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 2016/17. It covers the methodology on which NGET in its role as SO will base the NOA report which will be published by 31 January 2017. 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.

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Introduction

Overview

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 interconnector capacity.

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 capability, the options available to meet this capability and the SO's preferred options for further development. It is important to note that whilst the SO identifies its preferred options to progress to meet system needs, any investment decisions remain with the Transmission Owners (TOs) or other relevant parties as appropriate.

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

4 For the second NOA Report methodology, the SO assesses options for competition in providing transmission reinforcements and also does validation checks of boundary capabilities where the TO does this analysis. The SO has procured a new constraint costing modelling tool to replace ELSI and will introduce the tool during the NOA Report study period. The SO performed checks of boundaries for the first NOA Report and validated the results. The SO will continue this approach with the second NOA Report.

5 The NOA Report process was built on the Network Development Policy (NDP) process and extended its use to the whole Great Britain transmission system. The NDP is part of the evaluation of National Grid TO investment under its volume-driver (incremental wider works (IWW)) framework and so the SO is looking to fully replace the NDP with the NOA analysis.

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

7 This methodology describes the process and the headers used follow the flow diagram in Appendix C for clarity. Appendices A and B contain supporting information.

8 In accordance with Standard Licence Condition C27, the SO has sought the input of stakeholders. Appendix D summarises any views that the SO has not accommodated in producing this NOA report methodology.

Differences between NOA and ETYS

9 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 preferred options.

10 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' 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.

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

Introduction

12 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.

13 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, through assessing available solutions, to selecting and documenting the recommended option/s for further development and assessing the suitability of options for third party delivery by a Competitively Appointed Transmission Owner (CATO). The SO identifies and evaluates alternative solutions such as based around commercial arrangements and reduced-build options. Table 1 covers this in more detail.

14 The SO has engaged with the TOs to develop this second methodology statement. Following publication of the NOA report further stakeholder engagement is undertaken to inform the methodology statement for supporting the second NOA Report (2016) and further NOA reports.

15 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.

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

17 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.

18 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

19 Standard Licence Condition 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.*

20 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

21 The NOA report presents projects that are defined by Major National Electricity System Reinforcements (see definition above).

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

23 Once a Strategic Wider Works (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 because it is managed through the SWW process. Ofgem have agreed the approach of excluding options where they have agreed the SWW needs case. The NOA Report will include analysis of options under construction that are funded through the Incremental Wider Works mechanism.

Roles and responsibilities of SO and TOs

24 The roles and responsibilities of the SO and TOs are described below. However, as the NOA process evolves and matures, these roles and responsibilities will also develop and change.

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

- Analysis of UK Future Energy Scenarios (FES) data
- Technical analysis of boundary capabilities for England and Wales
- Running cost-benefit analysis studies
- Production and publication of NOA report
- Recommending options for further development and suitability for competition
- Devising and developing options for alternative reinforcements including reduced-build and Offshore Wider Works
- Validation checks of some TO boundary capabilities where the TO has done that analysis
- Advice on the performance of boundary reinforcement proposals in the cost-benefit analysis to facilitate further option development
- Assessment of outages and other system access requirements that might affect the Earliest in Service Date (EISD).

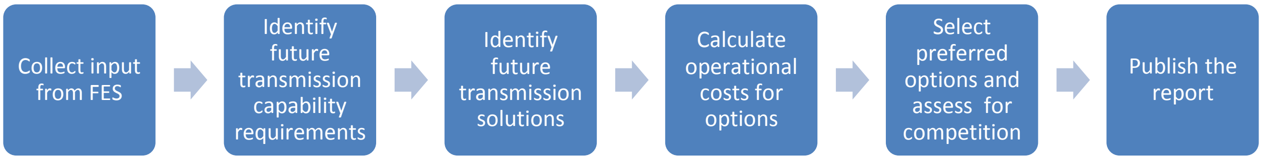
26 The TOs' roles and responsibilities include:

- Technical analysis of boundary capabilities by SPT and SHE Transmission in and affecting their areas[1]
- Cost information
- Environmental information
- Consents and deliverability information
- Capability improvements
- Earliest in Service Date (EISD)
- Stakeholder engagement (following review of draft outputs)
- Community engagement.

Overview of the NOA Report process

27 Figure 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 1: Overview of the NOA Report process



Collect Input

Updated Future Energy Scenarios

28 The relevant set of Future Energy Scenarios (FES) 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 2040 in detail and at a higher level to 2050. The FES document is consulted upon widely and published each year as part of a parallel process.

29 The NOA process utilises the main FES 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.

[1] This is anticipated for the first, second and possibly further NOA reports.

30 In 2016, the four main scenarios are:

- Gone Green – The Gone Green 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 interconnector 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 Gone Green. 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 Gone Green, leads to a slower uptake of renewables.

- No Progression – No Progression 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.

31 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). The scenario demands are then adjusted to match the metered average cold spell (ACS)[2] corrected actual outturns.

32 Using regionally metered data, the "ACS adjusted scenario demands" are split proportionally around GB.

33 Annual demand submissions are made by transmission system users, which are obtained between June and November each year. The regionally split "ACS adjusted

[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.

demand scenarios" are then converted into demand by Grid Supply Point using the same proportions as specified in the 'User' submissions.

Sensitivities

34 Sensitivities are used to enrich the analysis for particular boundaries to ensure that issues, such as the sensitivity of boundary capability to the connection of particular generation projects, are adequately addressed. The SO leads on the sensitivities in conjunction with the TOs and any feedback from stakeholders sought through the FES consultation process. This allows regional variations in generation connections and anticipated demand levels that still meet the scenario objectives to be appropriately considered.

35 For example, the contracted generation background on a national basis far exceeds the requirements for credible scenarios, but on a local basis, the possibility of the contracted generation occurring is credible and there is a need to ensure 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.

36 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.

37 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 into GB) and demand (when exporting to Europe). For example, when interconnectors in the South East are exporting to Europe, this changes the loading on the transmission circuits in and around London and hence creates different limits on the amount of power that can be transferred.

38 The modelling of interconnector flows during winter peak condition is based on an economic simulation driven by forecast energy prices for GB and remote markets in Europe. However, the modelling of interconnector flows during summer demand condition is based on historical precedent. The modelling of interconnector flows during summer demand condition is based on economic simulation. Therefore, we continue to work closely with stakeholders in developing our models of interconnector flows.

39 The SO extends sensitivities studies further to test import or security constraints. FES tends to produce export type flows such as north to south. In some circumstances, flows are reversed. The SO develops these sensitivities in consultation with stakeholders to produce transfer requirements for import cases.

Interconnectors

40 The SO undertakes analysis to assess and provide a view on the optimum level of interconnectors' capacity per interconnected market. 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.

41 The SO has procured a new Pan-European Market Model tool to enhance its capabilities in simulating inter-market flows and consequent prices changes. This allows the evaluation of potential benefits and costs of further interconnection capacities. The chief benefits analysed will be consumer, producer and interconnector welfare benefit, 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 interconnectors recommended by the SO.

42 The details of the proposed approach for 2016/17 are presented in the NOA for Interconnectors methodology. The NOA for Interconnectors will be a chapter in the NOA Report and hence be published by 31 January 2017.

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

43 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 capability requirements

National generation and demand scenarios

44 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.

45 The Security criterion is intended to ensure that demand can be supplied securely, without reliance on intermittent generators or imports from interconnectors. The level of contribution from the remaining generators is established in accordance with the NETS SQSS for assessing the average cold spell (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 intend to identify key network contingencies that test the system's robustness.

46 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

[3] ACS 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.

centres. Generation is scaled to meet the required demand level. Further details can be found in Appendix E and F of the NETS SQSS.

47 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.

48 The SO uses the FES 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 this information to TOs for identification of the future transmission solutions which are described in the following section.

Identify future transmission solutions

49 At this stage all high level potential transmission solutions that could provide additional capability across a system boundary found to be requiring reinforcement are identified (for economic and security criteria), including a review of any solutions previously considered. The NOA report presents a high level view of options, with key choices to be taken for further evaluation as outlined on a non-exhaustive basis below. The NOA options are based around choices for example:

- An onshore route of conventional AC overhead line (OHL) or cable
- An onshore route of HVDC
- Offshore options whether 'bootstrap' or integration between offshore generation stations (Offshore Wider Works).

50 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.

51 In response to the SO data on boundary capabilities and requirements, TOs identify and develop multiple credible options that deliver the potentially required reinforcements of boundaries. The SO produces and circulates the System Requirement Forms (SRF) to the TOs and in return, TOs provide high level details of credible onshore reinforcement options that are expected to satisfy the requirement. Appendix A of this document provides detailed information about the SRF template. The SO can suggest ideas to the TOs for options to achieve the boundary requirements.

52 The SO considers options for Non Developer-Associated Offshore Wider Works (NDAOWW) which would deliver offshore reinforcements where such an investment could achieve 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 OWW. As it is an initial and desk top exercise the capital costs 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 OWW options.

53 The options that the TOs provide are listed and described in the NOA report along with ‘reduced-build’ options such as operational or ‘minimal-build’ options that the SO develops. The reduced-build solutions might include liaison with distribution licensees. The SO produces the description of the ‘reduced-build’ option in conjunction with the relevant TOs. The description includes the boundary that the option relieves, categorising the option into ‘asset’, ‘reduced build’ etc and a technical outline such as an overhead line route connecting substation ‘X’ to substation ‘Y’. The option description includes any associated aspects such as the nature of the area affected, related network changes for example substation rebuilds etc.

54 It is recognised that as solutions develop, their level of detail increases. Solutions at a very early development stage might lack detail due to emerging drivers such as a changing generation background.

55 By the end of Week 23, the England and Wales TO returns the draft SRF with the necessary technical content for the SO to perform the boundary capability assessment. The England and Wales TO returns the full SRF form that includes costs and further commentary by the start of Week 38.

56 The Scottish TOs return the draft SRF by the end of Week 32. By the start of Week 38, the Scottish TOs return the full SRF with the boundary capabilities from their technical assessment of the credible reinforcement options for their respective areas.

57 Where a boundary reinforcement 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.

58 Once the TOs have submitted their SRFs, the SO checks its data and understanding of the costs by discussing them with the TOs.

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

60 Potential transmission solutions are presented in Table 1.

Table 1: Potential transmission solutions

Category		Transmission solution	Nature of constraint			
			Thermal	**Voltage**	**Stability**	**Fault Levels**
Operational		Availability contract *(contract to make generation available, capped, more flexible and so on to suit constraint management)*	✓	✓	✓	
Operational		Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
Operational		Reactive demand reduction *(this could ease voltage constraints)*		✓		
Operational		Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
Investment	**Low cost-investment**	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
Investment	**Low cost-investment**	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)*	✓	✓	✓	✓
Investment	**Low cost-investment**	Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
Investment	**Low cost-investment**	Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
Investment	**Low cost-investment**	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)*		✓	✓	
Investment	**Low cost-investment**	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*	✓	✓		
Investment	**Low cost-investment**	Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
Investment	**Low cost-investment**	HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	
Investment	**Low cost-investment**	'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)*	✓			
Investment	**Asset investment**	Overhead line re-conductoring or cable replacement *(replacing the conductors on existing routes with ones with a higher rating)*	✓			
Investment	**Asset investment**	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.*		✓	✓	
Investment	**Asset investment**	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).*	✓			✓
Investment	**Asset investment**	New build (HVAC / HVDC) – *new plant on existing or new routes.*	✓	✓	✓	✓

61 It is intended that the range of solutions 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 while it allows the SO to assess 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 preferred solution, we rely on the TO for deliverability, planning and environmental factors. We offer a lead on operability, reduced-build and offshore integration matters ahead of the cost-benefit analysis.

62 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 operation 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.

Scrutiny of the costs that the TOs submit

63 The SO reviews the costs that the TOs submit with their options. The criteria and extent of this review is still to be agreed.

Environmental impacts and risks of options

64 Using the SRF the TOs provide views on the environmental impact of the options that they have proposed. This includes the potential impact of the environmental issues on the practicality of implementing each option.

65 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.

66 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.

Basis for the cost estimate provided for each option

67 The forecast total cost for delivering the project is split to reflect the pre-construction and construction phases. The forecast cost is a central best view.

68 By Week 30, the TOs and SO agree each year the cost basis to be used for NOA analysis.

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

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

Build GB Model

71 The Scottish TOs submit a yearly power system model to the SO. The SO then creates the GB power system models and publishes the model for studies. Additional power system model/modelling information for network options should also be submitted from TOs such that SO have adequate models to carry out the necessary option analysis.

Boundary capability assessment for options

72 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. The SO performs validation checks of some TO boundary capabilities where the TO has done that analysis.

73 The boundary capability that is assessed is the lowest of the thermal, voltage and stability (where required) capability. Each of these capabilities is assessed at relevant points of the year to ensure that both the peak and off-peak capabilities are considered during the NOA process. In reporting the boundary capability each year, only the most restrictive of the capability values are published and the criteria for its definition provided in any accompanying narrative.

74 In order to minimise unnecessary repetition whilst maintaining robustness, winter peak network analysis is carried out under the FES scenario that will stress the transmission system the most (in 2016 this will be the Gone Green 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. For the purposes of any stability analysis (where required), year round demand condition is 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 Chapter 5.

75 The analysis is done in accordance with the NOA study matrix which describes the constraint type, FES 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 B of this document.

76 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.

77 The factors shown in Table 2 below are identified for each transmission solution to provide a basis on which to perform cost-benefit analysis at the next stage.

Table 2: Transmission solution factors

Note the Development Consent Order (DCO) applies to England and Wales only

Factor	Definition		
Output(s)	The calculated impact of the transmission solution on the boundary capabilities of all boundaries, the impact on network security		
Lead-time	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.		
Cost	The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases.		
Stage	The progress of the transmission solution through the development and delivery process. The stages are as follows:		
	Project not started		
	Pre-construction	*Scoping*	Identification of broad need case and consideration of number of design and reinforcement options to solve boundary constraint issues.
		Optioneering and DCO started	The need case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified.
		Design/ development and DCO started	Designing the preferred solution into greater levels of detail and preparing for the planning process.
		Planning	Continuing with public consultation and adjusting the design as required all the way through the planning application process.
		DCO approved	Development Consent Order approved but construction has not started
	Construction		Planning consent has been granted and the solution is under construction.

78 In order to assess the lead-time risk described in Table 2, if a new overhead line solution for example has significant consents and deliverability risks, the SO considers with both ‘best view’ and ‘worst case’ lead-times to establish the least regret for each likely project lead-time.

79 It is possible that alternative solutions 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 solutions, the scenarios or commercial assumptions.

80 If the SO or the Scottish TOs (who conduct boundary capability studies) decide that there are not sufficient 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 reinforcement requirement.

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

82 The Scottish TOs use their boundary capability results in the SRFs that they submit back to the SO.

83 The SO leads on reduced-build options in cooperation with the TOs. The economic analysis tool needs a MW value for the boundary capability which this analysis of reduced-build 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

84 Cost-benefit analysis is the best practice approach to inform an investment recommendation for a project. In particular, the approach compares forecast capital costs and monetised benefits over the project's life to inform this investment recommendation.

85 The NOA provides investment signals based on the Single Year Regret Decision Making process. If the investment signal triggers the TO's needs case for SWW assessment by Ofgem, the SO will assist the TO in undertaking a more detailed cost-benefit analysis.

86 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 projects to proceed with or to delay in the next year and which to delay. A secondary output is an indicative list of which reinforcements would be proposed at present if each of the scenarios were to turn out.

87 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 is proposing the project to the regulator, the needs case includes a cost-

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

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

Cost-benefit analysis Methodology

88 Since the number of reinforcements planned for the transmission system is quite large the country is split into regions and each reinforcement is determined to be in one of the regions. The cost-benefit analysis process for each region is conducted in isolation. The year in which each of the reinforcements 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 definition of a region is fluid and may change from year to year. The criterion by which a region is defined is that a reinforcement may not appear in more than one region (this is to prevent a reinforcement being evaluated more than once, with the risk of two different answers).

89 All of the FES scenarios are considered; furthermore it is usual for sensitivities to be considered as described previously. Each scenario is also 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.

90 To begin the process all proposed reinforcements within the region are disabled, the output of the model is analysed to determine which boundaries within the region require reinforcement and when the reinforcement is required, this simulation is referred to as the base case. This information is used to determine which reinforcement(s) should be evaluated first. The reinforcement that has been selected to be evaluated next is then activated in the constraint cost modelling tool (see the box on page 21 for a description) at its Earliest In Service Date (EISD), if a number of potential reinforcements have been identified as being candidates for the next reinforcement then this process must be repeated with each reinforcement 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.

91 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 FES scenarios do not contain detailed ranking orders beyond 20 years). Both 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 reinforcement is amortised over the asset life using the prevalent Weighted Average Cost of Capital (WACC) and discounted using the STPR. This value is added to the constraint cost forecast for the reinforced case. The present value of the base case is then compared to the

[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.

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

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

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

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

95 A reinforcement is critical if a decision to delay a reinforcement in the current year means that the optimum year for any scenario or sensitivity, could no longer be met (note that outage availability may play a part in this decision).

Constraint cost modelling tool

96 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 3.

Table 3: 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
CO_2 forecasts	FES	20 year forecast
Plant efficiencies and season availabilities	Historic data	
Plant bid and offer costs	Historic data	
Wind data	Poyry (historic)	Wind load factors for various zones around the UK
Demand data	FES	Annual peak and zonal distribution
Load duration curve	FES	20 year forecast by scenario
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

97 The model simulates 4 periods per day for 365 days per year and is set to simulate 20 years into the future. The year in which a reinforcement 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 preferred option

98 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 preferred option or combination of preferred options.

Single Year Least Regret Decision Making

99 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 reinforcement there are two choices, either to proceed with the project for the next year or to delay the project 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

reinforcement 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 reinforcements.

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

101 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.

102 The following section is a worked example of the least regret decision making process. Two projects have been determined to be ‘critical’ in this region, the EISD for reinforcement 1 is 2018 and the EISD for reinforcement 2 is 2019. The optimum years for scenarios A, B and C are shown in table 4. Note that the scenarios are colour-coded; this is used for clarity in following tables.

Table 4: Example of optimum years for two critical reinforcements.

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

Table 5: Example decision tree

Permutation	Year 1 Options	Year 1 Capital Costs	Completion Date	Regrets	Worst regret for each permutation
i	Proceed reinforcement 1	£20m	Reinforcement 1: 2018 Reinforcement 2: 2020	£51m	£51m
	Delay Reinforcement 2	£1m	Reinforcement 1: 2018 Reinforcement 2: 2022	£0m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£5m	
ii	Delay Reinforcement 1	£2m	Reinforcement 1: 2019 Reinforcement 2: 2019	£102m	£102m
	Proceed reinforcement 2	£10m	Reinforcement 1: 2019 Reinforcement 2: 2022	£35m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£10m	
iii	Proceed reinforcement 1	£20m	Reinforcement 1: 2018 Reinforcement 2: 2019	£0m	£15m
	Proceed reinforcement 2	£10m	Reinforcement 1: 2018 Reinforcement 2: 2022	£2m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£15m	
iv	Delay Reinforcement 1	£2m	Reinforcement 1: 2019 Reinforcement 2: 2020	£153m	£153m
	Delay Reinforcement 2	£1m	Reinforcement 1: 2019 Reinforcement 2: 2022	£32m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£0m	

103 Table 5 is an example of a least regret decision tree, since there are two 'critical' reinforcements there are therefore four permutations. From Year 2 onwards for each of the permutations the reinforcements are commissioned in as close to the optimum year for each reinforcement 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 Year 1 Capital Costs column indicates the expenditure needed in Year 1 and which is key in the Single Year Least Regret analysis. This might include delay costs.

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

- If the reinforcement is delayed and therefore cannot meet the optimum year then additional constraint costs will be incurred
- If the reinforcement is delayed unnecessarily then there will be additional delay costs

- If the reinforcement is proceeded with too early then there will be inefficient financing costs
- If the reinforcement is proceeded with and is not needed then the investment will have been wasted.

105 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 preferred option 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 reinforcements 1 and 2 which has a worst regret of £15m and is the least of the four permutations.

Process Output

106 Following Single Year Regret analysis, for each region in the country a list of 'critical' reinforcements for the region is presented with the investment recommendation for each. 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 on a preferred option.

Suitability for third party delivery and tendering assessment

107 The SO assesses the suitability of projects for competition in accordance with agreed tendering criteria. The cost-benefit analysis process identifies the preferred options. The SO notes up to three options where this is appropriate. The SO then assesses these options against the tendering criteria, this is projects that are:

- New
- Separable
- High value

The criteria is still to be finalised[6] in legislation and the methodology will include the final criteria. To achieve the assessment, the TOs will provide further information to the SO with the SRF form (see appendix A). The SO records the assessment for each option against the criteria and categorises the options.

[6] The tendering criteria is currently being considered within Ofgem's ongoing work on Extending Competition in onshore Transmission https://www.ofgem.gov.uk/publications-and-updates/extending-competition-electricity-transmission-proposed-arrangements-introduce-onshore-tenders

Report drafting

108 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 6: 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	Includes the competition assessment against criteria See table 7 on next page
4	Proposed Options	
5	Investment Recommendations	
6	Interconnector Analysis	
7	Stakeholder Engagement and Feedback	

109 Chapters 3 to 6 cover the options and their analysis. The component parts of these chapters and the responsibilities for producing the material are in the table below. Appendix E gives more detail on the form of the NOA Report.

Table 7: Topics in the options chapters in the NOA report

NOA report Options topic	Scotland	E&W	Reduced-build/ min-build	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 preferred options 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				

110 The report is transparent where possible 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 preferred options.

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

Report publication

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

113 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.

114 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.

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

Stakeholder consultation

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

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

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

Methodology

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

120 Following the final publication of the NOA report, the SO undertakes an internal review of the NOA process. This is completed within eight weeks of NOA report publication with the publication of an updated NOA methodology that consults stakeholders and invites comments/feedback. The deadline for comments is 14 weeks from NOA report publication. The SO considers these comments for a revised NOA methodology that is published 18 weeks from NOA report publication and submitted to Ofgem by 1 August 2016.

Report output

121 The SO makes available selected parts of the pre-release NOA report to key stakeholders particularly the relevant TOs based on discussions with those stakeholders while respecting confidentiality obligations. This is as the NOA report is being written based on assessment data, particularly economic data, becoming available.

122 Further engagement happens with stakeholders with the draft NOA report being circulated to them three weeks before the NOA report is due to be formally published. This gives them the opportunity 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.

123 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

124 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.

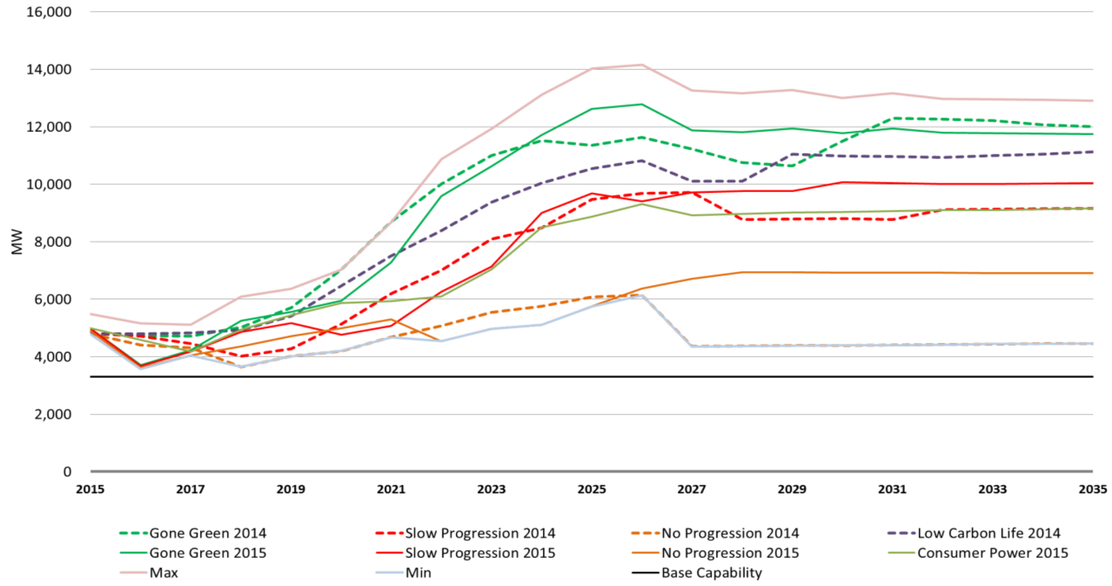
125 In accordance with Licence Condition C27 Part C, the SO provides information to electricity transmission licensees, interconnector developers and to the Authority (Ofgem) if requested to do so. The SO will assist TOs with cost-benefit analysis for SWW needs cases.

Appendix A: System Requirements Form Template

Boundary B6

Requirement proposer:
Passed To / Date: -
Boundary under Analysis: B6

Boundary Required Transfer Summary:



Economy / Export		Secured event	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
See Note 1	Gone Green Winter Peak Required Transfer (MW)												
	Slow Progression Winter Peak Required Transfer (MW)												
	No Progression Winter Peak Required Transfer (MW)												
	Consumer Power Winter Peak Required Transfer (MW)												
See Note 2	Gone Green Winter Peak Intact Boundary Capability (MW)												
	Gone Green Spring / Autumn Intact Boundary Capability (MW)												
	Gone Green Summer-max Intact Boundary Capability (MW)												
	Gone Green Summer-max Outage Boundary Capability (MW)												

Note 1: Required Transfers in accordance with NETS SQSS Chapter 4 Economy Background.
Note 2: Boundary Capabilities derived from modification of the Economy Background, with secured events as per NETS SQSS Chapter 5.

Assumed Annual Duration of Planned Boundary Outage: *TBC* boundary outage days per annum

Security / Import		Secured event	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
See Note 3	Gone Green Winter Peak Required Transfer (MW)												
	Slow Progression Winter Peak Required Transfer (MW)												
	No Progression Winter Peak Required Transfer (MW)												
	Consumer Power Winter Peak Required Transfer (MW)												
See Note 4	Gone Green Winter Peak Boundary Capability (MW)												
	Gone Green Spring / Autumn Boundary Capability (MW)												
	Gone Green Summer-max Boundary Capability (MW)												

Note 3: Required Transfers in accordance with NETS SQSS Chapter 4 Security Background
Note 4: Boundary Capabilities derived from modification of the Security Background, with secured events as per NETS SQSS Chapter 4.

Boundary Power System Analysis Summary:

Reinforcement options:

To satisfy the indicated future system requirement the following reinforcement options are suggested:

Option 1: **Ref number:** *Reference number if available*	Confidential (Y/N) see notes
Option Name: *Insert the name of the proposed reinforcement.*	N/A
Target boundary or boundaries: *List the boundary or boundaries that the option is to reinforce*	
Status: Same/Changed/New	
Description: *Provide a description of the physical nature of the reinforcement sufficient to allow power system modelling and costs to be developed.*	
Diagram: *Put diagrams here of how the new configuration will look including circuits and substation layouts.*	
Solution: *Describe how the proposed solution is intended to increase capability and under what conditions.*	
EISD: *Year*	N/A
Lead engineer: *Contact name in case of queries*	

Scheme # (England and Wales TO only): *All relevant or create a new reference if none already exist*		
Circuit(s) out: *List the circuit outages that are needed for the option*	Outage duration: *List the duration of the outages*	

NOA Description: *Description of the option suitable for public presentation*	N/A
Actual Capability Increase: *The studied capability increase of the option. Add extra boundaries if the option reinforces more than one boundary.*	N/A
Current Status: *Scoping, Delivery, etc (see Table 2 for descriptors)*	N/A
Environmental impacts and risks: *Provide views on the environmental impact of the options depending on current status of project*	
TO view on whether the option involves mainly or all new construction and assets: *NOA requirement for competition and whether and how much the option has new as opposed to refurbished or reconfigured existing assets*	
TO view on how separable the option is from existing assets: *NOA requirement for competition – separability criteria. How separable is the construction and new assets*	

from existing TO assets?	

Notes:

- Red is required text.
- The TO enters yes/no (Y/N) in the 'confidential' column on the table above. The SO treats confidential information as RSPI. Where the data item cannot be confidential, the cell is already marked 'N/A'.

Option 1 costs profile (based on current year costs)

	Spend to date	2017 /18	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	*	*
Pre-construction																			
Construction																			
Total																			

Cost basis	P50 P80 Other (specify)

Ongoing maintenance costs	

Breakdown of costs
We are consulting on what parts of the costs should be detailed in this table and would like to hear your views.

Costs		
Event or stage	**Now**	**After one year's progress**
Demobilisation		
Ongoing		
Remobilisation		
Reconsenting		
Cancellation		

Notes:

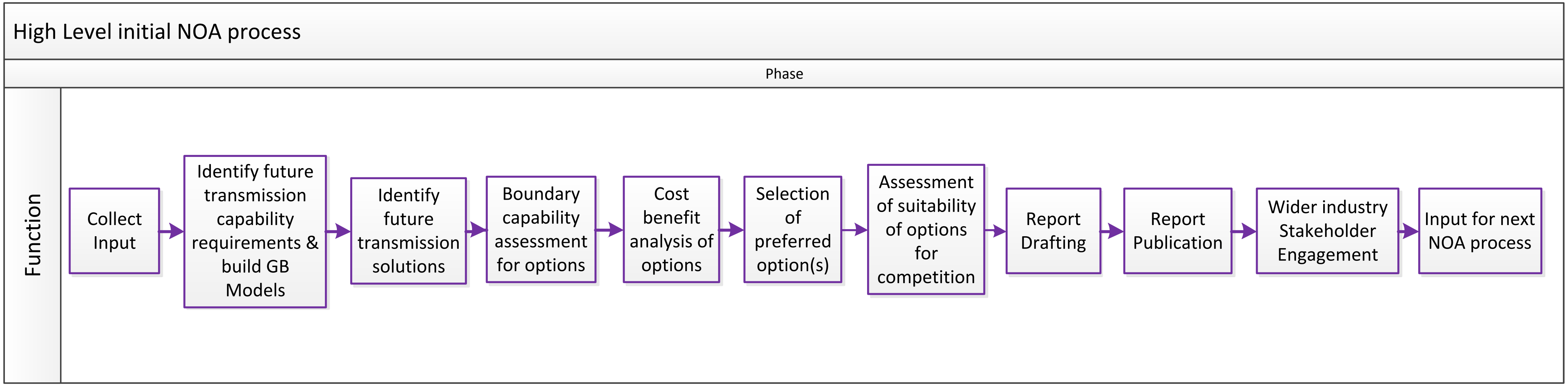
- Spend to date column in the last year if possible and inflation adjusted for the current year. Please state the year this is costed in.
- Use the columns marked * for mid-life refurbishment costs.

- The costs table covers for when a project is delayed or cancelled now and delayed or 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.

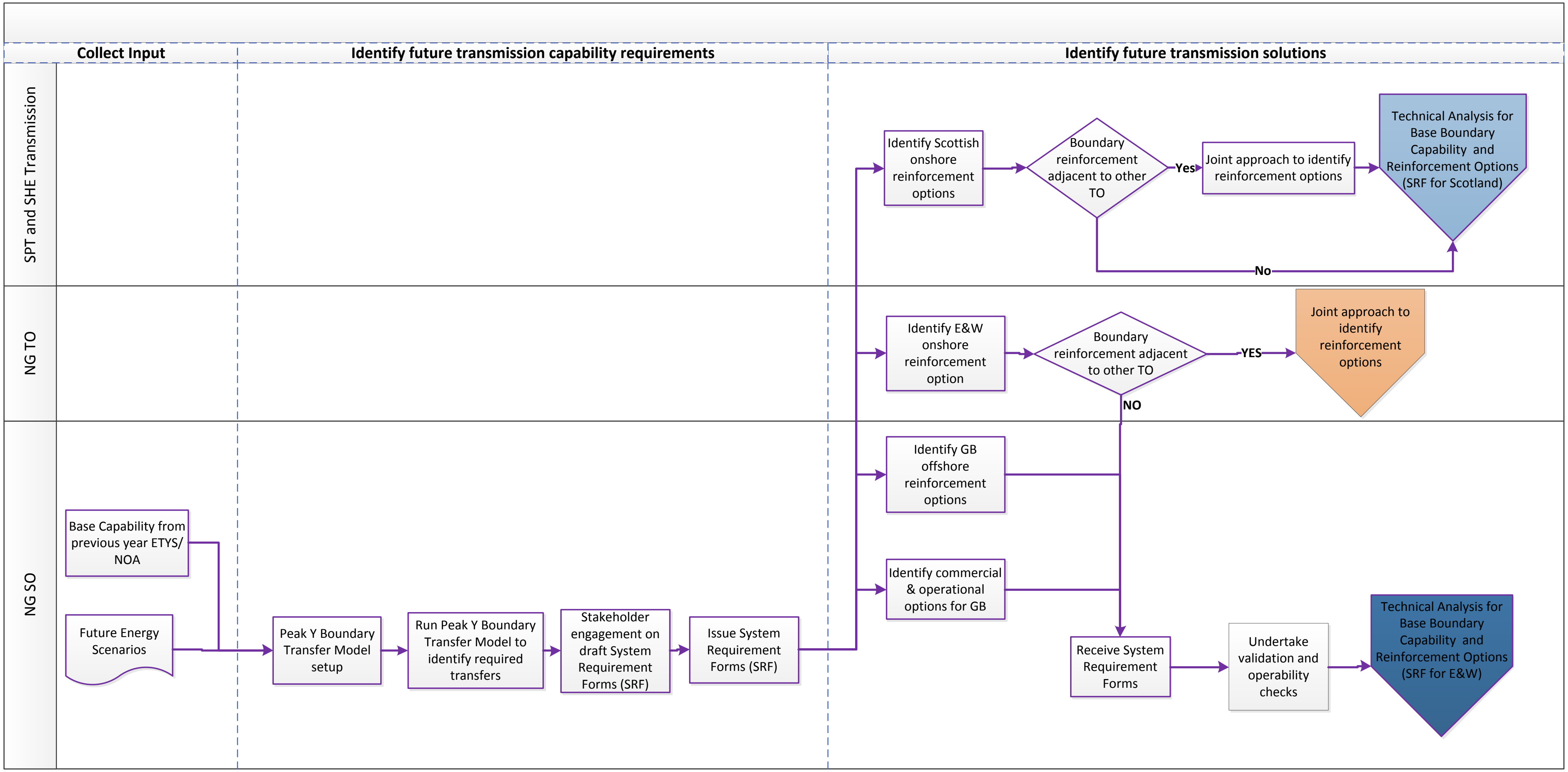
Appendix B: NOA Study Matrix

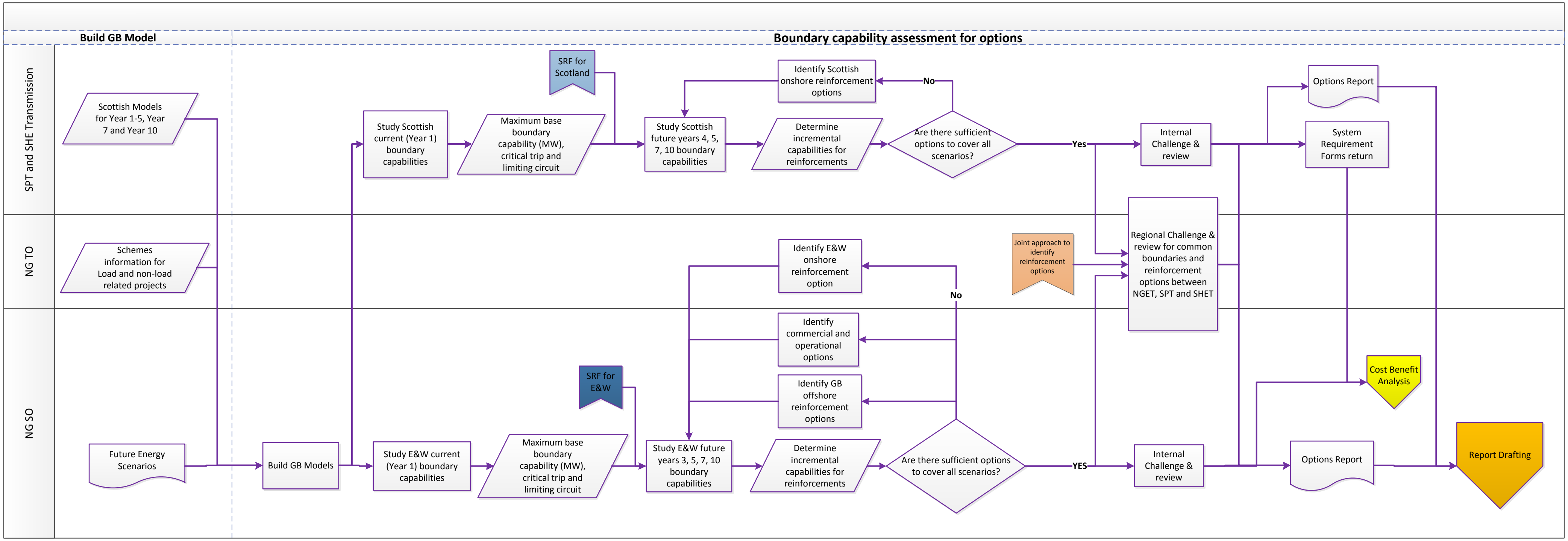
Assumption/Condition		Comments
Generation Scenarios	Gone Green	Technical and economic assessment of the reinforcement options; sensitivity studies where appropriate
	Slow Progression	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
	Consumer Power	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
	No Progression	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
Demand	Winter Peak	Technical and economic assessment of the reinforcement options
	Spring/Autumn	Economic assessment, boundary capabilities in NOA will 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	Economic assessment, boundary capabilities in NOA will 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	
	Alternative reduced-build reinforcements	Assessment of reduced-build reinforcement options
Study Years	Year 1	Assessment of reduced-build reinforcement options subject to availability
	Year 2	Assessment of reduced-build reinforcement options subject to availability
	Year 3	Assessment of reduced-build reinforcement options subject to availability
	Year 4	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 5	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 7	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 10	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement

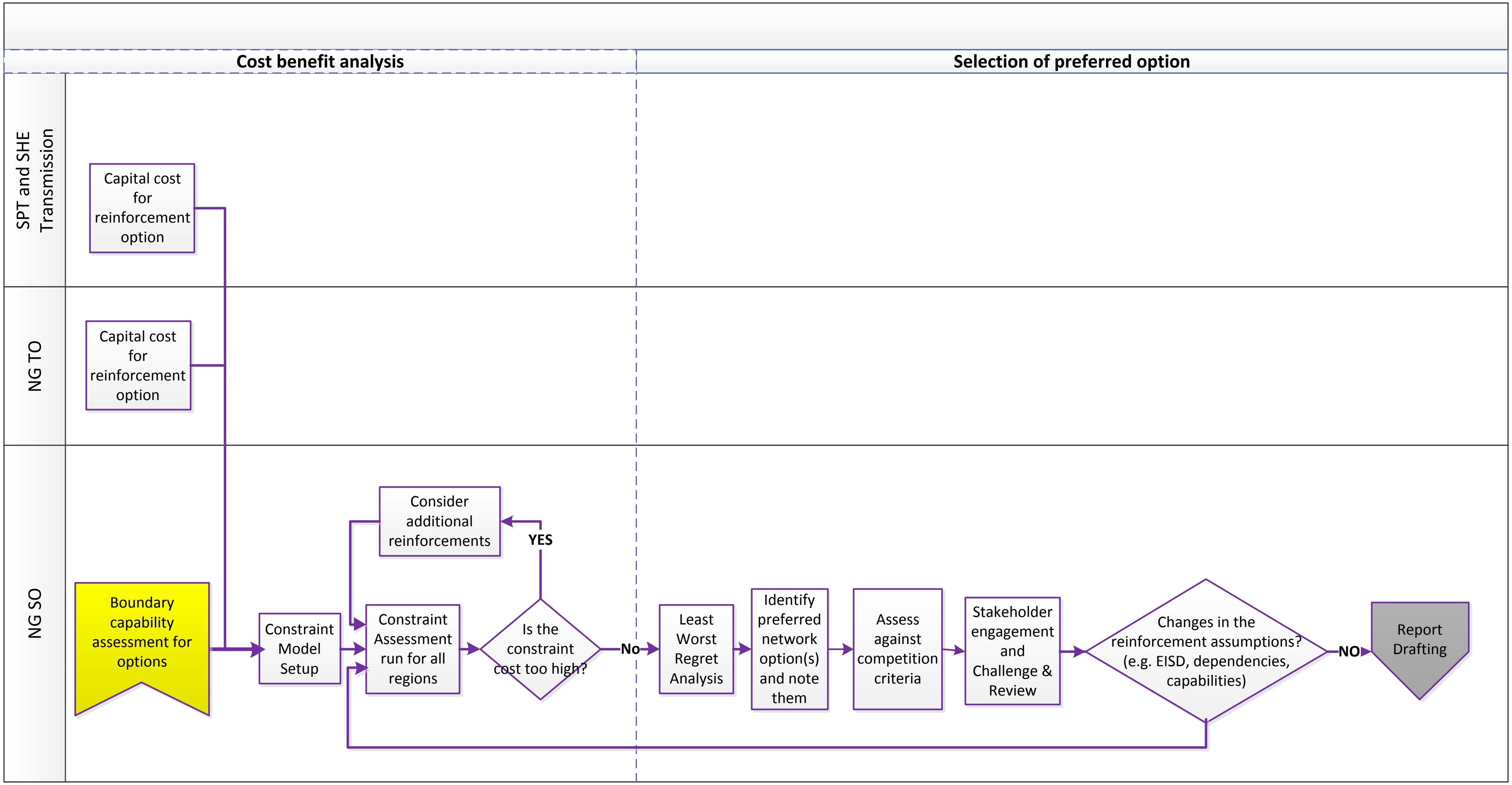
Appendix C: NOA Process Flow Diagram

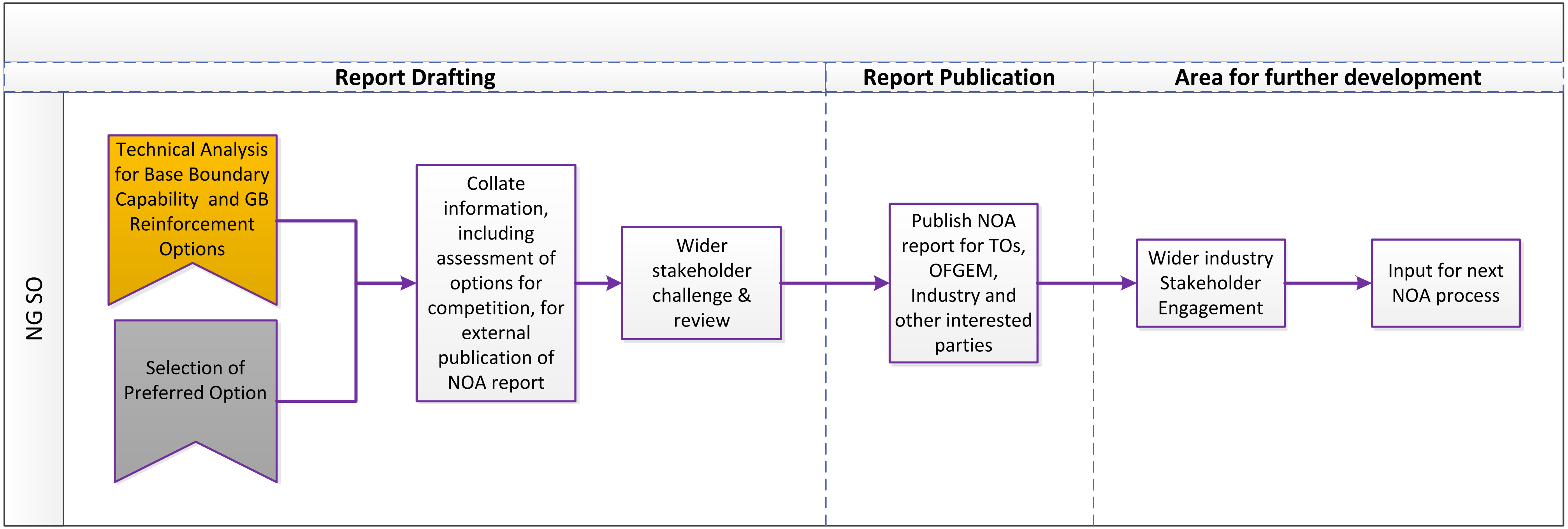


This diagram shows the overall NOA process. The text in each box corresponds to the descriptions of the stages at the top of the diagrams on the next pages. The process headings can also be found in the main methodology.


Collect Input
Identify future transmission capability requirements
Identify future transmission solutions
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
Study Scottish current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
SRF for Scotland
Study Scottish future years 4, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Identify Scottish onshore reinforcement options
Are there sufficient options to cover all scenarios?
No
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
No
Study E&W current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
SRF for E&W
Study E&W future years 3, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Are there sufficient options to cover all scenarios?
YES
Internal Challenge & review
Options Report
Cost Benefit Analysis
Report Drafting


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


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: Summary of Stakeholder feedback

This appendix summarises any views the SO has not accommodated in producing this NOA Report methodology

Appendix E: 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

Executive Summary

Contents Page

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.

The chapter will give stakeholders an overview of options to meet electricity transmission system reinforcement needs and the SO's view of the preferred options. It will reiterate that the final investment decision rests with the TO.

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 Reinforcements. 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 Chapter 3 Network Capacity and Requirements 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 in the main methodology) and a general overview. The description will also identify each option as build or reduced-build 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.

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 – that is needing a decision to proceed 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 outline the criteria once they are agreed for assessing whether recommended options will be proposed for competition. The chapter will then compare the options against the competition criteria and indicate those that are likely to meet the 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.

Chapter 5 will meet the SO obligation to produce the Network Development Policy output for Incremental Wider Works.

Chapter 6: Interconnection Analysis

This section of the report will detail the method of analysing GB's potential for interconnection.

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 spring 2016 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