RIIO T1

Network Development Policy

National Grid
Electricity Transmission

July 2017

Target audience

All stakeholders

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About this document

This document contains NGET's Network Development Policy and process. This clarifies for stakeholders how NGET makes decisions about the reinforcement of wider transmission system boundaries during the RIIO-T1 Price Control period, including decisions about anticipating customer requirements for transmission capability. These decisions cover the choice and timing of both the pre-construction and construction phases for all wider transmission reinforcements.

Network Development Policy

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Introduction

Objectives

1 This document is written with NGET as one legal entity and has references to the SO and TO based on their current responsibilities.

2 The objective of the Network Development Policy (NDP) is to make decisions for Incremental Wider Works (IWW) outputs to proceed, not start or to delay, all in an economic, efficient and coordinated manner. The NDP's analysis is conducted annually so that IWW options are reviewed for the coming year including those options that have started already. The analysis might conclude that stopping the work is the best option. The analysis takes account of the lead times to deliver IWW options. This means that in any given year some options might not yet need decisions whether to proceed.

3 The NDP determines the scope of transmission solutions by setting the wider works requirements that solutions are to meet. The future energy scenarios form the basis of the boundary transfer requirements and hence the wider works requirements. The SO assesses the associated congestion costs along with the investment costs of the solutions in an economic analysis as part of the NOA process. The TO uses the NOA output to make investment decisions to ensure that the transmission part of the industry provides the best value outcome for existing and future consumers.

Background

4 The most significant uncertainty facing the transmission network during the RIIO-T1 period is the quantity, type and location of the connected generation and the extent and location of new interconnection to other systems.

5 This problem is compounded by circumstances in which the lead-time for reinforcement of the wider transmission network is greater than the lead-time for the development of new generation projects.

6 In order to ensure that generation developers receive connection dates which are in line with their expectations, the connect and manage access arrangements have removed the contractual link between new generation connection dates and the completion of wider works, such that the connection of new generation is no longer reliant on the completion of wider works. New generation projects with short lead-times can now connect to the transmission system prior to the completion of the associated wider transmission system reinforcements[1].

7 To manage this situation, we need to balance the risks of investing too early in wider transmission reinforcements, which include the risk of inefficient financing costs and an increased stranding risk, with the risks of investing too late, which include inefficient congestion costs.

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[1] The only exception going forward being interconnector schemes which are made offers based on an 'invest then connect' basis.

8 Given this uncertainty, the decision process with which the preferred combination of transmission solutions is chosen needs to be well-structured and transparent. This allows stakeholders to understand why decisions to build, and not to build, have been taken.

9 We will continue to connect new generation projects as soon as possible, and a more transparent decision process around wider works gives stakeholders a clearer indication of which transmission projects are going ahead so that they can understand the overall impact on consumers and the power industry.

Key changes for 2017/18

10 Since the NDP was published in April 2013, the Integrated Transmission Planning and Regulation (ITPR) project led by Ofgem has resulted in the introduction of the Network Options Assessment (NOA) framework. The NOA process has a methodology that was derived from parts of the 2013 NDP. Changes to this NDP and NDP process have been made to ensure that there is alignment between the NOA and the NDP and to make clear where the NOA in England and Wales delivers parts of the output for the NDP. For this reason, parts of this revised NDP document refer directly to the NOA methodology. As mentioned earlier, the document is written with NGET as one legal entity with SO and TO references according to their current responsibilities.

Future Energy Scenarios

11 National Grid uses scenarios representing multiple views of the future. The total number of scenarios and their content is subject to change depending on stakeholder feedback received through the Future Energy Scenarios (FES) consultation process. In the event of any change, the rationale will be described and presented within the FES consultation report that is published each year.

12 The feedback the SO receives from our stakeholder engagement activities helps to shape our energy scenarios published in the current year. These in turn are used in the NOA and NDP processes.

13 It is inevitable that the scenarios will change over time and for this reason they are revised annually. These revisions take further stakeholder feedback into account. To facilitate this process, each published FES document is retained for comparison with subsequent years' scenarios.

14 The scenarios are based on a number of axioms that cover areas such as economic growth, fuel prices, volume of wind and nuclear, mix of coal/CCGT, possible future interconnectors, etc. These axioms are utilised to select a range of generation developments which then form the basis of the analysis required to determine the range of future transmission requirements.

15 However, transmission capability requirements are also sensitive to the location of demand and generation. For a number of the major boundaries (B6, B7, B8, etc), this sensitivity is relatively small but, for some of the smaller boundaries (NW3, EC5, etc), the future requirements are sensitive to relatively minor changes in assumptions. A discussion of how sensitivities are formulated is provided in the 'NDP policy' document (Appendix A) and the 'NDP process' document (Appendix B).

16 The detailed process for updating and consulting upon the FES is separate to the NDP process and is not covered in this document. More information on the FES can be found on the dedicated website www.nationalgrid.com/fes.

Structure of this document

Network Development Policy

17 The NDP gives the background and key component areas for the process that includes the following:

- An explanation of works types differentiating the wider works relevant to the NDP from the enabling works for connecting generation.
- How the uncertainty mechanism is used to categorise transmission solutions as strategic wider works or incremental wider works.
- Following the definition of boundary capability, there is an overview of the NOA process from the use of energy scenarios and their use in calculating boundary transfer requirements. It covers how transmission solutions are evaluated and decisions made and timings where appropriate.
- The selection of transmission solutions to include consideration of:

  a. Outputs from the NOA process;

  b. Projects with significant lead time risks;

  c. Generator and interconnector offers made on an 'invest then connect' basis;

  d. Wider work requirements as part of Nuclear Site Licence Provision Agreement (NSLPA) requirements.

- Treatment of boundary capability changes that have arisen from generation and demand changes as well as possible future changes in the security standards.

18 Our policy for making decisions about the choice and timing of wider transmission strategies is included as Appendix A.

Network Development Policy Process

19 The NDP process carries out the activities to meet the policy's requirements and the description in Appendix B includes:

- the tools used;
- our methodology for modelling constraints and benefits; and
- the decision-making process for selecting transmission solutions or strategies (defined as a logical set of inter-dependent solutions) to progress.

20 Where parts of the NDP have been adopted by the NOA process, the appendix refers to the relevant sections of the NOA methodology.

Appendix A: Network Development Policy

Introduction

A1. This document sets out how NGET makes decisions about the choice and timing of wider transmission network reinforcements such that the network continues to be planned in an economic and efficient manner. This involves making use of the available information to balance the risks of inefficient financing costs, stranding and inefficient congestion costs.

A2. The annual process to engage stakeholders on the key forecast data that is used in this decision making process is also described.

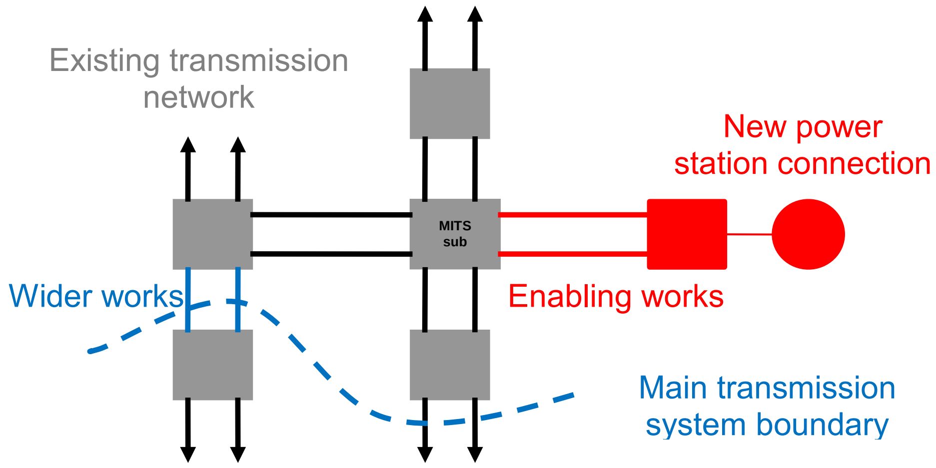
Scope

A3. The transmission reinforcement works required to accommodate new generation connections can be divided into enabling and wider works. In simple terms, the enabling works are those works that are required to connect a new generation project to the wider transmission network. This is likely to include local substation and overhead line works, but may also include other works which are more remote from the new connection to ensure the network remains safe, such as reinforcements to increase substation short-circuit rating, to ensure the stability of the network, or to ensure that there is no overloading of network assets prior to the consideration of faults or outages.

A4. Wider works are those works required to reinforce the main boundaries on the transmission network. On large transmission network boundaries (e.g. the North to Midlands boundary, B8) these works are more likely to be triggered by the combination of a number of generation connections and changes to the pattern of transmission demand rather than by individual projects. On more regional boundaries, wider works can still be triggered by the connection of particular dominant projects (e.g. the connection of a large offshore windfarm or new nuclear power station).

A5. Figure A1 below illustrates the distinction between enabling and wider works. The reinforcement works shown in red between the new generation connection and the nearest Main Interconnected Transmission System (MITS) substation are the enabling works for this connection. The reinforcement works shown in blue across the main North-South wider transmission system boundary are the wider works.

Figure A1: Enabling and Wider Works



A6. This document describes the decision making process for wider transmission reinforcement works only. Enabling works will continue to be identified during the generation connection application process.

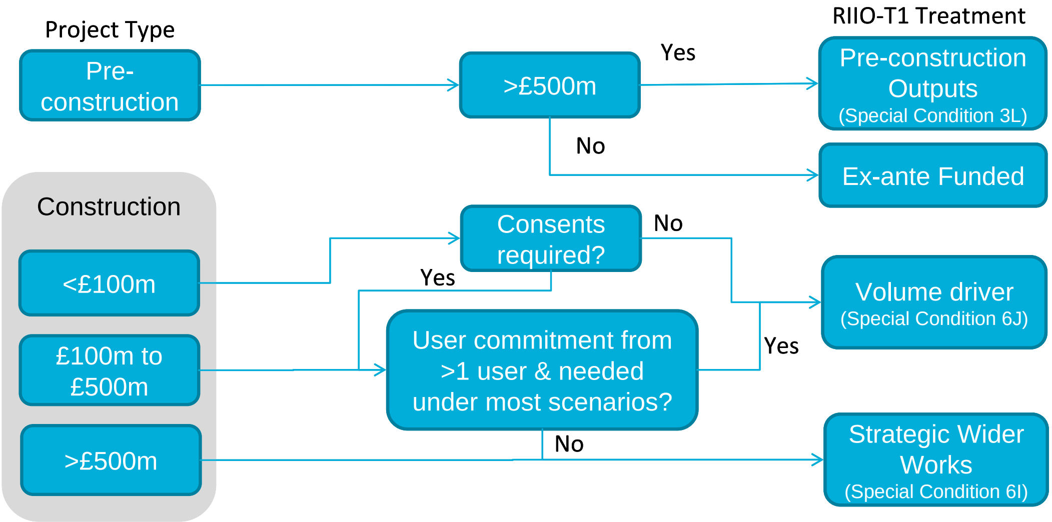
A7. In assessing existing or new wider reinforcement projects with outputs planning for beyond the RIIO-T1 period, the SO assumes that the NDP methodology continues into the future.

Interaction with RIIO-T1 uncertainty mechanisms

A8. The NDP applies to all wider works boundaries and associated transmission solutions in England and Wales.

A9. Each transmission solution that is to be progressed needs to be considered against the RIIO-T1 mechanisms. This assessment is summarised in Figure A2 below. The costs shown in the figure are the relevant total project costs (e.g. the pre-construction works associated with projects with a total project cost greater than £500m in 2009/10 prices are treated by Special Condition 3L).

Figure A2: Project types and RIIO-T1 mechanisms



A10. Where the NDP decision is to complete pre-construction works and the project has a total forecast cost which is less than £500m (in 2009/10 prices), this will be progressed. Those projects with a forecast cost of more than £500m (in 2009/10 prices) will be progressed in line with the associated process as defined in Special Condition 3L‘ Pre-construction Engineering Outputs for prospective Strategic Wider Works’) of our Licence.

A11. Where the NDP decision is to progress a project with a forecast cost which is more than £500m (in 2009/10 prices), the investment follows the Strategic Wider Works (SWW) process[2] as defined in Special Condition 6I (Specification of Baseline Wider Works Outputs and Strategic Wider Works Outputs and Assessment of Allowed Expenditure) of our Licence.

A12. Where the NDP decision is to progress a transmission solution with a forecast cost of less than £100m (in 2009/10 prices) that does not require planning consent, allowances will automatically be adjusted by multiplication of the change in boundary capability delivered by the solution and the relevant boundary Unit Cost Allowance as defined in Special Condition 6J (Allowed Expenditure for Incremental Wider Works) of NGET’s Transmission Licence.

A13. For NDP decisions to progress all other transmission solutions less than £500m (in 2009/10 prices), the potential allowance is calculated in line with Special Condition 6J if both of the following conditions are met:

- there is a positive cost benefit against a majority of the scenarios and sensitivities considered; and
- the transmission solution is supported by user commitment from more than one customer.

A14. If the transmission solution does not meet these criteria, funding associated with progression of the solution will be subject to Special Condition 6I (the SWW process).

Scenario data

A15. Generation and demand data is established following a stakeholder engagement process. The SO consults widely with the industry on our scenarios on an annual basis.

A16. This data includes a number of self-consistent demand and generation scenarios together with other key data necessary to facilitate cost benefit analysis. The cycle starts with the publication of our Future Energy Scenarios (FES) document.

A17. These scenarios are developed to give a broad range of potential outcomes. It is important to recognise that these are scenarios and not forecasts. It is possible to prepare forecasts for the next few years in stable market conditions but unforeseen events, such as a recession or the introduction of

[2] The same process and principles outlined in the NDP apply in developing SWW projects.

new government initiatives, makes forecasting several years ahead increasingly difficult.

A18. When developing the scenarios, the SO considers a number of key axioms that underpin these scenarios (at a broad energy level) and will vary across them, providing a wide range of possible outcomes. These axioms cover areas such as energy targets, economic growth, access to finance, fuel prices, energy efficiency improvements, new power generation developments for all fuel types and new technologies.

A19. From a power generation perspective, the SO also considers the factors listed below. This is by no means an exhaustive list but indicates some of the key areas for consideration.

- Development of renewable generation;
- Generation required to maintain an adequate plant margin for security of supply;
- Environmental legislation;
- Planning consents;
- Signed connection agreements; and
- Electricity demand growth.

A20. Stakeholders are consulted on the FES and can respond through targeted questionnaires, bi-lateral meetings, open sessions and workshops. The feedback the SO receives from stakeholders feeds into the production of future scenarios.

A21. There are other factors which are required to facilitate the completion of cost-benefit analysis. The SO obtains this data by undertaking a statistical analysis of historical data, that includes:

- Network availability data;
- Generation availability data;
- Demand duration curves; and
- Generation prices, including balancing mechanism bid and offer prices.

A22. To further improve stakeholder engagement, the SO publishes these data through appropriate means such as our external website.

Sensitivities

A23. In addition to the main scenarios, sensitivities are used to enrich the analysis for particular boundaries. This ensures that issues such as the sensitivity of boundary capability to the connection of particular generation projects are adequately addressed.

A24. In developing sensitivities, the SO uses feedback obtained from stakeholders sought through the FES consultation process to consider regional variations in generation connections and anticipated demand levels that still meet the scenario objectives. The SO with the TO's support explores sensitivities that are consistent with the local contracted background in addition to those that have no new local generation connections.

Definition of boundary capability

A25. Boundary capability is defined as the power flow across specific transmission circuits that can be accommodated following the most onerous secured event without overloading transmission equipment and ensuring adequate voltage performance and stability margins. A secured event is defined as an event causing the disconnection of one, or several, transmission circuits from the congruous transmission network and is specified in chapter four of the security standards[3] as follows:

- a single transmission circuit, a reactive compensator or other reactive power provider;
- a double circuit overhead line;
- a section of busbar or mesh corner; or
- any single transmission circuit with the prior outage of another transmission circuit, or a generating unit or reactive compensator.

A26. The security standards include a set of transparent rules for setting up the analysis models that are used to determine boundary capability.

A27. The boundary capability will be calculated with the network set to the peak demand condition with the generation and demand on either side of the boundary flexed to achieve different transfers. In addition, it is necessary to consider off-peak conditions for stability assessments and for some boundaries where the impact of interconnectors or local generation is significant.

Identify future transmission capability requirements

National generation and demand scenarios

A28. For every boundary, the future capability required under each scenario and sensitivity is calculated by the application of the security standards. The network at peak system demand is used to outline the minimum required transmission capability required to meet both the Security and Economy criteria.

[3] Security Standards – This refers to NET SQSS version 2.3 - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=38033

A29. There are a number of other security standard criteria which have to be considered to ensure the development of an economic and efficient transmission system. Beyond the criteria mentioned 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.

Identification of transmission solutions

A30. Where the analysis described above identifies a deficit of transmission capability across a particular boundary, a range of suitable solutions will be identified to address the deficit. The solutions identified are driven in part by the nature of the capability shortfall (i.e. a thermal, voltage or transient stability issue).

A31. The TO develops investment transmission solutions and supports the SO with operational and commercial solutions. The investment solutions are generally considered in cost order. For a deficit in thermal capability, for example, relatively inexpensive solutions such as circuit reconfiguration or thermal uprating[4] of circuits are considered and only if they are insufficient to address the deficit are other, more expensive solutions such as quadrature boosters, reconductoring of existing circuits or new circuits considered.

A32. It is essential that the range of solutions identified is sufficiently wide and includes, for example, both small-scale reinforcements with short lead-times and larger-scale alternatives reinforcements which are likely to have longer lead-times. Transmission solutions that do not provide sufficient capability to satisfy the security standard criteria are not discarded as they may, in combination with other solutions, still form part of the lowest cost transmission strategy.

A33. For each of the wider transmission solutions, the TO provides key information to the SO using the System Requirements Form (SRF) in the NOA process. This information provides:

(a) A technical description of the option so that the SO can calculate the boundary capability improvements.

(b) The earliest in service date of the option as well as any outage requirements. This allows the SO to calculate the optimum timing of the option's delivery against constraint costs.

(c) The forecast cost, cancellation costs and spend profile.

[4] Thermal uprating refers to operating existing overhead line circuits at higher temperatures to achieve higher thermal ratings. Operating at higher temperatures may require minor works, for example, the retensioning of particular spans to ensure safety clearances.

Recommendations from the NOA process

A34. All the possible solutions are compared on the basis of the present value of build costs, congestion costs and transmission losses. Congestion costs based on the short marginal cost of generation and balancing mechanism observations are considered.

A35. This analysis is consistent with the paper by the Joint Regulators Group (JRG) “Discounting for CBAs involving private investment, but public benefit”. The cost of transmission reinforcements will be annuitised at the post-tax weighted average cost of capital. This will then be added to the constraint and losses costs in each year, and the totals will be discounted at the Treasury’s social time preference rate[5].

A36. As the sums that are likely to be invested are very large, lead times are long, and the benefit of some of the investments necessarily uncertain, the dimensions of risk and timing are crucial. The SO does not therefore make recommendations based on a conventional cost-benefit analysis, and instead make use of a framework that allows us to take account of optimal timing and risk-adjusted values of any investments made.

A37. The fundamental trade-off is between:

- The risk of undertaking an investment that turns out to have been too early or unnecessary; and
- The risk of high congestion costs because network assets that turn out to have been needed are not yet available.

A38. Consequently, the question of timing is crucial. By waiting, information will be revealed (for example, from the management of the connection application process) that might confirm the need case for a given piece of infrastructure increasing the expected value of that investment and reducing (or eliminating) the risk of asset stranding. On the other hand, because of the long lead-times of investments, waiting too long could significantly increase the risk of very high congestion costs arising in some future scenarios.

A39. The optimum combination of transmission solutions for each of the demand and generation scenarios and sensitivities will be established. This is achieved with the application of detailed cost-benefit analysis.

A40. It should be noted that the options may include transmission solutions which are not included in the optimum combination of solutions for any of the individual demand and generation scenarios and sensitivities. For example, incremental solutions which delay commitment decisions for large reinforcements may be included.

A41. The SO identifies the discounted investment costs and the expected congestion and transmission losses costs associated with each of these options and their combinations for each of our future scenarios and

[5] The Social Time Preference Rate (STPR) used for the 2017 analysis is 3.5%

sensitivities. It then calculates the regrets associated with each of the options (where regrets are the cost of the option minus the cost of the optimum strategy for that scenario or sensitivity). This provides a picture of the risks and benefits of all possible options under a broad range of future scenarios and sensitivities.

A42. The investment options or their combinations which are most advantageous are recommended by the SO as a result of the NOA process based on the least regret decision approach. It has particular focus on schemes that need to be progressed in the following financial year. While this analysis produces recommendations that in principle cover the entire RIIO-T1 period, the SO repeats the analysis annually. Based on the evolution of generation and demand during the RIIO-T1 period, the SO might therefore recommend to bring forward some investments and delay others, relative to the plan with which the TO began. The SO might also recommend cancelling a project where work has begun, should the anticipated need for that investment strategy not materialise.

Selection and timing of transmission solutions

A43. The TO updates its wider works programme after evaluating new information and outputs from the NOA process in order to ensure best value for GB consumers. The TO makes its investment decisions taking into account the NOA process's recommendations and its own investment process. A transmission solution goes through a series of stage gates where the TO evaluates:

- The progress to date;
- Designing the solution in greater detail; and
- Timing factors that might be affected by supplier contracts and arrangements.

A44. There are a number of additional issues that the TO considers alongside the results of the least regret analysis:

- Generator connection agreements based on an 'invest then connect' approach;
- Wider work identified as part of Nuclear Site Licence Provisions Agreement (NSLPA) requirements;
- Any other issues that can reasonably be justified by the TO.

Generator connection agreements based on an "Invest then connect" approach

A45. The 'connect and manage' access arrangements do not apply to interconnectors. If an interconnector applies for a connection, they are provided with an "invest then connect" connection offer, in which the connection is made contingent upon the completion of all identified transmission reinforcement works, including wider works.

Wider work identified as part of NSLPA requirements

A46. Although the transmission connections to a nuclear power station are primarily used to export power into the system, they are also used to provide secure supplies to essential electrical auxiliary equipment and as such are crucial to the nuclear safety case.

A47. The NSLPA is used to manage the nuclear safety case between nuclear sites and the relevant transmission owner. It includes provisions for information exchange, network risk incident assessment and a review of the anticipated connection design. All nuclear connection agreements are made conditional upon the outcome of the NSLPA process.

A48. Work that is identified with direct material impact as part of the NSLPA process would therefore need to be progressed in timescales consistent with the contracted connection date.

Treatment of ‘invest then connect’ and NSLPA requirements

A49. The NDP analysis may conclude that reinforcements that are required as part of an “invest then connect” agreement or the NSLPA arrangements are not part of the “least regret” investment strategy.

A50. In these circumstances, the NDP conclusions will be updated to include decisions to progress these works in accordance with the contracted timescales, together with an explanation of why they are required.

Treatment of projects that are cancelled or delayed

A51. To avoid a perverse incentive to complete works under this process regardless of stakeholder benefit, it is necessary to be able to recover costs in the event that changing backgrounds mean that the efficient course of action is to abandon a reinforcement (such that the revenue driver is never triggered). Efficient spend up to the time of cancellation is considered as funded as this was economic (the least regret course of action) given what was known at the time of commitment. The TO endeavours to re-use equipment on other projects in order to minimise the cost to be written off. If a project is delayed such that the output is delivered beyond the RIIO-T1 period, the SO continues to assess that project by assuming that the NDP methodology still applies into the future.

Outputs

A52. NGET produces a reinforcement profile that covers the onshore England and Wales transmission system. This will record the transmission solutions considered and the assumptions made in selecting preferred transmission solutions. Works being triggered for delivery in the following year will be identified, and the timescales for longer-term investment strategies are recorded.

A53. The SO shares its NOA process outputs on incremental wider works and commercial solutions, such as Commercial Services, with stakeholders through the NOA feedback process. This provides stakeholders with an opportunity to challenge the NOA process outputs and suggest alternatives in order to enrich the analysis undertaken for NOA/NDP in the next annual cycle.

A54. The key points from these options are published in the NOA and facilitate stakeholder engagement.

A55. The TO publishes a document describing the selected options taking account of the NOA process's recommendations and in accordance with the TO's internal investment assessment process. The TO publishes the document annually by 30 June [to be discussed] each year. The TO publishes the document for stakeholders on the public website and provides paper copies on request.

Review of NDP performance

A56. Each year's FES, operational cost forecasting model, ETYS and NOA is retained to support a retrospective review of the NOA process and hence NDP performance. The outputs contained within the scenarios are tracked and reviewed as part of the FES process.

A57. When the annual NDP process has completed, the TO compares the outcomes with those from previous years. Where the selected transmission solutions have altered significantly, the reasons for change are analysed.

A58. The advantage of the year-by-year approach to least regret analysis is that any changes to the scenarios and sensitivities between years are always included. The potential disadvantage is that some of the forecast information about how scenarios and sensitivities diverge over time is ignored, which could lead to sub-optimal solutions being chosen (if the scenarios and sensitivities turnout to be accurate). The SO and the TO keep this approach under review as they collect more information about the accuracy of the scenarios and sensitivities and the effectiveness of the NOA and NDP processes.

Boundary capability changes

A59. Boundary capabilities can change over time due to:

- Variation between forecast and actual generation and demand background (including interconnector flows);
- Amendments to the security standards adopted.

Generation and demand background changes

A60. For a given boundary, the power flow across the boundary circuits is dependent upon the difference between the generation and demand volumes behind the boundary. However, the loading of the boundary circuits can also vary with the location of the generation and demand.

A61. These locational variations result in a different sharing of the power transfer between the circuits that cross the boundary, and can therefore increase the share on the circuits that limit the boundary capability resulting in a lower overall boundary capability. In addition, limitations that are caused by either voltage performance or stability margins can vary depending on the location and type of generator and demand. For example, in the case of generator stability margins, the type[6] of generation as well as the electrical impedance of the network as seen from the generator end determines the stability performance of the generator in question.

Application of security standards

A62. The security standards are kept under continuous review by the SO, all Transmission Owners and other stakeholders and changes are proposed when, in the opinion of the proposer, the revision would mean that the security standards better met their objectives. The objectives are to:

a. facilitate the planning, development and maintenance of an efficient, coordinated and economical system of electricity transmission, and the operation of that system in an efficient, economic and coordinated manner;

b. ensure an appropriate level of security and quality of supply and safe operation of the National Electricity Transmission System;

c. facilitate effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the distribution of electricity; and

d. facilitate electricity Transmission Licensees to comply with their obligations under EU law.

A63. It is therefore possible for the security standards to change and for this change to impact boundary capability.

Boundary capability changes and the NDP

A64. Changes to boundary capabilities can affect:

a. the forecast of boundary capability for the RIIO-T1 period;

b. the increase in boundary capability delivered by a transmission reinforcement.

Dealing with changes to the forecast boundary capability

A65. As described above, the boundary capability is reforecast as a part of each annual iteration of the ETYS/NOA/NDP analysis. The reasons for any

[6] Generation types refer to synchronous/ asynchronous generation with different mechanical properties (inertia constants) and different control system models

material differences between the latest forecast and the previous forecast are assessed and reported to stakeholders.

A66. The latest view of the boundary capability also forms part of the NDP analysis. This means both that an unexpected increase in boundary capability may lead to the deferral or cancellation of a transmission reinforcement, and that an unexpected decrease in boundary capability may lead to the advancement or inclusion of a reinforcement.

Dealing with changes to the incremental capability delivered by reinforcements

A67. Upon completion of each reinforcement, on behalf of the TO the SO calculates the actual boundary capability delivered by the reinforcement in the year of commissioning. The reasons for material differences between forecast and actual boundary capability increases are assessed and reported to stakeholders.

A68. Where differences have occurred between the decision to proceed with the reinforcement and commissioning, and these differences are caused by unexpected generation and demand background changes or changes to security standards, the conclusion of the NDP is the original incremental boundary capability for the purposes of the operation of the incremental wider works uncertainty mechanism described in Special Condition 6J of the Transmission Licence. This means that NGET TO and consumers will be protected from any windfall gains or losses associated with these changes.

Appendix B: Network Development Policy Process

Introduction

B1. The Network Development Policy (NDP) defines how we will assess the need to progress wider transmission system solutions to meet the requirements of our customers in an economic and efficient manner. The NDP uses the NOA analysis process to generate part of its outputs.

B2. This document sets out the annual process by which the NDP is applied to the onshore electricity transmission system in England and Wales. There are a number of major steps that run from identifying a future need for reinforcement, through considering all available solutions to provide the incremental network capability, to selecting and documenting the preferred solution for delivery.

B3. This annual process is used to review and update decisions as additional information is gained, for example in response to changing customer requirements or via the feedback from stakeholder engagement. The NDP provides a plan for the following year to drive the timely progression of investment in wider works. The SO engages stakeholders on annual updates to the key forecast data (as part of FES) used in this decision-making process, and shares the outputs from this process with our stakeholders through the publication of the NOA and annual review of the NOA methodology.

Inputs

Updated Future Energy Scenarios

B4. The Future Energy Scenarios are used in the inputs to the NOA process that provides the necessary outputs for the NDP. Below is an extract of the relevant sections from the NOA methodology relating to the use of 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) . The scenario demands are then adjusted to match the metered average cold spell (ACS) 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.

Sensitivities

B5. Sensitivities are used in the NOA process that provides outputs for the NDP. Below is an extract of the relevant sections from the NOA methodology relating to 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.

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

B6. 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 impact of these amendments will also be considered as part of this process.

Existing network capability

B7. The boundary capability that is identified is the lowest of the thermal, voltage and stability capability. Each of these capabilities is identified at the peak and, where appropriate, at relevant points of the year so that off-peak capabilities are considered during the NDP process. In reporting the boundary capability each year, only the most restrictive of the capability values is published and the criteria for its definition provided in any accompanying narrative.

B8. The reporting of the boundary capability each year includes an explanation of any material differences from the previous year.

B9. Table B1 shows the possible network configuration options for studies that would be required to determine the limiting factor for any particular boundary. Where the limitation in the boundary capability for a boundary moves from one set of analysis to another, the reason for this will be clearly identified, whether it is as a consequence of a specific change to the generation background or the completion of a network solution.

Table B1: Possible network configuration options

Option	Boundary type	Seasonal conditions	Scenario	Boundary cap identified	Secured event
A	Wider	Winter peak	Baseline	Thermal / Voltage	N-2
B	Wider	Off-peak	Baseline	Thermal / Voltage	N-2
C	Wider	Summer minimum	Baseline and generation sensitivities	Stability	N-2 (second main protection)
D	Local	Summer minimum	Local maximum generation, minimum demand	Thermal / Voltage	N-2
E	Local	Summer minimum	Local maximum generation, minimum demand	Stability	N-2 (second main protection)

B10. The majority of wider boundaries that are assessed fall within the boundary capability defined in option A, whilst the majority of local boundaries are defined by option D. Alternative capabilities may be necessary for specific reasons, for example, the wider B6 boundary between Scotland and England is limited by the stability capability of the network (as studied by option C, above) whilst the local boundary EC5 (East Coast) would be limited by the stability capability of the network (as studied by option E above) following the reconductoring of some local circuits removing an existing thermal restriction. In all cases, the appropriate seasonal and cyclic rating of circuits is employed.

B11. The above network configurations provide the baseline boundary conditions which 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 are 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.

Identify future transmission capability requirements

National generation and demand scenarios

B12. In the NOA process, the SO identifies the future transmission capability requirements. This process is needed to create the NDP outputs. Below is an extract of the relevant sections from the NOA methodology.

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 . 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 future transmission solutions

B13. In response to the requirements that the SO has identified, the TO provides options as part of the NOA process. Below are extracts of the relevant sections from the NOA methodology in the next two boxes.

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
- 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.

2.36 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 1.2: 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)*	✓	✓	✓	
Alternative Options	Operational Options	Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
Alternative Options	Operational Options	Reactive demand reduction *(this could ease voltage constraints)*		✓		
Alternative Options	Operational Options	Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
Alternative Options	Operational Options	Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
Alternative Options	Operational Options	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*	✓	✓		
Alternative Options	Reduced-build Options	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
Alternative Options	Reduced-build Options	Automatic switching schemes for alternative running arrangements *(automatic schemes that open or close selected circuit breakers to reconfigure substations on a planned basis for recognised faults)*	✓	✓	✓	✓
Alternative Options	Reduced-build Options	Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
Alternative Options	Reduced-build Options	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)*		✓	✓	
Alternative Options	Reduced-build Options	Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
Alternative Options	Reduced-build Options	HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	

	Thermal uprating ('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.

B14. In developing this range of solutions, the TO also considers the replacement priority of existing transmission assets and alignment with asset replacement programmes. If an asset is going to be replaced for condition reasons in the relevant timescales, then the marginal cost associated with rating enhancement (rather than the full cost of replacement and enhancement) will be calculated and recorded for the purposes of the application of the NDP.

B15. As part of the NOA process, the factors shown in Table B2 below will be identified for each transmission solution to provide a consistent basis on which to perform cost-benefit analysis at the next stage. Note that this table appears as Table 2.3 in the NOA methodology.

Table B2: Transmission solution factors

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.

<table>
<tr><td>Cost</td><td colspan="3">The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases. The cancellation cost is also provided.</td></tr>
<tr><td rowspan="9">Stage</td><td colspan="3">The progress of the transmission solution through the development and delivery process. The stages are as follows:</td></tr>
<tr><td colspan="3">Project not started</td></tr>
<tr><td rowspan="5">Pre-construction</td><td>Scoping</td><td>Identification of broad need case and consideration of number of design and reinforcement options to solve boundary constraint issues.</td></tr>
<tr><td>Optioneering and consenting started</td><td>The need case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified.</td></tr>
<tr><td>Design/ development and consenting</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process including stakeholder engagement.</td></tr>
<tr><td>Planning / consenting</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process.</td></tr>
<tr><td>Consents approved</td><td>Consents obtained but construction has not started</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction.</td></tr>
</table>

B16. In order to assess the lead-time risk described in Table B2, the SO will consider, for a project with significant consents and deliverability risks, both 'best view' and 'worst case' lead-times submitted by the TO to establish the least regret for each likely project lead-time.

B17. Table B3 below is an example of a list of transmission solutions developed for consideration across a specific boundary.

Table B3: Example list of transmission solutions

Transmission solutions	Incremental boundary capability (MW)	Lead time (comm. year)	Pre-construction cost (£m)	Construction cost (£m)	Stage
A	1000	2021	1	80	Design
B	2000	2023	10	200	Planning
C	800	2019	3	90	Scoping
D	700	2021	2	80	Optioneering

E	400	2019	3	40	Construction
F	600	2022	2	120	Scoping

B18. 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 developments alongside any updates to known transmission solutions, the scenarios or commercial assumptions.

Estimate lifetime costs for transmission solutions

B19. Following identification of the range of possible network solutions, the next step is to determine the total lifetime costs associated with each transmission solution against each of the scenarios. The quantitative analysis is limited to the investment and operational costs. The SO expects the operational cost to include the carbon cost[7].

B20. The SO uses the BID3 model supplied by Poyry to determine forecast constraint costs and transmission losses for transmission solutions against the agreed set of scenarios and sensitivities.

B21. The model requires the inputs for existing boundary capabilities and their future development to be calculated in a separate technical analysis package and neither their dependence on generation and demand nor the power sharing across circuits is modelled. The model is a simplification of a complex analysis tool with several limitations on constraint forecasting, including:

- Limited representation of generation dynamic performance;
- Limited number of samples used for generator availability modelling;
- Assumes ideal curtailment of demand and immediate restoration;
- Simplified modelling of network availability (maintenance outages considered but construction outages neglected).

B22. The key assumptions within the BID3 model are shown in Table B4 below.

Table B4: Key assumptions within BID3

Assumption	Validation of assumption
Generation and demand backgrounds	Consulted on through the FES process

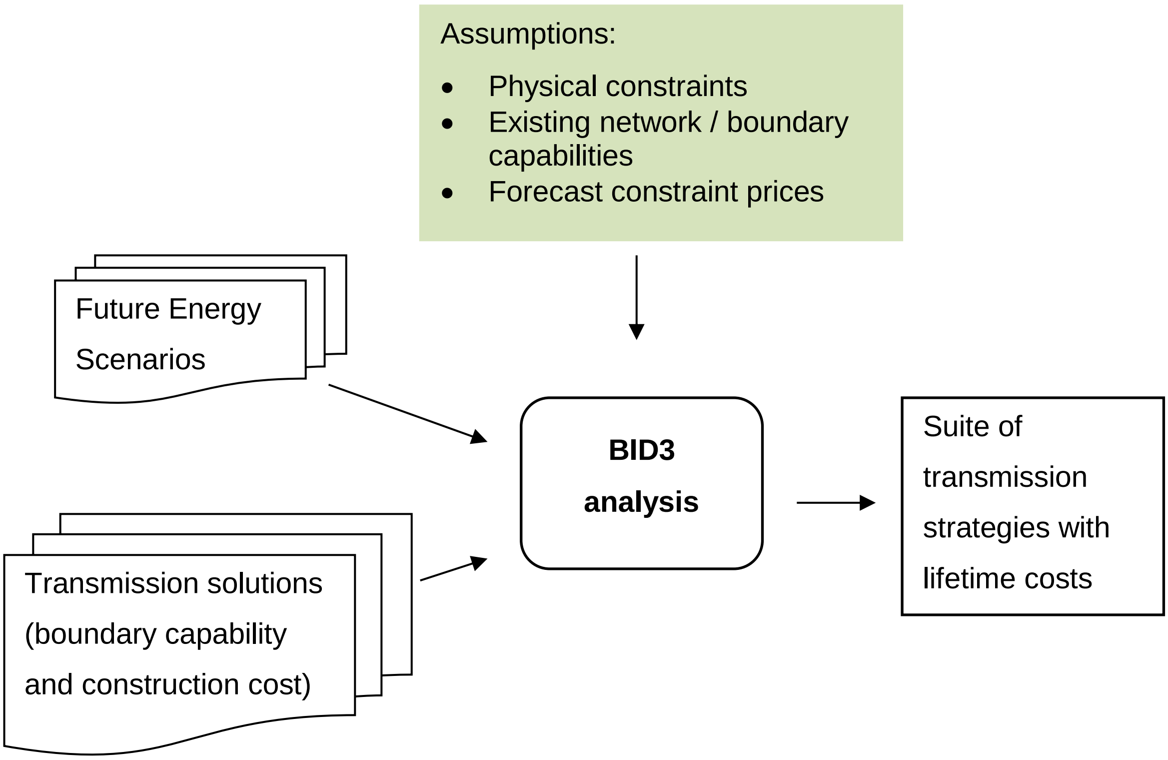
[7] BID3 calculations of constraints are based on the historical costs experienced through the balancing mechanism which is expected to include the cost of carbon

Assumption	Validation of assumption
Network capabilities	Calculated using power system analysis package and reported within ETYS & RRP
Cost profile and lead times of reinforcements	National Grid investment process as described above
Forecast constraint prices	Balancing market costs and Short-Run Marginal Costs (SRMC)

B23. These key assumptions are reviewed annually and any significant changes are identified and presented through the FES consultation and Regulatory Reporting Pack (RRP). The output of the BID3 analysis is the cost of different transmission solutions.

B24. The full lifetime cost analysis includes forecast transmission investment costs, constraint costs (based on the prices observed in the Balancing Mechanism). This analysis is consistent with the paper by the Joint Regulators Group (JRG) “Discounting for CBAs involving private investment, but public benefit”. The cost of transmission reinforcements is annuitised at the post-tax weighted average cost of capital. This is then added to the constraint and losses costs in each year, and the totals are discounted at the Treasury’s social time preference rate.

Figure B1: BID3 inputs, assumptions and outputs



B25. BID3 uses the more detailed energy scenarios to complete this analysis out to 20 years ahead. Then, in order to estimate full lifetime costs, the values from the final year of modelling are duplicated to give 40 years of data.

B26. Lifetime cost analysis is undertaken against various different transmission strategies (combinations and timings of transmission solutions) until the lowest costs are found for each of the scenarios and sensitivities. The first stage of this process involves the application of engineering judgement to combinations and timings of transmission solutions based on the capability deficits calculated through the application of the security standards and the capabilities delivered by each of the transmission solutions. The results from this first stage allow finer adjustments in choice and timing to be made to finalise the selected strategy.

Treatment of Interconnectors

B27. In undertaking the cost-benefit analysis in BID3, interconnectors are treated via an entry in the merit order, each with two prices quoted. If the GB system price is below the lower price, then it is assumed that the links export power, i.e. the receiving country takes advantage of low power prices in GB. Between the lower and upper price, there is assumed to be no power flow (i.e. the interconnectors are at float). If the GB system price is above the upper price, the interconnectors import power, i.e. the GB benefits from lower power prices abroad.

B28. Interconnectors are unique within our modelling since they do not generate power themselves, and are only able to transfer it between markets. Therefore, when a bid or offer action is taken on an interconnector they need be treated differently to balancing mechanism units/generators.

B29. There are two main components to bid/offer prices for interconnectors. Firstly, like generators, they must be paid to change the quantity of generation. In the case of interconnectors this is in the foreign market rather than GB. However this is generally the same as modelled in the GB market. The second component of interconnector bid/offer costs is the trader/interconnector being compensated for lost arbitrage revenue/sending additional power along the line. When the interconnector is importing to GB and is asked to bid off, or is exporting and is asked to offer on, then the trader loses arbitrage revenue as a result of reduced flows. In order for the trader to accept the bid/offer they must be compensated for this reduced arbitrage revenue. The SO is therefore assumed to compensate the trader for their lost revenue and must pay them the market spread adjusted for the losses they would have endured on the interconnector.

Development of current year options

B30. If the strategies that provide the lowest lifetime cost for each of the scenarios are different, there is a risk of regret, and the TO will develop a set of competing options which seek to minimise it.

B31. The SO always considers the ‘do nothing’ option.

B32. The SO initially focuses on the transmission solutions which require a decision to be made in the current year. For example, if a reinforcement with a lead-time of four years is required against one scenario in six years’ time, a decision is not required this year. In its options analysis, it simply assumes that it will be constructed for that scenario but not constructed for the others.

B33. The SO considers any restrictions to the movement of reinforcements between years (either deferral or advancement). For example, outage availability may mean that it is not possible to delay the commissioning of a reinforcement from year t to year (t+1) because other planned outages in year (t+1) would cause high congestion costs or demand insecurity.

Consideration of transmission solution commitment

B34. In most cases, the commitment required to progress physical network solutions is in sequential stages from scoping, through optioneering and pre-construction to construction works, with more detailed information revealed and more expenditure at risk of being stranded as they progress.

B35. This allows regret minimising options based on particular stages to be developed. For example, the option to complete pre-construction allows the earliest commissioning date to be achieved against a scenario for which the reinforcement is required, and allows work to cease with minimal regret against a scenario for which it is not required.

B36. It may also be possible to minimise regrets by considering the potential for assets to be reused in other network investments if the project turns out not to be required.

Consideration of alternative transmission solutions

B37. It should be noted that the options considered are not limited to those that constitute one of the minimum cost strategies. For example, consider a boundary with significant uncertainty, where doing nothing is the minimum cost solution for one scenario but completing a large, high-cost reinforcement is the minimum cost solution for another. When considering both scenarios, the best option may be to complete an incremental reinforcement which reduces regret until there is sufficient certainty regarding the scenario that will outturn to commit (or not) to the large reinforcement.

Selection of recommended option

Regret analysis

B38. The single year regret method is used to identify the recommended options as part of the NOA process. Below is an extract from the relevant sections of the NOA methodology.

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.

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 2.2. Note that the scenarios are colour-coded; this is used for clarity in the following tables.

Table 2.2: Example of optimum years for two critical reinforcements

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

Table 2.3: 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.

Test recommended transmission solutions/strategy against security criterion

B39. Once a transmission solution or strategy has been recommended with a least regret delivery date, it is necessary to consider whether this decision is robust against the security criterion contained in the security standards. If the criterion is not met, the TO considers the economic implications of a wider range of issues including (but not limited to):

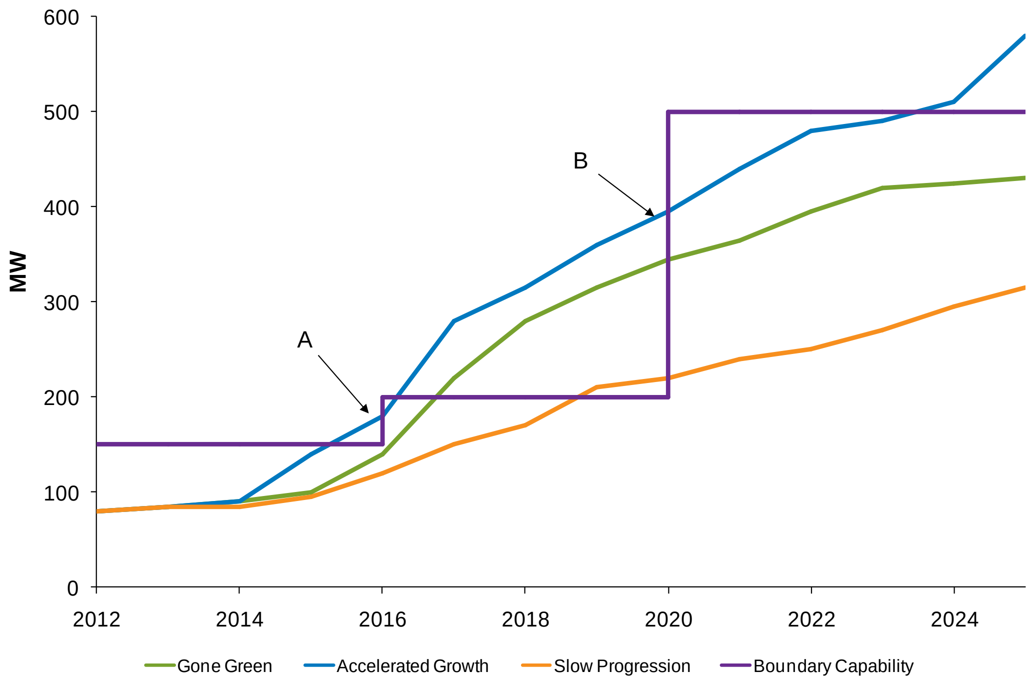
- Safety and reliability;
- Value of lost load and loss of load probability (to the extent that this is not already included in the BID3 treatment, i.e. ideal curtailment of demand and immediate restoration);
- Cost of reduced security on the system;
- Operational cost of constraints to complete the solution.

B40. If the economic implications of these considerations outweigh the cost of reinforcement to meet the security criterion, then the TO invests in the transmission strategy in accordance with its investment process to ensure we continue to build an economic and efficient network. This investment will be treated as being consistent with the NDP for the purposes of the RIIO-T1 uncertainty mechanisms.

B41. If the cost of reinforcement to meet the security criterion outweighs the economic implications, the TO will seek a derogation from Ofgem to not reinforce and diverge from the security standards; this process is described currently in Condition C17 of our Licence.

B42. An example of this, using hypothetical data, is illustrated in Figure B2 where the transmission strategies identified through the least regret analysis are compared to the capability required to achieve compliance with the security criterion.

Figure B2: Illustrative test against security criterion



B43. This example shows two reinforcements (A and B) that have been identified under the least regrets analysis for progression in early years. Comparing the resultant boundary capability to that required by the security criterion shows that the second reinforcement is to be delivered after there is an increase in the boundary capability for all three scenarios. It is necessary to consider the implications of this potential reduction in security and whether further investment, above the least regret solution, would be prudent or if a derogation should be sought.

Treatment of 'invest then connect' and NSLPA requirements

B44. As the NOA/NDP assessment is carried out on an annual basis, it is likely that a connection application from an interconnector or new nuclear power station will be received following an annual iteration of the process and before the analysis phase of the next iteration.

B45. In this event, the SO and TO will undertake a NOA/NDP assessment which includes the new interconnector or nuclear power station as part of the connection application process. This will allow us to identify the wider work or NSLPA requirements against the scenarios used in the NOA/NDP analysis. These works will then be listed in the offer to the customer.

B46. The following iteration of the NOA/NDP is based on a revised set of scenarios and could give rise to three outcomes in relation to the wider works identified and included in an interconnector or nuclear power station connection offer or agreement:

a. Reinforcements are still required within the timescale stated in the connection agreement. In this case, the conclusion of the NOA/NDP analysis would be consistent with the relevant connection agreement and the TO would progress with the wider work reinforcements;

b. Reinforcements are not required or required at a later date than specified in the connection agreement because the interconnector or nuclear power station is not included in the scenario or is assumed to connect at a later date. In this case, the TO would still be contractually obliged to progress with the wider works as specified in the agreement and therefore the NDP conclusions would be updated to include these reinforcements;

c. Reinforcements are not required or required at a later date due to a change in the scenarios which is not related to the interconnector or nuclear power station in question. In this case, the conclusion of the NDP would be that the reinforcement was not required, and the wider works in the connection agreement and/or NSLPA would be revised accordingly.

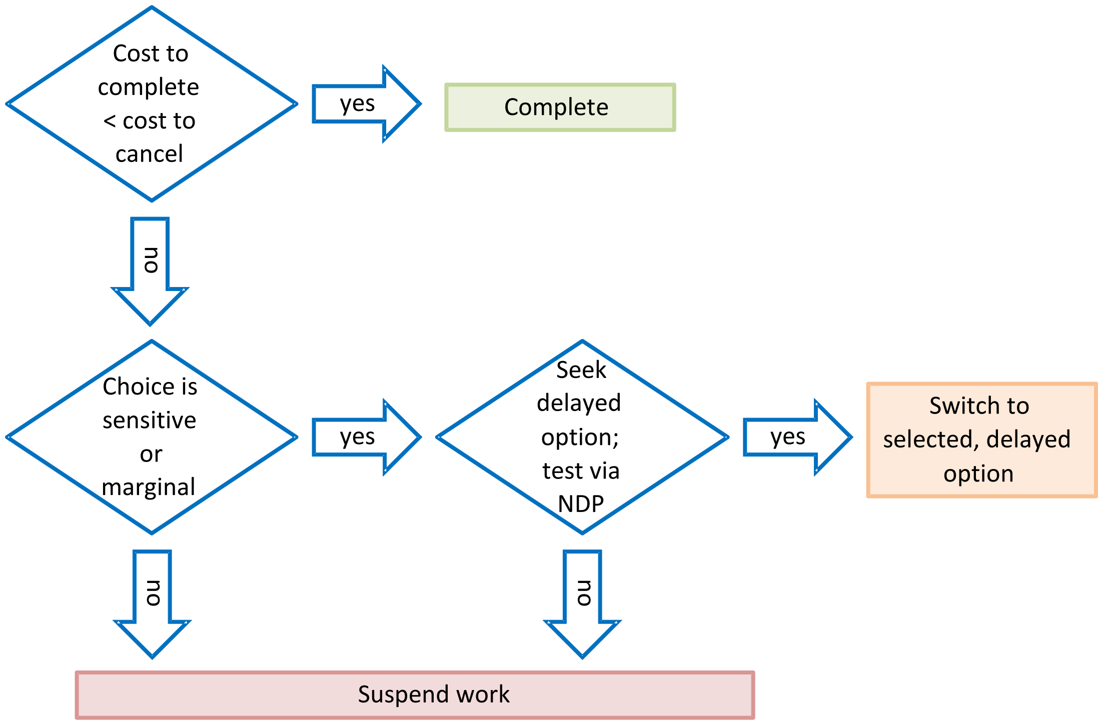
Stopping or delaying a transmission strategy

B47. The cost-benefit analysis includes cancellation costs as a factor. If a project is so far progressed that the cost of cancellation is greater than the cost to complete (for example, if pre-existing plant has been removed and scrapped and new plant would be required regardless of the re-forecast network benefit), the transmission strategy would be allowed to complete.

B48. Otherwise, if the decision is marginal and sensitive to a discrete assumption change, options to slow or delay completion of the transmission strategy and hence reduce potential regret will be sought. These options can then be considered as part of the least regret analysis, and one of these might then become the selected transmission strategy.

B49. If it is clear that a transmission strategy is no longer preferred under all revised scenarios and that the cost of cancellation is less than the cost to complete, work would be suspended and any associated, sanctioned projects would be deferred or closed.

Figure B3: Stopping or delaying a transmission strategy



B50. In the case of physical reinforcements (construction projects), any committed spend on plant will be assessed for possible re-deployment on other construction projects. For example, overhead line conductor (especially if it has not been cut to section lengths) can be diverted to other projects at minimal marginal cost. This activity will form part of the cost of cancellation analysis.

B51. In the case of the construction of a new transmission circuit, community consultation and planning consent are required and give rise to significant lead time, cost and credibility risks associated with stopping the planning consent process and then restarting later. The TO would therefore continue with the planning application process once it has commenced to completion. However, if the driver for the investment has been pushed back significantly or completely removed then the planning application will be withdrawn.

Outputs

Recommended options

B52. The recommended options are produced as part of the NOA that cover the onshore England and Wales transmission system. These:

- Identify the existing network capability for that region;
- Record all the transmission solutions identified to increase future boundary capabilities;

- Summarise the cost benefit analysis undertaken to select the recommended transmission strategies, making it clear where local sensitivities have been used to support a future boundary capability requirement;

- Demonstrate the need case for works that will be undertaken in the following year;

- Detail prospective solutions and strategies for the delivery of future incremental capability over the next ten years but which are not triggered in the following year.

NOA report and Regulatory Reporting Pack

B53. A summary of the key points of the reinforcement profile is published each January as part of the NOA report. This includes:

- The lowest cost strategy for each relevant scenario;

- Decision trees/tables which provide recommendations on actions for the current year based on least regret;

- Outputs and lead-times for longer-term solutions; and

- An invitation to stakeholders to provide feedback on any of the above.

B54. A summary of key points to be presented in the Regulatory Reporting Pack is given below:

- Network capabilities for all boundaries;

- Cost profiles and lead times of investments; and

- Agreed monitoring metrics for the application of NDP.

Feedback to Future Energy Scenarios

B55. Any additional, scenario-related feedback received during this process will be considered when developing the axioms and stakeholder engagement topics relating to future FES.

Review of NDP performance

B56. Each year's FES (which includes the national generation and demand scenarios), BID3 model (which contains bid/offer prices, treatment of storage, plant availability and discount factor assumptions), ETYS and NOA results (and copies of the network models used to run the supporting analysis) will be retained to support a retrospective review of NDP performance.

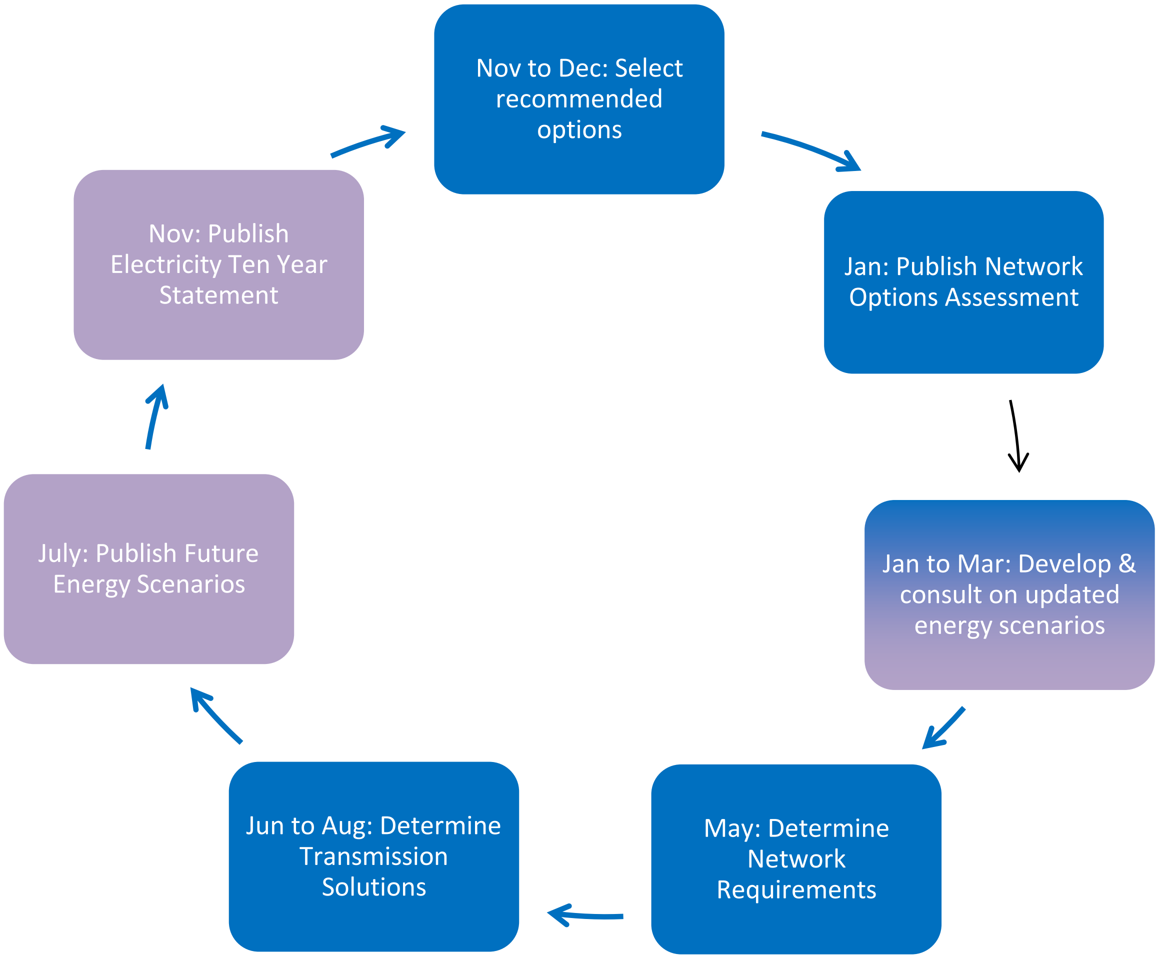
B57. When the annual process has completed, the SO compares the outcomes with those from the previous year(s). It reports reasons for any differences between latest forecast and previous forecast of boundary capability and incremental boundary capability delivered by transmission solutions in the NOA report.

B58. Where the selected transmission strategies have changed significantly, the reasons for change are analysed.

B59. The comparison will also include the actual versus forecast for the generation and demand backgrounds.

Annual timetable

Figure B4: Annual timetable



B60. The blocks shown in blue are the elements of the process which are mainly internal to National Grid. The light purple blocks are external publications within which the SO seeks feedback from stakeholders. As part of the development of the UK Future Energy Scenarios, there is a stakeholder engagement process.

Stakeholder engagement

B61. Agreed future energy scenarios are documented in the FES annually, with stakeholders being invited to provide feedback. In creating these scenarios, the SO seeks stakeholders' views on:

- The assumptions used in our analysis and development of future energy scenarios;

- Developments in electricity generation backgrounds;
- Electricity and gas demand and supply;
- Assumptions underlying our scenarios, including Government policy, economic background, heat and transport;
- The quality of our stakeholder engagement; and
- The clarity and value of the information presented.

B62. Stakeholder engagement on the development of scenarios will include the principles to be adopted in developing sensitivity studies.

B63. The SO engages with the TOs and wider electricity industry as part of the NOA review process.

B64. The recommended transmission solutions will be documented in the NOA each January, with stakeholders being invited to provide feedback. The SO seeks stakeholders' views on:

- The Network Options Assessment report and methodology;
- The appropriateness of the range of energy scenarios and sensitivities considered;
- The availability of generation and interconnectors;
- The reasonableness of the constraint cost forecasting assumptions;
- The completeness of the transmission solutions, including commercial solutions, and strategies identified; and
- The clarity of the information presented.

B65. The transmission solutions are presented in the form of a summary table giving details of each preferred solution in terms of boundary capability required, capability offered by the suggested solutions and lead-time. This is in accordance with the Form of Report in the NOA methodology.

B66. Presently, there are a number of Constraint Management Services which are contracted through a Commercial Services Agreement that provide transmission solutions. The SO works closely with stakeholders to develop the process and commercial frameworks to further enable and encourage new ideas and solutions.

B67. The feedback from the stakeholder consultation is used in the next annual iteration of the NOA process.

B68. The TO publishes a document annually describing the selected options taking account of the NOA process's recommendations and in accordance with the TO's investment process.

Glossary of terms

Transmission solution	A set of works or commercial arrangements that provide a change in transmission boundary capability
Transmission strategy	A combination of solutions which meet an identified network requirement
Selected transmission strategy	The strategy selected by the NDP process as being the least regret path to achieving a required increase in network capability
Lifetime cost	The total cost of a transmission solution or strategy, including the implementation/construction costs, lifetime constraint costs and the cost of transmission losses against a given energy scenario