12.

Figure 6.12
Rate of change of frequency for all four scenarios for the base case in 2037 and the optimal interconnection path in 2037

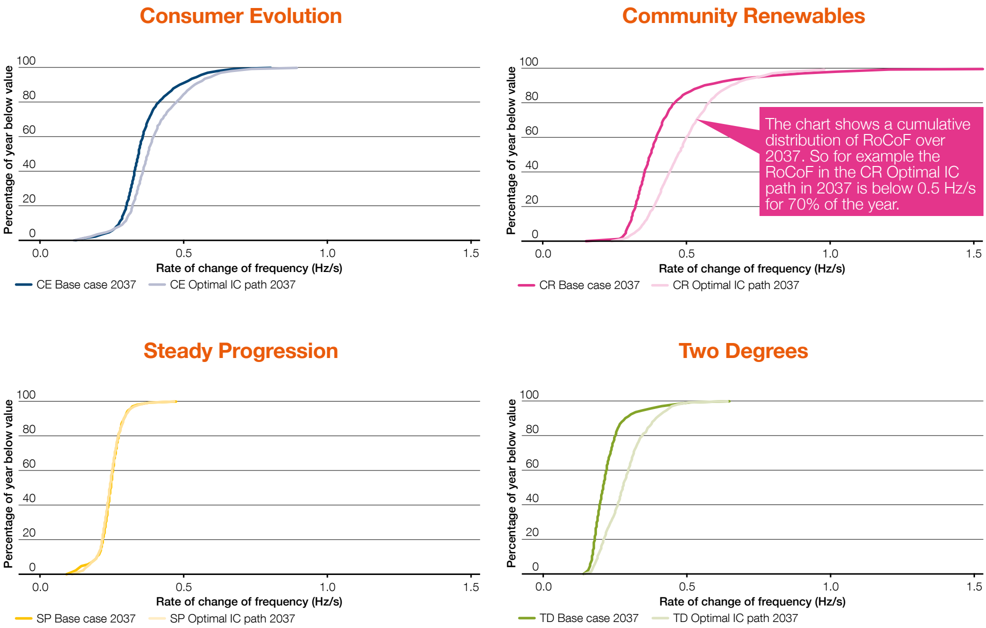


Figure 6.12 shows the rate of change of frequency as a cumulative distribution, with the vertical axis showing the percentage of the year that is below a given value. A detailed description of the results is not possible here, but a number of high level points can be made. In both Two Degrees and Community Renewables, the line representing RoCoF for the optimal interconnector path is to the right of the line for RoCoF for the base case, indicating that the inclusion of the additional interconnection in the optimal path has had a negative impact on the RoCoF, that is the time that RoCoF is below the 0.5Hz/s value decreased across the year. The shift in RoCoF is similar in Two Degrees and Community Renewables, although Two Degrees optimal path has an additional 5.5 GW of interconnector capacity, and Community Renewables only has an additional 2.5 GW, suggesting that RoCoF within the Community Renewables scenario is more sensitive to additional interconnection, possibly driven by the higher levels of distributed generation within it. Consumer Evolution also shows the RoCoF plot for the optimal path to the right of the base case plot, but not to the same extent as Two Degrees and Community Renewables. This may be because Consumer Evolution has less non-synchronous renewable generation capacity. Steady Progression shows very little difference in the RoCoF plots for the base case and the optimal interconnector path, possibly due to the scenario's lower levels of distributed generation.

Figure 6.12 shows that the potential effect of interconnection on RoCoF may be complex, whereby, depending on circumstances, interconnectors may have a positive or negative impact on future system operability, and therefore may improve or worsen the economics of satisfying system needs.

As previously mentioned the main *NOA* IC iterative analysis results in optimal levels of interconnection different to those initially set within the *FES* 2018. For this reason, care must be taken in trying to draw any detailed conclusions from any system operability analysis. To minimise any impact the change in interconnection levels might have on the generation merit order within the scenarios, the subsequent RoCoF analysis is focused on the Two Degrees optimal interconnection path, where the final level of interconnection of 21.4 GW is reasonably close to the original *FES* 2018 level of 20 GW by 2030. The RoCoF results for 2037 in Two Degrees confirm that the highest levels of RoCoF tend to occur at lower levels of demand, higher interconnector imports and lower interconnector exports and lower thermal generation, but there is significant volatility in the data. Rather than attempt a quantification of the impact of additional interconnection on RoCoF, the following section is a qualitative assessment of the change in RoCoF, over several days for the optimal interconnection path in 2037 for Two Degrees. The period is shown graphically in Figure 6.13.

Figure 6.13
Demand, supply and RoCoF for Two Degrees optimal interconnection path, 18 to 21 April 2037

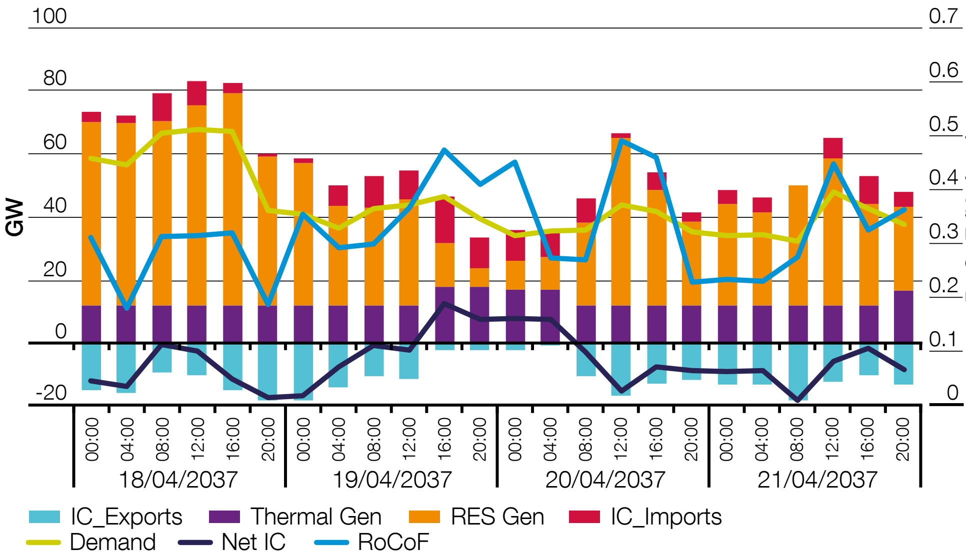


Figure 6.13 shows the supply demand balance over an illustrative four day period. Generation is broken down by thermal generation and renewable energy sources, interconnector imports and exports are shown, as well as the net position. The days are divided into four-hour blocks. RoCoF is shown on the right hand vertical axis. The chart shows a number of points. The first day (18 April) sees periods of high demand met by very high levels of RES generation and high interconnector exports and low imports, with relatively low levels of RoCoF. The second day (19 April) shows a decline in demand and a major reduction in RES, from a high in the previous day of 67 GW to a low of 6 GW, coupled with the interconnector position turning to significant net imports. RoCoF levels increase. The third day (20 April) shows a continuation of lower demand levels, but a return to higher RES peaking at 53 GW, high net interconnector exports and high RoCoF levels.

The chart shows that high RoCoF levels may occur with high RES and high interconnector exports, or low RES and low interconnector exports, depending on levels of synchronous generation and demand on the system, which will be affected by time of day, day of week and seasonal variations.

The impact on RoCoF of increased levels of interconnection is complex. Many factors will influence the level of RoCoF, including system demand, levels of synchronous, renewable and distributed generation. Interconnectors have the potential to provide an improvement in RoCoF, for example increased exporting can result in the dispatch of additional generation to meet demand, some of which may provide system inertia. Interconnectors can also contribute negatively to RoCoF, for example increased levels of import can displace conventional plants which were contributing to system inertia.

6.5.5.3 Voltage control: Short circuit level

Short circuit level (SCL) is an important parameter for an electricity system. When there is a short circuit, current flows towards the ground which must be isolated from the system as soon as possible. The size of the fault current is determined by the size of the generation producing a voltage, which is coupled with the system and how far away this generation is electrically (this being the impedance of the grid system). SCL is a measure of how strong the system is across system faults, and also across any voltage change. In a similar manner to how inertia determines how stable the electricity system is to frequency change, SCL provides a measure of how stable the electricity system is to voltage change.

SCL was modelled at an hourly level for 2026 to 2037 for both the base case and the optimal interconnection path for each *FES*. SCL is a regional indicator of system strength – at any given point of time the SCL in different areas of the electricity system will be different, and the SCL in that region is determined largely by local regional factors of what generation within or near that region is supporting it. Figure 6.14 shows the percentage difference in SCL between the base case and interconnector optimal paths for Consumer Evolution and Steady Progression for 2031 (the first year in the optimal interconnector paths when the additional interconnection is in operation). A positive number indicates that the SCL is higher in the optimal path compared to the base case, ie has improved, and a negative number indicates that the SCL is lower in the optimal path, ie has decreased. The results show the 95th percentile.

Figure 6.14
Regional short circuit level for Consumer Evolution

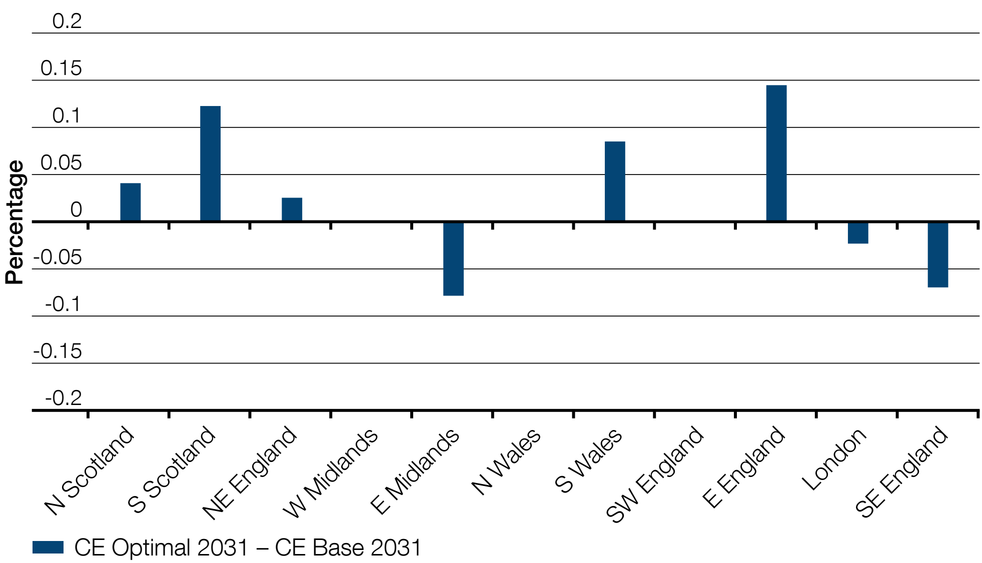


Figure 6.14 continued
Regional short circuit level for Steady Progression

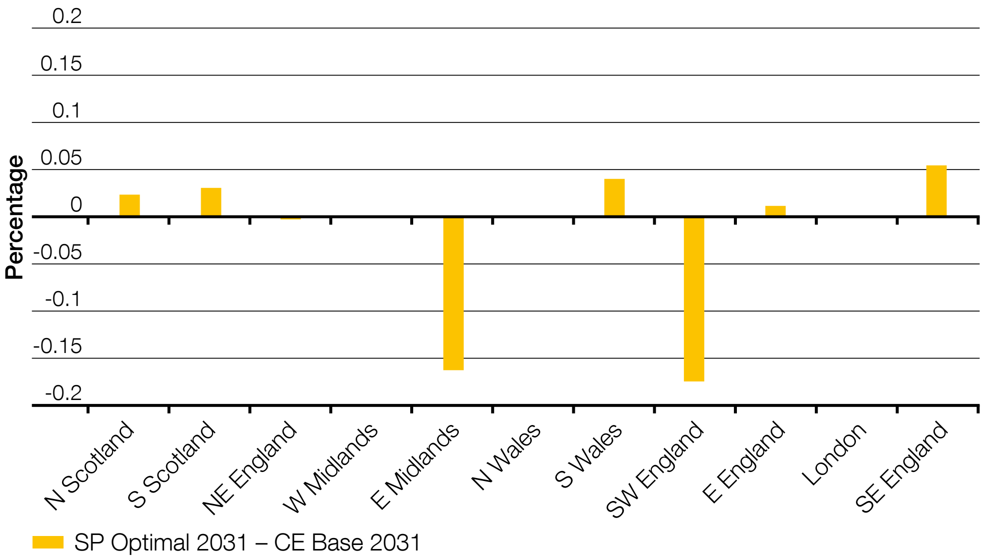


Figure 6.14 shows that there is some difference in SCL between the base case for 2031 (15.9GW of interconnection) and the optimal interconnector path (18.9GW for Steady Progression and 19.4GW in Consumer Evolution). There is also considerable regional variation across the two scenarios. The analysis shows that interconnectors may have a positive and negative impact on SCL. Whilst the percentage changes shown above are low, care needs to be taken in interpreting these results. Whilst the charts show annual differences in SCL, hourly changes due to interconnector flows may be more challenging from a system operability perspective. Further analysis needs to be undertaken to determine the potential effects of increased interconnection on SCL.

6.5.5.4 Voltage control: steady state voltage

Reactive power is used to control voltage levels across the electricity system, keeping them at a safe and efficient level for electricity transportation and consumption. Unlike system frequency, which in normal operation is consistent across the network, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. National Grid must manage voltage levels on a local level to meet the varying needs of the system.

To maintain security and quality of electricity supply, there are requirements to ensure the voltage of the network is maintained within strict limits. Reactive power is used to maintain voltage control: to increase voltage, reactive power is required and to reduce voltage, reactive power is absorbed. Voltage is a regional rather than national phenomenon and so reactive requirement varies across the country.

The requirements for reactive power will increase as network loading becomes more volatile and many conventional generators (which provide reactive power) run less predictably and less often. Reactive support can come from network assets such as capacitor banks which can provide reactive power, or reactors which can absorb reactive power.

We have looked at the impact interconnectors could have on voltage control. By taking the regional reactive requirement in the base case and comparing it to the reactive requirement for the optimal level of interconnection, we can see how increased interconnection may impact voltage control. Interconnectors themselves can provide reactive power, however they may also displace large conventional plants and so they are capable of both providing reactive support and necessitating the provision of voltage control methods, depending on factors in the wider network.

Figure 6.15 shows the difference in capacitive and reactive requirement between the base case and optimal interconnection path for Consumer Evolution and Two Degrees in the year 2031. A positive number for capacitive requirement shows where additional reactive power is required in the optimal path, and a positive number for the reactive requirement shows where additional reactive power must be absorbed.

Figure 6.15

Percentage change in capacitive and reactive requirement for Consumer Evolution and Two Degrees scenarios from the base case in 2031 and to the optimal interconnector path in 2031

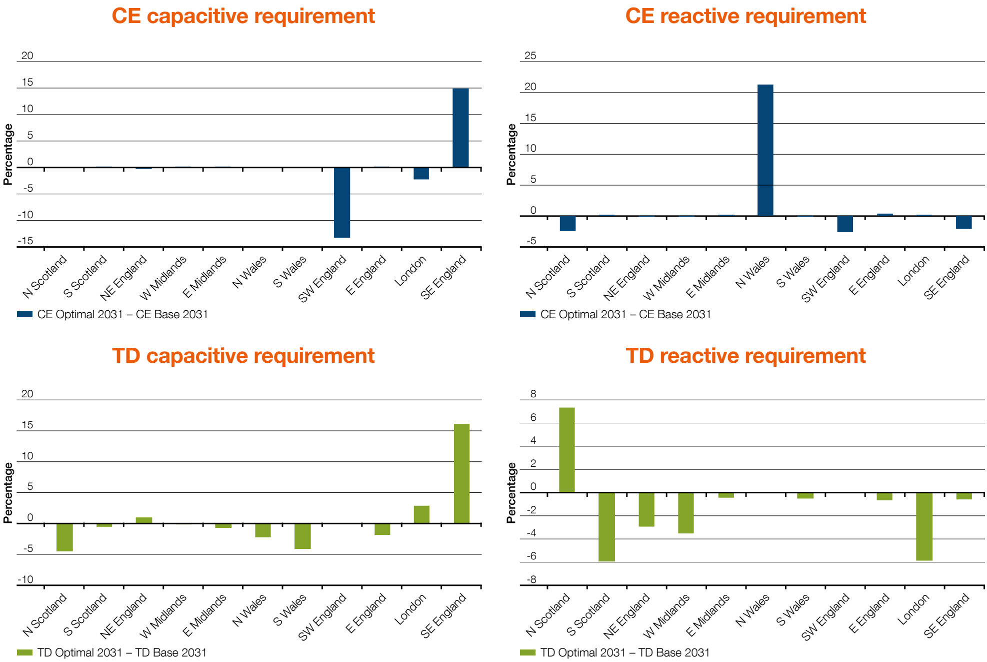


Figure 6.15 shows that for both Consumer Evolution and Two Degrees the percentage change in capacitive requirement and reactive requirement varies between the optimal interconnection path and base case. Some regions see an increase in requirement and some show a decrease. The highest percentage change is in Consumer Evolution for North Wales, which shows a 21% increase in reactive requirement in the optimal interconnection path compared to the base case. It is difficult to draw any other real conclusions from the results shown, and a more detailed analysis of the results is not possible here. When there are higher levels of interconnection, there is the possibility that the transmission system becomes used to facilitate high levels of renewables export, or interconnector import/exports are used to solve boundary constraint issues. The high transmission system usage results in a requirement for more reactive power generation for voltage management.

Another potential scenario is low power flows across the network because of high interconnector exports in the north and high interconnector imports in the south. This coupled with low synchronous plant running will lead to high reactive absorption requirements to manage high voltages.

Space precludes a more detailed analysis of voltage variation within day, but interconnectors ability to rapidly ramp between export and import is one area for potential further investigation.

6.5.5.5 System operability analysis – conclusions

Analysing the impact interconnectors may have on system operability and operational costs is complex, especially when considering the high levels of uncertainty regarding the future energy landscape as described within the *FES*. This initial attempt at system stability and voltage analysis as part of *NOA* for Interconnectors shows that interconnectors will have an impact on system operability. The results suggest that, as expected, in certain circumstances interconnectors can be beneficial to system operability, whereas in others, they may have a negative impact, for example where they represent the largest loss on the system.

Additional interconnection may lead to increases or decreases in reactive generation and absorption requirements. Our analysis also suggests that SCL may be increased or decreased by increased interconnection.

The effect on RoCoF due to increased interconnection is complicated. Figure 6.12 shows an overall increase in RoCoF as interconnector capacity increases, but interconnection can also reduce the problem in some scenarios. The situation is dynamic and Figure 6.13 shows how the situation can change rapidly within day.

No attempt has been made to quantify the impact of additional interconnection on system operation costs in the future, but just as interconnectors may have a positive or negative impact on system operability, then similarly there may be situations where interconnectors can provide system operability services and in other situations be required to support additional system costs.

Many factors will influence how the system might be impacted by additional interconnection in the future. With such uncertainty, the analysis presented here can only represent a preliminary exploration, especially as there are other system operability criteria that have not been covered.

If you would like to read more about how the changing energy landscape is shaping future operability challenges for the GB electricity network, then please visit our *System Operability Framework* webpage: **https://www.nationalgrideso.com/insights/system-operability-framework-sof**

6.6 Comparison of *NOA* IC to other relevant interconnector analysis

The NOA for Interconnectors analysis uses the *FES* 2018 as an input. Hence, the assumptions within these scenarios play an important role in determining the results of the analysis.

The European Network for Transmission System Operators for Electricity (ENTSO-E) also undertakes a cost-benefit analysis of various European interconnector projects[5], assessing amongst other things SEW and CO_2 emissions. This forms part of the Ten Year Network Development Plan (TYNDP) process, part of which is the development of a suite of scenarios. Like the *FES*, the TYNDP scenarios are developed with stakeholder engagement and are designed to reduce emissions sufficiently to meet the 2050 EU targets.

Differences between *FES* and the TYNDP scenarios may well lead to different results when attempting cost-benefit analyses. Whilst the intention of both the *FES* and TYNDP scenarios is to explore various pathways to decarbonising Europe, such that climate and energy targets are achievable, the *FES* and TYNDP scenarios will have significant differences in terms of scale, timing and growth rates of many generation technologies. In addition, there are variations in the CBA methodology used for *NOA* for Interconnectors and for TYNDP. For example within the TYNDP, each project is assessed using the pan-European CBA methodology. This methodology sets out the criteria for the assessment of costs and benefits of transmission and storage projects. Each TYNDP project is assessed against a range of benefit, cost and residual benefit indicators, which vary from the approach within the *NOA* for Interconnectors. Also, there are sequencing differences as the *FES* process results in new scenarios annually, whereas the TYNDP process develops new scenarios once every two years. Finally, there are significant differences in the presentation of the results. *NOA* for Interconnectors is focused on producing the optimum interconnection paths for each *FES*, whereas TYNDP includes an assessment of each interconnector and an assessment of the requirements for additional interconnection at a regional level. Consequently, it is difficult to undertake a direct comparison between the cost-benefit analysis within *NOA* for Interconnectors and that for interconnection within the TYNDP.

[5] The findings of the CBAs on interconnectors undertaken as part of ENTSO-E's 2018 Ten Year Network Development Plan (TYNDP) package are available at: https://tyndp.entsoe.eu/tyndp2018/projects/projects

6.7 Summary

The analysis shows that there are still significant potential opportunities for additional GB interconnection to create value for GB and Europe, both economically and environmentally.

Interconnection enables the more efficient dispatch of generation across Europe, resulting in higher SEW and constraint savings, leading to savings for consumers, increased profits for generators and income for interconnector developers.

The optimal level of interconnection varies across the energy scenarios used within the analysis. The analysis added a range of between 2.5 GW and 5.5 GW of additional interconnection capacity to the 15.9 GW already included within the interconnection base case, resulting in a total interconnection range of between 18.4 GW and 21.4 GW. This represents roughly five times more than the existing GB interconnection capacity of 4 GW.

Whilst the analysis highlights the optimal interconnector paths based on the *FES* 2018, the analysis shows that many of the interconnectors not in the optimal paths also add value.

Additional interconnection may improve or worsen system operability. In certain situations it may increase system security or potentially lower the cost of providing system security. In other situations it may decrease system security or raise the cost of providing system security.

It is important to restate that this is not a forecast, as many other factors outside the scope of this analysis will influence the outcome for GB interconnection over the next decade and beyond. The results of this analysis are dependent on the underlying assumptions within the FES: these scenarios aim to provide a range of credible energy futures. Uncertainty with respect to Europe's future energy landscape, as well as uncertainty regarding developments in the physical network and variations in network constraint and construction costs are just some of the variables which will have an impact on future interconnection.

6.8 Stakeholder feedback

This year we have continued to develop the *NOA* for Interconnectors methodology based on stakeholder feedback.

We want to hear your feedback on this year's analysis. Were the developments we implemented this year, such as the ancillary services analysis and providing a range for the optimal level of GB interconnection, of benefit to you? For *NOA* for Interconnectors 2019/20 we intend to continue to improve this analysis. What improvements would you like to see? We look forward to your involvement in the *NOA* for Interconnectors consultation in 2019.

Chapter 7
Stakeholder engagement

7.1 Introduction

Your feedback and comments on this *NOA* publication will help to improve it. Please take part in our 2019 stakeholder engagement programme so we know what you need.

7.2 Continuous development

Your feedback is important for us to continue developing and improving the *NOA* and the *ETYS*. And because the two documents are closely related, we'll make sure the way we communicate and consult with you reflects this. We'll make sure that the *NOA* publication continues to add value by:

- identifying and understanding your views and opinions
- providing opportunities for constructive debate throughout the process
- creating open and two-way communication to discuss assumptions, drivers and outputs; and
- telling you how your views have been used, and reporting back on the engagement process.

The *NOA* annual review process will help us develop the publication. We encourage all interested parties to get involved to help us improve the publication every year.

As mentioned in Chapter 1, we have published a long-term roadmap for network development in 2018 with developments to deliver further value from the *NOA*. We envisage that the findings in those additional areas will be included in our wider future *NOA* publications, as part of the main *NOA* report and/or as separate documents.

We will share the outcomes in those development areas and seek opportunities to work with a wider range of industry participants to shape our future *NOA*. If you would like to get involved, or for a member of your team to attend an event to talk about them, please contact us via the email address on the following page.

We have sought your views at various points through this *NOA*:

- We've highlighted the pathfinding projects we undertake when we talk about 'Evolution of the *NOA*'. We'd like to know your views on the development of these projects.
- This year we continued to evolve the *NOA* for Interconnectors methodology based on stakeholder feedback. We really need your feedback on this year's *NOA* for Interconnectors analysis so that we can continue to improve the value of the analysis to you.

7.3 Stakeholder engagement

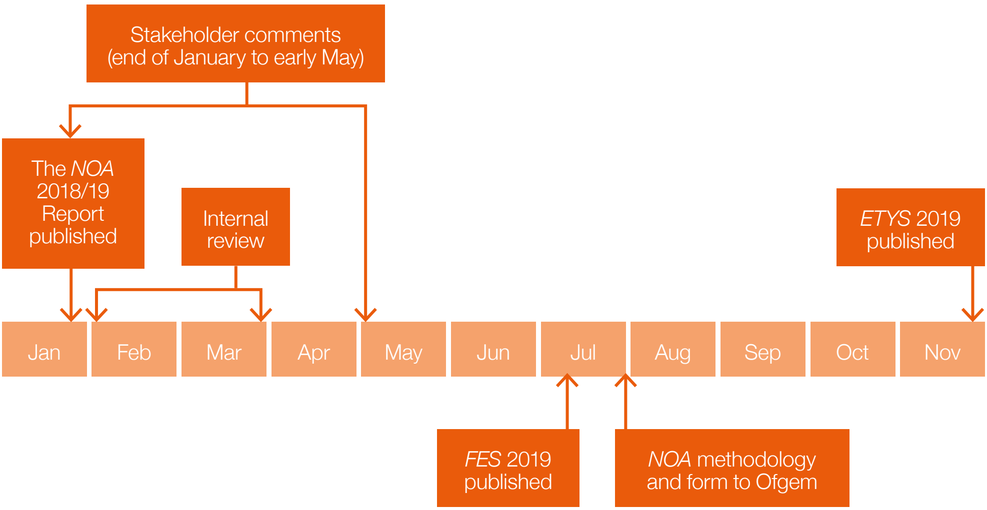
We are always happy to listen to your views:

- at consultation events, such as our customer seminars
- through responses to **transmission.etys@nationalgrid.com**
- at bilateral stakeholder meetings; and
- through any means convenient for you.

To make our information more accessible, we have published a summary of frequently asked questions (FAQ) from our stakeholder group meetings[1]. These give a high-level view of the *NOA* and it is useful if you want to know more about the process.

Now the *NOA* is published we'll start the review process, and we are looking forward to having conversations with you between now and June 2019. This consultation will cover the *NOA* methodology and form of the *NOA* report, as well as its contents. Because some parts of the NOA process start in May, we have already started on some of the methodology's higher-level aspirations.

Figure 7.1
ETYS/NOA stakeholder activities programme



[1] https://www.nationalgrideso.com/sites/eso/files/documents/NOA%20Q%20%26%20A%20from%20stakeholder%20group%20meeting.pdf

Appendix

Appendix A

Economic analysis results

Tables A.1–3 present the results from our cost-benefit analysis. The results highlight optimal options with optimum delivery dates across different scenarios and sensitivities. Options with an optimum delivery date that is the same as their EISD are deemed 'critical'. Critical options are in bold.

Table A.1
Optimum delivery dates – Scotland and the north of England region

			Optimum delivery date			
Option code	**Description**	**EISD**	**Two Degrees**	**Community Renewables**	**Consumer Evolution**	**Steady Progression**
CBEU	Creyke Beck to Keadby advance rating	2021	2025	2025	2026	2025
CDRE	**Cellarhead to Drakelow reconductoring**	**2022**	**2022**	**2022**	**2022**	**2023**
CPRE	Reconductor sections of Penwortham to Padiham and Penwortham to Carrington	2021	N/A	N/A	N/A	2024
CS01	**A commercial solution for Scotland and the north of England with a service duration of 40 years**	**2020**	**2020**	**2021**	**N/A**	**N/A**
CS03	A commercial solution for Scotland and the north of England with a service duration of 15 years	2020	N/A	N/A	2022	2021
DNEU	Denny North 400/275kV Supergrid Transformer 2	2022	2027	2027	2027	2027
DWNO	**Denny to Wishaw 400kV reinforcement**	**2028**	**2028**	**2028**	**2029**	**2029**
E2DC	**Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC**	**2027**	**2027**	**2027**	**2027**	**2027**
E4D3	**Eastern Scotland to England link: Peterhead to Drax offshore HVDC**	**2029**	**2029**	**2029**	**2029**	**2029**
ECU2	**East coast onshore 275kV upgrade**	**2023**	**2023**	**2023**	**2023**	**2023**
ECUP	**East coast onshore 400kV incremental reinforcement**	**2026**	**2026**	**2026**	**2026**	**2026**
ECVC	Eccles SVCs and real-time rating system	2024	2027	2027	2027	2027
EHRE	**Elvanfoot to Harker reconductoring**	**2024**	**2024**	**2024**	**2024**	**2024**
FSPC	**Power control device along Fourstones to Stella West**	**2020**	**2020**	**2020**	**2020**	**2020**
HAE2	**Harker Supergrid Transformer 5 replacement**	**2022**	**2022**	**2022**	**2022**	**2022**
HAEU	**Harker Supergrid Transformer 6 replacement**	**2021**	**2021**	**2021**	**2021**	**2021**
HNNO	**Hunterston East–Neilston 400kV reinforcement**	**2023**	**2023**	**2023**	**2023**	**2023**
HSRE	**Reconductor Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuit**	**2024**	**N/A**	**N/A**	**N/A**	**2024**
HSPC	**Power control device along Harker to Stella West**	**2020**	**2020**	**2020**	**2020**	**2020**
KBRE	Knocknagael to Blackhillock 275kV double circuit reconductoring	2024	2029	2029	2029	2030
KWHW	Keadby to West Burton circuits thermal uprating	2020	2022	2022	2022	2024
LDQB	**Lister Drive quad booster**	**2020**	**2020**	**2020**	**2020**	**2020**
LNRE	**Reconductor Lackenby to Norton single 400kV circuit**	**2022**	**2022**	**2022**	**2023**	**2022**
LNPC	Power control device along Lackenby to Norton	2020	2021	N/A	N/A	N/A
NEMS	**225MVAr MSCs within the north east region**	**2022**	**2022**	**2022**	**2022**	**N/A**
NEPC	Power control device along Blyth to Tynemouth and Blyth to South Shields	2020	2024	2024	2024	2024

Table A.1
Optimum delivery dates – Scotland and the north of England region (continued)

			Optimum delivery date			
Option code	**Description**	**EISD**	**Two Degrees**	**Community Renewables**	**Consumer Evolution**	**Steady Progression**
NOHW	Thermal uprate 55km of the Norton to Osbaldwick 400kV double circuit	2020	2029	2029	2029	2025
NOR1	Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit	2021	2024	2024	N/A	N/A
NOR2	Reconductor 13.75km of Norton to Osbaldwick 1 400kV circuit	2021	N/A	N/A	2024	2024
NOR4	Reconductor 13.75km of Norton to Osbaldwick 2 400kV circuit	2021	N/A	N/A	2029	2025
OENO	**Central Yorkshire reinforcement**	**2027**	**2027**	**2027**	**N/A**	**2027**
OTHW	Osbaldwick to Thornton 1 circuit thermal upgrade	2020	N/A	N/A	2029	N/A
SSHW	Spennymoor to Stella West circuits thermal uprating	2020	N/A	N/A	N/A	2024
TDR2	Reconductor Drax to Thornton 1 circuit	2021	2029	2029	N/A	2029
TDRE	Reconductor Drax to Thornton double circuit	2022	N/A	N/A	2027	N/A
THS1	**Install series reactors at Thornton**	**2023**	**2023**	**2023**	**2023**	**2023**
TURC	Reactive compensation at Tummel	2022	2029	2030	N/A	N/A
WHTI	**Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit**	**2021**	**2021**	**2021**	**2022**	**2022**
WLTI	Windyhill–Lambhill–Longannet 275kV circuit turn-in to Denny North 275kV substation	2021	2023	2023	2023	2023

Table A.2
Optimum delivery dates – the south and east of England region

Option code	Description	EISD	Optimum delivery date Two Degrees	Community Renewables	Consumer Evolution	Steady Progression
BDEU	Bramley to Didcot circuits thermal uprating	2021	2029	2030	N/A	N/A
BFHW	Bramley to Fleet circuits thermal uprating	2020	2024	2023	N/A	N/A
BMM2	**225MVAr MSCs at Burwell Main**	**2022**	**2022**	**2022**	**2022**	**2022**
BMM3	**225MVAr MSC at Burwell Main**	**2023**	**2023**	**2023**	**2023**	**2023**
BNRC	**Bolney and Ninfield additional reactive compensation**	**2022**	**2022**	**2022**	**2022**	**2022**
BPRE	Reconductor the newly formed second Bramford to Braintree to Rayleigh Main circuit	2022	2029	2029	N/A	2027
BRRE	Reconductor remainder of Bramford to Braintree to Rayleigh route	2021	2022	2022	2022	2022
BTNO	**A new 400kV double circuit between Bramford and Twinstead**	**2026**	**2026**	**2026**	**2026**	**2026**
CS21	A commercial solution for East Anglia with a service duration of 40 years	2020	2025	2034	N/A	2026
CS25	**A commercial solution for the south coast with a service duration of 40 years**	**2020**	**2020**	**2020**	**2020**	**2020**
CTRE	Reconductor remainder of Coryton South to Tilbury circuit	2020	2021	2021	2022	2022
EAMS	225MVAr MSCs at Eaton Socon	2022	2028	2029	2024	2027
ESC1	Second Elstree to St John's Wood 400kV circuit	2023	2030	2030	2033	N/A
FLR2	Fleet to Lovedean reconductoring (with a different conductor type to FLRE)	2020	2025	2025	2025	N/A
FLPC	Power control device along Fleet to Lovedean	2020	N/A	N/A	N/A	2026
FMHW	Feckenham to Minety circuits thermal uprating	2020	2024	2023	N/A	2026
GKEU	Thermal upgrade for Grain and Kingsnorth 400kV Substation	2021	2025	N/A	N/A	N/A
GRRA	Grain running arrangement change	2019	N/A	N/A	2021	2021
HWUP	Uprate Hackney, Tottenham and Waltham Cross 275kV to 400kV	2024	2028	2028	2028	2030
IFHW	Feckenham to Ironbridge circuits thermal uprating	2020	2024	2024	N/A	2026
KLRE	**Kemsley to Littlebrook circuits uprating**	**2020**	**2020**	**2020**	**2020**	**2020**
MBRE	Bramley to Melksham reconductoring	2022	2028	2027	2035	N/A
NBRE	Reconductor Bramford to Norwich double circuit	2022	2025	2025	2028	2025
RTRE	**Reconductor remainder of Rayleigh to Tilbury circuit**	**2021**	**2021**	**2021**	**2021**	**2022**
SCN1	**New 400kV transmission route between South London and the south coast**	**2026**	**2026**	**2026**	**2026**	**2026**
SEEU	**Reactive compensation protective switching scheme**	**2021**	**2021**	**2021**	**2021**	**2021**
SER1	**Elstree to Sundon reconductoring**	**2022**	**2025**	**2022**	**2024**	**2023**
SER2	Elstree–Sundon 2 circuit turn-in and reconductoring	2022	2030	2030	2033	N/A
THRE	Reconductor Hinkley Point to Taunton double circuit	2022	2028	2028	N/A	2028
WYQB	Wymondley quad boosters	2023	2024	2025	2030	2026
WYTI	Wymondley turn-in	2021	2022	2023	2029	2025

Table A.3
Optimum delivery dates – Wales and West Midlands region

			Optimum delivery date			
Option code	**Description**	**EISD**	**Two Degrees**	**Community Renewables**	**Consumer Evolution**	**Steady Progression**
BCRE	Reconductor the Connah's Quay legs of the Pentir to Bodelwyddan to Connah's Quay 1 and 2 circuits	2022	2029	2036	N/A	2034
PTC1	**Pentir to Trawsfynydd 1 cable replacement – single core per phase**	**2023**	**2024**	**2023**	**2035**	**2031**
PTC2	Pentir to Trawsfynydd 1 and 2 cables – second core per phase and reconductor of an overhead line section on the existing Pentir to Trawsfynydd circuit	2025	2028	2035	N/A	2033
PTNO	Pentir to Trawsfynydd second circuit	2025	2027	2034	2037	2032
PTRE	Pentir to Trawsfynydd circuits – reconductor the remaining overhead line sections	2025	2030	N/A	N/A	2036

Tables A.4–5 present the results from our single year least regret analysis. The top 10 investment strategies are listed with their economic regrets across different scenarios and sensitivities. The best strategy with the least worst regret is highlighted in green.

Table A.4

Regrets for Scotland and the north of England region options

	Two Degrees	Community Renewables	Consumer Evolution	Steady Progression	Worst regret
(1) Progress all options	£0.90m	£1.19m	£0.99m	£0.21m	£1.19m
(2) Progress all options except CS01	£1.80m	£1.19m	£0.99m	£0.21m	£1.80m
(3) Progress all options except CS01 and HSRE	£0.90m	£0.29m	£0.09m	£6.54m	£6.54m
(4) Progress all options except HSRE and DWNO	£6.91m	£3.72m	£0.06m	£6.50m	£6.91m
(5) Progress all options except DWNO	£7.80m	£4.62m	£0.96m	£0.18m	£7.80m
(6) Progress all options except CS01, HSRE, and DWNO	£7.81m	£3.72m	£0.06m	£6.50m	£7.81m
(7) Progress all options except CS01 and DWNO	£8.70m	£4.62m	£0.96m	£0.18m	£8.70m
(8) Progress all options except CS01 and LNRE	£3.44m	£16.89m	£0.96m	£14.27m	£16.89m
(9) Progress all options except CS01, LNRE, and DWNO	£10.35m	£20.32m	£0.92m	£14.23m	£20.32m
(10) Progress all options except CS01, HSRE, LNRE, and DWNO	£9.45m	£19.42m	£0.02m	£20.56m	£20.56m

Table A.5

Regrets for the south and east of England region options

	Two Degrees	Community Renewables	Consumer Evolution	Steady Progression	Worst regret
(1) Progress all options except SER1	£0.00m	£0.00m	£0.03m	£0.00m	£0.03m
(2) Progress all options	£0.01m	£0.80m	£0.04m	£0.00m	£0.80m
(3) Progress all options except BMM3 and SER1	£0.88m	£1.00m	£0.77m	£0.88m	£1.00m
(4) Progress all options except BMM3	£0.89m	£1.55m	£0.77m	£0.88m	£1.55m
(5) Progress all options except RTRE and SER1	£0.94m	£2.68m	£0.00m	£0.00m	£2.68m
(6) Progress all options except RTRE	£0.95m	£3.48m	£0.01m	£0.00m	£3.48m
(7) Progress all options except RTRE, BMM3, and SER1	£1.82m	£3.68m	£0.73m	£0.87m	£3.68m
(8) Progress all options except RTRE and BMM3	£1.83m	£4.23m	£0.74m	£0.88m	£4.23m
(9) Progress all options except RTRE, SER1, and SCN1	£7.94m	£30.85m	£146.65m	£62.27m	£146.65m
(10) Progress all options except RTRE and SCN1	£7.95m	£31.65m	£146.66m	£62.27m	£146.66m

Table A.6

Regrets for the south and east of England region options

	Two Degrees	Community Renewables	Consumer Evolution	Steady Progression	Worst regret
(1) Progress PTC1	£0.00m	£0.00m	£0.01m	£0.01m	£0.01m
(2) Do not progress PTC1	£0.00m	£0.67m	£0.00m	£0.00m	£0.67m

Appendix B SWW projects

B.1 Eastern network reinforcement

1. Background

The scope of the reinforcements included for the eastern network in the northern region includes offshore HVDC links as well as onshore reinforcement. These reinforcement projects increase capability on one or multiple of the MITS boundaries B1, B1a, B2, B4, B5, B6, B7, B7a and B8. The objective is to increase the north-to-south transfer capability on the east coast of the Scottish and northern England transmission system between boundaries B1 in the Scottish Hydro Electric Transmission (SHE Transmission) area and B8 in the National Grid Electricity Transmission (NGET) area, to safely enable greater volumes of north-to-south power flows arising from predominantly new renewable generation in Scotland. This includes key boundaries between SHE Transmission and SP Transmission (B4) and between SP Transmission (SPT) and NGET (B6).

A number of reinforcements are proposed to improve the transfer capability in accordance with the NETS SQSS[1] and pursuant to the Transmission Owners' obligations in their transmission licences. In previous years, two offshore eastern subsea HVDC links were considered within *NOA* – one from Peterhead in north east Scotland to Hawthorn Pit in north east England (E4DC), the other from Torness in south east Scotland to Hawthorn Pit (E2DC). The outcome of the *NOA* 2017/18 indicated that both of these links were required, which would then require multiple reinforcements around Hawthorn Pit to accommodate them. This led the TOs to develop alternative options that would bring power further south to bypass these additional works. As a result, six subsea HVDC link options have been considered in combination within this year's NOA process:

- E4DC – Peterhead to Hawthorn Pit.
- E4D2 – Peterhead to Cottam.
- E4D3 – Peterhead to Drax.
- E2DC – Torness to Hawthorn Pit.
- E2D2 – Torness to Cottam.
- E2D3 – Torness to Drax.

All options involve the construction of a 2 GW HVDC link and associated AC onshore works on either end of the link. The links from Peterhead can increase transfer capability on boundaries B1 down to B8[2]. The links from Torness increase transfer capability on boundaries B6 down to B8[3]. The combinations of HVDC link considered in the *NOA* 2018/19 are limited such that there is not more than one link at any of the onshore locations to minimise the associated onshore reinforcement works.

The scope of the eastern onshore reinforcements involves increasing the capacity of the eastern onshore circuits between Blackhillock and Kincardine that cross B1a, B2 and B4 by initially augmenting their capability at 275kV. Further uplift in capacity will be delivered by uprating these circuits to operate at 400kV. Also, an onshore network reinforcement is included to develop the network in the central belt of Scotland and increase the capability of the B5 boundary.

The recommendation from the 2017/18 NOA process is to progress the following reinforcements for the eastern network in the northern region to maintain the Earliest In Service Date (EISD):

- East coast onshore 275kV upgrade (ECU2) – EISD of 2023.
- East coast onshore 400kV incremental reinforcement (ECUP) – EISD of 2026.
- Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC (E2DC) – EISD of 2027.
- Eastern Scotland to England link: Peterhead to Drax offshore HVDC (E4D3) – EISD of 2029.
- Denny-Wishaw 400kV reinforcement (DWNO) – EISD 2028.

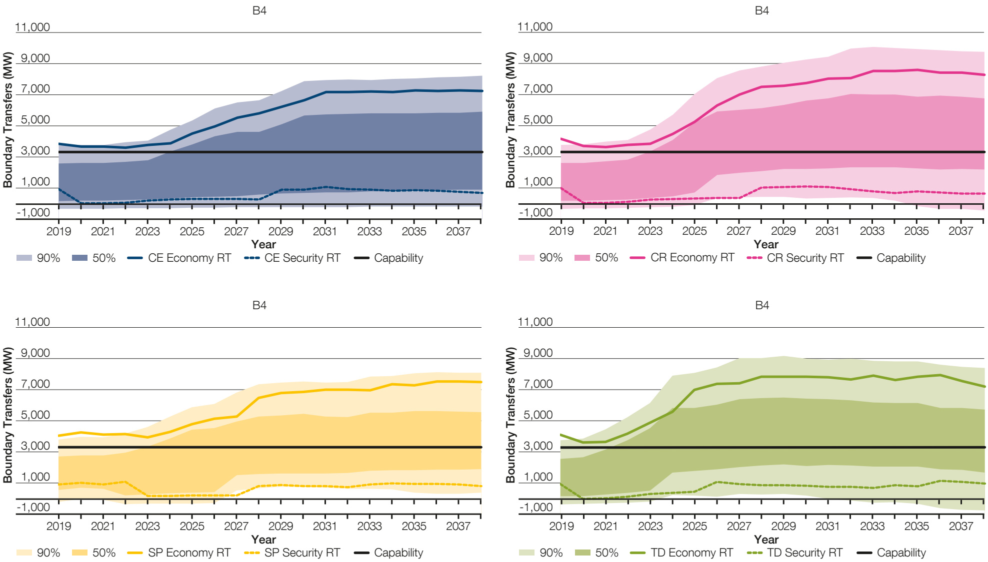
[1] The NETS SQSS is the National Electricity Transmission System Security and Quality of Supply Standard. GB Transmission Owners have licence obligations to develop their transmission systems in accordance with the NETS SQSS.

[2] Depending on onshore location in the north of England.

[3] Depending on onshore location in the north of England.

The requirement to reinforce the transmission network is driven fundamentally by the growth of predominantly renewable generation and interconnectors in the SHE Transmission, SPT and NGET (north England) areas, including offshore windfarms and interconnectors situated in the Moray Firth, in the Firth of Forth and off the north east coast of England. Figures 8.1 to 8.5 show the Required Transfers[4] for boundaries B4, B6, B7, B7a and B8 for the four scenarios in the 2018 *Future Energy Scenarios (FES)*. The figures also show the current network capabilities across the boundaries as well as the distribution of annual power flow for each scenario. Information on how to interpret these boundary graphs can be found in this year's *ETYS*. The difference between the Required Transfers and the network capability shows a requirement for further network reinforcement.

Figure 8.1
Boundary B4 (SHE Transmission/ SPT) required transfer, power flow distribution and base capability



[4] The Required Transfer figures shown take into account interconnectors connecting to the GB transmission system in the 2018 Future Energy Scenarios.

Figure 8.2
Boundary B6 (SPT/NGET) required transfer, power flow distribution and base capability

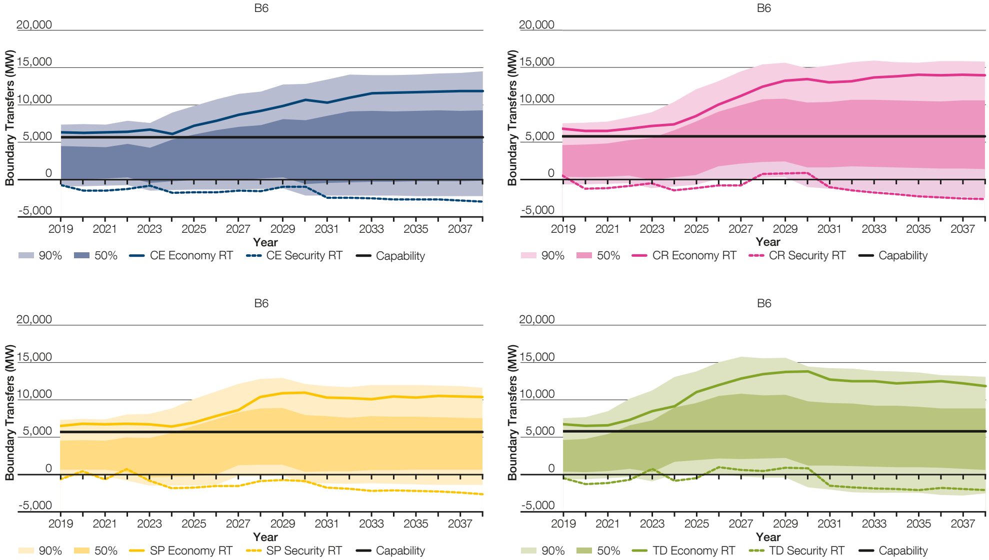


Figure 8.3

Boundary B7 (Upper north of England) required transfer, power flow distribution and base capability

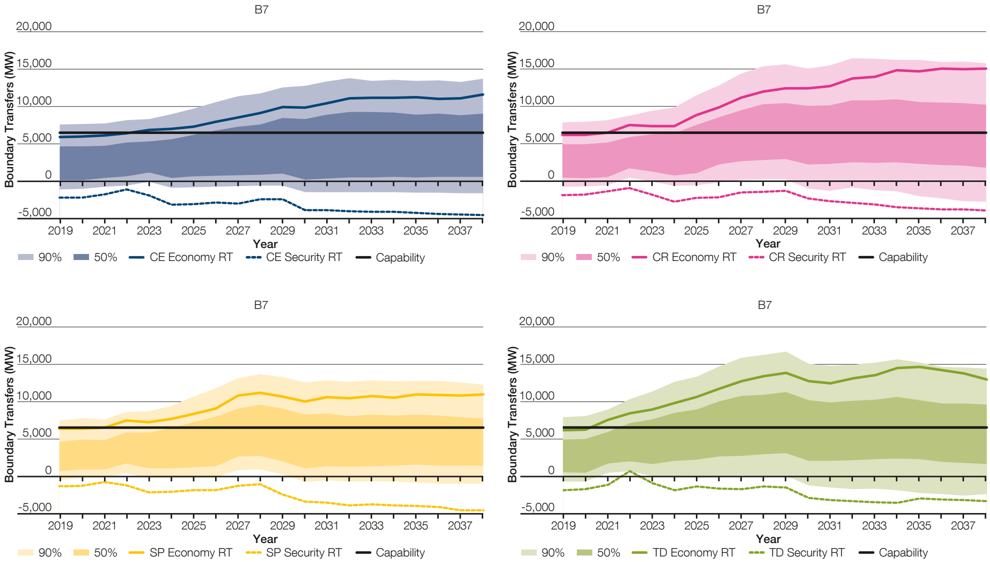


Figure 8.4
Boundary B7a (Upper north of England) required transfer, power flow distribution and base capability

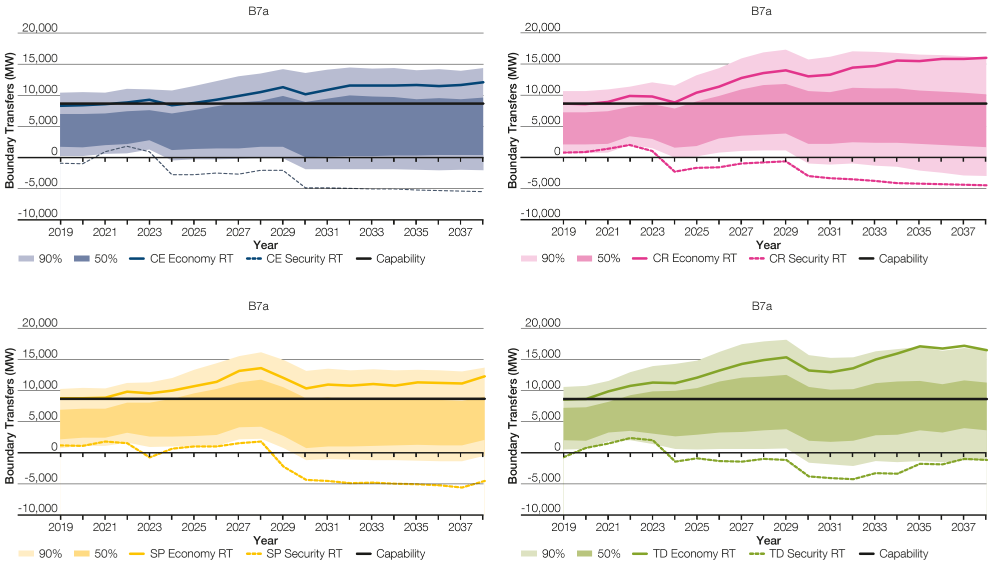
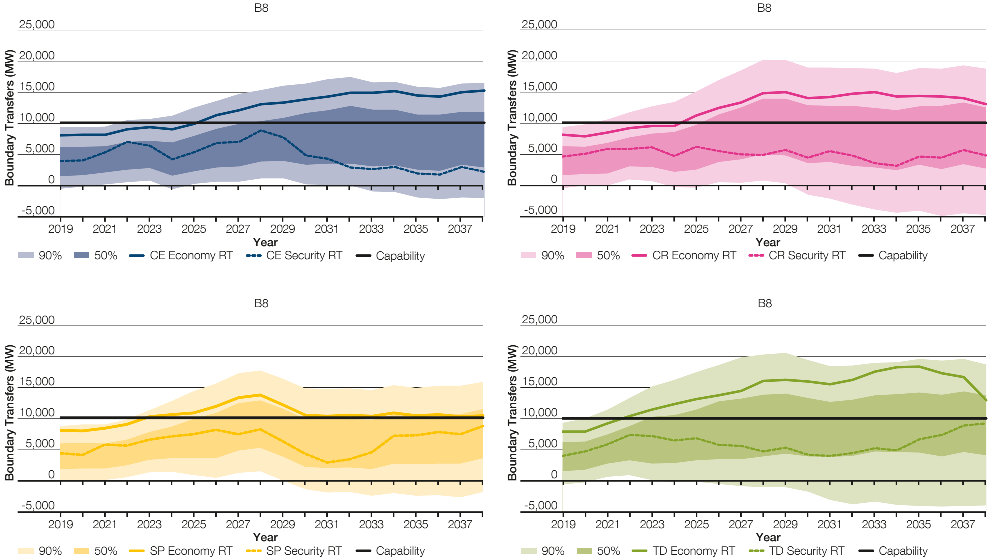


Figure 8.5
Boundary B8 (North of England to Midlands) required transfer, power flow distribution and base capability



2. Option development

A number of reinforcement options have been developed for the eastern network in the northern region to improve boundary capability across boundaries B1 to B8. These options consider onshore and offshore solutions.

2.1 Notable options

(a) East coast onshore 275kV upgrade (ECU2)

Establish a new 275kV substation at Alyth, including shunt reactive compensation at Alyth, extend Tealing 275kV substation and install two phase shifting transformers, re-profile the 275kV circuits between Kintore, Alyth and Kincardine, and Tealing, Westfield and Longannet, and uprate the cable sections at Kincardine and Longannet. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2 and B4.

(b) East coast onshore 400kV incremental reinforcement (ECUP)

Following ECU2, establish a new 400kV substation at Kintore, uprate Alyth substation for 400kV operation, re-insulate the 275kV circuits between Blackhillock, Peterhead, Rothienorman, Kintore, Fetteresso, Alyth and Kincardine for 400kV operation and install phase shifting transformers at Blackhillock. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2 and B4.

(c) East coast onshore 400kV reinforcement (ECU4)

Establish new 400kV substations at Kintore and Alyth, including shunt reactive compensation at Alyth, re-insulate the 275kV circuits between Blackhillock, Peterhead, Rothienorman, Kintore, Fetteresso, Alyth and Kincardine for 400kV operation, install phase shifting transformers at Blackhillock, re-profile the 275kV circuits between Tealing, Westfield and Longannet, and uprate the cable sections at Longannet. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2 and B4.

(d) Eastern Scotland to England link: Peterhead to Hawthorn Pit offshore HVDC (E4DC)

Construct a new offshore 2 GW HVDC subsea link from Peterhead (north east of Scotland) to Hawthorn Pit (north of England), including AC/DC converter stations and associated AC onshore works at the Peterhead and Hawthorn Pit ends of the link. The AC onshore works at the Peterhead end include the upgrade of the 275kV circuits along the Blackhillock–Rothienorman–Peterhead route to 400kV operation. The AC onshore works at Hawthorn Pit include a new 400kV Hawthorn Pit GIS substation, uprating of the Hawthorn Pit–Norton circuit and associated circuit reconfiguration works in the area. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2, B4, B5, B6, B7, and B7a.

(e) Eastern Scotland to England link: Peterhead to Cottam offshore HVDC (E4D2)

Construct a new offshore 2 GW HVDC subsea link from Peterhead (north east of Scotland) to Cottam (north Nottinghamshire in England), including AC/DC converter stations and associated AC onshore works at the Peterhead and Cottam ends of the link. The AC onshore works at the Peterhead end include the upgrade of the 275kV circuits along the Blackhillock–Rothienorman–Peterhead route to 400kV operation. The AC onshore works at Cottam is to connect into a bay at Cottam 400kV substation. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2, B4, B5, B6, B7, B7a and B8.

(f) Eastern Scotland to England link: Peterhead to Drax offshore HVDC (E4D3)

Construct a new offshore 2GW HVDC subsea link from Peterhead (north east of Scotland) to Drax (Yorkshire in England), including AC/DC converter stations and associated AC onshore works at the Peterhead and Drax ends of the link. The AC onshore works at the Peterhead end include the upgrade of the 275kV circuits along the Blackhillock–Rothienorman–Peterhead route to 400kV operation. The AC onshore works at Drax include a busbar extension, a new bay at the existing Drax 400kV substation and may also include associated fault level mitigation works. This reinforcement option provides additional transmission capacity across boundaries B1, B1a, B2, B4, B5, B6, B7, B7a and B8.

(g) Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC (E2DC)

Construct a new offshore 2GW HVDC subsea link from Torness area to Hawthorn Pit, including AC/DC converter stations and associated AC works at Torness and Hawthorn Pit. The AC onshore works in the vicinity of the Torness end include extension of the pre-existing 'Branxton 400kV substation' by two 400kV GIS bays to provide connection to the 'Branxton converter station'. The AC onshore works at Hawthorn Pit include a new 400kV Hawthorn Pit GIS substation, uprating of the Hawthorn Pit–Norton circuit and associated circuit reconfiguration works in the area. This reinforcement option provides additional transmission capacity across boundaries B6, B7 and B7a.

(h) Eastern Scotland to England link: Torness to Cottam offshore HVDC (E2D2)

Construct a new offshore 2GW HVDC subsea link from Torness area to Cottam, including AC/DC converter stations and associated AC works at Torness and Cottam. The AC onshore works in the vicinity of the Torness end include extension of the pre-existing 'Branxton 400kV substation' by two 400kV GIS bays to provide connection to the 'Branxton converter station'. The AC onshore works at Cottam is to connect into a bay at Cottam 400kV substation. This reinforcement option provides additional transmission capacity across boundaries B6, B7, B7a and B8.

(i) Eastern Scotland to England link: Torness to Drax offshore HVDC (E2D3)

Construct a new offshore 2GW HVDC subsea link from Torness area to Drax, including AC/DC converter stations and associated AC works at Torness and Drax. The AC onshore works in the vicinity of the Torness end include extension of the pre-existing 'Branxton 400kV substation' by two 400kV GIS bays to provide connection to the 'Branxton converter station'. The AC onshore works at Drax include a busbar extension, a new bay at the existing Drax 400kV substation and may also include associated fault level mitigation works. This reinforcement option provides additional transmission capacity across boundaries B6, B7, B7a and B8.

(j) Denny–Wishaw 400kV reinforcement (DWNO)

Construct a new 400kV double circuit from Bonnybridge to Newarthill and reconfigure associated sites to establish a fourth north to south double circuit Supergrid route through the Scottish central belt. One side of the new double circuit will be operated at 400kV, the other at 275kV. This reinforcement will establish Denny–Bonnybridge, Bonnybridge–Wishaw, Wishaw–Strathaven No.2 and Wishaw–Torness 400kV circuits, and a Denny–Newarthill–Easterhouse 275kV circuit. This reinforcement option provides additional transmission capacity across boundary B5.

(k) Eastern Scotland to England link: Torness to north east England double circuit (TLNO)

Install a new double circuit from a new 400kV substation in the Torness area to a connection point on the transmission system in north east England. Construct a new 400kV double circuit from the Torness area to the SPT/NGET border. Continue construction of the double circuit into a suitable connection point in north east England, providing additional substation equipment where required. This reinforcement option provides additional thermal capacity across boundaries B6, B7 and B7a.

2.2 Current lead options

In the 2018/19 *NOA*, E4DC3, E2DC, ECUP, ECU2 and DWNO have been identified as the most efficient and beneficial reinforcements.

(a) Eastern Scotland to England link: Peterhead to Drax offshore HVDC (E4D3)

E4D3 is identified in the optimal path and critical in all four 2018 Future Energy Scenarios. Driven by last year's *NOA* result of both short and long HVDC links and notional B8 reinforcement requirement, E4D3 is one of the new alternative proposals to the eastern subsea HVDC link between Peterhead and Hawthorn Pit (E4DC), providing boundary capability between B1 and B8. In combination with the HVDC link between Torness and Hawthorn Pit (E2DC), it can provide the highest boundary uplift among the combination of options in the Scottish and northern England region. It has a 'proceed' recommendation.

(b) Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC (E2DC)

E2DC is in the optimal path and critical in all four 2018 Future Energy Scenarios. It eases congestion across boundaries B5 to B7a from 2027 onwards. With the help of B8 reinforcements transporting Scottish energy further south, E2DC is required as early as possible to maximise its value.

(c) East coast onshore 275kV upgrade (ECU2)

ECU2 has a 'proceed' recommendation in the 2018/19 *NOA*. It is a justified reinforcement in all four 2018 Future Energy Scenarios. For two consecutive years, ECU2 has been identified as critical. Its main benefit is across boundaries B1 to B5 and ECU2 is the earliest reinforcement option to release the rapid build-up of B4 boundary constraints with an EISD of 2023.

(d) East coast onshore 400kV incremental reinforcement (ECUP)

ECUP is in the optimal path and critical in all four scenarios. As a further onshore network upgrade to ECU2 on the east coast, it provides transmission transfer capability across B1 to B5, with its main benefit being across B4. ECUP has a 'proceed' recommendation.

Other options that feature in the *NOA* 2018/19 analysis for Scotland and the north of England region but that fall below the SWW threshold are likely to be considered in the SWW analysis. This is because they are interdependent to meet the common need of improving boundary transfer capability.

3. Status

A joint team among the three onshore TOs has continued to assess the *NOA* options, examining them in more detail as part of the preparation of a SWW initial Needs Case submission to the regulator in 2019. This team is organised into workstreams to consider system requirements, project development and delivery, and differing technologies. The TOs are working with the ESO who provide a cost-benefit analysis of the reinforcement options in more detail to help identify optimum sequence and delivery dates for the reinforcements.

Preliminary subsea cable routeing and survey work carried out some time ago is to be refreshed in the coming year. Further technical and environmental surveys will also be required. For links out of Peterhead, planning permission for the 400kV substation at Peterhead has previously been granted and will be revised in the coming year, and a preferred location for this converter station has been identified. Design checks will be required for increasing the operating voltage of the overhead line between Peterhead and Blackhillock. For southern landing points of the links, the associated AC onshore works will be further optimised and included in the SWW Needs Case submission. It is expected in this *NOA* that the construction of the HVDC projects will take place between 2025 and 2029. The onshore projects in the SHE Transmission and SPT areas are scheduled for earlier delivery in the period 2023 for the 275kV works and 2026 for the 400kV uprate.

B.2 South east network reinforcement

1. Background

The South East region has a high concentration of both power demand and generation, with much of the demand found in London and generation in the Thames Estuary. Interconnectors to Europe are also in operation along the south coast and influence power flows in the region by importing and exporting power with continental Europe.

As the number of interconnectors as well as other new generation increases over the next decade, high power transfer levels in the long transmission circuits across the south coast of England will potentially lead to thermal overloading and system voltage collapse. This limits the transmission capacity of those relevant system boundaries which include SC1, SC1rev (SC1 reverse flows), SC2 and SC3.

Reinforcements are therefore required to develop the transmission network in the South East region in order to facilitate the forecast increase in generation and interconnectors.

2. Option development

A number of reinforcement options have been developed to improve transmission capacity of the transmission system. These options consider uprating existing routes, reactive compensation at key locations and a new transmission route between South London and the south coast.

2.1 Leading option

The *NOA* analysis has recommended for the second consecutive year a new transmission route between South London and the south coast as it provides economic benefit. The reinforcement consists of constructing a new 400kV double circuit and associated substation works. This reinforcement will significantly increase transmission capacity on system boundaries SC1, SC1rev, SC2 and SC3.

2.2 Other options

While the consideration of a new double circuit is at a very early stage, other recommendations from this year's NOA process include proceeding with the following reinforcements for the South East region:

- Kemsley to Littlebrook circuits uprating (KLRE) – EISD: 2020.
- Bolney and Ninfield additional reactive compensation (BNRC) – EISD: 2022.

NGESO and NGET will also continue to investigate other options, such as the Fleet to Lovedean reconductoring (FLRE/FLR2) and commercial solution (CS25) as proposed this year.

3. NGESO economic assessment

The proposed new transmission route (SCN1) provides transmission capacity for boundaries SC1, SC1rev, SC2 and SC3. In our assessment, it is economic under all scenarios to build SCN1 on its EISD, mainly due to import conditions from the south coast interconnectors that cause constraints on boundaries SC1, SC2 and SC3. SC1rev is constrained under export conditions on the interconnectors, which happens more often in the later years of the scenarios. SCN1 is not the most effective reinforcement for dealing with these constraints over SC1rev but is the most economic under all the conditions.

4. Status

There have been preliminary works to identify optimal connection substations on both ends of the new transmission route between South London and the south coast in order to maximise system boundary benefit. As a result, NGET has submitted an updated version of this reinforcement into this year's NOA process. NGET will work further with relevant stakeholders in advance of a Strategic Wider Works Initial Needs Case submission.

Appendix C

List of options

The list below is of the options assessed in this *NOA* publication together with their four-letter codes. The four-letter codes appear throughout the report in tables and charts. The list below is in alphabetical order. We've included the scheme number where it is available. Some options do not have scheme numbers, for instance if the option is new and/or has never been given the recommendation to proceed in previous assessments. Other options have more than one scheme number where schemes have been combined for an option. Some options that might have scheme numbers are omitted if they do not provide a boundary benefit for *NOA*. The TORI number is the Transmission Owner Reinforcement Instruction number and applies in Scotland.

Option code	Description	Boundaries affected	TORI or scheme number
BCRE	Reconductor the Connah's Quay legs of the Pentir to Bodelwyddan to Connah's Quay 1 and 2 circuits	NW3	32018L1
BDEU	Bramley to Didcot circuits thermal uprating	SW1	
BFHW	Bramley to Fleet circuits thermal uprating	SC1	033773
BFRE	Bramley to Fleet reconductoring	SC1	031885
BMM2	225MVAr MSCs at Burwell Main	LE1, B14e	100436
BMM3	225MVAr MSC at Burwell Main	LE1, B14e	100437
BMMS	225MVAr MSCs at Burwell Main	EC5	33452
BNRC	Bolney and Ninfield additional reactive compensation	SC1, SC2, B10, B12	33698, 33699
BPRE	Reconductor the newly formed second Bramford to Braintree to Rayleigh Main circuit	EC5	
BRRE	Reconductor remainder of Bramford to Braintree to Rayleigh route	EC5	33458
BTNO	A new 400kV double circuit between Bramford and Twinstead	EC5	21847, 20834-1, 20834-4, 20834-3, 20834-5, 20834-6, 20834-2, 20834-2C, 20834_2A, 20834-2Q
CBEU	Creyke Beck to Keadby advance rating	B8	
CDRE	Cellarhead to Drakelow reconductoring	B8, B9, NW4, B17	32021
COSC	Series compensation south of Cottam	LE1, B14e	100112
COVC	Two hybrid STATCOMS at Cottam	LE1	100123
CPRE	Reconductor sections of Penwortham to Padiham and Penwortham to Carrington	B7a	32647
CS01	A commercial solution for Scotland and the north of England with a service duration of 40 years	B6, B7a	
CS03	A commercial solution for Scotland and the north of England with a service duration of 15 years	B6, B7a	
CS21	A commercial solution for East Anglia with a service duration of 40 years	SC1, SC2	
CS25	A commercial solution for the south coast with a service duration of 40 years	EC5	
CTRE	Reconductor remainder of Coryton South to Tilbury circuit	EC5	21850-1

Option code	Description	Boundaries affected	TORI or scheme number
DCCA	Cellarhead to Daines cable replacement	B8	
DNEU	Denny North 400/275kV Supergrid Transformer 2	B1, B1a, B2	
DREU	Generator circuit breaker replacement to allow Thornton to run a two-way split	B7, B7a, B8, B9	
DWNO	Denny to Wishaw 400kV reinforcement	B4, B5, B6	SPT-RI-003
E2D2	Eastern Scotland to England link: Torness to Cottam offshore HVDC	B5, B6, B7, B7a, B8	
E2D3	Eastern Scotland to England link: Torness to Drax offshore HVDC	B5, B6, B7, B7a, B8	
E2DC	Eastern Scotland to England link: Torness to Hawthorn Pit offshore HVDC	B5, B6, B7, B7a, B8	SPT-RI-126
E4D2	Eastern Scotland to England link: Peterhead to Cottam offshore HVDC	B1, B1a, B2, B4, B5, B6, B7, B7a, B8	
E4D3	Eastern Scotland to England link: Peterhead to Drax offshore HVDC	B1, B1a, B2, B4, B5, B6, B7, B7a, B8	
E4DC	Eastern Scotland to England link: Peterhead to Hawthorn Pit offshore HVDC	B1, B1a, B2, B4, B5, B6, B7, B7a	SHET-RI-025a, SHET-RI-025b, SHET-RI-025c, SHET-RI-025d
EAMS	225MVAr MSCs at Eaton Socon	LE1, B14e	
ECU2	East coast onshore 275kV upgrade	B1, B1a, B2, B4	SHET-RI-009
ECU4	East coast onshore 400kV reinforcement	B1, B1a, B2, B4	Variant of SHET-RI-093, SHET-RI-026
ECUP	East coast onshore 400kV incremental reinforcement	B1, B1a, B2, B4	SHET-RI-093, SHET-RI-026
ECVC	Eccles SVCs and real-time rating system	B6	
EHRE	Elvanfoot to Harker reconductoring	B6	SPT-RI-231
ESC1	Second Elstree to St John's Wood 400kV circuit	B14, B14e, LE1	21594
EWNO	Ealing to Willesden 275kV second circuit and quad booster	LE1, B14e	
FBRE	Beauly to Fyrish 275kV double circuit reconductoring	B0	Alternative to SHET-RI-058
FLPC	Power control device along Fleet to Lovedean	SC1	
FLR2	Fleet to Lovedean reconductoring (with a different conductor type to FLRE)	SC1, SC2, B10, B12	100298
FLRE	Fleet to Lovedean reconductoring (with a different conductor type to FLR2)	SC1, SC2, B10, B12	31671-2
FMHW	Feckenham to Minety circuits thermal uprating	SC1	
FSPC	Power control device along Fourstones to Stella West	B6, B7, B7a, B8	
GKEU	Thermal upgrade for Grain and Kingsnorth 400kV substation	SC1, B15	100117
GKRE	Reconductor the Garforth Tee to Keadby leg of the Creyke Beck to Keadby to Killingholme Circuit	B7, B7a, B8	33763
GRRA	Grain running arrangement change	SC3	
HAE2	Harker Supergrid Transformer 5 replacement	B6, B7, B7a	100108
HAEU	Harker Supergrid Transformer 6 replacement	B6, B7, B7a	33753
HAMS	225MVAr MSC at Harker	B6	
HFPC	Power control device along Fourstones to Harker	B6, B7, B7a, B8	

Option code	Description	Boundaries affected	TORI or scheme number
HMHW	Hinkley Point to Melksham circuits thermal uprating	B13	
HNNO	Hunterston East–Neilston 400kV reinforcement	B5	
HPNO	New east–west circuit between the north east and Lancashire	B8	
HSIT	Harker to Stella West circuit intertrip	B6, B7, B7a	
HSPC	Power control device along Harker to Stella West	B6, B7, B7a, B8	
HSRE	Reconductor Harker to Fourstones, Fourstones to Stella West and Harker to Stella West 275kV circuit	B6, B7, B7a, B8, B9	33703
HSS1	Power control device along Fourstones to Harker to Stella West	B6, B7, B7a, B8	
HSS2	Power control device along Fourstones to Harker to Stella West	B6, B7, B7a, B8	
HWUP	Uprate Hackney, Tottenham and Waltham Cross 275kV to 400kV	B14, B14e, LE1	100126
IFHW	Feckenham to Ironbridge circuits thermal uprating	SC1	
KBRE	Knocknagael to Blackhillock 275kV double circuit reconductoring	B4	
KLRE	Kemsley to Littlebrook circuits uprating	B15, SC1, B14	20846-4
KWHW	Keadby to West Burton circuits thermal uprating	B8	
LDQB	Lister Drive quad booster	B7a	21590
LNPC	Power control device along Lackenby to Norton	B6, B7, B7a, B8	
LNRE	Reconductor Lackenby to Norton single 400kV circuit	B7, B7a	20669
LTR3	Lackenby to Thornton 1 circuit thermal upgrade	B7, B7a	
MBRE	Bramley to Melksham reconductoring	B13	
MHPC	Power control device along Harker to Gretna and Harker to Moffat	B6	
MRPC	Power control device along Penwortham to Kirkby	B6, B7, B7a, B8	
MRUP	Uprate the Penwortham to Washway Farm to Kirkby 275kV double circuit to 400kV	B7a	21631
NBRE	Reconductor Bramford to Norwich double circuit	EC5	11630, 11630I, 11630F
NEMS	225MVAr MSCs within the north east region	B6, B7, B7a	100110
NEPC	Power control device along Blyth to Tynemouth and Blyth to South Shields	B6, B7, B7a, B8	
NOHW	Thermal uprate 55km of the Norton to Osbaldwick 400kV double circuit	B7, B7a	33759
NOPC	Power control device along Norton to Osbaldwick	B6, B7, B7a, B8	
NOR1	Reconductor 13.75km of Norton to Osbaldwick 400kV double circuit	B7, B7a	20640
NOR2	Reconductor 13.75km of Norton to Osbaldwick 1 400kV circuit	B7, B7a	33705
NOR4	Reconductor 13.75km of Norton to Osbaldwick 2 400kV circuit	B7, B7a	
NPNO	New east–west circuit between the north east and Lancashire	B8	33525
OENO	Central Yorkshire reinforcement	B7, B7a, B8	33754
OTHW	Osbaldwick to Thornton 1 circuit thermal upgrade	B7, B7a	33777

Option code	Description	Boundaries affected	TORI or scheme number
PEM1	225MVAr MSCs at Pelham	LE1, B14e	
PEM2	225MVAr MSCs at Pelham	LE1, B14e	
PTC1	Pentir to Trawsfynydd 1 cable replacement – single core per phase	NW2	33711
PTC2	Pentir to Trawsfynydd 1 and 2 cables – second core per phase and reconductor of an overhead line section on the existing Pentir to Trawsfynydd circuit	NW2	33708
PTNO	Pentir to Trawsfynydd second circuit	NW2	30311, 30311-1L, 30311-1S, 30311-2, 30311-3C, 30311-6
PTRE	Pentir to Trawsfynydd circuits – reconductor the remaining overhead line sections	NW2	33712
RHM1	225MVAr MSCs at Rye House	LE1, B14e	
RHM2	225MVAr MSCs at Rye House	LE1, B14e	
RRRE	Reconductor the newly formed second Bramford to Pelham circuit	EC5	
RTRE	Reconductor remainder of Rayleigh to Tilbury circuit	EC5, B15	21850-1
SCN1	New 400kV transmission route between South London and the south coast	SC1, SC2, B10, B12, B15	31832-2, 31832-3
SEEU	Reactive compensation protective switching scheme	SC1, SC2, B10, B12	33702
SER1	Elstree to Sundon reconductoring	B14, B14e, LE1	33305
SER2	Elstree–Sundon 2 circuit turn-in and reconductoring	B14, B14e, LE1	30652
SPDC	Stella West to Padiham HVDC link	B6, B7, B7a, B8, B9	
SSHW	Spennymoor to Stella West circuits thermal uprating	B6, B7, B7a	
STSC	Series capacitors at Stella West	B6, B7, B7a	
SWEU	South Wales (Cardiff to Bristol) region thermal uprating	SW1	
SWHW	South Wales (Cardiff to Swansea) region thermal uprating	SW1	
TDR1	Reconductor Drax to Thornton 2 circuit	B7, B7a, B8	
TDR2	Reconductor Drax to Thornton 1 circuit	B7, B7a, B8	
TDRE	Reconductor Drax to Thornton double circuit	B7, B7a, B8	33762
THRE	Reconductor Hinkley Point to Taunton double circuit	B13, SC1	
THS1	Install series reactors at Thornton	B7, B7a, B8, B9	33506
TKRE	Tilbury to Grain and Tilbury to Kingsnorth upgrade	B15	100116
TLNO	Torness to north east England AC reinforcement	B6, B7, B7a, B8	
TURC	Reactive compensation at Tummel	B1, B1a, B2	SHET-RI-69
WHTI	Turn-in of West Boldon to Hartlepool circuit at Hawthorn Pit	B6, B7, B7a	21898-1
WLTI	Windyhill–Lambhill–Longannet 275kV circuit turn-in to Denny North 275kV substation	B5	SPT-RI-004
WYQB	Wymondley quad boosters	B14, B14e, LE1	32581S
WYTI	Wymondley turn-in	B14, B14e, LE1	32586S

Appendix D

Meet the NOA team

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The Networks team addresses the engineering challenges of electricity network operability by studying from the investment options stage in a changing energy landscape through to network access just a day ahead of real time.

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The Network Development team ensures the development of an efficient and operable GB and offshore electricity transmission system by understanding present capabilities and working out the best options to meet the possible requirements that Future Energy Scenarios show might happen.

Network Development

In addition to publishing the *NOA* we are responsible for developing a holistic strategy for the NETS. This includes performing the following key activities:

- Testing the FES against models of the GB NETS to identify potential transmission requirements and publish in the *ETYS*
- Supporting Needs Case studies of reinforcement options as part of the SWW process
- Supporting cost-benefit studies of different connections designs
- Developing strategies to enable a secure and operable GB transmission network in the long term against the network development and industry evolution background.

You can contact us to discuss:

The *Network Options Assessment*

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Supporting parties

Strategic network planning and production of the *NOA* requires support and information from many people. Parties who provide support and information that make our work possible include:

- National Grid Electricity Transmission
- SHE Transmission
- SP Transmission
- our customers.

Don't forget you can also email us with your views on the *NOA* at:
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Appendix E

Glossary

Acronym	Word	Description
ACS	Average cold spell	Average cold spell is defined as a particular combination of weather elements which gives rise to a level of winter peak demand which has a 50% chance of being exceeded as a result of weather variation alone. There are different definitions of ACS peak demand for different purposes.
BEIS	Department of Business, Energy & Industrial Strategy	A UK government department. The Department of Business, Energy & Industrial Strategy (BEIS) works to make sure the UK has secure, clean, affordable energy supplies and promote international action to mitigate climate change. These activities were formerly the responsibility of the Department of Energy and Climate Change (DECC) which closed in July 2016.
BID3		BID3 is an economic dispatch optimisation model supplied by Pöyry Management Consulting. It can simulate all European power markets simultaneously including the impact of interconnection between markets. BID3 has been specifically developed for National Grid to model the impact of electricity networks in GB, allowing the System Operator to calculate constraint costs it would incur to balance the system, post-gate closure.
	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.
CBA	Cost-benefit analysis	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 to be considered.
	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.
	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's 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.
DNO	Distribution Network Operator	Distribution Network Operators own and operate electricity distribution networks.
EISD	Earliest In Service Date	The earliest date when the project could be delivered and put into service, if investment in the project was started immediately.
	Embedded generation	Power generating stations/units that don't have a contractual agreement with the National Electricity Transmission System Operator (NETSO). They reduce electricity demand on the National Electricity Transmission System.
FES	Future Energy Scenarios	The *FES* is a range of credible futures which has been developed in conjunction with the energy industry. They are a set of scenarios covering the period from now to 2050, and are used to frame discussions and perform stress tests. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions.

Acronym	Word	Description
GW	Gigawatt	1,000,000,000 watts, a measure of power.
GWh	Gigawatt hour	1,000,000,000 watt hours, a measure of energy usage or consumption in 1 hour.
GB	Great Britain	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
HVAC	High voltage alternating current	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.
HVDC	High voltage direct current	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.
	Interconnector	Electricity interconnectors are transmission assets that connect the GB market to Europe and allow suppliers to trade electricity between markets.
	Load factor	The average power output divided by the peak power output over a period of time.
	Marine technologies	Tidal streams, tidal lagoons and energy from wave technologies (see **http://www.emec.org.uk/**).
MW	Megawatt	1,000,000 watts, a measure of power.
MWh	Megawatt hour	1,000,000 watt hours, a measure of energy usage or consumption in 1 hour.
	Merit order	An ordered list of generators, sorted by the marginal cost of generation.
MITS	Main Interconnected Transmission System	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.
NETS	National Electricity Transmission System	The National Electricity Transmission System comprises the onshore and offshore transmission systems of England, Wales and Scotland. It transmits high-voltage electricity from where it is produced to where it is needed throughout the country. The system is made up of high-voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single System Operator (SO).
NETSO	National Electricity Transmission System Operator	National Grid acts as the NETSO for the whole of Great Britain while 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.
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards	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.
NGET	National Grid Electricity Transmission plc	National Grid Electricity Transmission plc (No. 2366977) whose registered office is 1-3 Strand, London, WC2N 5EH

Acronym	Word	Description
	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 system access is carefully controlled to ensure system security is maintained.
NOA	*Network Options Assessment*	The *NOA* is the process for assessing options for reinforcing the National Electricity Transmission System (NETS) to meet the requirements that the Electricity Sytem Operator (ESO) finds from its analysis of the *Future Energy Scenarios* (*FES*).
OFGEM	Office of Gas and Electricity Markets	The UK's independent National Regulatory Authority, a non-ministerial government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers.
	Offshore	This term means wholly or partly in offshore waters.
	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.
	Onshore	This term refers to assets that are wholly on land.
	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.
	Peak demand	The maximum power demand in any one fiscal year: Peak demand typically occurs at around 5:30pm on a weekday between December and February. Different definitions of peak demand are used for different purposes.
PV	Photovoltaic	A method of converting solar energy into direct current electricity using semi-conducting materials.
	Planned transfer	A term to describe a point at which demand is set to the National Peak when analysing boundary capability.
	Power supply background (aka generation background)	The sources of generation across Great Britain to meet the power demand.
	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.
	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.
	SP Transmission	Scottish Power Transmission Limited (No. SC189126) whose registered office is situated at 1 Atlantic Quay, Robertson Street, Glasgow G2 8SP.

Acronym	Word	Description
	Summer minimum	The minimum power demand off the transmission network in any one fiscal year: Minimum demand typically occurs at around 06:00am on a Sunday between May and September.
	Supergrid	The part of the National Electricity Transmission System operated at a nominal voltage of 275kV and above.
SGT	Supergrid transformer	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 operability	The ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably.
SOF	System Operability Framework	The SOF identifies the challenges and opportunities which exist in the operation of future electricity networks and identifies measures to ensure the future operability.
ESO	Electricity System Operator	An entity entrusted with transporting electric energy on a regional or national level, using fixed infrastructure. Unlike a TO, the ESO may not necessarily own the assets concerned. For example, National Grid ESO operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power Transmission.
	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.
SWW	Strategic Wider Works	This is a funding mechanism, which is part of the RIIO-T1 price control, that allows TOs to bring forward large investment projects that have not been funded in the price control settlement.
	Transmission circuit	This is either an onshore transmission circuit or an offshore transmission circuit.
TEC	Transmission entry capacity	The maximum amount of active power deliverable by a power station at its grid entry point (which can be either onshore or offshore). This will be the maximum power deliverable by all of the generating units within the power station, minus any auxiliary loads.
	Transmission losses	Power losses that are caused by the electrical resistance of the transmission system.
TO	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.
TSO	Transmission System Operators	An entity entrusted with transporting energy in the form of natural gas or power on a regional or national level, using fixed infrastructure.

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