Network Options Assessment Report Methodology

System Operator

July 2018

Version	**FINAL 4.1**
Date	**2 July 2018**

About this document

This document contains National Grid's Network Options Assessment (NOA) report methodology established under NGET Licence, Licence Condition C27 in respect of the financial year 2018/19. It covers the methodology on which NGET, in its role as SO, will base the NOA which will be published by 31 January 2019. As the methodology evolves due to experience and stakeholder feedback, the methodology statement will be revised for subsequent NOAs as required by Licence Condition C27

Network Options Assessment Report Methodology

Table of Contents

Section 1: Introduction ... 4
Purpose ... 4
Key changes for 2018/19 ... 4
Key similarities to 2017/18 ... 6
Background ... 6
Differences between NOA and ETYS ... 7
The methodology ... 7
Major National Electricity Transmission System Reinforcements ... 9
Eligibility criteria for projects for inclusion / exclusion ... 9
Roles and responsibilities of SO and TOs ... 9
Stakeholder consultation ... 10
Methodology review ... 10
Report output ... 10
Provision of Information ... 11
Engagement with interested parties to share relevant information and how that information will be used to review and revise the NOA methodology ... 11
Future developments ... 11
Section 2: The NOA report process ... 13
Overview of the NOA report process ... 13
Collect Input ... 13
Updated Future Energy Scenarios ... 13
Sensitivities ... 14
Interconnectors ... 15
Offshore Wider Works (OWW) ... 15
Latest version of National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) ... 16
Identify future transmission boundary capability requirements ... 16
National generation and demand scenarios ... 16
Identify NOA options ... 17
Basis for the cost estimate provided for each option ... 21

Environmental impacts and risks of options ... 21
Checks of the costs that the TOs submit ... 22
Build GB model ... 22
Boundary capability assessment for options ... 22
Cost-benefit analysis ... 25
Introduction ... 25
Cost-benefit analysis methodology ... 26
Constraint cost modelling tool ... 28
Selection of recommended option ... 28
Single year least regret decision making ... 29
Process output ... 32
Cost bands ... 33
Report drafting ... 33
Report publication ... 34
Section 3: Network Options Assessment for Interconnectors ... 36
Overview ... 36
Structure of this section ... 37
Key changes for 2018/19 methodology ... 37
Key similarities to 2017/18 methodology ... 38
Factors for the assessment of future interconnection ... 38
Costs included within the methodology scope ... 38
Costs outside the methodology scope ... 40
Cost estimation for interconnection capacity ... 40
Cost estimation for network reinforcements ... 42
Components of welfare benefits of Interconnectors ... 43
Introduction ... 43
Social and Economic Welfare ... 43
Effects on Interconnected markets ... 44
Constraint cost implications of interconnection ... 45
Ancillary services ... 46
BID3 model ... 47
Options included in the assessment ... 49
Interconnection Assessment Methodology ... 50
Optimisation of GB-Europe Interconnection Process ... 50
Modelling inputs ... 51
Market modelling ... 52

Further Output 55
Process Output 56
Section 4: Suitability for third party delivery and tendering assessment 57
Overview 57
Connections 58
Bundling/splitting of work packages 58
Bundling 58
Splitting 59
Competition criteria 59
Section 5: SO process for Offshore Wider Works 64
Foreword 64
Offshore Wider Works – developer associated overview 65
Offshore Wider Works – developer associated: the SO's role 66
Offshore Wider Works – developer associated process flow diagram 72
Offshore Wider Works – non developer associated overview 73
Offshore Wider Works – non developer associated process 75
Offshore Wider Works – non developer associated process flow diagram 80
Appendix A: NOA study matrix 81
Appendix B: Validation checks of seasonal scaling factors 82
Appendix C: NOA process flow diagram 84
Appendix D: System requirements form template 85
Appendix E: Process for checking NOA option cost reasonableness 94
Appendix F: Form of the report 99
Appendix G: Summary of stakeholder feedback 102

Section 1: Introduction

Purpose

1.1 The purpose of the Network Options Assessment (NOA) is to facilitate the development of an efficient, coordinated and economical system of electricity transmission consistent with the National Electricity Transmission System Security and Quality of Supply Standard and the development of efficient interconnection capacity.

1.2 This document provides an overview of the aims of the NOA and details the methodology which describes how the System Operator (SO) assesses the required levels of network transfer requirement, the options available to meet this requirement and the SO's recommended options for further development. It is important to note that whilst the SO recommends progressing options in order to meet system needs, any investment decisions remain with the Transmission Owners (TOs) or other relevant parties as appropriate.

1.3 This methodology document describes the end to end process for the analysis and publishing of the NOA report and identifies the roles and responsibilities of the SO and TOs.

1.4 Where this methodology refers to 'TOs', it means onshore TOs.

Key changes for 2018/19

1.5 We are extending the process to assess eligibility for competition to new connections for the first time. It builds on the existing process that we have used for wider works. The process uses the same criteria of high value, new and separable, which are detailed further in Ofgem's latest publications[1].

1.6 We set out or proposed direction of travel for the NOA in our Network Development Roadmap consultation[2] at the beginning of May. This focuses on developments that should drive additional value to consumers and includes extending the range of needs the NOA approach applies to and the participants and options that can be put forward. We are building the capability and testing the value through a number of pathfinding projects. Where relevant we intend to include any applicable options in the 2018/19 economic analysis. We will report the pathfinding projects separately on our NOA webpage and through the Electricity Networks Association Open Networks Project[3]. The pathfinding projects being considered are as follows:

[1] https://www.ofgem.gov.uk/electricity/transmission-networks/competition-onshore-transmission
[2] https://www.nationalgrid.com/sites/default/files/documents/Network%20Development%20Roadmap%20consultation.pdf
[3] https://www.energynetworks.org/electricity/futures/open-networks-project

i. Regional Development Programme (RDP) learnings – Taking the learnings from the UK Power Networks and Western Power Distribution RDPs to develop processes and requirements for data exchange with a DNO. This will enable submission and assessment of distribution options (at appropriate voltage tiers) to meet transmission system needs for cost-benefit analysis. This is aimed for publication by the fourth quarter of 2018.

ii. High voltage regions - Assessment of high voltage needs on the system where the need is not associated with flows across boundaries, including assessment of options from both transmission and distribution networks and cost-benefit on non-MW system requirements. This is aimed for publication by the fourth quarter of 2018.

We are also developing the process to facilitate the inclusion of market participants in the provision of options associated with bulk power transfer. For all these developments, it is crucial for us to work closely with relevant network companies through the ENA Open Networks Project[4].

1.7 We are also enhancing and evolving the way we undertake our analysis. We recognise that the most challenging system needs are no longer just at the winter peak demand condition. This is mainly due to ever increasing level of interconnections and renewable energy resources which bring greater volatility and intermittency to generation and demand patterns. As the energy background evolves, using a deterministic approach based on winter peak conditions to identify year-round system requirements may result in an overly optimistic or pessimistic view of system needs. As such we are conducting a case study of the use of probabilistic analysis to identify year round thermal requirements for a region of the network where the system flows are considered volatile, providing a comparison of this against our current approach. We will keep engaging with relevant stakeholders when the case study is being developed to ensure the analysis is transparent and robust. We aim to publish this case study in the first quarter of 2019.

1.8 Following major changes to the SRF template in 2017/18, and subsequent feedback following use in the 2017/18 process we have refined the template. This takes into account the feedback received and aims to deliver a smoother handover process of information for this cycle.

1.9 We have consolidated the other NOA area methodologies as sections in the overall NOA methodology. These are:

- NOA for interconnection (NOA IC)
- SO process for Offshore Wider Works

1.10 Building on improvements to last year's NOA IC, this year the methodology is expanded to reflect the inclusion of the NOA results in the base network for analysis and also to include investigation of the benefit that interconnectors provide to GB consumers.

[4] http://www.energynetworks.org/electricity/futures/open-networks-project/open-networks-project-overview/

Key similarities to 2017/18

1.11 The overall NOA process and philosophy are the same as used last year. Our NOA Methodology Review that we submitted to Ofgem in March 2017 concluded that single year regret analysis is the best way to evaluate the needs of the national electricity transmission system. You can find the review document at https://www.nationalgrid.com/sites/default/files/documents/NOA%20Methodology%20Review%202017.pdf.

1.12 For NOA 2017/18 we successfully brought in the NOA Committee, implied probabilities and cost checking. These improvements delivered additional scrutiny to the inputs and output of the cost-benefit analysis ensuring that the recommendations we make are in the best interest of consumers. We will continue to refine and build on these areas during 2018/19. You can find the minutes of the NOA Committee meetings on the NOA webpage at www.nationalgrid.com/NOA.

Background

1.13 In order to recommend options, the SO uses the established investment recommendation process. This ultimately leads to the selection of recommended options based upon their capital investment and constraint savings across a range of scenarios. Constraint costs are a factor of bid/offer prices and the amount of generation constrained. Both factors vary across the scenarios resulting in no one scenario necessarily seeing higher constraint costs than another.

1.14 The SO performed seasonal validation checks for boundaries assessed in the first NOA report. The constraint cost modelling tool (ELSI at that time) used assumptions to scale the boundary capabilities across seasons. It scaled the capabilities from the winter reference values to values for other seasons and also for outages. The purpose of the seasonal validation checks was to see how the scaled values compared with the values from technical studies of the same boundaries. The validation checks showed that the assumptions were broadly correct and needed only slight adjustment. Appendix B gives a more detailed review of the seasonal validation checks.

1.15 The NOA report process was built on the Network Development Policy (NDP) process and extended its use to the whole Great Britain (GB) transmission system. The NDP is part of the evaluation of National Grid TO investment under its volume-driver (Incremental Wider Works (IWW)) framework). As such, the NDP is a National Grid TO document and the TO produces the NDP's necessary outputs.

1.16 This methodology describes the process and the headers used follow the flow diagram in Appendix C for clarity. Appendix D contains the SRF template; Appendix E is the cost checking process; and Appendix F is the form of the NOA report.

1.17 In accordance with Standard Licence Condition C27, the SO has sought the input of stakeholders. Appendix G includes a summary of any views that the SO has not accommodated in producing this NOA report methodology.

Differences between NOA and ETYS

1.18 The NOA process is an obligation under NGET Licence, Standard Licence Condition C27 (The Network Options Assessment process and reporting requirements). Specifically, paragraph 15 defines the required contents of the NOA report, which are the SO's best view of options for reinforcements for the national electricity transmission system together with alternatives and recommended options.

1.19 The Electricity Ten Year Statement (ETYS) is an obligation under NGET Licence, Standard Licence Condition C11 (Production of information about the national electricity transmission system). Paragraph 3 defines ETYS's required contents which are the SO's best view of the design and technical characteristics of the development of the national electricity transmission system and the system boundary transfer requirements.

1.20 In summary, ETYS describes technical aspects of the system and the system's development while NOA describes options for reinforcement to meet system needs.

The methodology

1.21 The Network Options Assessment (NOA) process set out in Standard Licence Condition C27 of the NGET Licence facilitates the development of an efficient, coordinated and economical system of electricity transmission and the development of efficient interconnection capacity. This NOA report methodology has been developed in accordance with Standard Licence Condition C27 of the NGET licence.

1.22 This document defines the process by which the NOA is applied to the onshore and offshore electricity transmission system in GB. The process runs from identifying a future reinforcement need, to assessing available options to meet this need, to recommending and documenting the option(s) for further development. It also defines the process of assessing the suitability of recommended options for competition in onshore electricity transmission. This assessment is against criteria defined by Ofgem in their document Guidance on the Criteria for Competition[5]. The SO identifies and evaluates alternative options such as those based around commercial arrangements or reduced-build options in addition to those provided by the TOs. Table 2.2 on page 20 covers these alternative options in more detail.

1.23 The SO has engaged with the TOs to develop this methodology statement. Following publication of the NOA report, further stakeholder engagement is undertaken to inform the methodology statement for supporting subsequent NOA reports.

1.24 As background information changes and new data is gained, for example in response to changing customer requirements, both the recommended options and their timing will be updated, driving timely progression of investment in the electricity transmission system.

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

1.25 The SO engages stakeholders on the annual updates to the key forecast data used in this recommendation process, and shares the outputs from this process through the publication of the NOA report.

1.26 Transmission Licence Standard Condition C27 Paragraph 15 sets out the contents of the NOA report. The licence condition is undergoing consultation and review[6] but this process will finish after the NOA methodology is submitted to Ofgem. We will take a view on reviewing the NOA methodology once the revised licence condition is published.

> Each NOA report (including the initial NOA report) must, in respect of the current financial year and each of the nine succeeding financial years:
>
> (a) set out:
>
> (i) the licensee's best view of the options for Major National Electricity Transmission System Reinforcements (including any Non Developer-Associated Offshore Wider Works that the licensee is undertaking early development work for under Part D), and additional interconnector capacity that could meet the needs identified in the electricity ten year statement (ETYS) and facilitate the development of an efficient, co-ordinated and economical system of electricity transmission;
>
> (ii) the licensee's best view of alternative options, where these exist, for meeting the identified system need. This should include options that do not involve, or involve minimal, construction of new transmission capacity; options based on commercial arrangements with users to provide transmission services and balancing services; and, where appropriate, liaison with distribution licensees on possible distribution system solutions;
>
> (iii) the licensee's best view of the relative suitability of each option, or combination of options, identified in accordance with paragraph 15(a)(i) or (ii), for facilitating the development of an efficient, co-ordinated and economical system of electricity transmission. This must be based on the latest available data, and must include, but need not be limited to, the licensee's assessment of the impact of different options on the national electricity transmission system and the licensee's ability to co-ordinate and direct the flow of electricity onto and over the national electricity transmission system in an efficient, economic and co-ordinated manner; and
>
> (iv) the licensee's recommendations on which option(s) should be developed further to facilitate the development of an efficient, co-ordinated and economical system of electricity transmission;
>
> (b) be consistent with the ETYS and where possible align with the Ten Year Network Development Plan as defined in standard condition C11 (Production of information about the national electricity transmission system), in the event of any material differences between the Ten Year Network Development plan and the NOA report an explanation of the difference and any associated implications must be provided; and
>
> (c) have regard to interactions with existing agreements with parties in respect of developing the national electricity transmission system and changes in system requirements.

1.27 References to 'weeks' in the NOA report methodology are to calendar weeks as defined in ISO 8601. Week 1 is at the start of January and is the same as the system used the Grid Code OC2.

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

Major National Electricity Transmission System Reinforcements

1.28 Standard Licence Condition C27 Section C refers to the term Major National Electricity System Reinforcements for the purpose of this NOA report methodology statement. The definition has been agreed from consultation with the onshore TOs and the Authority (Ofgem) as:

Major National Electricity Transmission System Reinforcements are defined by the SO to consist of 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.*

1.29 The intention of this definition is to maximise transparency in the investment decisions affecting the National Electricity Transmission System while omitting schemes that do not provide wider system benefits. Such system benefits might be a user connection or improved system reliability.

Eligibility criteria for projects for inclusion / exclusion

1.30 The NOA report presents projects as options to reinforce the wider network that are defined by Major National Electricity System Reinforcements (see definition above).

1.31 The SO provides a summary justification for any projects that are excluded from detailed NOA analysis.

1.32 Once a Strategic Wider Work's (SWW) needs case has been approved by Ofgem, the option is excluded from the NOA analysis although the report refers to it and it is included in the baseline. This is due to it being managed through the separate SWW process. Ofgem have agreed the approach of excluding options where they have already agreed the SWW needs case. The NOA report will include analysis of options under construction that are funded through the IWW mechanism.

Roles and responsibilities of SO and TOs

1.33 The SO role and responsibilities are based around its overview of the network requirements. Specific role areas are as follows:

- analysis of UK FES data
- joint technical analysis of boundary capabilities of the base network and uplifts from reinforcement options for England and Wales in conjunction with NGET TO
- devising and developing alternative options including operational options, commercial agreements and OWW
- identifying boundary transfer requirements and issuing SRF to TOs
- verification studies of some boundary analysis performed by the TOs to corroborate the TOs' analysis
- review of reinforcement options and their cost estimates that the TOs propose
- assessment of outages and other system access availability that might affect the options' Earliest in Service Dates (EISD)
- running cost-benefit analysis studies

- recommending options for further development
- assessing eligibility for competition
- advice on the performance of boundary reinforcement proposals in the cost-benefit analysis to facilitate further option development by the TOs
- provision of an explanation of the NOA Committee recommendations
- production and publication of the NOA report.

1.34 The TOs' roles and responsibilities include:

- technical analysis of boundary capabilities of the base network and uplifts from reinforcement options
- proposing and developing reinforcement options and reduced-build options and providing their technical information to the SO
- cost information for options
- outage and system access requirements for options
- environmental information for options
- consents and deliverability information for options
- EISD of options
- stakeholder engagement (following review of draft outputs)
- community engagement
- review of the draft NOA report and appendices relating to TO options.

Stakeholder consultation

1.35 The SO has consulted with the TOs and Ofgem whilst preparing this NOA report methodology.

1.36 The key consultation areas are the NOA methodology, form of the NOA report and the NOA report outputs and contents.

1.37 This section shows the timescales for the SO's consultation of stakeholders during the period of writing the NOA report.

Methodology review

1.38 The SO seeks stakeholder views annually for consideration and where appropriate implementation before the NOA process starts its annual cycle.

1.39 Following the final publication of the NOA report, the SO undertakes an internal review of the NOA process. This is completed within 18 weeks of the publication of the NOA report with the publication of an updated NOA methodology. This is then open for stakeholders' consultation where comments/feedback are invited. The consultation will close six weeks after the methodology is published for consultation. The SO considers these comments for a revised NOA methodology and submits the methodology to Ofgem by 1 August 2018.

Report output

1.40 The SO makes available selected parts of the pre-release NOA report to key stakeholders, particularly the relevant TOs, on a bilateral discussion basis to ensure confidentiality obligations. This is as the NOA report is being written based on assessment data, particularly economic data, becoming available. These discussions will occur as results become available and the report is being drafted.

1.41 Further key stakeholder engagement occurs with release of drafts of the NOA report, three weeks ahead of publication. This provides a final opportunity for stakeholders to comment on the NOA report and raise any significant concerns. When a stakeholder expresses concern with the conclusions of the report, a comment is incorporated in the relevant section(s).

1.42 The SO seeks approval from the Authority (Ofgem) on the NOA report methodology and form of the NOA report as part of the annual stakeholder engagement process.

Provision of Information

Engagement with interested parties to share relevant information and how that information will be used to review and revise the NOA methodology

1.43 The NOA methodology and NOA report adequately protects any confidential information provided by stakeholders or service providers, for example, balancing services contracts. For this reason, this methodology seeks to be as open and transparent as possible to withstand scrutiny and provide confidence in its outcomes, while maintaining confidentiality where necessary.

1.44 In accordance with Licence Condition C27 Part C, the SO provides information to electricity transmission licensees, interconnector developers and to the Authority (Ofgem) if requested to do so. The SO will assist TOs with cost-benefit analysis for SWW needs cases.

Future developments

1.45 The SO expects the following changes and developments in the NOA report methodology and process as it evolves:

- Building on the pathfinding projects to test distribution solutions as NOA options including identifying non-MW requirements and the necessary cost-benefit analysis methodology.
- Further refinement of the process for SO-led options building on our experience.
- Modification of the process for assessing eligibility for competition taking into account developments in the legislative framework and our experience with assessments to date.
- Probabilistic tools that would need a high level of automation and facilitate:
    - a) Year round (24/7/365) consideration of a wide range of possible outturns for demand and generation to ensure that potential operational issues are discovered and also understood on the basis of the likelihood of that condition occurring (such as varying mixes of renewable generators, for example, wind and solar PV on a regional basis)
    - b) Automation of study set-up and contingency analysis
    - c) Automated result handling and filtering.

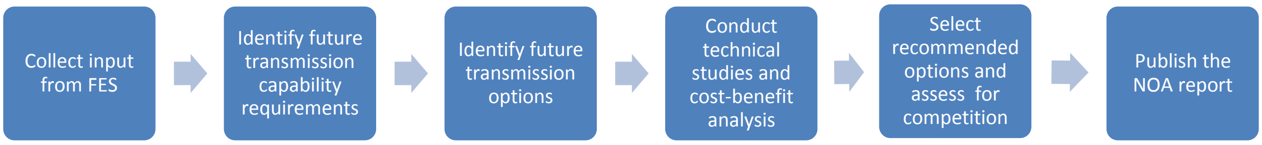
Our current work is related to a thermal probabilistic case study to investigate the concept that aims to assess the viability of using probabilistic tools for thermal studies in the year 2019. Having gained experience with thermal studies that includes performance levels and validation, we envisage voltage and any other elements would follow in the subsequent two years.

Section 2: The NOA report process

Overview of the NOA report process

2.1. Figure 2.1 gives an overview of the NOA report process. This methodology describes how the SO, working with the TOs, carries out these activities. The process diagram in Appendix C gives more details. The headers in this methodology follow the stage names in the process diagram in Appendix C.

Figure 2.1 Overview of the NOA report process



Collect Input

Updated Future Energy Scenarios

2.2. The relevant set of scenarios as required by NGET Licence Condition C11, is used as the basis for each annual round of analysis. These provide self-consistent generation and demand scenarios which extend to 2050. The FES document is consulted upon widely and published each year as part of a parallel process.

2.3. The NOA process utilises the scenarios as well as the contracted position to form the background for which studies and analysis is carried out. The total number of scenarios is subject to change depending on stakeholder feedback received through the FES consultation process. In the event of any change, the rationale is described and presented within the FES consultation report that is published each year.

2.4. FES 2018 will see some progressive rather than radical enhancements to the scenarios to address stakeholder feedback while still allowing some consistency with previous years' analysis[7]. The main points to note are that:

- There will be a continuation of four scenarios structured in a 2x2 matrix but new axes of "speed of decarbonisation" and "level of decentralisation" replace the "Green Ambition" and "Prosperity" axes applied in FES 2017.
- Two of the scenarios will meet the 2050 carbon reduction target (instead of one in FES 2017), but via different routes.

[7] See http://fes.nationalgrid.com/media/1346/future-energy-scenarios-2018-stakeholder-feedback-document-published-feb-2018.pdf for more details on the FES Scenario changes and, for more general FES information, on our website http://fes.nationalgrid.com/.

- As in previous years, security of supply for both gas and electricity is achieved across all four.

2.5. The FES Scenarios are created by using a mix of data sources, including feedback from the FES consultation process. The scenario demands are then adjusted to match the metered average cold spell (ACS)[8] corrected actual outturns against which generation is applied to ensure security of supply can be met.

2.6. Using regionally metered data, the “ACS adjusted scenario demands” are split proportionally around GB.

Sensitivities

2.7. Sensitivities are used to enrich the analysis for particular boundaries to ensure that issues, such as the sensitivity of boundary capability to the connection of particular generation projects, are adequately addressed. The SO and TOs use a Joint Planning Committee subgroup as appropriate to coordinate sensitivities. This allows regional variations in generation connections and anticipated demand levels that still meet the scenario objectives to be appropriately considered.

2.8. For example, the contracted generation background on a national basis far exceeds the boundary requirements under the four main scenarios, but on a local basis, the possibility of the contracted generation occurring is credible and there is a need to ensure that we are able to meet customer requirements. A “one in, one out” rule is applied: any generation added in a region of concern is counter-balanced by the removal of a generation project of similar fuel type elsewhere to ensure that the scenario is kept whole in terms of the proportion of each generation type. This effectively creates sensitivities that still meet the underlying assumptions of the main scenarios but accounts for local sensitivities to the location of generation.

2.9. The inclusion of a local contracted scenario generally forms a high local generation case and allows the maximum regret associated with inefficient congestion costs to be assessed. In order to ensure that the maximum regret associated with inefficient financing costs and increased risk of asset stranding is assessed; a low generation scenario where no new local generation connects is also considered. This is particularly important where the breadth of scenarios considered do not include a low generation case.

2.10. Interconnectors to Europe give rise to significant swings of power flows on the network due to their size and because they can act as both a generator (when importing energy into GB) and demand (when exporting energy out of GB). For example, when interconnectors in the South East are exporting to mainland Europe, this changes the loading on the transmission circuits in and around London and hence creates different boundary capabilities.

[8] The average cold spell (ACS) is defined as a particular combination of weather elements which give rise to a level of peak demand within a financial year (1 April to 31 March) which has a 50% chance of being exceeded as a result of weather variation alone.

2.11. The SO models interconnector power flows from economic simulation using a market model of forecast energy prices for GB and European markets. The interconnector market model was improved for 2016 and now covers full-year European market operation. The results of the market model are then used to inform which sensitivities are required for boundary capability modelling. Sensitivities may be eliminated for unlikely interconnector flow scenarios.

2.12. The SO and TOs extend sensitivities studies further to test import or security constraints. FES data tends to produce export type flows such as north to south. In some circumstances, flows may be reversed. The SO develops these sensitivities in consultation with stakeholders to produce boundary requirements for import cases.

Interconnectors

2.13. For the NOA for Interconnectors (NOA IC), the SO undertakes analysis to assess and provide a view on the optimum level of interconnection to other European markets. The markets considered are Belgium, Denmark, France, Germany, Iceland, Ireland (the combined market of Northern Ireland and the Republic of Ireland), The Netherlands, Norway and Spain. The NOA IC process will use the output from the 2018/19 NOA as the baseline network reinforcement assumptions. The proposed NOA IC approach for 2018/19 is presented in the NOA IC methodology which can be found in Section 3 of this document.

2.14. The main benefits of the potential further interconnection analysed will be consumer, producer and interconnector welfare benefit for GB and Europe, while costs captured will include locational impacts on the GB transmission system and capital expenditure of interconnectors and associated network reinforcements. The SO will develop the methodology to include consideration of potential operability challenges and solutions interconnectors can offer. The SO anticipates the market will respond to this intelligence with potential projects aligned with the optimum level of interconnection recommended by the SO.

2.15. The output from the NOA IC process will be presented as a chapter in the NOA report and hence be published in late January 2019.

Offshore Wider Works (OWW)

2.16. The SO has written the NOA report methodology so that it treats all options for system reinforcement fairly. These options can include OWW and alternative options.

2.17. The licence condition gives the SO the duty to devise and develop OWW. The SO has written a methodology to explain how it develops OWW up to the point that it can use the options in its economic analysis. It has been published for consultation in April 2017. This methodology is the SO Process for OWW and covers both developer-associated and non developer-associated works and can be found in Section 5 of this document.

Latest version of National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)

2.18. The existing version of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) is used for each annual update. If amendments are active, the potential impacts of these amendments are also considered as part of this process.

Identify future transmission boundary capability requirements

National generation and demand scenarios

2.19. For every boundary, the future capability required under each scenario and sensitivity is calculated by the application of the NETS SQSS. The network at peak system demand and other seasonal demands (spring/autumn and summer) is used to outline the minimum required transmission capability for both the Security and Economy criteria set out in the NETS SQSS.

2.20. The Security criterion is intended to ensure that demand can be supplied securely, without reliance on intermittent generators or imports from interconnectors in accordance with NETS SQSS section C.3.2. The level of contribution from the remaining generators is established in accordance with the NETS SQSS for assessing the ACS peak demand[9]. Further explanation can be found in appendices C and D of the NETS SQSS. To investigate the system against the Security criterion, the SO and TOs identify key network contingencies (system faults) that test the system's robustness. The SO and TOs do this by using operational experience from the current year and interpreting this in terms of network contingencies. These are not only used directly in studies but also used to identify trends or common factors and applied in the NOA report analysis to ensure that TO options do not exacerbate these operational issues. This may lead to investment recommendations.

2.21. The Economy criterion is a pseudo cost-benefit study and ensures sufficient capability is built to allow the transmission of intermittent generation to main load centres. Generation is scaled to meet the required demand level. Further details can be found in appendices E and F of the NETS SQSS.

2.22. The NETS SQSS also includes a number of other areas which have to be considered to ensure the development of an economic and efficient transmission system. Beyond the criteria above, it is necessary to:

- Ensure adequate voltage and stability margins for year-round operation.

[9] Average Cold Spell Peak Demand is defined as unrestricted transmission peak demand including losses, excluding station demand and exports. No pumping demand at pumped storage stations is assumed to occur at peak times. Please note that other related documents may have different definitions of peak demand, e.g. National Grid's 'Winter Outlook Report' quotes restricted demands and 'Future Energy Scenarios' quotes GB peak demand (end-users) demands.

- Ensure reasonable access to the transmission system for essential maintenance outages.

2.23. The SO uses the scenarios and the criteria stated in the NETS SQSS to produce the future transmission capability requirements by using an in-house tool called ‘Peak Y’. The SO then passes these capability requirements to the TOs to identify future transmission options which are described in the following section.

Identify NOA options

2.24. At this stage all the high level transmission options which may provide additional capability across a system boundary requiring reinforcement are identified (against economic and security criteria), including a review of any options considered in previous years. The NOA report presents a high level view of these options, with key choices to be taken for further evaluation as outlined on a non-exhaustive basis below. The NOA options are based around choices for example:

- an onshore route of conventional AC overhead line (OHL) or cable
- an onshore route of (High Voltage Direct Current) HVDC
- OWW options, such as integration between offshore generation stations.

2.25. Variations on each of these choices may be presented where there are significant differences in options, for instance between different OHL routes where they could provide very different risks and costs.

2.26. In response to the data on boundary capabilities and requirements, TOs identify and develop multiple credible options that deliver the potentially required boundary capabilities. The SO produces and circulates the SRF Part A to the TOs. In response to Part A, TOs provide high level details of credible reinforcement options that are expected to satisfy the requirement. These options could be subsea links as well as onshore. Appendix D of this document provides detailed information about the SRF template. As illustrated in Table 2.1, the SRF is split into six parts with a guideline on when the TO is required to complete and return each part.

Table 2.1 Description of the parts of the SRF template and when the TOs return them

SRF Part	Description	When NGET TO returns SRF part	When Scottish TO returns SRF part
A	Boundary requirement and capability	Mid-September for relevant boundaries	Mid-August (draft) Mid-September (final)
B	TO proposed options	Between early June and late August	Mid-August (draft) Mid-September (final)
C	Outages requirements	Mid-August (draft) Mid-September (final)	Mid-August (draft) Mid-September (final)
D	Studied option combinations	Mid-September	Mid-September
E	Options' costs	Mid-September	Mid-September
F	Publication information	Late October	Late October

The SO has the opportunity to suggest concepts to the TOs for options to achieve the boundary requirements.

2.27. The SO considers options for Non Developer-Associated Offshore Wider Works (NDAOWW) which would deliver offshore reinforcements capable of providing the desired improvement in a boundary capability. The SO continues with the early development of NDAOWW in accordance with NGET Standard Licence Condition C27 Part D. This is to provide high level initial inputs to the cost-benefit analysis. To achieve this, the SO forms a view on the technical outline and estimates the capital costs of the NDAOWW. As it is an initial and desk top exercise the capital cost estimates are likely to change significantly as the option starts to mature with further evaluation. The SO liaises with the relevant TOs in the development of NDAOWW options.

2.28. The options that the TOs provide are listed and described in the NOA report along with SO alternative options such as operational options. The SO alternative options might include liaison with TOs, distribution licensees or third parties. Each option's description includes the boundary that the option relieves, categorising the option into 'build', 'reduced-build' or 'operational' and a technical outline. The option description includes any associated aspects such as the nature of the area affected, related network changes etc. The SO is undertaking pathfinding projects in 2018/19 to trial analysis of additional system needs and to include options from non-TO sources. Where relevant the SO will include any applicable options in the 2018/19 economic analysis.

2.29. It is recognised that as options develop, their level of detail increases. Options at a very early development stage might lack detail due to uncertainty in detailed project design such as land and consents requirements.

2.30. During 2018, the England and Wales TO and the SO carry out joint technical analysis which means that there is a staged return for Parts A and B up to September and

August respectively. The Scottish TOs return the draft SRF Parts A and B in mid-August and the final version in mid-September. The timing is to support the SO's verification studies and cost checking process. All TOs provide draft Part C in mid-August and final Parts C to E in mid-September. These form the key inputs to the cost-benefit analysis process. Part F is the means for the TOs to advise the SO of the descriptions of the options to be published in the NOA report. The exact date is agreed between the SO and the TOs for the year's programme for the ETYS and NOA.

2.31. Where an option affects an adjacent TO, the TOs and SO coordinate their views on the reinforcement options and produce an agreed set of options by Week 32. The SO uses the agreed set of options in its economic analysis and might use the options in its verification studies. If there is no agreement, the SO forms a view on which options it assesses.

2.32. Once the TOs have returned the SRFs, the SO reviews the data and understands the costs by discussing them with the TOs. Through engagement, the SO presents the data that it plans to use in the economic studies.

2.33. The SO and TOs agree the combinations of options that the SO will use in the cost-benefit analysis.

2.34. A non-exhaustive list of potential transmission solutions are presented in Table 2.2. A wide range of options is encouraged including, where relevant, any innovative solutions.

Table 2.2 Potential transmission solutions

Category		NOA option	Nature of constraint			
			Thermal	**Voltage**	**Stability**	**Fault Levels**
Alternative Options	**Operational Options**	Availability contract *(contract to make generation available, capped, more flexible and so on to suit constraint management)*	✓	✓	✓	
		Reactive demand reduction *(this could ease voltage constraints)*		✓		
		Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
		Demand side services (contracted for certain boundary transfers and faults). *These allow peak profiling which can be used to ease boundary flows*	✓	✓		
		Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
		Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
		Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
	Reduced-build Options	Automatic switching schemes for alternative running arrangements *(automatic schemes that open or close selected circuit breakers to reconfigure substations on a planned basis for recognised faults)*	✓	✓	✓	✓
		Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
		Addition to existing assets of fast switching equipment for reactive compensation *(a scheme that switches in/out compensation in response to voltage levels which are likely to change post-fault)*		✓	✓	
		Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
		HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	
		'Hot-wiring' overhead lines *(re-tensioning OHLs so that they sag less, insulator adjustment and ground works to allow greater loading which in effect increases their ratings)*	✓			
		Storage (contracted for certain boundary transfers and faults). *This allows peak profiling or could exploit shorter term circuit ratings or provide voltage support to enhance boundary capabilities.*	✓	✓		
Build Options		Overhead line re-conductoring or cable replacement *(replacing the conductors on existing routes with ones with a higher rating)*	✓			
		Reactive compensation in shunt or series arrangements (MSC, SVC, reactors). Shunt compensation *improves voltage performance and relieves that type of constraint. Series compensation lowers series impedance which improves stability and reduces voltage drop.*		✓	✓	
		Switchgear replacement *(to improve thermal capability or fault level rating which in turn provides more flexibility in system operation and configuration. This would be used to optimise flows and hence boundary transfer capability).*	✓			✓
		New build (HVAC / HVDC) – *new plant on existing or new routes.*	✓	✓	✓	✓

2.35. It is intended that the range of options identified has some breadth and includes both small-scale reinforcements with short lead-times as well as larger-scale alternative reinforcements which are likely to have longer lead-times. The SO applies a sense check in conjunction with the TOs and builds an understanding of the options and their practicalities. In this way, the SO narrows down the options whilst allowing assessment of the most beneficial solution for customers. Other than the application of economic tools and techniques, to refine a shortlist of options or identify a potential recommended option, the SO relies on the TO for deliverability, planning and environmental factors. The SO leads on operability and offshore integration matters ahead of the cost-benefit analysis.

2.36. In checking for the suitability of an option, the SO reviews options for their operability and their effect on the wider system. As a result the SO checks for system access, ease of operation and the ability to adhere to operational policy and national standards. For system access, this means delivery of the option and the ability to manage outages to deliver future capital works and maintenance activities. In and affecting their areas, SPT and SHE Transmission undertake part of this review of options in conjunction with the SO. Because of their scale and complexity, some options may need more in-depth study work and involve an iterative approach with increasing detail added between NOA reports.

Basis for the cost estimate provided for each option

2.37. The forecast cost is a central best view. By Week 30, the TOs and SO agree each year the cost basis to be used for NOA analysis. The information that will have to be agreed includes but is not limited to:

- price base, that is the financial year of the prices and should be current year prices.
- annual expenditure profile reflecting the options' earliest in service dates.
- any major risks for options costed appropriately.
- delay costs.
- the TO's Weighted Average Cost of Capital (WACC).

2.38. The TOs provide the individual elements of the investments that provide incremental capability.

2.39. For consistency of assessment across all options, the TOs provide all relevant cost information in the current price base.

Environmental impacts and risks of options

2.40. Using the SRF the TOs provide views on the environmental impact of the options that they have proposed. This includes consideration of the environmental effects on the practicality of implementing each option.

2.41. As the TOs design and develop their options, their understanding of the environmental impacts of options improves. The more mature an option, its impact on the environment is better understood. Where appropriate, the TO indicates options that are relatively immature, which helps to highlight where the environmental impact needs further development. The SO gives a similar indication on options that it is leading, such as OWW. As the NOA is the first step in an economic analysis of the need for reinforcement of the national electricity transmission system, it is not intended to provide an environmental assessment of those options. The TO will take any appropriate and timely environmental considerations into account as part of their investment process and according to relevant planning laws.

2.42. Different planning legislation and frameworks apply in Scotland from those in England and Wales. Where reinforcements cross more than one planning framework, this is highlighted in the NOA report together with any implications. The TOs hold the specialist knowledge for planning and consents and provide the commentary.

Checks of the costs that the TOs submit

2.43. The SO reviews the costs that the TOs submit with their options and checks that they are reasonable. This is to help ensure the highest quality data goes into the NOA report process. The TOs use SRF Part E template to submit the costs which are also used to assess eligibility for competition. Consenting costs are submitted through the same template but are made distinct from the construction costs.

2.44. The SO checks the costs that the TOs submit against a range of costs for plant and equipment that the SO has gained from recent experience. If any costs are outside of the range, the SO discusses the costs with the TO. If following discussions the SO still believes that the costs are outside of the expected range and will unduly affect the economic analysis, the SO can omit the option from the economic analysis.

2.45. The SO performed the costs check for the first time as part of the second NOA report. The process the SO uses for the costs check is described by appendix E. This process takes into account experience gained with previous checks.

Build GB model

2.46. The Scottish TOs submit power system models to the SO for each year being modelled. The SO uses these and its own power system models of National Grid's network to create power system models of the GB network and shares these for analysis. Additional models and modelling information for different scenarios and network options are also submitted such that the SO and TOs have adequate information to carry out the necessary option analysis.

Boundary capability assessment for options

2.47. The SO and TOs complete boundary capability assessment studies to feed into the cost-benefit analysis process. The TOs submit the results of their boundary studies for their own areas with their SRFs. TOs study neighbouring areas to ensure TO coordination between base capabilities and options' uplifts for those that cross TO areas. The SO also performs studies of some of the same boundaries as the TO for the purpose of verification. For studies prior to the new SRF submission, the SO studies reinforcements using information that the TO submitted the previous year. This assumes that many reinforcement proposals are the same or very similar from one year to the next. The TO will endeavour to provide any updates to the SO on adjustments they make to their options that will allow the SO to modify its studies. The SO performs studies concurrently with the TOs to be able to perform a cross-check of some of the capability results, to the extent that the information on the options and any adjustments is available before the start of the economic analysis process. The SO can ask the TOs for additional SRFs in the period June to August if it finds that its studies highlight a need for further reinforcement.

2.48. Thermal loading, voltage and stability boundary limitations are assessed to find the maximum boundary power transfer capability. The boundary capability is the greatest power transfer that can be achieved without breaching any NETS SQSS limitation. Variations in background to represent different network conditions, such as generation patterns or time of the year that may cause critical variations in boundary capability are assessed separately from the traditional winter peak studies.

2.49. In order to minimise unnecessary repetition whilst maintaining robustness, winter peak network analysis is carried out under the scenario that will stress the transmission system the most (in 2018 this will be the Two Degrees scenario).This scenario has the highest electrical load and generation and therefore gives us the required stress on the system to test our boundary capabilities. Where there are significant differences in network conditions, either between scenarios or in time, additional sensitivity analysis is undertaken where appropriate to understand any network capability impact. For the purposes of any stability analysis (where required), year round demand conditions are considered. The secured events that are considered for these assessments are N-1-1, N-1 and N-D as appropriate in accordance with the NETS SQSS.

2.50. The analysis is done in accordance with the NOA study matrix which describes the constraint type, scenario, season and the years for the network assessment. Selected ‘spot’ years (7 and 10) are used as adjacent years would be too similar. The detailed NOA study matrix is populated in Appendix A of this document. The outputs of these studies are used as the England and Wales NDP boundary capabilities values.

2.51. For the purpose of the boundary capability assessment, the baseline boundary conditions need to be altered to identify the maximum capability across the boundary. To make these changes, the generation and demand on either side of the boundary is scaled until the network cannot operate within the defined limits. The steady state flows across each of the boundary circuits prior to the secured event are summed to determine the maximum boundary capability.

2.52. The factors shown in Table 2.3 below are identified for each transmission solution to provide a basis on which to perform cost-benefit analysis at the next stage.

Table 2.3 Transmission solution factors

<table>
<tr><th>Factor</th><th colspan="3">Definition</th></tr>
<tr><td>Output(s)</td><td colspan="3">The calculated impact of the transmission solution on the boundary capabilities of all boundaries, the impact on network security</td></tr>
<tr><td>Lead-time</td><td colspan="3">An assessment of the time required developing and delivering each transmission solution; this comprises an initial consideration of planning and deliverability issues, including dependencies on other projects. An assessment of the opportunity to advance and the risks of delay is incorporated.</td></tr>
<tr><td>Cost</td><td colspan="3">The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases.</td></tr>
<tr><td rowspan="9">Stage</td><td colspan="3">The progress of the transmission solution through the development and delivery process. The stages are as follows:</td></tr>
<tr><td colspan="3">Project not started</td></tr>
<tr><td rowspan="5">Pre-construction</td><td>Scoping</td><td>Identification of broad need case and consideration of number of design and reinforcement options to solve boundary constraint issues.</td></tr>
<tr><td>Optioneering and consenting started</td><td>The need case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified.</td></tr>
<tr><td>Design/ development and consenting</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process including stakeholder engagement.</td></tr>
<tr><td>Planning / consenting</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process.</td></tr>
<tr><td>Consents approved</td><td>Consents obtained but construction has not started</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction.</td></tr>
</table>

2.53. In order to assess the lead-time risk described in Table 2.3, the SO will consider, for a project with significant consents and deliverability risks, both ‘best view’ and ‘worst case’ lead-times submitted by the TOs to establish the least regret for each likely project lead-time.

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

2.55. If the SO or the TOs (who conduct boundary capability studies) decide that there are insufficient options to cover all scenarios, they initiate further work to identify reinforcement options. The TOs and SO aim for at least three options for each boundary requirement. The TOs can submit long-term conceptual options to ensure that there are enough options. The long-term conceptual options are high level and are developed only as far as their boundary transfer benefits and initial estimate of costs. Power system analysis is not conducted on the conceptual options.

2.56. Where there are boundaries affecting more than one TO, the TOs and SO arrange challenge and review meetings to determine the options for inclusion in the economic analysis and in the NOA report.

2.57. The TOs use their boundary capability results in the SRF Part D that they submit back to the SO.

2.58. The SO leads on operational options in cooperation with the TOs. The economic analysis tool needs a MW value for the boundary capability which this analysis of operational options must provide. In addition the SO must provide ongoing costs for the economic analysis such as intertrip arming fees as well as any capital outlay such as the cost of designing/installing the intertrip.

Cost-benefit analysis

Introduction

2.59. Cost-benefit analysis compares forecast capital costs and monetised benefits over the project's life to inform this investment recommendation.

2.60. The NOA provides investment recommendations based on the Single Year Regret Decision Making process. If the SO's NOA recommendation is to proceed to SWW needs case, the SO will assist the TO to produce an SWW needs case by undertaking a more detailed cost-benefit analysis.

2.61. The purpose of the Single Year Regret Decision Making process is to inform investment recommendations regarding wider transmission works for the coming year. The main output of the process is a list of recommended wider works reinforcement options to proceed with or to delay in the next year. A secondary output is an indicative list of which options would be proposed at present if each of the scenarios were to turn out.

2.62. The methodology for SWW cost-benefit analysis follows the **Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1** document published by Ofgem[10]. A needs case is submitted by the TO that proposes the option to the regulator, and which includes a cost-benefit

[10] https://www.ofgem.gov.uk/ofgem-publications/83945/guidanceonthestategicwiderworksarrangementsinriiot1.pdf

analysis section that outlines the financial case for the option. The output of this process is a recommendation of an option for the option that is to be proceeded with.

Cost-benefit analysis methodology

2.63. Since the number of options proposed for the transmission system is quite large the country is split into regions and each option is allocated to one of the regions. The cost-benefit analysis process for each region is conducted in isolation. The year in which each of the options outside the region that is being studied will be commissioned is fixed to a pre-determined value, which may vary by scenario. This is usually based upon the recommendations of the most recent NOA report. The size and extent of a region (that is where region dividing lines are drawn) may change from year to year. The criterion by which a region is defined is that an option may not appear in more than one region (this is to prevent an option being evaluated more than once, with the risk of two different answers).

2.64. All of the four scenarios are considered; furthermore it is usual for sensitivities to be considered as described previously. Each scenario is studied in isolation; the following description refers to the study of one scenario, the process is repeated (in parallel since there is no dependency) for the other scenarios. The process is an iterative process that involves adding a single reinforcement at a time and then evaluating the effect that this change has had on the constraint cost forecast.

2.65. To begin the process all proposed options within the region are disabled, the output of the model is analysed to determine which boundaries within the region require reinforcement and when the option is required, this simulation is referred to as the base case. This information is used to determine which option(s) should be evaluated first. The option that has been selected to be evaluated next is then activated in the constraint cost modelling tool (see the box on page 28 for a description) at its EISD. If a number of potential options have been identified as being candidates for the next option then this process must be repeated with each option in turn. There are now two sets of constraint cost forecasts, the base case and the reinforced case, which are compared using the Spackman[11] methodology.

2.66. It is assumed that each transmission asset is to have a 40 year asset life. Since the constraint cost modelling tool only forecasts for the next 20 years the constraint costs for each year after that are assumed to be identical to the final simulated year (note that this limitation occurs because the scenarios do not contain detailed ranking orders beyond 20 years). Constraint cost forecasts are discounted using HM Treasury’s Social Time Preferential Rate (STPR) to convert the forecasts into present values. The capital cost for the option is amortised over the asset life using the prevalent WACC and discounted using the STPR. This value is added to the constraint cost forecast for the reinforced case. The present value of the base case is

[11] The Joint Regulators Group on behalf of UK’s economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at HM Treasury’s Social Time Preference Rate (STPR). This is known as the Spackman approach.

then compared to the present value of the reinforced case plus the amortised present value of the capital costs to give the net present value (NPV) for this option.

2.67. This cost-benefit analysis process is carried out in a separate comparison tool which also automatically calculates the NPVs if the option being evaluated were to be delayed by a number of years. This list of NPVs allows the optimum year for the option, for the current scenario, to be calculated. If a number of alternative candidate options have been identified then the option that has the earliest optimum year should usually be chosen. The chosen option is then added to the base case and another option is chosen for evaluation. The process is then repeated until no further options produce a negative NPV (which would indicate that the capital cost of the option exceeds the saving in constraint costs). There may be an element of branching if it is not immediately obvious during the process which option should be chosen to be added to the base case at any given point.

2.68. The outcome of this process is a list of options, for the current region and scenario, and the optimum year for each. This is referred to as a ‘reinforcement profile’.

2.69. Once the reinforcement profile for each scenario within a region has been determined the ‘critical’ options for that region may be chosen. The definition of a ‘critical’ option has some flexibility but the definition below must be considered.

2.70. An option’s recommendation is critical if a decision to delay the option in the current year means that the optimum year, under any scenario or sensitivity, could no longer be met (note that outage availability may play a part in this decision).

Constraint cost modelling tool

2.71. The constraint cost modelling tool is used to forecast the constraint costs for different network states and scenarios. The high-level assumptions and inputs used in the tool are outlined in Table 2.4.

Table 2.4 Assumptions and input data for the constraint cost modelling tool

Input Data	Current Source	Description
Fuel price forecasts	FES	20 year forecast, varies by scenario
Carbon price	FES	20 year forecast
Plant efficiencies and season availabilities	Poyry (historic)	
Plant bid and offer costs	Historic data	See Long-term Market and Network Constraint Modelling[12]
Renewable generation	Poyry (historic)	Wind, solar, and tidal profiles for zones around the UK
Demand data	FES	Annual peak and zonal demand
Demand profile	Poyry	Within year profiles
Maintenance outage patterns	Historic data	Maintenance outage durations by boundary
System boundary capabilities	Power system studies	See text
Reinforcement incremental capabilities	Power system studies	See text

2.72. The model simulates 8 periods per day for 365 days per year and is set to simulate 20 years into the future. The year in which an option is commissioned can be varied. The primary output from the tool for the cost-benefit analysis process is the annual constraint forecast; there are further outputs that help the user identify which parts of the network require reinforcement.

Selection of recommended option

2.73. At this point all of the economic information available to assess the options is in place. The SO then uses the Single Year Least Regret analysis methodology to identify the recommended option or combination of recommended options.

[12] See https://www.nationalgrid.com/uk/publications/network-options-assessment-noa

Single year least regret decision making

2.74. The single year least regret methodology involves evaluating every permutation of the critical options in the first year (the year beginning in April following publication of the NOA report). For each critical option there are two choices, either to proceed with the option for the next year or to delay the option by one year (that is do nothing). It is assumed that information will be revealed such that the optimal steps for a given scenario can be taken from year two onwards – so only the impact of decisions in the first year are evaluated. If there is more than one critical option in the region then the permutations of options increase; the number of permutations is equal to 2^n, where n is the number of critical options.

2.75. Each of the permutations has a series of cost implications, these are either additional capital and constraint costs if the option were delayed (and further additional costs if the option were to be restarted at a later date) or inefficient financing costs if the project is proceeded with too early.

2.76. For each permutation and scenario combination the present value is calculated, taking into account operational and capital costs. For each scenario one of the permutations will have the lowest present value cost, this is set as a reference point against which all the other permutations for that scenario are compared. The regret cost is calculated as the difference between the present value of the permutation for a scenario and the present value that is lowest of all permutations for the scenario. This results in one permutation having a zero regret cost for each scenario.

2.77. The following section is a worked example of the least regret decision making process. Two options have been determined to be 'critical' in this region, the EISD for option 1 is 2018 and the EISD for option 2 is 2019. The optimum years for scenarios A, B and C are shown in Table 2.5. Note that the scenarios are colour-coded; this is used for clarity in the following tables.

Table 2.5 Example of optimum years for two critical reinforcements

Scenario	Option 1	Option 2
A	2018	2019
B	2018	2022
C	2025	N/A

Table 2.6 Example decision tree

Permutation	Year 1 Recommendations	Completion Date	NPV	Regrets	Worst regret for each permutation
i	Proceed Option 1 & Delay Option 2	Option 1: 2018 Option 2: 2020	£149m	£51m	£51m
		Option 1: 2018 Option 2: 2022	£100m	£0m	
		Option 1: 2025 Option 2: Cancel	£145m	£5m	
ii	Delay Option 1 & Proceed Option 2	Option 1: 2019 Option 2: 2019	£98m	£102m	£102m
		Option 1: 2019 Option 2: 2022	£65m	£35m	
		Option 1: 2025 Option 2: Cancel	£140m	£10m	
iii	Proceed Option 1 & Proceed Option 2	Option 1: 2018 Option 2: 2019	£200m	£0m	£15m
		Option 1: 2018 Option 2: 2022	£98m	£2m	
		Option 1: 2025 Option 2: Cancel	£135m	£15m	
iv	Delay Option 1 & Delay Option 2	Option 1: 2019 Option 2: 2020	£47m	£153m	£153m
		Option 1: 2019 Option 2: 2022	£68m	£32m	
		Option 1: 2025 Option 2: Cancel	£150m	£0m	

2.78. Table 2.6 is an example of a least regret decision tree, since there are two ‘critical’ options there are therefore four permutations. From Year 2 onwards for each of the permutations the options are commissioned in as close to the optimum year for each option for each scenario. For each scenario one of the four permutations is the optimum and therefore there is one £0m value of regret for each scenario. The table’s NPV column indicates the net present value for each of the permutations in each of the scenarios.

2.79. Studying Table 2.6 shows us that it is largely scenarios A and C that are deciding the single year least worst regret. There is a large regret in scenario A from choosing any other permutation than permutation 3 (at least £51m), and scenario C is the scenario that generates the maximum regret for permutation 3. If we calculate the implied probabilities for the decision to proceed with permutation 3 rather than 1 or 4 we find that the implied probabilities are roughly 16% and 9% for A vs. C respectively. This shows us that in order to make the same decision under expected NPV maximisation we would need to believe that A is at least 16% likely and C is less than 84% likely to choose 3 over 1, and A is at least 9% likely and C is less than 91% likely to choose 3 over 4. As an example, 16% implied probability for scenario A vs. C when considering 3 vs. 1 was found by solving the following equation:

$$200p + 135(1-p) > 149p + 145(1-p)$$

where p is the probability of scenario A and (1-p) is the probability of scenario C. It is worth noting that implied probabilities must be kept to two scenario comparisons for a single choice (i.e. 3 vs. 1) since expanding the scenario and permutation space would make the implied probabilities intractable to interpret.

2.80. The causes of the regret costs vary depending upon what the optimum year is for the reinforcement and scenario:

- If the option is delayed and therefore cannot meet the optimum year then additional constraint costs will be incurred.
- If the option is delayed unnecessarily then there will be additional delay costs.
- If the option is proceeded with too early then there will be inefficient financing costs.
- If the option is proceeded with and is not needed then the investment will have been wasted.

2.81. The regret costs for each permutation under all scenarios are then compared to find the greatest regret cost for each permutation. This is referred to as the worst regret cost. The permutation with the least 'worst regret' cost is chosen as the recommended option or combination of options to proceed in the coming year and appears in the report's investment recommendation. In the example shown above the least 'worst regret' permutation is to proceed with both options 1 and 2 which has a worst regret of £15m and is the least of the four permutations.

2.82. As the scenarios represent an envelope of credible outcomes it is possible that a reinforcement option is justified by just one scenario which doesn't always guarantee efficient and economic network planning if industry evolution were not to follow that particular scenario. In this event, the SO would examine the single year regret analysis result to establish the drivers and then examine the scenario further. How we do this varies according to circumstances but an example would be considering the cost-benefit analysis's sensitivity to specific inputs. This in turn informs our view on the robustness of the outcome and thus whether to make a recommendation based upon this scenario. The SO supports all the TOs in this manner to optioneer and develop their projects to minimise the cost such as reducing any frontloading of expenditure if there is doubt about the need for the reinforcement option or downgrading the importance of the investment completely. The SO examines any sensitivity studies in the same way to ensure none skew the results unfairly. For example, if a change in policy were to occur after the publication of the FES document, significant amounts of generation in the scenarios may be affected and their connection may then be delayed or unlikely to go ahead. We would flag this kind of background update, and identify in the single scenario driven investments where this is likely to be creating a skewed outcome. The areas of sensitivity study are outlined in Appendix A. The SO is investigating the development of probabilistic tools to deliver year round network analysis on system requirements, and further ensure that all sensitivities are covered. However, this is at an early stage and not yet ready for use with the NOA.

Process output

2.83. Following Single Year Regret analysis, for each region in the country a list of 'critical' options for the region is presented with the investment recommendation for each.

2.84. The SO has introduced implied scenario weightings to provide additional insight into the single year regret analysis. The SO does not assign probabilities to any of its scenarios, however it is useful to know what probability weights are consistent with the recommendations. This is particularly useful for options which are driven by a single scenario. The SO identifies the scenario where the option brings the most benefit and the scenario where the option brings the least benefit. It then calculates the weightings between these two scenarios that would be required in order to justify the recommendation for investment in this option under expected net present value maximisation. This allows the SO to reflect upon whether the implied probability of the driving scenario is reasonable to justify next year expenditure. For more information including examples, please see our NOA Methodology Review which can be found at www.nationalgrid.com/NOA .

2.85. The SO has created the NOA Committee to challenge the single year regret recommendations. The Committee is designed to allow the SO to review the investment recommendations that are marginal or risk being driven by a single scenario. This will seek to identify any 'false-positive' investment recommendations that could come about as a result of the single year regret process, and ensure that the single year regret analysis recommendations are justified. In addition the Committee will ensure the recommendations are supported by the holistic needs of the system. The Committee will consist of SO senior management who will challenge the robustness of the investment recommendations as well as provide holistic energy industry insight and take into account whole system needs to support or revise the marginal investment recommendations. Ofgem will also be present as observers to represent the consumers' interests and provide regulatory oversight, as well as understand the driving factors behind recommendations. In preparation for the Committee meeting, the SO will discuss the single year regret outputs with internal stakeholders and the TOs to ensure the final recommendations are robust. The TOs may be able to attend the NOA Committee to provide supporting evidence as the committee requires while maintaining the necessary commercial confidentiality.

2.86. The guiding principle behind the NOA committee is that, on the marginal decisions the Committee reviews, the members should advise the investment recommendation they believe is most prudent, on the balance of evidence. This means that they believe, on the balance of probabilities, the recommendation (to proceed or delay) is the best course of action for the GB consumer. This will take into consideration the many facets of the decision including, but not limited to: forecasted constraints in the scenario(s) advocating the option; the drivers behind the investment recommendation (e.g. specific generation build-up) and the latest market information on those drivers; what the regret is across the other scenarios; what next year's expenditure is acquiring and what it will achieve (e.g. will the expenditure allow the TO to learn more about the option); what effect a delay decision will have on the earliest in service date (e.g. more than one year postponement in the earliest in service date); what the implied scenario weight of the decision is (that is what probability would have to be placed on the driving scenario to make the same decision under expected net present value maximisation); and wider system operability considerations including the availability of commercial solutions to congestion issues. The committee members should seek to have a risk-neutral outlook in their deliberations, that is they should seek to make decisions dispassionately, and on the balance of evidence, bearing in mind as much as possible the likelihood of future events.

2.87. After deliberation committee members will conclude on the marginal options. The Committee's aim is to reach a consensus. The outcomes will be minuted and these minutes will show the rationale behind the recommendations as well as highlight the challenges raised. The minutes will be made available to Ofgem and the TOs and also published on the NOA webpage.

2.88. The SO uses the output from the single year regret analysis for the recommendation on whether a reinforcement option should proceed under the England and Wales NDP framework.

2.89. If the investment signal triggers the TO's needs case, the SO will assist the TO in undertaking a more detailed cost-benefit analysis. The SO reconciles the economy and security results (in accordance with NETS SQSS Chapter 4) as mentioned previously in the section on sensitivities before making a final recommendation.

Cost bands

2.90. The SO sorts reinforcement options with a 'Proceed' recommendation after economic analysis and connections into cost bands which it then includes in the NOA. The assumptions are that land costs are included in the costs but the cost of consents are excluded. The costs apply for new and separable elements only. Table 2.7 shows the cost bands that have been agreed.

Table 2.7 Table of cost bands

Cost bands
£100m - £500m
£500m - £1000m
£1000m - £1500m
£1500m - £2000m
Greater than £2000m

Report drafting

2.91. The SO drafts the NOA report but the responsibility for the content varies between the SO and TOs. The form of the report is subject to consultation and also to Ofgem approval. Appendix F gives more detail on the form of the NOA report.

2.92. Chapters 4 and 5 cover the options and their analysis. The component parts of these chapters and the responsibilities for producing the material are in Table 2.8. Appendix F gives more detail on the form of the NOA report.

Table 2.8 Areas of Responsibility

NOA report Options topic	Scotland	E&W	Alternative options	Offshore	Comments
Options: Status of the option (scoping, optioneering, design, planning, construction)	TO	TO	SO / TO	SO	
Options: Technical aspects – assets and equipment	TO	TO	SO / TO	SO	
Options: Technical aspects – boundary capabilities	TO	SO	SO / TO	SO / TO	
Options: Economic appraisal	SO	SO	SO	SO	Leads to investment recommendations for TOs
Options: Comparison of the options	SO	SO	SO	SO	
Options: Competition assessment	SO	SO	SO	SO	Includes competition criteria and how options were categorised
Table overview of boundaries and options	SO				

2.93. The report presents the relevant information to communicate the investment recommendations whilst maintaining appropriate commercial confidentiality. Information is therefore presented to demonstrate the relative benefits of options while protecting commercial confidentiality. This is in consultation with stakeholders. The SO passes outputs to the TOs to support its view of investment recommendations.

2.94. Report drafting is undertaken in the period late July to mid-December.

Report publication

2.95. The SO publishes the NOA report by 31January of each year or as instructed otherwise by Ofgem.

2.96. On publication the report is placed on the National Grid website in a PDF form that is widely readable by readily available software. The SO also prints copies such that it can provide on request and free of charge a copy of the report to anyone who asks for one.

2.97. Standard Licence Condition C27 Paragraph 12 provides for delaying publication if the Authority (Ofgem) delay their approval of the NOA report methodology or form of NOA report.

2.98. The Licence Condition allows for the omission of sensitive information.

Section 3: Network Options Assessment for Interconnectors

Overview

3.1 This section provides an overview of the aims of the NOA with respect to interconnectors and details the methodology which the SO will adopt for the analysis and publication within the fourth NOA report (to be published by 31st January 2019).

3.2 We have continued to develop the NOA for Interconnector methodology. This section represents latest thoughts following actively consulting, listening and responding to feedback from our customers and stakeholders on this methodology. The draft methodology has been revised and improved, resulting in a NOA for Interconnectors (NOA IC) analysis that will be of more value for our stakeholders.

3.3 For reference, below is a brief summary of the key features and developments of the previous NOA for Interconnector methodologies.

NOA IC 1 (2015/16)

- Modelled through ELSI
- GB consumer surplus only
- Price data procured from industry
- Only considered existing interconnectors and those applied through C&F
- Copper plate model with no transmission constraints

NOA IC 2 (2016/17)

- Modelled through Pan European Market Model (BID3)
- SEW as sum of producer and consumer surplus as well as interconnector revenue
- Consideration of benefit of additional capacity
- Copper plate model with no transmission constraints

NOA IC 3 (2017/18)

(As per NOAIC 2 plus…)

- Use of FES 2017 backgrounds
- Used optimized network found through NOA3 as baseline
- Combination of interconnectors and potential reinforcement
- Single optimal path generated through a least worst regret approach

Structure of this section

3.4 This section consists of the thirteen sub-sections listed below:

- **Key changes to 2018/19 methodology** - A summary of the major changes made to the NOA for Interconnector methodology for 2018/19.
- **Key similarities to the 2017/18 methodology** - A summary of which areas of the methodology have remained the same from 2017/19 to 2018/9.
- **Factors for the assessment of future interconnection** - A justification of the factors to be considered in determining whether additional capacity would be beneficial.
- **Cost estimation for interconnection capacity** – The costs associated with an interconnector and how these will be calculated.
- **Cost estimation for network reinforcement** – The costs associated with network reinforcements and how these will be calculated.
- **Components of welfare benefits of interconnection** – This sub-section outlines the concept of Socio-Economic Welfare in relation to interconnection and the components of the calculation.
- **Constraint cost implications** – An outline of how interconnectors could impact the operational costs on the network .
- **Ancillary Services** – A description of the system needs for operability, and how interconnection's impact on these will be assessed.
- **BID3 model** – A description of the SO's current market modelling capabilities
- **Options included within the assessment** – A listing of the options that will be assessed within the modelling.
- **Interconnection assessment methodology** – A description of the method by which the SO proposes to meet the aims of the NOA in relation to optimal interconnection capacity.
- **Further Output** – Additional results that may be of benefit to stakeholders.
- **Process Output** – How the NOA IC output will be delivered.

Key changes for 2018/19 methodology

3.5 This year we will continue to improve our stakeholder engagement. In particular we will:

- Provide stakeholders with a detailed plan of the proposed consultation process
- Brief stakeholders on National Grid's responsibilities with regard to stakeholder engagement for the NOA IC process
- Include a summary of all formal stakeholder feedback received as part of the consultation within the NOA IC Methodology document, and an explanation as to how this feedback was taken into account in the NOA IC Methodology and the form of the NOA IC report
- Provide greater clarity of the criteria and timing of any key decision making stage gates such as deciding the interconnector baseline
- Provide Ofgem with copies of any formal responses submitted to National Grid as part of the NOA IC consultation process

3.6 As well as focussing on Social Economic Welfare, capital costs and reinforcement costs, we intend to analyse the impact that interconnectors may have on other operational costs, specifically ancillary services 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.

3.7 We intend to analyse the effect of ancillary services as a sensitivity following the core iterative methodology. Ancillary services that may be included are: Inertia and Rate of Change of Frequency (RoCoF); Response and Reserve; Reactive Power/Voltage Support; and Black Start.

3.8 The 2018/19 NOA will also see the first use of the European FES; each foreign market will now have varied scenarios aligned to the GB FES, drawn from sources including the Europe wide Ten Year Network Development Plan and publications by the relevant TSOs. This will improve the quality and range of interconnector flow modelling that drives the NOA IC.

Key similarities to 2017/18 methodology

3.9 We will continue to take into consideration the locational impacts on the GB transmission network in addition to the welfare and capital cost implications.

3.10 We will use the output from the 2018/19 NOA as the baseline network reinforcement assumptions for the NOA IC analysis: this provides greater consistency between the NOA and NOA IC analysis which we believe will be of added value to our stakeholders.

3.11 We intend to use essentially the same iterative method used last year. The studies will involve a step-by-step process, where the market is modelled with a base level of interconnection, including current interconnection levels and projects with regulatory certainty. For the 2017/18 methodology, each iterative step concluded with a Least Worst Regret (LWR) calculation which then directed where the additional interconnection should be implemented across all four scenarios. However for NOA IC 2018/19, based on stakeholder feedback during the consultation, we will not perform a LWR calculation at the end of each iteration. This will result in four separate solutions and hence a range for the optimal level of interconnection. Stakeholders felt this was a much more beneficial output for the NOA IC analysis.

3.12 We will continue to calculate Social Economic Welfare for all EU countries as well as for GB and the connecting country. The optimal path shall be calculated based on the Social Economic Welfare of GB and the connecting country.

Factors for the assessment of future interconnection

Costs included within the methodology scope

3.13 There are multiple factors which could be considered when evaluating interconnector projects. The foremost are Social Economic Welfare, capital costs and impact on constraint costs. Constraint costs refer to GB network congestion costs borne by GB consumers as a result of interconnection.

3.14 SEW, CAPEX and Attributable Constraint Costs (ACC) are the most significant criteria for identifying the optimal level of interconnection. Therefore these factors will be used in the analysis to determine the economically optimal level of interconnection.

3.15 **Ancillary service contribution**: A major consideration is the impact of interconnectors on services which support system operability. This could potentially benefit both the interconnector owner, with additional income streams, and 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 SO being required to secure more in order to facilitate the inerconnector.

3.16 Ancillary services that may be included are: Inertia and Rate of Change of Frequency (RoCoF); Response and Reserve; Reactive Power/Voltage Support; and Black Start.

3.17 For the NOA for IC 2018/19 analysis we intend to analyse the effect of ancillary services as a sensitivity study to the core iterative approach. For more detail on how this will be used, please review paragraphs 3.47 to 3.49. For more information on ancillary services, please read our System Needs and Product Strategy (SNAPS) document[13]. This provides more information on our future system needs and seeks to consult on how we can best facilitate the evolution of balancing services markets.

3.18 Two further factors that will be analysed and have some accompanying commentary in the NOA report are changes in carbon emissions and use of Renewable Energy Sources (RES). These indicators are intended to aid understanding of interconnection's potential impact to meeting GB's climate change goals. They will not be used to optimise the interconnection presented. This is due to the complexity of combining Carbon/RES estimates with welfare and cost, especially where modelled welfare is already influenced by such factors through RES incentives and the European Trading System capping carbon emissions.

3.19 **Carbon costs**: modelling facilities allow for the extraction of total carbon emissions resulting from particular market states under different scenarios, thus the carbon savings or increases associated with various levels of interconnection can be presented with commentary.

3.20 **RES integration:** modelling facilities allow for the investigation of impact of interconnection on renewable generation. This can be reviewed through investigating the reduction or increase in renewable generation curtailment driven by the optimal level of interconnection being in place in future years, rather than the currently forecast level.

[13] https://www.nationalgrid.com/sites/default/files/documents/8589940795-System%20Needs%20and%20Product%20Strategy%20-%20Final.pdf

Costs outside the methodology scope

3.21 There are further benefits and costs that could be considered, which are briefly outlined below; they are outside the scope of this methodology:

3.22 **Operational costs:** Various costs associated with the day-to-day operation of the interconnector, and the maintenance of its components, are omitted from the analysis. This is driven by the complexity of defining these costs, per market. There is a high correlation between capital spend (which is included) and these operational costs. Moreover, there is unlikely to be a substantial variation in the 'standard' operational costs per European market under consideration, meaning it is equitable to remove them from consideration for all markets. One may argue that the operational costs may cause the end of the optimal path to be reached sooner however a decision has been made to omit this factor from the analysis due to the insignificance in relation to SEW over 25 years.

3.23 **Environmental/social costs:** In any large scale construction project, the local environment may potentially suffer damage. This affects local stakeholders, as well as disruption associated with the construction (traffic, noise etc.). The severity varies with the site chosen and the construction methods used. These are not considered here as they are more relevant to the choice of sites for individual projects.

3.24 **Social benefits**: Depending upon the procurement for the construction, the project may offer a boom to the local economy. This again is a project specific benefit, so is not estimated in this work.

Cost estimation for interconnection capacity

3.25 The cost of building interconnection capacity varies significantly between different projects - key drivers are convertor technology, cable length and capacity of cable. Estimating costs for generic interconnectors between European markets and GB is therefore challenging. An exercise of a similar nature has been undertaken by various industry bodies to allow the generation of 'Standard Costs'. These are generic values that can be applied to estimate the cost of generic projects. A report by ACER[14] provides sufficient granularity to differentiate between standard costs of connection to different markets. There are three elements to the capital costs; subsea cable, onshore connection costs and wider reinforcement costs.

3.26 Subsea cable costs will be identified by estimating the furthest and shortest realistic subsea cable length and taking the average distance for each market to GB zone permutation. Suitable substations have been identified using the ENTSO-E Transmission System Map. For each market and GB zone (as defined in paragraph 3.31), only logical substations which are neighbouring or have sufficient infrastructure will be reviewed in the study of route length. The length of the cable will vary with the GB zone it is connecting to and the measurements will be taken between these to the nearest 5km and are shown in the following table.

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

Table 3.1 Route distances

Country	GB Zone	Distance (Km)
Norway	1	705
Norway	2	795
France	5	175
France	6	100
Netherlands	4	215
Netherlands	6	210
Denmark	4	620
Denmark	7	660
Ireland	2	220
Ireland	3	220
Germany	4	520
Germany	7	590
Belgium	4	185
Belgium	6	140
Spain	5	810

3.27 Onshore connection costs will be included and dependant on distance from the coast to substation locations. Onshore works will be assumed as 80% double circuit 400kV overhead lines and 20% underground cables. This percentage is based on a range of GB reinforcements which may be built in the future.

3.28 Wider reinforcement costs will be included in capital costs for options where applicable.

3.29 The convertor station assumed value is drawn from an averaging of known HVDC projects performed by ACER. The ACER cost estimates are shown in the table below (these costs include the cost of installation):

Table 3.2 Standard costs

Total cost per route length (km)	Rating	Mean (€, 2014)
DC cables[15]	250-500kV	757,621
OHL[16]	380-400kV (2 circuits)	1,060,919
Underground cables[14]	380-400kV (2 circuits)	4,905,681

Total cost per rating (MVA)	Mean (€, 2014)
HVDC convertor station	87,173

[15] The DC cable cost provided is for a 500MW cable. An assumption has been made that for a 1000MW interconnector the cost per km will be double.

[16] The rating on the figures above is sufficient to accommodate an additional 2000MW of interconnection. Therefore, the figures will be adjusted to incur 70% of the total cost for the first 1000MW of capacity required and 30% for the second 1000MW of reinforcement capacity on the same boundary.

3.30 At the start of the analysis, the suitable rate of conversion from 2014 euros to present day sterling will be drawn from a credible source available to the SO (Bloomberg). The table can then be used to generate a generic cost for a given increase in capacity for each market. As connection can occur across a range of years, discounting is employed to standardise each cost in Present Value. This is done with the Social Time Preference Rate (STPR) of 3.5%. Additionally, the cost of capital is taken account of through the use of a Weighted Average Cost of Capital (WACC) of 6.8% for Interconnectors, drawn from a publically available Grant Thornton report.[17]

Cost estimation for network reinforcements

3.31 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 as illustrated in Figure 3.1.

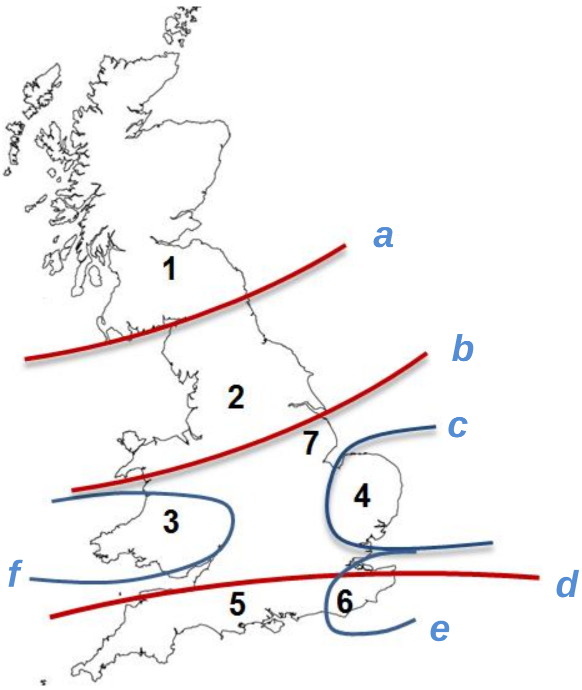


Figure 3.1 Illustration of Network Zones

3.32 The baseline boundary capabilities will be determined by using the outputs from the main NOA 2018/19 analysis.

3.33 Generic reinforcements will be created for each boundary using ACER costs as a guide (see Table 3.2). These will be based on where there are high levels of congestion on the network and an indication of the level of reinforcements required.

17 https://www.ofgem.gov.uk/ofgem-publications/51476/grant-thornton-interest-during-construction-offshore-transmission-assets.pdf

Components of welfare benefits of Interconnectors

Introduction

3.34 This section outlines the definition of Social Economic Welfare. The purpose of this section is to give the theoretical background of assessing the impact of connected importing and exporting markets on consumers, producers and interconnectors triggered by another interconnector.

Social and Economic Welfare

3.35 Social and Economic Welfare (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 important to understand it is an aggregate of different parties' benefits - so some groups within society may lose money as a result of the option taken. The society considered may be a single nation, GB, or the wider European society, in which case the benefits to European consumers and producers would be a part of the calculation. For the case of GB interconnectors, it is most informative to show both GB and the connected market's SEW values, and the components which make up each. This will be the optimised value in the NOA IC 2018/19. The stakeholder feedback received from the consultation provided a range of views on whether the analysis should focus on GB only, GB plus connecting country or GB plus all of Europe when performing the iterative optimisation. As the range of views was so diverse, we have decided to calculate the optimal paths based on SEW of GB and the connecting country, but also calculate SEW for GB only and GB and the rest of Europe to provide additional value.

3.36 SEW benefits of an interconnector includes the following three components:

a) Consumer surplus, derived as an impact of market prices seen by the electricity consumers

b) Producer surplus, derived as an the impact of market prices seen by the electricity producers

c) Interconnector revenue or congestion rents, derived as the impact on revenues of interconnectors between different markets.

3.37 Interconnectors could help to provide ancillary services (including black start capability, frequency response or reserve response), facilitate deployment of renewables, reduction in carbon emissions and displace network reinforcements. Interconnectors also provide benefits of being connected to more networks giving access to a more diverse range of generation which could lead to reduction in carbon emissions. Such benefits will not be a part of the main NOA IC assessment, as discussed in the previous section.

Effects on Interconnected markets

3.38 Power flow between two connected markets is driven by price differentials. Figure 3.2 shows the effects of such price differentials for two markets, A and B with variable prices over time. When the price is higher in market A, power will be transferred from B to A. When the price in A is lower than B power will be transferred from A to B.

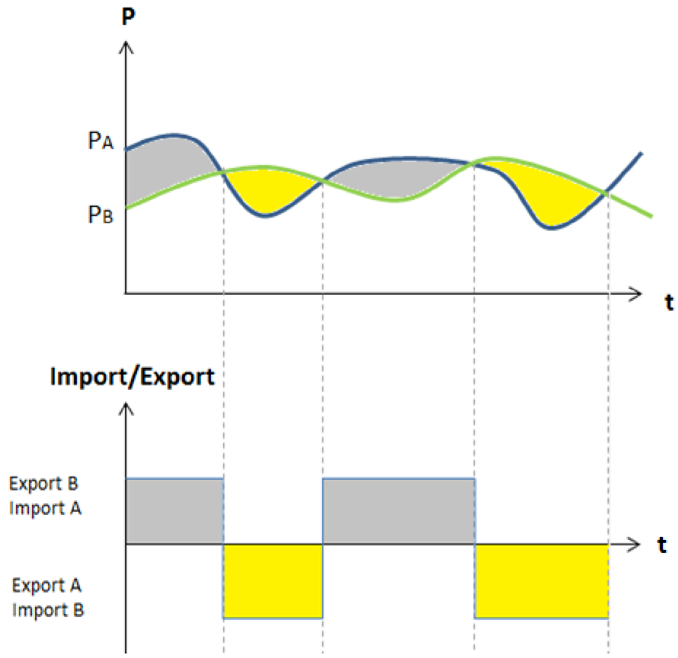


Figure 3.2 Price difference as import and export driver

3.39 Figure 3.3 shows the impact of an interconnector (+IC) linking two markets on consumer (Demand D) and producer (Supply S) costs. When two competitive markets with different price profiles are interconnected, price arbitrage drives power flow from the low price market (B) to the high price market (A). Consumers in market A are likely to gain (a + b) as they benefit from access to cheaper power. Consumers in market B are likely to lose (d). Generators in market A must now also compete with generators in B and are likely to be forced by competitive pressures to reduce their costs. This may lead to a reduction in their profits (a). Producers in market B are likely to gain (d + e). Interconnector revenue (c) is derived from the remaining price difference.

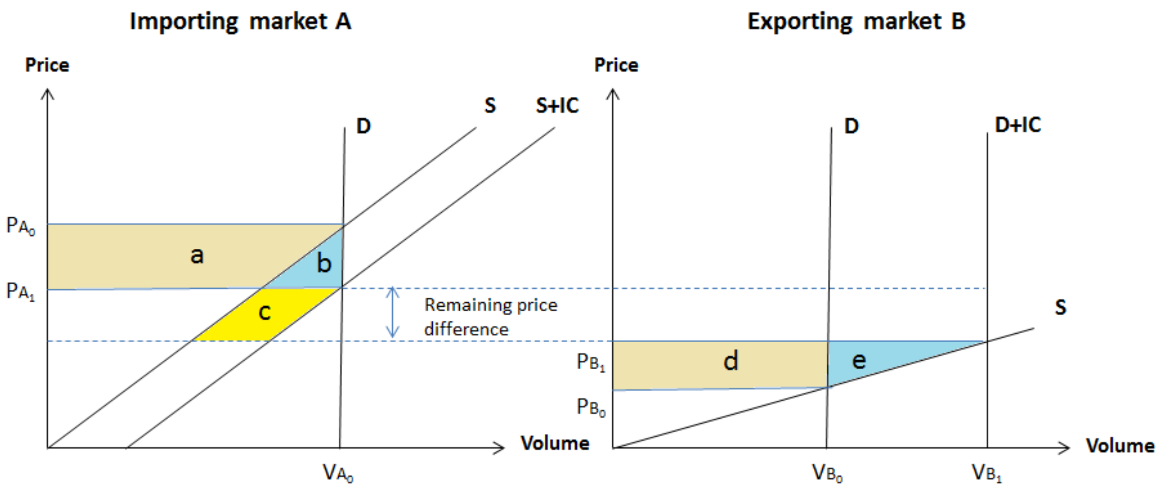


Figure 3.3 Consumer and Producer Surplus of connected markets

3.40 With greater interconnection the price difference between markets will decrease thus the revenue of the interconnector will be reduced as well. This phenomenon is known as ‘cannibalisation’. There is an optimal level of interconnection between any two markets because price differential reduces as capacity increases, i.e. area c in Figure 3.3 shrinks.

3.41 Forecasts of all components of SEW benefits will be key drivers to ascertain the optimum level of interconnection between GB and other European states. The outputs of this process will include monetised impacts on consumers, producers and considered interconnectors.

3.42 The Global SEW is the sum of the welfare of 5 parties (GB consumers, Europe consumers, GB producers, Europe producers and Interconnector owners). The British SEW is the sum of the welfare of all British parties. Using the ownership structure of existing GB interconnectors, assuming 50% of interconnector owner welfare remains in the GB economy is plausible.

3.43 Where the market is modelled with and without some additional interconnection capacity added, Socio-Economic Welfare is modelled in each year of a generic asset’s lifetime (25 years is the standard assumption used here). As connection can occur across a range of years, discounting is employed to standardise each year’s benefit in Present Value, also allowing comparison with the discounted capital spend. This is done with the Social Time Preference Rate of 3.5%.

Constraint cost implications of interconnection

3.44 The impact on constraint costs is dependent on the location of the interconnector on the GB network and the level of onshore reinforcement built to accommodate the interconnector. To enhance the methodology, further detail regarding optimal locations to connect will be output based upon the constraint costs calculated on the network with the interconnectors under consideration.

3.45 Constraint costs are incurred on the network when power that is economically “in merit” 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.

3.46 The output of the ETYS and NOA reports provides information on the current state and ongoing developments of the onshore network. This will be used to provide a general picture of the optimal network areas for accommodating interconnectors from certain countries. This will be based on constraint costs attributable to the interconnector under review. ETYS and NOA quantify the boundary limitations and present recommended options for reinforcement of the grid. This is intrinsically linked to the increasing presence of interconnection in the UK which can cause further strain on boundaries and potentially trigger investment in further reinforcements if the NOA process determines that to be the most economic and efficient course of action.

Ancillary services

3.47 Interconnectors are likely to have significant ramifications on future system operability, and have the potential to worsen or improve the economics of satisfying system needs. This year the NOA IC will include an investigation of the interactions between future interconnection, the amount of system need and the means of meeting these requirements. The investigations will be similar in form to work previously done by the SO for Cap & Floor appraisals, with the objective of capturing how the presence of further interconnectors changes a particular system operability need, how they can help address such needs, and the economic impact of these considerations on GB consumers.

Table 3.3 Interconnector impacts on operability topics

Topic	Impact of ICs on need	Can ICs meet this need?
RoCoF/System inertia	ICs can represent largest loss and displace inertia providers	Possible by providing enhanced response- more likely captured under Response heading
Reserve	Uncertainty in interconnector flows (and perhaps lack of SO ability to change them) might lead to increasing reserve requirement	Yes
Response	Potential impact due to impact on inertia Can be largest generation loss, or more significantly, the largest demand loss (increasing HF response requirement)	Yes
Reactive Support	Potential impact due to IC affecting system flows	Possible depending on design and location
Black Start	- (indirect risk of significant event at remote ends of interconnectors close together (e.g. North French Coast) propagating across to GB)	Possible, depending on design and location

3.48 The range of potential impacts will be explored to find a final range of economic costs or benefits that generic new interconnectors could generate. This will not be performed for every hypothetical future option explored in the main iterative analysis, but rather provide a single credible range. This limitation is imposed due to the complexity of the topics listed and their significant dependence on project specific details such as technology, design and location at the substation level- none of which are defined for the options tested by the main process.

3.49 The credible range of economic performance output from these investigations will allow the inference of where ancillary services could be a key factor in the relative performance of the future options assessed, or where they are significant enough to change the outcome for marginal NPV options if the best or worst case is assumed in terms of ancillary service impact. The final report will reflect on how the possible ancillary service benefit or dis-benefit affects the overall conclusions drawn by the main process as described in paragraphs 3.58 to 3.72.

BID3 model

3.50 BID3 is the tool which will be used to perform the NOA IC 2018/19 and employed by the SO to carry out a range of economic analysis.

3.51 BID3 is a Pan European Market Model created by Pöyry Management Consultants. BID3 will be used by National Grid to forecast the Socio-Economic Welfare (SEW) and the Attributable Constraint Costs (ACC).

3.52 A comprehensive guide to how National Grid uses BID3 for calculating constraints is available on our website[18]. It is an economic dispatch model which can simulate all ENTSO-E power markets simultaneously from the bottom up i.e. it can model individual power stations for example. It includes demand, supply and infrastructure and balances supply and demand on an hourly basis. BID3 models the hourly generation of power stations on the system, taking into account fuel prices, historical weather patterns, socio-economic welfare and operational constraints.

3.53 The GB electricity system in BID3 is represented by a series of zones that are separated by boundaries. Generators are allocated to their relevant zone based on where they are located on the network, and then the appropriate demand is allocated to that zone. The boundaries, which represent the actual transmission circuits facilitating the zonal connectivity, have a maximum capability that restricts the amount of power which can be securely transferred to across them.

3.54 The socio-economic welfare is calculated by summing the producer surplus, consumer surplus and interconnector revenue. The consumer surplus is the difference between the value of lost load and the wholesale price. The producer surplus is calculated and summed per plant based upon their Short Run Marginal Cost and the wholesale price.

[18] https://www.nationalgrid.com/sites/default/files/documents/Long-term%20Market%20and%20Network%20Constraint%20Modelling.pdf

3.55 Case collections are used for hourly generation and demand profiles as well as solar and wind profiles. An extensive study has identified the average historic year in terms of Generation, Demand, Wind output, Solar Output, interconnector flows and hydrological year. This is an approved approach but has limitations and could potentially undervalue countries with a high level of renewable generation such as Nordic countries with significant levels of hydro power.

Options included in the assessment

3.56 As there are infinite combinations of markets and reinforcements, applying engineering judgement, the number of options has been reduced to 29 credible options. These 29 options will be assessed in all iterations across all four scenarios.

3.57 The options which will be assessed are included in Table 3.4 below. The boundary reinforcements and zones refer to Figure 3.1.

Table 3.4 Options to be considered in the analysis

Market and Zone	Boundary Reinforcements	Market and Zone	Boundary Reinforcements
Belgium Zone 4	c	**Ireland Zone 2**	b
Belgium Zone 4	None	**Ireland Zone 2**	None
Belgium Zone 6	None	**Ireland Zone 3**	None
Belgium Zone 6	d + e	**Netherlands Zone 4**	c
Denmark Zone 4	c	**Netherlands Zone 4**	None
Denmark Zone 4	None	**Netherlands Zone 6**	None
Denmark Zone 7	None	**Netherlands Zone 6**	d + e
France Zone 5	None	**Norway Zone 1**	a + b
France Zone 5	d	**Norway Zone 1**	None
France Zone 6	None	**Norway Zone 2**	b
France Zone 6	d + e	**Norway Zone 2**	None
France Zone 6	d	**Spain Zone 5**	None
Germany Zone 4	c	**Spain Zone 5**	d
Germany Zone 4	None		
Germany Zone 4	f		
Germany Zone 7	None		

Interconnection Assessment Methodology

Optimisation of GB-Europe Interconnection Process

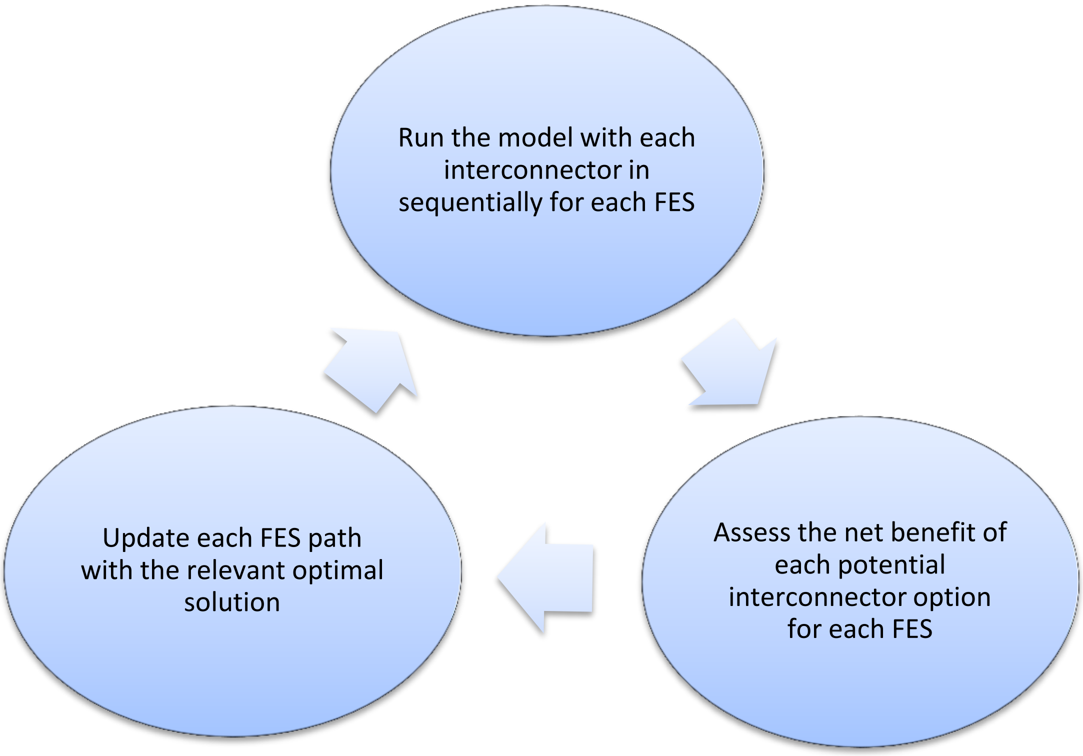


Figure 3.4 Process summary

3.58 Based on stakeholder feedback, we have revised the methodology to no longer include a Least Worst Regret analysis at the end of each interation. This will result in four separate optimal paths, one for each FES, and hence a range for the optimal level of interconnection to GB. This was a topic that stakeholders provided very strong agreement on.

3.59 The optimisation of future interconnection capacities is a multivariable search, maximising the SEW less CAPEX less Attributable Constraint Costs (ACC) value. The decision variables are the total MW capacities (the sum of all interconnector transfer capacities) between GB and 8 adjacent markets, for both importing and exporting. These markets are national electricity markets- there is some level of coupling between many of them, however price areas (areas with the same electricity price throughout) generally align with nations. Where some nations have multiple price areas, such as Norway, interconnector projects will be assumed to be in the coastal price area deemed most likely for interconnection to the UK. The countries in question are: Norway; Denmark; Germany; The Netherlands; Belgium; France; Spain; and Ireland (which includes the Republic of Ireland and Northern Ireland). For each country's additional interconnector capacity, there will be a small number of zones and reinforcement combinations studied. The number of variables makes an exhaustive search within a useful timeframe infeasible - a search strategy must therefore be defined.

3.60 Due to the unique properties of the Icelandic market, any interconnection to Iceland which appears in the Future Energy Scenarios (FES) will remain in the background. Further Icelandic interconnection will be removed from the iterative process.

3.61 The search is just for interconnection to the UK. The level of interconnection between European markets will remain fixed throughout the scenarios (though could vary across future years). These levels are defined by the FES European scenarios.

3.62 The market studies, which model the physical limitations of transmission between markets (but not within markets) start from the future levels of interconnection that will arise from commissioned links, and future projects with a high degree of regulatory certainty; either an approved Cap & Floor regime or an approved exemption by 1st September 2018. The interconnection capacities are then adjusted sequentially to search for improvements on this initial point, represented by an increase in the global SEW - CAPEX - ACC following the alteration of the capacity values. This global SEW-CAPEX-ACC value takes into account the whole asset life, such that the overall timing of connection is assessed in addition to the capacities per market.

3.63 We consulted on whether this resulted in an appropriate level for the baseline level of interconnection, ie the starting level for the analysis, and we received a wide range of views. Some stakeholders felt that this resulted in too high a level of baseline, whereas others felt it was too low. The largest number of responses stated that the baseline level of intercoinnection was appropriate. Hence for this year's analysis we intend to use the same criteria for setting the baseline. In addition some stakeholders felt that some form of sensitivity analysis would be beneficial whereby the baseline level of interconnection could be adjusted by sequentially reducing the level of interconnection to each country. This may be infeasible in the timeframes available, but we will endeavour to investigate whether any form of sensitivity analysis can be performed around the baseline level of interconnection.

Modelling inputs

3.64 The starting point of the process is National Grid's FES 2018 which includes generation plant ranking orders and demand forecasts across Europe for each scenario. FES 2018 is the first time European markets are being varied by GB scenario to achieve more coherent, higher quality modelling. Output from NOA 2018 will be used to determine the high level boundary capacities which form the 7 zones included in the analysis. All interconnectors which are in the NOA IC baseline will be included in the model from 2026 (the first year of study).

3.65 The FES make forecasts of the future interconnection capacities in GB, per scenario. The FES level of interconnection is calculated on a project by project basis, reviewing all axioms from economic, political, environmental etc. An important distinction between the FES and this process, therefore, is that the NOA IC aims to find what would be economically optimal rather than being based on specific projects. As a result, interconnectors included in the FES which are not deemed to have a high degree of regulatory certainty (such as the Cap and Floor regime) will be removed from the scenario. A shortfall of capacity will then drive further interconnection in the results.

3.66 The time period considered in the studies extends from the present to 2038. This is to match the FES, which will forecast up to 2038 in detail. For the timing analysis, only capacity in years 2026, 2028 and 2031 will be investigated. The reason for not starting to analyse additional capacity until 2026 is this is deemed the earliest an entirely new interconnector project could realistically be connected. Studying every year thereafter is infeasible, as each additional year studied requires a further set of model runs in the optimisation. This would lead to an unachievable number of required market simulations as constrained by time limitations.

Market modelling

3.67 The selected method of arriving at a recommendation for capacity development is an iterative optimisation per scenario. The iterative optimisation approach attempts to maximise present value, equal to SEW less CAPEX less Attributable Constraint Costs (ACC), using a search strategy. The whole process is repeated four times to arrive at an optimal development of capacity in each of the four FES. In last year's NOA IC 2017/18 A Least Worst Regret calculation was used at the end of each iterative step in order to determine a single optimal path across all FES. This year, based on strong stakeholder feedback, no LWR will be performed, resulting in four optimal paths: one per FES and hence a range for the optimal solution will be produced. A balance between computing resource and rigour in each step of the process must be found. An example step is outlined below, wherein multiple capacity changes are evaluated for SEW in each step.

3.68 Timing of capacity increases can affect the SEW generated and Attributable Constraint Costs (ACC) by the interconnection across the study window. Within each search step, therefore, timing combinations will be considered. The use of spot years will be necessary to allow a solution to converge, wherein the commissioning of additional projects would be evaluated only in future years 2026, 2028 and 2031. This means for each iteration, the welfare of the interconnectors in every spot year will be calculated.

3.69 The example below is based on a hypothetical situation, optimising the capacities and optimal timing of connection for potential interconnection to 3 markets. It shows a sample of the options of market, connecting year, FES scenarios, GB zone and reinforcement that need to be considered for each iterative step.

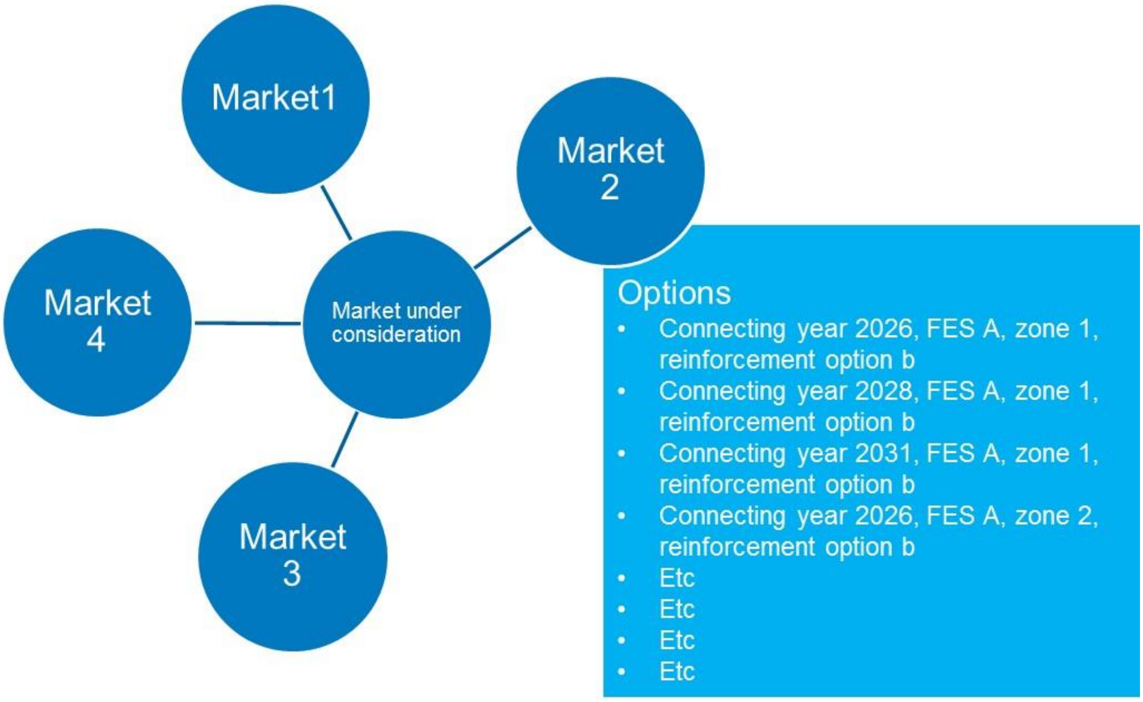


Figure 3.5 Example Markets

Table 3.5 Example of iteration 1 search step

	Iteration 1 Transfer Capacities (MW)						
	Baseline	Simulation 1		Simulation 2		Simulation 3	
		Increment	Simulated capacity	Increment	Simulated capacity	Increment	Simulated capacity
FES A Market 1	2000	+1000	3000	0	2000	0	2000
FES A Market 2	1000	0	1000	+1000	2000	0	1000
FES A Market 3	1000	0	1000	0	1000	+1000	2000
FES A CHANGE IN SEW-CAPEX-ACC	**0**	**+ £12M**		**+ £5M**		**+ £8M**	
FES B Market 1	2000	+1000	3000	0	2000	0	2000
FES B Market 2	1000	0	1000	+1000	2000	0	1000
FES B Market 3	1000	0	1000	0	1000	+1000	2000
FES B CHANGE IN SEW – CAPEX-ACC	**0**	**+ £7M**		**+ £3M**		**+ £11M**	

3.70 Table 3.5 gives an example of the iteration search step 1, whereby an additional 1000 MW of capacity os added sequentially to each option. The option that produces the highest change in SEW-CAPEX-ACC for each FES is then added to the baseline for the iteration search step 2 for that particular FES, as shown in Table 3.6.

Table 3.6 Example of iteration 2 search step

	Iteration 2 Transfer Capacities (MW)						
		Simulation 1		Simulation 2		Simulation 3	
	Baseline	Increment	Simulated capacity	Increment	Simulated capacity	Increment	Simulated capacity
FES A Market 1	3000	+1000	4000	0	3000	0	3000
FES A Market 2	1000	0	1000	+1000	2000	0	1000
FES A Market 3	1000	0	1000	0	1000	+1000	2000
CHANGE IN SEW – CAPEX-ACC	**0**	**+ £7m**		**+ £5M**		**+ £5M**	
FES B Market 1	2000	+1000	3000	0	2000	0	2000
FES B Market 2	1000	0	1000	+1000	2000	0	1000
FES B Market 3	2000	0	2000	0	2000	+1000	3000
CHANGE IN SEW – CAPEX-ACC	**0**	**+ £6M**		**+ £2M**		**+ £5M**	

FES A Market 1 Increased by 1000MW following the result of iteration 1 for FES A

FES B Market 3 Increased by 1000MW following the result of iteration 1 for FES B

3.71 The search finishes when it is deemed to have converged- that is, no further capacity alterations yield a higher overall present value for the whole study window for each scenario. The optimal capacity profiles will then be presented in the NOA report, providing the industry with a range, that is one for each FES.

3.72 To improve efficiency of arriving at the end of the optimal path, the incremental steps will be of 1000MW of capacity. Once there is no additional benefit from any interconnectors, the incremental capacity will be reduced to 500MW to analyse whether there is any benefit of a further 500MW.

Further Output

3.73 Accompanying the output of the optimal path market and network analysis, additional results will be provided illustrating the benefit each interconnector would potentially provide. This is to overcome this possibility of misinterpretation of the results, as many interconnectors which don't appear in the optimal path individually have a positive net benefit to consumers and therefore development should continue to be pursued.

3.74 The output will show the levels of welfare for GB and the connecting country for each interconnector, relative to the base case. Following stakeholder feedback, we wil also calculate SEW for GB only and GB and the rest of Europe.

Process Output

3.75 The above methodology will be employed to create a chapter of the NOA 2018/19 report. This chapter will present the main findings of the analysis – a range for optimised interconnection capacity level by market, and the best timing for capacity increases across all scenarios. It will include commentary on these results and other impacts of interconnection excluded from the optimisation. Our stakeholders clearly stated that they wanted us to keep the level of detail similar to that within NOA IC 2017/18. In addition, based on stakeholder freedback we will provide clearer commentary on the reasons for differences between the results of this analysis and other relevant pieces of interconnector analysis such as TYNDP. The results will be delivered by 31st January 2019.

Section 4: Suitability for third party delivery and tendering assessment

Overview

4.1 The SO has a clear role to play in facilitating the introduction of competition. As part of January's informal licence change consultation[19] Ofgem have made clear their intention and applicability of the criteria for competition assessment. The SO therefore believes it is sensible and pragmatic to continue to include an assessment for competition for major network reinforcements against these criteria of new, high value and separable as the timescales for delivery of many investments now fall in the RIIO-T2 timeframe, where any projects meeting the criteria could be subject to competitive tendering. As Ofgem develops the proposed competitive delivery frameworks and timing the SO will start to extend the assessment against the criteria for competition into connections where the enabling works meet the relevant criteria. This methodology describes the process for the assessment for both wider network reinforcement and connections, however only limited assessment for connections will be included in the NOA report published in January 2019. It should be noted that, in the current NOA, the time for the competitive tendering process is not considered when the TOs submit the EISDs or delivery dates for their wider transmission reinforcements or enabling works[20] for connection projects.

4.2 The SO assesses the suitability of projects for competition in accordance with published tendering criteria[21]. The single year regret analysis process identifies the recommended options. For each set of options, the SO identifies the most relevant options and assesses these options against the tendering criteria, which are options that are:

- new,
- separable,
- high value.

In order to undertake the assessment, the TOs will provide information to the SO via the SRF form (see appendix D) for wider works. The SO then carries out the following process:

- Reviews the information provided for each option.
- Assesses the most relevant options against the criteria for competition.
- Provides a recommendation for the options on how they meet or do not meet the criteria for competition and hence the options' suitability for competition.

[19] https://www.ofgem.gov.uk/publications-and-updates/consultation-changes-standard-licence-condition-c27
[20] For the definition of 'enabling works', please refer to section 13 of the Connection and Use of System Code (CUSC) https://www.nationalgrid.com/sites/default/files/documents/Complete%20CUSC%20-%20%201%20April%202018.pdf
[21] https://www.ofgem.gov.uk/system/files/docs/2018/01/competition_update.pdf and https://www.ofgem.gov.uk/system/files/docs/2018/01/draft_criteria_guidance.pdf

Note that some options will clearly not meet the criteria for competition, for instance because their value is far below the threshold. As a result, not all options are assessed for competition.

4.3 In addition to wider network reinforcement, the NOA also examines connections for eligibility for competition. For each NOA, the SO assesses transmission connections against the same criteria as wider work options (described above) and publishes the conclusions in the NOA. The assessment against the criteria does not mean that investments meeting the criteria will be subject to competitive tendering. Any decision for competitive tendering lies with Ofgem.

Connections

4.4 Prospective users can make connection applications and modification applications at any time of year whereas the NOA process works on an annual cycle. As a result the SO assesses connection projects when it receives them. Few connection projects meet the value criteria of £100m and of those that do, many provide wider network benefits and hence are of interest and already included in the NOA process. The SO uses the connection contract between the SO and the prospective user to take a view of the likelihood of meeting the value criteria.

4.5 For a new connection, the SO identifies the projects where there is the possibility of the required enabling works (not including works already covered in the NOA) meeting the value criteria. The SO informs the relevant TO(s) of the projects and provides a summary of the work proposed and the costs. This is in time for the SO to perform the assessment in October.

4.6 If the TO states that a project has wider network benefits, it can use the SRF at the usual time in the NOA process to submit the information for the competition assessment process.

4.7 The TO(s) responds to the SO's summary of the projects and the SO then uses the summary together with any input from the TO(s) for the process to assess eligibility for competition.

Bundling/splitting of work packages

4.8 The first step in the SO's competition assessment of larger projects, is to provide an opinion on bundling projects into larger packages, or splitting projects into smaller packages, to form a recommendation in the NOA. There are two aspects to the SO's consideration of bundling and splitting as follows:

a. The costs and size of the component aspects of projects to ensure that they can be most appropriately packaged.
b. Where the SO can identify opportunities or benefits from repackaging of projects.

Bundling

4.9 The SO considers whether combining one or more projects into a single tender could be appropriate (if they have common needs/drivers or it makes technical or commercial sense) and whether it is in the interests of consumers (e.g. economies of scale for procuring large quantities). If the SO believes that there is benefit from bundling (and where the constituent projects have not been challenged or corrected), then each constituent project should meet the high value threshold. Where work is bundled as part of this process, the component parts must each meet the competition criteria to be eligible.

Splitting

4.10 The SO is expected to recommend splitting a project into more than one tender package if it is in the interest of consumers (for example if an project constitutes new assets and refurbishment of existing assets these could be split so new assets could be competed). When it considers splitting a project, the SO will consider the impact this could have on project delivery. Each resultant package should meet the high value threshold, if these are to be competed.

Competition criteria

4.11 Ofgem has stated that there are significant benefits to consumers in introducing competition into the delivery of transmission projects that meet defined criteria. These criteria are:

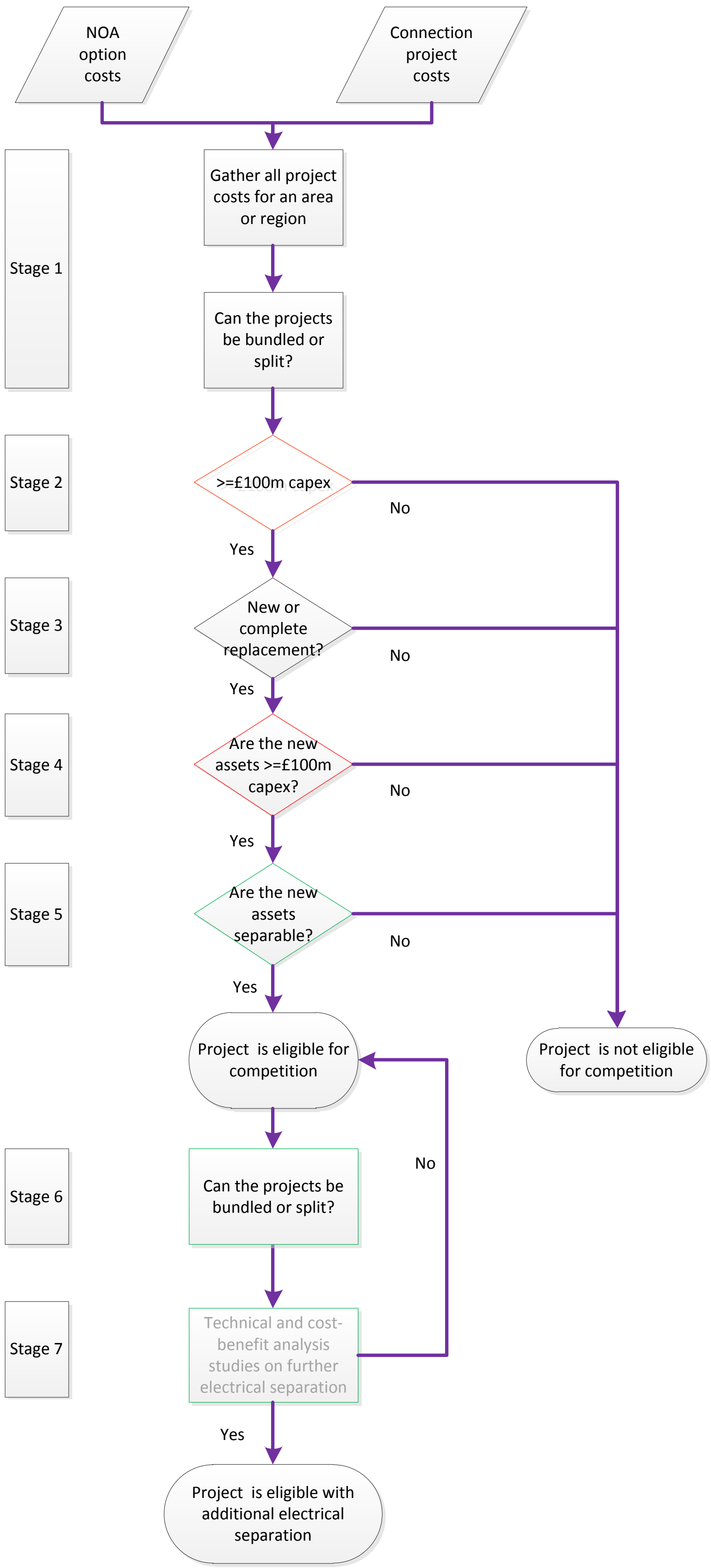
- **New** – completely new transmission assets or complete replacement of transmission assets.
- **Separable** – ownership between these assets and other (existing) assets can be clearly delineated.
- **High value** – at or above £100m in value of the expected capital expenditure of the project.

Figure 4.1shows the process for assessing whether reinforcement projects meet competition criteria.

4.12 Note that there are two stages in the high value assessment (red outline) and two stages in the separability assessment (green outline).

4.13 Process stages - the names of the process stages below match those on the diagram. The numbered stages below correspond to the boxes on the left side of the diagram.

Figure 4.1 The process for assessing suitability for competition



Stage 1

Can the projects be bundled or split?

Aim – to carry out a first check to ensure that sensible packages of work are developed together by assessing the proposed work to see if it should be split (broken into more than one smaller bundle) or whether work across more than one project should be bundled together.

Criteria for splitting:

- Does the project involve different technologies that suggests different skills and procurement are needed for the separate elements?
- Is there a variety of works involved? For example:
- Are there one or more new substations?
- Does the proposed project comprise OHL and cable sections and how do they affect existing networks?
- Are there one or more cable tunnels?
- Are the project phases adjoining or in naturally separate timeframes?

Criteria for bundling:

- Are there multiple projects with common needs / drivers?
- Are there several individual projects in a relatively self-contained area or corridor?
- Are there scheme works that are very similar?
- Is it one of several smaller projects that could be efficiently or more efficiently developed with other projects?

Stage 2

>=£100m capex

Aim – to assess whether the project or bundle of projects meets the high value criteria and include only projects that exceed the threshold within a 10% margin for consideration at the next stage. Table 4.1 lists the factors that affect the high value figure.[22]

Criteria – this is the first of a two-stage process (the second, stage 4 is below). The SO uses the costs that the TO(s) have provided and that have undergone cost checking or that appear in the connection contract to calculate the cost (or where we are looking to create a bundled package the total costs) of the project. The SO might seek advice from the TO if it has queries. The trigger threshold is set at £90m to highlight projects that are marginally below the £100m figure. This produces a straight yes/no output.

[22] As applied to the current framework for cost allocation under the RIIO-T1 framework

Table 4.1 List of factors that the high value figure includes or excludes

The £100m capex 'high value' figure	
includes • Costs of acquiring land	**excludes** • Consent costs

Stage 3

New or complete replacement
Aim – to test the projects against whether they are new assets or complete replacement assets rather than, say, refurbished assets. This test has the practical benefit of checking for complicated examples. For example where a new double circuit crosses an existing double circuit and because of routing and the existing circuits, the existing circuits need modification leading to new assets integrated into existing circuits. As a result, the affected existing circuits would become a mix of old and new assets. The consenting process might also change a simple double circuit route into a complicated one that includes mixed ownership because of old and new assets being integrated. As the project will be assessed annually in the NOA process this might lead to a change in the project's eligibility, from one year's assessment to another.
Criteria – is a project delivering completely new assets or complete replacement assets that fulfil the same function of the assets to be removed or replaced? This produces a straight yes/no output.

Stage 4

Are the new assets >=£100m value?
Aim – to test whether the new assets reach or exceed the high value threshold.
Criteria – this is the second part of a two-stage process (the first, stage 2 is above). If the project has a very high proportion of new assets and high value, the project will pass this stage. For more marginal projects, the SO uses the breakdown of costs from the TO to calculate the value of the new assets. This produces a straight yes/no output.

Stage 5

Are the new assets separable?
Aim – to test whether the project details indicate that the new assets are readily separable from the existing assets.
Criteria – this is to check if the project already has points of connection to existing assets that can be clearly delineated, in other words, clearly identified. Disconnectors are obvious points that can be delineated but Ofgem suggest that other points such

as clamps on busbars or points on overhead lines would also be acceptable as long as the point can be clearly identified. This produces a straight yes/no output.

Stage 6

Can the projects be bundled or split?

Aim – having gone through the process to check for eligibility, this stage is a recheck that sensible packages of work are developed together.

Criteria – these are the same as for stage 1 (above). Note that projects that are split must have component parts that meet or exceed the £100m value threshold.

Stage 7

Based on technical and cost-benefit analysis studies, is it appropriate for the SO to recommend additional electrical separation for the projects that have met the competition criteria?

If the SO concludes that the project proposals already have adequate electrical separation, it is not necessary to carry out this stage.

Aim – use cost-benefit analysis studies to test technical solutions and determine if it is worth extra investment in assets or amending the design to further delineate ownership boundaries to provide adequate electrical separability.

The SO is considering ways of conducting this assessment with the most likely being a study against some criteria to provide consistency. The SO believes that the assessment will be needed by exception only.

The SO maintains a log of connection projects that meet the competition criteria and liaises with the TOs about the outcomes of the competition eligibility assessments. This log forms the basis of the list that is published in the NOA.

Section 5: SO process for Offshore Wider Works

Foreword

5.1 This section contains National Grid's SO's proposed processes for Offshore Wider System Works in the following two areas:

5.2 **Offshore Wider Works – Developer Associated** describes the process for investment in transmission capacity to provide wider network benefit, which is led by developers (whether generator builds or OFTO build). It includes investment in offshore transmission assets or capacity that goes beyond that needed by a single developer and is for the purpose of supporting the reinforcement of the GB transmission network (the wider network). This could include investment providing for, or creating the potential for, increased boundary transfers between different zones of the wider network via offshore links.

5.3 **Offshore Wider Works – Non Developer Associated** describes the process for investment that would support reinforcement of the wider transmission network, but where developers are unwilling or unable to take forward the offshore wider works. Offshore Wider Works non developer-associated needs case is in many cases a substitute for onshore wider works.

Offshore Wider Works – developer associated overview

5.4 Current offshore transmission assets have been developed as standalone connections to shore known as a radial connections. However, the Round 3 offshore wind projects are larger, more complex and at a greater distance from shore than those that have been developed so far; as a result there is likely to be the potential for efficiencies from greater coordination of offshore transmission infrastructure. This could include coordination between connections, and coordination of the strategic development of the wider network through offshore reinforcement projects.

5.5 Offshore Wider Works developer-associated is investment in transmission capacity to provide wider network benefit, which is led by developers (whether generator builds or OFTO build). It includes investment in offshore transmission assets or capacity that goes beyond that needed by a single developer and is for the purpose of supporting the reinforcement of the GB transmission network (the wider network). This could include investment providing for, or creating the potential for, increased boundary transfers between different zones of the wider network via offshore links.

5.6 The offshore connection offer process has a key role in the development of a coordinated offshore transmission network. Where it is economic and efficient, Offshore Wider Works may form part of a developer's connection offer and subsequent bilateral connection agreement (BCA)[23].

5.7 In December consultation, Ofgem proposed high level roles and responsibilities to support a gateway assessment process for Offshore Wider Works. In responding to Ofgem proposals, stakeholders broadly agreed that the SO should support the needs case for developer-associated Offshore Wider Works at the gateway assessments. Ofgem maintain the position that the developer should lead in triggering and making submission to the voluntary gateway assessments, and that the SO (drawing on relevant Transmission Owners (TOs) as necessary) should assist with developing the needs case for the Offshore Wider Works for any Ofgem gateway assessments. Further, both parties will have a role in monitoring the needs case for the Offshore Wider Works, with the developer reviewing their design where this is an appropriate response to a change in the needs case.

5.8 Ofgem at this stage, consider that offshore developers should retain the choice to undertake preliminary Offshore Wider Works for the development of coordinated offshore transmission assets under developer-associated Needs Case.

[23] In planning and developing offshore transmission assets under the generator build option, developers are required under the Grid Code (Planning Code) to take into account reasonable requests from the NETSO where it is reasonable and practicable to do so (PC.8.3)

Offshore Wider Works – developer associated: the SO's role

5.9 Based on the consultation document from December 2013 a majority of the respondents agreed that the SO should support the needs case for Offshore Wider Works developer-associated. It was also very clear from the consultation that affected TO and offshore developer's contribution and cooperation would be also required. The following text is explaining each point of the SO process for Offshore Wider Works developer-associated.

5.10 Step 1: Identification of System Need. The Offshore Wider Works can be identified in two ways:

a. SO assess the system need through an annual Electricity Ten Year Statement (ETYS) process. Some of the system reinforcement options will be an Offshore Wider Works options and will be subsequently included in the NOA document.

b. Offshore Wind Farms Connection offer will also identify the investment need for the Offshore Wider Works.

5.11 Step 2: Offshore Wind Farm Connection Application and CION

c. As part of the connection offer process, SO is required to provide details to the developer of the preliminary identification and consideration of the connection options available. This includes the preliminary costs used in assessing such options and the offshore works assumptions, including the assumed interface point identified. SO fulfils these requirements by the production of the Connections Infrastructure Options Note (CION). The CION sets out the offshore works assumptions and consideration of options available and is provided to the developer during the connection offer process.

5.12 Step 3 & Step 4: SO and offshore developer are working together on development of the Offshore Wider Works Options

d. In collaboration with offshore developer, the SO develops the Offshore Wider Works options.

e. In developing Offshore Wider Works, SO will take into consideration two major transmission system design criteria: network capacity availability of local boundary and shortfall of the wider system boundaries.

f. According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary (e.g. for 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.)

g. In planning the Main Interconnected Transmission System (MITS) however, under Economic Criterion (NETS SQSS, Appendix E) different scaling factors are applied to different types of generating plant i.e. Nuclear Power – 85%, Pumped Storage – 50%, Interconnectors – 100%, Wind, Wave and Tidal – 70% while conventional generation is scaled variably. In the case of wind, this implies that the assets are assumed to be 70% utilized by the wind generated. Taking into account all this scaling factors, the offshore infrastructure is allowing some spare capacity in the assets. It is this ‘spare’ capacity that provides the opportunity for offshore wider works to be utilised as one of the options to provide boundary capability across a non-compliant boundary.

h. In providing the Offshore Wider Works design it is crucial SO and offshore developer to work together and agree on the generation background, scenarios and sensitivities which will be used as a basis for the Offshore Wider Works Design. In this stage SO will inform Ofgem on agreed background and scenario between SO and offshore developer.

i. The benefits of the Offshore Wider Works will also be assessed by utilising a combination of operational actions to maximize the capability across the boundaries (e.g. actions included QB optimisation and redirection of flows in HVDC links).

j. Once SO and the offshore developer agrees on Offshore Wider Works options, the agreed Offshore Wider Works options are progressing into the cost-benefit analysis.

5.13 Step 5: Cost-benefit analysis. SO, supported with information from offshore developer, perform the cost-benefit analysis on the agreed Offshore Wider Works options from Step 3 & 4. The rationale behind the Cost-benefit analysis is explained in the following text:

a. The key economic objectives for cost-benefit analysis for Offshore Wider Works are:

    i. Ensure value for money for the consumers by delivering cost effective reinforcements to ensure economically efficient design and operation of the network.
    ii. Timely delivery of necessary reinforcement(s) to minimise any cost exposure for consumers to either early investment or delayed implementation.

b. The objectives for Offshore Wider Works cost-benefit analysis are:

    i. To be consistent with Licence obligations and National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS); the analysis promotes economic and efficient investment.
    ii. To present economic justification for the preferred Offshore Wider Works designs and an explanation of how they compare with the alternative counterfactual case.
    iii. To present evidence on expected long-term value for money for consumers considering a range of sensitivities
    iv. To present evidence on optimal timing of the preferred reinforcement option.

c. Driven by these objectives the scope of the cost-benefit analysis is:

   i. To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across different generation background scenarios.
   ii. To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.

d. To undertake a cost-benefit analysis by:

   i. Appraising the economic case of the options by adopting the Spackman[24] approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
   ii. Establishing worst regrets associated with each design/technology appraised.
   iii. Identifying the Least Worst Regret option overall
   iv. Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
   v. Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

5.14 Step 6: SO discusses the preferred Offshore Wider Works option from cost-benefit analysis (Step 5) with offshore developer and affected TO

5.15 Step 7: Offshore Wider Works Needs Case submission through voluntary gateway process

a. SO makes a recommendation on preferred option for Offshore Wider Works developer-associated. SO supports offshore developer in submission of Offshore Wider Works needs case to Ofgem via voluntary gateway process

b. Based on the last consultation in December 2013 offshore developers will have the option to go through one or two Ofgem gateway assessments, timed broadly ahead of the commencement of preliminary works and ahead of construction works. Where a developer is comfortable that it can support its decision to develop the Offshore Wider Works as part of a cost assessment during a tender exercise, the developer can choose not to go through one, or both, of the gateway assessments. In general Ofgem is expecting that two voluntary gateway assessments would be sufficient. However, if a developer considers that there are substantial benefits to passing through more than two gateway assessments in a particular case (for example in the case of particularly large, complex projects) Ofgem would look to engage with the developer to understand these benefits and consider the best way forward.

[24] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

c. At the first gateway assessment, Ofgem will review the rationale for including the Offshore Wider Works in a developer's design solution at the preliminary works stage. This is the case for developers following both the generator build and OFTO build option. Where Ofgem is convinced by the developer's rationale for undertaking certain preliminary works associated with the Offshore Wider Works, Ofgem would not reassess this rationale during the tender exercise.

d. At the second gateway Ofgem will review the rationale for constructing the Offshore Wider Works. Where the developer choose the generator build option, Ofgem assessment at the second gateway will inform the cost assessment process undertaken during the subsequent tender exercise. Where Ofgem is convinced by the developer's rationale for including specific additional, or oversized, transmission assets associated with the Offshore Wider Works, Ofgem would commit to not reassessing this rationale during the tender exercise. Where a developer is following the OFTO build option, Ofgem assessment will help to inform the scope of the OFTO build tender exercise.

e. Any Ofgem commitment regarding not re-assessing the rationale for the Offshore Wider Works at the first or second gateway, would be conditional on the SO and the offshore developer continuing to engage and monitor the needs case for the Offshore Wider Works. Where the needs case changes, Ofgem is expecting expect these parties to review the design of the offshore assets and make any necessary changes where this would be economic and efficient. Ofgem is expecting that this process would take into account both the needs of the wider network and the impact of any changes on the cost and timing of an offshore developer's connection. In some instances, a change in the needs case for the Offshore Wider Works may mean that the Offshore Wider Works is no longer taken forward.

f. All the costs incurred in connection with development and construction of the agreed scope of the transmission assets, including the Offshore Wider Works elements, would remain subject to the economic and efficient test as part of Ofgem's cost assessment.

5.16 Step 8: Voluntary Gateway Process Assessment

a. 1st gateway assessment (preliminary works): The developer, supported by the SO, may submit a needs case for the Offshore Wider Works to Ofgem. Where a robust needs case is submitted, Ofgem makes commitments on approach to cost assessment on the rationale for Offshore Wider Works preliminary works.

b. 2nd gateway process: The developer, supported by the SO, may submit a needs case to Ofgem. Where a robust needs case is submitted, Ofgem make commitments on approach to cost assessment on the rationale for Offshore Wider Works construction works.

c. Tender Exercise: The developer triggers a tender exercise Ofgem conducts a cost estimate and assessment, taking into account commitments at the 1st and 2nd gateway assessments.

d. In the 2013 December consultation Ofgem proposed a number of high level criteria that would be used to evaluate gateway assessment submissions. These criteria included:

   vi. the (economic) needs case for investment
   vii. the timing and scope of the project and its technical readiness
   viii. proposals for ongoing SO-developer engagement

e. Gateway assessments will, in general, be expected to take place before a tender exercise has commenced. As the purpose of the gateway assessment is to inform a resulting tender exercise cost assessment, Ofgem expect the developer to be able to show their commitment to triggering a tender exercise for those assets before Ofgem undertake a gateway assessment.

f. Timing of the Gateway process

   i. In 2013 consultation Ofgem proposed providing flexibility in the timing of gateway assessments, driven by the needs of individual projects. The identified flexibility applied to the point at which the developer would trigger the gateway assessment, based on the developer's ability to provide sufficient information to enable Ofgem to conduct an informed assessment. Ofgem expect that early engagement between developers and Ofgem would inform the point at which the gateway assessment would be triggered.
   ii. Developers and the SO will need to undertake analysis to provide an evidence of the feasibility and needs case for taking forward the Offshore Wider Works before considering triggering the first gateway assessment. Ofgem is considering that developers will generally only be able to satisfy the assessment criteria for the first gateway assessment after they have signed a BCA. Ofgem expect that in most cases there may need to be significant further engagement on connection optioneering between the developer and the SO in order to inform a needs case submission. Ofgem also expect early engagement between developers and Ofgem will help inform when the gateway assessment should be triggered.
   iii. Similarly, for the second gateway assessment, developers will be able to trigger the gateway assessment when they have sufficient information to enable Ofgem to conduct an informed assessment. Under the generator build option, Ofgem expect the timing of this gateway assessment to be as late as possible, to help ensure that the evidence provided in an offshore developer's submission remains up to date at the point at which significant final procurement decisions for the Offshore Wider Works are made.

5.17 Step 9: SO and offshore developers are providing support to Ofgem in the Gateway Assessment Process

   iv. Ofgem will be working with SO and offshore developer to further develop what information for gateway assessment process is required.

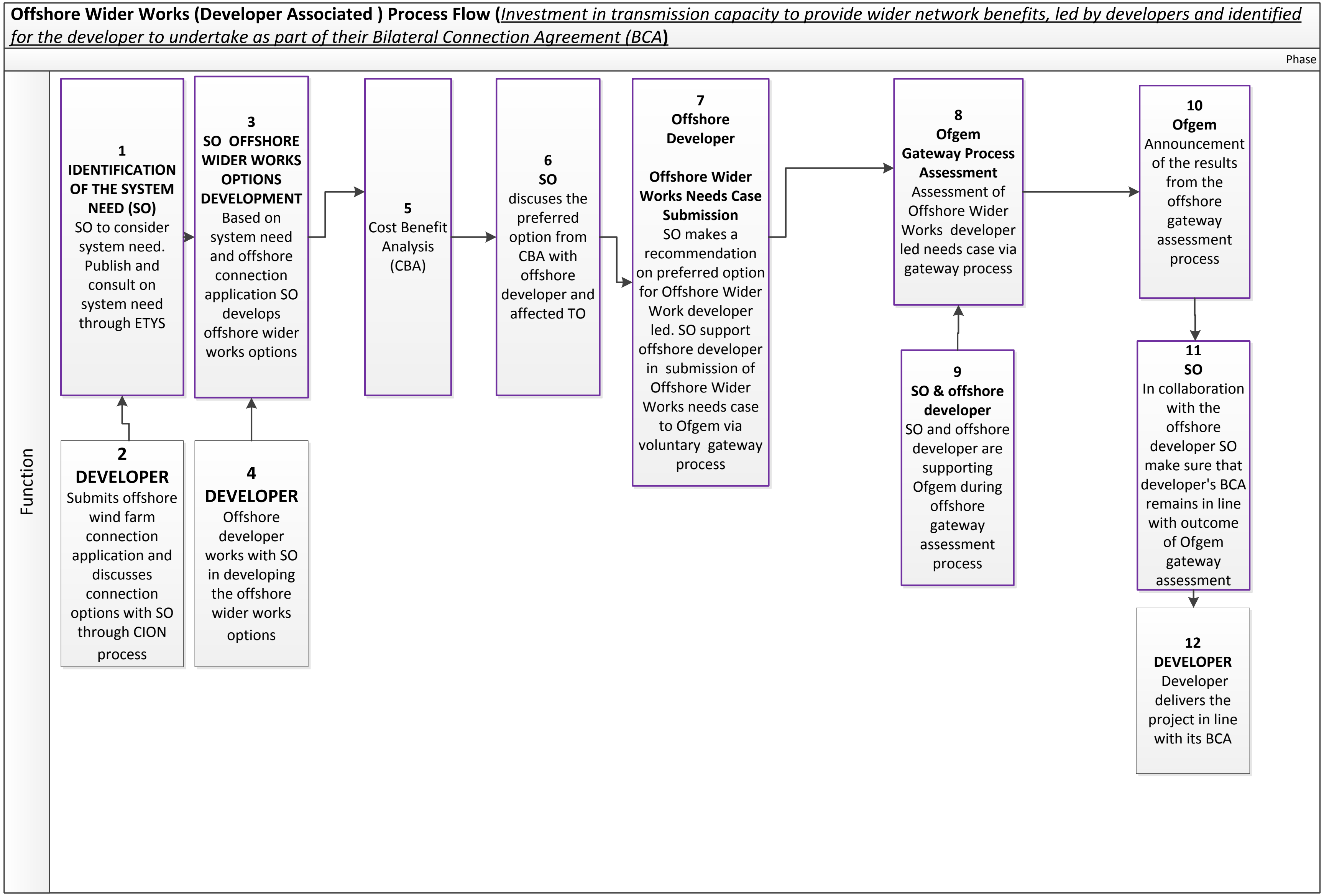
The criteria and needs case requirements will be applicable to all projects, ensuring transparency of approach. However, given the unique technical requirements of offshore transmission and variation between projects, early engagement with developers ahead of a gateway assessment submission will provide an opportunity for Ofgem to provide further details on what information will need to be contained within an individual gateway assessment submission

5.18 Step 10: Ofgem approves the Offshore Wider Works developer - associated project

5.19 Step 11: In collaboration with offshore developer SO make sure that developer's BCA remains in line with outcome of Ofgem gateway assessment process

5.20 Step 12: Offshore developer delivers the project in line with the BCA.

Offshore Wider Works – developer associated process flow diagram



This diagram shows the overall Offshore Wider Works process. The text in each box corresponds to the descriptions of the stages explained in general process above. The numbers correspond to the step numbering in the text.

Offshore Wider Works – non developer associated overview

5.21 Current offshore transmission assets have been developed as standalone connections to shore known as a radial connections. However, the Round 3 offshore wind projects are larger, more complex and at a greater distance from shore than those that have been developed so far; as a result there is likely to be the potential for efficiencies from greater coordination and integration of offshore transmission infrastructure. This could include coordination between offshore connections, and coordination of the strategic development of the wider network through offshore reinforcement projects.

5.22 Existing offshore transmission assets are designed as a radial links to allow the transfer of the power from the offshore generator to the onshore network, and are therefore the offshore asset rating is equal to size of wind farm. The non-developer-associated Offshore Wider Works is investment that would support reinforcement of the wider transmission network, but where developers are unwilling or unable to take forward the offshore wider works. Offshore Wider Works non developer-associated needs case is in many cases a substitute for onshore wider works and therefore is some way very similar to onshore wider works investment.

5.23 Currently there is no clear route for Offshore Wider Works to be taken forward where works not being undertaken by a developer. In last consultation in 2014 Ofgem set out their lead option: for onshore Transmission Owners (TOs) to undertake preliminary works[25] for non developer associated Offshore Wider Works, followed by a late OFTO build tender to identify an OFTO to construct, operate and own the transmission assets.

5.24 As a result of consultation responses, Ofgem also considered other potential models for non developer associated Offshore Wider Works.

5.25 The potential future models for non developer associated Offshore Wider Works are the following:

a. **Split OFTO Build**: an initial tender to determine a third party to undertake the preliminary works, followed by a late OFTO build tender to determine the party who will construct and own the assets

b. **Early OFTO Build:** an early OFTO build tender to determine the party with responsibility for preliminary works, construction and ongoing operation of the assets

[25] 'Preliminary works' is a defined term in the 2013 Tender Regulations. Generally, it includes project development activity ahead of construction and does not include construction activities. For the purposes of this consultation, the definition of preliminary works within the 2013 Tender Regulations may be used as a guide, recognising that the scope of preliminary works under different non developer-led WNBI models may ultimately vary from the current definition depending on the most appropriate scope of works for non developer-associated Offshore Wider Works projects.

c. **TO Initiated Late OFTO Build**: enabling TOs to undertake preliminary works ahead of a late OFTO build tender to determine the party who will construct, own and operate the assets.

Offshore Wider Works – non developer associated process

5.26 The coordination of offshore transmission assets could reduce the costs of the onshore system reinforcement requirements and potentially reduce the costs for the end consumers.

5.27 A non developer associated wider network benefit investment for Offshore Wider Works supports coordination of the development of offshore transmission assets and wider GB transmission network reinforcement. Offshore Wider Works non developer-associated is not limited to a specific connection offer and is the case where offshore generators are unwilling or unable to take forward the offshore wider works.

5.28 The following text describe the steps of the SO process for Offshore Wider Works non developer-led Needs Case.

5.29 Step 1: Identification of System Need. The need for non developer associated Offshore Wider Works will be identified by SO and the relevant TO. The system need for the Offshore Wider Works can be identified in the following ways:

a. SO assesses the system need through an annual Electricity Ten Year Statement (ETYS) process, which subsequently informs the NOA Report.

b. SO and TOs regularly discuss and review network capacity issues and the need for network reinforcement in a particular TO's area at Joint Planning Committee (JPC) meetings. Based on that information TO will consider Offshore Wider Options as an option to reinforce the network.

5.30 Step 2: SO and relevant TO identify the Offshore Wider Works Options

c. In collaboration with relevant TO the SO develops the Offshore Wider Works options.

d. In developing Offshore Wider Works SO will take into the consideration two major transmission system design criteria: network capacity availability of local boundary and shortfall of the wider system boundaries.

e. According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary (e.g. for 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.)

f. In planning the Main Interconnected Transmission System (MITS) however, under Economic Criterion (NETS SQSS, Appendix E) different scaling factors are applied to different types of generating plant i.e. Nuclear Power – 85%, Pumped Storage – 50%, Interconnectors – 100%, Wind, Wave and Tidal – 70% while conventional generation is scaled variably. In the case of wind, this implies that the assets are assumed to be 70% utilized by the wind generated. Taking into account all this scaling factors, the offshore infrastructure is allowing some spare capacity in the assets. It is this 'spare' capacity that provides the opportunity for offshore wider works to be utilised as one of the options to provide boundary capability across a non-compliant boundary.

g. In providing the Offshore Wider Works design it is crucial SO and affected TO to work together and agree on the generation background, scenarios and sensitivities which will be used as a basis for the Offshore Wider Works designs. In this stage SO will inform Ofgem on agreed background and scenario which will form the basis for the Offshore Wider Works designs.

h. The benefits of the Offshore Wider Works will be also assessed by utilising a combination of operational actions to maximize the capability across the boundaries (e.g. actions included QB optimisation and redirection of flows in HVDC links).

i. Once SO and the affected TO agrees on Offshore Wider Works Options, the agreed Offshore Wider Works options are progressing into the cost-benefit analysis.

5.31 Step 3: Cost-benefit analysis. SO will perform the cost-benefit analysis on the agreed Offshore Wider Works options from Step 2. The SO will lead the cost-benefit analysis depending on the preferred model for the non developer associated Offshore Wider Works.

5.32 In the model 1 (Split OFTO build) the preferred Offshore Wider Works options will be obtained in collaboration between TO and 3rd party. The 3rd party will be defined by Ofgem via tendering process.

5.33 In model 2 (Early OFTO build) the preferred option will be identified in collaboration between SO and OFTO. OFTO will be appointed by Ofgem via tendering process.

5.34 In the model 3 (Initiated late OFTO build) the preferred option will be determined in collaboration between SO and affected/relevant TO.

5.35 The Cost-benefit analysis will be performed by SO and the objectives and scope of the cost-benefit analysis is explained below:

a. The key economic objectives for cost-benefit analysis for Offshore Wider Works are:

    i. Ensure value for money for the consumers by delivering cost effective reinforcements to ensure economically efficient design and operation of the network.
    ii. Timely delivery of necessary reinforcement(s) to minimise any cost exposure for consumers to either early investment or delayed implementation.

b. The objectives for Offshore Wider Works cost-benefit analysis are:

    i. To be consistent with Licence obligations and National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS), the analysis promotes economic and efficient investment.

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

c. Driven by these objectives the scope of the cost-benefit analysis is:

i. To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across different generation background scenarios.
ii. To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.

d. To undertake a cost-benefit analysis by:

i. Appraising the economic case of the options by adopting the Spackman[26] approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
ii. Establishing worst regrets associated with each design/technology appraised.
iii. Identifying the Least Worst Regret option overall
iv. Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
v. Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

5.36 **Model 1: Split OFTO Build**

a. Under the Split OFTO Build model, the preliminary works would be completed by a third party appointed through an Ofgem-run tender. If there is a needs case to proceed with construction, Ofgem would then run a late OFTO build tender. At the completion of the preliminary works, Ofgem would appoint an OFTO licensee to take ownership of the preliminary works and construct, own and operate the transmission assets.

b. Ofgem would run a first tender to license a third party to undertake the preliminary works and develop the project through to the securing of consents. Ofgem would select the successful bidder on the basis of the price of bids to complete the preliminary works as well as the evidence the bidder provides on its plans, capability and experience.

[26] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

c. The successful bidder would complete the preliminary works and produce the relevant outputs needed to run a late OFTO build tender. The party undertaking the preliminary works would be expected to engage stakeholders and coordinate with other relevant parties, including affected developers, TOs and the SO. It would also be expected to support the eventual late OFTO build tender, undertaking activities such as populating the data room, responding to queries from bidders, and contributing to a smooth and timely tender process.

5.37 **Model 2: Early OFTO Build**

a. Under this model the OFTO would undertake the design work, consenting, procurement and delivery of the transmission assets work programme, as well as being responsible for the operation, maintenance and decommissioning of the assets. Ofgem would appoint an OFTO through an Ofgem-run tender either before, or during, the early stages of the preliminary works. The successful bidder would be selected based on its plans, capabilities and relevant experience, as well as its proposed fixed and indicative costs.

b. The early OFTO build tender would be held on the basis of a high-level specification for the transmission assets, including associated preliminary works.

c. The OFTO would complete all preliminary works associated with the assets, including securing consents. As part of these works, the OFTO would work with the SO and relevant TOs to ensure that the assets it would be developing would form part of a coherent network design that meets both the high level specification and network requirements.

d. At the invitation to tender (ITT) stage, bidders would be likely to bid their desired Tender Revenue Stream (TRS) based on a combination of fixed and indicative costs, with indicative costs possibly subject to a capped contingency or a sharing mechanism. The specifics of the bid requirement would be defined in the ITT document for each tender. Ofgem also envisage that the OFTO's revenue would be linked to the completion of key deliverables and outputs.

e. As the OFTO approached the completion of the preliminary works and ahead of construction, Ofgem would assess the needs case for the investment in more detail to determine whether proceeding to construction would be in the interests of consumers. If so, Ofgem would then engage with the OFTO to finalise its TRS to construct, own and operate the assets. As part of this process Ofgem would seek to fix the terms within the OFTO's licence (such as its TRS) which would have been set on an indicative basis during the ITT and licence award stage.

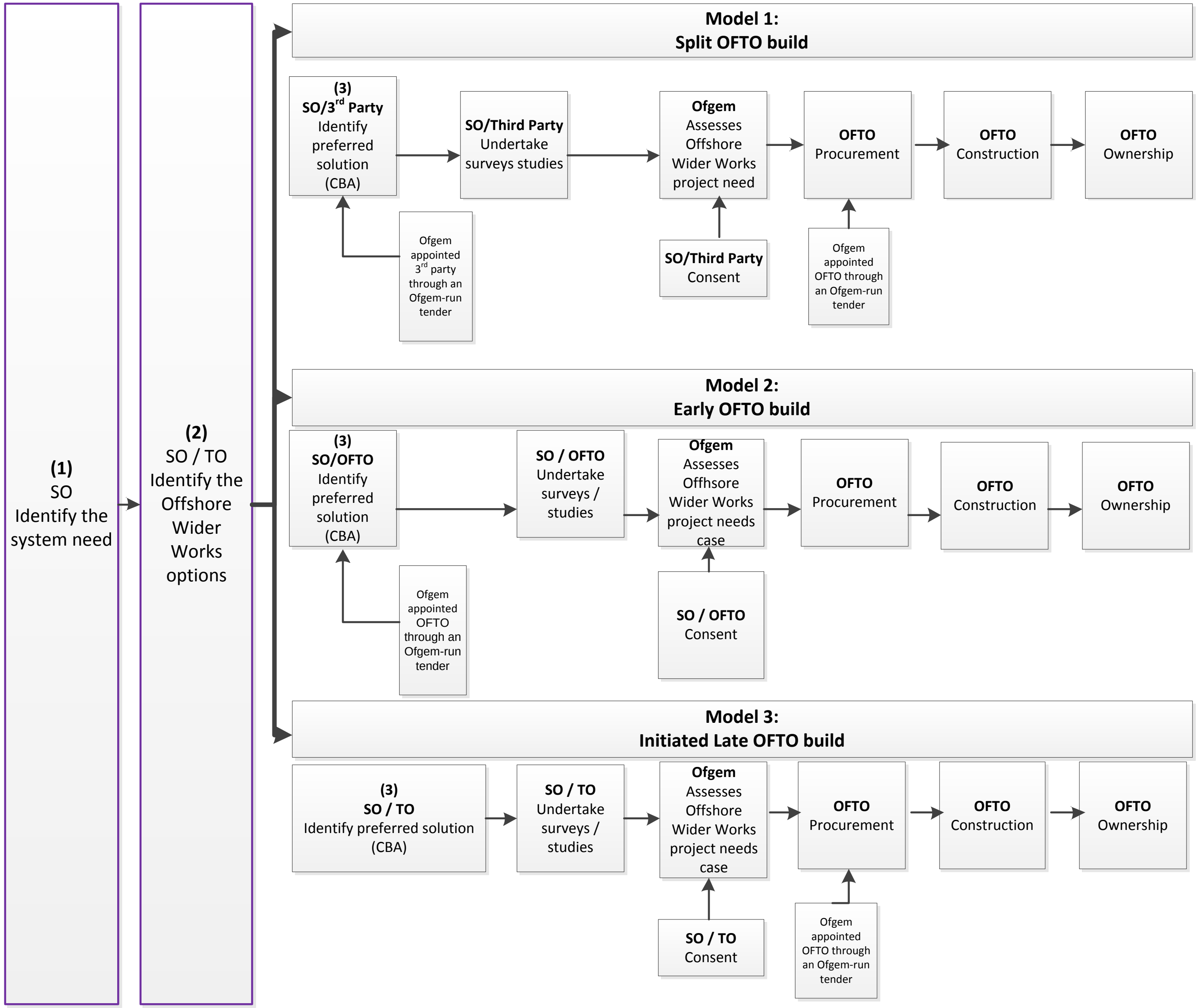
5.38 **Model 3: Initiated OFTO Build**

a. In the December 2012 consultation, Ofgem set out an option where onshore TOs could submit proposals for funding to undertake the preliminary works for non developer associated Offshore Wider Works, followed by a late OFTO build tender to identify an OFTO to construct, own and operate the assets.

b. Ofgem stated that the TO would work with the SO to identify the Offshore Wider Works opportunity and develop a corresponding needs case. There is the possibility that such a route would use a mechanism in the onshore TO licences (which would need to be introduced complementary to the onshore price control processes) to allow the TO to recover its cost of preliminary works for a project should Ofgem deem the works to be in the interests of consumers.

c. The TO would complete the preliminary works and produce the outputs needed to run a late OFTO build tender. The TO would be expected to engage stakeholders and coordinate with other relevant parties, including affected developers and the SO. It would also be expected to support the subsequent late OFTO build tender if it goes ahead, undertaking activities such as populating the data room, responding to queries from bidders, and contributing to a smooth and timely tender process. The late OFTO build tender would be similar to the approach set out in our May 2012 consultation on developer-led late OFTO build, with adaptations if necessary to reflect that the preliminary works were undertaken by a TO rather than a developer.

Offshore Wider Works – non developer associated process flow diagram



This diagram shows the overall Offshore Wider Works Non Developer – Associated process. The text in each box corresponds to the descriptions of the stages explained in general process above.

Appendix A: NOA study matrix

Assumption/Condition		Comments
Generation and Demand Scenarios	Two Degrees	Technical and economic assessment of the reinforcement options; sensitivity studies where appropriate
	Community Renewables	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Consumer Evolution	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Steady Progression	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
Seasonal Boundary Capability	Winter Peak	Technical and economic assessment of the reinforcement options
	Spring/Autumn	Technical and economic assessment of the reinforcement options. Technical assessment of boundary capabilities can be calculated based on agreed scaling factors from winter peak capabilities which are validated against benchmarked results. Benchmarking is subject to availability of the model and agreement on generation despatch
	Summer	Technical and economic assessment of the reinforcement options. Technical assessment of boundary capabilities can be calculated based on agreed scaling factors from winter peak capabilities which are validated against benchmarked results. Benchmarking is subject to availability of the model and agreement on generation despatch
Boundary Capability Study Type	Voltage Compliance	
	Thermal	
Contingencies	N-1-1	
	N-1	
	N-D	
Network Reinforcements	Build reinforcements	
	Reduced-build reinforcements	Assessment of reduced-build reinforcement options
	Operational reinforcements	Assessment of operational options
Study Years	Year 1	Assessment of alternative reinforcement options subject to availability
	Year 2	Assessment of alternative reinforcement options subject to availability
	Year 3	Assessment of alternative reinforcement options subject to availability
	Year 4	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 5	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 7	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 10	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement

Appendix B: Validation checks of seasonal scaling factors

Introduction

The SO's NOA report analysis uses a constraint cost model. In 2015/16, this was ELSI. ELSI applies scaling factors to the winter peak capabilities which are from technical studies. These give the seasonal boundary capabilities. We derived the scaling factors using a set of assumptions. The purpose of these validation checks was to verify the assumptions and if necessary recommend changes.

Background

We use a technical model to study the transmission network and find boundary limit based on winter peak loadings in the Two Degrees scenario. Boundary limits are dominated by thermal and voltage constraints that result from the loss of the worst fault on the boundary. Ambient temperature affects thermal limits so warmer seasons warm conductors more. This in turn depresses ratings and hence boundary capabilities. Voltage limits are not directly related to seasonal effects hence we considered them to stay constant across seasons. ELSI works by applying a set of scaling factors to the winter peak figure. The scaling factors change the winter values to represent warmer seasons and also for outages. Outages depend on the number of circuits on a boundary – the fewer circuits there are the greater the impact of a single outage. Once we have applied the scaling factor to get the boundary figure, the lowest of the thermal or voltage figures is the active constraint value in each season.

How we did the checks

We selected three boundaries and used the technical modelling tool to check the thermal and voltage limits for the spring/autumn and summer seasons. We also studied the effects of outages on these boundary limits. We turned the boundary limits from the technical studies into factors and compared them against the factors in ELSI. We chose boundaries B7. B7a and B8 because they had both thermal and voltage limits. They also demonstrated a variety of numbers of circuits crossing the boundaries. The table below shows the results:

Boundary Constraint	Season	Boundary	Existing ELSI Scaling	Studied Scaling	Relative Difference (ELSI vs Studied)
Thermal	**Spring/ Autumn**	Avg. B7,B7a,B8	90%	80%	**↓-10%**
	Summer	Avg. B7,B7a,B8	80%	80%	**≈0%**
	Summer Outage	B7	60%	72%	**↑+12%**
		B7a	66%	72%	**↑+6%**
		B8	71%	69%	**↓-2%**

Boundary Constraint	Season	Boundary	Existing ELSI Scaling	Studied Scaling	Relative Difference (ELSI vs Studied)
Voltage	**Spring/ Autumn/ Summer/ Summer outage**	Avg. B7,B7a,B8	100%	90%	**↓-10%**

Conclusion

There is a spread in the differences between the existing ELSI scaling factor and the technical model studies. In the study for summer thermal intact was fairly accurate while summer thermal outage had a 12 per cent difference. We concluded that different generation and demand patterns reduced the voltage limits. Scaling the voltage limit will give slightly pessimistic results in the studies but will help to highlight issues that we can investigate further.

Seasons and outages are just two of the factors that affect boundary capabilities. Wider system flows and how generation is located along the length of a boundary affects the distribution of loading of circuits across a boundary. This in turn affects how quickly a circuit overloads and hence when the boundary reaches its limit. The nearer a concentration of generators is to the overloaded circuit that sets the boundary limit, the sooner the boundary bites. As a result there will always be approximations in any methodology that does not use technical study tools at every stage of the process.

Recommendations

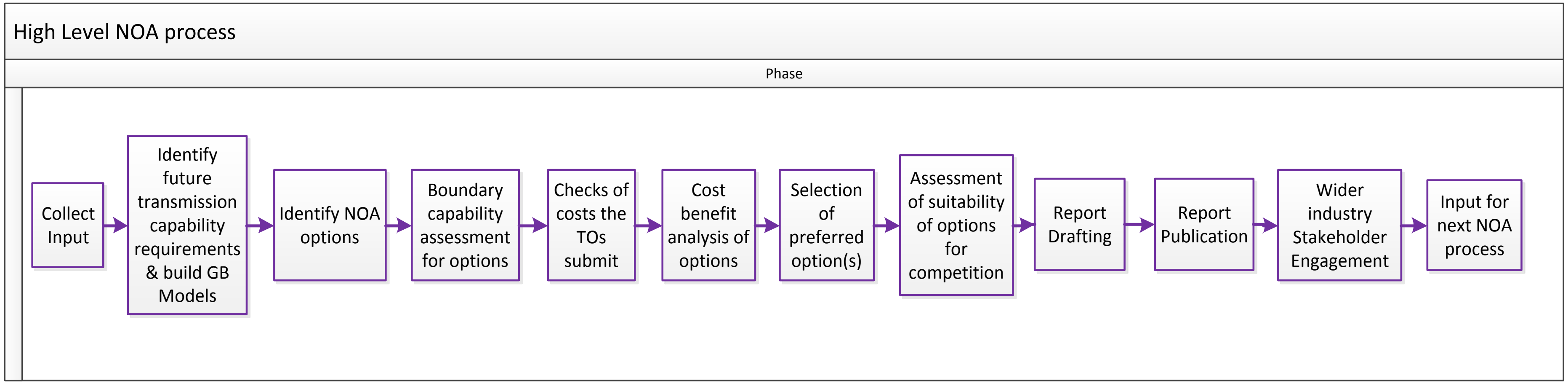
The validation checks led to recommendations to change the scaling factors in the economic model which the table below summarises:

	Existing ELSI scaling factor	Recommended change
Spring autumn scaling thermal	90%	85%
Summer scaling thermal	80%	No change
Summer outage scaling thermal	80% x (n-3)/ (n-2)	70%
Voltage scaling	100%	90%

‘n’ is the number of circuits crossing the boundary.

The SO implemented these revised seasonal scaling factors for the second NOA report analysis and will be prepared to amend them following future reviews. However, if the seasonal ratings are directly studied, then they may be used in place of the scaling factors.

Appendix C: NOA process flow diagram



This diagram shows the overall NOA process. The process headings can also be found in the main methodology.

Appendix D: System requirements form template

SRF Part	Changes	RSPI Content	
Part A – Boundary requirement and Capability	Reduced	RSPI	SO sends out a requirement level for each boundary which triggers the TO's response in providing options to meet the capability requirement level for that boundary. The form includes the BID3 unconstrained boundary transfers. Each boundary will have its own Part A.
Part B – TO Proposed Options	Reduced	RSPI	TO responds with an option that may partially or wholly meet the requirements set out by Part A. Each option will have its own Part B
Part C – Outage Requirements	Reduced	RSPI	TO responds with outage requirements for that option. Each option will have its own row in Part C.
Part D – Studied Option combinations	New	RSPI	TO and SO supply how the options' capabilities have been studied to ensure that the SO accurately and faithfully reproduces the options' order and capabilities in the economic analysis. Part D is a spreadsheet with some automation to generate flowcharts.
Part E – Options' Costs	Expanded	RSPI	TOs supply asset and cost information to allow the SO to proceed with 'cost reasonableness' (See Appendix E). Each option will have its own Part E, but only if it has featured in Part D.
Part F – Publication Information	Reduced	Safe	TOs supply names and descriptions of options for publication use. Each option will have its own row in Part E but only if it has featured in Part D.

SRF Part A: Boundary Requirement and Capability

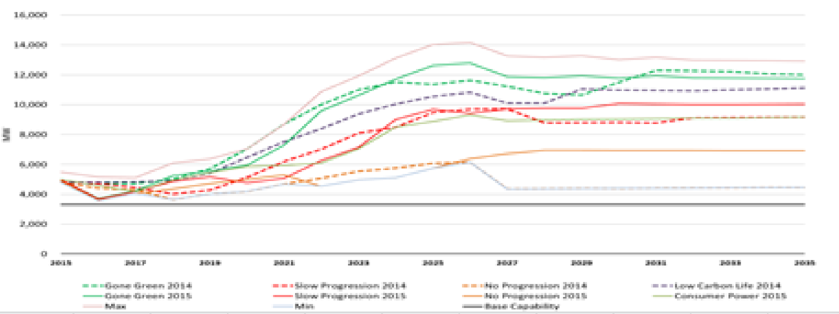
Part A: SO Requirement

For more information please see the information provided separately by the boundary studies.

Requirement preparer:	*SO to fill in the SO PSE studying this boundary*
Passed To/ Date:	*SO to fill in the TO engineer whom this was passed to and when*
Boundary under Analysis:	*SO to fill in which boundary this relates to*

Winter Peak Boundary Required Transfer Summary:

Year 1 Winter Peak Bare Capability (from previous year):	*SO to fill in last year's Year 1 winter peak bare capability for this boundary as a guidance for the TO*

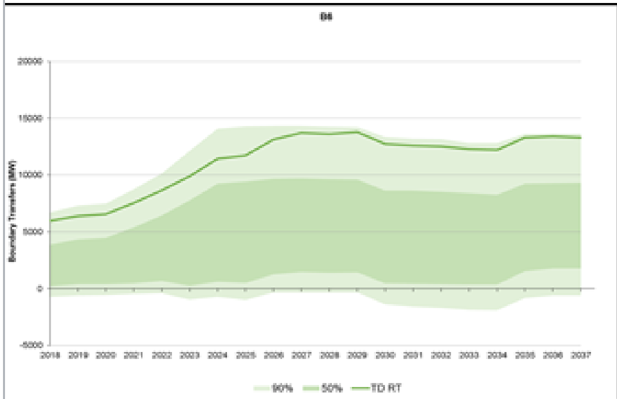


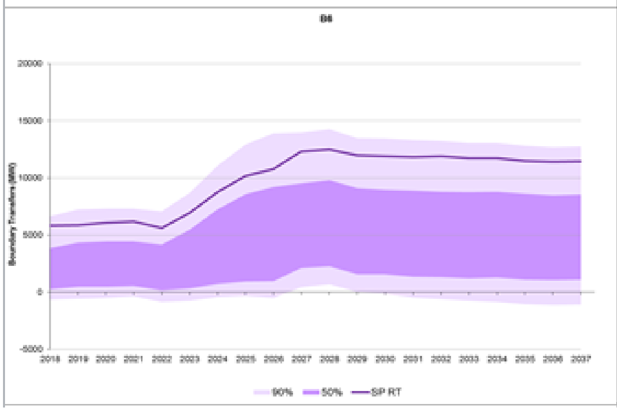
	Economy	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Economy Background (in MW)	Two Degrees	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Community Renewables	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Consumer Evolution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Steady Progression	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW

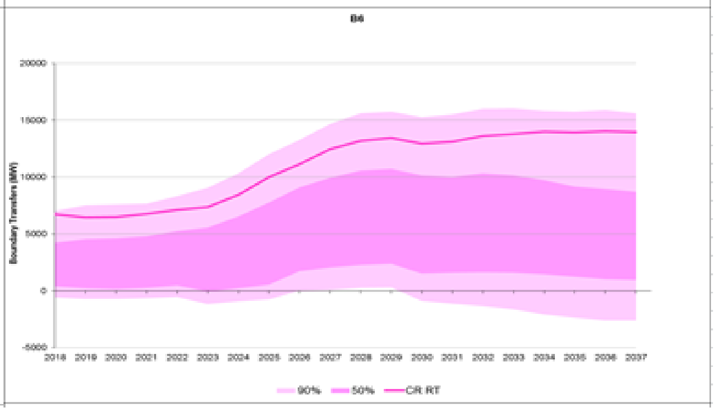
	Security	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Security Background (in MW)	Two Degrees	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Community Renewables	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Consumer Evolution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Steady Progression	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW

Unconstrained Boundary Flows

The section below details the unconstrained flows across the boundary. The 90th percentile and 50th percentile ranges have been highlighted for each scenario and this has been compared to the required transfer in accordance with the SQSS. The charts on the left illustrate the FES17 unconstrained flows and the charts on the right show this year's FES18 unconstrained flows.







SRF Part B: TO Proposed Options

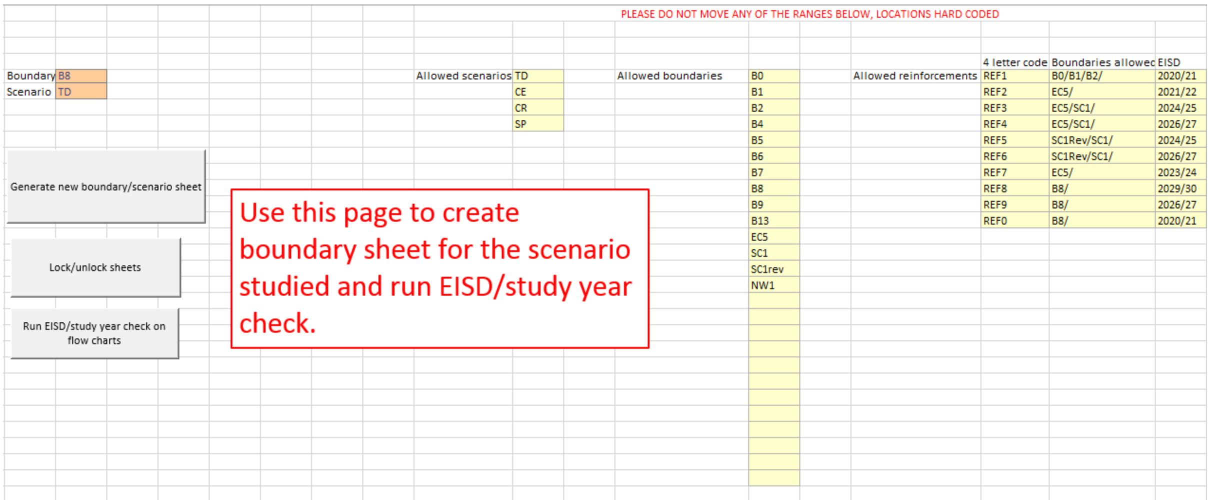
Part B: TO Proposed Options	
TO Ref number:	*Option reference number if available*
Option Name:	*Insert the name of the proposed reinforcement.*
Target boundary or boundaries:	*List the boundary or boundaries that the option is to reinforce*
Status: Same/Changed/New	*Select 'Same' if the option has been proposed before, or 'new' if is a new option.* ***If it has been proposed before but since modified please select 'changed' and note the modifications here along with background reasons for the change.***
Stage that option is at:	*Use the descriptions listed in the NOA methodology for the stage that the project is at. These are Project not started, Scoping, Optioneering and consenting started, Design/ development and consenting, Planning / consenting, Consents approved.*
Physical Description:	*Provide a description of the physical nature of the reinforcement sufficient to allow power system modelling. Please thoroughly list the all assets and works by type, number (for cable and OHL provide the length in km), voltage level and size. Please highlight any* ***new assets in bold.***
Diagram:	*Put a before and after diagram of how the configuration will look including circuits and substation layouts. This applies to the options which will introduce variations to the network topology and equipment layouts. For refurbishment options (e.g. Hotwiring, replacement of equipment), please put one diagram and highlight the alterations.*
What problem does the reinforcement solve?:	*Describe how the proposed solution will increase capability for each boundary in turn with reference to Part A or information supplied by boundary studier*
Lead engineer:	*TO contact name in case of queries*
Scheme # (England and Wales TO only):	*Scheme Numbers; this section is for England and Wales TO only*
Environmental Impacts:	Brief overview of any environmental implications that progressing this option may have
EISD:	*Year*
EISD change background if applicable:	*If the EISD has changed, please provide background reasons that have led to the change.*
Enabling works:	*State if the option also forms enabling works for a customer connection and if so which one(s).*
Enabling works' requirement nature:	*If the option* ***is*** *enabling works, please state the nature of the requirement that the works are intended to manage e.g. thermal, stability, fault level, voltage.*

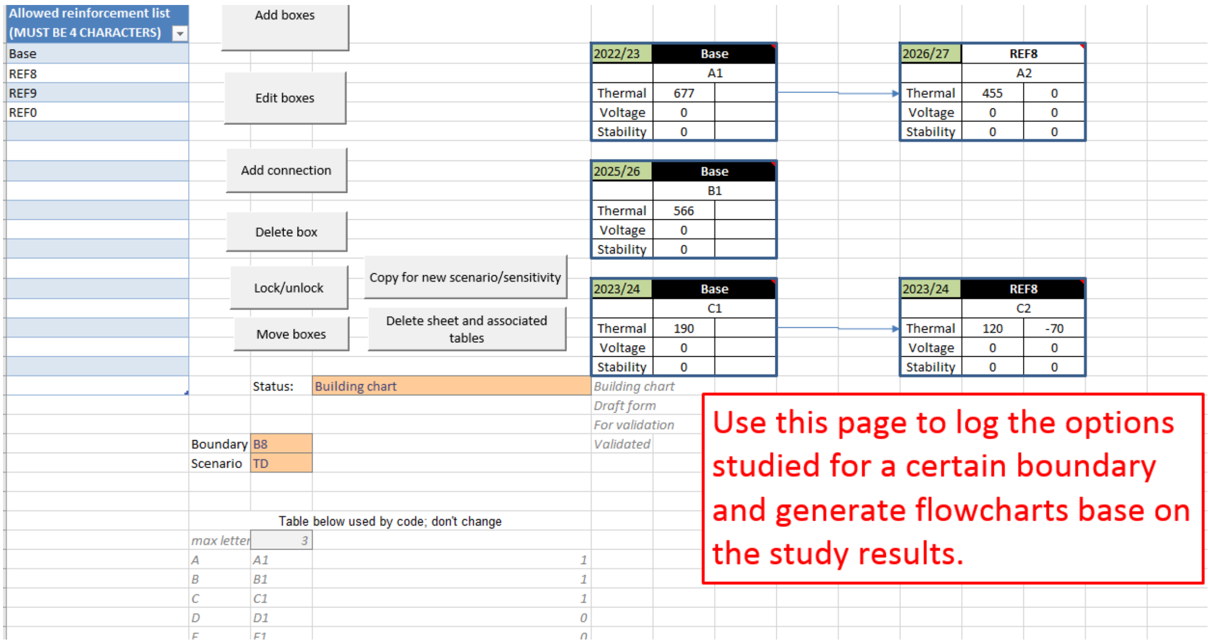
SRF Part C: Outage Requirements

Part C: Outage Requirements							
TO Option Reference Number	EISD	Year of Outage	Circuits Out	Outage Duration (weeks)	Restrictions in Sequence of Works	Lead Engineer	Additional Comments
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for SO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for SO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for SO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			

SRF Part D: Studied Option Combinations

We have refined the SRF Part D with an automated Excel spreadsheet. The boundary studiers can now use the coded Excel spreadsheet to log the options and associated capabilities found in their studies easily and create the boundary study handover documents in a consistent way. Templates of SRF Part D are presented as follows[27]:





[27] The SO will also provide a detailed user guide of the SRF Part D tool to the TOs for their reference.

Boundary Name	Seasonal Scaling Factor				Number of circuits crossing boundary	Number of outage days
	Winter	Spring/Autumn	Summer	Summer Outage		
Example	100%	85%	70%	50%	4	
B0						
B1						
B2						
B4						
B5						
B6						
B7						
B8						
B9						
B13						
EC5						
SC1						
SC1rev						
NW1						

Please enter data into column H OR column I. The number of outage days will be calculated based on the number of circuits crossing the boundary unless the number of outage days is specified.

Lock/unlock

Use this page to enter seasonal scaling factors for boundaries studied.

SRF Part E: Option Costs

Part E: Option's Costs

TO Reference Number	TO Reference number. Must be same as Part B.
WACC Used	% value used for Weighted Average Cost of Capital

Option Breakdown of Costs

Total Cost of New Assets/Works	**Cost in £m**	*The total cost of completely new transmission assets or complete replacement of transmission assets.*
Total Cost of New Assets/Works which are also separable	**Cost in £m**	*The portion of the above cost where the ownership between these assets and other (existing) assets can be clearly delineated.*
Total Cost of other Assets/Works	**Cost in £m**	*The remaining cost of any assets/works which are not completely new transmission assets or complete replacement of transmission assets.*
Total Cost of Consents	**Cost in £m**	*Total cost of consents for this option*
Total Cost of Option	**Cost in £m**	*Total cost of option (This should be the sum of 'New Assets/Works', 'other assets/works' and 'consents'*

Annual Breakdown

Spend to date column in the last year if possible and inflation adjusted for the current year. Please state the year this is costed in
*Use the columns marked * for mid-life refurbishment costs.*

	Spend to Date	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	*	*	Total Cost of Option
Total Spend for each year	Cost in £m	Cost in £m	Cost in £m	Cost in £m	Cost in £m	Cost in £m	Cost in £m	Cost in £m	Cost in	Cost in	Cost in	Cost in £m	Cost in £m	Cost in	Cost in	Cost in £m	Cost in	Cost in	Cost in £m	Cost in £m

Delay Costs *The costs table covers for when a project is delayed/cancelled now and delayed/cancelled after one year's work and resources have been put into it. The assumption is that costs after one year's progress will be the same for subsequent years apart from discounting. Use the 'reconsenting' row if the project will cost to restore consents. If there is no submisison in this table, the SO will assume it can cancel or delay projects at nil cost.*			
	2019/20	**2020/21 (if it were to be proceeded in 2019/20)**	**Additional Comments**
Cost of Demobilisation (£m)	*cost of bringing a project in flight to a stop*	*cost of bringing a project in flight to a stop*	*If you wish, insert additional comments if you'd like to further explain the impacts of demobilising a project if it is already in flight.*
Ongoing delay costs (£m)	*cost of continuing to delay a demobilised project*	*cost of continuing to delay a demobilised project*	*If you wish, insert additional comments if you'd like to further explain the impacts of delaying a demobilised project.*
Cost of Remobilisation (£m)	*cost of proceeding a demobilised project*	*cost of proceeding a demobilised project*	*If you wish, insert additional comments if you'd like to further explain the impacts of remobilising this project if it were to be demobilised.*
Costs of Reconsenting (£m)	*cost of new consents*	*cost of new consents*	*If you wish, insert additional comments if you'd like to further explain the impacts on consents if this project were to be delayed by any number of years.*
Other Delay Costs (£m)	*additional costs to delaying the option*	*additional costs to delaying the option*	*Please state the reason for the additional delay costs. If you wish, insert additional comments if you'd like to further explain the impacts on delaying this project.*
Cancellation (£m)	*cost of permanently cancelling the project*	*cost of permanently cancelling the project*	*If you wish, insert additional comments if you'd like to further explain the impacts of cancelling an option if it is already in flight.*
Total 1 year Cost to Delay (£m)	*total cost of delaying the project for 1 year*	*total cost of delaying the project for 1 year*	*If you wish, insert additional comments if you'd like to further explain the impacts of delaying a project for 1 year*

SRF Part F: Publication Information

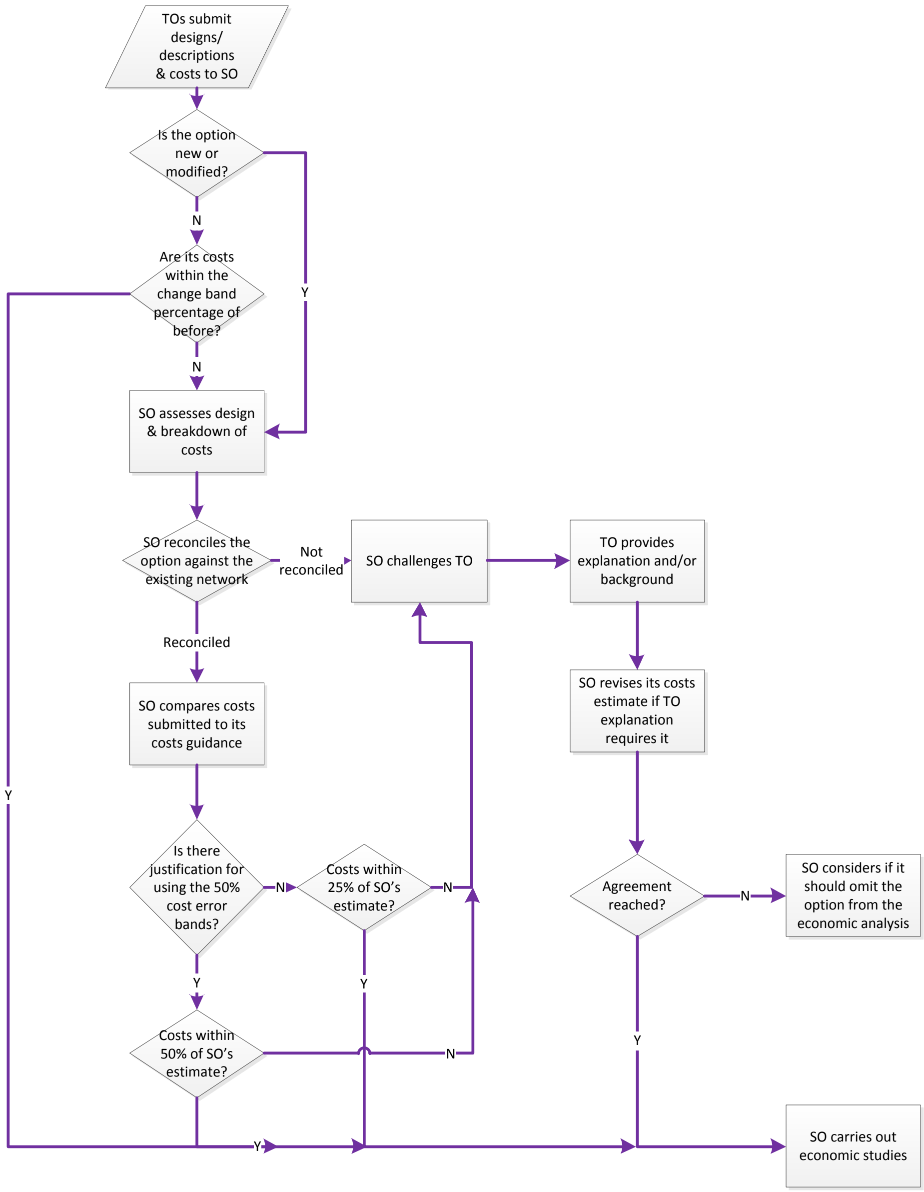
TO Reference Number	NOA Code	NOA Publication Name	NOA Publication Description	Additional Comments
TO Reference number. Must be same as Part B.	*Filled in by SO*	*The name of the option to be used in the NOA publication*	*The description of this option to be used in the publication*	*If required, additional comments for SO PSE*

Appendix E: Process for checking NOA option cost reasonableness

This appendix describes the process that the SO uses to assess the NOA option cost data that the TOs provide as an input to the NOA economic process.

Figure E1 shows the process map for the cost reasonableness checking process.

Figure E1: cost reasonableness checking process map



The input to the process is the costs that the TOs submit for their NOA options. The output of the process is the TOs' cost submissions to be deemed valid and act as an input into the NOA economic process. The TOs may modify their costs following discussions with the SO as part of this process. If following discussions the SO still believes that the costs are outside of their expected range and will consequently unduly affect the economic analysis, the SO may omit the option from the economic analysis.

The SO maintains independent cost guidelines which are derived from RIIO unit costs and external public domain market intelligence. The SO compares the costs of different options from a TO against previous years (allowing for inflation) and against its cost guidelines.

The headings below match the stages in the process map.

TOs submit designs/descriptions & costs to SO

Having received the cost information from the TOs via the SRFs, the SO gathers the information together. The SO needs the following data, which it captures from the SRF:

- Detailed technical breakdown of the reinforcement option
- Cost data for the option.

Is the option new or modified?
Are its costs within the change band percentage of before?

The first step is for the SO to identify which options should proceed through the cost reasonableness process. New or modified options always proceed through the cost reasonableness process. Options where the designs are unmodified from previous years' submissions may be exempt from the remainder of the cost reasonable process as they will have had their costs approved through previous years' SO cost checks, provided any increase in costs falls within an expected range. If the costs submitted for the current year are within the change band of +/- 5% of previous submissions, then the cost checking process for such an option ends here. Options where the costs have changed outside this range, or options which have modified or new designs, proceed through the process as normal.

SO assesses design & breakdown of costs

The aim of this step is for the SO to understand the option, how it is intended to deliver the benefit, the component parts of the option and its benefit. The SO takes the technical breakdown descriptions of the option and builds up its understanding of the reinforcement option:

- The SO checks the descriptive text with any diagrams that the TO has provided Note that some options will not need diagrams, for instance if they are about thermal upgrades or other overhead line work.
- The SO checks that equipment requirements are consistent and complete. For instance where a new circuit is proposed, does the SRF explain how it will connect to the existing transmission system – are new bays proposed and how many, or will it reuse existing bays?
- The SO checks for operational impacts, for example that proposed assets that change substation running arrangements are supported by new running arrangements and they deliver what is intended. An example is whether fault levels are within ratings for a revised running arrangement.
- The SO checks environmental factors. For example whether the option needs consents and whether the option is in a mainly urban or rural setting.

It is expected that the level of disaggregation of options included in the SRF and the cost accuracy will vary with the level of maturity of the option, with those options which have been developed over a few years being broken down into more detailed aggregate components with more accurately estimated costs than those in the initial stages of conception where design and costs are more approximate.

The SO reconciles the option against the existing network

Having built up its understanding of the option, the SO checks the existing part of the network that the option affects. This is to identify any parts of the option that might have been omitted and which may affect the cost estimate. The SO notes any omissions or discrepancies in the SRF and seeks clarification from the TO. An example might be that the SRF describes using a spare bay so the SO checks the latest system diagram to check for the bay's details. For an explanation of the remainder of the process, go to the **SO challenges TO** stage on the process map.

SO compares costs submitted to range of costs in its guidelines

The SO performs two tests for each option at this stage.

1. Having developed its understanding of the option, the SO compares the option's costs against the SO's cost guidelines.
2. The SO identifies similar options within a TO's portfolio and checks the cost consistency between them. For instance, where two options have cable sections at the same voltage, the SO calculates the unit costs based on the TO's submission and checks how similar they are.

Is there justification for using the 50% cost error bands?

Some aspects of options add a lot of uncertainty to the forecast cost of a project and so are allowed a larger cost error. For this reason, the SO measures against a 50% cost error band for any option affected by the following:

- consents
- new technology with high uncertainty.

Costs within 25% of SO's estimate?

This step applies to options that involve **no** added justification for the wider cost error bands.

The first stage is for the SO to compare the TO's submission with its own estimate of costs. If the costs are within 25%, the SO progresses to the second stage.

The second stage is to check that a TO's costs are consistent with other options' costs across its portfolio. If this is the case then the SO sets the option costs as 'agreed' and the costs are used in the economic process.

If the costs are outside of the 25% band and/or the costs are not consistent, the SO asks the TO for justification. For an explanation of the remainder of the process, go to **SO challenges TO** stage on the process map.

Costs within 50% of SO's estimate?

This step applies **only** to options where there is justification for wider cost error bands and is a similar two stage approach.

Firstly, the SO takes the TO's submission and compares it with its own estimate of costs. If the costs are within the 50%, the SO progresses to the cost consistency check across a TO portfolio.

If the costs are consistent with other options' costs in the TO portfolio, then the SO sets the option costs as 'agreed' and the costs are used in the economic process.

If the costs are outside of the 50% band and/or the costs are not consistent, the SO asks the TO for justification. For an explanation of the remainder of the process, go to the **SO challenges TO** stage on the process map.

SO challenges TO

If the SO finds that an option's costs lie outside of the range that it estimates, it approaches the TO for a more detailed understanding.

TO provides explanation and/or background

In response to the SO's challenge, the TO provides more information to solve the query. This information might be:

- adding information, for instance including the details of cable section lengths
- correcting assumptions about assets, for instance the amount of plant involved in work on a substation bay
- amending a cost submission due to an error
- the TO challenges the SO's understanding of costs or option scope.

This is part of an iterative stage.

If the TO provides more information to the SO, the SO will revise its cost estimation accordingly to check if the costs are within the 25% bracket or 50% bracket as applicable. If 'yes', then the SO sets the option costs as 'agreed' and the TO's costs are used in the economic process.

If the TO's response means that the SO's concerns remain, the SO reviews its concern, clarifies it and refers it back to the TO.

If after several attempts, the SO cannot agree to the costs and explanations that the TO is providing, the SO engineer escalates the matter within SO management. The SO management decides whether to include the costs for the option in question at this stage or to omit it from the economic analysis.

SO revises its costs estimate if TO explanation requires it

The discussion between the SO and the TO might mean that the SO has to recalculate its estimate of the costs. The SO notes the revised costs.

Agreement reached?

The SO engineer conducting the process passes the ‘agreed’ TO costs for use in the NOA economic process.

General points

The SO keeps the cost information for all options submitted by each TO and uses them to do consistency checks of options that the same TO submits in future years.

In general, the SO assumes that the TO cost submissions include the development costs. There might be occasions on which the submissions do not include the development costs in which case the TO and SO will discuss this further and decide how to proceed with the option for its economic analysis.

Appendix F: Form of the report

The System Operator (SO) will produce the main NOA report which will be public and produce appendices where there is confidential information. The confidential appendices will contain full cost details of options and will have very limited circulation that will include Ofgem. Extracts of this report will go to the relevant Transmission Owners (TO). The main NOA report will omit commercially confidential information. We will provide Ofgem with justification for the redactions. This appendix describes the contents and chapters of the report.

Foreword

Contents Page

Executive Summary

The executive summary will include headline information on options listing those that meet SWW criteria.

Chapter 1: Introduction and Aim of the Report

This chapter will describe the aim of the NOA report, provide the reader with clear guidance on its relationship with the Electricity Ten Year Statement (ETYS) and give guidance on how to navigate the NOA report.

Chapter 2: Methodology description and variations

This chapter will describe the assessment methodology used at a high level and refer the reader to the NOA report Methodology statement published on National Grid's public website.

The chapter will also include the definition of and commentary on Major National Electricity Transmission System Reinforcement options. We will include a description of how the SO treats Strategic Wider Works (SWW).

We expect options to improve boundary capabilities will fall broadly into three categories:

- SWW that have Ofgem approval. The NOA report will refer to these options which will be included in the baseline while presenting no analysis. The Report will justify why these options are treated as such.
- Options that have SWW analysis underway. This analysis and available results will be used in the NOA report.
- Options analysed using the Single Year Regret cost-benefit analysis. This analysis will appear in the NOA report.

Should any options fall outside of these three categories, the chapter will list them with an explanation as to how and why they are treated differently.

Chapter 3: Boundary Descriptions

The purpose of this chapter is to give an overview of the boundaries that make up the GB electricity network. This will comprise of a short paragraph introducing the boundary and the boundary's network map. It will refer the reader to the ETYS Network Capacity and Requirements chapter for details of the future capability requirements for each boundary.

Chapter 4: Proposed Options

The purpose of this chapter is to describe the options that the SO has assessed. The description will include the status of an option (see Table 2.3 in the main methodology) and a general overview. The description will also identify each option as build, reduced-build or operational and depending on the maturity of the option might include summaries of the technical, environmental, operability and deliverability aspects of the work. Where there are system security requirements for the boundary (in addition to economic), the chapter will highlight this. The section includes OWW options or records a nil return if there are none. The chapter will also include a commentary on reduced-build or non-transmission ones, where applicable.

Chapter 5: Investment Recommendations

This chapter will cover the economic benefits of each option. The data will be tabulated and to support the comparison include earliest in service (EISD) and optimum delivery dates. The chapter will then give the regret values for the options and combinations of options where the options are critical, i.e those that need a decision to proceed (or otherwise) imminently. Chapter 5 will detail the SO recommendation whether or not to proceed with each option. In some instances, there might be a recommendation to proceed with more than one option. Such an instance could be at an early stage when two options are closely ranked but there is uncertainty about key factors for example deliverability.

The chapter will indicate options that are likely to meet the competition criteria. As the competition framework is uncertain due to the necessary legislation not being passed, the chapter will highlight this. The chapter will explain how options meet competition criteria.

The chapter will finish with a summary of the options for the boundary. It will provide:

- Any differences in preferred options between annual NOA reports where the SO has carried out similar analysis in the past.
- How the scenarios have different requirements and how they affect the options.
- A comparative view of each option's deliverability and how it affects the choice of the preferred options.

The cost band will appear beside options that have a 'Proceed' recommendation.

Chapter 5 will meet the SO obligation to produce the Network Development Policy output for Incremental Wider Works as pursuant to NGET's license obligation.

Chapter 6: NOA for Interconnectors

This section of the report will introduce the method of analysing GB's potential for interconnectors to other markets and publish the analysis.

Chapter 7: Stakeholder engagement and feedback

To help our understanding of stakeholder views, through the document we will include feedback questions. We will use this feedback to refine the NOA report process and methodology for the next report.

We have used our seminars to continue to talk with stakeholders and have received some interest. Onshore TOs have engaged with us and assisted in developing this NOA report methodology. We want to extend our engagement further and will use our NOA email circulation lists.

Glossary

Appendix G: Summary of stakeholder feedback

This appendix summarises the views the SO has on the comments we've received. We would like to thank the organisations for their feedback and contribution.

Area of feedback	Feedback	SO response
Third party participation	It is unclear in the methodology how third parties could submit solutions to address system needs.	We recognise this is not incorporated in the current NOA process, but as highlighted in the Network Development Roadmap, this is one of the proposed developments for our future NOA process.
Storage to meet NOA needs	The NOA doesn't take into account large scale electricity storage projects as a potential solution.	We recognise this is not incorporated in the current NOA process, but as highlighted in the Network Development Roadmap, this is one of the proposed developments for our future NOA process.
Environment	The NOA should include the social economic/financial impacts of reinforcement on affected communities.	We believe that the best place for socio economic/financial impacts to be published is through the stakeholder liaison and consenting processes that the TOs undertake. The NOA report is an economic assessment recommending what, where and when to invest. Including the socio economic/financial impacts to an adequate depth for an option would fundamentally change the purpose and nature of the NOA. It would also duplicate the material that the TOs publish as part of their stakeholder liaison and consents processes that we believe is the best place to publish such information.
Pathfinding projects	It is important that the NOA process remains transparent and effective and maintains timely delivery of solutions.	We will keep engaging with our stakeholders on the pathfinding projects as they progress along with the NOA. We will publish, and where relevant consult on, outcomes from the pathfinding projects.
Probabilistic analysis	Challenging year-around conditions and analysis should be better articulated.	We have revised paragraph 1.7 to give a better explanation on the challenges we face in terms of year-around conditions.
Probabilistic analysis	It is important that probabilistic analysis is transparent and verified.	We have revised paragraph 1.7 to reassure transparency and robustness of the process we will take to deliver the probabilistic analysis.
Competition	It should be clearly highlighted that current NOA makes no assessment of the potential impact of the competitive tendering process.	We have amended the paragraph 4.1 and 4.2 to highlight that the current NOA doesn't take into account the timing implications of the competition process.
Competition	Relevant industry codes should be cross-referenced when 'enabling works' is mentioned as a defined term in the NOA methodology.	We have added a footnote in paragraph 4.1 to reference the term 'enabling works' as defined in the CUSC.

Competition	Eligibility assessment of new connections projects would be better identified as an area for future development and included in the methodology for the NOA 2019/2020.	Ofgem see us starting on competition this year but for pragmatic reasons, it would ramp up rather than step up. It allows us to learn lessons and would avoid a step up in 2020. We anticipate that the licence condition changes on C27 in relation to competition will come into effect before the next NOA publication.
NOA simulation tool	Provision of the NOA simulation tool should be referenced in the methodology.	The NOA simulation tool is still under development. We will reference the tool in the future NOA methodology when it is more mature.
NOA IC: Baseline level of interconnection	Range of views on what the baseline level of interconnection should be.	We received a wide range of views on what the baseline level of interconnection should be. As continuing with the current methodology was marginally in the majority, we have continued with it. However we will investigate whether any form of sensitivity analysis can be performed around the baseline level of interconnection.
NOA IC: Providing a range of results	Unanimous feedback that NOA IC should provide a range of results.	We have removed the Least Worst Regret analysis from the iterative process, resulting in four optimal pathways, ie one for each FES, leading to a results range.
NOA IC: Ancillary Services	Unanious feedback that NOA IC should include an analysis of the impact of interconnectors on services that support system operability.	We intend to include a number of analyses covering ancillary services, including: Rate of Change of Frequency (RoCoF); Response and Reserve; Reactive Power/Voltage Support; and Black Start .
NOA IC: Social Economic Welfare (SEW)	Range of views on what SEW to include within the analysis.	As the range of views was so diverse, we intend to calculate the optimal paths based on SEW of GB and the connecting country, but also calculate SEW for GB only and GB and the rest of Europe to provide additional value to stakeholders.
NOA IC: Explanation of differences between NOA IC and other analyses	Strong agreement that we should provide greater explanation of the reasons for any differences between NOA IC and any other relevant interconnector analyses, such as within the TYNDP	We intend to provide more context and explanation to the findings of the NOA IC analysis in relation to other interconnector analyses.
NOA IC: Providing greater level of detail of analysis	Range of views on whether we should provide more detail.	We intend to provide the same level of detail for the analysis, but endeavour to include an improved summary and explanation of the analysis, results and conclusions.