RIIO T1

Network Development Policy Update

National Grid
Electricity Transmission

April 2013

Target audience

All stakeholders

About this document

This annex contains NGET's proposed network development policy and process. This clarifies for stakeholders how we will make 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

Table of Contents

Introduction

Background

1 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.

2 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.

3 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].

4 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.

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

6 We will continue to connect new generation projects as soon as possible, and a more transparent decision process around wider works will give 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.

Future Energy Scenarios

7 National Grid has replaced a single ‘best view’ forecast of electricity and gas demand and supply with scenarios representing multiple views of the future. In 2011 and 2012, we published details of three scenarios: Slow Progression, Gone Green and Accelerated Growth. The total number of scenarios is subject to change depending on stakeholder feedback received through the UK Future Energy Scenarios (UK FES) consultation process. In the event of any change, the rationale will be described and presented within the UK FES consultation report that is published each year.

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

8 In the 2012 UK Future Energy Scenarios[2] (UK FES) document, we describe the assumptions behind all scenarios, look at the resulting energy demand, examine the CO_2 emissions and contribution from renewable energy, and (where appropriate) describe how our approach has developed since 2011. Projections to 2030 are discussed in considerable detail, while the period 2030 to 2050 is described in a more qualitative manner.

9 The feedback we received from our stakeholder engagement activities helped shape our 2012 scenarios. Following the publication of the UK FES in November 2011, we sought feedback on our scenarios from our stakeholders in an annual consultation. We used a range of formats including bilateral meetings, workshops, questionnaires and presentations followed by question and answer sessions and gathered views on a wide range of energy-related topics.

10 We documented the feedback in a new publication (The UK Future Scenarios Stakeholder Feedback Document[3], July 2012), and the inclusion of major themes such as macro factors and demand and supply uncertainty have led to the 2012 scenarios featuring a broader range of assumptions. We published the underlying assumptions in 2011 for each of the scenarios to aid understanding and to encourage debate.

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

12 The scenarios are based on a number of axioms (34 in 2012) that cover areas such as economic growth, fuel prices, volume of wind and nuclear, mix of coal/CCGT, possible future interconnectors, etc. Appendix 1 in the UK FES document describes the full set of axioms used in our 2012 scenarios. 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.

13 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).

14 The detailed process for updating and consulting upon the UK FES is separate to the Network Development Policy process and will not be covered in this document.

---

[2] http://www.nationalgrid.com/NR/rdonlyres/C7B6B544-3E76-4773-AE79-9124DDBE5CBB/56766/UKFutureEnergyScenarios2012.pdf

[3] http://www.nationalgrid.com/NR/rdonlyres/F153FB85-F043-46F5-8779-ABCAB2243679/54699/UKFESStakeholderFeedback2012.pdf

Structure of this document

Proposed Network Development Policy

15 Following further engagement with Ofgem and wider stakeholders, our draft policy from November 2012 has been refined. In particular, we have included the following:

- Explanation and treatments for boundary capability changes that have arisen from generation and demand changes as well as possible future changes in the security standards;
- Selection of transmission solutions to include considerations of:
  a. Projects with significant lead time risks;
  b. Generator offers made on an 'invest then connect' basis;
  c. Wider work requirements as part of Nuclear Site Licence Provision Agreement (NSLPA);
- The verification process for boundary capabilities; and
- A process for stakeholder engagement on wider work outputs.

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

17 We are now seeking approval from Ofgem for the adoption of this policy.

Proposed Network Development Policy Process

18 Having set out our proposed policy for selecting transmission strategies, we have created a process document to support this activity. This provides more detail on the steps undertaken to apply the Network Development Policy, including:

- 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.

19 The 'NDP Process' document is included as Appendix B.

Appendix A: Proposed Network Development Policy

Introduction

A1. This document sets out how we will make 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 will involve 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 will be used in this decision making process is also described.

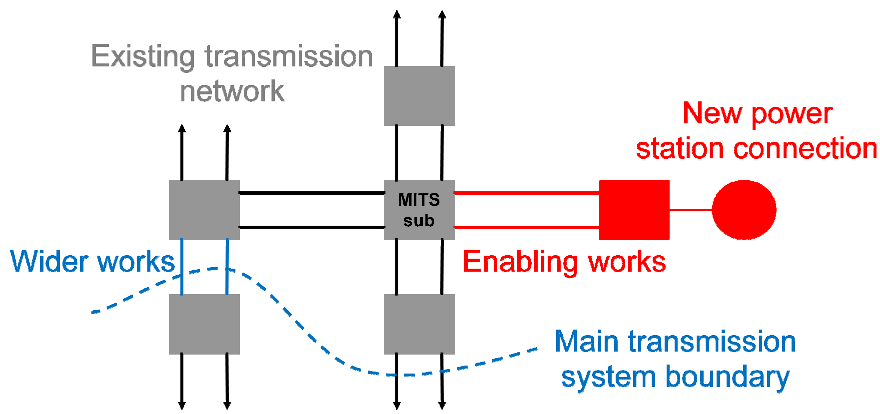
Scope

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.

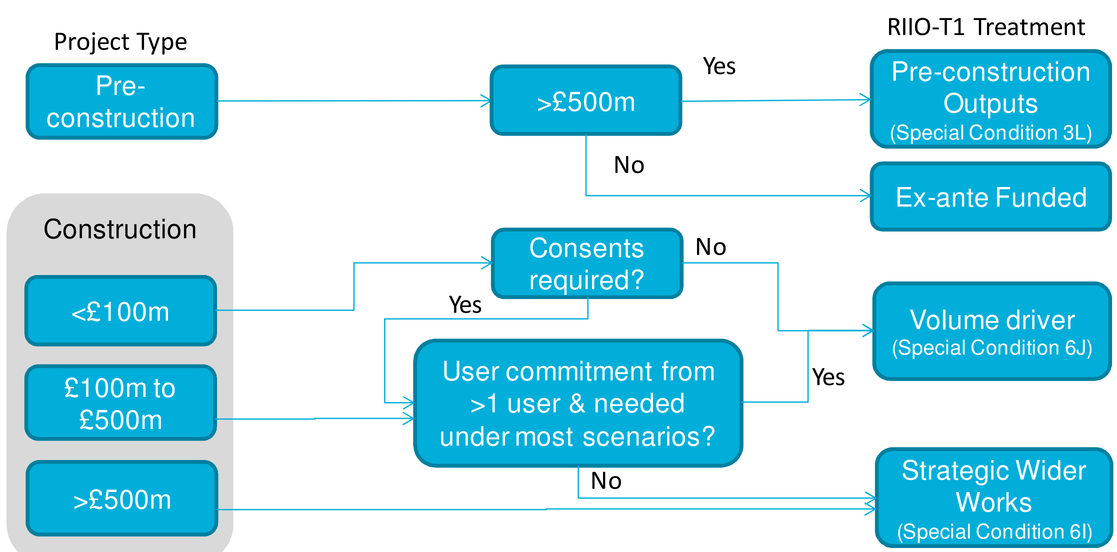
A7. In assessing existing or new wider reinforcement projects with outputs planned for beyond the RIIO-T1 period, we will assume that the Network Development Policy methodology continues into the future.

Interaction with RIIO-T1 uncertainty mechanisms

A8. The Network Development Policy will be applied to all wider works boundaries and associated transmission solutions.

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 recommendation 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 recommendation 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[4] 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 recommendation 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 our Licence.

A13. For NDP recommendations to progress all other transmission solutions less than £500m (in 2009/10 prices), the potential allowance will be 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 will be established following a stakeholder engagement process. We will consult widely with the industry on our scenarios on an annual basis.

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

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

[4] We intend to apply the same process and principles outlined in the Network Development Policy in developing SWW projects.

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

A18. When developing the scenarios, we will consider 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, we also consider 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 will be consulted on the UK FES and will be able to respond through targeted questionnaires, bi-lateral meetings, open sessions and workshops. The feedback we receive from stakeholders will feed into the production of future scenarios.

A21. There are other factors which are required to facilitate the completion of cost benefit analysis. We would obtain this data by undertaking a statistical analysis of historical data, and this would be expected to include:

- 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, we also propose to publish these data through appropriate means such as our external website.

Sensitivities

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

A24. In developing sensitivities, we will use feedback obtained from stakeholders sought through the UK FES consultation process to consider regional variations in generation connections and anticipated demand levels that still meet the scenario objectives. We will, for example, explore 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[5] 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 necessary 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.

[5] This refers to NETS SQSS version 2.2: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

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 will be driven in part by the nature of the capability shortfall (i.e. a thermal, voltage or transient stability issue).

A31. We will develop both investment and operational transmission solutions. The investment solutions will generally be considered in cost order. For a deficit in thermal capability, for example, relatively inexpensive solutions such as circuit reconfiguration or hot-wiring[6] of circuits will be considered and only if they are insufficient to address the deficit will other, more expensive solutions such as quadrature boosters, reconductoring of existing circuits or new circuits be 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 will not be 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 following information will be identified:

(a) Forecast total cost and phasing

This will include a consideration of the cancellation costs associated with various project milestones (for example, splitting projects into pre-construction and construction phases).

It will also include an assessment of both the opportunity to deliver at a lower cost and the risk of overspend. This may be relevant to the comparison of solutions (i.e. when comparing two solutions, the solution with the marginally higher mean expected cost but lower cost uncertainty may be preferable).

[6] Hot-wiring 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.

(b) Forecast lead-time

This will include a consideration of risks associated with planning issues and any deliverability issues, such as the physical manufacturing time for specialist plant, the availability of outages and internal and external resources.

The construction of a new transmission circuit requires community consultation and planning consent and therefore our analysis needs to take into account risks associated with changing lead times of the project. These risks include:

i. Community engagement which includes environmental impact assessments (e.g. migrating birds can require several seasons of analysis);

ii. The length of time it takes to gain consent from the Secretary of State can vary based on the complexity of the project;

iii. Loss of production slots and system outage windows due to delays in the early stages.

To deal with these issues, once a planning application process has commenced, we will take it to completion unless the driver for the investment has been completely removed or significantly pushed back.

We will also identify a 'best view' and 'worst case' lead-time for the construction of a new transmission circuit.

Where solutions are identified that may require major consents and public consultation, a range of options will need to be developed and presented for consultation publicly, and may therefore be subject to change in scope, cost and time as part of those optioneering and public consultation processes.

We will identify linkages between projects (e.g. project 1 must be completed to provide sufficient capability to facilitate the outages required to construct project 2).

(c) Outputs delivered

This will include additional boundary capability, reduced impedance (which will impact on losses) and impact on security.

A34. This information will be collated on an annual basis and included in the Regional Strategies document. This part of the Regional Strategies document will then be used as the basis for selecting solutions or strategies (sets of solutions) to progress.

Select transmission solution and timing

A35. All the possible solutions shall be 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 will be considered.

A36. This analysis will be consistent with the recent 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 been added to the constraint and losses costs in each year, and the totals will be discounted at the Treasury’s social time preference rate[7].

A37. 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. We will therefore not make decisions based on a conventional cost-benefit analysis, and instead make use of a framework that will allow us to take account of optimal timing and risk-adjusted values of any investments made.

A38. 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.

A39. 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.

A40. The optimum combination of transmission solutions for each of the demand and generation scenarios and sensitivities will be established. This will be achieved with the application of detailed cost benefit analysis.

A41. We will then identify the set of feasible options, based on combinations of the transmission solutions set out in the Regional Strategies. In developing these options, we will take account of the full range of information captured in the Regional Strategies, including practical constraints on what can be delivered such as the transmission solution inter-dependencies and both the ‘best view’ and ‘worst case’ lead-time identified for the construction of new transmission circuits.

A42. 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.

[7] The Social Time Preference Rate (STPR) used for the 2012 analysis is 3.5%

A43. We will identify the discounted investment costs and the expected congestion and transmission losses costs associated with each of these strategies for each of our future scenarios and sensitivities. We will then calculate 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 will provide a picture of the risks and benefits of all possible options under a broad range of future scenarios and sensitivities. In addition to this quantitative analysis, we will also estimate the carbon emissions associated with each transmission solution against each of the scenarios and sensitivities.

A44. The investment strategy which is most advantageous will be chosen based on the least regret decision approach, with particular focus on schemes that need to be progressed in the following financial year. While this analysis will produce an investment strategy that will in principle cover the entire RIIO-T1 period, we intend to repeat the analysis annually. We will therefore update our wider works programme as new information is revealed in order to ensure best value for our customers. Based on the evolution of generation and demand during the RIIO-T1 period, we might therefore decide to bring forward some investments and delay others, relative to the plan with which we will begin. We might also decide to cancel a project where work has begun, should the anticipated need for that investment strategy not materialise.

A45. There are a number of additional issues that need to be considered alongside this analysis:

- Generator connection agreements based on an 'invest then connect' approach;
- Wider work identified as part of Nuclear Site Licence Provisions Agreement (NSLPA) requirements.

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

A46. 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 connection is made contingent upon the completion of all identified transmission reinforcement works, including wider works.

Wider work identified as part of NSLPA requirements

A47. 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.

A48. 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 an ex-ante review of the connection design. All nuclear connection agreements are made conditional upon the outcome of the NSLPA process.

A49. 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

A50. 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.

A51. In these circumstances, the NDP conclusions will be updated to include recommendations 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

A52. 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 will be considered as funded as this was economic (the least regret course of action) given what was known at the time of commitment. We will endeavour 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, we will continue to assess that project by assuming that the Network Development Policy methodology still applies into the future.

Outputs

A53. We will produce a set of Regional Strategies that cover the onshore England and Wales transmission system. These will record the transmission solutions considered and the assumptions made in selecting preferred transmission strategies. Works being triggered for delivery in the following year will be identified, and the timescales for longer-term investment strategies will be recorded.

A54. We will share our proposed incremental wider works and commercial solutions, such as Commercial Services, with our stakeholders through the ETYS feedback process. This will provide stakeholders with an opportunity to challenge the proposed solutions and suggest alternatives in order to enrich the analysis undertaken for NDP in the next annual cycle.

A55. The key points from these Regional Strategies will be published in the Electricity Ten Year Statement (ETYS) to facilitate stakeholder engagement.

Review of NDP performance

A56. Each year's UK FES, operational cost forecasting model, Regional Strategies and ETYS will be retained to support a retrospective review of NDP performance. The outputs contained within the scenarios will be tracked and reviewed as part of the UK FES process.

A57. When the annual process has completed, we will compare the outcomes with those from previous years. Where the selected transmission strategies have altered significantly, the reasons for change will be 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 a sub-optimal strategy being chosen (if the scenarios and sensitivities turnout to be accurate). We will keep this approach under review as we collect more information about the accuracy of the scenarios and sensitivities and the effectiveness of the NDP.

A59. We will consult with stakeholders through the UK FES consultation process and the ETYS. We will then use this feedback to make improvements to the process and propose changes to the policy as appropriate.

Boundary capability changes

A60. 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

A61. 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.

A62. 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[8] 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

A63. The security standards are kept under continuous review by 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:

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

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.

A64. It is therefore possible for the security standards to change and for this change to impact boundary capability.

Boundary capability changes and the NDP

A65. 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

A66. As described above, the boundary capability will be reforecast as a part of each annual iteration of the NDP analysis. The reasons for any material differences between the latest forecast and the previous forecast will be assessed and reported to stakeholders.

A67. The latest view of the boundary capability will also form 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

A68. Upon completion of each reinforcement, we will calculate 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 will be assessed and reported to stakeholders.

A69. 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 will be 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 National Grid 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.

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. At the relevant stages of the NDP process, we will engage with our stakeholders.

B3. This annual process will be 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. We will engage stakeholders on annual updates to the key forecast data used in this decision-making process, and share the outputs from this process with our stakeholders through the publication of the Electricity Ten Year Statement (ETYS).

Inputs

Updated Future Energy Scenarios

B4. The relevant set of UK Future Energy Scenarios (UK FES) will be used as the basis for each annual round of analysis. These provide self-consistent generation and demand scenarios which extend to at least 2030 in detail and at a higher level to 2050. The UK FES document is consulted upon widely and published each year as part of a parallel process.

B5. The NDP process will utilise the main UK Future Energy Scenarios as well as the contracted position to form the background for which studies and analysis will be carried out. The total number of scenarios is subject to change depending on stakeholder feedback received through the UK FES consultation process. In the event of any change, the rationale will be described and presented within the UK FES consultation report that is published each year.

B6. In 2012, the three main scenarios were:

- Slow Progression – assumes a focus on extending existing plant and building new gas plants with a much slower deployment of renewable or low carbon generation than in Gone Green or Accelerated Growth and therefore slower progress towards environmental goals.

- Gone Green – assumes a balanced approach with contributions from different generation sectors in order to meet the environmental targets:

15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting the carbon budgets out to 2027 and an 80% reduction in greenhouse gas by 2050.

- Accelerated Growth – assumes a much faster development of low carbon technology which will lead to the environmental targets being exceeded.

B7. In 2013, we moved to two main scenarios following stakeholder feedback. We are comfortable that the use of these two scenarios together with the range of sensitivities gives adequate coverage of the likely range of future backgrounds.

B8. Demand information is based on the annual submissions made by transmission system users. These 'User' submissions are obtained between June and November each year and the demand is aggregated to form a national demand. This national demand figure is then adjusted to match the metered ACS[9] corrected actual outturn from the previous year whilst keeping the proportional demand by GSP the same as the 'User' submissions.

Sensitivities

B9. Sensitivities will be 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 developing sensitivities, we will use feedback obtained from stakeholders sought through the UK FES consultation process to consider regional variations in generation connections and anticipated demand levels that still meet the scenario objectives.

B10. 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 may be credible and there is a need to ensure that we are able to meet customer requirements. A "one in, one out" rule will be applied: any generation added in a region of concern will be 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 axioms and assumptions of the main scenarios but accounts for local sensitivities to the location of generation.

B11. The inclusion of a local contracted scenario will generally form a high local generation case and allow 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, we will also consider a low generation scenario where no new local generation connects. This is particularly important where the breadth of scenarios considered do not include a low generation case.

[9] 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.

B12. Interconnectors to Europe give rise to significant swings of power flows on the network due to their size and the fact that they can act as both a generator (when importing into GB) and a 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 into London and hence provides different limits to the amount of power that can be transferred.

B13. The modelling of interconnector flows based on historical precedent does not provide the best interconnector forecast going forward. Therefore, we will continue to work closely with stakeholders in developing our models of interconnector flows.

B14. The Regional Strategies will make it clear where additional sensitivities have been used to identify a future boundary capability requirement. We will further develop these sensitivities in consultation with stakeholders on a regional basis as it not possible to share the assumptions made on individual power stations.

Latest version of security standards

B15. The extant version of the security standards will be 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

B16. The boundary capability that will be identified will be the lowest of the thermal, voltage and stability capability. Each of these capabilities will be identified at relevant points of the year to ensure that both the peak and off-peak capabilities will be considered during the NDP process. In reporting the boundary capability each year, only the most restrictive of the capability values will be published and the criteria for its definition provided in any accompanying narrative.

B17. The reporting of the boundary capability each year will include an explanation of any material differences from the previous year.

B18. 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, we will clearly identify the reason for this, 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)

Option	Boundary type	Seasonal conditions	Scenario	Boundary cap identified	Secured event
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)

B19. The majority of wider boundaries that are assessed fall within the boundary capability defined in option A, whilst the majority of local boundaries will be 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) will 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 will be employed.

B20. The above network configurations will 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 will be 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 will be summed to determine the maximum boundary capability.

Identify future transmission capability requirements

National generation and demand scenarios

B21. For every boundary, the future capability necessary 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 for both the Security and Economy criteria.

B22. 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 based on a ranking order, and where necessary the generators are scaled to match 120% of Average Cold Spell (ACS) peak demand[10]. Further explanation can be found in Appendices C and D of the security standards.

---

[10] 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.

B23. 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. In these studies, nuclear, intermittent and pumped storage generation and generation fitted with carbon capture and storage are set to specific contributory levels. Other contributory generation is scaled to meet the required demand level. Further details can be found in Appendix E of the security standards.

B24. The security standards also include 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.

Identify future transmission solutions

B25. This stage identifies all potential transmission solutions that could provide additional capability across the boundary concerned, including a review of any solutions previously considered. We will consider low-cost investments, operational and investment options and whether an individual solution or a combination of solutions (known here as a transmission strategy) will resolve the identified capability constraint.

B26. Potential transmission solutions are presented in Table B2 in order of increasing likely cost.

Table B2: Potential transmission solutions

Category	Transmission solution	Nature of constraint			
		Thermal	Voltage	Stability	Fault Levels
Low cost-investment	Co-ordinated Quadrature Booster Schemes	✓	✓		
	Automatic switching schemes for alternative running arrangements	✓	✓	✓	✓
	Dynamic ratings	✓			
	Enhanced generator reactive range through reactive markets		✓	✓	
	Fast switching reactive compensation		✓	✓	
Operational	Availability contract	✓	✓	✓	

Category	Transmission solution	Nature of constraint			
		Thermal	Voltage	Stability	Fault Levels
	Intertripping	✓	✓	✓	
	Reactive demand reduction		✓		
	Generation advanced control systems	✓	✓	✓	
Investment	Hot-wiring overhead lines	✓			
	Overhead line reconductoring or cable replacement	✓			
	Reactive compensation (MSC, SVC, reactors)		✓	✓	
	Switchgear replacement	✓			✓
	New build (HVAC / HVDC)	✓	✓	✓	✓

B27. The range of solutions identified shall be sufficiently wide and include both small-scale reinforcements with short lead-times as well as larger-scale alternative reinforcements which are likely to have longer lead-times.

B28. In developing this range of solutions, we will also consider 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 Network Development Policy.

B29. The factors shown in Table B3 will be identified for each transmission solution to provide a consistent basis on which to perform cost benefit analysis at the next stage.

Table B3: 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 and the forecast impact on transmission losses

<table>
<tr><th>Factor</th><th colspan="3">Definition</th></tr>
<tr><td>Lead-time</td><td colspan="3">An assessment of the time required developing and delivering each transmission solution; this comprises an initial consideration of planning consent and deliverability issues, including dependencies on other projects. An assessment of the opportunity to advance and the risks of delay will be incorporated.</td></tr>
<tr><td>Cost</td><td colspan="3">The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases. The risk of over-/under-spend (for example, due to uncertainty associated with the levels of undergrounding required) will also be quantified to improve the consideration of solutions; a marginally higher mean expected cost may be preferred if the risk of over-spend is significantly reduced.</td></tr>
<tr><td rowspan="6">Stage[11]</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 rowspan="4">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</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</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process.</td></tr>
<tr><td>Planning</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process.</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction.</td></tr>
</table>

B30. In order to assess the lead-time risk recorded in Table B3, new overhead line solutions with significant consents and deliverability risks will be considered with both ‘best view’ and ‘worst case’ lead-times to establish the least regret for each likely project lead-time.

B31. Table B4 is an example of a list of transmission solutions developed for consideration across a specific boundary.

---

[11] These project categorisations are consistent with definitions defined as part of the ENSG process and published by DECC.

Table B4: 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	2017	1	80	Design
B	2000	2019	10	200	Planning
C	800	2015	3	90	Scoping
D	700	2017	2	80	Optioneering
E	400	2015	3	40	Construction
F	600	2018	2	120	Scoping

B32. It is possible that alternative solutions will be identified during each year and that the next iteration of the NDP 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

B33. 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. We expect the operational cost to include the carbon cost[12]. We will also identify the carbon emissions associated with each transmission solution against each of the scenarios.

B34. We will use the Electricity Scenarios Illustrator (ELSI) model to determine forecast constraint costs and transmission losses for transmission solutions against the agreed set of scenarios and sensitivities.

B35. The ELSI model was developed by National Grid to support the stakeholder engagement process for the purposes of our RIIO-T1 submission[13]. Our stakeholders have been presented with the tool and associated information to allow them to perform their own analysis on the possible development of wider works. Simplifications have been made within the tool to allow this to be made publicly available whilst ensuring that any compromise on accuracy is minimal.

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

[13] The Electricity Scenarios Illustrator (ELSI model) and a user guide are available at: http://www.talkingnetworkstx.com/consultation-and-engagement.aspx

B36. The model requires the inputs for existing boundary capabilities and their future development to be calculated in a separate 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;
- Limited modelling of European market implications;
- Simplified modelling of network availability (maintenance outages considered but construction outages neglected).

B37. The key assumptions within the ELSI model are shown in Table B5 below.

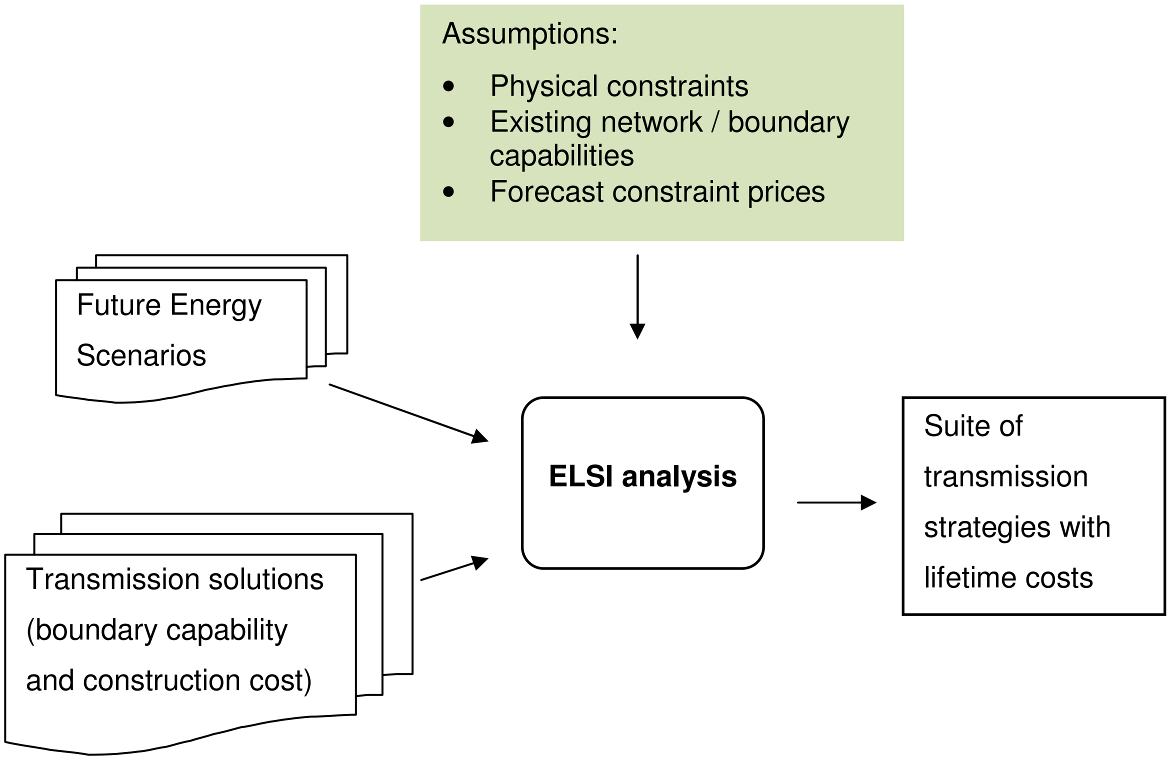
Table B5: Key assumptions within ELSI

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

B38. These key assumptions will be reviewed annually and any significant changes will be identified and presented through the UK FES consultation, Regulatory Reporting Pack (RRP) and ETYS. The output of the ELSI analysis is the cost of different transmission solutions.

B39. The full lifetime cost analysis includes forecast transmission investment costs, constraint costs (based on the prices observed in the Balancing Mechanism) and the cost of transmission losses. This analysis is consistent with the recent 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 been added to the constraint and losses costs in each year, and the totals are discounted at the Treasury’s social time preference rate.

Figure B6: ELSI inputs, assumptions and outputs



B40. ELSI uses the more detailed energy scenarios to complete this analysis out to 2030. Then, in order to estimate full lifetime costs, the values from 2030 are duplicated to give 45 years of data.

B41. Lifetime cost analysis will be 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

B42. In undertaking the cost benefit analysis in ELSI, 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.

B43. In reality, this treatment is somewhat idealised. We will consider more detailed models of these flows in future developments of ELSI. This could include utilising the European scenarios developed by ENTSO-E (which are subject to stakeholder engagement) to inform how these interconnectors should be modelled when considering the GB network requirements. In addition, interconnectors are not used as part of the constraint management solution unless it has specific trading agreements in place.

Development of current year options

B44. If the strategies that provide the lowest lifetime cost for each of the scenarios are different, there is a risk of regret, and we will develop a set of competing options which seek to minimise it.

B45. We will always consider the 'do nothing' option.

B46. We will initially focus on the strategies 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 our options analysis, we will simply assume that it will be constructed for that scenario but not constructed for the others.

B47. We will consider 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

B48. In most cases, the commitment required to progress physical network solutions will be 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.

B49. 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.

B50. It may also be possible to minimise regrets by considering the potential for assets to be re-used in other network investments if the project turns out not to be required.

Consideration of alternative transmission solutions

B51. 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.

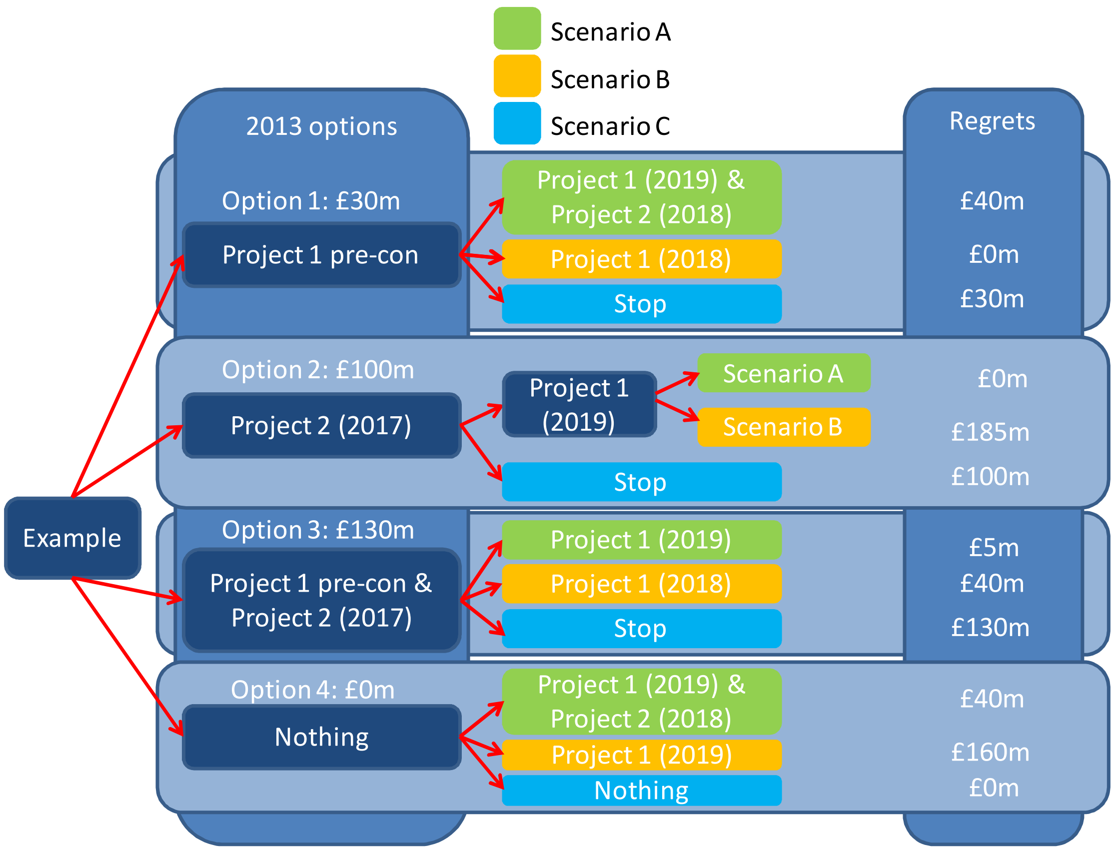
Selection of preferred option

Least regret analysis

B52. The regret associated with each of the current-year options will be calculated against each of the scenarios. The regret against a particular scenario is defined as the difference in cost between the option and the best possible transmission strategy for that scenario.

B53. This is illustrated in Figure B7, which includes four current-year options.

Figure B7: Example decision tree



B54. The four options available in the current year are shown with their associated forecast total costs. The regrets for each of these options against each of the scenarios are also shown.

B55. The regrets have been calculated assuming that information will be revealed such that the optimal next steps can be taken against each of the scenarios. For example, the optimal strategy for Scenario B is to complete Project 1 in 2018. This can be achieved with options 1 and 3, and therefore the regrets have been calculated assuming this will happen. It cannot be achieved with options 2 and 4 because they do not include the Project 1 pre-construction works, and therefore the regrets are calculated assuming that Project 1 will be completed as soon as possible after 2018, i.e. 2019.

B56. The preferred option is then selected based on the least regret approach. The worst regrets associated with each of the current-year options are identified, and the option with the 'least worst' regret is chosen.

B57. This is illustrated in Table B8, where option 1 is selected as the preferred solution for the following year.

Table B8: Example 'least regret' analysis

Option	Scenario A	Scenario B	Scenario C	Worst regret
1	£40m	£0m	£30m	£40m
2	£0m	£185m	£100m	£185m
3	£5m	£40m	£130m	£130m
4	£40m	£160m	£0m	£160m

B58. The advantage of this 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 a sub-optimal strategy being chosen (if the scenarios and sensitivities turn-out to be accurate).

B59. We will keep this approach under review as we collect more information about the accuracy of the scenarios and sensitivities and we will seek to further develop this process such that the analysis includes an increased number of decision points (i.e. instead of assuming that all information is revealed in a year, we will seek to include decision points further into the future when it is likely that more information has been revealed).

Test selected transmission strategy against security criterion

B60. Once a transmission solution or strategy has been selected 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, we will consider the economic implications of a wider range of issues including (but not limited to):

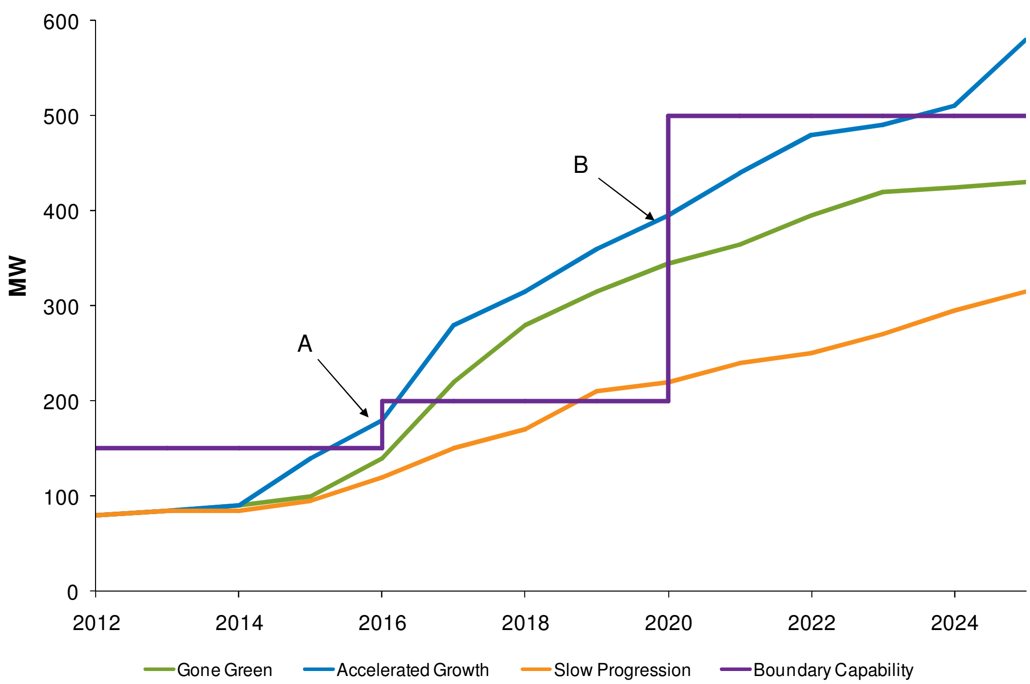
- Safety and reliability;
- Value of lost load and loss of load probability (to the extent that this is not already included in the ELSI treatment, i.e. ideal curtailment of demand and immediate restoration);
- Cost of reduced security on the system; and
- Operational cost of constraints to complete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

B61. If the economic implications of these considerations outweigh the cost of reinforcement to meet the security criterion, then we will invest in the transmission strategy 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.

B62. If the cost of reinforcement to meet the security criterion outweighs the economic implications, we will seek a derogation from Ofgem to not reinforce and diverge from the security standards; this process is described in Condition C17 of our Licence.

B63. An example of this, using hypothetical data, is illustrated in Figure B9 where the transmission strategies identified through the least regret analysis are compared to the capability required to achieve compliance with the security criterion.

Figure B9: Illustrative test against security criterion



B64. 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

B65. As the 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.

B66. In this event, we will undertake an 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 NDP analysis. These works will then be listed in the offer to the customer.

B67. The following iteration of the NDP will be 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 NDP analysis would be consistent with the relevant connection agreement and we 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, we 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.

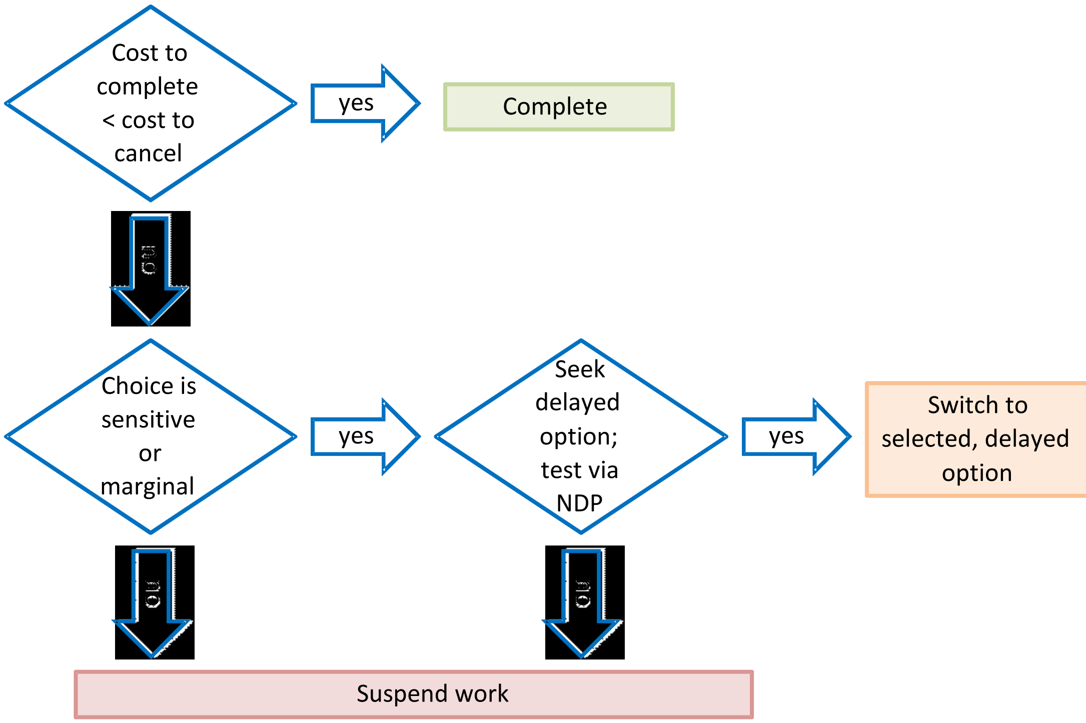
Stopping or delaying a transmission strategy

B68. As the price control period progresses, it is possible that a transmission strategy selected in a prior year will no longer be the least regret option identified in the current year. In this event, the transmission strategy will be reviewed in detail to understand the committed cost to date and cost of cancellation. If the 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.

B69. 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.

B70. 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 B10: Stopping or delaying a transmission strategy



B71. 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.

B72. 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. We will 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

Regional Strategies

B73. A set of Regional Strategies will be produced that cover the onshore England and Wales transmission system. These will:

- 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 preferred 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; and

- 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.

Electricity Ten Year Statement & Regulatory Reporting Pack

B74. A summary of the key points of the Regional Strategies will be published each November as part of the ETYS. This will include:

- The lowest cost strategy for each relevant scenario;

- Decision trees/tables which provides 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.

B75. 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

B76. Any additional, scenario-related feedback received during this process will be considered when developing the axioms and stakeholder engagement topics relating to future UK FES.

Review of NDP performance

B77. Each year's UK FES (which includes the national generation and demand scenarios), ELSI model (which contains bid/offer prices, treatment of storage, plant availability and discount factor assumptions), Regional Strategies (and copies of the network models used to run the supporting analysis) and ETYS will be retained to support a retrospective review of NDP performance.

B78. When the annual process has completed, we will compare the outcomes with those from the previous year(s). We will report reasons for any differences between latest forecast and previous forecast of boundary capability and incremental boundary capability delivered by transmission solutions in ETYS.

B79. Where the selected transmission strategies have changed significantly, the reasons for change will be analysed.

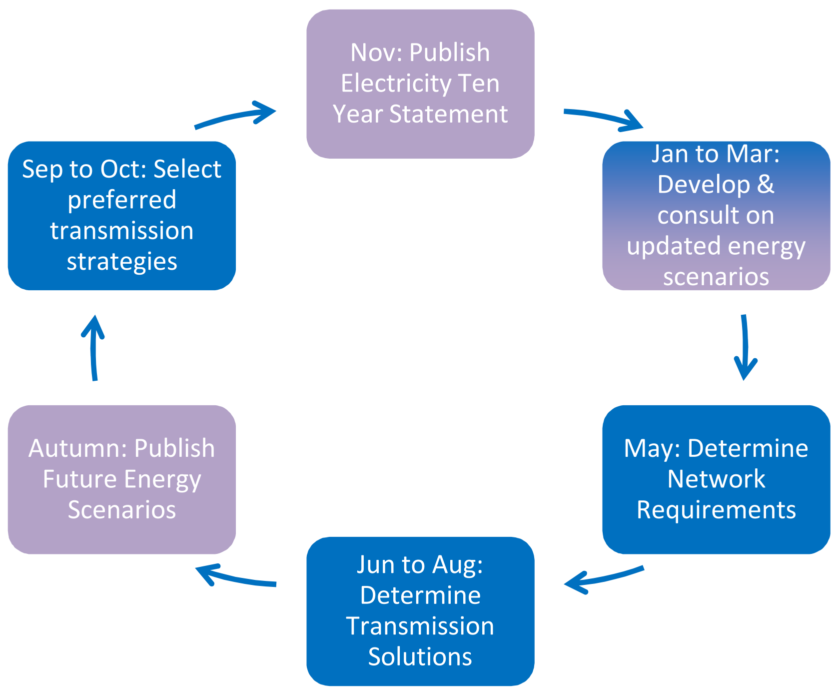
B80. The comparison will also include the actual versus forecast for the generation and demand backgrounds.

B81. In addition, we propose to discuss the following with Ofgem at the mid-term review:

- The overall performance of NDP;
- Ways to improve the NDP process; and
- The need to change, add or remove boundaries.

Annual timetable

Figure B11: Annual timetable



B82. 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 we will seek feedback from stakeholders. As part of the development of the UK Future Energy Scenarios, there is a stakeholder engagement process.

Stakeholder engagement

Updated Future Energy Scenarios

B83. Agreed future energy scenarios will be documented in the UK FES annually, with stakeholders being invited to provide feedback. In creating these scenarios, we will seek 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.

B84. Stakeholder engagement on the development of scenarios will include the principles to be adopted in developing sensitivity studies.

Electricity Ten Year Statement

B85. The selected transmission strategies will be documented in the ETYS each November, with stakeholders being invited to provide feedback We will seek stakeholders' views on:

- The Network Development Policy 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.

B86. The transmission solutions will be presented in the form of an NDP summary table giving details of each preferred solution in terms of boundary capability required, capability offered by the suggested solutions and lead-time.

B87. Presently, there are a number of Constraint Management Services which are contracted through a Commercial Services Agreement that provide transmission solutions. We will work closely with stakeholders to develop the process and commercial frameworks to further enable and encourage new ideas and solutions.

B88. The feedback from the stakeholder consultation will be used in the next annual iteration of the 'NDP 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