Network Options Assessment Report Methodology

nationalgrid

System Operator

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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 2017/18. It covers the methodology on which NGET, in its role as SO, will base the NOA which will be published by 31 January 2018. 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

Contents

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 2017/18

1.5 We have separated the methodology document into sections to help improve readability. The first section covers an introduction to the document, the second section covers the overall process including the technical and economic assessment while a third section covers assessing the eligibility of options for competition.

1.6 We have reviewed the use of Future Energy Scenarios (FES but hereby referred to as 'the scenarios') and the regrets process to produce the NOA results. Recommendations made using regret analysis are determined by the two scenarios at the opposite end of the need for network development. As a result, recommendations are particularly sensitive to the assumptions behind these two scenarios. In particular, when the two scenarios are well separated the regret result can be primarily determined by the scenario with the highest levels of congestion on the system. This can potentially lead to the emergence of 'false-positive' investment recommendations depending on the exact specification of the scenarios regret is paired with. Our review recommended two additional stages to the process rather than any fundamental changes, with both being applicable to marginal investment recommendations. The two additional stages are as follows however the full NOA Methodology Review (that does not form part of this NOA methodology) can be found at www.nationalgrid.com/NOA :

- To include implied probability weightings on scenarios. This is a post process step that involves calculating the probability of each scenario required in order to justify the recommendation for an investment. For more information, please see paragraph 2.86.

- To introduce a NOA committee to further strengthen confidence in our investment recommendations. This will be an SO committee with Ofgem observers to discuss investment recommendations where the CBA results give marginal recommendations or are being driven by a single scenario. The Committee will provide a robust and transparent review of the results to ensure there is conclusive justification for all investment recommendations. For more information, see paragraph 2.87.

1.7 We have formalised the process for cost checking, which the SO applies to the costs of the options that the TOs submit. This is to ensure that the cost benefit analysis and resulting investment recommendations are based on the best information available. . Our new appendix E describes our proposed approach.

1.8 We continue to include detail as to how the SO assesses options for competition in providing transmission reinforcements although it is recognised that legislation underpinning the proposed competitively appointed transmission owner (CATO) regime has been delayed. The existing section “Suitability for third party delivery and tendering assessment” has been moved into the new Section three of this document. It covers the detail of our process.

1.9 We have also reviewed and redesigned the System Requirement Form (SRF) template so that it works better to support the cost checking and competition processes.

1.10 We have reviewed the wording around reduced-build options so that it is clear that the TOs lead these. In cases where the SO suggests a reduced-build option, the TOs will lead further development on the option.

1.11 We have reviewed the language around options that the SO leads on. These include Offshore Wider Works (OWW) and operational options.

1.12 We have included new information on cost bands. Ofgem has asked the SO to allocate to cost bands those projects that have a ‘proceed’ and that would reach the high value threshold of £100m. For more information, see paragraph 2.92.

Key similarities to 2016/17

1.13 We have reviewed our NOA process including single year regret analysis and scenario based assessments to ensure that these tools can deliver optimal network planning. We considered alternative decision making tools and concluded that the scenario and single year regrets-based assessments are still the most pragmatic and robust approaches at present. Our NOA Methodology Review captures our investigation and can be read at www.nationalgrid.com/NOA. Note that the NOA Methodology Review does not form part of this NOA methodology document.

1.14 SO and TO responsibilities are broadly unchanged from last year although we have added detail to where these are listed; see paragraphs 1.35 to 1.36.

Background

1.15 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.

1.16 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.

1.17 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). The SO has proposed to amend the NDP to link it to the NOA and formally recognise that it uses NOA output data.

1.18 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.

1.19 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

1.20 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.

1.21 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.

1.22 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

1.23 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.

1.24 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 third party delivery by Competitively Appointed Transmission Owners (CATO). This assessment is against criteria defined by Ofgem in anticipation of legislation, which at the time of writing has yet to be published. 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.

1.25 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.

1.26 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.

1.27 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.

1.28 Transmission Licence Standard Condition C27 Paragraph 15 sets out the contents of the NOA report:

> 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.

1.29 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.

Major National Electricity Transmission System Reinforcements

1.30 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.*

1.31 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

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

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

1.34 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

1.35 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
- technical analysis of boundary capabilities of the base network and uplifts from reinforcement options for England and Wales on behalf of NGET TO
- devising and developing alternative options including operational options, commercial agreements and OWW
- identifying boundary transfer requirements and issue SRF to TOs
- shadow studies of some boundary analysis performed by the TOs to corroborate the TO's 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 suitability 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.

1.36 The TOs' roles and responsibilities include:

- technical analysis of boundary capabilities of the base network and uplifts from reinforcement options by SPT and SHE Transmission in and affecting their areas
- 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
- boundary capability uplifts provided by 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

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

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

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

Methodology review

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

1.41 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 deadline for comments is 24 weeks from the NOA report publication. The SO considers these comments for a revised NOA methodology and submits the methodology to Ofgem by 1 August 2017.

Report output

1.42 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.

1.43 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.

1.44 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

1.45 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.

1.46 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

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

- The role of the SO to perform shadow studies to verify analysis of boundaries where the TOs have studied those boundaries.
- Further refinement of the process for SO-led options.
- Refinement of the process to maintain the SO's cost guidelines used for checks of the costs that the TOs submit.
- Refinement of the process for assessing eligibility for competition taking into account developments in the legislative framework and including cost-benefit studies for further electrical separation to support competition in electricity transmission.
- 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.

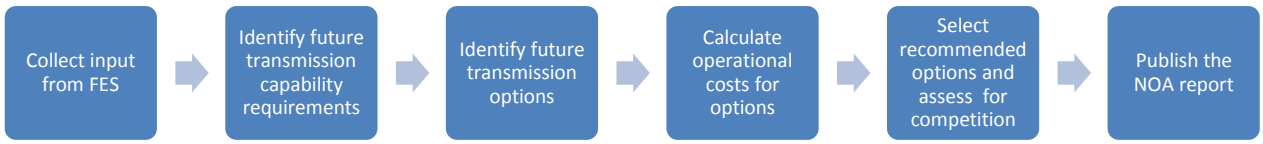
It is not envisaged that such a tool would be available for a few years although some elements might be available sooner once sufficient performance levels and validation have been achieved.

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, 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 In 2017, the four scenarios are:

- Two Degrees – The Two Degrees scenario represents a potential generation and demand background which maintains progress towards the UK's 2050 carbon emissions reduction target. The achievement of the climate change targets requires the deployment of renewable and low carbon technologies. EU aspirations regarding interconnection capacity for each member country remain applicable.

- Slow Progression – Slow Progression is a scenario where secure, affordable and sustainable energy sources are the political objectives, but the economic conditions are less favourable than under Two Degrees. Therefore carbon reduction policies cannot be implemented as quickly. The focus on the green agenda ensures that the generation landscape is shaped by renewable

technology. Ambition for innovation is constrained by financial limitations, which, in comparison to Two Degrees, leads to a slower uptake of renewables.

- Steady State – Steady State is a scenario where secure and affordable energy sources are the major political objective and there is less of a focus on sustainability. This means that ambitious carbon reduction policies are not expected to be implemented. Gas and existing coal feature in the generation mix over renewables and nuclear, with focus being on the cheapest sources of energy. The lack of focus on the green agenda and limited financial support available for low carbon results in a limited new build programme for nuclear and minimal deployment of less established technology.

- Consumer Power - Consumer Power is a scenario where there is high prosperity but less political emphasis on sustainable energy policy. There is more money available in the economy to both consumers and Government, but there is a lack of political will for centralised carbon reduction policy. The favourable economic conditions encourage development of generation at all levels. There is high renewable generation at a local level and high volumes of gas generation at a national level. There is less focus on developing low carbon technologies to meet environmental targets. As such, technologies such as carbon capture and storage (CCS) do not reach commercialisation.

2.5 The demand scenarios are created by using a mix of data sources, including feedback from the FES consultation process. The overall scenarios are a composite of a number of sub-scenarios: inputs; the key scenarios being the economic growth projections, fuel prices, domestic heat/light/appliance demand, and projections of manufacturing and non-manufacturing output. Other inputs include (but are not limited to) small scale generation, consumer behaviour and the effect of smart meters/time of use tariffs and new technologies (e.g. electric vehicles, heat pumps, LED light bulbs)[1]. The scenario demands are then adjusted to match the metered average cold spell (ACS)[2] corrected actual outturns.

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

2.7 Annual demand submissions are made by transmission system users, which are obtained between June and November each year. The regionally split “ACS adjusted demand scenarios” are then converted into demand by Grid Supply Point using the same proportions as specified in the ‘User’ submissions.

[1] You can find FES information on our website http://fes.nationalgrid.com/

[2] 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.

Sensitivities

2.8 Sensitivities are used to enrich the analysis for particular boundaries to ensure that issues, such as the sensitivity of boundary capability to the connection of particular generation projects, are adequately addressed. In England and Wales the SO leads on the sensitivities in conjunction with the TOs and any feedback from stakeholders sought through the FES consultation process. In Scotland the TOs create the sensitivities in conjunction with the SO. 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.

2.9 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.

2.10 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.

2.11 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.

2.12 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.

2.13 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

2.14 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 is independent from the NOA process, and the proposed NOA IC approach for 2017/18 is presented in the NOA IC methodology which can be found at www.nationalgrid.com/NOA .

2.15 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 capital expenditure. The SO anticipates the market will respond to this intelligence with potential projects aligned with the optimum level of interconnection recommended by the SO.

2.16 The output from the NOA IC process will be presented as a chapter in the NOA report and hence be published in late January 2018.

Offshore Wider Works (OWW)

2.17 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.

2.18 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 at www.nationalgrid.com/NOA .

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

2.19 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

2.20 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.

2.21 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[3]. 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.

2.22 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.

2.23 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.
- Ensure reasonable access to the transmission system for essential maintenance outages.

2.24 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 transmission reinforcement options

2.25 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

[3] 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.

- an onshore route of (High Voltage Direct Current) HVDC
- OWW options, such as integration between offshore generation stations.

2.26 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.

2.27 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	N/A	Mid-August (draft) Mid-September (final)
B	TO proposed options	Between early June and late July	Mid-August (draft) Mid-September (final)
C	Outages requirements	Mid-August	Mid-August (draft) Mid-September (final)
D	Studied option combinations	SO completes this	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.

2.28 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 Licence, 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 onshore TOs in the development of NDAOWW options.

2.29 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.

2.30 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.

2.31 Between early June and late July, the England and Wales TO returns the draft SRF Part B with the necessary technical content in stages for the SO to perform the boundary capability assessment and option uplift assessment. The England and Wales TO returns SRF Parts C, E and F that include costs and further commentary during mid-September. The exact date is agreed between the SO and England and Wales TO for the year’s programme for the ETYS and NOA.

2.32 The Scottish TOs return the draft SRF Part B in mid-August. In mid-September, the Scottish TOs return the full SRF comprising Parts B to F with the boundary capabilities from their technical assessment of the credible reinforcement options for their respective areas. The exact date is agreed between the SO and the Scottish TOs for the year’s programme for the ETYS and NOA.

2.33 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 then uses the agreed set of options in its boundary capability analysis (for England and Wales) and for the economic analysis. If there is no agreement, the SO forms a view on which options it assesses.

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

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

2.36 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		Transmission 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)*	✓	✓	✓	
		Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
		Reactive demand reduction *(this could ease voltage constraints)*		✓		
		Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
		Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
		Demand side services which could involve storage (contracted for certain boundary transfers and faults). *These allow peak profiling which can be used to ease boundary flows*	✓	✓		
	Reduced-build Options	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
		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)*	✓			
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.*	✓	✓	✓	✓

2.37 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.

2.38 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

2.39 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
- 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).

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

2.41 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

2.42 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.

2.43 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.

2.44 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

2.45 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 distinct from the construction costs.

2.46 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.

2.47 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

2.48 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 is also submitted such that the SO and TOs have adequate information to carry out the necessary option analysis.

Boundary capability assessment for options

2.49 The SO completes boundary capability assessment studies for England and Wales to feed into the cost-benefit analysis process. The Scottish 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 performs shadow studies of some TO boundary capabilities where the TO has done that analysis. The SO performs these shadow studies at the same time as the TO is studying the reinforcements using the

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.

2.50 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.

2.51 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 2017 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.

2.52 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.

2.53 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.

2.54 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="8">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>

2.55 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.

2.56 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.

2.57 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.

2.58 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.

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

2.60 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

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

2.62 The NOA provides investment recommendations based on the Single Year Regret Decision Making process. If the investment recommendation is for the TOs to submit a needs case for SWW assessment by Ofgem, the SO will assist the TO in undertaking a more detailed cost-benefit analysis.

2.63 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.

2.64 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[4]. A needs case is submitted by the TO that proposes the option to the regulator, and which includes a cost-benefit

[4] See 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

2.65 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).

2.66 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.

2.67 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[5] methodology.

2.68 It is assumed that each transmission asset is to have a 40 year asset life. Since the constraint cost modelling tool only forecasts 20 years the constraint costs for each year of the second half of the 40 year asset life 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

[5] 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.

the base case is 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.

2.69 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.

2.70 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'.

2.71 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.

2.72 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

2.73 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[6]
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 Factory studies	See text
Reinforcement incremental capabilities	Power Factory studies	See text

2.74 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

2.75 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.

[6] See http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589938715

Single Year Least Regret Decision Making

2.76 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.

2.77 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.

2.78 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.

2.79 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	

2.80 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.

2.81 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.

2.82 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.

2.83 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.

2.84 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 further development is planned over the next few years before this can be applied to the NOA.

Process Output

2.85 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.

2.86 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 .

2.87 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.

2.88 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.

2.89 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.

2.90 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.

2.91 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

2.92 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

2.93 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. The NOA report covers the areas in the table below.

Table 2.8: Overview of the NOA report contents

Report chapter	NOA report topic	Comments
1	Aim of report	
2	Methodology	SO consults with TOs
3	Boundary Descriptions	See *Table 2.9* below for more detailed description on chapters 4 and 5
4	Proposed Options	
5	Investment Recommendations	
6	Interconnector Analysis	
7	Stakeholder Engagement and Feedback	

2.94 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 2.9. Appendix G gives more detail on the form of the NOA report.

Table 2.9: 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				

2.95 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.

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

Report publication

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

2.98 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.

2.99 Standard Licence Condition C27 Paragraph 10 provides for delaying publication if the Authority (Ofgem) delay their approval of the NOA report methodology or form of NOA report.

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

Section 3: Suitability for third party delivery and tendering assessment

Overview

3.1 The SO has a clear role to play in facilitating the introduction of competition. It recognises the direction of travel in the area of competition and Ofgem's intention on the criteria for assessment as published in their decision on extending competition in transmission (ECIT)[7] in November 2016. It believes it is sensible and pragmatic to continue to include an assessment for competition for major network reinforcements against the criteria of new, high value and separable and that this is a sensible approach as the timescales for delivery of many investments now fall in the RIIO-T2 timeframe. However until there is further clarity of proposed competitive delivery frameworks and timing it does not propose to extend the assessment against the criteria for competition into connections where the enabling works meet the relevant criteria, as this would introduce unnecessary uncertainty at this point in time to any affected customer projects. This methodology describes the process for the assessment for both wider network reinforcement and connections, however only the assessment for wider network reinforcement will be included in the NOA report published in January 2018.

3.2 The SO assesses the suitability of projects for competition in accordance with published tendering criteria[7]. This assessment will be undertaken by the SO despite the absence of a transmission licence obligation to do so. 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.

The criteria are still to be finalised in legislation and this methodology will include the final criteria once available. As acknowledged in Ofgem's letter of 27 June 2017 titled "Update on Extending Competition in Transmission", it currently looks unlikely that such legislation will be introduced in the immediate future. Until the legislation is available the SO provides its best view of the criteria, as defined in Ofgem's relevant policy documentation[7], to support assessing options for the NOA. In order to undertake the assessment, the TOs will provide further information to the SO via the SRF form (see appendix D). 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.

[7] See https://www.ofgem.gov.uk/system/files/docs/2016/11/ecit_november_2016_decision.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. It should also be noted that the EISD data the TOs submit for their options does not build in time for the tendering process.

3.3 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. For the NOA due to be published in January 2018 the SO will only undertake an assessment against the criteria for competition for wider network reinforcement. 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

3.4 Prospective users can make connection 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 to take a view of the likelihood of meeting the value criteria.

3.5 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. To perform the competition assessment the SO will request the TO submit an SRF.

3.6 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. Where the TO states that the project is for connection only, the SO can ask for the SRF information early and perform the competition assessment before it would according to the NOA process timetable.

3.7 The TO uses the SRF template to provide connection project information for the process to assess eligibility for competition.

Bundling/splitting of work packages

3.8 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

3.9 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

3.10 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

3.11 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:

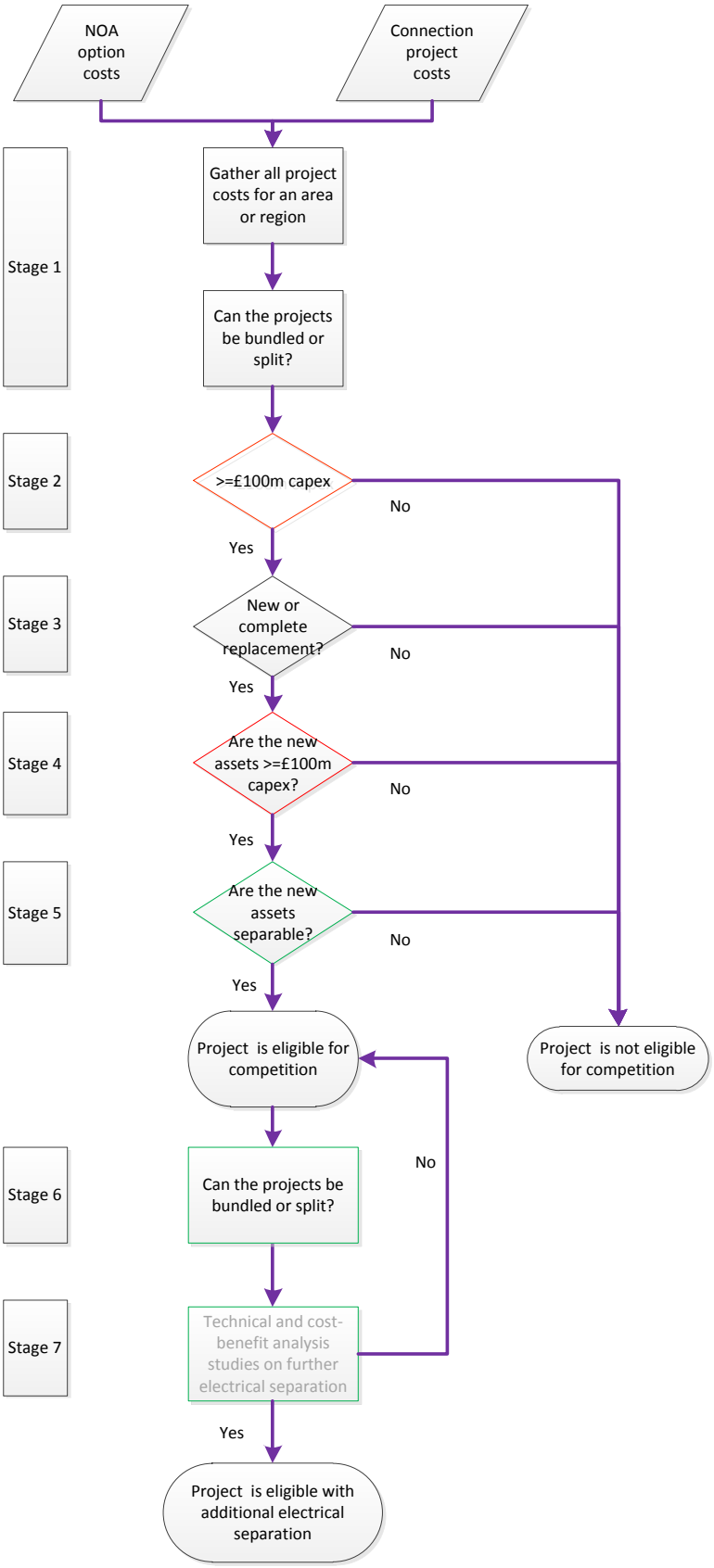
- **New** – completely new transmission assets or complete replacement of transmission assets.
- **Separable** – ownership between these assets and other (existing) assets can be clearly delineated.
- **High value** – at or above £100m in value of the expected capital expenditure of the project.

Figure 3.1 shows the process for assessing whether reinforcement projects meet competition criteria.

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

3.13 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 3.1: 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 3.1 lists the factors that affect the high value figure.[8]

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.

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

Table 3.1: List of factors that the high value figure includes or excludes

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

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.

An appropriate approach for this stage has yet to be developed and the SO anticipates consulting industry on this preparing it for use for NOA4 in 2018/19.

The SO maintains a log of connection projects that meet the competition criteria. This log forms the basis of the list that is published in the NOA.

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
	Slow Progression	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Consumer Power	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Steady State	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

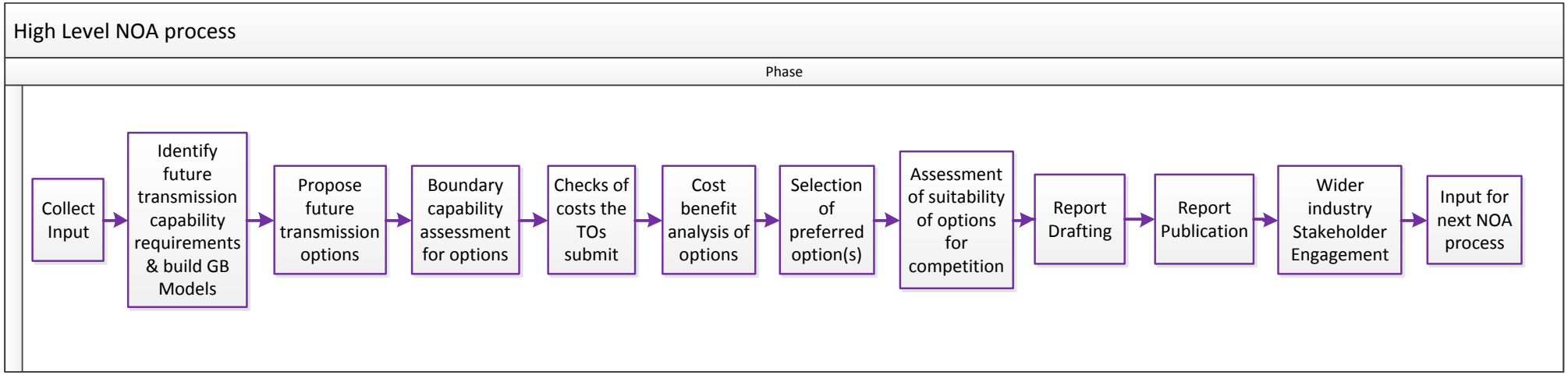
The validation checks led to recommendations to change the scaling factors in the economic model which the table below summarises:

	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%

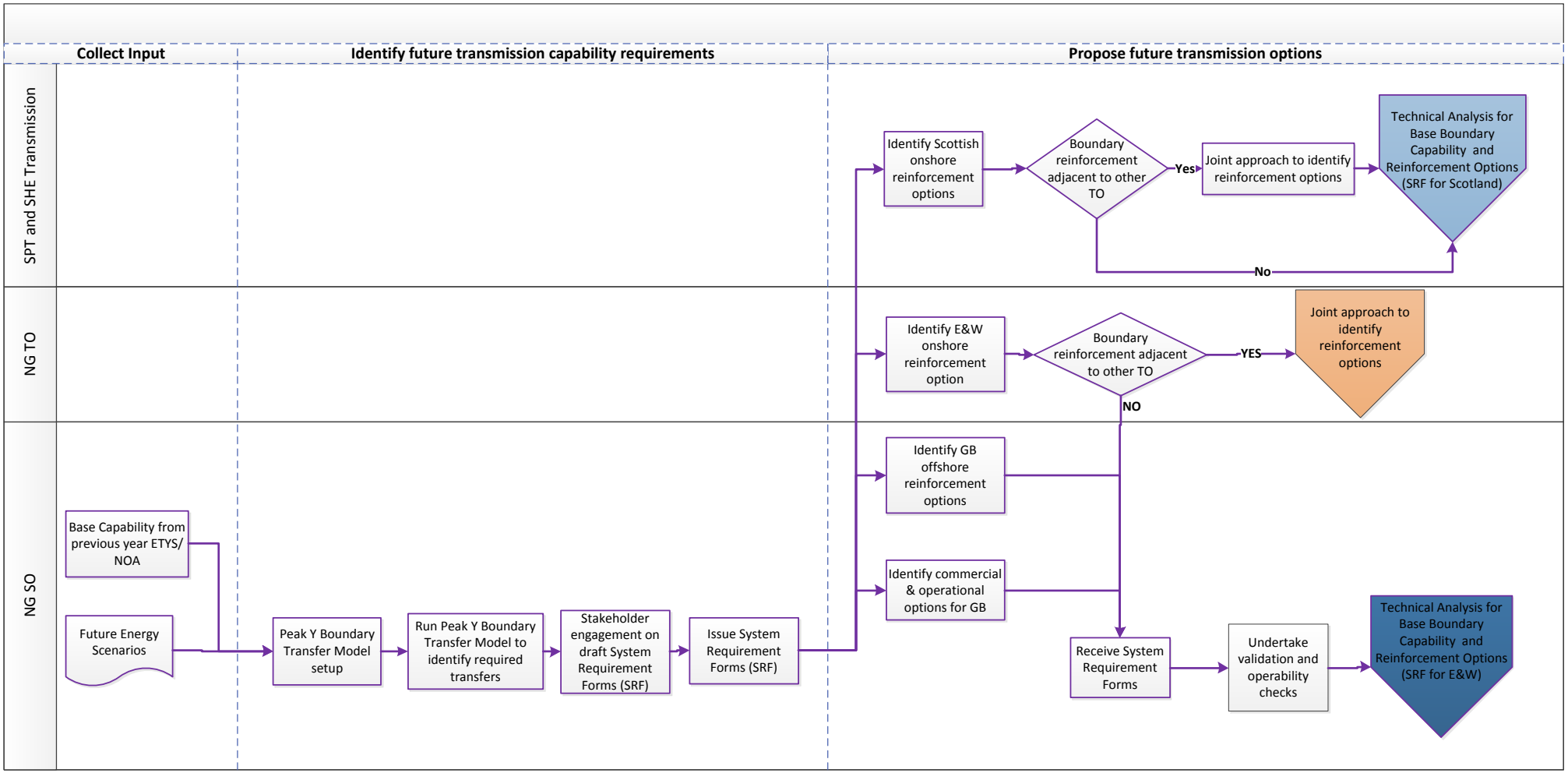
‘n’ is the number of circuits crossing the boundary.

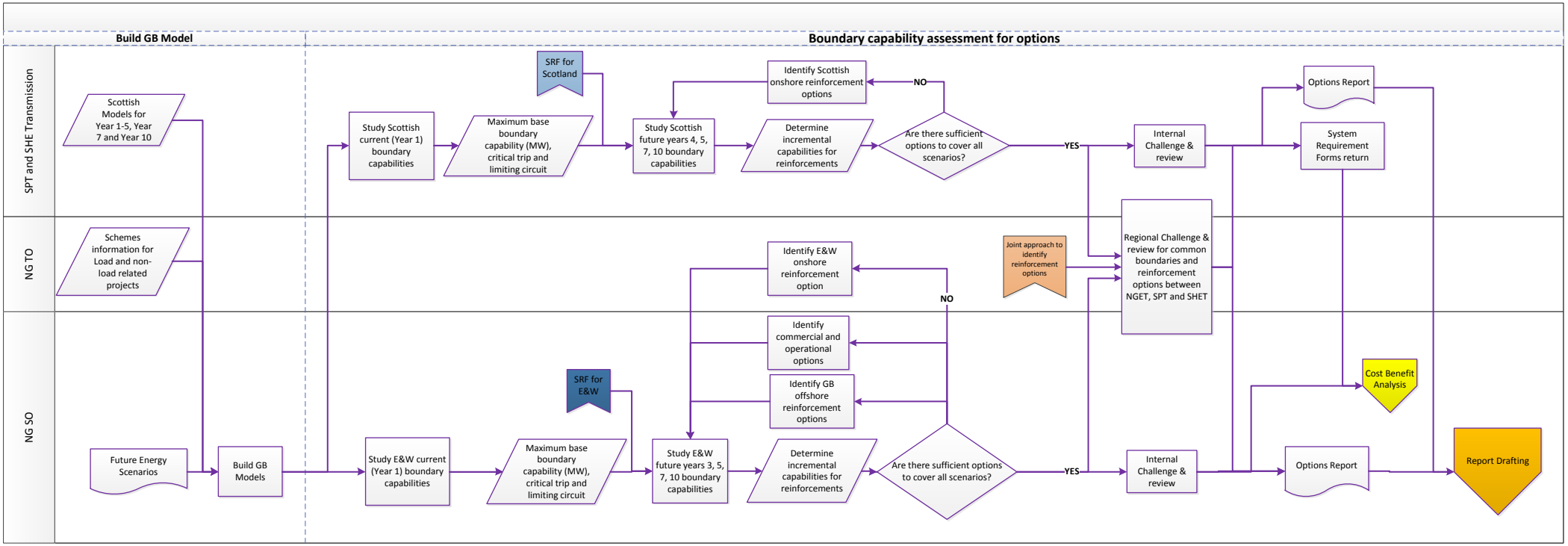
The SO implemented these revised seasonal scaling factors for the second NOA report analysis and will be prepared to amend them following future reviews. However, if the seasonal ratings are directly studied, then they may be used in place of the scaling factors.

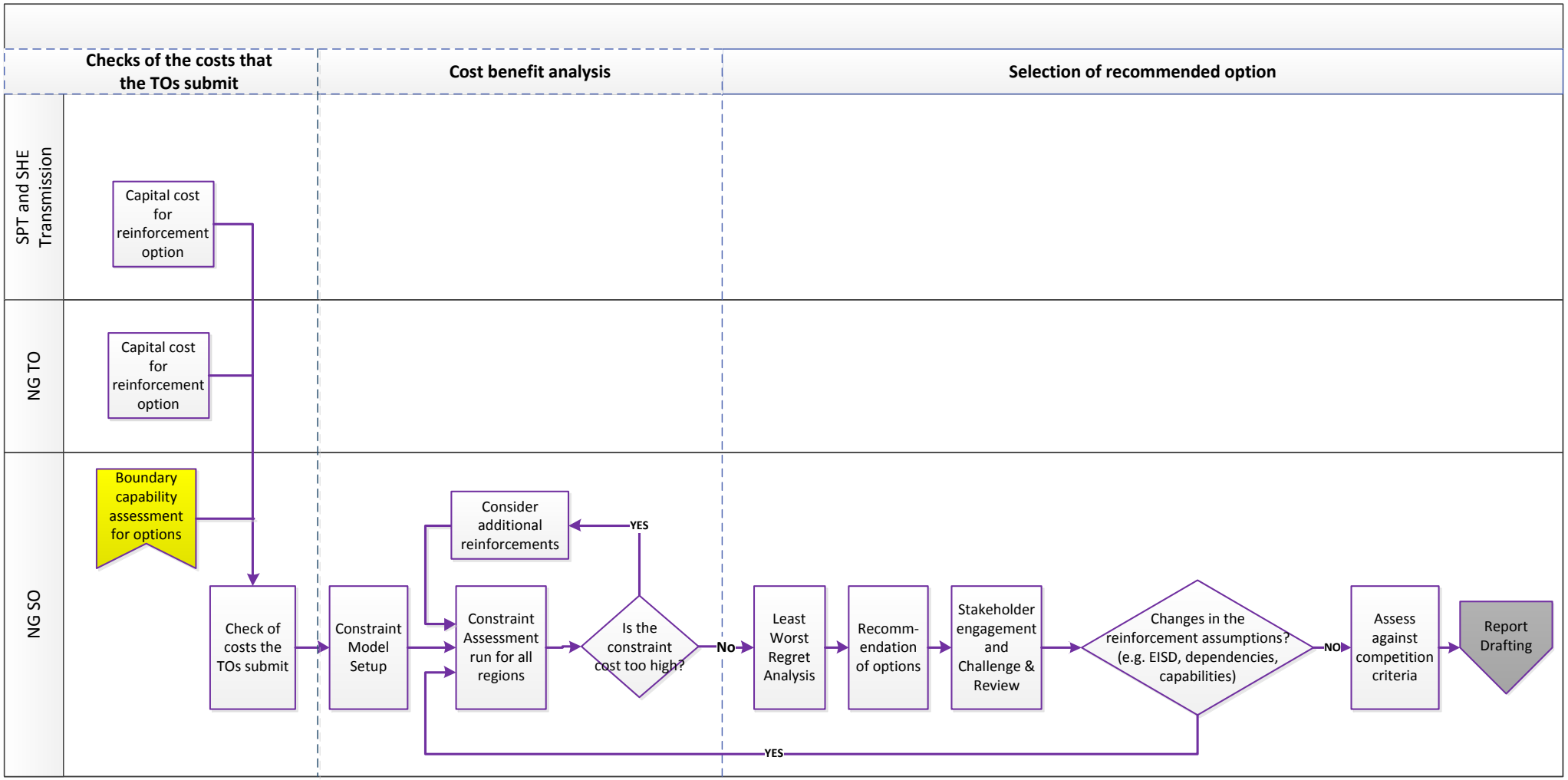
Appendix C: NOA Process Flow Diagram

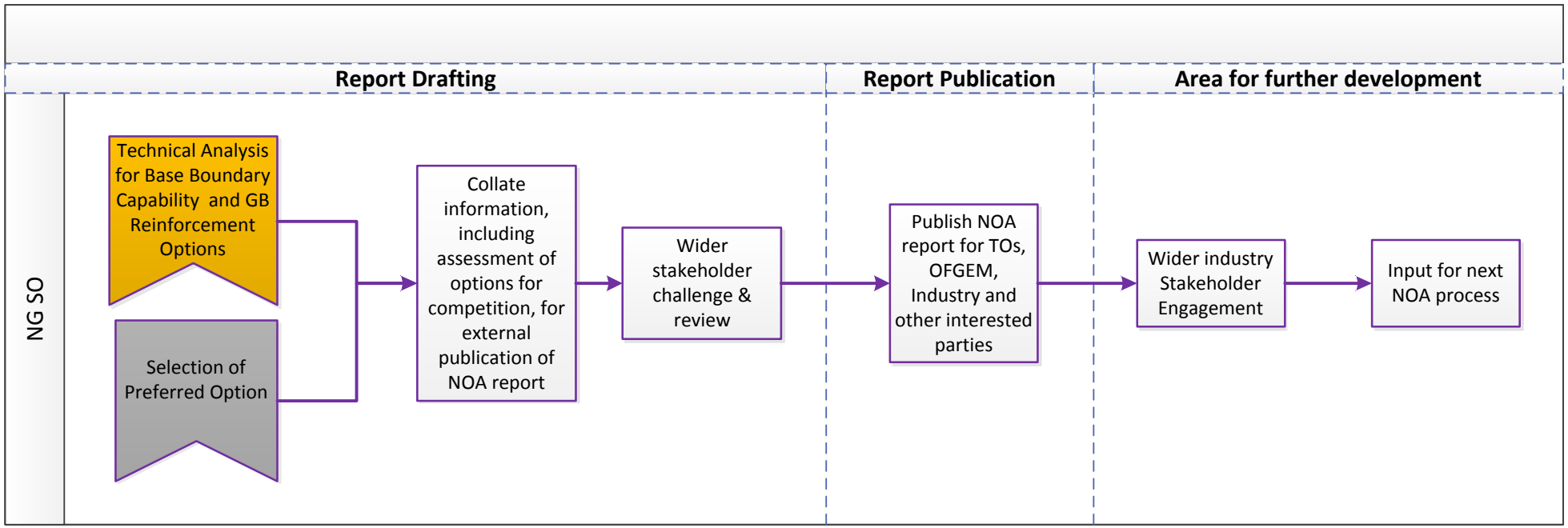


This diagram shows the overall NOA process. The text in each box corresponds to the descriptions of the stages at the top of the diagrams on the next pages. The process headings can also be found in the main methodology.


Collect Input
Identify future transmission capability requirements
Propose future transmission options
SPT and SHE Transmission
NG TO
NG SO
Identify Scottish onshore reinforcement options
Boundary reinforcement adjacent to other TO
Yes
Joint approach to identify reinforcement options
Technical Analysis for Base Boundary Capability and Reinforcement Options (SRF for Scotland)
No
Identify E&W onshore reinforcement option
Boundary reinforcement adjacent to other TO
YES
Joint approach to identify reinforcement options
NO
Identify GB offshore reinforcement options
Identify commercial & operational options for GB
Base Capability from previous year ETYS/ NOA
Future Energy Scenarios
Peak Y Boundary Transfer Model setup
Run Peak Y Boundary Transfer Model to identify required transfers
Stakeholder engagement on draft System Requirement Forms (SRF)
Issue System Requirement Forms (SRF)
Receive System Requirement Forms
Undertake validation and operability checks
Technical Analysis for Base Boundary Capability and Reinforcement Options (SRF for E&W)


Build GB Model
Boundary capability assessment for options
SPT and SHE Transmission
NG TO
NG SO
Scottish Models for Year 1-5, Year 7 and Year 10
Schemes information for Load and non-load related projects
Future Energy Scenarios
Build GB Models
SRF for Scotland
Study Scottish current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
Study Scottish future years 4, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Are there sufficient options to cover all scenarios?
NO
Identify Scottish onshore reinforcement options
YES
Internal Challenge & review
Options Report
System Requirement Forms return
Joint approach to identify reinforcement options
Regional Challenge & review for common boundaries and reinforcement options between NGET, SPT and SHET
Identify E&W onshore reinforcement option
Identify commercial and operational options
Identify GB offshore reinforcement options
SRF for E&W
Study E&W current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
Study E&W future years 3, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Are there sufficient options to cover all scenarios?
NO
YES
Internal Challenge & review
Cost Benefit Analysis
Options Report
Report Drafting


Checks of the costs that the TOs submit
Cost benefit analysis
Selection of recommended option
SPT and SHE Transmission
NG TO
NG SO
Capital cost for reinforcement option
Capital cost for reinforcement option
Boundary capability assessment for options
Check of costs the TOs submit
Constraint Model Setup
Consider additional reinforcements
YES
Constraint Assessment run for all regions
Is the constraint cost too high?
No
Least Worst Regret Analysis
Recomm-endation of options
Stakeholder engagement and Challenge & Review
Changes in the reinforcement assumptions? (e.g. EISD, dependencies, capabilities)
NO
Assess against competition criteria
Report Drafting
YES


Report Drafting
Report Publication
Area for further development
NG SO
Technical Analysis for Base Boundary Capability and GB Reinforcement Options
Selection of Preferred Option
Collate information, including assessment of options for competition, for external publication of NOA report
Wider stakeholder challenge & review
Publish NOA report for TOs, OFGEM, Industry and other interested parties
Wider industry Stakeholder Engagement
Input for next NOA process

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. 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 (SHE Transmission and SPT) 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. Each boundary will have its own Part D.
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

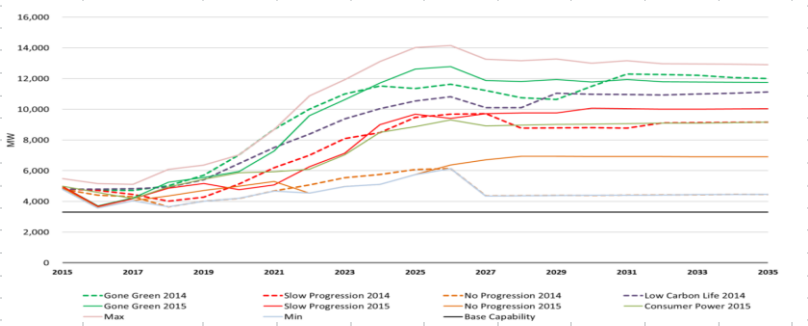
Part A: Boundary Requirement and Capability

For more information please use the information provided separately by the boundary studier.

Requirement proposer:	*SO PSE studying this boundary*
Passed To/ Date:	*To which TO engineer and when*
Boundary under Analysis:	*Boundary to be reinforced*

Winter Peak Boundary Required Transfer Summary:

Last Year's Boundary Base Capability: *In MW*



	Economy	Secured Event	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Economy Background (in MW)	Two Degrees												
	Slow Progression												
	Steady State												
	Consumer Power												

	Security	Secured Event	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Security Background (in MW)	Two Degrees												
	Slow Progression												
	Steady State												
	Consumer Power												

Boundary Base Capability:

		Secured Event	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Boundary Base Capabilities with secured events as per NETS SQSS (in MW)	**Two Degrees - Winter Peak**												
	Two Degrees - Spring												
	Two Degrees - Summer												
	Two Degrees - Autumn												
	Slow Progression - Winter Peak												
	Slow Progression - Spring												
	Slow Progression - Summer												
	Slow Progression - Autumn												
	Steady State - Winter Peak												
	Steady State - Spring												
	Steady State - Summer												
	Steady State - Autumn												
	Two Degrees - Winter Peak												
	Two Degrees - Spring												
	Two Degrees - Summer												
	Two Degrees Autumn												

If spring, summer or autumn capabilities are left empty, then the agreed scaling factor will be applied to the Winter capability to derive these capabilities. If the boundary's capability has been studied to provide both North and South flow capabilities then please submit this information as a separate Part A as though it were a separate boundary. For example, B6 can have a Part A for its usual North to South flow requirement/capability and a separate Part A for its South to North requirement/capability.

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.*
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 with 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*
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*

SRF Part C: Outage Requirements

Part C: Outage Requirements

TO Option Reference Number	EISD	Circuits Out	Outage Duration (weeks)	Restrictions in Sequence of Works	Lead Engineer	Additional Comments
TO Reference number. Must be same as Part B.				*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*
TO Reference number. Must be same as Part B.				*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*
TO Reference number. Must be same as Part B.				*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*

SRF Part D: Studied Option Combinations

Year xx	Base/Reinforcement Options Note #	
Thermal	Capability	+/-
Voltage	Capability	+/-
Stability	Capability	+/-

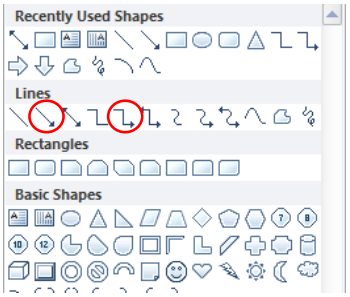
Year 3	Base	
Thermal	10000	300
Voltage	12000	800
Stability	NA	NA

Year 10	Option 1 1*	
Thermal	9000	1000
Voltage	NA	NA
Stability	NA	NA

- The box on the top left is the basic building block of the flowchart.
- The bottom two boxes are examples of how to populate the information depending on if the study is for a Base Case or for a Reinforcement assessment.
- The "Options Note" is used to provide a reference number which can be referred to in the "Option Notes" text box to provide any commentary.
- "Capability" refers to the boundary capability in MWs
- "+/-" refers to the incremental capability in MWs

To show the flow of the path taken to assess a set of reinforcements please use the "lines" object as outlined below to connect the boxes.

To connect the boxes please insert the "line types" below circled in red.



When you left click on one of the "line types" and hover over the box, 4 red connection points will appear.

Year xx	Base/Reinforcement Rule	
Thermal	Capability	+/-
Voltage	Capability	+/-
Collapse	Capability	+/-

Left click on the desired connection point and then while still holding down the left mouse button drag the line to the next shape, where again the connection points will appear.

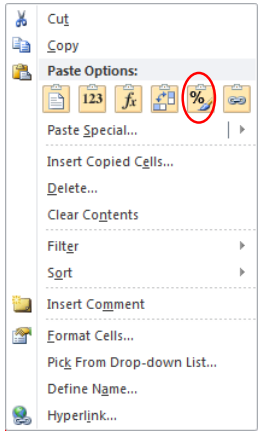
Year 1	Base	
Thermal	10000	0
Voltage	11000	0
Stability	NA	NA

Year 5	Base	
Thermal	11000	1000
Voltage	12000	1000
Stability	NA	NA

	Rules	Comments/Details
	Base Case	Please highlight the boxes that show the base case boundary capability, this will help to identify them against reinforcements.
	Mutually Exclusive	These reinforcements cannot exist in the same path likely due to physical restrictions e.g. Two shunt reactor running arrangements at the same substation.
	Alternative	These reinforcements solve the same issue and are therefore alternatives, however, both can be used in the same path if the issue they solve reoccurs at a later stage.
	Always after	This applies to reinforcements that can only be built following the impact of another reinforcement. E.g. A new HVDC link will change power flows significantly triggering the need for this reinforcement.
	No restriction	This reinforcement provides the same boundary capability at all times and can therefore appear at any point in the path. This is most likely on boundaries that are not nested, such as the northern Scottish boundaries.
	Must happen together	This applies to situations when two reinforcements are required to be built together before any incremental capability is realised.
	Miscellaneous	This rule is for any situation that does not fall into the rules above or further background information is offered that may help with the CBA process. Use the box provided to elaborate.

These are the rules which have been colour coded.

Please copy (ctrl+c) the colour and paste the "formatting" (circled in red below) to the "Base/Reinforcement" cell only.



Please see below for an example

Year 7	Option 1	
	1*	
Thermal	10000	1000
Voltage	NA	NA
Stability	NA	NA

Reinforcement Identifier	Brief Description
Option 1 (example)	Reconductoring circuit xxx (example)

Please list all the reinforcements analysed including its unique identifier and a brief description of the option.
*** Please note that the unique reinforcement identifier must be inserted in to the box circled in red below:**

Year xx	Base/Reinforcement Options Note #	
Thermal	Capability	+/-
Voltage	Capability	+/-
Stability	Capability	+/-

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	2018/19	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	2033/33	*	*	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 £m	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 £m	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.

	2018/19	2019/20 (if it were to be proceeded in 2018/19)	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

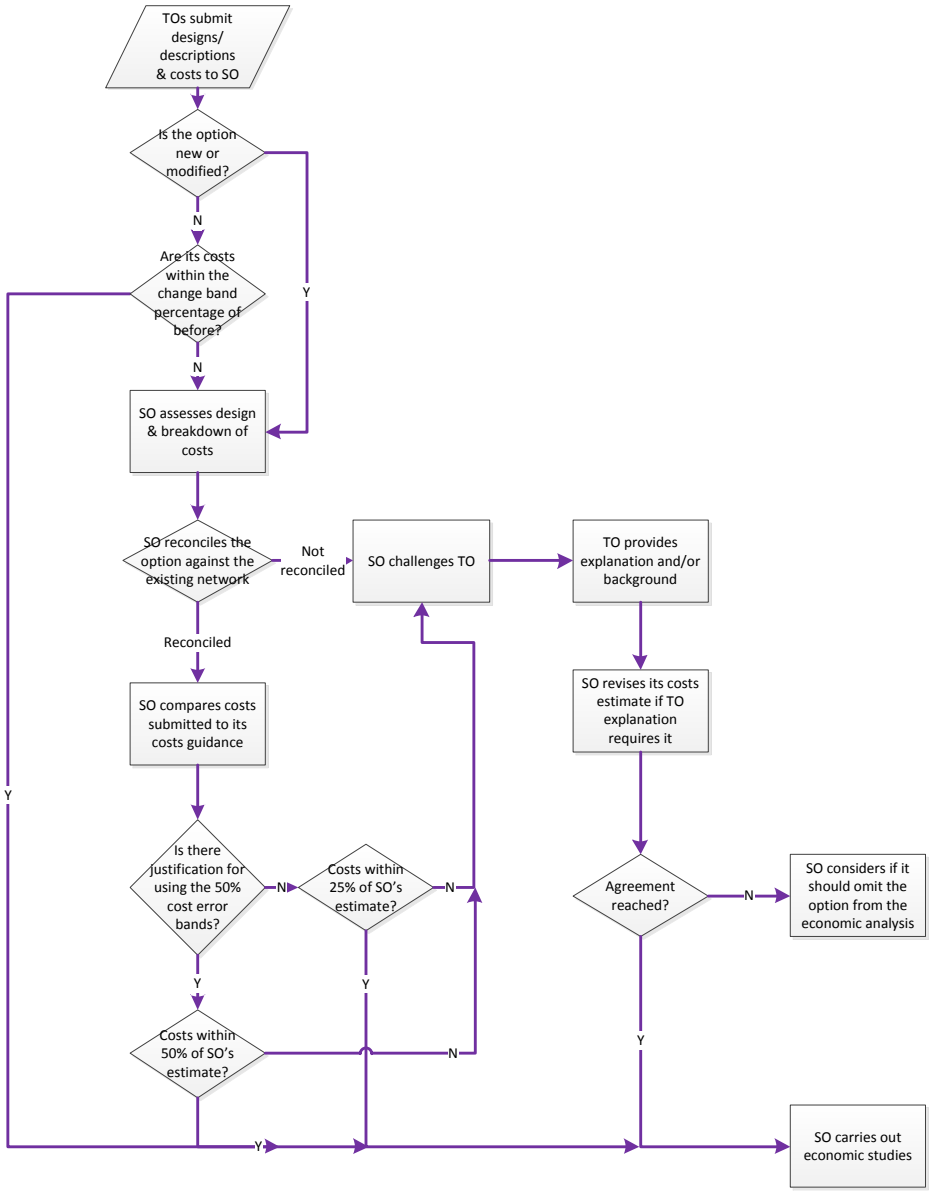
TO Reference Number	NOA Code	NOA Publication Name	NOA Publication Description	Additional Comments
TO Reference number. Must be same as Part B.	*Filled in by SO*	*The name of the option to be used in the NOA publication*	*The description of this option to be used in the publication*	*If required, additional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

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 the January 2017 customer 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
Competition	Stakeholders feel that there is an insufficient level of detail on the process for assessing competition in connections contained within the NOA methodology. Stakeholders feel that there should be no assessment against any criteria for competition as there is no current legal framework.	The SO feels that the methodology document has the correct level of detail for assessing for eligibility for competition for connections. It has worked with the interested parties to develop the level of detail for working level documents. Assessment against the criteria for competition for connections will not be undertaken this year whilst there is uncertainty over the competitive delivery models which, if included, could give rise to unnecessary concern for any affected customer. The SO recognises the concerns of stakeholders with regard to the lack of legal framework for competition, but also notes the commitment from Ofgem to pursue alternative competitive delivery models in the interim ahead of any primary legislation. On this basis, and with further consultation on competition due this summer, we believe it remains relevant to hold the position from the previous NOA and conduct an assessment against the consulted competition criteria of new, high value and separable for this year also.
Connections	Stakeholders feel that using contracted backgrounds for connection as opposed to scenarios causes a discrepancy that complicates their submissions and affects connections designs and hence competition.	This is a wider topic that the Joint Planning Committee that exists under STCP16-1 is considering.
Cost reasonableness check	Stakeholders were concerned about how the SO creates and maintains its cost guidelines. One stakeholder indicated an alternative approach to the SO's proposed method which it considers to take disproportionate effort.	The SO has created some guidelines to support its estimate of the costs of reinforcement costs. The methodology refers to the wider sources of publicly available information to maintain the cost guidelines. The SO recognises that one stakeholder is considering pursuing its alternative approach further.
Cost bands	A stakeholder sought clarity about how the cost bands are applied	The SO highlights that the methodology says cost bands apply to options with a 'proceed' status and that satisfy the competition criteria. The SO has amended the reference to competition criteria to strengthen the text's meaning.

Environment	A stakeholder was concerned that National Grid risks breeching its legal obligations on the environment.	The NOA is the first step in determining if there is an economical need for reinforcement. Many of the investment options that the TOs propose to the NOA to be analysed are at a very early conceptual stage and are concerned with theoretical power transmission between two points, rather than a defined route. The TOs meet legal obligations over the environment if they go on to develop the option.
Implied probabilities	The stakeholder asked for a worked example about implied probabilities in the section Selection of Recommend Option.	We have added a worked example to support our description of implied probabilities. To help this explanation, we have adapted the earlier part of the section to use NPVs rather than capital costs in the description.
NOA Committee	The stakeholder sought details of workings and attendance.	We have amended the methodology text to refer to the TOs attending the NOA Committee meeting.
NOA Study matrix	A stakeholder suggested amending Appendix A NOA Study Matrix where it describes the studies.	We have amended Appendix A NOA study matrix to say that economic studies are carried out with technical studies as required for three scenarios. These scenarios are for Slow Progression, Consumer Power and Steady State.