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RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas

Cost assessment and uncertainty Supporting Document

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Overview:

This Supporting Document sets out further detail on our Initial Proposals for the transmission price control for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT) from 1 April 2013 to 31 March 2021.

This document sets out the results of our assessment of each element of NGET's and NGGT's costs and our Initial Proposals for an efficient level of expenditure for both companies. It also sets out our assessment of NGET's and NGGT's proposed risk sharing arrangements and our Initial Proposals for mechanisms to efficiently manage the uncertainty and risk of the price control package.

Alongside this document we are publishing two other Supporting Documents focusing on 'Outputs, incentives and innovation' and 'Finance'.

This document and the other Supporting Documents are aimed at those seeking a detailed understanding of the Initial Proposals. Stakeholders wanting a more high-level overview should refer to the Initial Proposals Overview document.

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Associated documents

Main consultation paper

RIIO-T1: Initial Proposals for NGET and NGGT- Overview
RIIO-T1: Initial Proposals for NGGT and NGET - Overview

Supporting Documents

RIIO-T1: Initial Proposals for NGET and NGGT – Outputs, incentives and innovation
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RIIO-T1: Initial Proposals for NGET and NGGT – Impact Assessment
RIIO-T1: Initial Proposals for NGGT and NGET – Impact Assessment

RIIO-T1 and RIIO-GD1: Initial Proposals – Real price effects and ongoing efficiency appendix
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RIIO-T1/GD1: Draft licence conditions – First informal licence drafting consultation
RIIO-T1 and RIIO-GD1: Draft licence conditions – First informal licence drafting consultation

Associated documents

RIIO T-1 Stage 4 NGET Final Assessment – A report for Ofgem
RIIO-T1 Stage 4 NGET Final Assessment – A report for Ofgem

RIIO-T1 Summary report – Gas. A report to the Office of Gas and Electricity Markets July 2012
RIIO-T1 SUMMARY REPORT – GAS A report to the Office of Gas and Electricity Markets July 2012

RIIO-T1 Stage 4 - National Grid System Operator Electricity and Gas Capex and Opex Final Assessment – Summary
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Cost of capital study for RIIO –T1 and GD1

Financial model
RIIO–T1/GD1: Financial model

Other Relevant Documents

RIIO-GD1: Initial Proposals – Overview
RIIO-GD1: Initial Proposals - Overview

RIIO-T1: Final proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd

RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas

RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd

Decision on strategy for the next transmission price control - Overview paper
Decision on strategy for the next transmission price control – RIIO-T1

Glossary
Glossary for all the RIIO-T1 and RIIO-GD1 documents

1. Introduction

Chapter Summary

This chapter explains the structure and purpose of this document, and of the associated documents published alongside it. The chapter also summarises our approach to assessing efficient costs and uncertainty mechanisms in setting our Initial Proposals for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT).

Purpose of this document

1.1. Under the RIIO process, network companies are required to take into account the needs and views of stakeholders in order to submit to us well-justified business plans. Our March 2011 Strategy Document for RIIO-T1[1] set out decisions on the key aspects of the regulatory framework. It also set out what we expected to see in a well-justified business plan and the criteria against which we would assess such a plan. We used five broad criteria to assess the plans:

- Process: has the company followed a robust process?
- Outputs: does the plan deliver the required outputs?
- Resources (efficient expenditure): are the costs of delivering the outputs efficient?
- Resources (efficient financial costs): are the proposed financing arrangements efficient?
- Uncertainty/risk: how well does the plan deal with uncertainty and risk?

1.2. This document aims to provide further detail to support the Initial Proposals Overview document in relation to the third and fifth of those criteria - the costs that the companies would be able to recover, and the arrangements for addressing risk and uncertainty around those costs.

1.3. Alongside this document we have published an Overview document[2] and two other Supporting Documents:

- RIIO-TI: Initial Proposals for NGET and NGGT – Outputs, incentives and innovation[3]

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[1] Decision on strategy for the next transmission price control: RIIO-T1 – Ofgem, 31 March 2011 Ref:46/11
Decision on strategy for the next transmission price control – RIIO-T1
[2] RIIO-T1: Initial Proposals for NGET and NGGT- Overview
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20Initial%20Proposals%20for%20NGGT%20and%20NGET%20Overview%202707212.pdf

- RIIO-T1: Initial Proposals for NGET and NGGT – Finance.[4]

1.4. The Supporting Documents are aimed primarily at network companies, investors and those who require a more in-depth understanding of the proposals.

1.5. Therefore, this document provides more detail on our Initial Proposals for funding the efficient expenditure for both companies to deliver the required outputs over the next transmission price control, RIIO-T1, from 1 April 2013 to 31 March 2021. Our Initial Proposals cover both baseline funding and uncertainty mechanisms to adjust the companies' allowed revenue according to outcomes such as generation connections volumes or specific events to trigger changes in funding.

1.6. The document also describes the results of our assessment of the cost efficiency of NGET's and NGGT's forecasts for baseline capex and opex in their March 2012 business plans and their proposed risk sharing arrangements for managing uncertainty and risk over RIIO-T1.

1.7. This document does not set out Initial Proposals for SP Transmission Ltd (SPTL) or Scottish Hydro Electric Transmission Ltd (SHETL). This is because the price control packages put forward by SPTL and SHETL were subject to "fast-tracking".[5] We published Final Proposals for those companies in April 2012.

Assessment process

1.8. During the development of the Initial Proposals presented in this document. we have used a range of qualitative and quantitative tools to assess the March 2012 business plans submitted by NGET and NGGT (TO and SO). This has included dashboard analysis[6], unit cost benchmarking, trend analysis, supplementary questions and sample scheme review. We have also engaged extensively with NGET and NGGT to understand, discuss and question their plans. In some areas this has led to further development of expenditure forecasts and uncertainty mechanisms.

1.9. In the development of the Initial Proposals for the TOs set out in this document, we have been supported by Pöyry Management Consulting as engineering consultants. In practice, Pöyry led two consortia who separately looked at electricity

[3] RIIO-T1: Initial Proposals for NGET and NGGT – Outputs, incentives and innovation
RIIO-T1: Initial Proposals for NGGT and NGET – Outputs, incentives and innovation
[4] RIIO-T1: Initial Proposals for NGET and NGGT – Finance
[5] Subject to statutory consultation on implementing the licence conditions: see RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd – Overview document
RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd
[6] Dashboard analysis uses a suite of Excel spreadsheets to analyse the detailed data in the business plan tables provided by the network companies. Amongst other things, this analysis highlights areas for further and more detailed investigation.

and gas. For electricity, the consortium comprised Pöyry Management Consulting, PPA Energy and TNEI. For gas, the consortium was made up of Pöyry Management Consulting and GL Noble Denton. For the rest of this document, we will use engineering consultants or Pöyry as a shorthand reference for the relevant consortium.

1.10. Our engineering consultants provided support through the following activities :

- a review of NGET and NGGT's March 2012 business plans (with reference where appropriate to their July 2011 business plans);
- a detailed review of relevant documentation for a representative sample of load-related capex and non-load related capex schemes;
- a 3 day cost visit to NGET and NGGT in late April 2012;
- analysis of extensive further information and data received from NGET and NGGT in answer to supplementary questions raised by Ofgem;
- relevant consideration of comparative data and information within the business plans of SHETL and SPTL;
- the engineering consultant's own independent analysis, eg on unit cost benchmarking;
- a review of feedback from NGET and NGGT on the draft reports (May 2012) from the engineering consultants, including any subsequent further assessment this triggered.

1.11. In the development of the Initial Proposals for the SOs set out in this document, we were supported by our engineering consultants, PPA Energy, who accompanied us on cost visits to NGET and NGGT. PPA Energy not only reviewed the companies' forecast costs, but also considered how these related to the information given in their business plans and expenditure in the TPCR4 period. PPA Energy has also taken into account the implications for system operation requirements of the plans set out by the TOs. For the rest of this document, we will use engineering consultants or PPA as a shorthand reference to the support on SO expenditure provided by PPA Energy.

1.12. In developing our Initial Proposals, we took into consideration the results of our analysis, the responses to our questions and the recommendations of our engineering consultants, as summarised in the following reports published alongside this document:

- NGET (TO)[7]
- NGGT (TO)[8]

[7] RIIO T-1 Stage 4 NGET Final Assessment – A report for Ofgem
RIIO-T1 Stage 4 NGET Final Assessment – A report for Ofgem

- NGET (SO) and NGGT (SO).[9]

1.13. Our Initial Proposals are also informed by responses to our March 2012 business plan consultation[10], views received from the Consumer Challenge Group (CCG)[11] and information provided by other stakeholders.

1.14. Although we have considered issues related to the TOs' performance during previous price control, TPCR4, and the forecasts in the one year adapted Rollover control (together TPCR4+R) during this assessment process, the analysis has been focused on the implications for RIIO-T1. During 2013, we will carry out a full efficiency review of expenditure in TPCR4+R.

Structure of this document and associated documents

1.15. The remainder of this document is structured as follows:

- Chapter 2 sets out our Initial Proposals for the uncertainty mechanisms that will apply across NGET and NGGT
- Chapter 3 summarises our Initial Proposals for the efficient costs and uncertainty mechanisms for NGET (TO)
- Chapter 4 provides more details on the efficient costs and uncertainty mechanisms for NGET (TO) in relation to load-related capital expenditure
- Chapter 5 provides more details on the efficient costs and uncertainty mechanisms for NGET (TO) in relation to non load-related capital expenditure
- Chapter 6 provides more details on the efficient costs and uncertainty mechanisms for NGET (TO) in relation to opex and non-operational capex
- Chapter 7 sets out the efficient costs and uncertainty mechanisms for NGGT (TO).

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[8] RIIO-T1 Summary report – Gas. A report to the Office of Gas and Electricity Markets July 2012
RIIO-T1 SUMMARY REPORT – GAS A report to the Office of Gas and Electricity Markets July 2012
[9] RIIO-T1 Stage 4 - National Grid System Operator Electricity and Gas Capex and Opex Final Assessment – Summary
RIIO-T1 Stage 4 - National Grid System Operator Electricity and Gas Capex and Opex Initial Assessment – Summary Report
[10] RIIO-T1: Publication of the revised business plans of NGET plc and NGG plc
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/NGET per cent20BP.pdf
[11] The CCG comprises consumer and environmental experts acting as a critical friend to Ofgem in the RIIO-T1 and RIIO-GD1 processes.

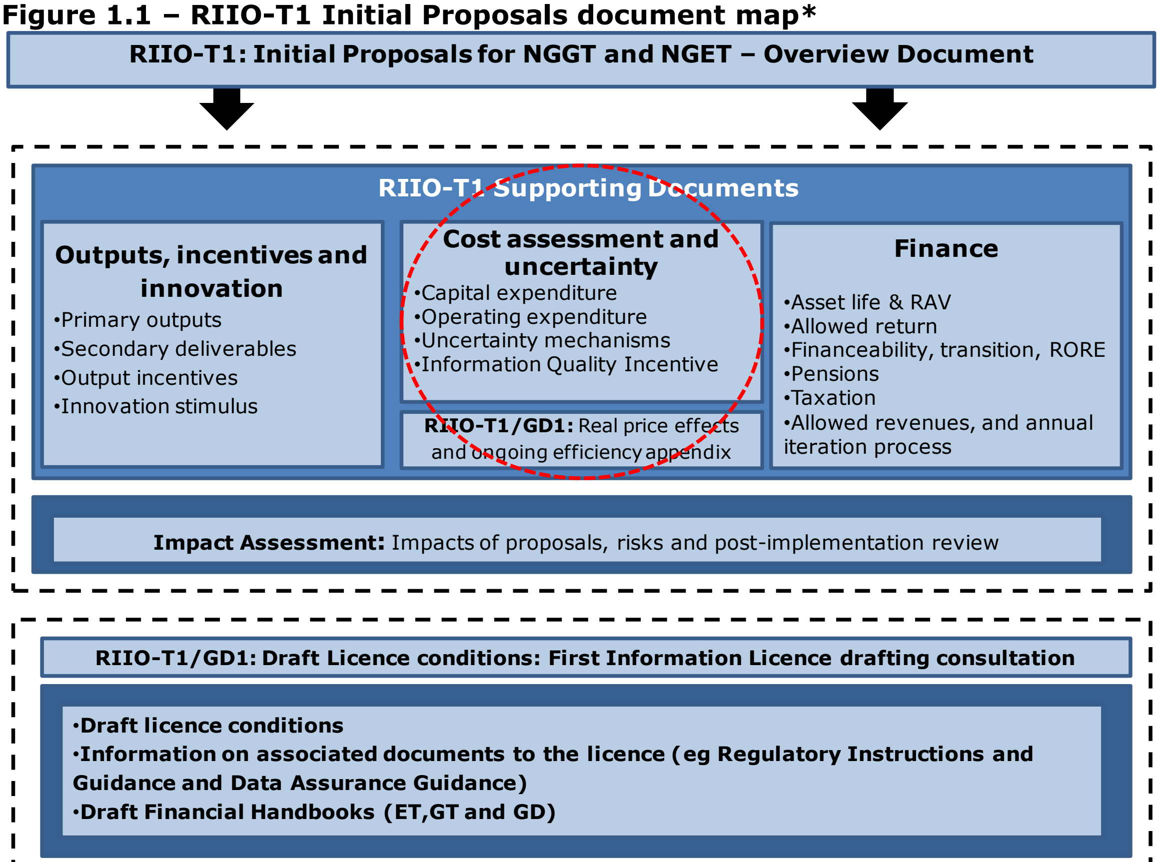
- Chapter 8 sets out the efficient costs and uncertainty mechanisms for NGET (SO) and NGGT (SO).

1.16. The appendices contain further details on the Information Quality Incentive (IQI) mechanism, the Strategic Wider Works (SWW) mechanism, load-related expenditure by NGET (TO), and our approach to assessment of business support costs.

1.17. All monetary amounts in this document are in 2009/10 prices unless otherwise stated. There may be slight differences between tables due to the rounding of numbers.

1.18. Figure 1.1. provides a map of the RIIO-T1 Initial Proposals documents. We have also published an initial consultation on licence drafting for all transmission companies.[12] Several draft conditions implement the uncertainty mechanisms discussed in detail in this document.

Figure 1.1 – RIIO-T1 Initial Proposals document map*



***Document links can be found in the 'Associated documents' section of this paper.**

[12] RIIO-T1/GD1: Draft licence conditions – First informal licence drafting consultation
RIIO-T1 and RIIO-GD1: Draft licence conditions – First informal licence drafting consultation

2. Uncertainty mechanisms

Chapter Summary

This chapter summarises our Initial Proposals in relation to uncertainty mechanisms that will apply to both NGET and NGGT.

Question 1: Do you agree with our assumptions for real price effects and ongoing efficiency?
Question 2: Do you agree with our proposed materiality thresholds of one per cent (subject to the efficiency incentive rate) for the majority of costs to be treated under the reopener mechanism?
Question 3: Do you agree with our proposal to restrict the reopeners for the roll-out of innovation to the two standard reopener windows, ie 2015/16 and 2018/19?
Question 4: Do you have any other comments in relation to our approach to uncertainty mechanisms?

Introduction

2.1. The Initial Proposals price control package proposes an ex ante, or baseline, revenue allowance for each company to finance and deliver an agreed level of outputs over the RIIO-T1 period. For some outputs, such as connections and wider system reinforcements, the actual level a TO delivers and, therefore, the costs it would incur could be significantly different to the agreed ex ante package due to changing customer requirements. Similarly, a TO's costs or ability to efficiently finance delivery could alter during the price control period due to new legal requirements or other circumstances beyond the TO's control. We have therefore put in place uncertainty mechanisms to deal with such circumstances.

Strategy Document

2.2. The overarching principle for uncertainty mechanisms that we set out in our Strategy Document was that network companies should manage the uncertainty they face and that the regulatory regime should not protect network companies against all forms of uncertainty. The use of uncertainty mechanisms should be limited to instances in which they will deliver value for money for existing and future consumers while also protecting the ability of networks to finance efficient delivery.

2.3. In our Strategy Document we proposed a number of uncertainty mechanisms for RIIO-T1. We also outlined the information that TOs would need to provide in their business plans in support of requests for additional or alternative mechanisms.

2.4. In particular, for NGGT we proposed a continuation of the existing use of revenue triggers for incremental exit and entry capacity. For NGET we proposed the use of volume drivers for new connections. We also set out options for uncertainty mechanisms in relation to wider reinforcement works, including the potential use of revenue triggers, within-period determinations and volume drivers.

2.5. We set out our policy for a reopener mechanism to deal with uncertainty relating to enhanced physical site security. In particular we noted that requests for additional funding would be restricted to two reopener windows (with any changes to allowed revenues impacting in 2016 and 2019) and that costs would have to breach a materiality threshold.

2.6. We proposed a materiality threshold of 1 per cent of allowed expenditure in year one of the price control, following the application of the efficiency incentive rate.[13] We also outlined that the innovation roll-out mechanism would also be subject to the same materiality threshold, but we proposed there would be an annual opportunity for TOs to apply for revenue adjustments.

2.7. We set out a number of mechanisms relating to financial instruments, eg cost of debt indexation; tax claw-back etc. We decided to retain the existing disapplication arrangements in the event that a network company experiences deteriorating financial health. We also outlined our proposed approach to inflation indexation using a 12 month average of the Retail Prices Index (RPI) and retaining of current policy to pass through licence fees and business rates.

2.8. Finally, we set out the basis for the mid-period review of outputs. We noted that the mid-period review would be tightly restricted to:

- changes to outputs that can be justified by clear changes in government policy
- the introduction of new outputs that are needed to meet the needs of consumers and other network users.

2.9. We provided an indicative timetable for the mid-period review, with a start date of January 2016. We stated that any changes to output requirements as a result of the mid-period review would impact allowed revenues from April 2017 (the start of the fifth year of RIIO-T1). We also stated that any change to outputs and allowed revenues at the mid-period review would be subject to a licence change, and to appeal.

2.10. We also note our April 2012 consultation on network charging volatility.[14] This consultation considered the option of introducing a lag on uncertainty mechanisms. We have not yet reached a decision following this consultation. Any change as a result of our decision would not impact on the mechanisms proposed in this document, it would only impact on when they would affect customers' charges.

2.11. Our aim in restricting potential changes to specified periods, ie using reopener windows and the mid-period review, and applying a materiality test is to limit the impact that uncertainty mechanisms will have on end customers' charges.

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[13] As described in Appendix 1.
[14] Mitigating network charging volatility arising from the price control settlement: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=368&refer=Networks/Policy

Initial Proposals

2.12. We set out below the details of the general uncertainty mechanisms that we have included in our Initial Proposals for both NGET and NGGT. A summary of the suite of the uncertainty mechanisms for each company is included in the relevant chapter, along with details of company-specific uncertainty mechanisms (eg Chapter 4 includes details of the connections volume driver).

Information Quality Incentive (IQI)

2.13. We use the IQI mechanism to set the strength of the upfront efficiency incentives each company faces according to the difference between the company's forecast and our assessment of its expenditure requirements. The IQI provides an incentive for companies to reveal their efficient costs at the price review, and provides an incentive within the review to minimise costs (as companies retain outperformance according to the efficiency incentive rate).

2.14. We issued a draft IQI mechanism with the Strategy Document, and used this with the "fast-track" companies. Since the "fast-track" business plans were accepted in full, they earned the full IQI additional income amount, i.e. 2.5 per cent of base totex. The efficiency incentive rate for the "fast-track" companies is 50 per cent, ie any over or underspend is shared equally between the network company and its customers.

2.15. We have used the same matrix with both NGET and NGGT using their March 2012 business plans adjusted for output changes. This results in additional income for NGET of around £19m per year and an efficiency incentive rate of 48 per cent, ie NGET would be exposed to 48 per cent of any over or underspend with its customers exposed to the remainder. For NGGT there is a small amount of negative additional income of around £0.9m per year, and an efficiency incentive rate of 45 per cent reflecting the larger difference between our cost assessment and NGGT's forecasts.

2.16. In the overview of our Initial Proposals for each company, we present total figures pre- and post-IQI. All other values are pre-IQI (unless otherwise stated). We also summarise the operation of the IQI mechanism in Appendix 1.

2.17. Our Strategy Document provides more details on the IQI mechanism.

Indexation

2.18. We will provide TOs with protection against economy wide inflation through annual indexation of revenues using the Retail Prices Index (RPI). We have changed our approach to indexation, from that set out in the Strategy Document. The background and reason for this change can be found in our decision on RPI indexation published in July 2011.[15] In summary, allowed revenues will be indexed

[15] Decision on the RPI indexation method:

by forecast RPI over the 12 months of the relevant year. There will be an additional adjustment two years later to true-up for the difference between forecast and actual RPI.

Real price effects

The TOs are also provided with an allowance for real price effects (RPEs), which represent the expected change in input prices (eg wages) relative to economy wide inflation. Further details can be found in the separate document on real price effects and ongoing efficiency.

2.19. We do not support an additional uncertainty mechanism, as proposed by NGET and NGGT, for further mitigating the risk of uncertainty in commodity prices. We consider that NGET and NGGT are best able to manage this risk and the provision of an uncertainty mechanism would put excessive risk on customers, and remove the incentive on NGET and NGGT to manage this risk. NGET and NGGT will receive some protection from outturn input prices through the efficiency incentive rate which allows for underspend or overspend to be shared with customers.

Pass through

2.20. We are not proposing any changes to our Strategy Document and will continue to allow for the pass through of specified costs that are uncontrollable.

Enhanced security reopener mechanism

2.21. A reopener mechanism is intended to allow for changes in allowances as a result of additional costs that are predominantly outside of a company's control and could not be forecast with any certainty at the price control review. It is not intended to protect the company against all risks.

2.22. We stated in our Strategy Document that we would provide a reopener mechanism to allow for additional funding in relation to the requirement to enhance physical security as a result of Government requirements for enhanced physical security around certain infrastructure. This is in addition to the ex ante allowance provided for sites where it was known that work would be required and costs included in the TOs' business plans. We have decided to also allow a reopener for enhanced security on the SO for the recovery of additional costs in relation to enhanced IT security, as required by Government.

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http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

2.23. We confirm below the detailed design of the reopener mechanism which was set out in the Strategy Document.

- The reopener can be triggered by a network company or by us. In order to trigger a reopener the efficient costs either already incurred (or saved), or likely to be incurred (or saved) over the remaining years of RIIO-T1, will need to pass a materiality threshold. We are setting this materiality threshold as a percentage of average annual forecast base revenue[16] over the price control period. We propose to use allowed revenue as opposed to allowed expenditure set out in our Strategy Document, for consistency with previous reviews. The materiality threshold percentage will be 1 per cent after the application of the efficiency incentive rate.
- Reopeners will be restricted to defined periods. A successful funding request will result in changes to allowed revenues from April 2016 and/or April 2019. NGET and NGGT will be required to submit a reopener request in May, of the previous year, for each applicable reopener. We have moved the reopener two months earlier than set out in the Strategy Document to allow enough time for assessment and consultation on changes to allowed revenue.
- All allowed revenue adjustments as a result of the application of uncertainty mechanisms will be part of the annual iteration of the financial model which will occur in November each year.

Wider application of reopener mechanism

2.24. NGET proposed that a number of additional areas be subject to a reopener mechanism. We are not proposing to provide any additional reopeners to NGET but we are proposing to address a number of the areas it identified as part of the mid-period review. These are discussed in further detail in Chapter 3 (TO) and Chapter 8 (SO).

2.25. We consider that there is merit in expanding the scope of the proposed reopener to include some additional areas of potential cost identified by NGGT, as described in more detail in Chapter 7.

Innovation roll-out mechanism

2.26. In our Strategy Document we stated that there would be an annual opportunity for the TOs to request additional funding under the innovation roll-out mechanism. However, we propose to restrict the reopener to two windows in line with other costs subject to reopeners. We do not consider that there is a requirement to provide greater scope to reopen the control for innovation relative to other cost areas. Restricting the number of reopeners will also minimise the opportunity for changes to allowed revenues and hence changes to customer charges. Again the materiality threshold will be 1 per cent after the application of the efficiency incentive rate.

[16] By this we mean NGET's and NGGT's Best View forecast.

Mid-period review

2.27. We do not propose any changes to the mid-period review as set out in our Strategy Document. Any changes to outputs and/or allowed revenues as a result of the mid-period review will apply from April 2017.

2.28. NGET and NGGT set out a number of areas in their business plans for which they were requesting a facility to request additional funding during the price control. We consider a number of these areas fall within the scope of the mid-period review, including (but not limited to):

- changes in safety legislation
- changes to environmental legislation
- contributions towards the Environment Agency's flood defence costs
- changes to the GB or EU energy markets.

2.29. As with any additional funding requests we would expect NGET and NGGT to provide evidence that they have engaged fully with stakeholders in order to minimise the cost impact of any legislative change.

3. Initial Proposals on cost and uncertainty for NGET (TO)

Chapter Summary

This chapter summarises our Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for NGET to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGET's March 2012 business plan and the reasons for this.

Question 5: Do you consider that our proposed funding baseline for NGET (TO) has been set at an appropriate level?
Question 6: Do you consider that our proposed uncertainty mechanisms for NGET (TO) are appropriate?

Introduction

3.1. This chapter sets out a summary of our Initial Proposals for the efficient costs to be recovered by NGET (TO) and the arrangements for addressing risk and uncertainty around those costs that will apply during RIIO-T1.

3.2. There are various costs that NGET incurs as a TO and for which it seeks to recover revenue in its price control. The main cost areas are capital expenditure (capex), primarily load-related capex and non-load related capex, and operating costs (opex).

3.3. Load-related capital expenditure (LRE) is the investment required to connect new generators and customers to the transmission network, to upgrade the existing transmission network including boundaries between TOs and to cater for growth in demand. The amount and location of load-related capex are dependent upon the quantity and location of new customers, particularly new generation customers and changes in demand for existing customers.

3.4. As a result, there is significant uncertainty in load-related capex over the price control period. To overcome this we use a number of different mechanisms to fund the TO's load related capex, with a baseline forecast being funded ex ante for each year of RIIO-T1, and uncertainty mechanisms (including revenue drivers and within-period determinations) which adjust revenue according to outcomes such as the volume of generation connected or capacity across defined boundaries.

3.5. Non-load related capital expenditure (NLRE) principally comprises of expenditure required to replace existing assets on the TO network, but also includes expenditure relating to network resilience, flooding, physical security and a telecoms network upgrade. Non-load related capex depends on the age and condition of existing assets and their criticality to the operation of the network. As this type of expenditure can be forecast with greater accuracy than load-related capex, it is generally funded through ex ante expenditure baselines.

3.6. Operating expenditure (opex) covers the ongoing costs of running the TOs' business, including asset maintenance and support services. It is funded through ex ante expenditure baselines.

Overview

3.7. Table 3.1 summarises the key cost parameters for NGET (TO)'s Best View, both in terms of NGET's forecast and our Initial Proposals.

3.8. 'Best View' is the expenditure that we consider the licensees will need to deliver the outputs under their central scenario. It comprises 'baseline' and 'uncertainty mechanism' funding. 'Baseline' is the expenditure that is funded through ex ante allowances. 'Uncertainty Mechanism' funding adjusts allowed expenditure automatically where the level outputs delivered differ to the baseline level, or is triggered by events defined in the transmission licences, or is provided at certain times during the price control period after further assessment by Ofgem of needs case and costs.

3.9. Table 3.1 includes non-controllable opex. those costs outside of the companies control including items such as licence fees and Network Rates, . Non controllable costs for RIIO have a value of £642m.

Table 3.1 – Key cost parameters for NGET (TO)[17]

£b, 2009/10 prices	**NGET's Best View**	**Initial Proposals**
LRE	7.5	6.7
NLRE	4.8	4.3
Non-operational capex	0.2	0.1
Total Capex	**12.5**	**11.2***
Customer contributions	-0.2	-0.2
Total Capex (net of customer contributions)	**12.3**	**11.0**
Total Opex including non controllable opex	**2.6**	**2.2**
Total expenditure (Totex) exc RPEs	**14.9**	**13.2**
RPEs	1.2	0.5
Totex before IQI adjustment	**16.1**	**13.7**
IQI adjustment	n/a	0.2
Totex after IQI adjustment	**n/a**	**13.9**

*This reflects rounding differences

[17] The figures in this table exclude RPEs unless otherwise stated.

3.10. The Transmission Investment Incentives (TII) framework was introduced on 1 April 2010 to provide project-specific, interim funding for critical large-scale investments within TPCR4. The framework was subsequently modified for application in the TPCR4 rollover year 2012-13.

3.11. The TII framework is being superseded by the arrangements for Wider Works under RIIO-T1, as discussed in Chapter 4. However, certain provisions within the current TII framework will need to be retained under RIIO-T1:

- the adjustment mechanisms and reporting arrangements, as they apply to relevant works undertaken in 2012-13
- the provisions, which were introduced as part of the modifications to this condition for 2012-13, for future revenue adjustments to be made under RIIO-T1, such as the "true-up of revenues", and the application of the capital efficiency incentive to the relevant works.

Summary of NGET's expenditure forecasts

3.12. Table 3.2 sets out NGET's forecast expenditure in relation to its requirements for a baseline amount of revenue set at the start of the price control to cover expenditure in each year of RIIO-T1 for the relatively more certain portion of investment; and for its Best View scenario.

Table 3.2 – NGET forecasts for baseline and Best View expenditure (excluding Non Controllable Opex)[18]

£m - year to 31 March 2009/10 prices	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**RIIO-T1**
LRE	1,061.2	1,289.4	1,149.4	1,043.7	660.8	520.3	312.7	203.6	**6,241.2**
NLRE	578.1	531.5	477.5	483.1	601.9	701.7	756.0	670.5	**4,800.4**
Non-operational capex	30.2	29.1	20.8	20.2	18.9	10.8	15.1	26.0	**171.2**
Customer contributions	-46.3	-34.8	-31.5	-40.3	-34.3	-29.4	-13.5	-1.6	**-231.7**
Opex	234.9	238.7	244.1	245.1	243.1	243.2	243.2	244.2	**1937.4**
RPEs	38.7	74.7	102.7	124.4	121.6	135.5	135.6	129.4	**862.6**
Baseline expenditure	**1,896.8**	**2,128.6**	**1,963.0**	**1,876.2**	**1,612.0**	**1,582.1**	**1,449.1**	**1,272.1**	**13,781.1**

[18] The figures in this table exclude RPEs unless otherwise stated.

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	1,073.9	1,338.6	1,287.4	1,289.2	923.4	828.3	465.6	292.4	**7,498.9**
NLRE	578.1	531.5	477.5	483.1	601.9	701.7	756.0	670.5	**4,800.4**
Non-operational capex	30.2	29.1	20.8	20.2	18.9	10.8	15.1	26.0	**171.2**
Customer contributions	- 46.3	-34.8	- 31.5	- 40.3	-34.3	-29.4	-13.5	-1.6	**-231.7**
Opex	234.9	238.7	244.1	245.1	243.1	243.2	243.2	244.2	1937.4
RPEs	47.5	86.5	125.2	161.0	172.0	203.3	197.5	180.6	**1,173.5**
Best View expenditure	**1,918.3**	**2,189.6**	**2,123.5**	**2,158.3**	**1,925.0**	**1,957.9**	**1,663.9**	**1,412.1**	**15,349.7**

Initial Proposals for efficient expenditure

3.13. Table 3.3 sets out how our Initial Proposals differ from NGET's forecast expenditure. In total we have reduced NGET requested costs by around £2.0bn for the TO. We have also moved £1.4bn from NGET's baseline into uncertainty mechanisms. The key changes are summarised below.

3.14. We have moved some expenditure which NGET had proposed in its baseline into uncertainty mechanisms. This comprises two elements:

- We have reduced NGET's proposed baseline by £0.55bn to reflect the greater downside risk that new generation capacity will be less than that on which the Gone Green scenario is based. However, our "Best View" of expenditure is based on the Gone Green scenario with the extra funding being delivered via volume drivers.

- Since the publication of its business plan, NGET has indicated that the total project cost of reinforcement works associated with the upgrade of Hinkley Point nuclear power station are likely to cost more than £500m. Given that, we moved the £0.47bn (amount in RIIO-T1) associated with wider works into the SWW funding mechanism. NGET will be able to bring forward a request for funding for this project when it has confirmed a needs case.

3.15. We have reduced the proposed capex for NGET by around £1.3bn to reflect capex efficiency challenges resulting in reductions in unit costs derived from comparisons to TPCR4, the Scottish TOs and evidence from our engineering consultants, Pöyry, and including reductions to Real Price Effects (RPEs).

3.16. We have assumed lower RPEs than those proposed by NGET. This reflects both a reduction in the assumption for real wage growth and a reduction in NGET's proposed real growth in materials costs. Lower RPEs will also reflect the lower baseline we have proposed.

3.17. We have also disallowed expenditure relating to the delivery of outputs in RIIO-T2. This accounts for around £0.4bn of the reduction in LRE capex funding.

3.18. We have reduced the proposed opex expenditure by around £0.4bn reflecting TPCR4 comparisons, our engineering consultants' reviews and reductions in RPEs.

Table 3.3 – Difference between NGET forecasts and our Initial Proposals

£bn 2013-2021	Baseline	UMs	Total
July 2011 business plan	**14.7**	**1.5**	**16.2**
Changes between first and second business plan	-0.03	-0.2	-0.3
March 2012 businesss plan	**14.7**	**1.3**	**16.0**
Reduction in baseline	-0.6	0.6	-
Efficiency challenge – load-related capex	-0.3		-0.3
Efficiency challenge – non-load related capex	-0.5		-0.5
Efficiency challenge – opex incl RPEs	-0.4		-0.4
Transfer Hinkley reinforcement from baseline to SWW	-0.5	0.5	-
Reduction in capex RPEs	-0.5		-0.5
Disallow expenditure for outputs in RIIO T2	-0.4		-0.4
Transfer RPEs for Uncertainty Mechanisms (UMs) out of baseline	-0.3	0.3	-
Provisional IP totals	**11.1**	**2.6**	**13.7**

3.19. Table 3.4 sets the annual profile for our Initial Proposals, with respect to baseline expenditure and Best View.

Table 3.4 – Initial proposals for baseline and Best View expenditure (excluding Non Controllable Opex)

£m - year to 31 March, 2009/10 prices	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**RIIO-T1**
LRE	873.3	999.8	840.8	776.1	462.1	304.6	133.6	44.4	**4,434.7**
NLRE	458.6	438.4	423.3	424.7	538.4	625.3	673.0	593.5	**4,175.3**
Non-operational capex	25.7	25.8	19.1	16.2	14.6	9.0	7.5	6.3	**124.2**
Customer contributions	-45.6	-34.2	-30.7	-39.0	-33.1	-28.2	-12.9	-1.5	**-225.1**
Opex	198.77	198.4	200.30	199.6	198.4	196.3	195.0	191.9	1,578.7
RPEs	14.9	32.7	43.6	55.7	58.4	65.6	66.8	60.8	**398.6**
Baseline expenditure	**1,525.7**	**1,660.9**	**1,496.4**	**1,433.3**	**1,238.8**	**1,172.6**	**1,063.0**	**895.4**	**10,486.4**

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	1,004.0	1,224.7	1,163.4	1,213.5	848.8	762.9	360.5	146.0	**6,724.7**
NLRE	535.89	481.79	429.34	435.79	540.56	627.43	675.14	595.62	**4,321.6**
Non-operational capex	25.70	25.80	19.10	16.20	14.60	9.00	7.50	6.30	**124.2**
Customer contributions	- 45.63	- 34.17	- 30.66	- 39.04	- 33.06	- 28.16	- 12.89	- 1.49	**- 225.1**
Opex	204.0	204.7	206.8	206.4	204.7	202.6	201.3	198.2	**1,629.0**
RPEs	13.69	37.05	54.79	78.00	84.34	102.89	92.19	78.55	**541.5**
Best View expenditure	**1,737.7**	**1,939.9**	**1,842.8**	**1,910.9**	**1,659.9**	**1,676.7**	**1,323.7**	**1,023.2**	**13,115.9**

Uncertainty mechanisms

3.20. NGET has proposed a range of mechanisms in the RIIO-T1 control to help it manage the potential uncertainty it has identified during the eight year price control period. This includes a number of additional or alternative uncertainty mechanisms to those set out in our Strategy Document.

3.21. Table 3.5 sets out an overview of the uncertainty mechanisms that we propose to provide for NGET, and lists where further information can be found. In addition, the Supporting Document on Finance sets out details of mechanisms related to the cost of debt, pension deficit repair and tax trigger.

Table 3.5 – Proposed uncertainty mechanisms for NGET

Uncertainty mechanism	NGET proposal	Our proposal	Timing of potential change	Reference
Efficiency Incentive Rate	Keep 50 per cent of the percentage of underspend/ overspend against allowed expenditure	48 per cent (calculated by applying the IQI mechanism)	Annual	Chapter 2 and Appendix 1
Indexation	Annual indexation of revenues using the RPI	Our decision on RPI indexation was published in July 2011[19]	Annual	Chapter 2
Real price effects (RPEs)	Allowance for RPEs to represent	Allowance for RPEs but no specific	Ex-ante allowance	Chapter 2

[19] Decision on the RPI indexation method: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Uncertainty mechanism	NGET proposal	Our proposal	Timing of potential change	Reference
tracker	expected relative change in input prices, with an additional copper price tracker	copper price tracker		
Pass through	Pass through of specified costs outside of the control of the TOs – eg Licence fees, business rates,[2] inter-TSO scheme payments	Consistent with Strategy Document	Annual	Chapter 2
Disapplication	If company experiences financial distress	Consistent with Strategy Document	At any time	
Reopener mechanism	Reopener mechanism for a number of trigger events	Reopener mechanism for additional funding to enhance physical security (as per Strategy Document)	Twice: April 2016, April 2019	Chapter 2
Mid-period review	Limited to changes to outputs	Consistent with Strategy Document	Once: April 2017	Chapter 2
Innovation roll-out mechanism		Restrict the reopener to two windows in line with general reopener mechanism	Twice: April 2016, April 2019	Chapter 2
NLRE advancement mechanism	A dead-band for clawing back LRE to allow NGET to advance NLRE	Do not intend to include. The efficiency incentive will provide some protection to financing costs.		
Volume drivers	Covering local generation connections, new demand connections, wider works, and visual amenity impact of new infrastructure	Consistent with Strategy Document	Annual	Chapter 4

Uncertainty mechanism	NGET proposal	Our proposal	Timing of potential change	Reference
Within period determination	For specifc projects over £500m, or projects not meeting NDP criteria.	Consistent with Strategy Document	Annual	Chapter 4
Pre-construction funding mechanism	No proposal	Within-period determination of efficient costs for pre-construction engineering works in relation to a combined onshore/offshore transmission project if incumbent TO best placed to do early design work[20]	If measures are implemented to trigger a request	Chapter 4

[20] All funding for pre-construction works will be conditional on being able to transfer deliverables into an offshore or onshore tender process if required.

4. Initial Proposals for Load-Related Capex for NGET (TO)

Chapter Summary

This chapter sets out our Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for load-related capital expenditure for NGET to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGET's March 2012 business plan and the reasons for this.

Introduction

4.1. This chapter sets out our assessment of NGET's RIIO-T1 business plan for load-related capital expenditure (LRE) and our Initial Proposals for efficient costs and risk sharing arrangements with consumers.

4.2. As part of its business plan, NGET set out its forecast of the LRE it expects to undertake over RIIO-T1 to connect new generators and customers to its transmission network, to increase the capacity of its network and to cater for demand growth.

4.3. NGET's LRE forecasts comprise three main expenditure categories: Local Enabling, Wider Works and Transmission System Support (TSS).

4.4. Local Enabling works are driven by the connection of (or changes in) Generation ('Entry') or the connection of (or changes in) Demand ('Exit'). These works are the minimum transmission works needed to connect a customer to the transmission network.

4.5. Wider Works are other transmission reinforcement works (ie not Local Enabling works) associated with reinforcing the integrated network to accommodate large changes in Generation or Demand and to comply with security standards.

4.6. TSS is a relatively small category of investment on the network and is driven by the System Operator (SO).

4.7. In our Strategy Document, we said that the each TO should develop its LRE forecasts in line with its 'Best View', or best estimate of the costs and outputs it could be required to deliver out to the end of RIIO-T1. This is important for business planning as it ensures the TO fully considers the deliverability and financeability of its plan, implications of the level of delivery for resourcing and organising the business, as well as the phasing of delivery, particularly where there might be synergies or conflicts in output delivery.

4.8. Whether the amount of LRE NGET will incur over RIIO-T1 is the same as its Best View is dependent upon the quantity and location of new customers, particularly new generation customers and changes in demand for existing customers. As a result there is considerable uncertainty around the amount and timing of LRE NGET will actually make over the price control period.

4.9. To manage this uncertainty we proposed in our Strategy Document that Best View LRE is funded through a combination of the following:

- a baseline amount of revenue set at the start of the price control to cover expenditure in each year of RIIO-T1 for the relatively more certain portion of investment.

- a variable revenue adjustment implemented through pre-defined uncertainty mechanisms (UMs), such as volume drivers and within-period determinations. This would modify annual allowed revenues according to actual output delivery in a given price control year, such as the volume of generation connected or capacity across defined boundaries, where these differ to the baseline amount.

4.10. The rest of this chapter is structured as follows.

4.11. We start with an overview of NGET's forecasts for LRE and proposed uncertainty mechanisms in its March 2012 business plan and our Initial Proposals for both areas. We also highlight the key differences between our Initial Proposals and NGET's business plan.

4.12. We then look at our Initial Proposals for each LRE category in more detail. This includes an annual profile of baseline expenditure to deliver the associated outputs, and the UMs we propose to use to adjust LRE in that category over the price control. In each section we also set out our assessment of NGET's proposals, how this has informed our Initial Proposals and why we think our Initial Proposals represent good value for existing and future consumers.

4.13. We conclude by setting out our Initial Proposals for LRE funding requests which are separate to RIIO-T1 but submitted by NGET alongside its RIIO-T1 business plan. This includes additional funding for certain works undertaken in 2012/13 and a request for pre-construction funding in relation to a combined onshore/offshore transmission project on the east coast of England.

Overview

Overview of NGET's LRE forecasts

4.14. NGET has developed its Best View of LRE during RIIO-T1 based on the Gone Green scenario developed by the Electricity Network Strategy Group[21]. Under this scenario for connections more than 30GW of generation are to be completed during the RIIO-T1 period.

4.15. As shown in Table 4.1, NGET's Best View forecast of the LRE needed to accommodate the Gone Green scenario totals nearly £7.5bn. This is a 177 per cent increase on NGET's combined LRE under TPCR4+R (£2.7bn) and accounts for around 60 per cent of its total RIIO-T1 capex plan (£12.5bn excluding RPEs).

4.16. The total LRE RPEs forecasted by NGET is £564.4m. The figures presented in this chapter (including in this table) are in 2009/10 prices and exclude RPEs, but where it is relevant references to RPE adjustments are stated.

Table 4.1 - NGET's forecasts for baseline and Best View LRE (excluding RPEs)

LRE Categories	Baseline funding (£m)	Uncertainty mechanism funding (£m)	Best View of total LRE (£m)
Local Enabling (Entry - Sole Use)	0.0	0.0	0.0
Local Enabling (Entry – Shared Use)	1,313.4	0.0	1,313.4
Local Enabling (Exit - Sole Use)	485.8	0.0	485.8
Local Enabling (Exit – Shared Use)	508.9	0.0	508.9
Wider Works (Entry)	3,695.7	1,257.7	4,953.4
Wider Works (Exit)	0.0	0.0	0.0
Wider Works (General)	230.0	0.0	230.0
Infrastructure - TSS	7.3	0.0	7.3
Total LRE	**6,241.1**	**1,257.7**	**7,498.8**

4.17. NGET proposes in its business plan that around 83 per cent of forecast LRE is included in its RIIO-T1 baseline revenues. To get to its Best View, NGET proposes a further £1.3bn would be funded through UMs and subject to specific project approval by Ofgem during the price control as and when the consumer benefits of the project become more certain. In such cases Ofgem would assess the needs case and efficient costs of delivering the Strategic Wider Works (SWW), defined as large

[21] ENSG "Our Electricity Transmission Network: A Vision for 2020 – An Updated Full Report to the Electricity Network Strategy Group – February 2012".
http://www.decc.gov.uk/publications/basket.aspx?filetype=4&filepath=11%2fmeeting-energy-demand%2ffuture-elec-network%2f4263-ensgFull.pdf&minwidth=true#basket

reinforcements with costs greater than £500m, and make a revenue adjustment (for more detail see the later section on SWW in this chapter).

4.18. Owing to the uncertainty associated with an eight year period and the scope for actual outcomes to differ from its baseline, NGET's March 2012 business plan[22] included UMs for each of the main LRE categories, as summarised in Table 4.2. These would automatically adjust revenue in each year of RIIO-T1 to reflect the level of outputs NGET actually delivers, based on the unit costs of delivering an additional unit of the relevant output. Such mechanisms are known as volume drivers with the parameters, such as the unit cost allowances (UCA), set at the start of the price control period.

Table 4.2 - LRE volume drivers in NGET's March 2012 business plan

LRE Category	Source of Uncertainty	Volume Driver Constituents	UCA
Local Enabling (Exit – Shared Use)	Volume and timing of demand connections	Substation Costs	£4.6m/ Super Grid Transformer (SGT)
		Overhead Lines Costs (OHL)	£1.2m/circuit km
Local Enabling (Entry – Shared Use)	Location and timing of local generation connections	Substation Costs	£23/kW
		Within-zone Costs	Zonal (£2.7/kW to £36.8/kW)
		OHL	£1.2m/circuit km
Wider Works (Entry)	Location and timing of new generation load	Network Development Policy and Boundary Specific Reinforcement costs	Boundary specific unit costs for capacity increases; Banded for below gone green and above gone green; Range between £33/kW to £155/kW.
	Planning requirements for new infrastructure	Undergrounding Costs	Unit costs for undergrounding from Institution of Engineering and Technology's 2012 industry report
		DNO Mitigation Costs	Undergrounding of DNO OHL (£1.1m/single circuit km) DNO Tower dismantling ([Redacted]) New DNO single circuit OHL (£0.7m/single circuit km) New DNO Switchgears ([Redacted])

[22] For more information on NGET's Uncertainity mechanisms can be found in its Business Plan chapter on Risk and Uncertainity. http://www.nationalgrid.com/NR/rdonlyres/4F6EF249-C014-4B70-BEF6-3A821BDE978E/52234/2012_NGET_managing_risk_and_uncertainty_redactedsecure1.pdf

4.19. Consistent with our Strategy Document NGET propose a Wider Works (WW) volume driver for managing the uncertainty around the timing of reinforcements needed to accommodate new generation load. Under this mechanism NGET would have some discretion as to the WW outputs (measured as an increase in transfer capability) it will deliver at system boundaries over the price control. NGET's decisions regarding the delivery of additional boundary capacity would be subject to a Network Development Policy (NDP) in which NGET will set out how it will decide whether to deliver additional reinforcements that are in consumers' interests.

Overview of Ofgem's Initial Proposals for LRE and uncertainty mechanisms

4.20. Table 4.3 summarises our Initial Proposals for NGET's LRE for which our Best View is £6,728m over RIIO-T.

Table 4.3 – Ofgem's Initial Proposals for baseline and Best View LRE (excluding RPEs)

Load Related Category (2009/10 Prices)	**Baseline funding (£m)**	**UM funding (£m)**	**Best View of total LRE (£m)**
Local Enabling (Entry - Sole Use)	0.0	0.0	0.0
Local Enabling (Entry – Shared Use)	794.2	220.5	1,014.7
Local Enabling (Exit - Sole Use)	492.0	0.0	492.0
Local Enabling (Exit - Shared Use)	227.5	25.6	253.1
Wider Works (Entry)	2,558.7	1,988.8	4,547.5
Wider Works (Exit)	0.0	0.0	0.0
Wider Works (General)	413.8	0.0	413.8
Transmission System Support	7.3	0.0	7.3
Total	**4,493.5**	**2,234.8**	**6,728.3**

4.21. Table 4.4 summarises our Initial Proposals for UMs to manage the uncertainty associated with the costs and volumes of the Best View LRE and to ensure efficient risk sharing arrangements with consumers.

4.22. As set out in Table 4.4 we are proposing volume drivers for each of the main LRE categories to automatically adjust revenues each year to remunerate NGET for the efficient costs of the outputs actually delivered. These would operate both up and down from the baseline. In the event output delivery in a given year was less than that allowed for in the baseline the volume driver would reduce baseline revenues for that year. Alternatively if output delivery exceeds the baseline level the volume driver would increase NGET's allowed expenditure for the efficient costs of delivery.

4.23. We are proposing another type of UM for some LRE for which it is more difficult to ascribe a simple output measure. In this instance, the UM would trigger funding by events defined in the transmission licences such as planning conditions.

4.24. The third type of UM we are proposing is within-period determinations of project specific revenue adjustments for SWW outputs, after further assessment by Ofgem of needs case and costs, which NGET could request during the price control period.

4.25. More detail on the proposed design and operation of the UMs can be found in the following sections on each area of LRE, along with our assessment of NGET's proposals.

Table 4.4 – Ofgem's Initial Proposals for uncertainty mechanisms

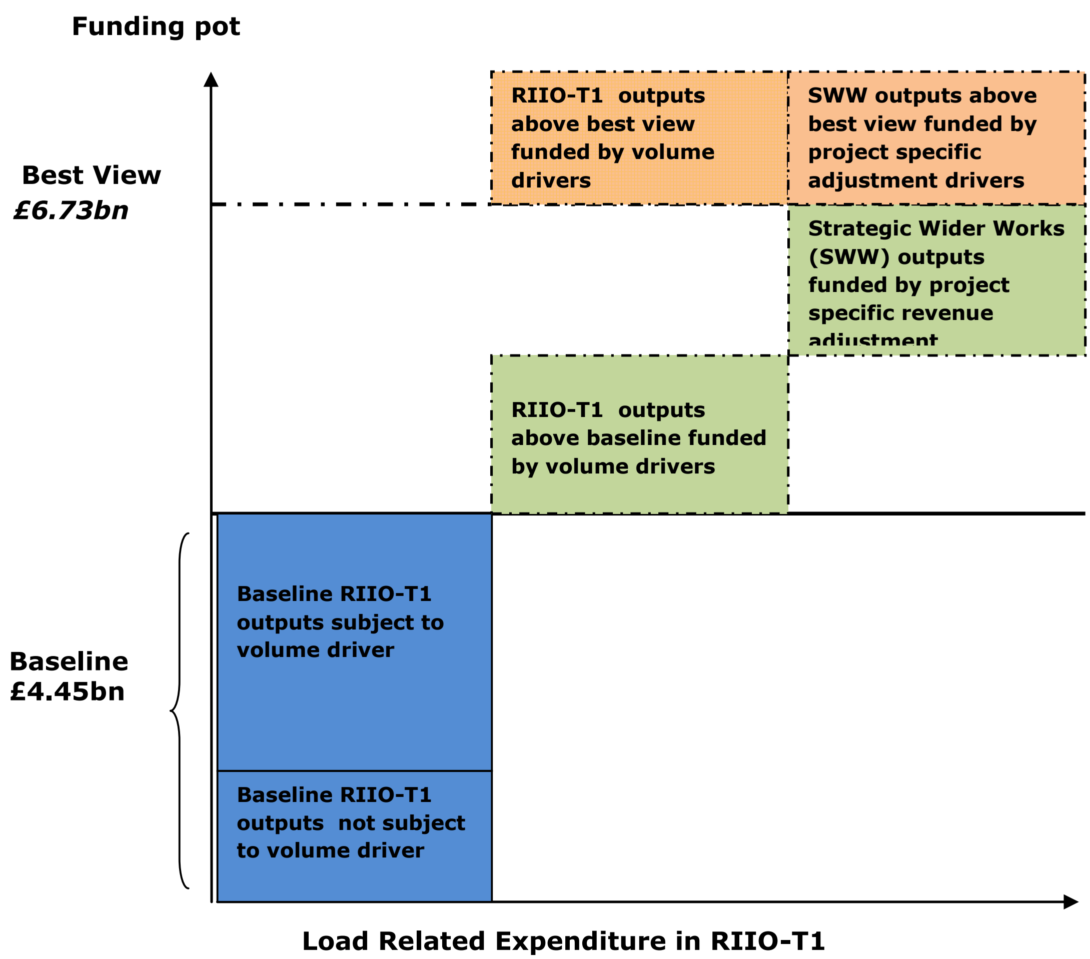
LRE category	Source of uncertainty	Proposed uncertainty mechanism
Local Enabling (Entry – shared use)	Location, volume and timing of new generation connections	Volume driver based on additional MW capacity connected and kilometres of OHL and cable.
Local Enabling (Exit – sole and shared use)	Volume and timing of new demand connections	Volume driver based on the number of new transformers, and kilometres of OHL and cable.
Wider Works (Entry)	Timing and volume of new generation load	Volume driver based on delivered WW outputs (additional transfer capability) that meet Network Development Policy (NDP) criteria to be funded using boundary specific unit costs and delivered outputs.
		Strategic Wider Works (within-period determination) mechanism for large reinforcements (>£500m) or projects not meeting NDP criteria.
	Planning requirements for new infrastructure	Volume driver based on requirements of planning decisions using Institution of Engineering and Technology's industry report on underground cable costs.
		Volume driver using unit costs of DNO mitigation.

4.26. Figure 4.1 below shows how our Initial Proposals provide flexible and efficient funding arrangements for the Best View of NGET's load related business plan over RIIO-T1.

4.27. Our Initial Proposals set a baseline LRE of £4,447.5m (the grey shaded stack in the left hand bottom corner of Figure 1.1), or 66 per cent of Best View LRE. The baseline is the amount of revenue we propose to set NGET at the start of the price control for LRE in each year of RIIO-T1. Some of the proposed baseline LRE is for outputs (the first block of the baseline stack) that are not suited to a volume driver because of the unique nature of the works in question. However, for the majority of the baseline outputs we propose that the baseline funding in each LRE category is subject to the applicable volume driver in Table 4.4 in order to true up NGET's funding each year for the efficient costs of outputs it delivers.

4.28. Our Initial Proposals set a baseline LRE of £4,447.5m (the grey shaded stack in the left hand bottom corner of Figure 1.1), or 66 per cent of Best View LRE. The baseline is the amount of revenue we propose to set NGET at the start of the price control for LRE in each year of RIIO-T1. Some of the proposed baseline LRE is for outputs (the first block of the baseline stack) that are not suited to a volume driver because of the unique nature of the works in question. However, for the majority of the baseline outputs we propose that the baseline funding in each LRE category is subject to the applicable volume driver in Table 4.4 in order to true up NGET's funding each year for the efficient costs of outputs it delivers.

Figure 4.1 - Ofgem's proposed funding arrangements for Best View LRE



4.29. Our Initial Proposals set a baseline LRE of £4,447.5m (the blue stack in the left hand bottom corner of Figure 1.1), or 66 per cent of Best View LRE. The baseline is the amount of revenue we propose to set NGET at the start of the price control for LRE in each year of RIIO-T1. Some of the proposed baseline LRE is for outputs (the first block of the baseline stack) that are not suited to a volume driver because of the unique nature of the works in question. However, for the majority of the baseline outputs we propose that the baseline funding in each LRE category is subject to the applicable volume driver in Table 4.4 in order to true up NGET's funding each year for the efficient costs of outputs it delivers.

4.30. We also propose that LRE for RIIO-T1 outputs above the baseline level is funded through the UMs in Table 4.4 (the green stack blocks). Our proposed Best View of £6.7bn for LRE required in RIIO-T1 is not a cap. This is an estimate for the purposes of setting the price control. In reality total LRE for RIIO-T1 will be determined by customer requirements and the obligations NGET has to meet as owner of the transmission network. The UMs set out in these Initial Proposals can potentially adjust NGET's LRE above the Best View (the orange stacks) to ensure it can finance the efficient delivery of outputs that turn out to be required in RIIO-T1.

4.31. Potentially NGET could incur additional LRE that is not covered by the baseline or the UMs operating in each LRE category. The first area is any overspend NGET incurs relative to the efficient costs of delivering the outputs set out in these Initial Proposals. We propose that any overspend in relation to the outputs required for RIIO-T1 is subject to the total expenditure (totex) sharing factor of 48% (as calculated under the IQI mechanism and described in Chapter 3).

4.32. Another source of LRE NGET could incur which is not included in our baseline or UMs are for works that it might need to start towards the end of RIIO-T1 but where the outputs would not be delivered in RIIO-T2.

4.33. For the avoidance of doubt, SWW outputs that are started in RIIO-T1 for delivery in the next price control would not fall into this category of LRE. For such outputs we propose that NGET would be able to request funding during RIIO-T1 on a project specific basis under the SWW arrangements described in more detail later in this chapter.

4.34. Given the separate SWW arrangements, we expect any other works for RIIO-T2 outputs that NGET might need to start in RIIO-T1 would be smaller to medium sized projects. In such circumstances the totex sharing factor would ensure that NGET is partly funded during RIIO-T1.

4.35. We propose that the remainder of LRE that NGET incurs in RIIO-T1 for outputs delivered in RIIO-T2 would be reviewed as part of our assessment for the next price control. This assessment would be based on the principle that NGET is fully remunerated, on a cost neutral basis, for the efficient costs of delivering the RIIO-T2 outputs.

4.36. This could either be included as part of their baseline revenues for RIIO-T2 or through applicable volume driver arrangements that are set in the future as part of the RIIO-T2 price control settlement. As part of any future settlement, we would consider the appropriate glide path between the T1 and T2 arrangements.

4.37. We have looked at the potential level of works for RIIO-T2 outputs that NGET might be required to start in the latter years of RIIO-T1. We consider that the potential level of such works would be fairly modest relative to NGET's overall asset base. Consequently we do not anticipate this would have any significant implications for NGET in terms of its cash flow or credit ratings to warrant any measures in addition to the totex sharing factor ahead of the efficiency assessment in the next price control.

Key differences between Ofgem's Initial Proposals and NGET's March 2012 business plan

4.38. The differences between Ofgem's Initial Proposals and NGET's March 2012 business plan plan for the LRE categories are summarised in Table 4.5.

Table 4.5 - Key differences between NGET's forecasts and our Initial Proposals

LRE categories	**NGET's proposals (March 2012)**	**Ofgem's Initial Proposals**	**Change**
	(£m)	**(£m)**	**%**
Local Enabling (Entry - Sole Use)	0.0	0.0	0.0%
Local Enabling (Entry – Shared Use)	1,313.4	794.2	-39.5%
Local Enabling (Exit - Sole Use)	485.8	492.0	1.3%
Local Enabling (Exit – Shared Use)	508.9	227.5	-55.3%
Wider Works (Entry)	3,695.7	2,558.7	-30.8%
Wider Works (Exit)	0.0	0.0	0.0%
Wider Works (General)	230.0	413.8	79.9%
Infrastructure - TSS	7.3	7.3	0.0%
Baseline LRE	**6,241.1**	**4,493.5**	-28.0%
Strategic Wider Works	1,257.7	1,679.8	33.6%
Outputs funded by UMs	0.0	555.0	
Best View LRE	**7,498.8**	**6,728.3**	-10.3 %
RPEs	564.4	282.7	-49.9%

4.39. The proposed reduction in RPEs is driven in part by the lower level of Best View expenditure and also by a general reduction in the RPE factor.

4.40. Based upon our analysis and supporting evidence and recommendations from our engineering consultants, we propose a Best View for LRE in our Initial Proposals that is £770.6m less than NGET's forecasts in their March 2012 business plan. This difference is comprised of:

- Efficiency Savings identified across all LRE categories (£290.5m)
- Disallowed LRE in relation to DNO mitigation costs (£18.1m)
- Removal of RIIO-T2 output expenditure (£462.0m).

Efficiency savings (£290.5m)

4.41. We are proposing to apply £290.5m efficiency savings which come from across the LRE categories. These efficiency savings are based on our assessment, taking into account the benchmarking undertaken by our engineering consultants, comparisons to TPCR4 and the Scottish TOs unit cost data. Our consultants used a range of possible cost adjustments for each asset class in combination with the information available on costs by asset category to estimate the scope of possible efficiency savings in baseline funding for each LRE category.

4.42. We estimated savings in three asset classes (switchgear, transformers and cables) by applying the following percentage reduction for each asset class to the forecast baseline expenditure in RIIO-T1 for each asset class (excluding WHVDC):

- 11.1 per cent transformers
- 21.8 per cent switchgear
- 1.0 per cent cables.

Table 4.6 - Proposed efficiency savings by LRE category

LRE Category	**Efficiency Saving (£m)**
Local Enabling (Entry – Sole Use)	0.0
Local Enabling (Entry – Shared Use)	107.7
Local Enabling (Exit – Sole Use)	62.9
Local Enabling (Exit – Shared Use)	35.1
Wider Works (Entry)	52.7
Wider Works (Entry) (reduction to schemes moved to UM)	9.1
Wider Works (General)	23.0
Transmission System Support	0.0
TOTAL	**290.5**

Disallowed expenditure for DNO mitigation works (£18.1m)

4.43. We propose a reduction in forecast expenditure in DNO Mitigation Works from £26.1m to £8.0m. The £8.0m reflects the amount that can be justified when applying NGET's proposed unit cost allowances to the outputs shown in NGET's plan for DNO Mitigation costs. In the absence of a justification or clear outputs for the remaining £18.1m we propose to exclude this amount from our Initial Proposals.

Disallowed expenditure for RIIO-T2 Outputs (£462.0m)

4.44. Proposed disallowed expenditure includes removal of £462.0m baseline allowances for works delivering outputs in RIIO-T2. The totex sharing factor will ensure NGET is partly funded during RIIO-T1 for works started within the price control, with the remainder considered under assessment for the next price control.

Reallocation of expenditure between baseline and UM (£1,023.1m)

4.45. In addition to the above changes we propose to reallocate costs between the baseline and UM funding mechanisms. As a result of these changes we propose to move £1,023.1m of expenditure out of baseline. This means that a larger proportion of NGET's funding for Best View will come through uncertainty mechanisms. We believe this represents a better balance of risk sharing between NGET and consumers. To describe this change in terms of Figure 4.1, this is a movement of LRE from 'Baseline RIIO-T1 outputs subject to volume driver' into 'RIIO-T1 outputs above baseline funded by volume drivers' and 'Strategic Wider Works (SWW) outputs funded by project specific revenue adjustment'.

4.46. We have reallocated from baseline funding to UM funding for the following expenditure categories:

- LRE on Local Enabling Work (OHL)
- LRE for Wider Works Entry.

4.47. We propose to move baseline funding of £246.1m for OHL into RIIO-T1 outputs above baseline funded by volume drivers

4.48. We propose to reduce the baseline for WW outputs that are subject to volume driver and the NDP to set it at a level with a more equal likelihood of downward or upward adjustments in allowances (to make it more more symmetrical). This causes a number of small to medium sized WW outputs in Gone Green to move out of baseline into the UM funding pot.

4.49. Since the publication of its business plan, NGET has indicated that the total project cost of reinforcement works associated with the upgrade of Hinkley Point nuclear power station are likely to cost more than £500m. Given that, we moved the £0.47bn (amount in RIIO-T1) associated with wider works into the SWW funding mechanism. NGET will be able to bring forward a request for funding for this project when it has confirmed a needs case.

Reallocation of expenditure between LRE categories (with no change in total funding)

4.50. We also propose to accept NGET's suggested reallocation of some expenditure between LRE categories (for more details see Appendix 3). The re-allocation of works between the LRE categories was caused by :

- Re-categorisation of wrongly classified schemes . This issue was identified by NGET during our assessment period, which resulted in some movement of costs between LRE categories. NGET has identified process and control improvements to its asset management process, which should reduce the risk of misclassification in the future. These improvements are due to be implemented by Summer/Autumn 2012.

- Review of baseline outputs not subject to volume driver. These costs refer to expenditure that is not directly linked to the main RIIO-T1 outputs in each category eg expenditure related to fault levels, reactive compensation, generator closure or tunnels. We challenged NGET to derive suitable outputs for such costs to bring their plan more in line with RIIO's output-led framework. The outcome of this exercise involved NGET moving such schemes between categories where links to outputs were eventually established.

- Grouping expenditure related to planning requirements. We propose moving the undergrounding provision (£454.5m) from Wider Works (General) into Wider Works (Entry) to keep both elements of the planning requirements UM in the same LRE category (the other element being 'DNO mitigation').

Local Enabling (Entry – Shared Use)

4.51. Local Enabling works are driven by new generation ('Entry') or demand ('Exit') connections. These works are the minimum transmission works needed to connect a customer to the transmission network.

4.52. 'Sole Use' distinguishes between assets which are for the use of a single customer, (covered by connection charges) from assets which are shared by other users of the transmission network (covered by Transmission Network Use of System charges). Due to shallow ownership boundaries, generator customers tend to own their connection assets and NGET does not have to finance these assets for them. It is for this reason that NGET has not forecast any expenditure or outputs on Local Enabling (Entry – Sole Use).

4.53. Local Enabling (Entry - Shared Use) relates to expenditure triggered by individual generation connection projects but provides assets or reinforcements which are shared by several users of the transmission network.

4.54. This section sets out our Initial Proposals for the Best View Local Enabling (Entry – Shared Use) outputs NGET will deliver over RIIO-T1, the proposed funding arrangements and the associated UMs to manage the uncertainty around timing and volumes of outputs.

Local Enabling (Entry – Shared Use) - baseline LRE and outputs

4.55. Table 4.7 sets out our Initial Proposals for NGET to deliver Local Enabling (Entry - Shared Use) outputs during RIIO-T1 of approximately 33GW of new generation connections.

Table 4.7: Initial Proposals for baseline LRE and outputs

Costs £m (2009/10 prices)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Local Enabling (Entry – shared use)	145.4	153.0	138.9	148.2	78.8	69.3	40.6	20.0	**794.2**

Local Enabling (Entry – shared use) Outputs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Generation (MW)	504	1,597	3,264	3,036	1,540	3,797	5,650	13,819	**33,207**
Closures (MW)	5,663	436	4,612	1,250	229	515	2,176	6,238	**21,119**

4.56. The output measure against which Local Enabling (Entry - Shared Use) expenditure will be accountable is the additional generation connection capacity and the level of generation closures catered for without impacting the security of the network.

4.57. We propose to have a higher baseline level of generation connection capacity than assumed under the Gone Green scenario. This takes into account some schemes in the Gone Green scenario that will incur no additional expenditure to accommodate a higher level of MW. Examples of this include the Irish Sea offshore wind farms and some round 3, zone 5 offshore wind farms. For these schemes the maximum capacity has been used to derive the baseline output.

4.58. The key differences between our Initial Proposals for baseline LRE and NGET's March business plan for Local Enabling – Shared Use Entry are summarised below:

Local Enabling (Entry – Shared Use)	**£m**
NGET March 2012 baseline	**1313.4**

Recategorisation of schemes between LRE categories	-68.8
Movement of outputs within baseline (see Appendix 3)	120.5
OHL - funded by volume drivers (rather than baseline funding)	-220.5
Removal of RIIO-T2 outputs expenditure	-242.7
Efficiency saving	-107.7
Ofgem IP baseline	**794.2**

Movement of outputs within baseline

4.59. This refers to the reallocation of expenditure between LRE categories in baseline, the details of which can be found in Appendix 3. The figures presented are net values i.e. the overall value of movements of costs to and from the LRE category is considered.

Movement of overhead lines (OHL) from baseline expenditure to UMs

4.60. Out of the 33GW of potential generation projects in NGET's Best View for RIIO-T1 only a handful require OHL to connect to the transmission system. The length of OHL potentially required for these few projects also varies considerably ranging from 5km to 100km.

4.61. Potentially a number of generation projects in Best View might not progress to connection. At the same time, some new generation projects not currently anticipated under the Best View could come forward for a connection.

4.62. Given the uncertainty around which specific projects will connect during RIIO-T1, and the potential difference in the OHL lengths needed, we propose that it would be more efficient to separate the costs of OHL from the other costs of connecting a megawatt of new generation capacity such as substation works.

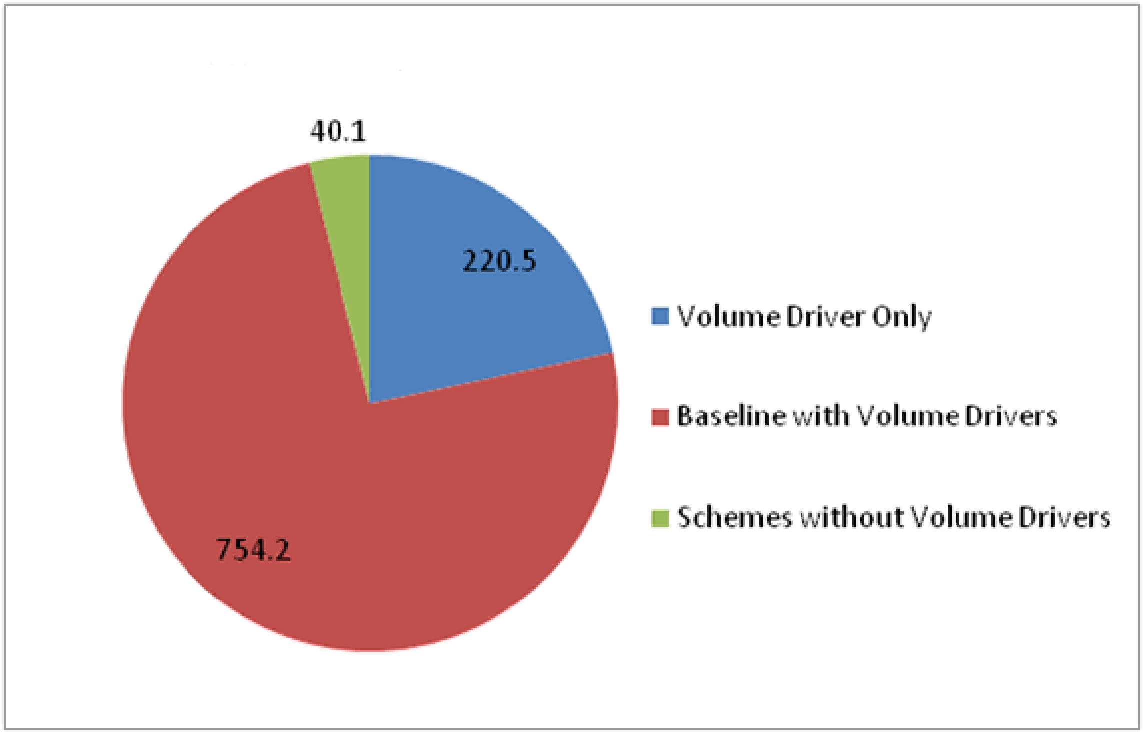
4.63. In general, the baseline LRE for local enabling is not dependent on individual projects as the diversity, number and total capacity of connections is large for the price control period. However, NGET's Best View of the OHL component of connections is associated with a few specific projects. It is also not directly linked to the capacity of new generation connections.

4.64. In the RIIO framework outputs are a key tool for holding the network companies to account for delivery where it has received a baseline allowance. We do not consider it is consistent with the RIIO emphasis on outputs to undertake a separate reconciliation of OHL actually delivered relative to an assumed baseline of OHL used in the connections. We consider it would be more consistent with the RIIO principles to only include LRE in the baseline that is directly linked to the output measure. Therefore we propose to exclude the OHL component of new connections from the baseline LRE and to remunerate NGET for the OHL component of connections when these are delivered.

4.65. Under this proposal NGET would be required to report annually on the amount of OHL used in generation connections it has delivered to trigger the revenue adjustment as part of the volume driver arrangements for new generation connections.

4.66. Figure 4.2 shows the Best View of Local Enabling (Entry - Shared Use) by the funding mechanisms.

Figure 4.2 Funding arrangements for Best View Local Enabling Entry LRE (£m)



4.67. We propose that around three quarters of Best View LRE for Local Enabling Entry infrastructure is included in NGET's baseline allowances and subject to the generation connections volume driver. We also propose that OHL used in connections will be funded through the volume driver only (rather than through baseline funding).

4.68. Less than 5 per cent of baseline LRE is not directly linked to the generation connections output. This is for expenditure on works required to protect the network from the impact of generation closures.

Volume driver for generation connections (to operate in Local Enabling – Shared Use Entry category of LRE)

4.69. There is a large degree of uncertainty around the volume and timing of new generation connections in NGET's transmission area. Given this uncertainty about the level of outputs that will be delivered over RIIO-T1 and the LRE NGET will require we need to ensure there is enough flexibility and certainty in the price control settlement to allow NGET to meet any changes in customer requirements and to finance its activities. To protect consumers it is important there are also sufficient incentives on NGET to meet such changes efficiently.

4.70. We consider that a volume driver based on the output of new capacity connected will provide the necessary flexibility and accountability to NGET to deal with changes in the volume and timing of new generation connections. It would also provide strong incentives to NGET to meet customer requirements efficiently and innovatively by setting unit costs at the start of the price control for delivery of connection outputs.

4.71. We propose to set a volume driver for delivering new generation connections with parameters set at the start of the price control for the unit costs of connecting additional generation capacity (MW) and the unit costs of OHL and cable lengths.

4.72. Under these proposed arrangements NGET will report annually on the amount of new generation capacity it has connected and the number of kilometres of OHL used. We would use the volume driver to calculate automatically the allowed expenditure for the delivered output and OHL or cable in a given price control year and compare this to NGET's baseline allowances. An adjustment would be made to their allowed expenditure if NGET has delivered more or less than the baseline level of outputs and/or used OHL in completing the connections. The totex sharing factor will apply in respect to any over or underspend such that this will be shared with consumers on a 48:52 basis.

Unit cost allowances (UCA)

4.73. In its March 2012 business plan NGET proposed a set of UCA, detailed in table 4.8 below, to adjust its baseline over the RIIO-T1 period to reflect the actual volume of generation connections (i.e. the operation of a volume driver).

4.74. Since March NGET has provided further supporting information to justify the use and efficiency of the UCA. This has led to further refinement of its UCA, including:

- Further development of the 'within zone' UCA and their background assumptions.
- Adjusting the UCA downwards to reflect the efficiency savings NGET identified in its business plan.
- Inclusion of some of the non-boundary works following the review of baseline RIIO-T1 outputs not subject to a volume driver (for futher

explanation, see earlier section on the Key differences between Ofgem's Initial Proposals and NGET's March 2012 business plan).

Table 4.8 - Local generation UCA

Connection works	NGET's proposed UCA (March 2012)	Ofgem's proposed UCA
Substation costs (£k/MW) **Within Zone UCA (RD2 to RD22) (£k/MW)**	**UCA 1**: 23.0 **Plus** **UCA 2**: 2.7 to 36.8 **Total: 25.7 to 59.8**	Single national rate **26.8**
Overhead lines (£m/cct km)	1.2	1.1
Cables	Matrix of additional capitalised costs for undergrounding from the 2012 IET report.[23]	Matrix of additional capitalised costs for undergrounding from the 2012 IET report (see Planning requirements section of this chapter).
RPEs		0.9 per cent per annum

4.75. NGET proposed to use up to four UCA to adjust the baseline when it delivers a new connection scheme. For each additional MW capacity delivered NGET propose to apply the substation UCA (£23k/MW) and a zonal UCA (ranging from £2.7k/MW and £36.8k/MW) resulting in a combined UCA between £25.7k and £59.8k being applied for each additional MW delivered. The OHL or cable UCA will apply if either of these components are required as part of the new generation connections scheme.

4.76. NGET has proposed having a zonal UCA. We are not convinced from the information NGET provided that disaggregating to this level provides additional accuracy and less risk to NGET and its customers. We are also concerned about the sensitivity that the zonal drivers had to the background assumptions of demand and

[23] http://www.theiet.org/factfiles/transmission.cfm

closures, which do not seem to be related to the actual within zone costs incurred in a particular zone.

4.77. The 'within zone' costs appear to be more scheme specific rather than zonal. Information provided by NGET over the assessment period highlighted that in many zones only one scheme out of the group of schemes had 'within zone' costs associated with it. This gives a higher risk that the UCA would either over or under compensate for the level of expenditure incurred depending on whether the scheme had associated 'within zone' costs.

4.78. We compared the sensitivity of both NGET's proposed UCA and our proposed simpler three-volume driver combination against some different scenarios. These included, among others, the Gone Green[24], Slow Progression[25] and Accelerated Growth[26] scenarios on which NGET has based its March 2012 business plan. For each test the more simple UCA gave a value that was closer to the estimated cost incurred.

4.79. We also noted that some of the generation schemes themselves had NLRE capex work included. This may drive up the cost of the UCA, which would lead to a UCA that did not reflect the general cost of a generation scheme. Analysis showed that the impact of these NLR capex works on the UCA was less than £0.01/kw, which we do not consider is material enough to remove NLR costs and work from the generation schemes.

4.80. Based on the above assessment we propose to use a volume driver with three separate UCA to flex NGET's baseline for the actual volume of generation connections delivered over the RIIO-T1 period. These UCA's are set out in Table 4.8 above.

4.81. We propose that the UCA are based on schemes that are known to NGET, except for cable, which are based on the report on the whole life costing study of installing new transmission lines, commissioned by the IET and issued on 31 January 2012.

4.82. The UCA include schemes that are covered by other scenarios and those that are within NGET's contracted background. Where information was available, the MW capacity is the maximum capacity delivered by the cost of the reinforcement. This takes into account that some schemes will incur no additional cost to deliver a higher MW capability than has been assumed in the Gone Green scenario, which is described in more detail in the earlier section on Baseline Allowances and Outputs section.

[24] Gone Green is an Electricity Networks Strategy Group (ENSG) scenario. It represents a potential generation and demand background which meets the UK's 2020 environmental targets and maintains the country's progress towards meeting its 2050 emissions targets.
[25] Slow Progression is an ENSG scenario. In this scenario, the emphasis is on slower than planned progress towards the UK's 2020 environmental targets. These targets are not met until around 2024/25.
[26] Accellerated Growth is an ENSG scenario, which assumes that the 2020 renewable targets are met ahead of schedule.

4.83. The UCA are based on the post efficiency savings outlined by NGET in its business plan and subsequent cost reductions identified by our engineering consultants in their detailed scheme analysis:

- The substation UCA (£/MW) is based on the weighted average reinforcement costs (excluding OHL and cables) to deliver additional MW capability.

- The OHL UCA is based on the weighted average of load related OHL schemes in NGET's Business Plan Tables.

- The cable UCA is based on the additional costs that would be needed to underground cable. These costs are derived from the unit costs in the IET report, in line with the unit costs proposed for the undergrounding uncertainty mechanism.

4.84. We propose to apply the cost reductions recommended by our engineering consultants to the UCA in line with the cost reductions applied to the baseline. These are in addition to the efficiency savings applied by NGET since its March 2012 business plan. As the cost reductions were identified for asset classes and not schemes, we have reviewed the asset class mix of schemes where information was provided in sufficient detail to obtain the average percentage cost reductions for all schemes. We then applied the average percentage reduction, 10.8 per cent, to the substation UCA. No cost reductions were identified by the engineering consultants for overhead lines or cables in this category.

4.85. We propose that the UCA will be adjusted annually for changes in Retail Price Index and for 0.9 per cent RPEs. For more information on our assessment on RPEs, please see the additional document on RPEs and ongoing efficiency.

Local Enabling (Exit – Sole Use) & (Exit - Shared Use)

4.86. Local Enabling (Exit – Sole Use) is defined as expenditure by the TO required to meet increases or changes in the power demand of grid supply points and other directly connected customers as a result of load growth, load transfer or closure of embedded generation. It only includes expenditure on assets that are covered by connection charges as per the connection charging boundary in Section 14 of the CUSC.

4.87. Unlike Local Enabling (Entry – Sole Use), NGET has forecast expenditure for Local Enabling (Exit – Sole Use). This is because demand customers tend not to own connection assets and require NGET to construct the connection.

4.88. Local Enabling (Exit – Shared Use) relates to expenditure triggered by individual demand connection projects but only provides assets or reinforcements which are shared by users of the transmission network.

4.89. Both LRE categories share the same output and are presented together in this section. However the baseline LRE and outputs for each category will be considered separately.

Baseline LRE and outputs for Local Enabling (Exit – Sole Use)

4.90. Table 4.9 summarises the expenditure profile and outputs in our proposal for NGET to deliver Local Enabling (Exit – Sole Use) works during RIIO-T1.

Table 4.9 - Proposed Local Enabling (Exit – Sole Use) baseline LRE and outputs

Costs (£m)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Local Enabling (Exit – Sole Use)	94.4	83.0	77.5	91.1	77.1	52.7	15.0	1.3	**492.0**

Outputs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Super Grid Transformers (SGTs)	4	6	8	9	17	8	10	10	**72**
Bramford Grid Supply Point (GSP)	-	-	1	-	-	-	-	-	**1**
New Cross 275kV Circuit Breakers	-	-	-	1	-	-	-	-	**1**
Stalybridge SGT	-	-	-	1	-	-	-	-	**1**
Willington SGT	1	-	-	-	-	-	-	-	**1**

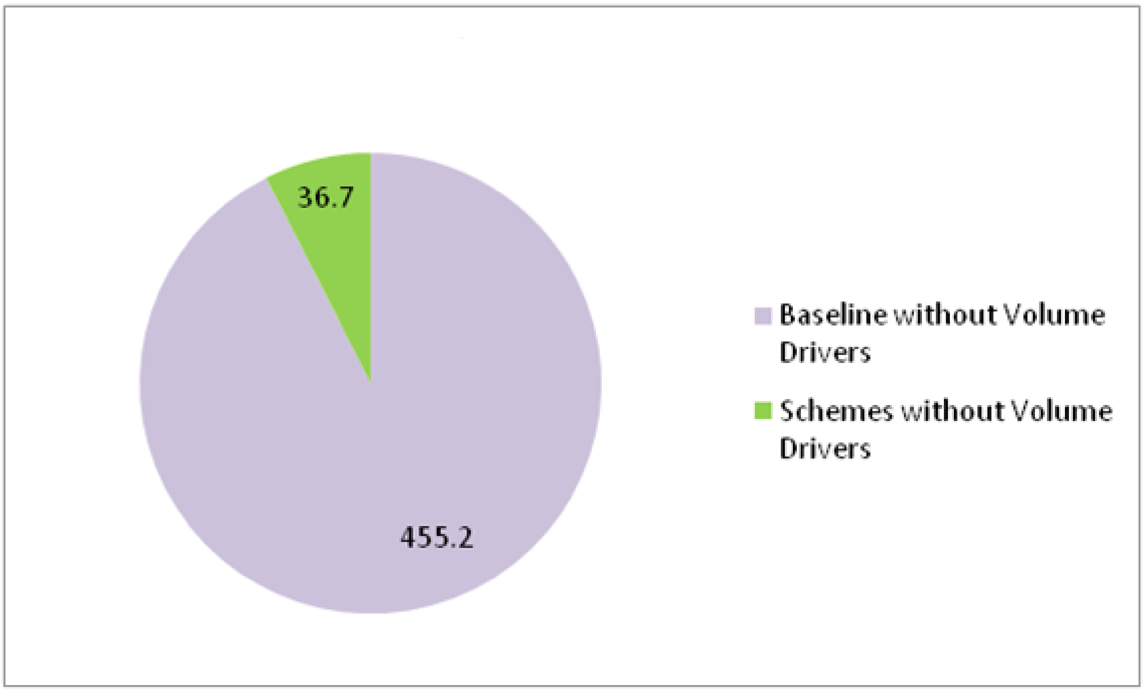
4.91. The key changes from NGET's March 2012 business plan to Initial Proposals for Local Enabling (Exit – Sole Use) are summarised below:

Local Enabling (Exit - Sole Use)	**£m**
March 2012 baseline	485.8
Recategorisation of schemes between LRE categories	69.9
Movement of outputs within baseline	-0.2
Removal of RIIO-T2 outputs expenditure	-0.7
Efficiency saving	-62.9
Ofgem IP baseline	**492.0**

4.92. The Demand Related Infrastructure UM does not adjust Local Enabling (Exit – Sole Use) which is treated as an excluded service. This means that the Best View is the same in this case as the baseline.

4.93. Figure 4.3 below illustrates the Best View funding for Local Enabling (Exit-Sole Use).

Figure 4.3 – Initial Proposals for Best View funding for Local Enabling (Exit – Sole Use) (£m)



4.94. The 'Schemes without Volume Drivers' refers to costs related to works at Bramford Grid Supply Point (GSP), installation of switchgear for higher fault levels at New Cross substation and the installation of Super Grid Transformers (SGTs) at Willington and Stalybridge substations.

Baseline LRE and outputs for Local Enabling (Exit – Shared Use)

4.95. Table 4.10 summarises the expenditure profile and outputs in our proposal for NGET to deliver Local Enabling (Exit - Shared Use) works during RIIO-T1. The output against which the 'RIIO-T1 Outputs' expenditure will be monitored is the number of SGTs which will be installed to cater for the growth in demand, backed by commercial agreements or DNO requests.

Table 4.10: Proposed Local Enabling (Exit – Shared Use) baseline LRE and outputs

Costs (£m)	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	Total
Local Enabling (Exit – Shared Use)	47.6	33.5	26.1	26.7	44.6	37.1	11.0	0.9	**227.5**

Outputs	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	Total
SGTs	4	6	8	9	17	8	10	10	**72**
Islington Tunnel	-	-	-	-	1	-	-	-	**1**

4.96. The key changes from NGET's March business plan to Initial Proposals for Local Enabling (Exit – Shared Use) are summarised below:

Local Enabling (Exit – Shared Use)	**£m**
March 2012 baseline	**508.9**
Recategorisation of schemes between LRE categories	2.0
Movement of outputs within baseline (see Appendix 3)	-38.5
Moving overhead Lines out of baseline	-25.6
Removal of RIIO-T2 outputs expenditure	-184.2
Efficiency saving	-35.1
Ofgem IP baseline	**227.5**

Moving overhead lines out of baseline

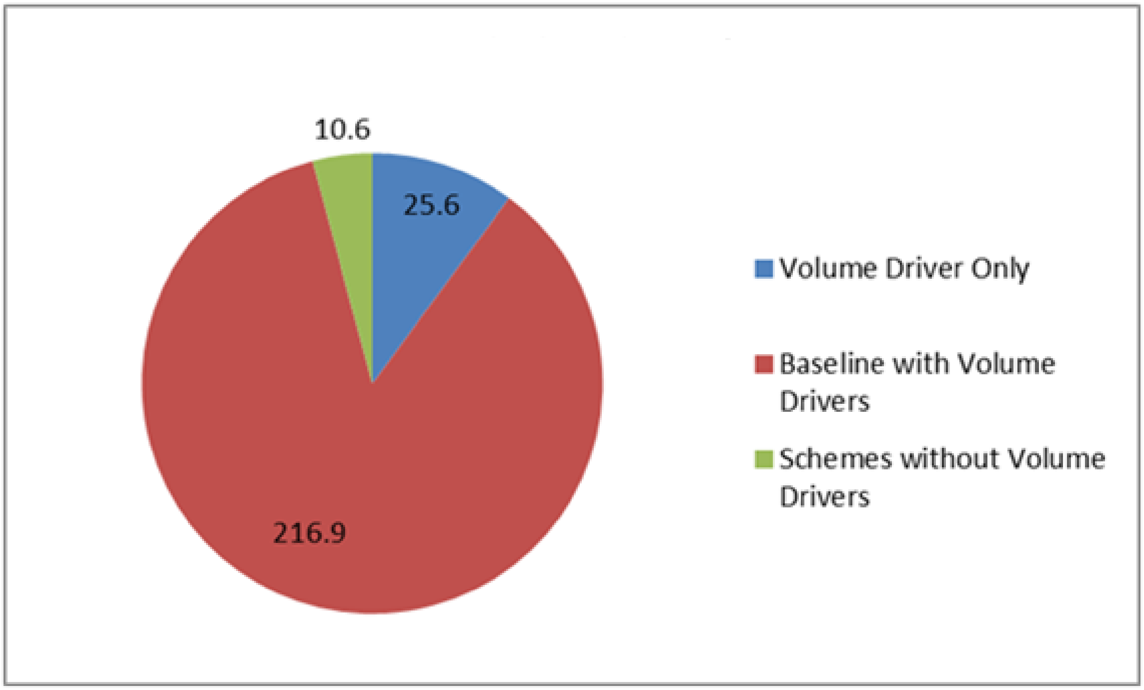
4.97. Similar to our proposal for setting the baseline LRE for new generation connections we also propose to exclude the OHL component of demand related infrastructure from the baseline allowances. We propose instead to remunerate NGET for the OHL component of connections when these are delivered.

4.98. Under this proposal NGET would be required to report annually on the amount of OHL used in demand connections it has delivered to trigger the revenue adjustment as part of the volume driver arrangements for demand related infrastructure.

4.99. Figure 4.4 shows our Best View of Local Enabling (Exit - Shared Use) by the funding pots. We propose that most of the funding in this category is included in NGET's baseline with the safeguard that it is subject to the volume driver for Demand Related Infrastructure.

4.100. The 'Schemes without volume drivers' relates to the construction of the [redacted].

Figure 4.4 - Funding arrangements for Best View Local Enabling Sole Use LRE



Volume driver for demand related infrastructure (to adjust NGET's Local Enabling – Shared Use Exit LRE)

4.101. The key drivers for NGET's Best View of LRE for Local Enabling (Exit-Shared Use) over RIIO-T1 are largely for transformer works to meet rising DNO-demand or to deliver traction supply points for Network Rail. There is a big variation in the costs of the schemes in NGET's Best View of demand-driven investment. There are also considerably fewer schemes than for generation connection.

4.102. Given the uncertainty over the timing of schemes, particularly in the latter half of RIIO-T1, we propose setting a volume driver UM in this LRE category to provide the necessary flexibility, accountability and efficiency safeguards for consumers.

4.103. We propose a volume driver for Local Enabling (Exit - Shared Use) LRE based on demand related infrastructure with parameters set at the start of the price control for the unit costs of key components. We propose NGET would report annually on commercial agreements for customer connections it has completed, the transformer works and the length (number of kms) of OHL used.

4.104. We will use the volume driver to calculate automatically the allowed expenditure for the delivered output and OHL in a given price control year and compare this to NGET's baseline allowances. An adjustment will be made to their allowed expenditure if NGET has delivered more or less than the baseline level of outputs and/or used OHL in completing the connections. The totex sharing factor of 48% will apply in respect to any over or underspend (as calculated under the IQI mechanism).

Unit cost allowances

4.105. NGET set out in its March business plan the set of UCA it proposed to use to adjust the baseline to reflect the actual volume of demand related schemes delivered in Local Enabling (Exit – Shared Use) works over the RIIO-T1 period.

4.106. Since March NGET has provided further supporting information to justify the use and efficiency of the UCA.

4.107. The only significant change made by NGET since the March 2012 business plan was to incorporate the efficiency savings outlined in its business plan into the UCA. This resulted in a slight reduction in the UCA for substation costs and OHL for our Initial Proposals as shown in Table 4.11.

Table 4.11: Demand related infrastructure UCA

Connection works	**NGET's proposed UCA (March 2012)**	**Ofgem's proposed UCA**
Substation Costs (£m/SGT)	4.6	3.7
Overhead lines (£m/cct km)	1.2	1.1
Cables	Matrix of additional capitalised costs for undergrounding from the 2012 IET report.[27]	Matrix of additional capitalised costs for undergrounding from the 2012 IET report (see Planning requirements section of this chapter).
RPEs		0.9% per year

4.108. Over the assessment period NGET has provided further information to support the efficiency of its UCA. We have looked at disaggregating the UCA further but found that any increase in accuracy gained was not sufficient to warrant the

[27] http://www.theiet.org/factfiles/transmission.cfm

additional complexity.   Based on the supporting information and our analysis we have not proposed any changes to the design of the uncertainty mechanism.

4.109. The UCA calculations are based on the detailed information provided by NGET on the demand related schemes that are forecast under the Gone Green Scenario and that deliver an increase in the number of transformer volumes within the RIIO-T1 period. This includes schemes that increase the transformer volume but have no demand-related infrastructure costs associated with it (e.g. schemes that are being funded through excluded services).

4.110. The UCA include the efficiency savings that NGET identified within its business plan and the cost reductions identified by our engineering consultants through their detailed scheme analysis.   The UCA will be adjusted annually for changes in RPI and for 0.9 per cent Real Price Effects.

4.111. The basis for calculating the UCA are as follows:

- The substation UCA (£/SGT) is based on the weighted average of all scheme costs (excluding overhead lines and cables costs) that deliver additional SGTs volumes.

- The overhead lines UCA is based on the weighted average of load related overhead line schemes in NGET's business plan tables.

- The cables UCA is based on the matrix of unit costs outlined in the IET report on undergrouding(as for the local generation volume driver).

4.112. We have applied cost reductions recommended by the engineering consultants to the UCA in line with the cost reductions applied to the baseline. These are in addition to the efficiency savings applied by NGET since its March 2012 business plan, which resulted in a small reduction in all UCA. As the cost reductions were identified for asset classes and not schemes, we have reviewed the asset class mix of schemes where information was provided in sufficient detail to obtain the average percentage cost reduction. This has resulted in an average reduction of 12.0 per cent being applied to the substation UCA.

Wider works (Entry)

4.113. Wider Works (Entry) LRE is required for generation driven reinforcement of the transmission system to meet security standards and to fulfil NGET's licence obligations. Under the RIIO output framework, we have termed reinforcements of the main transmission system Wider Works (WW) outputs.

4.114. Wider Works (Entry) LRE also comprises two additional sub categories of expenditure that are indirectly linked to delivering WW outputs. These are for Pre-

Construction Engineering works and mitigation measures such as underground cables to meet Planning Requirements.

4.115. This section sets out our Initial Proposals for the various Wider Works (Entry) outputs NGET could be required to deliver over RIIO-T1, our proposed baseline funding arrangements and the associated UMs to adjust NGET's Wider Works (Entry) LRE for the outputs that turn out to be actually needed.

4.116. The first set of UMs aims to address the uncertainty around the timing and volume of WW outputs that might be required over the price control period. We are proposing two separate mechanisms:

- A volume driver mechanism to automatically adjust NGET's funding as long as the delivered wider works outputs comply with the requirements and criteria of NGET's NDP.

- A project specific reopener which would enable NGET to request Ofgem to make a within-period determination on the needs case and efficient costs of delivering the output. We expect the latter provisions to be appropriate for large SWW outputs ie reinforcement works that cost more than £500m or do not meet the criteria set out in its NDP.

4.117. We are also proposing another set of UMs to manage the uncertainty around Planning Requirements and the additional cost of technologies that NGET might need to deploy to address visual amenity issues of some WW outputs and to obtain development consent. We set out two UM proposals:

- a volume driver for undergrounding of transmission cables

- a volume driver for other mitigation measures such as undergrounding DNO overhead lines.

Baseline Wider Works (Entry) LRE and outputs for Wider Works (Entry)

4.118. Table 4.12 sets out out our Initial Proposals in relation to the baseline LRE profile for delivering WW outputs, completing pre-construction engineering works and meeting planning requirements. The second part of the table sets out the baseline WW outputs NGET could be required to deliver over RIIO-T1. The baseline pre-construction works and planning requirements outputs are set out in the respective sub-sections.

4.119. The baseline WW outputs in Table 4.12 are measured in terms of the transfer capability across system boundaries. A system boundary splits the transmission network into two parts across which the capability to transfer electrical power can be assessed. For the avoidance of doubt, system boundaries are not network ownership boundaries and each licensee's network could contain multiple system boundaries.

4.120. Thermal, voltage and stability capabilities for each boundary are assessed in accordance with the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS). NGET may phase work to increase either thermal, voltage, stability or a combination of these properties across system boundaries. In some cases the investment to improve one element of boundary capability is not obvious because another constraining capability exists temporarily (e.g. investment to improve thermal capability in the middle of the price control period will not show an increase in overall boundary transfer capability until a voltage constraint across the boundary is resolved by a later investment).

Table 4.12: Initial Proposals for Baseline Wider Works (Entry) LRE and baseline WW outputs

Allowances	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
(£m)	511.0	654.4	545.9	457.4	212.6	110.9	54.6	11.8	2,558.7
Boundary transfer capacity (MW)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	
B6	3300	**4300**[2]	**6700**[1]	6700	6700	6700	6700	6700	
B7	2000	**3400**[2]	**5800**[1]	5800	5800	5800	5800	5800	
B7a	4900	5300	**7700**[1]	7700	7600	7600	7600	7600	
B8	11300	11300	11300	11500	11500	10600	10600	10600	
B9	12600	12600	12600	11500	11500	11500	11500	11500	
B10	5800	5800	5700	5700	5700	5700	5700	5700	
B11	9900	9900	10000	10000	10000	10000	10000	10500	
B12	5800	5800	5100	5100	5100	5100	5100	5200	
B13	1800	1800	1800	1800	1800	1800	1800	1800	
B14	9600	9600	9600	9600	9600	9600	9600	9600	
B14e	8700	8700	9400	10150	10150	10150	9950	9950	
B15	6400	6400	6400	6400	6400	6400	6400	6500	
B16	15200	15500	15500	15500	15500	15500	15500	15500	
B17	5200	5200	5200	5200	5200	5200	5200	5200	
NW1	1800	1800	1800	1800	4400	4400	4400	4400	
NW2	1500	1500	1500	4600	4600	4600	4600	4600	
NW3	2900	2900	2900	2900	**4400**[2]	4400	4400	4400	
NW4	6000	6000	6000	6000	6000	6000	6500	6500	
EC1	4100	4100	4100	4100	4100	7000	7000	7000	
EC3	3200	3200	**4300**[2]	4300	4300	4300	4300	4300	
EC5	2600	2600	**3600**[3]	3600	6800	6800	6800	6800	
SC1	5600	5600	5600	5600	6100	6100	6600	6600	

Notes:
1. Maximum transfer capability increase of 2,400MW delivered by Western High Voltage Direct Current link between Scotland and England.
2. Transfer capability increases from delivery of scheduled baseline outputs in Table 4.13.
3. Scheduled baseline output delivers 1,700MW increase in thermal capability. However, due to the boundary stability constraint actual increase in transfer capability only increases by 1000MW.

4.121. At some boundaries, such as B8, B9, B10, and B12 there may even appear to be a decrease in overall boundary capability because of the phased investment described above. For these boundaries the transfer capability is forecast to improve if the Wylfa-Pembroke scheme is delivered at the end of the regulatory period. NGET's funding will reflect the timing of overall increases in boundary transfer capability.

4.122. In total, the baseline WW outputs in Table 4.12 would give a gross increase in transfer capability of 28,600MW across system boundaries in NGET's transmission area. Together with the Strategic Wider Works outputs (potentially a further 22,000 MW), the additional increase in transfer capability over RIIO-T1 is broadly consistent with the level of reinforcement needed to accommodate the UK's renewable energy targets.

4.123. The key differences between our Initial Proposals for baseline LRE and NGET's March business plan Wider Works (Entry) are summarised below:

Wider Works (Entry)	**£m**
March 2012 baseline	**3695.7**
Recategorisation of schemes between LRE categories	-3.1
Movement of outputs within baseline (see Appendix 3)	-743.0
Moving Hinkley-Seabank into SWW	-468.1
Moving several East-Anglia schemes out of baseline	-318.0
Moving planning requirements provision into WW (Entry)	454.5
Moving SWW pre-construction costs into baseline	46.0
Reduction in DNO mitigation	-18.1
Removal of RIIO-T2 outputs expenditure	-34.4
Efficiency saving	-52.7
Ofgem IP baseline	**2558.8**

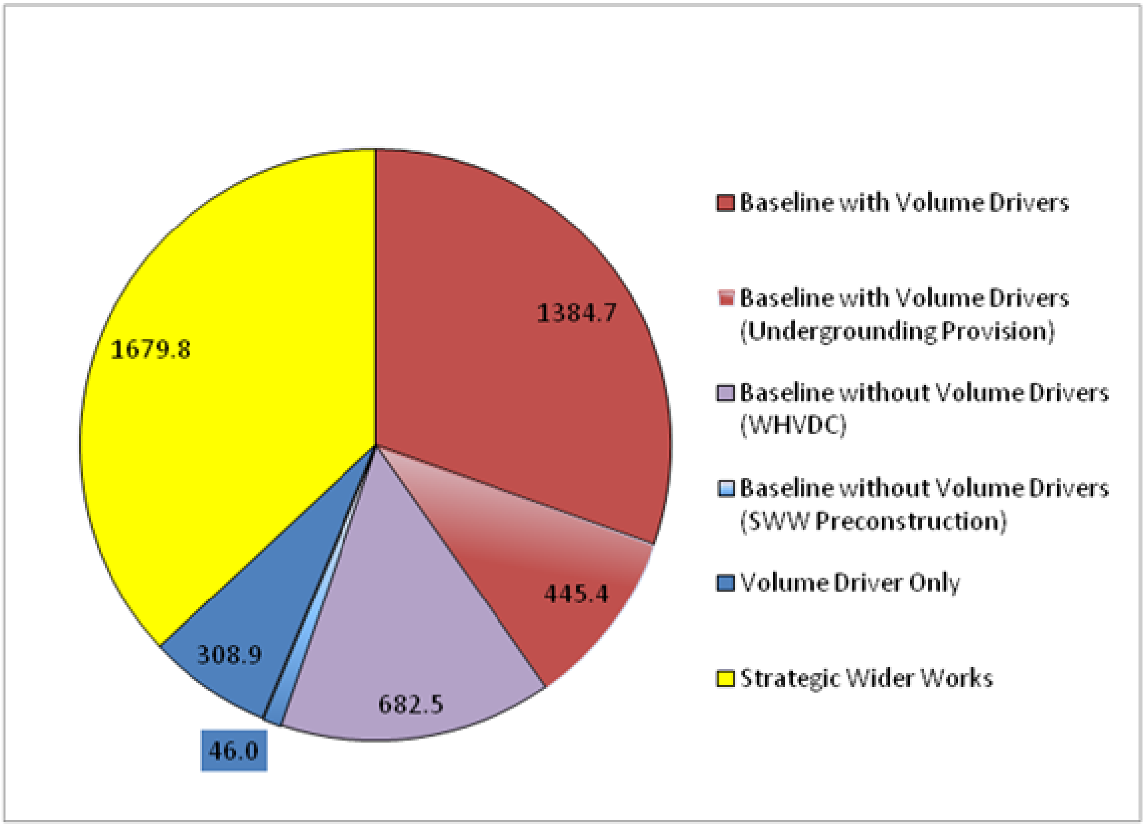
4.124. Figure 4.5 illustrates our Best View of LRE for WW outputs, Pre-construction outputs and Planning Requirements over RIIO-T1 and our proposed funding arrangements.

4.125. We propose that the 'Baseline' segment in Figure 4.5 includes funding for Pre-construction Engineering outputs. It will also include funding for the Western High Voltage Direct Current (WHVDC) link.The WHVDC link is being jointly delivered by NGET and SPTL, and forms part of their respective baselines under RIIO-T1. In May 2012 we consulted on the details of our proposed funding arrangements for the WHVDC link for under TII and RIIO-T1, for both NGET and SPTL. [28] Alongside this document we are publishing our final decision on the ex ante allowances and risk sharing arrangement between the transmission companies and consumers for this project under TII (to end 2012-13) and RIIO-T1 (from 2013-14 onwards). As such,

[28] See TII webpage, where all documents related to TII that are referred to in this letter can be found:
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Pages/InvestmentIncentives.aspx

these matters are out of scope of this consultation on our Initial Proposals for NGET. We will finalise details of the licence changes for both NGET and SPTL in line with this decision, with basline WW outputs based on delivery of additional transfer capbability between Scotland and England (affecting Boundaries B6, B7, B7a) consistent with a continuous rating of 2.25GW and a short-tem (6 hour) rating of 2.4GW.

Figure 4.5 - Funding arrangements for Best View Wider Works Entry LRE (£m)



4.126. We propose that funding in this category would be subject to the totex sharing factor of 48% (as calculated under the IQI mechanism).

4.127. We propose to fund most of the smaller to medium sized WW outputs in the Best View through 'Wider Works baseline with volume driver adjustment'. We consider there is a good likelihood of these being needed over the price control period given the high level of contracted new generation connections. Under this arrangement NGET's allowed LRE would automatically adjust each year by a WW volume driver for the level of WW outputs NGET actually delivers, based on the unit costs agreed at the start of the price control for delivering an additional unit of transfer capacity at the particular boundary.

4.128. We propose not to include baseline funding for a small proportion of the Best View WW outputs. This means that a NGET's funding for these WW outputs will come through the 'Wider Works volume driver only'. We believe this represents a better balance of risk sharing between NGET and consumers.

4.129. We propose to adopt NGET's business plan proposal that all large reinforcements above £500 million, known as 'Strategic Wider Works' (SWW), would be subject to a project specific determination by the Authority on the needs case and efficient costs of delivery. Strategic Wider Works outputs accounts for nearly a third of the Best View LRE.

4.130. We also propose to fund LRE for Planning Requirements as part of NGET's 'Planning Requirements Baseline with volume driver adjustment' for undergrounding new transmission lines and to undertake works to complete mitigation on the distribution network where this is required by the planning authority.

Wider Works baseline with volume driver adjustment

4.131. Several of the baseline WW outputs in Table 4.12 have a strong needs case for delivery in the first half of the price control. NGET has previously received part funding for some baseline WW outputs through the Transmission Investment Incentive (TII) and several of these WW outputs are already in construction, or shortly due to start (this includes the WHVDC). Therefore we propose to set a scheduled date by which NGET will have to deliver these by. The project specific WW outputs and scheduled delivery dates are set out in Table 4.13.

Table 4.13 - Scheduled baseline WW outputs

Project	**Wider Works output (additional boundary capability)**	**Scheduled for delivery in Regulatory Year**
Harker Hutton Re-conductoring	Boundary7: 1400MW increase	2013/14*
Series and Shunt Compensation (Anglo-Scottish Incremental schemes)	Boundary 6: 1000MW increase	2014/15
Re-conductoring of Trawsfynyyd-Treuden Tee	Boundary NW3: 1500MW increase	2014/15**

Project	Wider Works output (additional boundary capability)	Scheduled for delivery in Regulatory Year
Turning-in Norwich-Sizewell circuit at Bramford; and extending Bramford substation	Boundary EC3: 1100MW increase Boundary EC5: 1700MW increase	2015/16***

Notes:
* This project is scheduled to complete in 2013/14 but the benefits of this scheme on the boundary transfer capability will not be fully realised until the Anglo-Scottish incremental schemes are completed in 2014/15.
**This project is scheduled to complete in 2014/15 to take advantage of delivery synergies with non load related work. However, the benefits of this scheme on the boundary transfer capability will not be realised until Deeside-Trawsfyndd sometime around 2017/18.
*** The additional transfer capability across EC5 boundary will not be realised until the Bramford-Twinstead OHL and the installation of a Mechanically Switched Capacitor at Barking is completed sometime around 2017/18.

4.132. In the event NGET under or over delivers in relation to the specific WW outputs in Table 4.13, we propose to adjust allowed revenue to match using the WW volume driver.

4.133. For the remainder of baseline WW outputs in Table 4.12, excluding the WHVDC, there is some uncertainty around the exact timing of when these will be needed. We note that the timing and magnitude of WW outputs in Table 4.12 are indicative only.

4.134. Given this uncertainty, we do not propose to specify a scheduled delivery date for these outputs. Instead we propose, consistent with NGET's business plan, that NGET develops a NDP setting out how it will assess whether or not WW outputs are needed and the process it will use to update its investment programme.

4.135. Subject to the Authority's approval of NGET's NDP, NGET would have discretion to advance these works when the WW outputs meet the criteria set out in its NDP. Under this arrangement, all WW outputs, other than those in Table 4.13 and the WHVDC, would be subject to further assessment and confirmation under NGET's annual NDP and stakeholder engagement process.

4.136. For outputs delivered in accordance with its NDP we propose to adjust NGET's baseline revenue to match the efficient costs of the delivered WW outputs through a WW volume driver and boundary specific unit cost allowances for additional transfer capacity.

4.137. The advantage of this proposal is that it provides efficient arrangements to progress small to medium sized wider works with minimum regulatory input. It also makes NGET's network investment appraisal process very transparent and provides an opportunity for stakeholders to have input to this process.

4.138. In our view NGET should set out in its NDP how it will assess both the need and optimal timing of delivering WW outputs that ensure long term good value for consumers. To provide safeguards that consumers only pay for new infrastructure that is needed (ie to avoid the risk of stranded assets) we believe NGET's NDP should only apply when the proposed WW outputs have:

- a needs case with diverse potential users
- a high degree of user commitment ie 70 per cent or more
- a relatively short lead time ie up to three years
- shows a positive needs case under a range of generation and demand scenarios.

4.139. We have reviewed the initial draft NDP included in its March business plan. In our view NGET's draft NDP could be improved with the following additions and amendments:

- an explanation of internal processes, tools and methodology for modelling costs and benefits of network reinforcement and an assessment of modelling performance to date
- the application of judgement or probabilistic weighting to the generation/demand scenarios
- an explanation of NGET's decision rules (eg least regrets) for advancing WW outputs into investment plan and how these ensure long term good value for consumers
- further explanation about how NGET would revise its investment programme if a annual review of investment plan suggests the case for a WW output in construction has weakened
- the inclusion of a general review of outcomes under the NDP in the latter half of the price control
- further consideration of the opportunities for stakeholder consultation and input.

4.140. NGET will need to do further work on its NDP over the coming months in order to provide an updated draft before the end of the year for the Authority's consideration.

Unit cost allowances

4.141. NGET set out in its March business plan the set of UCA it proposes to use to adjust the baseline to reflect the actual additional transfer capability added over the price control period.

Table 4.14: Wider Works volume driver UCA proposed by NGET in the March business plan

Boundary	**Below the Baseline (Gone Green)**	**Above the Baseline (Gone Green)**
	£/kW	**£/kW**
B6	87	87
B7	64	64
B7a	54	130
B8	NA	17
B9	10	68
B13	155	155
B14	119	49
B14e	106	106
NW1	57	57
NW2	55	50
NW3	67	50
EC1	85	85
EC3	33	33
EC5	82	82

4.142. NGET proposes to have a baseline consistent with Gone Green. NGET propose to adjust this baseline with boundary specific UCA.

4.143. Although reinforcement schemes would be assessed and confirmed through the NDP process, the actual UCA is triggered on every boundary that additional transfer capability occurs and is not influenced by whether the capability is required on every boundary it impacts. This reflects the occasions where the most efficient scheme delivers additional capacity on boundary X but incidentally also increases capability on boundary Y. The UCA calculation takes this into account.

4.144. On each boundary the UCA (below the baseline) will adjust the baseline down from the total transfer capability that has been assumed in the baseline at the end of RIIO-T1 (excluding any transfer capability added to the boundary through the SWW mechanism and WHVDC). After the baseline capability threshold has been reached the UCA for above the baseline will apply. For example for boundary B7a, which has an existing transfer capability is 4,900MW, the UCA (up to baseline) £54/KW will apply to the first 2,400MW of additional transfer capability, which would take the boundary to the forecast baseline transfer capability of 7,300 MW (excluding any additional capability added through the SWW mechanism). If NGET exceeds 7,300 MW the above baseline UCA (£130/KW) will apply..

4.145. NGET proposes to split the cost of reinforcement across each of the boundaries that it delivers transfer capability to, in proportion to the amount of transfer capability delivered. For example, if reinforcement delivers an additional 2,000MW of transfer capability to boundary B6 and 1,000 MW to B7 at a cost of £30m, the costs will be split £20m to boundary B6 and £10m to boundary B7.

4.146. Since March NGET has provided further information to support the efficiency of their UCA. We consider that NGET's approach of having two UCA for each boundary, one for 'below the baseline' and 'above the baseline' is appropriate as it reflects the likely ordering that schemes will be delivered during the RIIO-T1 period.

4.147. NGET continued to develop the UCA following their business plan submission in March taking into account the detailed discussions and changes made elsewhere to the LR plan. These changes include:

- moving non-boundary work into specific boundaries so that these schemes have measurable outputs that can be adjusted to reflect whether a scheme is actually delivered. This requirement has resulted in NGET identifying a new boundary (SC1), which has two non-boundary schemes associated with it. NGET also incorporated the efficiency savings into the UCA, which it has embedded within its March 2012 business plan.
- reducing the baseline has resulted in a number of schemes being moved into 'above' the baseline for the purposes of deriving UCA.
- reducing the UCA to incorporate the efficiency savings identified by NGET in its business plan
- excluding preconstruction costs so that these costs are not clawed back through the UCA.

4.148. Our assessment of the efficiency of the UCA identified that some of the boundaries have a large range in UCA across individual reinforcement schemes. Analysis showed under some scenarios where we assumed only some of the schemes take place, could lead to a substantial difference between the actual reinforcement costs and the amount that would be remunerated through the UCA. For these boundaries we felt that introducing bandings would significantly reduce the risk to both NGET and its customers, without causing undue complexity.

4.149. We are proposing to make three additional admendments to the UCA.

- We propose to apply an average UCA to boundary B13, to ensure that NGET will have a mechanism to fund any future reinforcements should the need arise. This was the result of our proposal to move Hinkley-Seabank into SWW (described in more detail in the section on key differences between Ofgem's Intial Proposals and NGET's March 2012 business plan). This led to no schemes being associated with this boundary.

- As a result of our assessment detailed above we propose to introduce bandings for 'above the baseline' on boundaries B14e and E5.

- Apply cost reductions recommended by the engineering consultants to the UCA in line with the cost reductions applied to the baseline. These reductions have been estimated on a scheme by scheme basis taking account the asset mix of each scheme where sufficient detail was available.

4.150. All the changes detailed above made since March have been reflected in Table 4.15 below.

Table 4.15: Ofgem's Proposed Wider Works Volume Driver UCA

Boundary	**Below the Baseline**			**Above the Baseline**		
	Ofgem proposals	**Cost Reductions**	**Capability Thresholds**	**Ofgem Proposals**		**Cost Reductions**
	£k/MW	**%**	**MW**	**Threshold**	**£k/MW**	**%**
B6	80.4	4.1	4300*		89.5	3.6
B7	62.4	0.0	3400*		61.3	3.6
B7a	51.0	4.1	5200*		75.6	3.6
B8	N/A	N/A	10600		14.3	3.6
B9	9.6	4.1	11500		56.5	3.6
B13	N/A	N/A	1800		65.7	4.8
B14	103.1	10.7	9600		34.4	3.6
B14e	98.1	9.0	9950	<250	50.0	5.9
				>250	287.7	3.6
NW1	52.8	0.0	4400		26.6	3.6
NW2	51.6	1.6	4600		43.6	3.6
NW3	63.7	1.2	4400		43.6	3.6
EC1	86.2	7.7	7000		86.2	7.7
EC3	41.8	4.1	4300		41.8	4.1
EC5		5.3	6800	<125	36.2	3.5
				125<x<400	149.9	2.3
	68.9			>400	548.8	3.6
SC1	96.3	4.1	6600		96.3	4.1

*Excludes the baseline capability delivered by the WHVDC scheme, as this scheme is not adjusted by this revenue driver

4.151. The UCA are based on the weighted mean of all the reinforcements within each of the 'above the baseline' and 'below the baseline' boundary categories. For the boundaries where there is a material variance of UCA for individual schemes we have subdivided the schemes into bandings at suitable intervals and calculated the weighted mean for each of these bandings. On boundaries where there are no reinforcements identified by NGET (ie B13) we have used the weighted mean of reinforcements schemes on all boundaries.

4.152. The UCA for 'below the baseline' is derived from those reinforcements that are forecast to occur within the RIIO-T1 period under all three ENSG scenarios - Slow Progression, Gone Green and Accelerated Growth. The above the baseline UCA is derived from schemes that are only covered by one or two scenarios.

4.153. We propose to adjust the UCA annually for changes in Retail Price Index and for 0.9 per cent Real Price Effects. For more information on our assessment on Real Price Effects, please see our additional document on RPEs and ongoing efficiency.

Strategic Wider Works

4.154. In addition to the baseline WW outputs in Table 4.12, NGET also identified prospective SWW reinforcements in its Best View. Consistent with our Strategy Document, NGET proposed that SWW outputs with a potential to cost more than £500m, or that do not meet the criteria set out in its NDP should be subject to within-period determination by the Authority during the price control. Table 4.16 sets out the prospective SWW outputs with indicative costs and timing. The difference between RIIO-T1 construction costs and Total Project Costs is comprised of SWW pre-construction costs and any pre-RIIO-T1 expenditure.

Table 4.16 - Prospective Strategic Wider Works

Projects	**SWW outputs (Increase in boundary transfer capability)**	**Indicative**		
		RIIO-T1 construction costs (£m)	**Project cost (£m)**	**Delivery Year**
Eastern HVDC	B6 : 2,100MW B7 : 1,000MW B7a: 700MW	566.2	589.8	2018/19
Wylfa-Pembroke HVDC	B8 : 2,800MW B9 : 2,500MW B12: 1,800MW B17: 800MW NW1: 2,000MW NW2: 2,000MW NW3: 2,000MW NW4: 2,000MW	645.5	672.4	2020/21
Hinkley-Seabank	B13 :3,000MW	468.1	502.4	2019/20
TOTAL		**1,679.8**	**1,764.6**	

4.155. We propose NGET would make funding requests for the above outputs using the within-period arrangements for Strategic Wider Works. Under these arrangements NGET would request Ofgem to determine the needs case for the SWW output and where the case is positive the efficient costs of delivering wider works outputs. Ofgem would then adjust NGET's revenues during the price control period (ie within-period determination). These arrangements will replace the Transmission Investment Incentives (TII) introduced during TPCR4.

4.156. We propose to include a provision as part of the SWW arrangements for NGET to allow a reopener mechanism to adjust revenues for a pre-defined event. In line with NGET's proposal, we propose that the reopener would cover the following predefined events:

- extreme weather (worse than 1 in 10 for land-based activity, equivalent provisions for marine-based activity)
- the imposition of additional conditions or constraints by a statutory body
- movement of agreed outages by the SO
- changes in the project scope that could not have been anticipated during the assessment process, such as unforeseen ground or sea-bed conditions.

4.157. The reopener would make an adjustment to NGET's allowed revenues for delivering the SWW output only if a pre-defined event caused the total costs of delivery to change by more than 20 per cent before application of the efficiency incentive sharing factor.

4.158. In Appendix 2, we set out more information on the proposed SWW arrangements for making within-period determination on a project specific basis. This covers the application requirements, assessment stages and timeline, implementation of decision, provisions for cost and output adjusting events during the construction phase and incentives for timely delivery.

Pre-construction funding in the baseline

4.159. We propose to include some funding as part of baseline allowances for NGET to progress pre-construction engineering works for its baseline WW outputs as well as for the proposective SWW outputs.

4.160. This is a relatively small cost category compared to LRE of delivering the Best View of WW outputs over RIIO-T1. This funding will ensure that NGET is ready to progress projects when the needs case is more certain.

4.161. For the avoidance of doubt, funding for pre-construction work in NGET's baseline does not pre-judge decisions by Ofgem about whether to approve fudning for delivering SWW outputs or whether there could be benefits from a role for third parties in construction and owning the assets.

4.162. The pre-construction funding requested by NGET is shown in Table 4.17.

Table 4.17 – Pre-construction funding requested by NGET

Pre-construction Costs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Included in Baseline Projects (£m)	19.8	12.5	11.9	9.8	0.2	-	-	-	**54.2**
Beyond Baseline Projects (£m)	18.1	1.3	2.6	1.4	0.4	0.5	0.0	-	**24.4**
SWW Projects (£m)	12.7	11.8	11.9	9.6	-	-	-	-	**46.0**
Total Cost (£m)	50.7	25.6	26.3	20.8	0.6	0.5	0.0	-	**124.6**

4.163. NGET has requested £24.4m of forecast expenditure to cover pre-construction activities for outputs delivered in RIIO-T2. This amount was not part of NGET's March 2012 business plan. We are proposing not to allow this amount on the basis that it has not yet been accompanied by supporting information.

4.164. Alongside the RIIO-T1 price control, Ofgem has been working jointly with DECC as part of the Offshore Transmission Coordination Project to look at the potential costs and benefits of a coordinated approach to offshore network development. In March 2012 we consulted on some options to support the delivery of coordinated networks. One of the measures was the potential role of onshore TOs in undertaking pre-construction works for network developments where connections between offshore and onshore have wider network benefits and reduce the need for separate reinforcements of the onshore transmission network.

4.165. Final decisions have not yet been taken in relation to implementing such measures. However, in the event an affirmative decision is taken on the onshore TO undertaking pre-construction activities for antipatory integrated offshore transmission projects, we propose to include an uncertainty mechanism in the price control to adjust NGET's revenues and outputs for acitivities it carries out in this role.

4.166. The volumes and costs associated with optioneering and value engineering work in relation to future offshore integrated projects are uncertain. Therefore we propose the most appropriate uncertainty mechanism would be a within-period determination on a scheme specific basis. As part of this provision, we would also include obligations on NGET regarding the transfer of outputs developed during the pre-construction phase to the offshore tender process.

Planning Requirements for the undergrounding of new transmission cables and DNO mitigation measures

4.167. Consistent with NGET's business plan, we propose to include baseline funding based on the assumption that 10 per cent of new OHL will need to be undergrounded to address visual amenity issues of new assets. Of course this assumption could be too little or too large. Consequently, we also propose a UM to adjust revenues for what is actually needed.

Undergrounding volume driver

4.168. We consider a volume driver to be a reasonable approach for a number of reasons.

- In our Strategy Document we said that addressing visual amenity issues are for the planning process rather than any fixed funding rule.
- It recognises that planning outcomes would be a 'known-unknown' during the price control period and might be more efficiently managed through an uncertainty mechanism triggered by planning decisions.
- NGET has published a policy statement setting out how it will, on a case by case basis, identify the location and technology for any new transmission route informed by stakeholder engagement.
- National Policy Statements will guide planning decisions which requires proposals to show how they balance visual impacts against other factors eg availability and cost of alternative sites, routes and technologies.
- NGET's actual revenues will reflect the actual level of mitigation needed to address stakeholders' concerns and achieve development consent.
- In developing proposals NGET also has to fulfil its licence obligations to develop its transmission system in an economic and efficient manner.

4.169. NGET set out in its March business plan the UCA, detailed below, that it proposes to use to adjust its baseline to reflect the actual type and volume of underground cable, incurred during the RIIO-T1 period, as a result of planning requirements. As with local generation and demand infrastructure, NGET has proposed to use the unit costs set out in the IET report, capitalised. These are the additional costs above overhead lines costs that are need to underground the lines. As the table only sets out unit costs for discrete lengths NGET propose to apply the UCA using the following criteria:

- for all routes less than 3kms the 3km UCA will apply
- for all routes between 3kms and 15kms, the 15km UCA will apply
- for all other routes the 75km UCA will apply

Table 4.18 - UCA for underground cables

Type	Length	Rating (MVA)	Additional capital costs (£m/km)

Underground cable	3km	2x1595	10.3
	3km	2x3190	18.8
	3km	2x3465	20.0
	15km	2x1595	8.2
	15km	2x3190	15.7
	15km	2x3465	16.9
	75km	2x1595	7.8
	75km	2x3190	15.1
	75km	2x3465	16.3
HVDC LCC	75km	2x1500	8.5
	75km	2x3000	14.4
HVDC VSC	75km	2x1500	10.7
	75km	4x1500	21.5

4.170. Over the assessment period NGET has supplied further information to support the matrix of unit costs. Our engineering consultants assessed the unit costs and were satisfied with NGET's approach to converting from lifetime cost in the IET report to capital cost for UCA. As a result we propose to accept NGET's proposal.

4.171. We note that NGET are currently exploring alternative technologies, such as Gas Insulated Line. We would expect to apply the appropriate capitalised unit costs outlined in the original IET report to reflect the technology used.

DNO mitigation baseline expenditure

4.172. Diversion work refers to the activity of relocating existing assets which are obstructing planned works. The TO bears the cost of diverting DNO assets to accommodate transmission work.

4.173. We have set out in the table 4.19, below, the volume of activities that we propose to fund through the baseline. NGET have forecast an expenditure of £26m to carry out this volume of activities. However upon application NGET UCA, set out below, only £8m of the £26m forecast expenditure is associated with the delivery of outputs under this UM. The basis of the remaining £18m of expenditure has not been specified and we propose disallowing this amount.

Table 4.19 – Outputs for DNO mitigation activities

Output	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
132kV tower removal (#)	-	-	-	90	-	-	197	-
132kV bays (#)	-	-	-	5	-	-	-	-
132kV overhe	-	-	-	1	-	-	-	-

ad line (km)								

Unit cost allowances

4.174. NGET set out in its March 2012 Business Plan further details of the DNO mitigation UCA that it has proposed to use to adjust the DNO baseline expenditure to reflect the actual volumes of work undertaken. Since March NGET has provided further supporting information and further refined its UCA's through:

- inflating the unit costs of undergrounding the DNO overhead lines and constructing new DNO overhead lines to 2009-10 prices

- introducing a further unit cost for a new DNO double circuit.

4.175. All costs proposed by NGET apart from the tower dismantling and DNO switchgear were based on the average unit costs in the Initial Proposals for DPCR5, inflated for 2009/10 prices. The DNO switchgear was taken as the average cost of DNO switchgear in NGET's business plan data tables. DNO tower dismantling is a new unit cost put forward by NGET.

Table 4.20: UCA for DNO mitigation activities

Mitigation	**NGET's UCA (March 2012)**	**Ofgem's UCA**
Undergrounding of DNO overhead line (based on 132kV underground cable) (£m/ single circuit km)	1.1	1.1
DNO tower dismantling (£k/tower)	[redacted]	[redacted]
New DNO overhead line(based on reconductoring of 132kV tower line and assuming three towers per km) (£m/ single circuit km)	0.7	0.7
New DNO double circuit overhead line (based on reconductoring 132kV tower line and three towers per km) (£m/double ciruit km)	N/A	0.8
New DNO switchbays (based on NGET unit cost – average of air-insulated and gas-insulated switchgear) (£m/bay)	[redacted]	[redacted]
RPE's		0.9 per cent per annum

4.176. We have outlined in Table 4.20 above, the amendments we propose to make to NGET's UCA. This takes into account both the changes made by NGET, our assessment and the recommendations made by the engineering consultants.

4.177. Our engineering consultants benchmarked the unit costs against the costs held within its cost database. From this assessment it was concluded that all costs, apart from switchgear, were reasonable. We note that the unit costs proposed by NGET, taken as the average unit cost from the Initial Proposals for DPCR5, are slightly higher than the final allowance made by Ofgem in the Final Proposals for DPCR5. However, we consider that this is reasonable as it takes into account the large increase in real price effects that have occurred since DPCR5 came into force.

4.178. Switchgear was assessed by our engineering consultants as part of their unit cost assessment. In line with the recommendations made by the engineering consultants and the reductions made elsewhere, we have propose to reduce the unit cost of switchgear by 21.8 per cent.

4.179. We propose to adjust the UCA annually for changes in RPI and for 0.9 per cent Real Price Effects.

Wider works (General)

4.180. This section focuses on Wider Works (General) which captures expenditure that cannot be clearly attributable to either large changes in generation or demand. There are no anticipated demand changes which are large enough for NGET to forecast any Wider Works (Exit) funding.

Baseline LRE and outputs

4.181. Baseline expenditure associated with Wider Works (General) is comprised of ex-ante funding that is not adjustable by any of the proposed UMs. The expenditure is comprised of non-boundary work, fault level capability, reactive compensation and easements. Table 4.21 summarises proposed expenditure.

Table 4.21 - Proposed Wider Works (General) baseline LRE and output

Costs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	RIIO-T1
Wider Works (General)	82.8	90.6	66.7	64.5	50.2	35.4	12.9	10.6	413.8

Outputs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	
Fault Level replacement (# sites)	2	1	4	1	0	0	1	0	
Outputs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	
Shunt Reactors (#)	0	0	5	2	1	2	1	0	

4.182. We summarise below the change in LRE for Wider Works (General) from NGET's business plan.

Wider Works (General)	**£m**
March 2012 baseline	**230.0**
Movement of outputs within baseline (see Appendix 3)	661.3
Moving planning requirements baseline into WW (Entry)	-454.5
Efficiency saving	-23.0
Ofgem IP baseline	**413.8**

4.183. Wider Works (General) is split into several categories by NGET. These are Non-Boundary work, Easements, Fault Level Replacement and Shunt Reactors.

4.184. We propose to use real to reactive power ratio (P/Q ratio) as a measure of the requirement install shunt reactors for reactive compensation. For fault level replacement of circuit breakers we propose to verify the fault level at substations where the circuit breakers are replaced.

4.185. There are no outputs attached to Non-Boundary Work, provision for Easements, Ex-Ante or Other. Any over or underspend against these provisions will be subject to the totex sharing factor which we propose to apply at the end of the regulatory period when the amount of any over or underspend can be ascertained.

4.186. Another area of proposed expenditure within Wider Works (General) is Non-Boundary work which does not have outputs associated with it. The schemes categorised as such include.

- reconductoring Barking-West Ham and Thames Crossing
- operational tripping schemes in the South West and South Wales
- Smart zone installation
- Humber smart zone fault recorder upgrade
- rebuild Walpole 400kV substation
- work on Beddington-Wimbledon circuits.
- work on the Tees crossing (Lackenby – Saltholme – Tod Point and Lackenby – Saltholme – Hartlepool circuits)
- replacement of Willington SGT
- cooling scheme for Medway cable tunnels

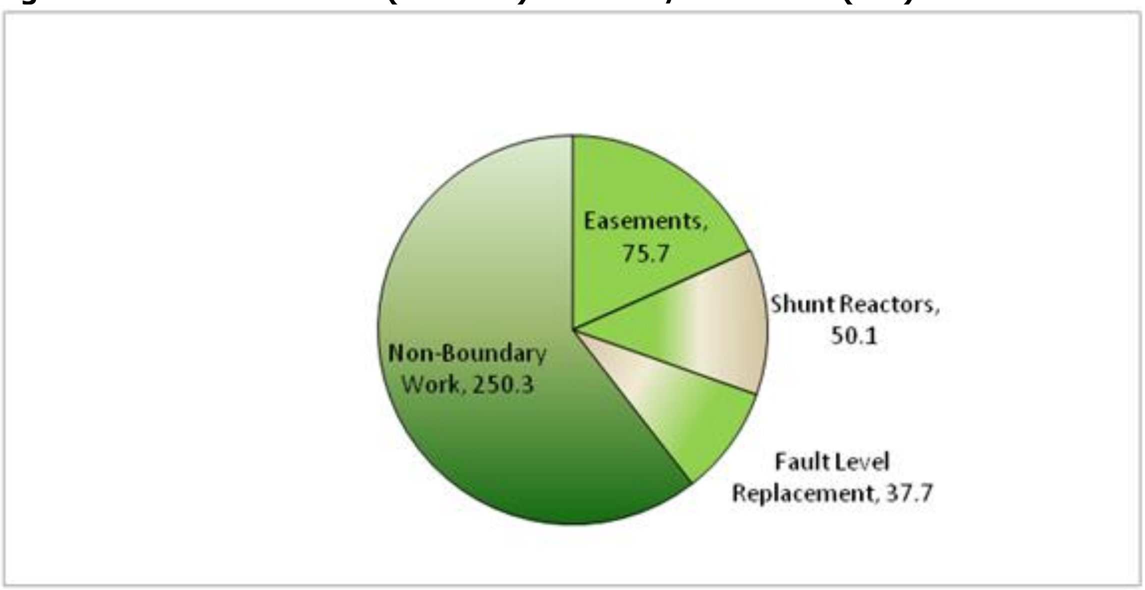
- Ross and Beddington – Chessington cable uprating

- installation and replacement of autoclose schemes

- fibre optic installation on new circuits.

4.187. A breakdown of our Initial Proposals for this LRE category is shown in Figure 4.6.

Figure 4.6 – Wider Works (General) baseline/Best View (£m)



Funding Requests Separate to RIIO-T1

Additional Funding for 2012/13

4.188. NGET's RIIO-T1 business plan includes a request for additional funding of £29.9m for TII expenditure in 2012/13. These projects were submitted together with RIIO-T1 plans but are separate from funding for RIIO-T1 and apply only to expenditure in 2012/13. We do not propose any changes to the amount requested by

NGET as it is supported by the latest information on expenditure (already incurred) for outputs that we anticipate verifying for Final Proposals.

East Coast Submission

4.189. We have received an anticipatory funding request from NGET to carry out pre-construction works to ensure that the optimal onshore / offshore solution is delivered for the East Coast Offshore Network development. We are seeking clarification on a number of technical and non-technical elements of the funding request and will present our findings in our Final Proposals for NGET for RIIO-T1, which we expect to publish in December 2012.

4.190. This request is also being considered as part of our ongoing development of offshore coordination policy, specifically for anticipatory investment. Our open letter sets out further detail on the potential role of TOs in undertaking pre-construction for some offshore wider works and invites views on this[29]. This includes the potential obligations on TOs and required outputs from the work that can be transferred into an offshore tender process.

4.191. Findings with respect to the East Coast Offshore Network development request will not prejudge our ongoing consultation on, and development of, policy to support efficient offshore network coordination, nor the policies of our enduring regime for offshore transmission.

[29] 'Offshore transmission: update on coordination policy developments' http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=49&refer=Networks/offtrans/pdc/cdr/2012

5. Initial Proposals for Non-Load Related Capex for NGET (TO)

Chapter Summary

This chapter sets out our Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for non-load related capital expenditure for NGET to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGET's March 2012 business plan and the reasons for this.

Introduction

5.1. Non-load related capital expenditure (NLRE) consists of two categories of investment: primary plant type asset investment and non-primary plant type asset investment.

5.2. The investment on primary plant type assets includes the replacement and refurbishment of transformers, switchgear, overhead lines, underground cables and cable tunnels.

5.3. The investment on non-primary plant type assets includes the costs for replacing reactors, meters, protection, control and other miscellaneous assets as well as the cost for weather related resilience.

5.4. We start by providing an overview of the NGET forecasts and our Initial Proposals for NLRE. The rest of this chapter then provides further details of our Initial Proposals, including:

- our assessment of TPCR4 performance
- our proposals on uncertainty mechanisms
- our proposed baselines for primary and non-primary assets.
- our proposed approach for assessing performance against the NOMs

Overview

5.5. We propose an ex-ante capex baseline of £4170.3m for NLRE exclusive of security resilience cost. This compares to £4654.1m forecast by NGET in its RIIO-T1 business plan. Our recommendation represents a 10.4 per cent reduction to NGET's forecast.

5.6. Table 5.1 summarises the cost breakdown excluding RPEs of NGET's business plan forecast and our recommendation.

Table 5.1 - Breakdown of forecasts and Initial Proposals for NLRE by asset types (excluding RPEs and security resilience)

NLRE - Asset Categories	**NGET Forecast Baseline (£m)**	**Ofgem IP Baseline (£m)**	**Reduction in IP from forecasts (£m)**	**Reduction in IP from forecasts (per cent)**
Primary Plant Type Assets	**3,797.0**	**3,456.2**	**-340.9**	**9.0 %**
Switchgear	1,180.4	1,028.8	-151.6	12.8 %
Overhead Lines	763.7	733.6	-30.1	3.9 %
Transformers	573.7	510.6	-63.1	11.0 %
Underground Cables	827.3	738.2	-89.1	10.8 %
Cable Tunnels	452.0	444.9	-7.0	1.6 %
Non-Primary Plant Type Assets	**857.1**	**714.2**	**-142.9**	**16.7 %**
Protection & control	361.0	300.5	-60.5	16.8 %
Weather Related Resilience	116.1	104.9	-11.1	9.6 %
Substation Other (Not requiring asset replacement)	173.1	137.1	-36.0	20.8 %
Other TO	99.9	71.4	-28.5	28.5 %
BT21CN	38.1	38.1	-0.0	0.0 %
Reactors	33.4	29.7	-3.7	11.0 %
Substation Other	27.7	24.6	-3.0	11.0 %
Metering	7.7	7.7	-0.0	0.0 %
Total NLRE	**4,654.1**	**4,170.3**	**-483.8**	**10.4 %**

5.7. Because there is a reasonably high degree of certainty around the need, timing and cost of NLRE, we propose that all funding is to be through baselines, with no uncertainty mechanisms needed.

5.8. NLRE ensures the reliability of NGET's network, and so the primary output associated with this expenditure is Energy Not Supplied. Details of this output, and the incentive related to it, are set out in the Supporting Document on outputs, incentives and innovation.

5.9. In addition, NGET will deliver a defined level of network risk by the end of the RIIO-T1 period, as as set out in the Network Output Measures (NOMs). In our Strategy Document we set out our policy on assessing performance against this output. In this document, we provide some additional information on our assessment approach. We will continue to work with the TOs during the RIIO-T1 period to refine this approach, which will be finalised during the strategy consultation process for RIIO-T2.

NGET's NLRE forecast

5.10. NGET forecast a total NLRE of £4.7bn, of which £3.8bn consists of the investment on primary plant type assets in its March 2012 business plan. Figure 5.1 summarises the breakdown of primary type assets by activities. Within the primary plant type asset investment, underground cables and cable tunnels attract the largest expenditure £1.3bn, followed by switchgear £1.2bn, overhead lines £0.8bn and transformers £0.6bn. NGET's forecast expenditure on non-primary plant type assets is relatively small compared to the expenditure on primary assets, amounting to £857.1m or 18 per cent of the total NLRE.

5.11. Within the non-primary plant type asset investment, the biggest expenditure of single asset category comes from protection and control (£361m), followed by substation other (not requiring assets replacement) (£173m), and weather related resilience (£116m). The expenditure on the remaining single asset categories is less than £100m per category.

Figure 5.1 - Breakdown of NGET's NLRE forecast for primary assets

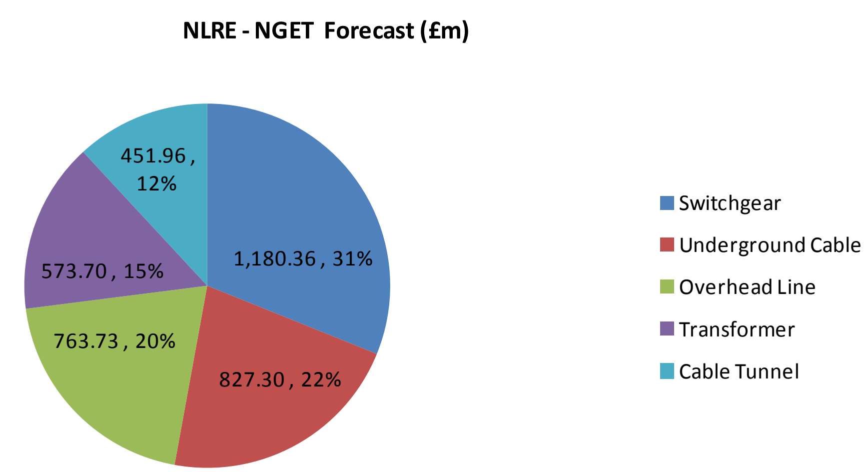
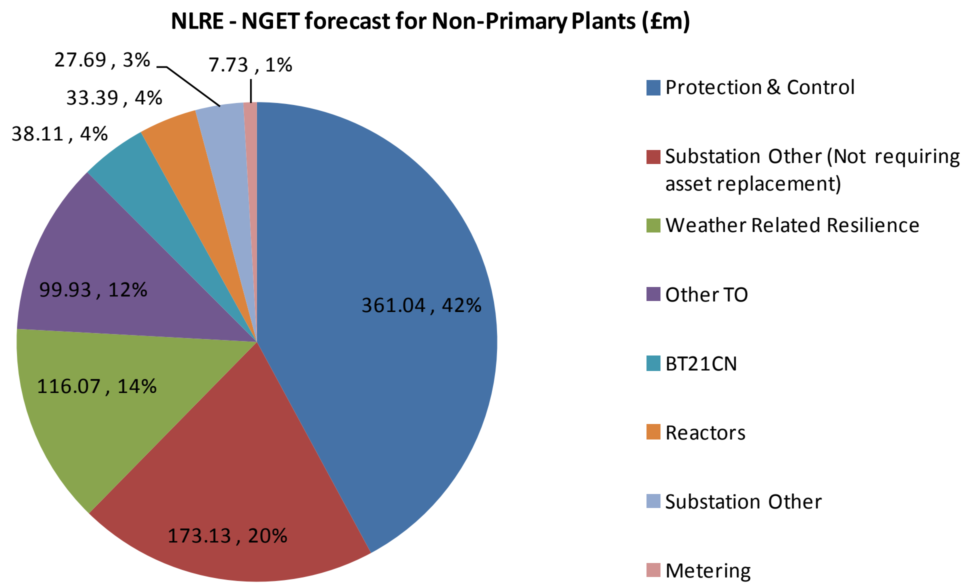


Figure 5.2 Breakdown of NGET's NLRE forecast for non primary assets



Approach to our assessment

5.12. In addition to the assessment activities set out in Chapter 1, we undertook a number of specific activities for NLRE.

5.13. We undertook detailed scrutiny on NGET's forecast expenditure on primary plant type assets given the materiality of the forecast expenditure and its impact on network risks.

5.14. We developed an age-based asset replacement forecast model to forecast the replacement volume of primary plants. Our forecast was based on the estimate of probability density functions (PDF) of asset lives and the distributions of asset population submitted by NGET. We also reviewed the evolvement of PDFs of asset lives since the beginning of TPCR4 and modelled its impact on forecast volume in RIIO-T1. For each primary plant class, we presented two forecast results based on two sets of asset life estimates named after 2010 PDF and 2005 PDF, respectively. While we used the evidence from both estimates, we considered the 2010 PDF model to provide a better estimate of likely RIIO-T1 volumes since it incorporated more recent data. We also developed a Monte-Carlo simulation tool to capture the uncertainty of our forecast in comparison with NGET's forecast.

5.15. We also used this model to assess NGET's TPCR4 performance against baselines set at the beginning of that price control period.

5.16. Our consultants compared NGET's unit costs with their internal database of costs, unit costs in TPCR4, different TOs' unit costs based on the common definitions and the unit cost information from the Institution of Engineering and Technology (IET) as well as publicly available sources of international transmission projects. In reviewing a range of sample schemes, our consultants examined NGET's scheme costing model and used a bottom-up approach to analyse the needs case and costs. Our consultants also asked NGET a wide range of questions to explore the justification of NGET's forecast. Based on this analysis, our consultants provided recommendations for NLRE baselines, which we took into account when deciding on our proposals.

5.17. For non-primary plant-type assets, given the relative low materiality comparing to primary plant expenditure, we took a proportionate approach to reviewing the forecast costs. As a result we did not use the asset replacement forecast model to review NGET's forecast replacement volumes. Instead we committed our engineering consultants to reviewing various sample replacement schemes and benchmarking the unit costs using their in-house database, NGET's historical unit costs and the other TOs' unit costs.

Initial Proposals

5.18. We summarise our proposed baseline costs for NLRE for NGET in Table 5.2. We exclude security resilience cost in our proposal as this will be discussed in the section on physical security expenditure. Our proposed costs are explained in the discussions that follow.

Table 5.2 - Proposed baselines for NGET's non-load related capex (excluding security resilience)

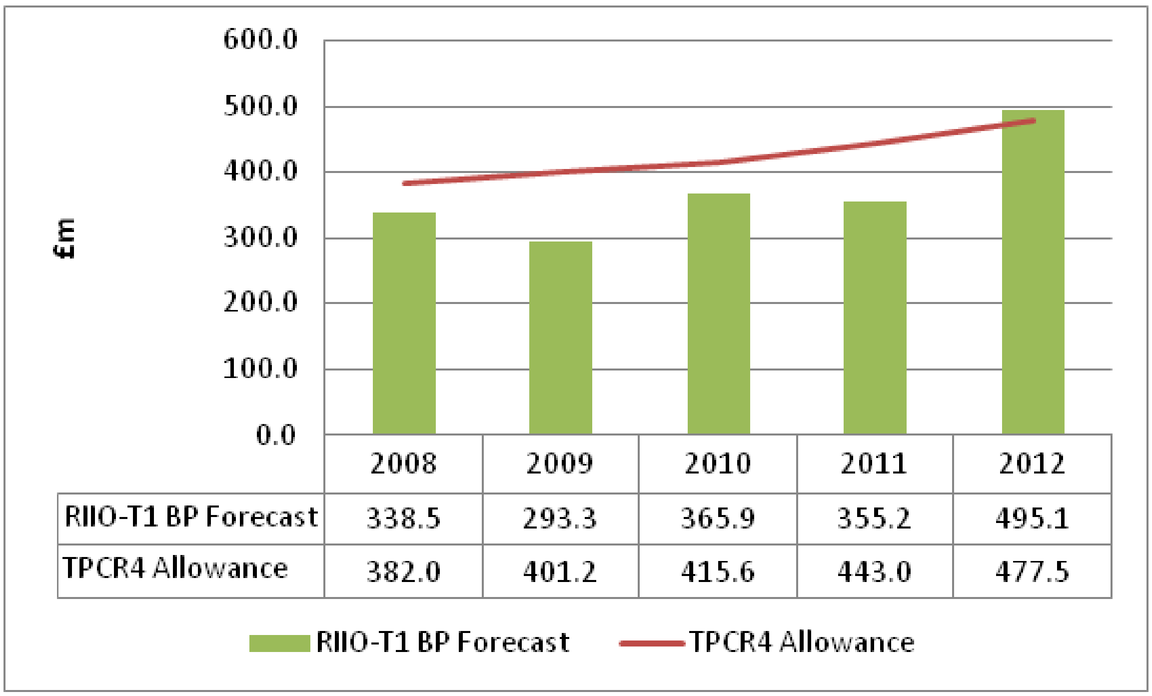
£m - year to 31 March 2009/10 prices	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Underground Cable	115.6	95.3	88.6	109.9	169.1	205.4	185.1	214.0
Switchgear	137.1	129.3	130.7	111.1	111.4	146.1	148.7	114.4
Overhead line	66.0	67.0	59.3	53.4	79.9	103.8	162.7	141.5
Transformer	46.7	33.2	40.6	55.0	80.2	90.8	106.6	57.5
Other non-load related expenditure	88.8	111.4	105.5	96.2	100.6	76.3	67.8	67.5
Real price effects	5.1	10.0	14.6	19.7	31.4	44.1	55.8	56.5
Total non-load related capex baseline	459.3	446.2	439.4	445.3	572.6	666.5	726.7	651.5

TPCR4 Asset Renewal Performance

5.19. NGET’s forecast on NLRE in RIIO-T1 was built on the historical asset management performance, cumulative knowledge on its assets and evolving asset management practice. It was therefore necessary for us to review its historical asset renewal performance during TPCR4 in order to assess its forecast in RIIO-T1.

5.20. We compared NGET’s TPCR4 NLRE reported in its RIIO-T1 business plan against the ex ante NLRE allowance for TPCR4 in Figure 2.3. NGET’s forecast of NLRE in TPCR4 is £1,848m. This is approximately £271m or 12.8 per cent lower than Ofgem’s NLRE allowance of £2,119m.

Figure 5.3 - Comparison of NGET’s NLRE forecast and Ofgem allowance in TPCR4



	2008	2009	2010	2011	2012
RIIO-T1 BP Forecast	338.5	293.3	365.9	355.2	495.1
TPCR4 Allowance	382.0	401.2	415.6	443.0	477.5

5.21. We then further compared NGET’s NLR asset addition and disposal volumes in TPCR4 with allowances and forecast results from Ofgem’s asset replacement model. The results are set out in Table 5.3.

Table 5.3 - Comparison between TPCR4 asset addition & disposal volumes, Ofgem allowance and Ofgem model forecast results

TPCR4 Lead Asset Replacement Comparison	TPCR4 Volume			Ofgem Allowance	Ofgem Model 2010 PDF	Ofgem Model 2005 PDF
	Addition	Disposal	NLR Disposal +LR Disposal in Window	Addition	Disposal	Disposal
TRANSFORMER						
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spare	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
QB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	53	55	60	64	33	61
SWITCHGEAR						
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	88	136	152	243	168	300
OHL						
Conductor Total	510	525	776	1045	809	1264
Fittings Only	714	714	543	546		
UNDERGROUND CABLES						
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	45	70	70	72	78	78

5.22. We used two forecast results from the Ofgem model in comparison: one forecast is based on the 2010 PDF estimate of asset lives, and the other one is based on the 2005 PDF estimate of asset lives. Because the PDFs of asset lives represent NGET's views on asset health and condition at the time of estimate, the difference between the two forecast results reflect NGET's asset renewal policy changes over TPCR4. We can see the asset replacement volume reduction from 2005 forecast to 2010 forecast for transformers, switchgears and overhead lines. The reduction indicates that there are general trends of asset life extension made by NGET during TPCR4.

5.23. For the majority of asset classes, we can see that after taking account of the trade-off between different voltage levels, NGET's asset renewal volumes are close to Ofgem allowances and the 2010 forecast from the Ofgem model. However, there remains one concern on the apparent under-delivery of 132kV switchgear replacement volume comparing to the Ofgem allowance and 2010 forecast. We were also concerned about NGET's explanation that the lower volume delivery was mainly driven by the program delay to align with the works of distribution network operators (DNOs). In the light of evidence so far, we estimate that the cost of delayed 132kV switchgear investment is between £50m and £122m. After multiplying the TPCR4 sharing factor of 25 per cent, we believe that NGET could gain a benefit between £12m and £31m from this delayed investment. Therefore we propose to adjust the TPCR4 revenue downwards to avoid duplicating funding for the delayed 132kV switchgear replacement in RIIO-T1.

5.24. Our modelling is based on actual figures for the first four years of TPCR4 (2007/8 to 2010/11) and NGET's forecast for expenditure in the final year of TPCR4 (2011/12). Rather than base any revenue clawback on partly-forecast figures, we will determine the correct amounts during 2013. This will also enable us to evaluate performance against the Rollover year allowances.

Uncertainty Mechanisms

5.25. Due to the uncertainty associated with the forecast of asset degradation and unexpected type faults, the asset renewal volumes forecast by NGET may vary over the RIIO-T1 period. NGET's forecast on risk is P50 based and we consider that the risk of uncertain renewal volumes is symmetric. As an asset owner, NGET is best placed to manage this risk. Therefore we do not propose any uncertainty mechanism to address the risk associated with uncertain asset renewal volumes.

5.26. In its business plan, NGET set out an uncertainty mechanism to fund earlier asset replacement in the event that load-related expenditure projects were delayed during RIIO-T1.

5.27. We do not consider this uncertainty mechanism to be necessary. Whilst we accept that there may be a rationale to advance replacement work, NGET has not justified the need for an uncertainty mechanism. We consider that our proposed total funding package and incentives will allow NGET to do this without the need for an additional uncertainty mechanism. Furthermore, any expenditure above baselines will be subject to the totex efficiency incentive, meaning that the cost effects of moving this expenditure forward will be shared with customers.

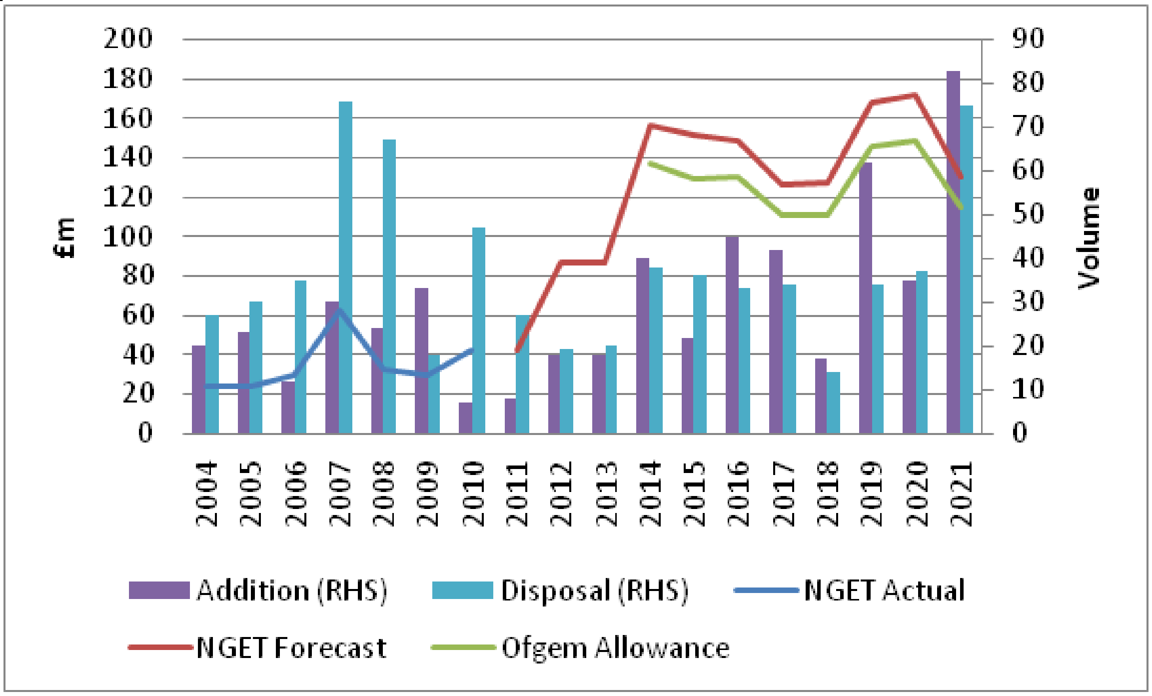
Primary plant-type assets

Switchgear

5.28. We compared NGET's historical switchgear replacement and refurbishment performance and RIIO-T1 forecast, and we noticed that the volume of disposal is not always equal to the volume of addition. This is because although most of the assets were replaced on a like-for-like basis, there were opportunities for NGET to rationalise their network while replacing the aging assets, therefore the volume of addition is not necessarily equal to the volume of disposal. Specifically for switchgear, the large difference between disposal volume and additional volume in TPCR4 was caused by the transfer of ownership of a few substations to DNOs.

5.29. We compare NGET's historical switchgear replacement performance, RIIO-T1 forecast and our proposed allowance in Figure 5.4.

Figure 5.4 - Comparison of switchgear replacement & refurbishment performance and forecast



5.30. We undertook an independent asset age based modelling in assessing the replacement volume forecast by NGET, and the comparison between NGET's forecast and Ofgem's model is shown in Table 5.4.

5.31. NGET's forecast replacement volume of 275kV switchgears is lower than either of the Ofgem model forecasts, and its forecast volume of 400kV switchgears is higher than the 2010 forecast but lower than the 2005 forecast from the Ofgem model. For 132kV switchgear replacement volume, NGET's forecast is considerably higher than either of the Ofgem model forecasts.

Table 5.4 - Comparison of switchgear replacement volume

Switchgear	Addition	Disposal			Ofgem Model	
	NLR	LR in Window	NLR	Total	2010 PDF	2005 PDF
	(#)	(#)	(#)	(#)	(#)	(#)
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	336	5	283	288	172	422

5.32. After considering our review on NGET's TPCR4 performance and the evidence submitted to us by NGET, we believe that NGET's forecast volume of 275kV and 400kV switchgears is reasonable because the difference between NGET's forecast and Ofgem's 2010 forecast was caused by the prioritisation of the switchgear replacement program. However, we believe that NGET's forecast of the large volume of 132kV switchgear replacement was the combined consequence of the under-delivery in TPCR4 and deteriorating asset conditions. We have proposed to deal with the under-delivery in TCPR4 to avoid the double funding issue in RIIO-T1 in the section of TPCR4 Asset Renewal Performance; therefore, we propose to accept NGET's forecast volume for switchgear replacement in RIIO-T1.

5.33. We propose to cut NGET's forecast cost for switchgear replacement by 12.8 per cent, and the reduction is mainly driven by the assessment that:

- our consultants estimated that NGET's circuit breaker replacement costs were about 17 per cent higher than their estimate

- NGET's forecast costs on current and voltage transformers' replacement and circuit breaker refurbishment were reasonable.

5.34. We therefore set out our proposed baseline costs for switchgear replacement in comparison to NGET's forecast in Table 5.5.

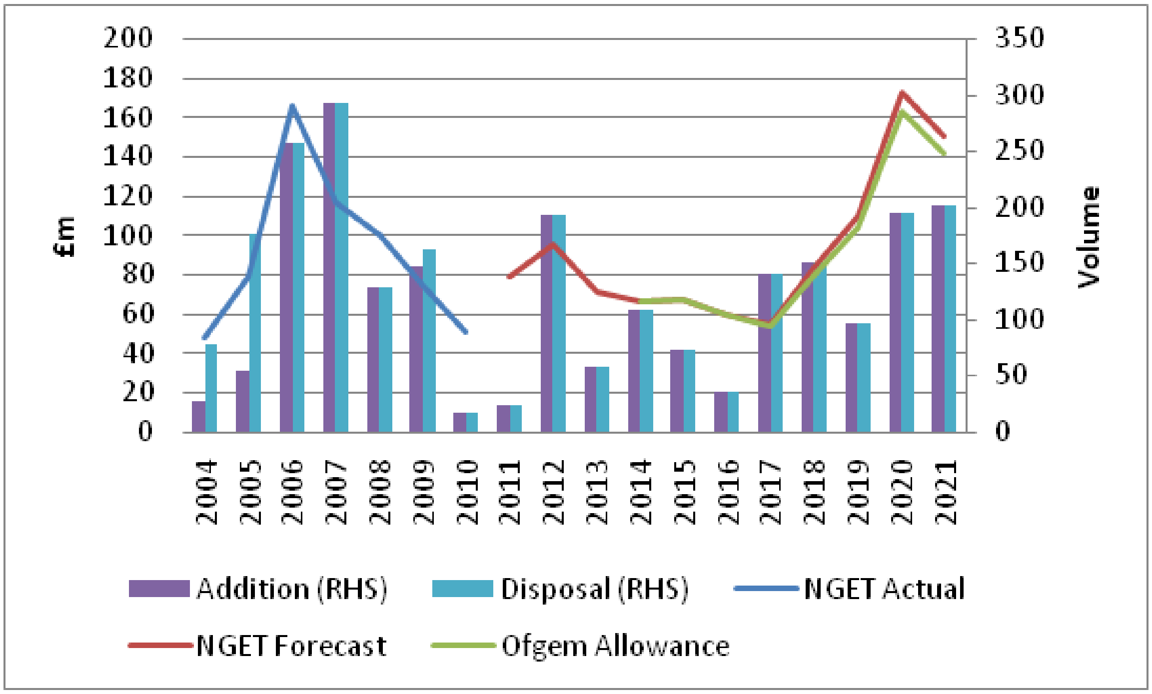
Table 5.5 - Ofgem's baseline Initial Proposals for switchgear

NLRE - Switchgear (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	137.1	129.3	130.7	111.1	111.4	146.1	148.7	114.4	1028.8
NGET BP forecast	156.8	151.7	148.4	126.0	126.9	168.3	171.8	130.5	1180.4

Overhead Line

5.35. We compare NGET's historical overhead line replacement performance, RIIO-T1 forecast and our proposed allowance in Figure 5.5.

Figure 5.5 - Comparison of overhead line replacement performance and forecast



5.36. We undertook an independent asset age based modelling in assessing the conductor replacement volume forecast by NGET, and the comparison between NGET's forecast and Ofgem's model is shown in Table 5.6. Although we did not model the fitting replacement volume, we include NGET's forecast in Table 5.6.

Table 5.6 - Comparison of overhead line replacement volume

OHL	Addition	Disposal			Ofgem Model	
	NLR	LR in Window	NLR	Total	2010 PDF	2005 PDF
	(#)	(#)	(#)	(#)	(#)	(#)
Conductors	[Redacted]	[Redacted]	[Redacted]	[Redacted]	[Redacted]	[Redacted]
Fittings	[Redacted]	[Redacted]	[Redacted]	[Redacted]	[Redacted]	[Redacted]

5.37. NGET's forecast replacement volume of overhead line conductors is lower than either of the Ofgem model forecasts. NGET explained that its conductor replacement volume forecast was based on the assessment of the overhead line (OHL) conductor's health and criticality. The lower volume relative to Ofgem's model forecasts was as a result of improved asset conditions and prioritisation of conductor replacement program.

5.38. Line fittings in general have much shorter asset lives compared to conductors. As a result, NGET forecast to replace more line fittings than conductors in order to manage the risks associated with deteriorating conditions of line fittings. We believe NGET's approach to overhead line replacement is reasonable and consistent to its TPCR4 performance. Therefore we propose to accept NGET's forecast replacement volume for overhead line conductors and fittings.

5.39. We propose an ex ante baseline cost for overhead line replacement expenditure 3.9 per cent lower than NGET's forecast, and this is mainly reflected by the assessment that:

- our consultants estimated that NGET's cost of overhead line steelwork was about 16 per cent higher than their estimate;
- NGET's forecast costs of overhead line replacement, refurbishment and line fittings were reasonable.

5.40. We therefore set out our proposed baseline costs for overhead line replacement in comparison to NGET's forecast in Table 5.7.

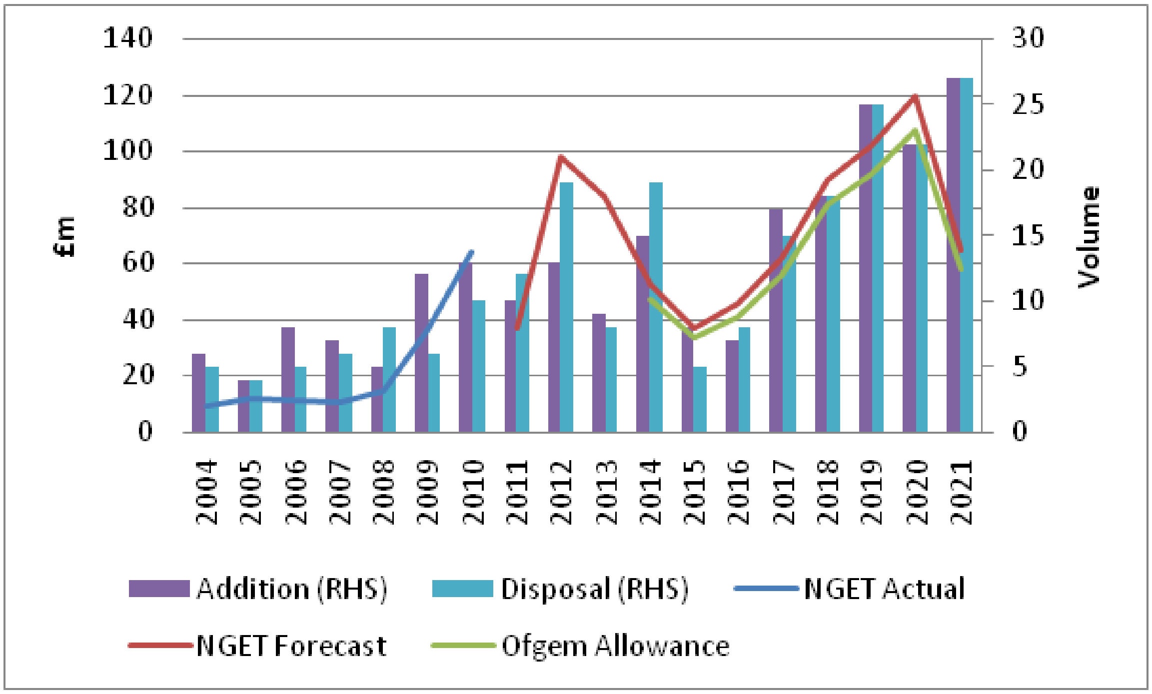
Table 5.7 - Ofgem's baseline cost proposal of NLRE - overhead line

NLRE - Overhead Line (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	66.0	67.0	59.3	53.4	79.9	103.8	162.7	141.5	733.6
NGET BP forecast	66.1	67.2	59.5	54.4	83.6	110.2	172.4	150.2	763.7

Transformer

5.41. We compare NGET's historical performance, RIIO-T1 forecast and our proposed allowance in Figure 5.6.

Figure 5.6 - Comparison of transformer replacement performance and forecast



5.42. We undertook an independent age based asset replacement modelling in assessing NGET's forecast of replacement volume, and the comparison between NGET's forecast and Ofgem's model is shown in Table 5.8.

Table 5.8 - Comparison of transformer replacement volume

TRANSFORMERS	Addition	Disposal			Ofgem Model	
	NLR	LR in Window	NLR	Total	2010	2005
	(#)	(#)	(#)	(#)	(#)	(#)
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spare	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
QB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	139	7	139	146	97	152

5.43. NGET forecast higher replacement volume of transformers compard to the Ofgem model 2010 forecast. However, its forecast is lower than the Ofgem model 2005 forecast.

5.44. NGET explained that while the asset lives of transformers were extended the replacement volume could not be reduced to the same extent as life extension. This is because most transformers have relatively high criticality due to its immediate impact on customers as a result of failure. We believe NGET's approach to transformer replacement forecast is prudent and balances the needs for investment and network reliability. Therefore we propose to accept NGET's transformer replacement volume.

5.45. We propose to cut NGET's forecast cost of transformer replacement expenditure by approximately 11 per cent, and the reduction is mainly driven by the assessment that our consultants estimated that NGET's transformer replacement cost is approximately 11 per cent higher than the median of our engineering consultants' benchmarking unit costs.

5.46. We therefore set out our proposed baseline costs for transformer replacement in comparison to NGET's forecast in Table 5.9.

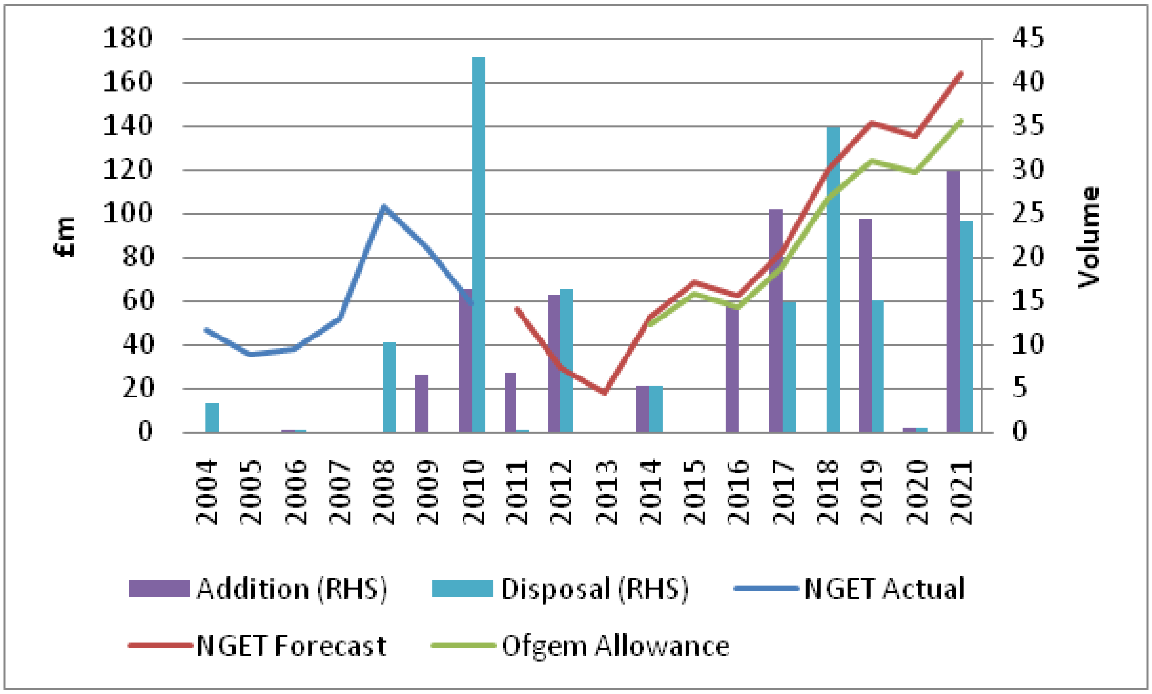
Table 5.9 - Ofgem's baseline cost proposal of NLRE transformers

NLRE - Transformer (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	46.7	33.2	40.6	55.0	80.2	90.8	106.6	57.5	510.6
NGET BP forecast	52.5	37.3	45.6	61.8	90.1	102.0	119.7	64.6	573.7

Underground Cable

5.47. We compared NGET's historical underground cable replacement performance, RIIO-T1 forecast and our proposed allowance in Figure 52.7.

Figure 5.7 - Comparison of underground cable replacement performance and forecast



5.48. We undertook an independent asset age based modelling in assessing NGET's forecast replacement volume of underground cables, and the comparison between NGET's forecast and Ofgem's model is shown in Table 5.10.

Table 5.10 - Comparison of underground cable replacement volume

UNDERGROUND CABLES	Addition	Disposal			Ofgem Model	
	NLR	LR in Window	NLR	Total	2010 PDF	2005 PDF
	(#)	(#)	(#)	(#)	(#)	(#)
400kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
275kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	100	5	94	100	146	146

5.49. NGET's forecast replacement volume of underground cables is lower than either Ofgem model forecast. The difference between NGET's and Ofgem's forecasts is largely due to the fact that underground cable replacement is less likely to occur on a like-for-like basis and the replacement volume is driven by a few large schemes. This weakens the predictive power of our model. After further investigation on the scheme details, we are satisfied that NGET justified its forecast volume.

5.50. Within NGET's total forecast cost of cable replacement, only a small amount was sanctioned and largely related to London cable replacement works.

5.51. Our consultants reviewed the details of various cable replacement schemes. They believed that the cost included in the sanctioned schemes was reasonable considering the uniqueness of the London situation. However, they estimated that NGET's forecast cost for unsanctioned cable replacement schemes was about 15 per cent higher due to the misapplication of complexity factors assigned by NGET. Considering the unsanctioned cost forecast was based on desktop assumptions, and recognising the difficulty in estimating cable scheme costs as a desktop exercise and the opportunity for NGET to learn and gain experience in design, procurement and delivery, our consultants also recommended a 1 per cent efficiency saving on unsanctioned cable cost.

5.52. We therefore propose to cut NGET's forecast cost of underground cable replacement by 10.8 per cent, and set out our proposed baseline costs in comparison to NGET's forecast in Table 5.11.

Table 5.11 - Ofgem's baseline cost proposal of NLRE - underground cables

NLRE - Underground Cable (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NGET BP forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cable Tunnel

5.53. Within NGET's total forecast cost [redacted], [redacted] includes the costs of unsanctioned cable tunnel schemes. Most of the sanctioned cable tunnel scheme costs are related to London cable tunnel works.

5.54. Our engineering consultants reviewed the details of some cable tunnel schemes and noted that some of unsanctioned cable tunnel works in the latter half of RIIO-T1 has the potential for system rationalisation. To create a further incentive to gain cost savings by redesign, over and above efficiencies of procurement and delivery, our consultants recommended a further 1 per cent efficiency saving on unsanctioned cable tunnel costs.

5.55. We propose to accept our consultants' recommendation and therefore set out our baseline cost for cable tunnel 1.6 per cent lower than NGET's forecast. Our proposal and NGET's forecast are compared in Table 5.12.

Table 5.12 - Ofgem's baseline cost proposal of NLRE - cable tunnels

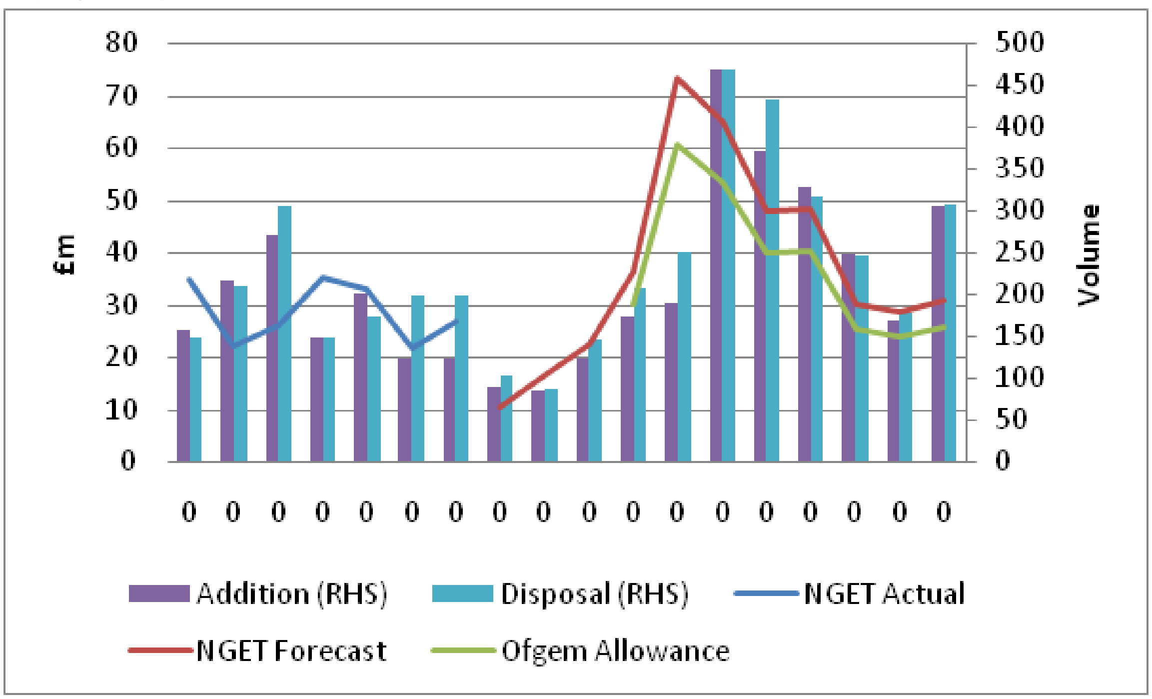
NLRE - Cable Tunnel (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NGET BP forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Non-primary plant type assets

Protection & Control

5.56. Protection & Control are the asset classes of largest expenditure in non-primary plant type investment. We compared NGET's historical performance of protection and control replacement with its RIIO-T1 forecast and our proposed allowance in Figure 5.8.

Figure 5.8 - Comparison of protection and control replacement performance and forecast



5.57. We propose to cut NGET's forecast on control replacement cost by 20 per cent and cut NGET's forecast on protection replacement cost by 11 per cent. Our proposals are based on our engineering consultants' assessment that:

- NGET forecast very high control replacement costs as a result of estimated high complexity factors and management overheads as well as inflated system access costs. This led our consultants to normalise the complexity factor down and recommend a cost reduction of 20 per cent;

- NGET forecast high protection replacement costs by applying a high complexity factor across the board. This led our consultants to normalise the complexity factor down and recommend a cost reduction of 11 per cent.

5.58. Therefore we set out our proposed baseline costs for protection and control replacement in Table 5.13.

Table 5.13 - Ofgem's baseline cost proposal of NLRE – protection & control

NLRE - Protection & Control (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	30.3	60.8	53.5	39.9	40.5	25.5	24.0	25.9	300.5
NGET BP forecast	36.2	73.5	65.1	48.0	48.4	30.3	28.7	30.9	361.0

Weather Related Resilience

5.59. NGET forecast a total cost of £116m for weather related resilience covering flooding protection works for high risk sites at a total cost of £105m and tower flood protection works with an estimated cost of £11.1m.

5.60. Our consultants reviewed weather related resilience schemes in detail and came to the following conclusions:

- NGET's costing approach was in line with the Engery Networks Association (ENA) recommendation and the forecast cost was reasonable for the flooding protection works for high risk sites;

- There is a high degree of uncertainty over the work scope and cost for the tower flood protection forecast by NGET. Therefore we propose to disallow it from the ex-ante baseline cost. We note that there is an uncertainty mechanism that can deal with this.

5.61. We therefore propose to cut NGET's forecast cost by £11.1m and spread the cost reduction proportionately over the eight years of RIIO-T1. The proposed baseline costs for weather related resilience are set out in Table 5.14.

Table 5.14 - Ofgem's baseline cost proposal of NLRE – weather related resilience

NLRE - Weather Related Resilience (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	7.9	5.8	16.2	16.2	20.1	18.9	9.9	9.9	104.9
NGET BP forecast	8.7	6.4	18.0	18.0	22.2	21.0	11.0	11.0	116.1

Substation Other (Not requiring asset replacement)

5.62. This category of investment mainly includes substation civil engineering works, strategic spares, minor works on non-prime items of switchgears and transformers. NGET forecast a total cost of £173m in this category over RIIO-T1.

5.63. We propose to reduce NGET's forecast by £36m for the following reasons:

- Our engineering consultants recommended a further 1 per cent of efficiency saving applied to substation civil engineering works and minor works on non-prime items of switchgears and transformers in recognising the potential for synergy savings. This is because these works could be bundled in with other primary asset replacement activities to maximise efficiency of site possessions and mobilisations.
- Our engineering consultants considered that NGET's funding request for strategic spares was not fully justified or explained and introduced a risk of double counting with the other types of capital investment. We propose to disallow NGET's forecast of £31.7m for strategic spares.

5.64. We therefore spread the cost reduction proportionately over RIIO-T1 and set out our proposed baseline costs for this category in Table 5.15.

Table 5.15 - Ofgem's baseline cost proposal of NLRE – Substation Others (not requiring asset replacement)

NLRE - Sub Other (not requiring asset replacement) (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	19.3	18.0	17.9	16.4	17.8	16.9	15.6	15.4	137.1
NGET BP forecast	23.0	21.9	22.2	20.9	22.5	21.7	20.5	20.5	173.1

Other TO

5.65. NGET forecast a total cost of £100m for Other TO type of investment mainly including overhead line miscellaneous, operational telecom (Optel) and the other miscellaneous.

5.66. We propose to accept NGET's forecast on OHL miscellaneous and the other miscellaneous due to the low materiality and reasonable forecast approach.

5.67. Our engineering consultants reviewed NGET's forecast of Optel costs and considered that a forecast of £28.5m expenditure on Optel was based on some assumed developments that may not materialise within the RIIO-T1 period and recommended that we disallow such cost.

5.68. We therefore spread the cost reduction proportionately over the eight years of RIIO-T1 and set out the baseline costs in comparison to NGET's forecast in Table 5.16.

Table 5.16 - Ofgem's baseline cost proposal of NLRE – Other TO

NLRE – Other TO (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	8.8	7.3	5.9	8.3	7.9	10.7	10.7	11.9	71.4
NGET BP forecast	14.3	9.5	5.9	9.2	8.2	17.2	17.1	18.4	99.9

BT 21st Century Network (BT21CN)

5.69. Due to the cessation of some services provided by BT, NGET has incurred some expenditure to replace the BT service during TPCR4+R. NGET forecast a further cost of £38m over RIIO-T1 to upgrade its telecommunication service to meet its operational requirements.

5.70. Our consultants reviewed the details of such cost and regarded the unit costs as reasonable although some were towards the high end of the range.

5.71. We therefore propose to accept NGET's forecast and the proposed baseline costs are set out in Table 5.17.

Table 5.17 - Ofgem's allowance proposal of NLRE – BT21CN

NLRE - BT21CN (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	5.7	8.1	5.7	8.6	10.0	0.0	0.0	0.0	38.1
NGET BP forecast	5.7	8.1	5.7	8.6	10.0	0.0	0.0	0.0	38.1

Reactors

5.72. Reactors, similar to transformers, are wound plant type assets. We propose to cut NGET's forecast cost by 11 per cent based on our engineering consultants' recommendation that NGET's forecast is about 11 per cent higher than the benchmark unit cost.

5.73. We therefore set out our proposed baseline costs for reactor replacement in comparison to NGET's forecast in Table 5.18.

Table 5.18 - Ofgem's baseline cost proposal of NLRE - reactors

NLRE - Reactor (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	11.2	7.1	3.9	1.7	1.1	2.2	2.1	0.4	29.7
NGET BP forecast	12.6	8.0	4.4	1.9	1.2	2.5	2.3	0.5	33.4

Substation Other

5.74. NGET forecast a total cost of £27.7m to replace the low voltage alternating current (LVAC) equipment and battery in substations over the eight years of RIIO-T1.

5.75. Our consultants recommended imposing an 11 per cent cut in recognising synergy savings and cost assessment results on the other types of substation expenditures. This was also informed by the observation that the expenditure under this category has been re-phased towards the end of RIIO-T1 period, and therefore greater capital efficiency could be applied to this category.

5.76. We therefore propose to follow our engineering consultants' recommendation and set out our proposed baseline costs for substation other as in Table 5.19.

Table 5.19 - Ofgem's baseline cost proposal of NLRE – Substation Other

NLRE - Sub Other (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	1.1	1.2	2.3	5.2	3.3	2.1	5.5	4.0	24.6
NGET BP forecast	1.3	1.3	2.5	5.9	3.7	2.3	6.2	4.5	27.7

Metering

5.77. We propose to accept NGET's forecast cost of meter replacement due to the low materiality. We therefore set out our proposed baseline costs equal to NGET's forecast in Table 5.20.

Table 5.20 - Ofgem's baseline cost proposal of NLRE - metering

NLRE - Metering (£m)	2014	2015	2016	2017	2018	2019	2020	2021	Total
Ofgem IP baseline	4.5	3.2	0.0	0.0	0.0	0.0	0.0	0.0	7.7
NGET BP forecast	4.5	3.2	0.0	0.0	0.0	0.0	0.0	0.0	7.7

Network Output Measures

5.78. The Network Output Measures (NOMs) provides a means for TOs to profile network assets into the asset's risk of failure and the criticality of such failures. Although this measure is of no immediate consequence to customers compared to measures like reliability of supply, NOMs is a good indication of a network company's ability to achieve a reliable service for future customers. It enables TOs to evolve asset management policies that do not compromise their ability to deliver reliable service in future periods. Therefore, our assessment of NGET's delivery of its NLR asset management performance will centre on performance against its NOMs.

5.79. In the remainder of this section, we set out the principles and approaches based upon which we will assess the performance of TOs against their NOMs.

Reconciliation between asset replacement volume and NOMs

5.80. We will base the assessment of NLR investments on a company's delivery of NOMs over the RIIO-T1 price control period. The NOMs gap, defined as the difference in NOMs at the end of RIIO-T1 between NOMs with all investments and NOMs with LR only investments, must reflect the level of investment proposed under NGET's NLR investment programme. In this section, we set out further detail on the assessment of NOMs.

5.81. NGET shares the same NOMs definition with SHETL and SPTL. This definition categorises assets into four groups based on replacement priority (RP):

- RP1: assets needing replacement within 2 years
- RP2: assets needing replacement between 2 and 5 years
- RP3: assets needing replacement between 5 and 10 years
- RP4: assets needing replacement after 10 years.

5.82. The RP groups are determined by the asset health (AH) and criticality (C) of assets, which determines their positions on a NOMs matrix. An example NOMs matrix is set out below.

Figure 5.9 - Replacement Priority matrix

	AH1 New or as new	**AH2** Good or serviceable condition	**AH3** Deterioration, requires assessment or monitoring	**AH4** Material deterioration, intervention requires consideration	**AH5** End of serviceable life, intervention required
C1 Very High	**RP4** 10 + Years	**RP3** 5 -10 Years	**RP2** 2- 5 Years	**RP1** 0-2 Years	**RP1** 0-2 Years
C2 High	**RP4** 10 + Years	**RP3** 5 -10 Years	**RP2** 2- 5 Years	**RP1** 0-2 Years	**RP1** 0-2 Years
C3 Medium	**RP4** 10 + Years	**RP3** 5 -10 Years	**RP2** 2- 5 Years	**RP2** 2- 5 Years	**RP1** 0-2 Years
C4 Low	**RP4** 10 + Years	**RP3** 5 -10 Years	**RP2** 2- 5 Years	**RP2** 2- 5 Years	**RP1** 0-2 Years

5.83. The NLR asset investment actions undertaken by a company will have significant impacts on the volume of the assets in each RP group. For example, if an asset within RP1 to RP3 groups is replaced, the total volume of RP1 to RP3 groups will decrease by 1 unit, and the volume of RP4 group will increase by the corresponding 1 unit. Meanwhile, the volume of RP4 group could decrease because asset conditions gradually degrade and degraded assets will move into lower RP groups (ie RP1 to RP3). While most assets will move in this way, it is possible for an asset to move from a lower RP group (eg RP3) into a higher RP group (eg RP4) as a result of an engineering intervention or the re-assessment of its criticality on the network. We will work with NGET and the other TOs through the annual reporting process to understand the detail of the movement of assets between RP groups.

Evaluation of NOMs performance as part of RIIO-T2 price control

5.84. We propose to review the NOMs performance in RIIO-T1 as part of the RIIO-T2 price control review and set out below our current thinking on how we would take this performance into account in the setting of the RIIO-T1 price control. However, we will work with the TOs and other relevant stakeholders to refine this thinking during the RIIO-T1 period and to take into account any further relevant developments.

5.85. We currently propose to take the RIIO-T1 NOMs target as the opening position from which a network company will be funded to deliver the RIIO-T2 NOMs target. Any under delivery or over delivery against the NOMs target during RIIO-T1 would either require catch-up or be carried forward as the case may be by the company in order to meet its RIIO-T2 NOMs target.

5.86. We propose a two tier approach to assess the RIIO-T1 NOMs performance as follows.

- **Tier 1:** assess the actual NOMs against the NOMs target as set out in the RIIO-T1 price control, and reach one of three possible conclusions: on target, above target, or below target.

- **Tier 2:** review the required replacement volume that underlie the under or above target delivery. This volume will enable us to estimate the costs associated with the under or over delivery against the NOMs target. The estimate will be based on the underlying asset volume and relevant unit costs.

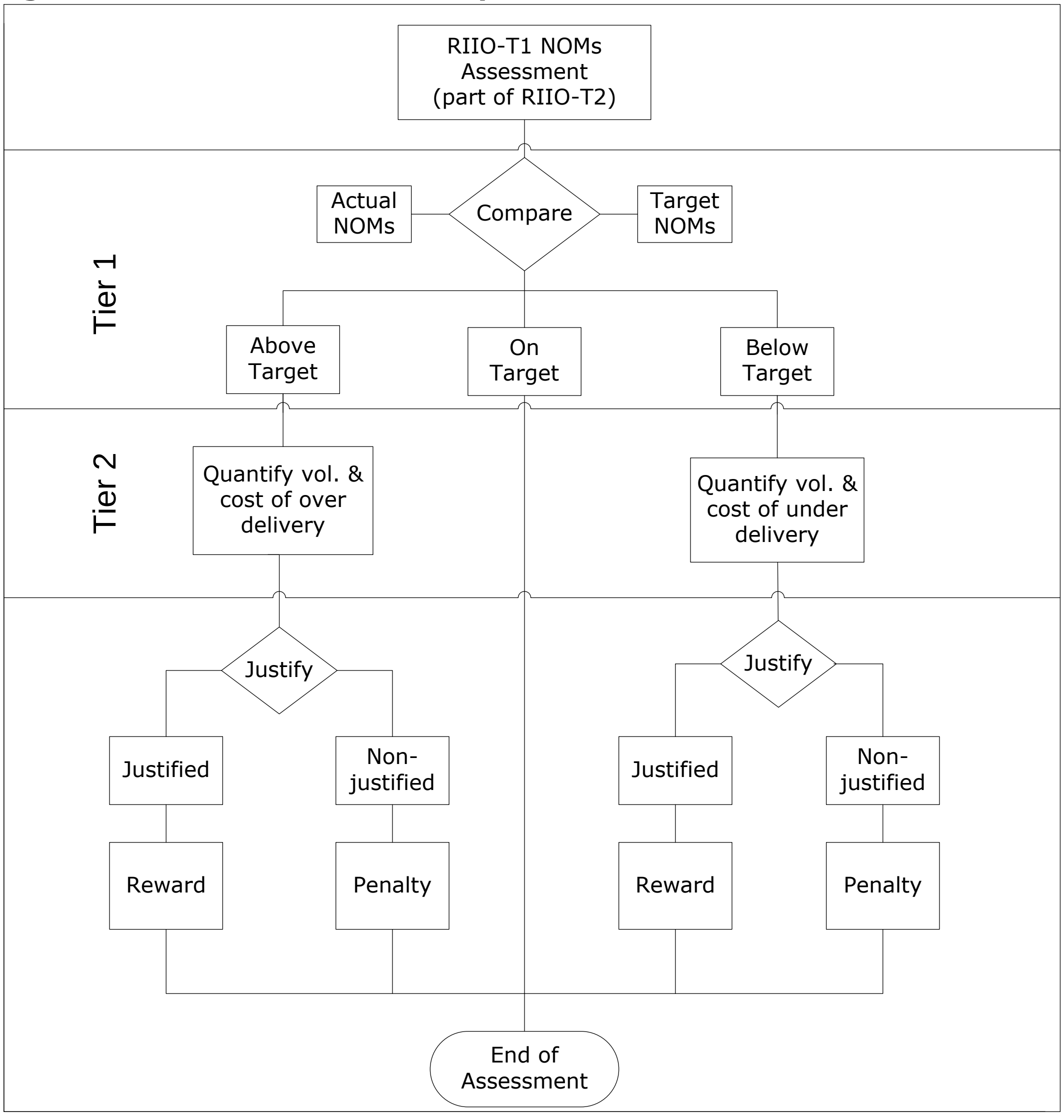
5.87. Our assessment would be centred on Tier 1 assessment results. In the event of delivery not being on target, we would carry out the Tier 2 assessment to identify the asset replacement volumes and costs required in reverting the actual NOMs back to on target. The identified costs associated with under or over delivery would be used to determine a financial reward or penalty. This assessment process is illustrated in Figure 5.10.

5.88. If a company achieves its NOMs target[30] or an equivalent NOMs target, we would not apply any additional financial adjustment to its allowance or revenue. In assessing whether the company has met the target, we would take into account trade-offs in NOMs between asset classes. As a result the company would be able to under deliver against NOMs targets in one asset class provided that it can over deliver to an equivalent extent in another asset class, leading to an equivalent level of risk at a network level.

5.89. If a company achieves above target or below target against the NOMs target, it would need to justify this variance in its RIIO-T2 business plan. We would still take the RIIO-T1 NOMs target as an opening position when setting out the allowance for the company to deliver its RIIO-T2 NOMs target. This ensures that any under-delivery is not funded twice, and that any over-delivery receives funding.

[30] We are also considering using a dead-band around this target to take into account inherent uncertainties in the assessment methodology.

Figure 5.10 - NOMs assessment process flow chart



5.90. As part of our assessment, we propose to determine the extent of justified and unjustified variances, and treat them as set out in Table 5.21.

Table 5.21 - Treatment of under/over delivery against NOMs

	Justified	Unjustified
Over delivery	The cost of the over delivery (net of the amount that has already been funded through the sharing factor) will be funded on a NPV neutral basis through the RIIO-T2 allowance. We will provide the company with a reward for carrying out this additional justified work.	The cost of the over delivery (net of the amount that has already been funded through the sharing factor) will be funded when the work is required. The company will be exposed to the financing costs associated with this work plus an additional penalty. .
Under delivery	The costs of catching up with the RIIO-T1 targets will not be funded in the RIIO-T2 allowance. The TO will be rewarded for an efficient deferral of work	The costs of catching up with the RIIO-T1 targets will not be funded in the RIIO-T2 allowance The TO will be penalised for an inefficient deferral of work.

5.91. The size of reward and penalty will be related to the costs associated with the under delivery, and we would set out these parameters during the RIIO-T2 price control review.

True-up of NOMs delivery at the end of RIIO-T1

5.92. Because the RIIO-T2 price control review process will start a few years earlier before the end of RIIO-T1, we propose to use the forecast NOMs of 2021 to evaluate the RIIO-T1 NOMs performance. Therefore when we receive the actual NOMs when the RIIO-T1 completes, we would need to true-up the difference between the forecast and actual NOMs of RIIO-T1. Any difference would be used to reconcile the over-delivery or under-delivery volumes and costs. The size of reward or penalty will also be adjusted as necessary.

6. Initial Proposals for Opex and Non-operational Capex for NGET (TO)

Chapter Summary

This chapter sets out our Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for non-operational capex and for opex for NGET to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGET's March 2012 business plan and the reasons for this.

Non-operational capex

6.1. Non operational capex is expenditure on new and replacement assets which are not system assets. This includes; IT & telecoms, vehicles including mobile plant and generators, land and buildings used for administrative purposes, and, plant & machinery (including small tools and equipment and office equipment).

NGET's proposal

6.2. NGET's forecast for non operational capex shows an average annual increase from £14.1m to £21.4m, 51.8 per cent as against expenditure and forecasts in the TPCR4+R period. The most significant increase is in IT expenditure where the forecast increase in average annual expenditure is from £10m to £17.4m (74.0 per cent).

6.3. Proposed expenditure on vehicles in RIIO-T1 for NGET is on average £1.7m per year. This is lower than average expenditure in the TPCR4+R period of £2.7m. Proposed expenditure on land and buildings in T1 for NGET is on average £2.3m per year. This is higher than average spending in the TPCR4+R period, which was £1.4m per year. The reason for the increase is due to the transfer of site care for substations from non-load related capex to non operational capex.

Table 6.1– NGET Forecasts

	NGET Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO-T1**	**Annual Expenditure over RIIO-T1**
Non Operational capex			
Transmission Front Office (TFO)		62.8	7.9
Strategic Asset Management (SAM)		32.7	4.1
Other	10.0	43.9	5.5
Total IT Expenditure	10.0	139.4	17.4
Vehicles	2.7	13.9	1.7
Land and Buildings	1.4	18.1	2.3
Total	**14.1**	**171.3**	**21.4**

* This is 4 years actual expenditure plus 2 years forecast

6.4. Expenditure on IT systems within the RIIO-T1 period is driven by 2 main projects, Transmission Front Office (TFO) and Strategic Asset Management (SAM), which are being implemented across both NGET and NGGT. The TFO system involves the integration of a number of separate systems. NGET claims that TFO will deliver enhanced capability in capital investment, programme management, policy development, scheduling and despatch. NGET's share is £62.8m over the RIIO-T1 period. The SAM system is a data capture, storage, and information system to integrate asset data and analysis across National Grid (NG). It involves a range of changes to system interfaces. It is a key enabler for a risk and criticality approach to maintenance and to enable condition monitoring of assets. NGET's share is £32.7m over RIIO-T1.

6.5. Other IT systems expenditure for NGET amount to £43.9m over RIIO-T1. This expenditure is spread over a number of systems which are proposed to be enhanced or refreshed at differing times over the RIIO-T1 period.

Approach to our assessment

6.6. We reviewed NGET's proposed expenditure on non operational capex. We raised questions and carried out a cost visit to gain more information behind the forecasts. We have also asked our engineering consultants to review expenditure on TFO and SAM as these have an influence on forecasts for direct opex and non-load related capex.

Initial Proposals

6.7. Table 6.2 summarises our Initial Proposals for non-operational capex.

6.8. With regard to the proposed expenditure on vehicles, and, land and buildings in RIIO-T1 the forecast expenditure in NGET's business plan is well-justified. Our proposal is to allow these forecasts in full.

Table 6.2 – Comparison of NGET's forecast and Initial Proposals

£m 2009/10 prices	**NGET Forecast Total Expenditure over RIIO-T1**	**Initial Proposals Total Expenditure over RIIO-T1**	**Change £m**	**Change %**
Non Operational capex				
Transmission Front Office (TFO)	62.8	43.8	-19.0	-30.3%
Strategic Asset Management (SAM)	32.7	26.5	-6.2	-19.0%
Other	43.9	21.9	-21.9	-50.0%
Total IT Expenditure	139.4	92.2	-47.1	-33.8%
Vehicles	13.9	13.9	0.0	0.0%
Land and Buildings	18.1	18.1	0.0	0.0%
Total	**171.3**	**124.2**	**-47.1**	**-27.5%**

6.9. With regard to IT expenditure we have split this into two areas; specific expenditure on TFO and SAM, and, all other expenditure. Our engineering consultants have suggested NGET's forecast for TFO should be reduced to £43.8m, or 69.7 per cent of forecast and SAM reduced to £26.5m, or 81.0 per cent of forecast. This is based on their opinion that application refreshes towards the end of RIIO-T1 could be delayed until RIIO-T2 and costs (other than those that have at least been partially sanctioned) could be reduced by 15 per cent. Despite the proposed reductions in the forecasts for the TFO and SAM systems our consultants agree with the need for these systems. These developments will enable NGET to deliver further efficiencies within direct opex and non-load related capex. We propose to reduce other IT systems expenditure for NGET by 50 per cent.

6.10. We have based this reduction on two assumptions. Firstly, we consider that a lot of IT resources within National Grid's IT department will be consumed in ensuring TFO and SAM are delivered.

6.11. Secondly, we consider that some of the proposed system refreshes in the NGET business plan will not take place within the RIIO-T1 period.

6.12. With respect to system refreshes, our Initial Proposals assume are based on the view that whilst IT systems will be reviewed regularly (maybe every 5 years) to ensure they are up-to-date, system refreshes will not happen every time such a review is undertaken.

Opex

6.13. Opex represent the costs associated with the day to day operational running of the networks. For the purposes of the price control opex are grouped into Direct Opex, Closely Associated Indirects (CAI) and Business Support.

6.14. Direct Opex represents those activities directly related to the network assets and mainly consists of maintenance.

6.15. CAI are those activities linked, but not directly related to capex and direct opex delivery – they include elements of planning and designing the network.

6.16. Business support costs are the costs that support the overall business and include: information systems and telecoms, property management, finance, audit and regulation, HR and non operational training, CEO and other corporate functions. In its plan NG has stated

6.17. In its plan NGET has stated that

> *"The requirements of the RIIO-T1 period are such that all the upward cost pressure cannot be absorbed, although we will be able to deliver economies of scale and productivity improvements in many of our processes to minimise the cost increases. We are forecasting the delivery of challenging opex efficiency levels which are at the high end of historical precedent to offset some of the upward pressure from these and other drivers, but a net increase in TO opex is still predicted".*[31]

6.18. From the table it can be seen that overall Opex forecasts from NG are forecast to increase from an average of £218m per year in the TPCR4 and Rollover periods to £262m in RIIO–T1.

Table 6.3 – NGET forecasts for opex

	NGET Forecast		
£m 2009/10 Prices	**Anuual Expenditure over TPCR4+R***	**Total Expenditure over RIIO**	**Annual Expenditure over RIIO**
Direct	95.4	1,001.6	125.2
Closely Associated Indirect	65.5	530.0	66.2
Business Support	56.5	405.7	50.7
RPEs	0.8	156.5	19.6

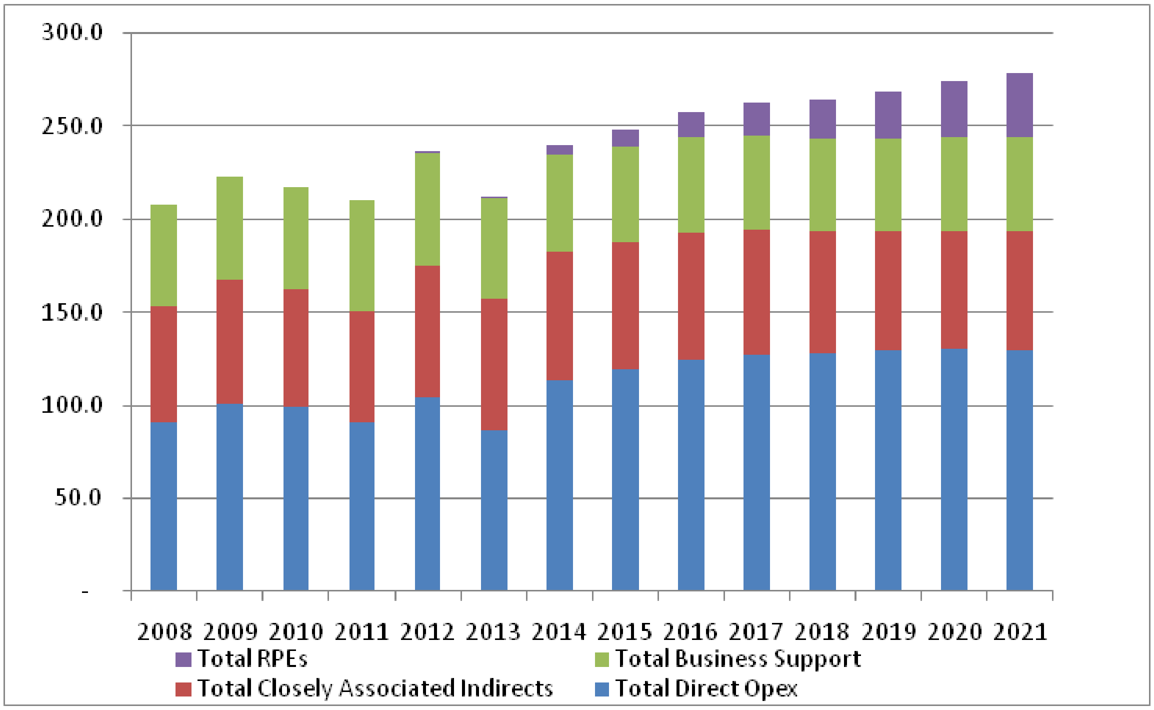
[31] pp175 Detailed Plan NLRE Annex, NGET Business Plan

Total	**218.2**	**2,093.8**	**261.7**

* This is 4 years actual expenditure plus 2 years forecast

6.19. The graph below shows actual costs from 2007/08 to 2010/11 and forecast costs for the remainder of TPCR4+R and the whole of RIIO-T1.

Figure 6.1 - Graph of Direct Opex, Closely Associated Indirects and RPEs from 2008 to 2021 for NGET TO



Note: 2008 to 2011 are actuals

6.20. From the graph we can see that the costs before RPEs increase from 2013, peaking in 2017 (which broadly coincides with the delivery of the main capex programme) and then continuing as a plateau for the remainder of the period. We also note a spike in 2012 which we understand was largely caused by decommissioning costs and the removal of asbestos – which in turn caused an increase in Direct Opex.

6.21. We have assessed these costs and are proposing £1,650m for operating costs which equates to circa £205m per year. Our proposals are discussed in more detail below. The rationale for our proposed RPEs is set out in our additional document on RPEs and ongoing efficiency.

6.22. We consider that our Initial Proposals represent an appropriate baseline for the RIIO-T1 period. In setting this proposed allowance consideration has also been given to past performance where NGET has for most years up to 2010/11 spent over the baselines set. Furthermore, it is expected that NGET will again spend above the allowances set for the remaining years of TCPR4+R.

Table 6.4 – Initial Proposals for opex

	Ofgem's view		
£m 2009/10 Prices	**NGET Forecast Total Expenditure**	**Initial Proposals Total Expenditure**	**Change**
Direct	1,001.6	843.0	-16 %
Closely Associated Indirect	530.0	467.5	-12 %
Business Support	405.7	320.0	-21 %
RPEs	156.5	19.3	-88 %
Total	**2,093.8**	**1,649.9**	**-21 %**

Direct Opex

NGET forecasts

6.23. The table below summarises Direct Opex forecasts provided by NGET. In the table we can see that for Direct opex there is an increase from an average of £95.4m per year for TPCR4+R to an average of £125.2m per year for the RIIO-T1 period. Fault Repairs and Planned Inspections contribute most to the increase over the period and between them account for about £650m of NGET's forecast expenditure in RIIO-T1.

Table 6.5 – NGET forecasts for Direct Opex

	NGET Forecast		
£m 2009/10 Prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO**	**Annual Expenditure over RIIO**
DIRECT			
Fault Repairs	35.1	264.9	33.1
Planned Inspections & Maintenance	35.8	387.3	48.4
Vegetation Management	3.6	26.9	3.4
Operational Property Management	14.3	123.6	15.4
Physical Security and Other	6.6	198.9	24.9
Total	**95.4**	**1,001.6**	**125.2**

* This is 4 years actual expenditure plus 2 years forecast

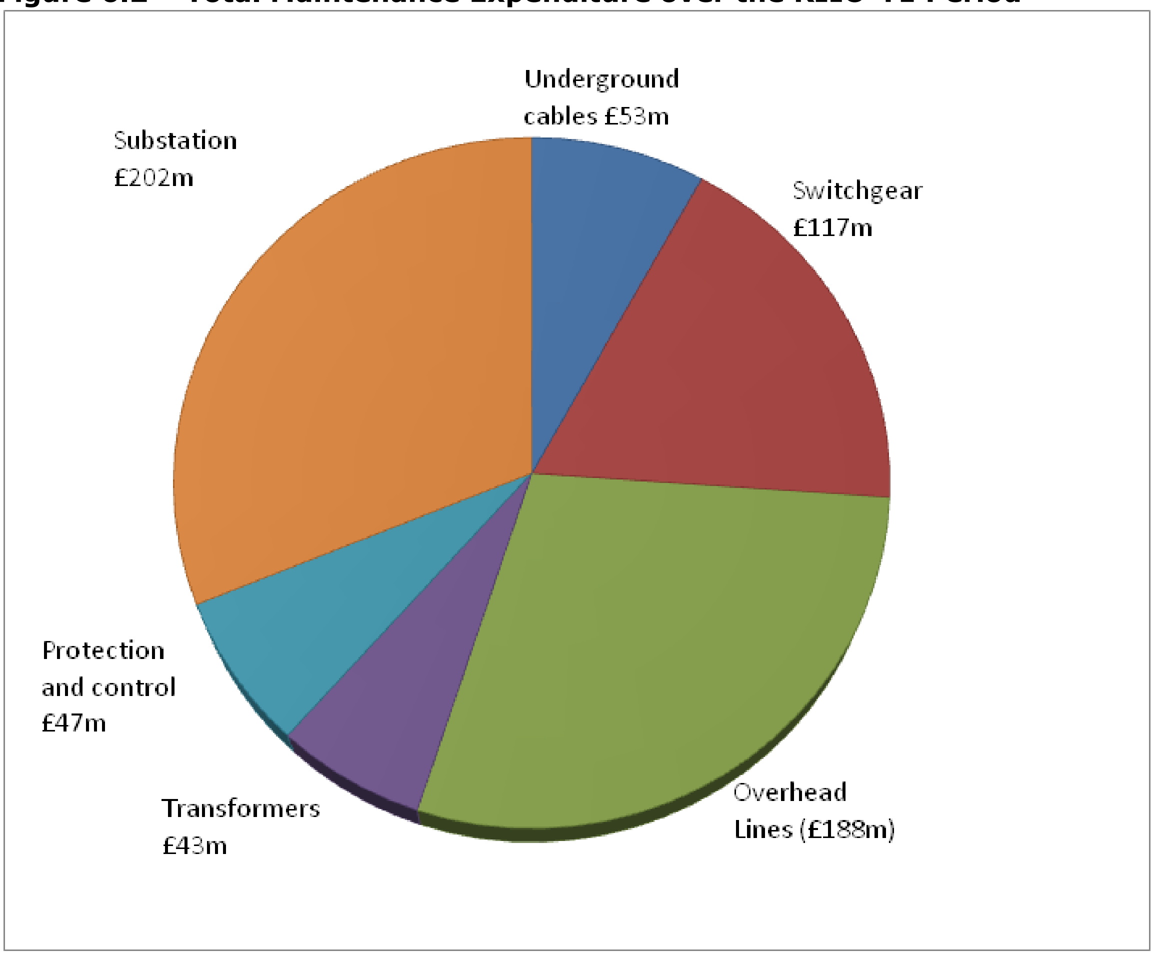
6.24. NGET has argued that as the RIIO period progresses the network will become more complex with older assets being managed in conjunction with new technologies (such as the HVDC Links) which causes a net increase in costs.

6.25. Furthermore NGET also argued it has a network with a larger population of older assets with poorer asset health – resulting in a rise in planned maintenance as such assets require greater management. NGET stated that this also increases unplanned maintenance (or fault repairs) as older assets are more prone to failure.

6.26. NGET provided limited clarification on the interaction between opex and capex expenditure forecasts. We understand that its approach to asset health and criticality considers some areas of opex. We also understand that this approach is still evolving and for other areas costs have been derived from asset management policies.

6.27. NGET's March 2012 business plan sets out maintenance costs on the basis of asset type, as summarised in Figure 6.2.

Figure 6.2 – Total Maintenance Expenditure over the RIIO-T1 Period



6.28. We can see that a large part of expenditure relates to substations which in turn covers civil works which NGET has stated are needed to ensure safe access, enabling maintenance and expenditure to comply with statutory obligations – amounting to about one third of total maintenance expenditure.

6.29. NGET has highlighted various issues including costs drivers and efficiency initiatives which shape their costs for each asset type. We summarise them below:

Table 6.6 – Cost drivers and NGET forecasts

	Asset Class	**Forecast Spend**	**Issues for Opex**
1	Underground Cables and tunnels	£53m	NGET has stated the activities driving opex costs for underground cables are monitoring and planned maintenance, Post-Delivery Support Arrangements (PDSAs), defect repairs (unplanned maintenance) and HVDC cable maintenance costs arising from the Western HVDC link project.
2	Switchgear	£117m	NGET has stated that switchgear opex is driven by defects and unplanned maintenance, a consequence of its move to a risk and criticality based approach to asset management.
3	Overhead Lines	£188m	For OHL opex costs NGET has stated it has become more sophisticated in cost forecasting and has deployed more technology producing efficiencies in its operations, particularly in tower painting.
4	Transformers, quadboosters and reactors	£43m	Using the Networks Output Measures (NOMs) NGET is forecasting an increase in Unplanned Maintenance ("Fault Repairs") as the RIIO-T1 period progresses
5	Protection and Control, Telecommunications and metering	£47m	NGET said that the introduction of the SAM IT system will deliver savings in planned maintenance. Other costs include PDSAs to support substation control systems.
6	Substation Other (excluding operational property management)	£202m	NGET has identified issues around site care activities and planned safety expenditure driving costs for this asset class
	TOTAL	**£650m**[32]	

Assessment Approach

6.30. As described in Chapter 1, our engineering consultants have helped us in the assessment of the forecasts set out in NGET's March 2012 business plan.

[32] Please note there are rounding differences between this total and the sum of the maintenance expenditure presented in Table 6.5.

6.31. In reviewing Direct Opex (and Closely Associated Indirects), the engineering consultants took into account the following factors:

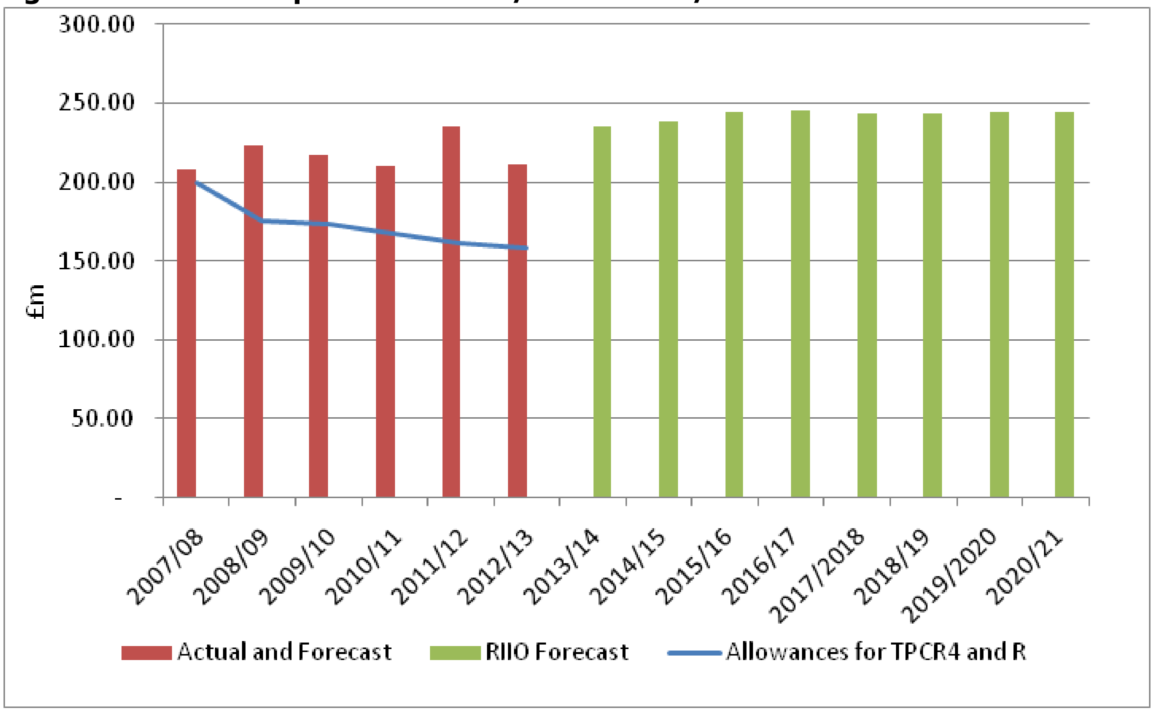
- Actual costs that have been incurred in 2010/11 and preceding years
- Efficiency improvements
- Changes in the size of the network
- Changes in asset condition, complexity and diversity
- Specific assessment of some cost components where significant changes were expected (eg tower painting).

6.32. We have reviewed and analysed the evidence put forward by NGET as well as the report prepared by the engineering consultants. For our Initial Proposals we are basing much of the opex baselines on the recommendations of the engineering consultants, as this was supported by our own analysis. The following sections outline the consultants' approach and our proposed baselines.

6.33. The engineering consultants developed a methodology for assessment which took 2010/11 actual opex as the starting point then determined opex costs on a component by component basis, scaled using appropriate measures based on information from the asset population. Subsequent adjustments have then been made for complexity factors and efficiency assumptions. Using this methodology they have remodelled the direct opex costs to provide recommendations on baselines to us.

6.34. In their methodology the consultants have applied an efficiency factor of 2.25 percent. We agreed with the consultants proposals although it is higher than our assumed efficiency of 1 percent. NGET have consistently overspent (or forecast to overspend) in the TPCR4+R period and therefore we believe an element of catch up efficiency is required. We note that the efficiency factor of 2.25% is less than the efficiency factor of 2.50% claimed by NGET in their business plans.

Figure 6.3 – Total Opex from 2007/08 to 2012/13



6.35. The application of the efficiency factor brings NGET's Opex costs towards the baseline allowances glide path which we believe is appropriate since the much of NGET's argument for the forecast costs have been based on actuals during the TPCR4+R period.

Initial Proposals

6.36. Table 6.7 summarises our Initial Proposals for Direct Opex for NGET.

Table 6.7 – Initial Proposals for Direct Opex

	Ofgem's view			
£m 2009/10 Prices	**NGET Forecast Total Expenditure**	**Initial Proposals Total Expenditure**	**Change £m**	**Change %**
DIRECT				
Fault Repairs	264.9	213.8	-51.1	-19 %
Planned Inspections & Maintenance	387.3	300.4	-86.9	-22 %
Vegetation Management	26.9	23.1	-3.8	-14 %
Operational Property	123.6	106.8	-16.8	-14 %

Management Physical Security and Other	198.8	198.9	-	-
Total	**1,001.5**	**843.0**	**-158.5**	**-16 %**

6.37. In assessing the main categories of Direct Opex, we make the following observations.

Fault Repairs

6.38. NGET has outlined a number of factors which in their view leading to certain elements of fault costs to increase. These include deterioration in overall asset condition, network size, network growth and asset diversity (with a mixture of asset technologies on the network). The engineering consultants have re-assessed this using the methodology outlined above and propose a baseline of £214m – representing a 19 per cent reduction on NGET's baseline.

Planned Inspections and Maintenance

6.39. As described earlier the engineering consultants have remodelled costs from levels at 2010/11 taking into consideration network growth, changes in asset condition and changes in complexity. Using this approach they have recommended a 22 per cent reduction to NGET's forecast of £387m, and we propose to adopt this approach.

6.40. For tower painting, forecast expenditure significantly increases during RIIO-T1 in NGET's plan, more than doubling from £41m per year in TPCR4+R periods to £86m in the RIIO controls. NGET argued that it was limited in the TPCR4 period because of a lack of suppliers and the financial need to constrain expenditure as a result of overspending on opex allowances but that it now wishes to return to historical levels. We found the justification for this unconvincing, although we recognised the need for some additional tower painting.

Vegetation management

6.41. Expenditure on vegetation management as proposed by NGET remains broadly flat over the RIIO-T1 period. For this category revised expenditure through the period has been modelled on the basis described earlier. For the RIIO-T1 period our proposed opex in this category amounts to about £23m which represents a reduction on NGET's baseline forecast of some £3.8m or 14 per cent.

Operational property management

6.42. Expenditure on operational property management as proposed by NGET again remains broadly flat over the RIIO-T1 period. The engineering consultants have commented that limited information was provided in this category. Based on the engineering consultants' recommendations we propose a baseline of £106m which is a 14 per cent reduction on NGET's forecast.

Physical Security Expenditure

6.43. NGET has proposed £50.1m ex-ante funding for certain costs relating to Physical Security. This funding is part of an ongoing programme of works, and at the moment these costs are remunerated through the uncertainty mechanisms within the licence. For the purposes of Initial Proposals we have assumed this expenditure will proceed and therefore the tables provide these allowances on a Best View basis. However as the work progresses and we have greater certainty over the costs of works at certain sites, we will look to move these costs into baseline funding. We will work with NGET between now and Final Proposals to achieve an appropriate balance between ex ante funding and uncertainty mechanisms.

Innovation Funding Allowance

6.44. We have shown no change to NGET's forecast for innovation spending although the actual allowance will be set as a percentage of revenue. This is discussed in more detail in the Supporting Document on outputs, incentives and innovation.

Closely Associated Indirect costs

NGET forecasts

6.45. The table below summarises NGET forecasts for Closely Associated Indirect expenditure (CAI). For CAI, NGET is forecasting a small increase for RIIO-T1 compared to TPCR4+R, with forecast expenditure averaging at around £66m per year.

Table 6.8 – NGET forecasts of CAI spending

	NGET Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Annual Expenditure over RIIO**	**Annual Expenditure over RIIO**
Closely Associated Indirect Costs			
Operational IT & Telecoms	24.0	153.4	19.2
Project Management	4.2	14.4	1.8
Network Design & Engineering	4.4	41.9	5.2
Engineering Management & Clerical Support	4.9	40.5	5.1
Network Policy (incl. R&D)	2.7	21.1	2.6
Health, Safety & Environment	3.5	44.6	5.6
Operational Training	11.7	134.4	16.8
Stores and Logistics	1.1	8.2	1.0

Vehicles & Transport	3.4	24.2	3.0
Market Facilitation	0.8	9.2	1.2
Network Planning	4.7	37.8	4.7
Total	**65.5**	**530.0**	**68.2**

6.46. NGET has highlighted the following upward cost pressures for CAI costs.

6.47. As with direct opex, NGET has argued that network complexity is creating upward pressure on CAI costs. We understand from NGET that the upward pressure relates to the volumes of work undertaken to support capital projects and relates to third party contracts. NGET argues this is necessary due to the diverse asset base which needs more reactive maintenance. Specifically it has highlighted the following activities:

- Engineering management and project management activities within which NGET uses third parties for key specialist contracts such as Site Electrical Testing and for offsite testing of new available technologies.

- Network planning activity where greater volumes of work are forecast.

- Vehicles and transport activity where the growth in assets is requiring NGET to increase its headcount and thus its commercial fleet for the field force, leading to higher opex.

6.48. NGET has argued for an increase in resourcing to support the growth in the Opex and Capex programmes being undertaken for the RIIO period and to replace an ageing workforce. NGET therefore proposes to increase the recruitment of apprentices and skilled staff in the RIIO-T1 period. NGET proposes to recruit staff in advance of the increase in workload so as to ensure they are fully trained when additional resources are needed. This also drives the increase in training costs.

6.49. NGET has indicated that one of the primary drivers for environmental costs is the Carbon Reduction Commitment (CRC) scheme where they are required not only to monitor all emissions but also to purchase allowances.

6.50. Another environmental driver, NGET has stated, has been contamination liabilities where NGET have stated they have statutory requirements for further monitoring to undertake remedial action at identified sites

Initial proposals

6.51. For CAI costs, our engineering consultants used their methodology – that is taking the levels of cost from 2010/11 actual then for each cost category profile them using assumptions about changes on the network taking place and application of the 2.25 per cent efficiency factor. As mentioned earlier in the Direct Opex section and for the same reasons, we consider that the application of the efficiency factor is reasonable.

6.52. Table 6.9 summarises our Initial Proposals for CAI, comparing them to the NGET forecasts.

Table 6.9 – Initial Proposals for CAI

	Ofgem's Initial Proposal			
£m 2009/10 prices	**NGET Forecast Total Expenditure**	**Initial Proposals Total Expenditure**	**Change £m**	**Change %**
Closely Associated Indirect Costs				
Operational IT & Telecoms	153.4	132.1	-21.3	-14 %
Project Management	14.4	14.5	-	-
Network Design & Engineering	41.9	35.6	-6.3	-15 %
Engineering Management & Clerical Support	40.5	34.8	-5.7	-14 %
Network Policy (incl. R&D)	21.1	17.6	-3.5	-16 %
Health, Safety & Environment	44.6	37.4	-7.2	-16 %
Operational Training	134.4	124.3	-10.1	-16 %
Stores and Logistics	8.2	5.9	-2.3	-7 %
Vehicles & Transport	24.5	24.4	-	--
Market Facilitation	9.2	6.9	-2.3	-25 %
Network Planning	37.8	34.0	-3.8	-10 %
Total	**530.0**	**467.5**	**-62.5**	**-12 %**

Operational IT and telecoms

6.53. Initially there appeared to have been a significant reduction in operational IT and telecoms costs between those forecast for the RIIO-T1 period and TPCR4. NGET said that this reduction is mainly due to the impact of an operational telecommunication (Optel) allocation change which switches £4.3m from TO opex to SO opex in 2012/13. Taking this into account, our consultants re-modelled costs and we propose a baseline of £132m for Initial Proposals, representing a 14 per cent reduction on NGET's baseline.

Project Management

6.54. Forecast project management costs are significnatly less in RIIO-T1 than previously and are relatively small in total. In these circumstances we have accepted the forecast NGET expenditure.

Network design and engineering, Engineering management and clerical support and Network policy

6.55. For all these items NGET explains that costs temporarily peak between 2010/11 and 2012/13 due to preparations for the increased capital workloads in the RIIO-T1 period, before returning to historical averages.

6.56. For the Network Design and Engineering component costs in the latter years of the RIIO-T1 period remain significantly higher than previously. For Engineering management and clerical support costs broadly follow the path set out by NGET above while for Network policy costs are broadly similar throughout the period.

6.57. For Network, Design and Engineering we propose a reduction of 15 per cent while for Engineering management and clerical support and Network policy we propose reductions of 14 per cent and 16 per cent respectively. We have based our proposals on our analysis and our consultants' recommendations.

Health, safety and environment

6.58. The profile of expenditure varies and the consultants could not ascertain the drivers behind this. We propose a reduction on NGET's baseline plan of around £7m or 16 per cent.

Operational training

6.59. NGET states that there is an increase in these costs in advance of the increased capital workload and in order to respond to a shortage of available specialist engineering skills. As a result of these factors NGET indicates that it is increasing the intakes into their development schemes in order to create a more sustainable pool of future resources. We recognise that there is likely to be a substantial operational training requirement on NGET. However, we consider that the increase requested by NGET is significant and there should be some potential for efficiency improvements above than those included within the NGET business plan. Therefore we propose to limit the increase to 80 per cent of that requested for 2013/14 with an efficiency factor applied through the rest of the RIIO-T1 period.

Stores and logistics

6.60. For stores and logistics we have applied the results of the cost modelling undertaken by our engineering consultants. Consequently, our Initial Proposals reduce baseline expenditure to £5.9m.

Vehicles and transport

6.61. We have accepted in full NGET's forecast costs for vehicles and transport, which are falling over time.

Market Facilitation

6.62. Although there is a small component of the overall costs there is a significant increase in costs for which we have found limited justification. Whilst some increase in workload can be foreseen this needs to be tempered by likely future efficiency improvements. As a result, we propose to limit the cost increase to 70 per cent of that requested by NGET.

Network planning

6.63. These costs remain broadly flat over the whole period. We propose a reduction on NGET's forecast of around £4m or 10 per cent, based on the engineering consultants' cost methodology.

Business Support

6.64. Business support covers the activities are the costs that support the overall business and include: information systems and telecoms, property management, finance, audit and regulation, HR and non operational training, CEO and other corporate functions.

NGET's Forecasts

6.65. The forecasts submitted by NGET in its March 2012 business plan show a decrease in average business support costs from £56.5m in TPCR4+R to £50.7m in RIIO-T1, before RPEs.

Table 6.10 – Summary of NGET's Business Support Cost Forecasts

	NGET TO Forecasts		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total expenditure over RIIO**	**Annual Expenditure over RIIO**
Business support costs	56.5	405.7	50.7

* This is 4 years actual results plus 2 years forecast

6.66. Whilst the overall total costs are reducing mainly due to efficiencies being made there are small increases in certain areas. The increases identified by NGET are in the areas of:

- finance and regulation due to increases in regulatory reporting
- insurance due to increases in premiums
- procurement due to increases in the asset base.

Assessment Approach

6.67. Our assessment of business support activity costs has been informed primarily by benchmarking all UK energy network companies (transmission, gas distribution, electricity distribution) against each other and against external benchmarks developed in collaboration with the Hackett Group. This assessment covered the following activities: IT & telecom; property management; finance, audit & regulation; HR & non-operational training; procurement; and CEO & group management. Insurance costs were assessed separately and added to the benchmark assessed costs.

6.68. Where network companies exist as part of a group their operating costs are mainly derived from central group functions with the costs associated with delivering these group functions allocated to the individual networks. Therefore assessment of business support costs has been carried out at an overall group level with allowances allocated to networks in the same group in proportion to their submitted forecasts.

6.69. RIIO-T1 and RIIO-GD1 business support cost assessments were carried out together as a single process. Appendix 4 contains more detail on the business support cost assessment.

Initial Proposals

6.70. Table 6.11 summarises our Initial Proposals for Business Support Costs.

Table 6.11 – Summary of our Initial proposals for Business Support Costs

£m 2009/10 prices	**NGET Forecast Total Expenditure over RIIO-T1**	**Initial Proposals Total Expenditure over RIIO-T1**	**Change £m**	**Change %**
Business support costs	405.7	318.3	-87.4	-21.5%

7. Initial Proposals on cost and uncertainty for NGGT (TO)

Chapter Summary

This chapter sets out our Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for NGGT to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGGT's March 2012 business plan and the reasons for this.

Question 7: Do you consider that our proposed baseline for NGGT (TO) has been set at an appropriate level?
Question 8: Do you consider that our proposed uncertainty mechanisms for NGGT (TO) are appropriate?
Question 9: Do you agree with our proposals to expand the provisions of the reopener mechanism for NGGT to cover a number of additional cost areas?
Question 10: Do you agree with our proposed materiality thresholds of 2 per cent (subject to the efficiency incentive rate) for the reopener mechanism in relation to asset health shocks?

Introduction

7.1. This chapter sets out our Initial Proposals for an efficient level of expenditure for NGGT (TO), and the arrangements for addressing risk and uncertainty around those costs. Our proposals are informed by our assessment of NGGT (TO)'s forecasts for baseline capex and opex and for incremental capex.

7.2. There are various costs that NGGT incurs as a TO and for which it seeks to recover revenue in its price control. The main cost areas are capital expenditure (capex), primarily load-related capex and non-load related capex, and operating costs (opex).

7.3. Load related capital expenditure (LRE) is the investment required to:

- connect new loads coming from customers (CCGTs, storage facilities, etc.) to the National Transmission System (NTS) (incremental capex);
- ensure that the NTS is able to cope with the changing pattern of flows in the network (network flexibility capex). This is described in more detail below.

7.4. Projects that are currently in progress, or that can be forecast with sufficient accuracy, are funded through ex ante baselines and/or from previously set revenue drivers.

7.5. However, the amount and location of incremental capex is dependent upon customer signals at entry capacity auctions or through the exit capacity application process. Customers' requirements cannot be accurately forecast ex-ante, therefore incremental capex will be funded through revenue drivers when the signals are received.

7.6. Network Flexibility capex is a new category of expenditure which NGGT suggests is driven by changing network flows. This expenditure is also difficult to accurately forecast over the whole RIIO-T1 period, so it is also proposed to be largely funded through uncertainty mechanisms where evidence of need becomes available.

7.7. Non-load related capital expenditure (NLRE) principally comprises expenditure required to replace existing primary and secondary assets on the TO network. Additionally, it includes expenditure relating to the reduction of direct emissions resulting from the operation of the NTS, network resilience, physical security and telecoms network upgrades.

7.8. The amount of NLRE required depends on the age and condition of existing assets and their criticality to the operation of the network. Because this type of expenditure can be forecast with greater accuracy than load-related capex, it is generally funded through ex ante expenditure baselines.

7.9. However, there is uncertainty about some of the non-load related capex (emissions abatement expenditure and major asset health projects). To overcome this, we propose a portfolio of uncertainty mechanisms. These will improve deliverability and align expenditure with project delivery. Generally, the uncertainty mechanisms proposed for load and non-load related capex include revenue drivers, investment triggers and mid-period re-openers.

7.10. Opex covers the ongoing costs of running the TOs' business, including asset maintenance and support services. It is mainly funded through ex ante expenditure baselines.

7.11. We now summarise NGGT's forecasts and our Initial Proposals for baseline funding and uncertainty mechanisms before looking in more detail (in turn) at:

- LRE
- NLRE
- Non-operational capex
- Opex, covering direct opex, closely associated indirects (CAI) and business support.

7.12. In each section, we consider both the baseline costs and the operation of any associated uncertainty mechanisms.

Overview

7.13. Table 7.1 summarises the key cost parameters for NGGT (TO)'s Best View, both in terms of NGGT's forecast and our Initial Proposals. It excludes non-controllable opex of £772m[33], which includes items such as licence fees or business rates.

7.14. 'Best View' is the expenditure that we consider the licensees will need to deliver the outputs under their central scenario. It comprises 'baseline' and 'uncertainty mechanism' funding. 'Baseline' is the expenditure that is funded through ex ante allowances. 'Uncertainty Mechanism' funding is either provided automatically where outputs are delivered over the baseline level, or is triggered by events defined in the transmission licences, or is provided at certain times during the price control period after further assessment by Ofgem of needs case and costs.

Table 7.1 – Key cost parameters for NGGT (TO)

£b, 2009/10 prices	NGGT's Best View	Initial Proposals
Load-related capex	3.5	2.2
Non-load related capex	1.4	1.0
Non-operational capex	0.1	0.04
Total Capex	5.0	3.1
Customer contributions	-	-
Total Capex (net of customer contributions)	5.0	3.1
Total Opex (incl. non controllable)	1.5	1.5
Total expenditure (Totex) exc RPEs	6.5	4.6
RPEs	0.4	0.2
Totex before IQI adjustment	6.9	4.8
IQI adjustment	n/a	0.1
Totex after IQI adjustment	**n/a**	**4.9**

7.15. The capex figure in Table 7.1 includes £309.3m relating to previously signalled incremental capex projects as explained below in the Load-related capex section.

Summary of NGGT's forecasts

7.16. Table 7.2 sets out NGGT's forecast expenditure in relation to its requirements for a baseline amount of revenue set at the start of the price control to cover

[33] This does not include £10.7m for Xoserve costs which appear in NGGT's March Business Plan. These costs have been moved to SO.

expenditure in each year of RIIO-T1 for the relatively more certain portion of investment; and for its Best View scenario.

7.17. NGGT forecasts LRE baseline of £68.3m. Most of this relates to network flexibility and aims to address the issue of new flow patterns due to declining UKCS gas flows.

7.18. NGGT forecasts further LR expenditure of £3,403.3m, to be funded through uncertainty mechanisms. This aims to provide sufficient funds for incremental loads that will be triggered during the period, to provide sufficient capacity in South West England after a planned decommissioning of a Liquefied Natural Gas Storage (LNGS) facility and to meet network flexibility requirements.

7.19. NGGT forecasts NLRE baseline of £1,432.0m. This aims to provide sufficient funds for the emissions mitigation projects and to maintain the asset health of the NTS. The baseline also includes £[redacted]relating to the replacement of the Feeder 9 pipeline across the Humber River.

7.20. NGGT states in its business plan narrative:

> *"'Over the next ten years our network is forecast to: (a) grow significantly with an 11 per cent increase in pipeline and over 60 per cent increase in compressor units, (b) have nearly three times more pipeline on the network aged beyond its design life compared to the TPCR4 period with an increase from 1,745 to over 4,600 km".*[34]

7.21. NGGT forecasts opex funding of £786.0m, which represents a significant increase on spending in TPCR4+R. NGGT attributes this to a growth in network assets, such as pipelines and compressor units, and the ageing of the pipeline network.

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[34] National Grid Gas Transmission Business Plan Annex 'Detailed Plan' page 145, paragraph 679.

Table 7.2 – NGGT expenditure baseline and Best View forecasts (Excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	23.9	16.7	6.0	5.7	10.4	5.2	0.5	-	**68.3**
NLRE	142.6	207.7	188.4	197.3	232.2	199.2	142.1	122.4	**1432.0**
Non-operational capex	10.7	10.2	6.9	6.7	6.1	4.6	7.5	11.2	**64.0**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	97.3	96.4	99.4	98.8	99.4	99.0	98.3	97.4	**786.0**
RPEs	5.5	10.8	14.2	19.5	27.9	30.5	29.0	30.9	**168.3**
Baseline expenditure	**280.1**	**341.8**	**314.8**	**328.0**	**376.0**	**338.5**	**277.5**	**262.0**	**2518.7**

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	153.2	267.4	504.7	639.5	845.4	798.9	248.1	14.5	**3471.6**
NLRE	142.6	207.7	188.4	197.3	232.2	199.2	142.1	122.4	**1432.0**
Non-operational capex	10.7	10.2	6.9	6.7	6.1	4.6	7.5	11.2	**64.0**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	97.3	96.4	99.4	98.8	99.4	99.0	98.3	97.4	**786.0**
RPEs	8.8	19.8	39.8	61.9	98.7	114.3	60.6	33.1	**437.6**
Best View expenditure	**407.1**	**601.5**	**839.1**	**1004.1**	**1281.7**	**1216.1**	**556.6**	**278.6**	**6190.5**

Initial Proposals

7.22. Table 7.3 sets out how our Initial Proposals differ from NGGT's forecast expenditure. In total we have reduced NGGT requested costs by around £2.2bn and we have moved £0.5bn from NGGT's baseline into uncertainty mechanisms.

7.23. This reflects our assessment, as supported by the analysis of our engineering consultants, Pöyry, that NGGT's forecasts address the operational and other requirements that will be put upon the NTS during RIIO-T1. However, we consider that several proposals could have been considerably better developed and provide more value to consumers. Our concerns relate primarily to non-load related expenditure projects, but we also have concerns about some of the load-related expenditure projects.

7.24. The key changes are:

- We have reduced the volume of incremental capex included in the Best View because we are concerned about the amount of projects that are included by NGGT, but are not yet backed by user commitment.

- We have reduced baseline volumes and unit costs for compressors and other non-load-related capex. Some expenditure has been classified under uncertainty mechanisms to reflect uncertainties on timings and volumes.
- NGGT's Avonmouth project has been transferred into the baseline but has been subject to an £[redacted]m efficiency reduction.
- We have broadly accepted NGGT requested opex but reduced the requested amount slightly reflecting TPCR4 comparisons and our engineering consultants' reviews.

Table 7.3 – Summary of differences between NGGT's forecasts and Ofgem's Initial Proposals (Including Non Controllable Opex))

£bn, 2009/10 prices	Baseline	UMs	Total
July 2011 business plan	3.46	3.36	6.82
Changes between first and second plan	-0.23	0.31	0.08
March 2012 business plan[35]	3.23	3.67	6.90
Reduction in incremental capex forecast	-	-1.26	-1.26
Efficiency challenge – compressor replacement	-0.69	0.34	-0.35
Efficiency challenge – Load-related capex	[redacted]	[redacted]	[redacted]
Efficiency challenge – non-load related capex	-0.19	0.13	-0.06
Efficiency challenge – opex	-0.06		-0.06
Move Avonmouth to baseline + challenge	[redacted]	[redacted]	[redacted]
Reduction in RPEs	-0.09	-0.11	-0.20
Provisional IP totals	**2.27**	**2.60**	**4.87**

7.25. Table 7.4 sets out the annual profile for our Initial Proposals, with respect to baseline expenditure and Best View.

Table 7.4 – Initial proposals for NGGT expenditure baseline and Best View (Excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**RIIO-T1**
LRE	19.6	11.9	6.9	41.1	58.4	7.1	0.2	-	**145.3**
NLRE	65.6	70.1	84.0	71.9	78.0	63.8	57.8	57.2	**548.2**
Non-operational capex	9.6	8.7	6.1	5.3	4.7	3.4	4.5	2.4	**44.7**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	85.5	84.1	84.6	84.6	85.8	85.8	85.4	84.1	**679.9**
RPEs	-0.3	1.3	3.1	5.7	8.8	7.2	7.9	9.3	**43.1**
Baseline expenditure	**180.0**	**176.0**	**184.8**	**208.6**	**235.8**	**167.3**	**155.8**	**153.0**	**1461.2**

[35] Baseline figures include NLRE for projects in St. Fergus. These were subsequently removed by NGGT because of the reclassification of compressor units in St. Fergus. This is explained below in compressor stations emissions mitigation expenditure section.

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	67.4	95.3	191.9	286.9	379.4	318.0	382.7	429.8	**2151.4**
NLRE	82.3	88.3	109.8	129.2	170.3	145.9	119.3	106.7	**951.9**
Non-operational capex	9.6	8.7	6.1	5.3	4.7	3.4	4.5	2.4	**44.7**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	90.5	89.3	90.0	90.0	91.1	91.0	90.6	89.3	**721.8**
RPEs	0.1	2.9	8.6	15.3	24.4	25.3	33.9	42.6	**153.1**
Best View expenditure	**249.9**	**284.6**	**406.4**	**526.8**	**669.9**	**583.7**	**631.0**	**670.8**	**4022.9**

Uncertainty mechanisms

7.26. NGGT has proposed a range of mechanisms in the RIIO-T1 control to help it manage the potential uncertainty it has identified during the eight-year price control period. This includes a number of additional or alternative uncertainty mechanisms to those set out in our Strategy Document.

7.27. Table 7.5 sets out an overview of the uncertainty mechanisms that we propose to provide for NGGT, and lists where further information can be found. In addition, the Supporting Document on Finance sets out details of our approach to the cost of debt, pension deficit repair and tax trigger.

Table 7.5 – Proposed uncertainty mechanisms for NGGT

Uncertainty mechanism	NGGT proposal	Our view	Timing of potential change	Reference
Efficiency Incentive Rate	Keep 50 per cent of the percentage of underspend/overspend against allowed expenditure	45 per cent (calculated by applying the IQI mechanism)	Annual	Chapter 2 and Appendix 1
Indexation	Annual indexation of revenues using the RPI	Our decision on RPI indexation was published in July 2011[36]	Annual	Chapter 2
Real price effects (RPEs) tracker	Allowance for RPEs to represent expected relative change in input prices, with steel price tracker	Allowance for RPEs but no specific steel price tracker	Ex-ante allowance	Chapter 2

[36] Decision on the RPI indexation method: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Uncertainty mechanism	NGGT proposal	Our view	Timing of potential change	Reference
Pass through	Pass through of specified costs outside of the control of the TOs	Consistent with Strategy Document	Annual	Chapter 2
Disapplication	If company experiences financial distress	Consistent with Strategy Document	At any time	
Reopener mechanism	Reopener mechanism for a number of trigger events	Reopener mechanism for additional funding to enhance physical security (as per Strategy Document) to be extended to other events	Twice: April 2016, April 2019	Chapter 2 and Chapter 7
Mid-period review	Limited to changes to outputs	Consistent with Strategy Document	Once: April 2017	Chapter 2
Innovation roll-out mechanism		Restrict the reopener to two windows in line with general reopener mechanism	Twice: April 2016, April 2019	Chapter 2
Revenue driver	Incremental capacity	Further work required on commercial changes		Chapter 3 and outputs, incentives & innovation Supporting Document
Constraint management / buy back	Both entry and exit capacity constraints to be considered within a single incentive scheme,combined these with operational buyback scheme	We are seeking views on two options: 1) Status quo 2) Single scheme		Chapter 7
Network flexibility	Reopener to fund new network investment to meet future peak day requirement	Annual reopener windows for peak day needs; mid-period review for commercial	Annual reopener in mid-period review – April 2017	Chapter 7

		needs		

7.28. We consider that there is merit in expanding the scope of the proposed reopener mechanism to include some additional areas of potential cost identified by NGGT. We therefore propose to include a number of additional defined cost areas within the scope of the reopener mechanism. These are as follows:

- Asset health shocks – this would capture high impact, low probability events, e.g. a type of fault the on NTS assets or an emergent need to replace a significant length of pipeline.

- Feeder 9 - there are uncertainties over costs and timing of this project. We are therefore proposing to include it as a category in the reopener mechanism. NGGT can apply for the appropriate funding upon granting of planning permission.

- Pipeline diversion costs – this will capture additional costs that may arise from the need for NGGT to divert existing pipelines. If these costs materialise they are likely to be substantial, but given the level of uncertainty around the need to divert pipelines it would not be in consumers' best interests to provide ex ante funding for such work.

- IPPCD costs - requirement to install appropriate either electric drives or compatible gas drives in specific sites in order to comply with the Integrated Pollution Prevention and Control Directive (IPPCD).

- Quarry and loss of development claims – to be used for additional and material one-off claims that could not have been foreseen in advance. NGGT will need to demonstrate that not only have they negotiated on these claims, to reduce where possible, but that they represent one-off claims related to specific project requirements.

7.29. We propose, for the majority of these costs, that the materiality threshold will be 1 per cent after the application of the efficiency incentive rate, as per the enhanced security reopener described above in Chapter 2.

7.30. The only exception is for one-off asset health events where we are setting the materiality threshold at 2 per cent after the application of the efficiency incentive rate. We consider that a higher materiality threshold on asset health shocks is appropriate because NGGT will also be provided for funding for asset health related costs in their baseline allowance. Therefore, we do not want the incentive to manage this allowance weakened. NGGT themselves consider that this mechanism would only be used for high impact, low probability events. Therefore we expect the likelihood of a claim to be low.

7.31. Each area of cost subject to the reopener mechanism will need to individually pass the materiality threshold. In other words, if the combined impact across a number of areas is to breach the materiality threshold but individually they do not, they will not qualify for assessment under this mechanism.

7.32. The areas of uncertainty identified by NGGT which we would propose to consider as part of the mid-period review are:

- GB or EU market change – costs associated with new market facilitation roles/functions stemming from GB or EU legislation
- Flood and erosion protection – in the event that the Government requires NGGT to contribute to flood protection or erosion schemes
- Network flexibility – costs to increase the flexibility of its network to meet commercial obligations
- Industrial Emissions Directive (IED) - Requirement to replace compressor units with either electric drives or compatible gas drives in order to comply with the IED.

7.33. We are also seeking views on two options for constraint management.

(1) A variant of NGGT's proposed single unified incentive covering entry/exit and operational/incremental actions but with no caps and collars on the incentive.

(2) The retention of the existing separate incentive schemes. This is an alternative, particularly if further analysis and discussion with stakeholders identifies major weaknesses in NGGT's proposal.

7.34. More details on the constraint management mechanism can be found in the Supporting Document on outputs, incentives and innovation.

Load-related capex

NGGT's forecast

7.35. The LRE forecast of £68.3m principally comprises £61.7m of ex-ante funding for additional operational capability – defined as Network Flexibility. The anticipated projects relate to (i) projects in Scotland; (ii) works at Lockerley compressor station; and (iii) further analysis of network flexibility requirements and identification of solutions.

7.36. NGGT proposes that the projects in Scotland will enable the NTS to cope with diminishing UKCS flows arriving at St Fergus. The works in Lockerley relate to additional compression capacity in response to changing flows in the Southwest area of the NTS. Both projects are intended in order to maintain the 1-in-20 obligation. In addition, NGGT has forecast a small amount ([redacted]) for environmental related expenditure (monitoring, pipeline aftercare, etc). This is required under the planning consent provided for the Milford Haven project.

7.37. For the LRE forecast to be funded under uncertainty mechanisms, NGGT has included £266.4m within the generic Network Flexibility category. The expenditure relates to additions and modifications to the existing assets in various areas of the NTS. The outcome is enhanced operational capability, so that the NTS will be able to cope with the increasingly dynamic nature of flows, caused by wind intermittency and the interaction of the various entry and exit points around the NTS.

7.38. Finally, NGGT estimated that another £3,136.9m will be required for Incremental Capacity. This estimate includes:

- already signalled projects of £309.3m, based on previously calculated revenue drivers[37] which are not in addition to previous allowances
- a pipeline solution of £[redacted], which will be required to substitute for the decommissioning of the LNGS Avonmouth facility
- other projects resulting from future capacity signals.[38]

7.39. Table 7.6 below shows NGGT's baseline and incremental capex proposals.

Table 7.6 – NGGT Load related baseline capex forecast (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	**Total**
Total Baseline Load Related	23.9	16.7	6.0	5.7	10.4	5.2	0.5	-	**68.3**

7.40. Table 7.7 below shows NGGT's incremental capex forecasts

[37] These include projects in Fleetwood and in the Southwest quadrant of the NTS. Under the Fleetwood project a shipper requested a new entry point to be created. Capacity at this entry point was booked from October 2010. Early capacity holdings have lapsed and at the present time it is unclear whether the future capacity as signalled by this shipper will be needed. We will continue to monitor the situation and should circumstances arise which require Ofgem to take action to protect the interests of consumers, we will take the appropriate steps to ensure an economic and efficient outcome is achieved (which might affect the treatment of capacity at Fleetwood). This represents how we would expect to act in any similar situation, as we will generally consider taking steps in accordance with our principal objective to protect the interests of consumers.
[38] The estimate for the capex for these signals will be based either on previously calculated revenue drivers during TPCR 3 & 4, or through new revenue drivers.

Table 7.7 – NGGT Load related incremental capex forecast (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Total
Network Flexibility (not triggered)	28.5	46.5	65.3	34.0	39.5	42.7	8.4	1.6	266.4
Entry	27.4	76.6	141.8	82.0	242.5	304.8	14.8	3.2	893.2
Exit	41.1	53.9	107.7	265.4	272.5	88.0	72.6	3.4	904.7
Bi-directional	32.3	73.7	183.9	252.4	280.4	358.3	151.7	6.3	1,339.0
Total Incremental	**129.3**	**250.7**	**498.8**	**633.7**	**835.0**	**793.8**	**247.5**	**14.5**	**3,403.3**

Our assessment

7.41. For our assessment, we used a number of analytical tools and sources of evidence, including.

- Assessing NGGT's justification of its forecast expenditure alongside the related outputs.
- Exploring the methodology employed by NGGT to evaluate alternative solutions to various investment projects.
- Evaluating the links, synergies and efficiencies resulting from other areas of the business plan, such as the non-load related expenditure.
- Comparing cost forecasts to data from past projects and, where available, other data.
- Seeking the advice of our engineering consultants regarding the justification for the expenditure (as described in Chapter 1).

7.42. Our assessment shows that the reasoning for the projects in Scotland is justified. These projects address current and future needs in the NTS. We have therefore only made some minor reductions to NGGT's forecasts for our Initial Proposals.

7.43. Also, we consider that NGGT's work on further analysis has merits, and may enable future cost savings through better investment decisions. Therefore, further to our engineering consultants' recommendation we consider it appropriate for NGGT to initiate some preliminary work, such as further analysis and modelling of gas flows. This will ensure that any potential issues on areas of the NTS are identified early. We have included £5.0m of NGGT's forecast £9.3m in our proposed baseline.

7.44. However, we believe that NGGT has not demonstrated the necessity for the works at Lockerley compressor station, as the analysis undertaken has not taken into consideration fully the pipeline solution in relation to the LNGS Avonmouth facility. Therefore, we have excluded the forecast expenditure from Initial Proposals, and consider that if expenditure can be justified in the future then it will be able to be funded through an uncertainty mechanism.

7.45. As mentioned above, we consider that NGGT has rightly projected to decommission the Avonmouth LNGS facility. We are in agreement with the methodology to explore alternatives and its outcome of investing in a pipeline solution. Nevertheless, we consider that there are savings to be exploited as forecast costs look high. In particular, our engineering consultants provided us with comparator pipeline cost data which they have previously evaluated. NGGT's unit costs are higher than the unit costs set out in this data and there is a lack of supporting evidence to justify these higher costs. We therefore propose to include £[redacted]of NGGT's forecast £[redacted]in Initial Proposals. As mentioned earlier we have transferred this to the baseline.

Initial Proposals

7.46. Following our assessment we propose to set a LRE baseline of £145.3m. This will fund the projects in Scotland, the further analysis, and the installation of the pipeline sections proposed in the pipeline solution following the decommissioning of the LNGS Avonmouth facility at a reduced cost.

7.47. Table 7.8 below shows our proposal for NGGT's load related capex baseline.

Table 7.8 – NGGT Load related baseline allowance (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	**Total**
Total Load Related	19.6	11.9	6.9	41.1	58.5	7.1	0.2	-	**145.3**

7.48. Load related investment relates to the Reliability and Availability output. Given NGGT's proposal for load related expenditure, we consider that the specific projects should be set as specific outputs. Table 7.9 below lists these projects in terms of LR area, project scheme, output, start date, delivery date and costs.

Table 7.9 – Outputs of load related baseline allowance (excluding RPEs)

LR Area	Project Scheme	Output	Start date	Delivery date	Cost (£m)
Network flexibility	Projects in Scotland & further analysis	Maintain 1-in-20 obligation (Scotland) & Timely identification of required investment	[redacted]	[redacted]	[redacted]
Entry	Pipeline environmental monitoring & aftercare	Satisfaction of permit obligations	[redacted]	[redacted]	[redacted]
Exit	Avonmouth decommissioning	Pipeline solution	[redacted]	[redacted]	[redacted]

Uncertainty Mechanisms

7.49. NGGT has proposed an uncertainty mechanism to manage potential future network flexibility expenditure requirements not included in its ex-ante capex proposals. In our view NGGT's proposal to introduce an uncertainty mechanism is appropriate, but we have concerns that it has been unable to define clearly neither the triggers for investment nor the outputs that it will deliver. We set out our views on the uncertainty mechanism in more detail below.

7.50. Further to our engineering consultants views and for the purposes of the mechanism we propose to differentiate network flexibility expenditure between investment necessary to meet future peak day requirements, and expenditure required to meet more dynamic commercial capacity obligations. In our view this will enable us to evaluate the potential expenditure against specific outputs

7.51. For the future peak day requirement, we propose an annual re-opener window, where NGG may apply for additional funding for projects that need to be undertaken to meet peak day requirements. However, when assessing any request for additional funding we will consider the reasons why the need for this expenditure has not been previously identified.

7.52. In the section above we set out our view that NGGT has described and presented sufficient evidence in relation to the projects in Scotland, but at this stage this has not been the case for the remainder of the projects. The uncertainty mechanism is intended to manage potential future network flexibility expenditure requirements not included in ex-ante capex. Given that we have excluded NGGT's network flexibility proposals in respect of the Lockerley investment, it may be that this project could be presented for future consideration under this mechanism.

7.53. For network flexibility expenditure intended to assist with commercial obligations, we propose to require NGGT to introduce a specific output that is needed to meet the needs suggested within the network flexibility. This will be considered at the mid-period review of outputs.

7.54. For both re-openers, there will be a materiality threshold of approximately £26m per project which represents 2 per cent of average annual forecast revenue after the application of the totex efficiency incentive rate.

7.55. We propose that other incremental capex will be derived from revenue drivers which will be calculated upon receipt of the relevant signals. We recognise that NGGT's proposal is based on the information on costs and phasing which is currently available. However, we are concerned about the amount of projects that are suggested by NGGT, but are not yet backed by user commitment. Based on past experience there is a 25 percent attrition in such projects and the remainder of those are on average deferred by 2 years. Also, we are concerned about the level of underlying pipeline and compressor station unit costs for the anticipated incremental capex. Although specific revenue drivers have not yet been calculated, we expect them to result in a 20 percent reduction in incremental capex.

7.56. In view of the above, our Best View, as seen in Table 7.4 earlier, takes into consideration these adjustments. We propose that the remainder of the projects within incremental capex, i.e. those backed by user commitment and those related to flexibility, are kept as forecast by NGGT.

Non-load related capex

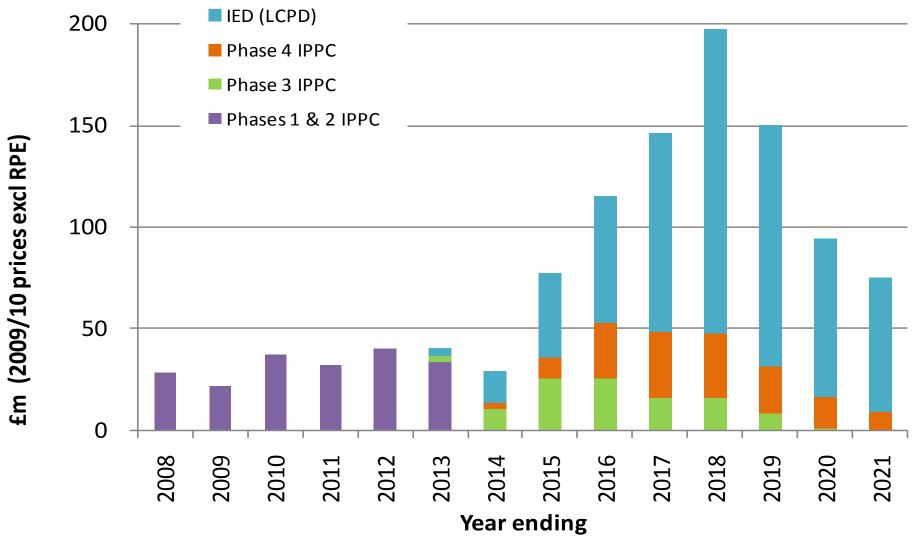
7.57. This section sets our Initial Proposals in two parts, reflecting the different nature of expenditure for emissions and expenditure for asset health.

Compressor stations emissions mitigation expenditure - NGGT's proposal

7.58. NGGT forecasts spending of £813.5m[39] on compliance with two environmental directives: the IPPCD[40] (Integrated Pollution Prevention and Control Directive) and the IED[41] (Industrial Emissions Directive), which are explained further below. Figure 7.1 below shows graphically the phasing of forecast investment and investment over TPCR4+R.

[39] The forecast reflects the changes in the projects relating to St. Fergus site as a result of late information becoming available at a late stage. The initial forecast was £885.8m.
[40] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:024:0008:0029:EN:PDF
[41] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:en:PDF

Figure 7.1 – NGGT Emissions mitigation baseline forecast[42] (excluding RPEs)



7.59. The investment under IPPCD is a continuation of the previous investment undertaken in TPCR4+R, which was undertaken in Phase 1 and 2 as can be seen in Figure 7.1. The primary legislative driver for the emissions reduction investment is the European Integrated Pollution Prevention and Control Directive (IPPCD). This is currently implemented in the UK through the Environment Permitting Regulations (2010) enforced in England and Wales by the Environment Agency (EA), and the Pollution Prevention and Control Regulations (2000) enforced in Scotland by the Scottish Environment Protection Agency (SEPA).

7.60. The associated investment progresses through the Network Review process. The environmental agencies (EA & SEPA) review annually the operation of the entire network. This review identifies high utilisation compressor station sites and the more polluting ones. Based on this information, these sites are targeted for investment. We note that sites are targeted and not individual compressor units, and based on the information available we consider that the IPPCD investments at St. Fergus, Kirriemuir and Hatton compressor stations have been incurred efficiently.

7.61. The two environmental agencies (EA and SEPA) place an obligation on operators of permitted processes, such as NGGT, to apply Best Available Techniques (BAT) to the way in which an installation is designed, built, maintained, operated and decommissioned. BAT is considered to lead to the most effective and advanced stage in the development of activities and methods of operation. This indicates the

[42] The graph is taken from NGGT's business plan, p. 127 (http://www.nationalgrid.com/NR/rdonlyres/87A406CE-136F-4F7C-936F-ADBF0D8F86C3/52255/2012_NGG_detailed_plan_redactedsecure.pdf)
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practical suitability of particular techniques and provides, in principle, the basis for emission limit values. These techniques are designed to prevent and, where not practicable, to reduce emissions and the impact on the environment as a whole. That means that compressor sites need to have implemented a BAT solution in order to have the necessary permits.

7.62. NGGT forecasts investment for Phase 3 will be undertaken at Peterborough and Huntingdon compressor stations. Investment for Phase 4 has been indicated at another three sites.

7.63. The Industrial Emissions Directive (IED) will strengthen the principle of applying BAT to the way in which a compressor installation is designed, built, maintained, operated and decommissioned. The most significant impacts of the IED are the setting of (i) a new Emission Limit Value (ELV) for Carbon Monoxide (CO) and (ii) a more stringent ELV for Nitrogen oxides (NOx) for all Large Combustion Plant (LCP). All gas turbines with thermal input greater than 50MW are considered as LCP.

7.64. NGGT has several gas turbines, driving compressor units at various sites, which are classified as LCP and need to comply with the new ELVs for CO and NOx. Table 7.10 lists the sites NGGT has identified as having non-compliant gas turbines and their number.

Table 7.10 – Compressor installations forecast investment under IED

Aylesbury	Carnforth	Hatton	Kirriemuir	Moffat	St. Fergus	Warrington	Wisbech
2	2	3	1	2	7	2	2

7.65. NGGT forecasts £631m within RIIO-T1 to deal with the requirements resulting from the IED. It aims to render the aforementioned sites compliant with the ELVs.

Compressor stations emissions mitigation expenditure - our assessment

7.66. In order to assess NGGT's proposal we undertook the following actions.

7.67. We engaged with the Environment Agency (EA) and the Scottish Environment Protection Agency (SEPA). This enhanced our understanding of the background and the implementation process of the relevant environmental legislation (IPPCD and IED) and of the Network Review process.

7.68. We explored the IED to understand its provisions and applicability to the operational profile of the NTS. In doing so, we evaluated information provided from NGGT regarding the compressors' future utilisation in a world of changing flow patterns.

7.69. Furthermore, we analysed proposals from other Europeans TSOs facing the same obligations under the IED. Additionally, we evaluated NGGT's proposals alongside the incremental capex forecasts to identify potential savings that would result from streamlining and combining projects.

7.70. To assess the efficiency of costs, we analysed the data set of the same six most recent projects that were used by NGGT to derive its suggested unit cost. NGGT's unit cost was based on the cost data of the works in St. Fergus, Kirriemuir, Hatton, Churchover, Wormington and Felindre compressor stations. We compared these projects against the type of projects that were forecast and potential savings and with publicly available costs. Additionally, we engaged our engineering consultants to provide analysis and opinion on the efficiency of unit costs.

7.71. Then we identified actual cost drivers, separated extraordinary items and evaluated them with respect to the nature of the projects. We established a revised unit cost and validated it against the original data set and other publicly available international[43] or past GB data, such as the installation of the Avonbridge compressor station.

7.72. Overall, for each compressor unit specified for replacement, we considered:

- Whether there was a definite need for the compressor to be replaced and whether there was uncertainty around that need

- the efficiency of the suggested unit costs and the suitability of the compressor size.

Needs case - IPPCD

7.73. Through our assessment we have established that the Phase 3 IPPCD projects are justified. In relation to the Phase 4 IPPCD projects however, we have identified that these are not integrated with load related investment in NGGT's business plan. Moreover, these projects do not relate to current high utilisation sites, and we are conscious that there is also significant uncertainty around these sites' future operation because of changing network flows.

Needs case – IED

7.74. We have verified that the compressors targeted for replacement under the IED do not comply with the new ELVs. We also note that NGGT has adjusted its forecasts for St. Fergus as a result of new information becoming available at a late stage. This has had the effect of reducing the initial baseline forecasts by £72.3m, i.e. from £885.8 to £813.5m, and we agree with this change.

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[43] Such as the data for compressor stations projects for an Alaskan pipeline: http://www.jpo.doi.gov/SPCO/DOE Spurline Documents/Appendix 3-5 Compressor Cost Estimate.pdf

7.75. However, we consider that overall NGGT's proposal in relation to the funding of IED compliance related investment was not sufficiently justified. More specifically, NGGT has not explored all available options in terms of technical solutions, legal provisions and exemptions. In addition, we found that it had not justified its proposed unit costs.

7.76. The operation of compressor stations as a fleet has reduced considerably, because of (i) the decline in gas coming from the UKCS and (ii) the introduction of gas from new supply points (Milford Haven, Isle of Grain, Bacton, etc). As a result of these two developments, on average gas now travels smaller distances from supply to demand points than in the past. The aggregate level of compressor stations' operation demonstrates this clearly. Whereas in the past compressor units were operated in total more than 100,000 hours per year, currently this has reduced to around 50,000-60,000. In some cases it has dropped even lower. More specifically, several compressor sites operate currently below 1,000 hours per year and several compressor units operate far less than 500 hours per year.

7.77. As highlighted earlier, the changing pattern of flows creates an uncertainty about the NTS's profile of operation throughout and after RIIO-T1. This includes the operation of the compressor station sites in terms of running hours.

7.78. We note that the new VSD units that have been installed in St. Fergus, Kirriemuir and Hatton compressor stations have not yet been commissioned. Their operation after 2013 is expected to reduce even further the operation of the compressor station fleet as a whole and on specific sites.

7.79. Although the IED sets stringent ELVs, it also includes some derogations and exemption clauses. One of these allows a compressor unit to be exempted from compliance with the ELVs, if it is operated less than 500 hours per year. Additionally, all compressor sites have two or more units.

7.80. However, NGGT's business plan did not take this exemption into account, despite its own forecasts for low future operation at several sites. Additionally, it has not provided any further evidence that low utilisation sites will face increased operation either within or after RIIO-T1.

Unit cost and compressor sizing

7.81. Through our analysis we identified a number of issues.

- Future projects are of a different nature to some of the projects used to derive NGGT's unit cost[44].

[44] These were the Churchover and Wormington compressor station projects, which were undertaken as part of the Milford Haven project. The works undertaken in these sites required significant flow modifications, thus increasing project costs significantly.

- One-off items, which will not be required in future projects, are not discounted from NGGT's generic unit cost.
- The availability of existing infrastructure, such as a High Voltage connection, is not taken into account to deliver cost efficiencies.
- In some cases, specific projects are oversized or are not required.
- Other European TSOs have opted for more cost effective technical solutions[45] to meet the IED requirements, such as modifications to the combustion chambers, or exchange of gas turbines with newer ones. These solutions are cost efficient compared to NGGT's approach.
- Commercially driven projects are completed in shorter timescales.

7.82. Therefore, we deem that the suggested compressor unit cost is not efficient. The outcome of our assessment has been to identify more efficient unit costs. These are split into a single unit cost for gas turbine driven compressor units and a range of unit costs for electric VSD compressor unit depending their size. Tables 7.11 and 7.12 below set out our proposed unit costs.

Table 7.11 – Proposals for gas turbine driven units

Fixed costs (£m/unit)	Variable costs (£m/MW)
[redacted]	[redacted]

Table 7.12 – Proposals for electric VSD driven units

<table>
<tr><th>Size (MW)</th><th>Fixed costs (£m/unit)</th><th>Variable costs (£m/MW)</th><th>HV connection[46] (£m)</th><th>Compressor Train costs[47] (£m)</th></tr>
<tr><td>[redacted]</td><td rowspan="5">[redacted]</td><td rowspan="5">[redacted]</td><td rowspan="5">[redacted]</td><td>[redacted]</td></tr>
<tr><td>[redacted]</td><td>[redacted]</td></tr>
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<tr><td>[redacted]</td><td>[redacted]</td></tr>
</table>

7.83. Table 7.13 summarises our findings in relation to NGGT's forecast expenditure regarding IPPCD Phases 3, 4 and the IED. This has informed our proposals.

[45] The German TSO has published its 10-year development plan: http://www.bundesnetzagentur.de/cln_1911/DE/Sachgebiete/ElektrizitaetGas/GasNetzEntwicklung/NetzEntwicklungsPlan/NetzEntwicklungsPlan_node.html

[46] This is included in the unit cost only for stations without an HV connection. In cases where an HV connection is available this item is excluded.

[47] Compressor train includes typically the motion generator (gas generator and power turbine, or electric motor) and the compressor and/or the unit control system. These cost figures are reported within the context of the data set provided by NGGT.

Table 7.13 – Outcome of assessment process for NGGT's forecast IPPCD and IED projects

<table>
<tr><th colspan="2">IPPCD</th></tr>
<tr><td>Phase 2 – Hatton</td><td>Sufficient funding provided in TPCR4 and Roll-over year.</td></tr>
<tr><td>Phase 3 – Peterborough</td><td rowspan="2">Projects are justified for both sites.
Project are oversized and based on high unit costs.
Projects can be streamlined to achieve cost and delivery efficiencies.</td></tr>
<tr><td>Phase 3 – Huntingdon</td></tr>
<tr><td>Phase 4 – Three sites</td><td>Projects are not streamlined with Incremental capex projects.
Projects sites are not high utilisation and there is uncertainty due to changing flow patterns.
Projects are oversized and based on high unit costs.</td></tr>
<tr><th colspan="2">IED</th></tr>
<tr><td>Aylesbury</td><td>Projects are justified.
Project costs are based on high unit costs.</td></tr>
<tr><td>Carnforth</td><td>Project sites are of low utilisation – could use the 500hrs derogation.
Project costs are based on high unit costs.</td></tr>
<tr><td>Hatton</td><td>Projects do not reflect reduced future utilisation and the introduction of a VSD unit.
Projects are oversized and based on high unit costs.</td></tr>
<tr><td>Kirriemuir</td><td>Projects do not reflect reduced future utilisation and the introduction of a VSD unit.
Project costs are based on high unit costs.</td></tr>
<tr><td>Moffat</td><td>Project sites are of low utilisation – could use the 500hrs derogation.
Projects are not streamlined with Flexibility Uncertainty Mechanism.
Project costs are based on high unit costs.</td></tr>
<tr><td>St Fergus</td><td>Reduced volume of works due to reclassification is justified.
Remaining projects works do not reflect reduced future utilisation and the impact of the introduction of VSD units – could use the 500hrs derogation.
Project costs are based on high unit costs.</td></tr>
<tr><td>Warrington</td><td>Project sites are of low utilisation – could use the 500hrs derogation.
Project costs are based on high unit costs.</td></tr>
<tr><td>Wisbech</td><td>Project sites are of low utilisation – could use the 500hrs derogation.
Project costs are based on high unit costs.</td></tr>
</table>

Compressor stations emissions mitigation expenditure – Initial Proposals

7.84. Based on the above findings, our proposals provide a baseline for specific projects, whereas some projects are rejected. Furthermore, in order to facilitate efficient and cost effective delivery of the baseline projects and future requirements, we propose the use of (i) the reopener windows for the IPPCD Phase 4 projects following commissioning of Phase 3 projects and (ii) an additional assessment during the mid-period review window for the low utilisation sites which can opt for the 500hrs derogation. Additionally, one IPPCD Phase 4 site and one IED site will be handled through the load related incremental capex and flexibility uncertainty mechanism.

Table 7.14 specifies our proposals in terms of classification and funding per compressor station site.

Table 7.14 – Proposed treatment and respective allowances for emissions related projects

Legislation Driver		**Initial Proposals Funding (£m)**
IPPCD		
Phase 2 – Hatton	No further funding	-
Phase 3 – Peterborough	**Baseline** projects	[redacted]
Phase 3 – Huntington		[redacted][48]
Phase 4	One project to be handled **through load related increment capex**.	[redacted]
	Two projects to be handled **through Uncertainty Mechanism** – If needs case is valid upon commissioning of Phase 3 projects, NGGT may reapply for funding.	[redacted]
IED		
Aylesbury	**Baseline** projects	[redacted]
Carnforth	Re-evaluation of needs case **in the mid-period review.**	[redacted]
Hatton	Project components disallowed. Re-evaluation of needs case **in the mid-period review.**	[redacted]
Kirriemuir	Re-evaluation of needs case **in the mid-period review.**	[redacted]
Moffat	Project to be handled through the **flexibility uncertainty mechanism**.	-
St Fergus[49]	Re-evaluation of needs case **in the mid-period review.**	[redacted]
Warrington	Re-evaluation of needs case **in the mid-period review.**	[redacted][50]
Wisbech	Re-evaluation of needs case **in the mid-period review.**	[redacted][51]

7.85. As a result of the above, the baseline is set at £119.5m and the amounts included within the Uncertainty Mechanism and the mid-period review window are set at £320.6m. This compares to NGGT's forecast of £813.5m.

[48] Additional 10 per cent efficiencies included due to project bundling.
[49] NGGT has not presented evidence to verify the need for this project for the site's operational capability following the commissioning of the two VSD units.
[50] Additional 10 per cent efficiencies included due to project bundling.
[51] Additional 10 per cent efficiencies included due to project bundling.

7.86. We are disallowing £127.1m of NGGT's forecast, because of projects that will be undertaken within the (a) incremental capex and (b) the flexibility uncertainty mechanism. There are additional reductions of £79.4m for the projects in Hatton, and of £166.6m due to our unit costs efficiency challenge.

7.87. Table 7.15 below shows the baseline's profile.

Table 7.15 – NGGT Emissions mitigation baseline (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Total
Allowance	7.9	18.7	19.9	18.4	26.9	12.6	7.8	7.3	**119.5**

7.88. Table 7.16 below lists the baseline projects in terms of the project group, output, start date, delivery date and costs.

Table 7.16 – Outputs of Emissions mitigation baseline (excluding RPEs)

Project Scheme	Output	Start date	Delivery date	Cost (£m)
IPPCD Phase 3	Peterborough	[redacted]	[redacted]	[redacted]
IPPCD Phase 3	Huntingdon			
IED	Aylesbury			

7.89. More specifically the outputs are set as follows:

- Appropriately sized electric Variable Speed Drives (VSD) in Peterborough and Huntingdon compressor stations, and
- Rendering Aylesbury compressor station compliant with the IED requirements, via the installation of an appropriately sized VSD and a compliant gas turbine.

7.90. Delivery of these outputs will be monitored through the annual reporting process.

7.91. We are not setting outputs with respect to gaseous emissions, such as Nitrogen Oxides (NOx), Carbon Monoxide (CO) and Carbon Dioxide (CO_2), as these can vary depending on the level of operation of the entire compressor station fleet. The benefits in emissions reduction will accrue through the modernisation and upgrade of the compressor station facilities.

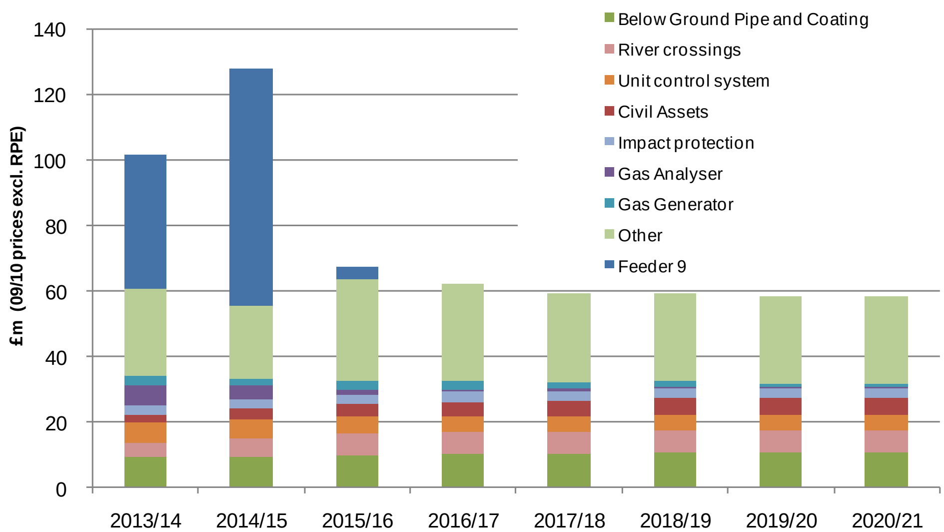
Asset Health expenditure – NGGT's forecast

7.92. NGGT has forecast to spend £594.4m to maintain the condition of the primary assets, ie the entry points, pipelines, multi-junctions, compressor sites and exit points of the NTS. This aims to minimise the risk of creating a major disturbance to customers through long outages and network disruption by maintaining the reliability, performance and condition of the secondary assets. The expenditure is broken down with respect to the secondary assets comprising the NTS.

7.93. Minor quasi-capex costs of £10.3m have been anticipated. These relate to disconnection of Feeder 1 and for decommissioning of some secondary assets.

7.94. Figure 7.2 shows the phasing of the forecast investment and provides a high-level by secondary assets.

Figure 7.2 – NGGT Asset Health baseline forecast[52] (excluding RPEs)



7.95. The two biggest components of the expenditure relate to Feeder 9 ([redacted]) and to Below Ground Pipe and Coating (£79.1m).

Network Output Measures methodology

7.96. In order to assess the need for investment NGGT has developed the Network Output Measures methodology (NOMs). The NOMs methodology assesses the secondary assets in terms of asset health (AH) and criticality (C). The output of this methodology is the Replacement Priority (RP) matrix. Figure 7.3 below shows the form of the Replacement Priority matrix.

[52] The graph is taken from NGGT's business plan, p. 110 (http://www.nationalgrid.com/NR/rdonlyres/87A406CE-136F-4F7C-936F-ADBF0D8F86C3/52255/2012_NGG_detailed_plan_redactedsecure.pdf).

Figure 7.3 – The Replacement Priority matrix

	AH1 New or as new	AH2 Good or serviceable condition	AH3 Deterioration, requires assessment or monitoring	AH4 Material deterioration, intervention requires consideration	AH5 End of serviceable life, intervention required
C1 Very High	RP4 10 + Years	RP3 5 -10 Years	RP2 2- 5 Years	RP1 0-2 Years	RP1 0-2 Years
C2 High	RP4 10 + Years	RP3 5 -10 Years	RP2 2- 5 Years	RP1 0-2 Years	RP1 0-2 Years
C3 Medium	RP4 10 + Years	RP3 5 -10 Years	RP2 2- 5 Years	RP2 2- 5 Years	RP1 0-2 Years
C4 Low	RP4 10 + Years	RP3 5 -10 Years	RP2 2- 5 Years	RP2 2- 5 Years	RP1 0-2 Years

7.97. The replacement priority indicator system is used to plan and prioritise the asset health expenditure across the NTS. This tool allows risk prioritisation to be systematically calculated using the NOMs, assessing the asset condition and the criticality of each asset. The criticality is defined as a function of the direct impact of failure of the secondary asset and the impact on the primary asset should the secondary asset fail. When considering the impact of an asset failure NGGT assesses the criticality of the primary assets and the impact of the failure on the entire network. In essence, this tool is a representation of the NTS risk profile.

7.98. However, it is not the only tool employed by NGGT to assess the risk profile of the NTS. NGGT is using the NOMs methodology alongside the site specific engineering knowledge, historical benchmarking data, market intelligence, innovative techniques and other influencing factors where applicable to determine the most efficient course of action.

Asset Health expenditure - our assessment

Feeder 9

7.99. In considering NGGT's forecasts we assessed new information that became available relating to Feeder 9 following the business plan's submission. This referred to the suggested costs and acquiring of permits to undertake the works.

7.100. Our assessment of NGGT's proposed treatment of the Feeder 9 project showed that NGGT's approach has been appropriate in terms of exploring various options, ie installing either an onshore pipeline, or an offshore pipeline, or a tunnelling solution. However, its proposals in respect of these options are based on unit costs which we consider to be high. If our proposed unit costs for compressor stations and/or pipelines were to be used in option analysis, it is possible that a different solution could be chosen.

7.101. In addition, this project has recently been classed as a Nationally Significant Infrastructure Project (NSIP), and so is subject to the provisions of the Planning Act 2008. As a result, approval from the Planning Inspectorate will need to precede any construction activities. Therefore, under NGGT's current plans the tunnel construction is anticipated between 2017 – 2020, with pipe fabrication and insertion in 2021.

Secondary asset areas of expenditure

7.102. We compared forecast replacement volumes and unit costs against TPCR4 allowances and expenditure for the primary and secondary asset groups. Our engineering consultants also assessed the volume of works forecast, the justification and the underlying costs of secondary assets.

7.103. With respect to the expenditure for the primary asset groups, pipelines and compressors collectively comprise approximately 75 per cent of the asset health investment which NGGT has planned for the RIIO-T1 period.

7.104. With respect to the secondary asset groups in general, we consider that NGGT's business plan has not provided a sufficiently robust methodology around NOMs and asset health expenditure. In particular, the linkage of replacement priorities and outputs is less clear than for the electricity TOs. To overcome this, we and our engineering consultants evaluated the volumes and evidence provided for the specific secondary asset groups.

7.105. Expenditure on specific secondary assets such as gas generators, gas analysers, locally actuated and remote isolation valves, power turbines and pre-heaters has been justified and we propose to include all of the forecast expenditure in the baseline.

7.106. In particular, we consider that converting existing locally actuated valves to remote isolation will improve the network's emergency isolation capability and maintain gas supplies to an offtake in the event of an incident. NGGT's proposal would ensure that all distribution offtakes would have remote isolation valves. Also, installing more remotely operable valves will enable the removal of manual block valves, reducing the asset health spend associated with the refurbishment of block valve sites.

7.107. However, we also consider that NGGT could achieve further savings in other areas of expenditure in line with TPCR4 expenditure profiles. In particular, there is insufficient evidence to support the need for increased funding for the coal tar enamel (CTE) coating, in-line inspections (ILI) and above ground cathodic protection works, river crossings, impact protection and civil assets. This is similar to the findings to the Opex expenditure in these areas. Therefore, we propose a reduced baseline as seen below.

7.108. We also believe that NGGT could achieve savings from economies of scale in works related to unit control systems, exhausts and electrical equipment (including standby generators), and has not provided sufficient evidence in relation to the security expenditure, further to that relating to physical security and its subcomponents.

7.109. As a result, we consider that NGGT's forecast expenditure should be reduced accordingly, as seen in Table 7.17 below:

Table 7.17 – NGGT Secondary Asset forecast expenditure and Ofgem proposal (excluding Feeder 9 and RPEs)

Secondary Asset	NGGT Forecast (£m)	Ofgem Proposal (£m)	Difference (£m)	Difference (%)
Below Ground Pipe and Coating	79.1	62.4	- 16.7	-21%
River Crossings	50.0	40.0	- 10.0	-20%
Unit Control Systems	41.3	39.0	-2.3	-6%
Impact Protection	23.1	16.0	- 7.1	-31%
Civil Assets (Access)	20.0	14.3	- 5.7	-29%
Gas Generators	16.2	16.2	0.0	0%
Gas Analysers	15.6	15.6	0.0	0%
LA Valves	15.4	15.4	0.0	0%
RI Valves	11.5	11.5	0.0	0%
Security	15.2	12.2	- 3.0	-20%
Electrical	11.0	10.5	-0.5	-5%
Exhausts	13.3	12.7	-0.6	-5%
Power Turbines	13.0	13.0	0.0	0%
Preheaters	12.2	12.2	0.0	0%
Other	140.6	120.9	-19.6	-14%
Totals	**477.5**	**411.8**	**-65.1**	**-14%**

Asset Health Condition - Initial Proposals

7.110. Based on the above findings, we propose to set a baseline at £418.4m as seen in Table 7.18 below. This includes the allowances as shown in Table 7.17 plus £6.6m for Feeder 9.

Table 7.18 – NGGT Asset Health baseline (including Feeder 9 and excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Total
Asset Health	57.0	51.3	55.3	53.5	50.9	50.9	49.8	49.8	418.4

7.111. The allowance includes funds to actively manage and maintain the NTS and achieve the primary outputs of Safety and Reliability through achievement of the target NOMs.

7.112. Additionally we set two secondary outputs with respect to:

- undertaking the necessary activities relating to applications, permitting and preliminary engineering in relation to the Feeder 9 project.
- proceeding with the specific works for locally actuated and remote isolation valves.

7.113. Table 7.19 below lists these secondary outputs

Table 7.19 – Secondary outputs of Asset Health baseline

Project Scheme	Output	Start date	Delivery date
Feeder 9	Preliminary engineering & construction permitting	2013	2021
Remote isolation valves & Locally actuated valves	Completion of suggested works		

7.114. We will monitor the accuracy of NOMs outputs through the annual reporting process. In addition, Ofgem has developed a model to monitor the NOMs methodology for NGET. We will use this model, to the extent possible, to verify NGGT's expenditure and monitor potential under- or over-delivery against the volumes anticipated and the final risk profile of the NTS.

7.115. In relation to quasi-capex, we agree with NGGT and set the baseline as forecast at £10.3m.

Uncertainty Mechanism

7.116. As a result of uncertainties over costs and timing, we propose an Uncertainty Mechanism regarding Feeder 9. In particular, NGGT can apply for the appropriate funding through the reopener windows, upon granting of planning permission. Costs will be re-evaluated then, as the submitted cost data are not sufficient.

Non-operational capex

7.117. Non operational capex is expenditure on new and replacement assets which are not system assets. This includes IT & telecoms, vehicles including mobile plant and generators, land and buildings used for administrative purposes, and, plant & machinery including small tools and equipment and office equipment.

NGGT's forecast

7.118. NGGT forecast an increase of 86 per cent (from £4.3m to £8.0m) in average annual non operational capex. The most significant increase is in IT expenditure where the forecast increase in average annual expenditure is from £3.1m to £6.9m.

7.119. Proposed expenditure on vehicles in RIIO-T1 for NGGT is on average £0.3m per year. This is lower than average expenditure in the TPCR4+R period of £0.6m. Proposed expenditure on land and buildings in RIIO-T1 for NGGT is on average £0.8m per year. This is higher than average spending in the TPCR4 period, which was £0.4 per year. The reason for the increase is due to the transfer of site care for compressors from non-load related capex to non operational capex.

Table 7.20 – NGGT Forecasts

	NGGT Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO-T1**	**Annual Expenditure over RIIO-T1**
Non Operational capex			
Transmission Front Office (TFO)		22.5	2.8
Strategic Asset Management (SAM)		12.0	1.5
Other	3.1	20.3	2.5
Total IT Expenditure	3.1	54.8	6.9
Vehicles	0.6	2.7	0.3
Land and Buildings	0.4	6.5	0.8
Total	4.3	64.0	8.0

* This is 4 years actual expenditure plus 2 years forecast

7.120. Expenditure on IT systems within the RIIO-T1 period is driven by 2 main projects, Transmission Front Office (TFO) and Strategic Asset Management (SAM), which are being implemented across both NGET and NGGT. The TFO system involves the integration of a number of separate systems. NGGT claims that TFO will deliver enhanced capability in capital investment, programme management, policy development, scheduling and despatch. NGGT's share of forecast expenditure is £22.5m over the RIIO-T1 period. The SAM system is a data capture, storage, and information systems to integrate asset data and analysis across National Grid. It involves a range of changes to system interfaces. It is a key enabler for a risk and criticality approach to maintenance and to enable condition monitoring of assets. NGGT's share is £12.0m over RIIO-T1.

7.121. Other IT systems expenditure for NGGT amount to £20.3m over RIIO-T1. This expenditure is spread over a number of systems which are proposed to be enhanced or refreshed at differing times over the RIIO-T1 period.

Approach to assessment

7.122. We have reviewed NGGT proposed expenditure on non operational capex. We have raised questions and carried out a cost visit to gain more information behind the forecasts.

Initial Proposals

7.123. Table 7.21 compares NGGT's forecast for non-operational capex with our Initial Proposals.

Table 7.21 – Comparison of NGGT's forecast and Initial Proposals

£m 2009/10 prices	**NGGT Forecast Total Expenditure over RIIO-T1**	**Initial Proposals Total Expenditure over RIIO-T1**	**Change £m**	**Change %**
Non Operational capex				
Transmission Front Office (TFO)	22.5	15.7	-6.8	-30.2%
Strategic Asset Management (SAM)	12.0	9.7	-2.3	-19.2%
Other	20.3	10.2	-10.2	-50.0%
Total IT Expenditure	54.8	35.6	-19.3	-35.1%
Vehicles	2.7	2.7	0.0	0.0%
Land and Buildings	6.5	6.5	0.0	0.0%
Total	64.0	44.8	-19.3	-30.1%

7.124. With regard to the proposed expenditure on vehicles and land and buildings in RIIO-T1, the forecast expenditure in NGGT's business plan is well justified. Our proposal is to allow these forecasts in full.

7.125. With regard to IT expenditure we have split this into two areas specific expenditure on TFO and SAM and all other expenditure.

7.126. Expenditure on TFO and SAM was assessed by our engineering consultants for NGET (TO), in reflection of the common issues across NGET (TO) and NGGT (TO).

7.127. We have reduced NGGT's forecast for TFO to £15.7m, or 69.7 per cent of forecast, and SAM to £9.7m, or 81.0 per cent of forecast. This is based on our engineering consultants opinion that application refreshes towards the end of RIIO-T1 could be delayed until RIIO-T2 and costs (other than those that have at least been partially sanctioned) could be reduced by 15 per cent. Despite the proposed reductions in the forecasts for the TFO and SAM systems our consultants agree with the need for these systems. These developments will enable NGGT to deliver further efficiencies within direct opex and non-load related capex.

7.128. We propose to reduce other IT systems expenditure for NGGT by 50 per cent. We have based this reduction on two main assumptions.

7.129. First, we consider that a lot of IT resources within National Grid's IT department will be consumed in ensuring TFO and SAM are delivered, meaning that other projects may be de-prioritised.

7.130. Secondly, we consider that some of the proposed system refreshes in the NGGT business plan will not take place within the RIIO-T1 period. We have taken the view that whilst IT systems may be reviewed regularly (maybe every 5 years) to ensure they are up-to-date, system refreshes will not happen every time such a review is undertaken.

Opex

7.131. Operating Costs are broadly the costs associated with the day to day operational running of the networks. For the purposes of the price control Operating Costs are grouped into Direct Opex, Closely Associated Indirects and Business Support.

7.132. Direct Opex represents the inspections, maintenance and fault repair costs associated with maintaining NGGT's transmission network.

7.133. Closely associated indirects (CAI) represent the back office functions that support the inspections and maintenance teams work on the network.

7.134. Both areas of cost are driven, to some extent, by the age and condition of the network and by proposed capex (especially non-load related).

7.135. Business Support costs are the costs that support the overall business and include: IS and Telecoms; Property Management; Finance; Audit and Regulation; HR and Non Operational Training; Insurance; Procurement; CEO and Other Corporate Functions.

7.136. NGGT states in its business plan narrative:

"'Over the next ten years our network is forecast to: (a) grow significantly with an 11 per cent increase in pipeline and over 60 per cent increase in compressor units, (b) have nearly three times more pipeline on the network aged beyond its design life compared to the TPCR4 period with an increase from 1,745 to over 4,600 km".[53]

7.137. NGGT argues that this will drive opex higher in RIIO-T1, but it also states that the rises will be minimised through ongoing efficiency and innovation.

Table 7.22 – NGGT forecasts for Total Opex

	NGGT Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO**	**Annual Expenditure over RIIO**
Direct Costs	50.6	518.0	64.8
Closely Associated Indirect Costs	16.3	123.6	15.4
Business Support Costs	20.5	144.4	18.0
RPEs	0.0	53.9	6.8
Total	**87.4**	**839.9**	**105.0**

* This is 4 years actual results plus 2 years forecast

7.138. We and our engineering consultants have reviewed NGGT's business plan and forecast costs for the RIIO-T1 period.

7.139. Table 7.23 summarises our Initial Proposals and shows how these differ from NGGT's own forecast. The reasons for the difference are discussed in more detail in the following sections.

Table 7.23 – Initial Proposals for Total NGGT Opex

£m 2009/10 prices	**NGGT Forecast Total Expenditure over RIIO**	**Initial Proposals Total Expenditure over RIIO**	**Change £m**	**Change %**
Direct Costs	518.0	491.5	-26.6	-5.1%
Closely Associated Indirect Costs	123.6	117.7	-5.9	-4.7%
Business Support Costs	144.4	112.6	-31.8	-22.0%
RPEs	53.9	16.0	-38.0	-70.4%
Total	**839.9**	**737.8**	**-102.1**	**-12.2%**

[53] National Grid Gas Transmission Business Plan Annex 'Detailed Plan' page 145, paragraph 679.

Direct Opex

NGGT's Forecast

7.140. The forecasts submitted by NGGT in its revised business plan in March 2012 show an increase in average direct opex spend from £50.6m per year in TPCR4+R to £64.8m in RIIO-T1 (see Table 7.24).

Table 7.24 – Comparison of NGGT Direct Opex Forecast and TPCR4 (excluding RPEs)

	NGGT Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO**	**Annual Expenditure over RIIO**
Direct Costs			
Fault Repairs (excluding Decommissioning)	5.6	55.3	6.9
Planned Inspections & Maintenance	18.7	184.3	23.0
Operational Property Management	5.3	38.1	4.8
Sub Total	**29.6**	**277.7**	**34.7**
Physical Security	1.3	41.9	5.2
Security (Armed Guards)	11.5	108.0	13.5
Quarry and Loss Development	5.9	20.2	2.5
Allowed Innovation Costs (incl. IFI)	2.5	70.3	8.8
Total	50.6	518.0	64.8

* This is 4 years actual results plus 2 years forecast

7.141. The main reasons given by NGGT for the increases in direct opex costs are:

- Planned Inspections and Maintenance - NGGT forecasts an increase from an average spend of £18.7m p.a. in TPCR4 to an average of £23.0m in RIIO-T1. NGGT is forecasting increases in maintenance costs for pipelines and compressor stations. The forecast for pipelines assumes a loss of income by the Pipeline Maintenance Centre (PMC) when the emergency pipeline repair service contract with the independent GDNs comes to an end in 2015, hence net costs increase. Compressor station costs are forecast to increase slightly as a result of statutory inspections, but offtake costs are forecast to remain flat over the RIIO-T1 period.

- Fault costs - the TPCR4+R figure is lower as a result of an insurance claim in 2010/11 which reduced the costs in that year, adjusting for this brings the average costs increase over TPCR4+R to £6.5m.

- Physical Security – maintenance costs increase in RIIO-T1 as the assets were only commissioned at the end of the TPCR4+R period.

- Security (Armed Guards) – NGGT forecast an increase average spend from £11.5m in TPCR4+R to £13.5m in RIIO-T1, which is based upon current information from the Ministry of Defence (MOD).

Initial Proposals

7.142. Having reviewed the consultants' report and allowances we have accepted the majority of their recommendations, but in some areas we propose different changes as a result of further analysis. The following paragraphs detail the engineering consultants' proposals and how they have been adjusted to come to our Initial Proposals.

7.143. The overall ongoing efficiency applied to NGGT's forecasts is 1.5 per cent. This is higher than the efficiency of 1.3 per cent assumed by NGGT but lower than the 2.0 per cent proposed by our engineering consultants. This efficiency is applied from 2011/12 onwards. The additional 0.2 per cent efficiency takes account of the fact that NGGT are investing in new IT systems in RIIO-T1 and therefore should be able to drive out increased efficiencies above those already identified. This is lower than the 2 per cent efficiencies NGGT have achieved during the TPCR4.

7.144. As well as applying the slightly higher general efficiency percentage to the costs our consultants propose some specific changes to the forecasts, these are as follows:

- Fault Repairs – NGGT have assumed that fault costs will increase due to increased in-line-inspection (ILI) digs and cathodic protection work, connected with the forecasted deterioration in coal tar enamel coated pipe. Our engineering consultants believe that NGGT is being too pessimistic in this area as relevant literature does not point to this problem in other pipelines of similar age. As a result, we propose to reduce annual costs by £2.1m per year.

- Planned Inspections and Maintenance – NGGT receives income from the independent GDNs for the provision of a pipeline emergency repair service. NGGT forecasts losing 26 per cent of its income as the independent GDNs decide to provide their own service. In their analyis, our engineering consultants assume that some income will be lost but that NGGT should be able to identify alternative sources to mitigate some of the lost income. Our proposed allowances assume no loss of income from the independent GDNs. We believe that if there is a loss of income NGGT should either find an alternative source or reduce its costs accordingly. We do not accept that gas transmission costs should rise if the independent GDNs withdraw from this service.

- Physical security – NGGT have proposed ex-ante funding for certain costs relating to physical security. At the moment these costs are remunerated through the uncertainty mechanisms within the licence. For the purposes of Initial Proposals we have assumed this expenditure will proceed and therefore the tables provide these allowances on a 'Best View' basis. However further work will be required between now and final proposals as Ofgem ascertain the certainty around these costs and the appropriate balance between ex ante funding and uncertainty mechanisms. Where costs have a degree of ambiguity we would propose to move them to the uncertainty mechanisms being developed.

- Security (Armed Guards) – We have accepted NGGT forecast for these costs as they are pass-through and NGGT will recover the actual amount of expenditure.

- Quarry and loss of development claims – We have accepted NGGT's forecast for these costs incurred when land owners claim compensation for lost revenue due to pipeline developments. The average forecast spend per year is £2.5m, lower than the average spend per year of £5.9m for TPCR4+R. This allowance will cover the vast majority of claims. For exceptional claims we propose an income adjusting event, but this will have a high materiality threshold.

- Allowed Innovation – We have shown no change to NGGT's forecast for innovation spending although the actual allowance will be set as a percentage of revenue. This is discussed in more detail in the Supporting Document on outputs, incentives and innovation.

Table 7.25 – Comparison of NGGT Direct Opex Forecast and Initial Proposals (excluding RPEs)

£m 2009/10 prices	**NGGT Forecast Total Expenditure over RIIO**	**Initial Proposals Total Expenditure over RIIO**	**Change £m**	**Change %**
Direct Costs				
Fault Repairs (excluding Decommissioning)	55.3	38.0	-17.3	-31.3%
Planned Inspections & Maintenance	184.3	177.9	-6.4	-3.5%
Operational Property Management	38.1	35.3	-2.8	-7.4%
Sub Total	**277.7**	**251.1**	**-26.6**	**-9.6%**
Physical Security	41.9	41.9	0.0	0.0%
Security (Armed Guards)	108.0	108.0	0.0	0.0%
Quarry and Loss Development	20.2	20.2	0.0	0.0%
Allowed Innovation Costs (incl. IFI)	70.3	70.3	0.0	0.0%
Total	518.0	491.5	-26.6	-5.1%

Closely Associated Indirect Costs

NGGT's Forecast

7.145. The forecasts submitted by NGGT in its revised business plan in March 2012 are shown in Table 7.26. The average annual spend forecast falls in RIIO-T1 from an average of £16.3m per year to £15.4m (-5.5 per cent).

Table 7.26 – Comparison of NGGT Closely Associated Indirect Cost Forecast and TCPR4+R (excluding RPEs)

	NGGT Forecast		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total Expenditure over RIIO**	**Annual Expenditure over RIIO**
Closely Associated Indirect Costs			
Operational IT & Telecoms	2.1	21.9	2.7
Network Design & Engineering	1.0	7.1	0.9
Engineering Management & Clerical Support	4.6	22.1	2.8
Network Policy (incl. R&D)	2.0	15.4	1.9
Health, Safety & Environment	0.6	6.8	0.8
Operational Training	2.0	20.0	2.5
Vehicles & Transport	0.6	4.7	0.6
Market Facilitation	2.3	22.0	2.8
Network Planning	0.4	3.5	0.4
Total	**16.3**	**123.6**	**15.4**

* This is 4 years actual results plus 2 years forecast

7.146. Although closely associated indirect costs are forecast to reduce overall some categories are forecast to increase as follows:

- Operational IT and Telecoms – NGGT is forecasting an increase in costs from an average of £2.1m per year in TPCR4+R to £2.7m in RIIO-T1. This is as a result of increased support costs for two new IT systems, Transmission Front Office and Strategic Asset Management, although some of the increase is expected to be offset by efficiencies.

- Health, Safety and Environment (HSE) – costs are forecast to increase in 2016 as a result of increasing requirements of environmental legislation.

- Operational training – costs increase in RIIO-T1 as a result of the need to recruit apprentices to replace the current ageing workforce.

- Market Facilitation – costs increase due to increasing demands placed upon NGGT by European energy regulation. This also requires more changes to the structure of the UK network code.

- Other closely associated indirect costs – Network design and engineering, engineering management and clerical support and network policy are forecast to fall over the RIIO-T1 period against what was spent in TPCR4+R. This is mainly due to continuing efficiencies being made within the business.

Initial Proposals

7.147. Having reviewed the consultants' report and allowances we have accepted the majority of their recommendations, but in some areas we have made changes.

7.148. As for direct opex we have applied the general efficiency assumption of 1.5 per cent to CAI costs. There are also some additional specific adjustments as follows:

- Operational IT and Telecoms - NGGT forecast that costs would increase as a result of the need to support new IT systems. We do not accept that new systems will lead to increases in support costs. These have therefore not been included in our Initial Proposals.

- In the case of HSE, operational training, and market facilitation we have accepted NGGT's rationale for cost increases over the RIIO-T1 period.

Table 7.27 – Comparison of NGGT Closely Associated Indirect Cost Forecast and Initial Proposals (excluding RPEs)

£m 2009/10 prices	**NGGT Forecast Total Expenditure over RIIO**	**Initial Proposals Total Expenditure over RIIO**	**Change £m**	**Change %**
Closely Associated Indirect Costs				
Operational IT & Telecoms	21.9	17.3	-4.5	-20.7%
Network Design & Engineering	7.1	7.0	-0.1	-1.3%
Engineering Management & Clerical Support	22.1	21.8	-0.3	-1.3%
Network Policy (incl. R&D)	15.4	15.2	-0.2	-1.3%
Health, Safety & Environment	6.8	6.7	-0.1	-1.3%
Operational Training	20.0	19.8	-0.3	-1.3%
Vehicles & Transport	4.7	4.7	-0.1	-1.3%
Market Facilitation	22.0	21.7	-0.3	-1.3%
Network Planning	3.5	3.4	0.1	-1.3%
Total	**123.6**	**117.7**	**-5.9**	**-4.7%**

Business Support Costs

7.149. Business Support costs are the costs that support the overall business and include: IS and Telecoms; Property Management; Finance; Audit and Regulation; HR and Non Operational Training; Insurance; Procurement; CEO; and Other Corporate Functions.

NGGT's Forecast

7.150. The forecasts submitted by NGGT in its March 2012 business plan show a decrease in average annual business support costs from £20.5m in TPCR4+R to £18.0m in RIIO-T1 (excluding RPEs).

7.151. Whilst the overall total costs, and within that costs in many areas, are reducing as a result of efficiencies being made there are some small increases in certain areas. The increases identified by NGGT are in the areas of finance and regulation as a result of increases in regulatory reporting, and procurement as a result of increases in the asset base.

Table 7.28 – Comparison of NGGT Forecasts for Business Support spend (excluding RPEs)

	NGGT TO Forecasts		
£m 2009/10 prices	**Annual Expenditure over TPCR4+R***	**Total expenditure over RIIO**	**Annual Expenditure over RIIO**
Business support costs	20.5	144.4	18.0

* This is 4 years actual results plus 2 years forecast

Our assessment approach

7.152. Our assessment of business support activity costs has been informed primarily by benchmarking all UK energy network companies (transmission, gas distribution, electricity distribution) against each other and against external benchmarks developed in collaboration with the Hackett Group. This assessment covered the following activities: IT & telecoms; property management; finance, audit & regulation; HR & non-operational training; procurement; and CEO & group management. Insurance costs were assessed separately and added to the benchmark assessed costs.

7.153. Where network companies are part of a group, their operating costs are mainly derived from central group functions with the costs then allocated to individual networks. The assessment of business support costs has been carried out at an overall group level with allowances allocated to networks in the same group in proportion to their submitted forecasts.

7.154. We carried out the RIIO-T1 and RIIO-GD1 business support cost assessment as a single process. Appendix 4 contains more detail on the business support cost assessment.

Initial Proposals

7.155. Table 7.29 summarises our Initial Proposals for business support costs.

Table 7.29 – Comparison of NGGT's Business Support Cost Forecasts and Initial Proposals (excluding RPEs)

£m 2009/10 prices	NGGT Forecast Total Expenditure over RIIO-T1	Initial Proposals Total Expenditure over RIIO-T1	Change £m	Change %
Business support costs	144.4	112.6	-31.8	-22.0%

8. Initial Proposals on cost and uncertainty for NGET (SO) and NGGT (SO)

Chapter Summary

This chapter sets out Initial Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for NGET (SO) and NGGT (SO) to deliver the associated outputs over the RIIO-T1 period. We also highlight where our Initial Proposals differ to proposals in NGET's and NGGT's March 2012 business plans and the reasons for this.

Question 11: Do you consider that our proposed baseline for NGET (SO) has been set at an appropriate level?
Question 12: Do you consider that our proposed uncertainty mechanisms for NGET (SO) are appropriate?
Question 13: Do you consider that our proposed baseline for NGGT (SO) has been set at an appropriate level?
Question 14: Do you consider that our proposed uncertainty mechanisms for NGGT (SO) are appropriate?
Question 15: Do you agree with our proposals in relation to uncertainty with respect to Xoserve's costs?

Introduction

8.1. This chapter sets out our Initial Proposals for the costs to be recovered by NGET (SO) and NGGT (SO), and the arrangements for addressing risk and uncertainty around those costs alongside the associated incentives that will apply around delivery for RIIO-T1.

8.2. There are various costs that NGET and NGGT incur as a SO and for which they seek to recover revenue in their price controls. The main cost areas are capital expenditure (capex), primarily related to investment in IT systems; and operating costs (opex), covering the ongoing costs of running the business, including support for IT systems.

8.3. Ofgem has also published proposals on the external costs incurred by NGET (SO) and NGGT (SO).

Overview

8.4. Tables 8.1 and 8.2 summarise the key cost parameters for Best View for NGET (SO) and NGGT (SO) respectively, both in terms of NGET's and NGGT's forecasts and our Initial Proposals.

Table 8.1 – Key cost parameters for NGET (SO)

£bn, 2009/10 prices	NGET's Best View	Initial Proposals
Total Capex	0.3	0.2
Total Opex	0.7	0.6
Total expenditure (Totex) exc RPEs	1.0	0.8
RPEs	-	-
Totex before IQI adjustment	1.0	0.8
IQI adjustment	n/a	0.0
Totex after IQI adjustment	n/a	0.8

Table 8.2 – Key cost parameters for NGGT (SO)

£bn, 2009/10 prices	NGGT's Best View	Initial Proposals
Total Capex	0.3	0.2[54]
Total Opex	0.3	0.3
Total expenditure (Totex) exc RPEs	0.6	0.5
RPEs	-	-
Totex before IQI adjustment	0.6	0.5
IQI adjustment	n/a	0.0
Totex after IQI adjustment	n/a	0.6

Summary of NGET's and NGGT's forecasts

8.5. Table 8.3 sets out NGET's forecast expenditure for the SO function over the RIIO-T1 period.

Table 8.3 – NGET (SO) expenditure forecasts (Excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
Total opex[55]	79.9	81.4	82.9	83.8	83.7	83.6	84.6	85.8	**665.7**
Opex RPEs	0.6	1.7	3.0	3.8	4.8	5.8	7.0	8.1	**34.3**
Total Opex expenditure	80.5	81.4	82.9	83.8	83.7	83.6	84.6	85.8	**700.0**
Capex	**82.3**	**39.1**	**33.4**	**32.1**	**33.2**	**29.3**	**31.2**	**31.4**	**312.4**

8.6. Table 8.4 sets out NGGT's forecast expenditure for the SO function over the RIIO-T1 period.

54 Includes £63m Xoserve costs
55 Controllable Opex

Table 8.4 – NGGT (SO) expenditure forecasts (excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Sum
Total opex[56]	39.8	41.8	41.7	39.6	39.8	40.4	40.6	40.9	**324.6**
Opex RPEs	0.2	0.7	1.2	1.7	2.2	2.7	3.3	3.8	**15.9**
Total Opex expenditure	40.0	42.5	42.9	41.3	42.0	43.1	43.9	44.7	**340.5**
Capex	**74.5**	**33.5**	**27.8**	**30.2**	**30.2**	**26.1**	**22.9**	**18.5**	**263.9**

Assessment approach

8.7. We have assessed NGET's and NGGT's plan for SO costs in the same way as other areas of the plan (as described in Chapter 1).

8.8. In coming to their proposals our engineering consultants not only reviewed NG's forecast costs, but also how they related to the information given in its business plan and expenditure in the TPCR4 period. The engineering consultants have also taken into account the implications for system operation requirements of the plans set out by the TOs.

8.9. The engineering consultants have produced a range for consideration – Case 1 the upper reduction scenario and Case 2 the lower reduction scenario.

Initial proposals

8.10. NGET and NGGT have presented a large volume of information which we have considered in depth and scrutinized. We accept there are changes taking place within the wider operating environment which will impact on their businesses and on the baselines being set, and that some increase in expenditure may be necessary.

8.11. However, the significant increases being presented by NGET and NGGT are not in all instances well justified. There are some instances where the forecasts have considerable uncertainty built into them and consequently into NGET's and NGGT's s proposed baselines. Given the lack of justification and to protect the interests of consumers we consider that the Case 1 upper reduction scenario is appropriate.

8.12. For NGET (SO), we have reduced the baseline by £0.2bn reflecting capex and opex efficiency challenges, with a further reduction of £0.04bn associated with the construction of a new data centre.

8.13. For NGGT (SO), we have reduced NGGT requested costs by £0.1bn, reflecting capex and opex efficiency challenges, with further reductions of £0.06bn in relation to XoServe, and £0.04bn associated with the construction of a new data centre.

[56] Controllable Opex

Table 8.5 – Difference between NGET (SO) and NGGT (SO) forecasts and our Initial Proposals

£bn 2013-2021	NGET SO	NGGT SO
July 2011 plan	1.0	0.6
Changes between first and second plan	0.1	0.02
March 2012 plan	1.0	0.6
Efficiency challenge	-0.2	-0.1
Reduce data centre expenditure	-0.0	-0.0
Provisional IP totals	**0.8**	**0.5**

8.14. Table 8.6 sets the annual profile for our Initial Proposals for NGET (SO).

Table 8.6 – NGET (SO) Initial Proposals (Excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
Total opex	66.7	68.0	69.1	69.5	69.4	69.2	69.9	70.7	**552.5**
Opex RPEs	-2.3	-1.5	-0.8	0.0	0.8	1.6	2.5	3.4	**3.8**
Total Opex expenditure	64.4	66.5	68.3	69.5	70.2	70.8	72.4	74.1	**556.3**
Capex	**49.9**	**31.4**	**25.4**	**24.6**	**27.4**	**13.4**	**18.7**	**12.4**	**203.2**

8.15. Table 8.7 sets out our Initial Proposals for NGGT (SO).

Table 8.7 – NGGT (SO) Initial Proposals (Excluding Non Controllable Opex)

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
Total opex	31.7	33.6	33.5	31.8	31.9	32.4	32.6	32.8	**260.3**
Opex RPEs	-1.27	-0.74	-0.36	0.01	0.37	0.74	1.12	1.51	**1.61**
Total Opex expenditure	30.6	32.7	33.1	31.8	32.3	33.1	33.7	33.4	**261.9**
Capex	**52.7**	**30.9**	**25.6**	**22.6**	**22.7**	**13.8**	**13.2**	**16.3**	**197.8**

NGET System Operator

NGET's Forecast

8.16. NGET has proposed significant increases to both opex and capex. From the table it can be seen that NGET's average spend for both opex and capex increases over the RIIO period from TPCR4 such that total spend for the new control is forecast at £977m.

Table 8.8 – Comparison of NGET SO Forecast and TPCR4+R figures

	NGET Forecast		
	Average Annual Expenditure over TPCR4 (£m)	Total Expenditure over RIIO (£m)	Average Annual Expenditure over RIIO-T1 (£m)
SO Capex	19.3	312.4	39.1
SO Opex	66.2	665.2	83.2
Total	85.6	977.6	122.2

8.17. The following factors have been identified as driving the increases.

- Decarbonisation of Electricity – NGET states that with more wind farms connecting there is greater volatility in output created compared to thermal generation. Consequently the frequency and volume of the balancing activities changes.

- Transmission network complexity – the existing transmission network will be adapted and upgraded to maximise electricity flows associated with new generation connecting. The likelihood of unplanned events occurring subsequently increases and therefore NGET has stated that it requires more real time studies and tools to implement network configuration.

- Supplier Demand Management – NGET argues that suppliers have to source more energy from renewable generation and are incentivised to balance their contracted positions helping to ensure their supply obligations can be met. With increasing wind intermittency they may choose to balance their position using Demand Side Response (that is re-phasing demand to another period where supply is greater or an absolute reduction). This consequently could influence how NGET uses reserve capacity and balances the system.

- Smarter Grids and distribution networks – DNOs are expected to have more renewable generation connecting to the systems. These changes could mean DNOs become more active controlling flows across the network. Such changes, NGET has argued, will impact on the balancing activities of the SO.

- European interconnection and market harmonisation – NGET has stated there is expected to be greater interconnection with the rest of Europe over the RIIO period as interconnectors come online and capacity increases up to a forecast 7GW in 2020 – this could lead to swings of 14GW creating volatility for the SO. To help manage this volatility NGET is requesting investment in additional systems.

8.18. In considering capex NGET has identified investments for the following activities:

- Data Centres –NG is proposing an overhaul of current Data Centre arrangements and has forecast £109m, allocated between the electricity and gas SOs and its Gas Distribution Networks (GDNs). This includes building two new data centres at pre-selected sites. NG has undertaken some optioneering for Data Centres including the possibility of Third Party hosting.

- Operational forecasting – the ability to forecast demand and generation. NGET has stated that investment in this capability focuses on continually improving its forecasting ability to cope with increasing volumes of installed wind generation and to understand the effect on DNO demand. NGET argues that forecasting electricity demand will be more difficult in RIIO-T1 as it becomes more variable.

- Operational Planning – study of operational conditions to optimise the configuration of the network from 12 hours to one year ahead. NGET states that the current method of planning will become invalid as thermal generation output is displaced by varying levels of wind generation, embedded generation from DNOs and power flows from interconnectors. NGET further states that a consequence of this is that the network will be run much closer to its operational limits.

- Operational short term strategy – optimising the balancing strategy and network configuration for up to 12 hours ahead. NGET states many of the uncertainties in generation and demand forecasting that currently exist in the planning phase will continue into the short term operational phase some four to 12 hours ahead. NGET further argues operational assessments that are currently carried out in the planning phase will have to be carried out nearer to real-time.

- Operational control – capability to undertake actions from four hours ahead through to real time that are taken to operate the transmission network assets and to change the power outputs of generators and demand consumption. NGET argues that due to the near real-time nature of this capability, IT systems are the only viable option in many instances and they will be relying on the processing power of these systems to manage the increasing system complexity, maintaining reliability and control costs of operation. NGET also argues its control capability therefore needs to be enhanced so that they can respond to both planned and unplanned events.

- Operational situational awareness – ability to identify and act on information in real time as operational situations happen. NGET states the amount of data available to operators will invariably increase as the operating environment becomes inherently more complex and operating conditions are subject to a greater level of variability than present. Consequently its staff will increasingly find they are unable to interpret the data quickly and accurately enough using current techniques and processes.

8.19. In considering Opex the main factors driving the increase are headcount growth and information systems (IS) projects. These are considered separately below.

Headcount Growth

8.20. NGET has stated more people are required to work in the following areas.

- Data Management Requirements – NGET argues that an increase in people is required to manager Phasor Management Units (PMU), series compensation units and other new IT tools.
- EU and market changes – NGET states that additional staff are required to work on:
  - European Network of Transmission System Operators for Electricity (ENTSO-E) – a policy forum for electricity TSOs
  - European codes – development of single European codes and incorporating these changes into UK codes
  - European data interaction – to manage the growing interconnection with Europe operators.
- Demand side participation – formulating commercial agreements to reduce electricity demand during times of low supply.
- Connections and operation planning – NGET states that as more connection takes place more analysis is required to support operational planning.

IS Projects

8.21. This refers to more project support opex for the implementation of the SO capex programmes. It also captures the wider allocations from business support, which are discussed in Appendix 4.

Initial Proposals

8.22. For Initial Proposals we propose to follow Case 1 of the engineering consultants' findings. This results in reductions of 35 per cent to NGET's forecasts. In proposing their cases the engineering consultants considered:

- The ability to defer the more speculative enhancement projects
- Creating a more viable workload with less risk
- Providing more time to clarify requirements
- Identifying those developments likely to provide most benefit to consumers
- Risk-sharing arrangements.

8.23. In reviewing NGET's business plans our engineering consultants have identified potential reductions to some specific investments deemed unjustified in our consultants' view. The investments include:

- offshore grid control
- automation and system integration
- interaction of gas and electricity operation
- the hardware refresh of the Offline Transmission Analysis.

8.24. Furthermore our engineering consultants have recommended that certain investments be deferred given uncertainties surrounding their need. Their recommendations are summarised below.

- Phase 2 of the Energy Balancing System is delayed by two years, allowing more time to clarify requirements against the build up of wind.
- Offline Transmission Analysis improved modelling is delayed by one year.
- Improved Situational Awareness Tools Enhancement is delayed by two years, removing all planned expenditure.
- Smart Demand Side Data Interface.
- Future control rooms is delayed, reducing expenditure to allow further research.
- Infrastructure for business systems is scaled back in line with the TPCR4 expenditure.

- Wokingham Smart Workplace is reduced pending further research to demonstrate benefits.

- Intelligent Alarm processor further enhancement is delayed, as this is forecast for only three years after the system is commissioned.

- Integrated Electricity Management System Future upgrade scheduled for 2019 to 2021 is deferred as this immediately follows on from a replacement.

Data Centres

8.25. NG has forecast £109m to upgrade its Data Centres, including the building of 2 new data centres. The costs are to be allocated between NGET SO (42 per cent), NGGT SO (42 per cent) and NG's GDNs (16 per cent), reflecting shared usage. The review of Data Centres has been excluded from the engineering consultants' review.

8.26. We have reviewed NG's forecasts and have held discussions to understand more about its plans. We do not consider that NG has provided adequate justification for its plans, and the operational need for its chosen solution has not, in our opinion, been proven. We therefore propose to fund baseline expenditure of £30m to cover necessary refurbishments and upgrades to data centres. NGET SO's share of this baseline is £12.6m. Any further expenditure will be subject to the uncertainty mechanisms being proposed elsewhere in the document.

Operating Costs

8.27. Our engineering consultants have recommended a 15 per cent reduction to electricity SO opex baselines, from £652m to £552m, and we propose to follow this recommendation. This reduction is centred around FTEs (where the engineering consultants have reduced NGET's controllable costs according to the relative number of proposed FTEs in each business activity) and Engineering Support where costs have been scaled back in line with the proposed changes for SO Capex.

8.28. Our consultants have also suggested appropriate uncertainity mechanisms be proposed. We consider uncertainity mechanisms elsewhere in this document

Table 8.9 – Comparison of NGET SO Forecast and Initial Proposals

	NGET Forecast	**Ofgem Initial Proposal**	**Change**	
	Total Expenditure over RIIO (£m)	Total Expenditure over RIIO (£m)	£m	%
SO Capex	312.4	203.2	109.0	-35%

SO Opex	665.2	552.5	113.0	-17%
Total	977.6	755.7	222.0	-23%

Uncertainty mechanisms

8.29. Table 8.10 sets out an overview of the uncertainty mechanisms that we propose to provide for NGET (SO), and lists where further information can be found.

Table 8.10– Proposed uncertainty mechanisms for NGET(SO)

Uncertainty	NGET proposal	Our view	Timing of potential change	Further Discussion
Efficiency Incentive Rate	Keep 50 per cent of the percentage of underspend/overspend against allowed expenditure	48 per cent (calculated by applying the IQI mechanism)	Annual	Chapter 2 and Appendix 1
Indexation	Annual indexation of revenues using the RPI	Our decision on RPI indexation was published in July 2011[57]	Annual	Chapter 2
Real price effects (RPEs)	Allowance for RPEs to represent expected relative change in input prices	Allowance for RPEs	Ex-ante allowance	Chapter 2
Financial distress	Disapplication of the price control where outside the company's control	Consistent with Strategy Document	At any time	
Reopener mechanism	Reopener mechanism for a number of trigger events	Reopener mechanism for additional funding to enhance security	Twice: April 2016, April 2019	Chapter 2
Mid-period review	Limited to changes to outputs	Consistent with Strategy Document	Once: April 2017	Chapter 2

NGGT System Operator

NGGT's Forecast

8.30. The table below provides an NGGT's SO forecasts.

[57] Decision on the RPI indexation method: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Table 8.11 – Comparison of NGGT SO Forecast and TCPR4+R figures

	NGGT Forecast		
	Average Annual Expenditure over TPCR4 (£m)	Total Expenditure over RIIO (£m)	Average Annual Expenditure over RIIO-T1 (£m)
SO Capex	17.3	263.9	33.0
SO Opex	34.2	324.5	40.6
Total	51.4	588.4	73.6

8.31. Overall NGGT's SO costs are forecast to increase from an average of £51.4m in the TPCR4+R Period to £73.6m in the RIIO-T1 period. NGGT has stated that the following factors are driving this increase:

- Changing flow patterns and supply dynamics – supply sources are changing as a result of the decline of the UK continental shelf which NGGT state has changed supply patterns from near predictability to considerable uncertainty. Furthermore the pattern of flows is also changing, moving away from the historic north to south movement. This creates a wider set of scenarios and challenges for operation. NGGT argue that this demands flexibility in network transmission and capability must be a key design consideration.

- Changing demand patterns – NGGT argues that volatility of demand causes operational challenges and requires enhanced system operation capabilities and quicker reconfiguration of the NTS to ensure the demand can be met. Demand for gas is greatly impacted by the electricity market given Combined Cycle Gas Turbine (CCGT) generation. CCGT connection capacity is expected to increase to balance the closure of nuclear life and fossil fuel power stations. Furthermore demand from these sites will become increasingly intermittent as they become the primary alternative for balancing wind generation on the electricity network.

- Operational changes – NGGT argues the dynamics of the system are changing with greater volatility of supply and demand, greater intermittency of electricity generation impacting on gas network operation, and increased utilisation of European Interconnectors. NGGT states that this is creating a challenging operational environment and that this needs to be responded to.

8.32. For capex NGG has identified the following investments:

- Data Centres – as with NGET SO, NGGT proposes an overhaul of the current data centre arrangement.

- Operational short term strategy – enhancing balancing strategy. NGGT has argued there is a need to enhance operational strategy processes to ensure that customer and environmental impact of strategies are fully taken into account. This includes the development of intra-day volatility tools which it states will aid identification of the lowest cost and lowest risk operational strategies as well as enable the management of constraint issues.

- Operation Control - Enhancements for decision support process. NGGT would aim to introduce new automated data interfaces with all customers and connectees to feed real time data into optimisation and forecasting tools.

- Market Facilitation – NGGT has assumed within its investment plan that the major systems will be impacted by changes, driven by GB and / or EU regulation, and has taken a view as to the likely extent of such change (particularly in the early years). NGGT considers that a significant proportion of the cost of such change to these systems is likely to be unrelated to the context of the change itself and so is consequently proposing that it is dealt with through uncertainty mechanisms. We have considered the issue of the provision of funding for costs driven by regulatory change through uncertainty mechanisms, and believe such funding is better dealt with through the mid period review.

8.33. For Opex NGGT also forecast increasing spend from TPCR4+R (with average expenditure of £34m) to the RIIO Period (with average expenditure of £40m). The main factors driving this are headcount growth and IS projects. These are considered below.

Headcount Growth

8.34. This is driven mainly by two areas:

- Managing supply and demand volatility - NGGT forecasts recruiting more staff to work at the National Control Centre and work on various analysis roles.

- European impacts - NGGT forecasts higher staffing requirements for work on UK Codes and issues falling out of European Working Groups, particularly related to European Network of Transmission System Operators for gas (ENTSO-G).

IS Projects

8.35. This is in effect an increase in from IT in business support. It represents the allocation to the SO Function from a centrally provided activity. Business support costs are discussed in Appendix 4.

Initial Proposals

8.36. For Initial Proposals we propose to use Case 1 (higher reduction) of the engineering consultants' findings. In proposing their cases the engineering consultants considered:

- a lower rate of increase in the volatility in supply and demand patterns than that forecast in NGGT's business plan;
- delaying some refresh expenditure outside of the RIIO-T1 period; and
- a lower amount of regulatory driven change.

8.37. In reviewing NGGT SO's business plans the engineering consultants have proposed some investments are reduced as these are deemed unjustified in their view. The investments include:

- integrated gas management system future system refreshes and enhancements;
- regulatory driven enhancements to SO systems (GB and EU);
- Gas National Control Centre enhancements and maintenance;
- network real-time analysis and optimisation;
- information provision enhancements; and
- Control room training infrastructure enhancement.

8.38. Furthermore, our engineering consultants have proposed that other investments be deferred into RIIO-T2 given uncertainties surrounding their need. These are summarised below:

- supply and demand forecasting enhancements - defer further functional developments and asset refresh;
- network simulation multi-scenario modelling - defer second phase (2016);

- network simulation asset refresh - defer 2021 refresh; and

- MIPI infrastructure refresh - defer refresh in 2021

Data Centres

8.39. Our proposals with respect to data centres are set out in the NGET SO section above.

Operating Costs

8.40. For Operating costs our engineering consultants have proposed a 20 per cent reduction to NGGT SO opex baselines, from £324.5m to £260.3m. This reduction is centred around FTEs (where the engineering consultants have reduced NGGT's controllable costs according to the relative number of proposed FTEs in each business activity) and Engineering Support where costs have been scaled back in line with the proposed changes for SO Capex

8.41. As with NGET SO, our consultants have also suggested appropriate uncertainty mechanisms be proposed and we have considered these mechanisms elsewhere in this document.

Summary

8.42. Table 8.12 summarises our Initial Proposals for NGGT (SO).

Table 8.12 – Comparison of NGGT SO Forecast and Initial Proposals

	NGET Forecast	**Ofgem Initial Proposal**	**Change**	
	Total Expenditure over RIIO (£m)	Total Expenditure over RIIO (£m)	£m	%
SO Capex	263.9	197.7	66.2	-25%
SO Opex	324.5	260.3	64.2	-20%
Total	588.4	458.0	130.4	-22%

Uncertainty mechanisms

8.43. Table 8.13 sets out an overview of the uncertainty mechanisms that we propose to provide for NGGT, and lists where further information can be found.

Table 8.13 – Proposed uncertainty mechanisms for NGGT(SO)

Uncertainty	**NGGT proposal**	**Our view**	**Timing of potential**	**Further Discussion**

			change	
Efficiency Incentive Rate	Keep 50 per cent of the percentage of underspend/overspend against allowed expenditure	45 per cent (calculated by applying the IQI mechanism)	Annual	Chapter 2 and Appendix 1
Indexation	Annual indexation of revenues using the RPI	Our decision on RPI indexation was published in July 2011[58]	Annual	Chapter 2
Real price effects (RPEs)	Allowance for RPEs to represent expected relative change in input prices	Allowance for RPEs	Ex-ante allowance	Chapter 2
Financial distress	Disapplication of the price control where outside the company's control	Consistent with Strategy Document	At any time	
Reopener mechanism	Reopener mechanism for a number of trigger events	Reopener mechanism for additional funding to enhance security	Twice: April 2016, April 2019	Chapter 2
Review		Xoserve funding review	At any time	Chapter 8
Mid-period review	Limited to changes to outputs	Consistent with Strategy Document	Once: April 2017	Chapter 2

Xoserve funding review

8.44. We propose that there is provision in NGGT's price control to review funding in the event that there are changes to the way in which Xoserve is funded[59]. This was not part of our Strategy Document.

8.45. We published a decision in January 2012 on the options for future funding arrangements of Xoserve.[60] Our open letter did not reach a decision on the details of the new funding arrangements. Therefore we are not able at this time to conclude on the appropriate funding for NGGT and the GDNs. We will continue to provide an ex

[58] Decision on the RPI indexation method: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

[59] Xoserve provides data services on behalf of transporters. For example, they provide billing services for shippers for use of the transportation network, manage the booking of capacity on the network, run the industry settlement systems and manage the change of supplier process.

[60] Open letter: Review of xoserve: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=345&refer=Networks/GasDistr/RIIO-GD1/ConRes

ante allowance based on current arrangements. The review will allow us to alter this funding once a decision has been reached on the final funding model.

Appendices

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Appendix 1 – Operation of the IQI mechanism

1.1. The Information Quality Incentive (IQI) mechanism is designed to provide incentives to network companies to provide robust expenditure forecasts in their business plans. We use the IQI to set the strength of the upfront efficiency incentives each company faces according to the difference between the company's forecast and our assessment of its efficient expenditure requirements.

1.2. In our Strategy Decision document, we stated that we would calibrate the IQI matrix such that the cost sharing factor or efficiency incentive rate for TOs was in the range of 40-50 per cent, ie with companies that obtain an IQI ratio of 100 (meaning our assessment of costs equals the companies view of costs) would receive an efficiency incentive towards the top-end of this range. We also stated that we would calibrate the IQI such that companies who submitted efficient cost forecasts would earn a positive financial reward.[61]

1.3. In order to determine the IQI efficiency incentive rate and reward/penalty, we stated that we would compare companies' first cost submissions with our last assessment. However, we also said that we would accept reasonable changes to the first business plan for non-fast-tracked companies.

1.4. We fast-tracked both SPTL and SHETL and as we accepted their business plans in total, including their cost submissions, by definition their IQI score was 100 and both companies obtained a 50 per cent incentive rate and a 2.5 per cent additional income reward on their base capex.

Initial Proposals

1.5. For NGET and NGGT we have therefore retained the same IQI matrix. We have assessed both NGET's and NGGT's costs against our benchmarks to identify their IQI score, which will dictate their incentive rate. We have used their second business plan as changes between the first and second plans appeared to be reasonable and there was no indication that the revisions were aimed at improving their IQI index score. We have made adjustments to the plan to ensure consistency with our cost assessment and these adjustments are described further below. We have applied the IQI matrix to the combined forecasts for TO and SO.

1.6. We propose to treat the incentive rate as post-tax. That is, if the TO outperforms by 100, with a sharing factor of 50 per cent, the TO incurs a benefit of 50 post-tax, and the remaining 50 will comprise additional tax payments (in relation

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[61] See: Ofgem (March 2012) http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf

to the outperformance), and a reduction in costs to consumers. Likewise, if the TO underperforms by 100, it incurs a cost of 50 (post-tax), and the remaining amount represents a reduction in tax payments, and the additional cost recovered from the consumer. Taking a simple example, assuming a marginal tax rate of 15 per cent, and a sharing factor of 50 per cent the sharing of out/under performance of 100 would be around: 50 (company); 9 (tax adjustment); and, 41 (consumer).[62] In practice the impact of the tax adjustment and the change to allowed revenues will be calculated by the financial model as part of the annual iteration process (as detailed in the Supporting Document on finance).

1.7. Table A1.1 sets out the IQI matrix.

Table A1.1 - RIIO-T1 IQI matrix

IQI Ratio	100	105	110	115	120	125	130	135
Efficiency Incentive	50%	49%	48%	46%	45%	44%	43%	41%
Additional income (£/100m)	2.5	1.9	1.2	0.5	-0.3	-1.0	-1.8	-2.6
Rewards & Penalties								
Allowed expenditure	100.00	101.25	102.50	103.75	105.00	106.25	107.50	108.75
Actual Expenditure								
85	10.0	9.8	9.5	9.2	8.8	8.3	7.8	7.2
90	7.5	7.3	7.1	6.8	6.5	6.1	5.6	5.1
95	5.0	4.9	4.8	4.5	4.3	3.9	3.5	3.0
100	2.5	2.5	2.4	2.2	2.0	1.7	1.4	1.0
105	0.0	0.0	0.0	-0.1	-0.3	-0.5	-0.8	-1.1
110	-2.5	-2.4	-2.4	-2.4	-2.5	-2.7	-2.9	-3.2
115	-5.0	-4.8	-4.8	-4.7	-4.8	-4.8	-5.0	-5.2
120	-7.5	-7.3	-7.1	-7.0	-7.0	-7.0	-7.1	-7.3
125	-10.0	-9.7	-9.5	-9.3	-9.3	-9.2	-9.3	-9.3
130	-12.5	-12.2	-11.9	-11.7	-11.5	-11.4	-11.4	-11.4
135	-15.0	-14.6	-14.3	-14.0	-13.8	-13.6	-13.5	-13.5
140	-17.5	-17.0	-16.6	-16.3	-16.0	-15.8	-15.6	-15.5
145	-20.0	-19.5	-19.0	-18.6	-18.3	-18.0	-17.8	-17.6

Calculating NGET and NGGT's IQI ratios

1.8. In order to calculate the IQI ratio for NGET and NGGT (ie their bid relative to our assessment of costs), we have made a number of adjustments to forecast data for consistency with our assessed costs. In particular, we exclude the following costs from NGET's and NGGT's bids (and our baseline):

- non-controllable costs including network rates, licence fees, NTS exit capacity, shrinkage and NTS pensions.
- costs which we propose to fund through uncertainty mechanisms, such as electricity load-related expenditure funded by volume drivers, Strategic Wider Works, and certain emissions-related and asset health expenditure for NGGT.
- cost associated with disallowed outputs, eg where we have reduced load-

62 Tax calculation: (Company retained post tax amount*marginal tax rate)/ (1- marginal tax rate) = (50*15 per cent)/(1-15 per cent) = 9.

related expenditure baselines for NGET, we have not included this adjustment in our calculations.

1.9. Consistent with our Strategy Document, we have included NGET and NGGT's proposed real price effects (RPEs) within their bid, and we have included our forecast of RPEs net of ongoing productivity within our baseline.

1.10. The IQI scores are set out in Table A1.2.

Table A1.2 - Proposed IQI scores, income reward/penalty and sharing factor

	NGET	NGGT
IQI Score	108	122
Income reward /penalty as per cent of base Totex	1.5%	(0.5 %)
Incentive Rate	48.1%	44.6 %

Appendix 2 - Strategic Wider Works

Introduction

1.11. We are committed to encouraging network companies to play a full role in a sustainable energy sector and tackling climate change. In 2009, the Transmission Study (ENSG Report), a joint industry initiative, identified that a large number of major transmission reinforcements would be needed to meet the Government's 2020 targets. We introduced Transmission Investment Incentives (TII) in 2010 to supplement capital allowances and deep revenue drivers set within TPCR4 to facilitate the timely delivery of critical electricity transmission infrastructure projects. We are extending these arrangements for the rollover year 2012-13.[63]

1.12. In our Strategy Document on the next price control strategy, we set out the options for funding strategic wider reinforcements under RIIO-T1. One option is the provision to allow us to make within-period determinations on revenue adjustments for TOs to deliver increases in boundary capability (or equivalent where there is no existing boundary) beyond the baseline wider works output capacity set out in Chapter 2, during the price control period. These Strategic Wider Works (SWW) arrangements will replace TII but will retain some elements of TII where appropriate. The SWW process would cover costs of construction works and an allowance for the opex associated with the completed asset; funding for associated pre-construction works would be included in each TO's core revenue package ('baseline revenue') agreed for the RIIO-T1 price control.

1.13. As set out in the supporting document on cost efficiency and uncertainty, NGET propose to progress a number of large reinforcement projects through SWW arrangements as and when more information confirms the technical and economic case for progressing such projects.

1.14. We propose to apply the same financial parameters for NGET's overall price control package (set out in Financial Issues Supporting Document) to projects approved under SWW during RIIO-T1. This is consistent with the principles in our Strategy Document.

1.15. In terms of risk sharing arrangements with consumers on SWW projects, we propose NGET would include the efficient means of managing risks within the overall cost of the project, where appropriate. In addition, we propose the totex costs of SWW projects are subject to the same efficiency incentive that applies to NGET's price control package. This means that NGET would be exposed to 48% of any over or under spend of delivering the SWW output, including any additional costs arising from events, where the costs of managing such risks are incorporated into the efficient costs of delivery. We propose that in some cases it would be more efficient

[63] For more information please see the decision letter published in November 2011 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=29&refer=Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives

for consumers overall to account for some low probability and high impact risks after the fact by means of a cost and output adjusting event (COAE). NGET has identified specific risks that they consider would be more efficient to address after the event had occurred. This is because it would avoid building in high mitigation costs for an event that has a low likelihood.

1.16. The SWW arrangements are designed to ensure value for money for consumers and timely funding of the construction costs and additional opex associated with large projects that are needed to meet customer requirements of wider network capability. It will achieve this by, firstly, providing NGET with flexibility to request a reopener to fund the costs of delivering SWW outputs once more information is available; and, secondly, allowing us to apply proportionate scrutiny, on a case-by-case basis, to the needs case and project assessment for delivering SWW outputs.

1.17. NGET has identified in their business plans a number of projects that they consider are suitable for future consideration under the SWW arrangements. We will require NGET to keep us up to date on the status of these projects, as well as give us notice of any other potential projects that emerge during the RIIO-T1 period.

1.18. The SWW arrangements would operate alongside any framework for third party delivery of onshore transmission assets which may be developed. We are looking further at the potential benefits of competitive onshore framework over the coming months. Under our current thinking for a potential competitive onshore framework we would take into account the interactions between the two frameworks, including the appropriate point at which we would assess whether a project is suitable for a competitive approach. This appendix sets out our current thinking on how to treat construction projects that we determine to be appropriate for delivery by the incumbent TO under the SWW arrangements.

Staged approach

1.19. We propose that the SWW arrangements will generally take a staged approach for the assessment, delivery and closure of these projects. Under the assessment stage we propose to determine whether the project meets the eligibility criteria for consideration under the SWW arrangements, with reference to its cost materiality and the needs case for the project. We also propose to assess the specifics of the costs and outputs for the construction phase. Following this, we propose there is the delivery stage where we would implement decisions about additional funding and output delivery and the TO will regularly report on delivery progress. We propose the final stage is delivery review and closure where we will confirm whether the TO has delivered the agreed output to the standards expected.

1.20. The following table sets out our proposed stages for the regulatory treatment of a project under SWW. In reality, it is likely that there will be some interaction between some of the various stages and that the process is more iterative or involves overlapping steps in practice. For example, in stepping between the needs case and project assessment, we would expect to have an initial view on the needs case but this may be subject to further review in light of some aspects of the project assessment.

Table A2.1: Generic stages for the regulatory treatment of an SWW project

Stage of process	Objective	TO	Ofgem
Eligibility assessment	Determine eligibility for assessment under SWW mechanism.	Advises Ofgem of its intention to submit a request for SWW and provides evidence of the scheme meeting the pre-defined eligibility criteria. Provides information on the project timescales for modelling and tender results.	Assesses whether scheme is eligible. If appropriate, sets out the timetable for assessment.
Needs case assessment	Determine needs case for the project, including the scope of proposed works and timing; and show that lessons (eg for planning) from previous projects are being applied.	Submits details of needs case (based on Security and Quality of Supply Standards (SQSS , cost-benefit analysis, user commitment, etc), including justification of proposed timing and explanation of how proposed project would meet the required scope.	Assesses the needs case, including whether the proposed timing is appropriate.
Project assessment	Justify proposals against technical readiness and cost effectiveness, including that any outstanding pre-con work is on track according to proposed project timelines. Determine funding allowances and outputs, and criteria for any future adjustments to costs or outputs.	Submits detailed information about design, costs and risks for project.	Assesses the TO's forecasts of total construction costs to complete the secondary deliverable by the scheduled completion date. Issue consultation on initial findings and issues under consideration. Propose funding allowances, secondary deliverable and

Stage of process	Objective	TO	Ofgem
	This process will build on the TII process.		completion date.
Implementing decisions			Publish decisions. Consult on licence changes. Issue licence changes.
During construction	Monitor progress towards outputs, and expenditure against profiled allowances.	Report to Ofgem on progress and expenditure. Notify Ofgem of any asset value adjusting event.	Consider requests for any COAE. Apply efficiency incentive annually.
Post-commissioning	Determine delivery of outputs.	Advise Ofgem about delivery of outputs.	Determine performance in delivery of outputs.

1.21. We anticipate that we will conduct a small number of assessments during 2012/13. These assessments will not be conducted under the TII framework, but will be assessed in the context of RIIO-T1. This could include assessments of large projects that would, were they to be submitted during RIIO-T1, be eligible for assessment under the SWW arrangements. These will be treated, in some respects, as "test cases" for refining and improving the arrangements. As noted above, this will also allow us to take into account interactions with the framework for third party delivery of onshore transmission assets as this develops.

More detail on SWW arrangements

Eligibility assessment

1.22. When a TO considers the needs case for a project is sufficiently clear, the TO would notify us of its intention to proceed with the construction phase of the project. For projects that are to be undertaken jointly between more than one TO, it is important that they all participate in this initial notification. We need to have confidence at this early stage that there is sufficient coordination between TOs, which is essential for the efficient planning and delivery of a project. Also, if we clearly understand the working arrangements between the TOs (eg a formal joint venture) then this will help us in planning what information will be required from which TOs at each stage of the assessment.

1.23. At this eligibility assessment stage, the TO(s) would provide us with evidence to enable us to decide whether the project is eligible for consideration under the

SWW arrangements, ie whether the project meets the eligibility criteria the TO has pre-defined. NGET has proposed eligibility criteria and these are set out in Chapter 4. If the project meets the eligibility criteria, we would work with the TO to set an indicative assessment timeline. This would be subject to further review as the assessment progresses, and to the timely provision of information by the TO.

Needs case assessment

1.24. In line with the agreed timetable, the TO would submit to us the needs case for the project. This information would have to include evidence to justify: the overall need for reinforcement (eg key specific drivers and SQSS analysis); the reasoning for preferring the proposed project (eg using optioneering and cost-benefit analysis under different scenarios); and the proposed timing of commissioning (eg using least regret analysis). We would assess the TO's submission, and determine whether there was a demonstrable need for the reinforcement in the timescale proposed by the TO, and whether the proposed scope of the works was appropriate.

Project assessment

1.25. Subject to a demonstrable need for the proposed reinforcement, the process would then move on to the project assessment stage. In line with the agreed timetable, the TO would submit to us the detailed plans and evidence that the proposed costs (capex and opex) are efficient.

1.26. We would use two approaches to determine the appropriateness of the proposed costs: Firstly, the costs would have to be broken down by the TO in sufficient detail to allow a thorough assessment, including benchmarking of specific elements. Secondly, we would need to understand the TO's processes for procurement and selection, to determine whether these were efficient and could therefore be expected to lead to an efficient outcome.

1.27. The TO would also have to provide more detail on the project risks and their proposed risk sharing arrangements, showing how they had been evaluated and allocated efficiently. We would expect the TO to have identified the most efficient means of managing risks and including these, where appropriate, within the overall cost of the project (and hence within the allowed expenditure). However, we recognise that there could be some risks that have low probability and high impact that could be addressed more appropriately by means of a COAE discussed below.

1.28. We would also require the TO to keep us informed with progress towards being ready to proceed with construction in the proposed timescales, eg status of applications for all necessary consents. This would help us to determine whether the work is likely to proceed as proposed, and whether construction funding will be required as requested by the TO. It could be the case that any funding allowances were contingent upon the TO satisfying certain criteria in relation to outstanding points.

Implementing funding and output decisions

1.29. We propose that our SWW funding decisions will allow the TOs to recover the efficient totex costs of delivering the SWW output. Our assessment for a scheme would establish the efficient construction costs for the project, profiled over the construction period, along with the efficient opex costs that the TO would incur as a result of the changes to its network associated with the project, eg maintenance costs during the RIIO-T1 period. Our assessment for a scheme would also establish the required wider works output, expressed in terms of increases in boundary capability (or equivalent where there is no existing boundary), delivered by a specific date.

1.30. We propose to specify in the TO's licence the new SWW outputs, and adjust the TO's revenues based upon the profiled totex expenditure, adjusted for inflation. We propose that all SWW outputs will be subject to the provisions of a COAE as specified in these Initial Proposals. Finally, we propose to include licence provisions setting out timely delivery standards, which would be set to correspond to the point in time at which the reinforcement works are deemed optimal to minimise system costs and to comply with security standards.

1.31. In general, in our funding decision, we will commit to funding the total cost of the works. However, there could be exceptions. For example, where an overall project can be delivered in stages and the needs case only justifies progressing the first stage while keeping options open to proceed with later stages. Another example could be particular SWW outputs that span the RIIO-TI and RIIO-T2 price control periods. In such cases, we might commit to funding only up to that juncture, in order to avoid complicating funding decisions taken under the next price control.

1.32. However, we recognise that this could create uncertainty for the TOs for two key areas of the treatment of such projects, namely:

- the funding commitment to deliver the entire output
- the financial parameters that would apply and therefore the financial risk and return.

1.33. It is important that the regulatory regime does not create a barrier to the efficient financing of key reinforcements. We think our approach under the SWW arrangements will help to avoid such situations. As set out above we will assess the relative merits of the entire reinforcement (the needs case and the detailed project cost assessment) that spanned the two price controls. Where the needs case justified delivery by the proposed date (in the next price control), Ofgem would consider the impact on the efficient costs of delivery of the TO taking a staged approach to procurement and to contracting with suppliers.

1.34. Where a staged approach is not considered to have a material impact on costs and risks, Ofgem would take a minded to position on the needs case for the entire project, but only take funding decisions on key milestones for the RIIO-T1 period via SWW arrangements. Ofgem would defer a decision on the allowances for the remaining stages of the reinforcement to our decision on the TO's business plan for the next price control. The TO would have sufficient certainty about the level of funding to allow them to proceed with the works under RIIO-T1.

1.35. If it could be demonstrated that staging the project would increase the costs of delivery, we would seek to:

- give a minded-to position on the needs case and a funding decision on key milestones for the T1 period via SWW arrangements (as above)
- give a minded-to decision on the efficient costs of delivering the entire project, and a minded-to position on funding the later stages of the project through the TOs' baseline for the next price control.

1.36. Whichever route was used (whether a staged funding arrangement, or a single funding arrangement), the funding granted under the next price control would be subject to the financial parameters of that price control. In setting funding allowances for that next price control Ofgem, would have regard to potential impacts that might arise from changes in price control policy in relation to an existing service contract the TO had for delivery of an output that spanned both price controls.

1.37. As is the case with baseline totex, a fixed proportion of the capital additions arising from the within-period determinations during RIIO-T1 would be entered into the main RAV in line with actual expenditure and the capitalisation rate. This would earn the same rate of return as the rest of the regulatory asset value under RIIO-T1. The remainder of the costs would be expensed.

1.38. The actual expenditure incurred on SWW projects by the TO in any year would be compared with the allowed expenditure for that year. We would apply the totex efficiency incentive so that the TO is exposed to a proportion of any overspend (and similarly retains a proportion of any underspend). There would be a two year lag in any revenue adjustments due to the efficiency incentive.

During construction

1.39. The TO would be required to provide information on an annual basis on the status of SWW projects and delivery progress. Details of actual expenditure as compared with forecast expenditure would be used in our annual iteration of the financial model to make revenue adjustments in line with the efficiency incentive. Information on the status of progress towards outputs would be used as a means of monitoring delivery and to give us "early warning" of any issues.

1.40. NGET has identified some specific risks that could be more efficient to address after the fact by means of a cost and output adjusting event. We propose that this provision would apply only for prescribed events in material cases, where costs (as measured before the application of the efficiency incentive) changed by more than a certain threshold.

1.41. We propose that a COAE will only apply for NGET's SWW outputs if a single prescribed event led to a change in total delivery costs of at least 20% (before the efficiency incentive). The prescribed events are:

- extreme weather (worse than 1 in 10 for land-based activity, equivalent provisions for marine-based activity)
- the imposition of additional conditions or constraints by a statutory body
- movement of agreed outages by the SO
- changes in the project scope that could not have been anticipated during the assessment process, such as unforeseen ground or sea-bed conditions.

1.42. The TO will provide evidence, including the assessment of independent technical experts, to support the submission for a COAE. We will determine whether the event constituted an asset value adjusting event. If applicable, then we would determine whether the project remained economically efficient as a consequence of the event. Finally, if applicable, we would determine the amount by which the project costs should be adjusted for each year of construction.

Post commissioning

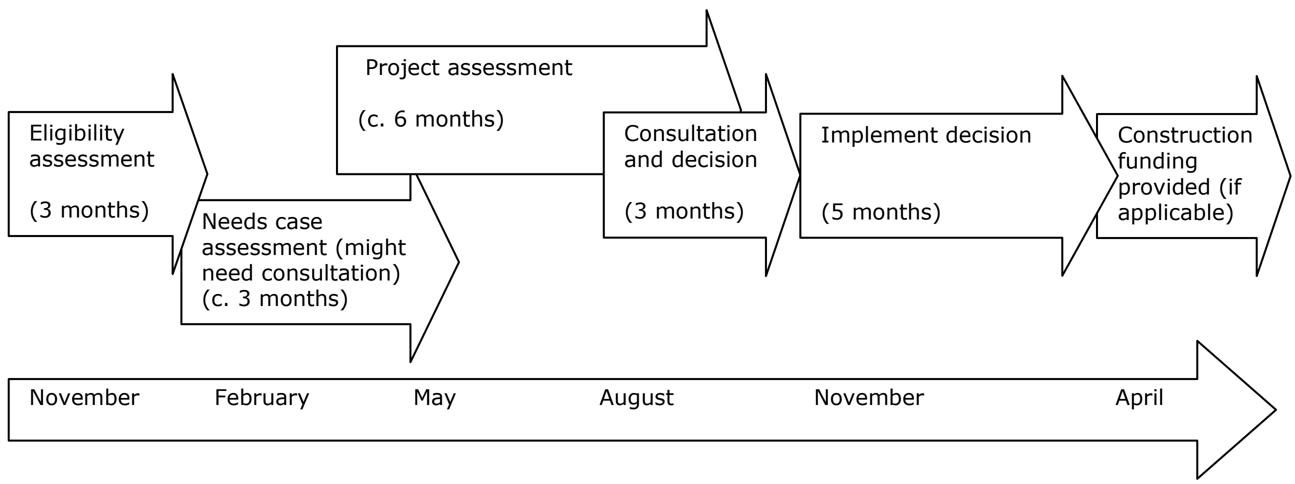
1.43. Once the project has been commissioned, we propose to require the TO to confirm delivery of the wider works outputs. Each project would have an associated output, defined as the increase in boundary capability. The TO would be required to verify that the agreed increase had been delivered, and to advise Ofgem of this, along with the relevant supporting evidence.

1.44. Ofgem would review the TO's performance in the delivery of the outputs. Where the TO had not delivered the agreed output on time, we would work with the TO to understand the reasons for this. Failure by a TO to deliver the output on time as specified in the licence could potentially constitute a contravention of the licence condition. In considering whether this is the case or not, the Authority would look at the factors leading to the late delivery and the extent to which the TO could be held responsible for events as well as whether or not it took reasonable steps to mitigate the impact of such events where it could do so efficiently. Consistent with our Strategy Document we propose to address late delivery in RIIO-T1 through the imposition of a financial penalty. If the Authority is satisfied that the late delivery constitutes a contravention the TO could potentially be subject to financial penalty determined under the Authority's 'Statement of Policy with Respect to Financial Penalties'.

1.45. In setting a financial penalty the Authority would take into consideration the level of consumer detriment that is a consequence of the late delivery, as well as aggravating or mitigating actions undertaken by the TO in relation to the late delivery and its impact on consumers.

Timing of stages under SWW

1.46. The following diagram is an indicative timeline for the SWW process. In reality, it is likely that there will be a degree of interaction between some of the stages that means this process is more iterative or involves overlapping steps in practice. Also, we recognise that there will be valid reasons for using different timings for certain projects, and this would have to be agreed in advance between Ofgem and the TO(s). For example, we note that the split between the needs case assessment and the project assessment could vary, depending upon the relative extent of work required for the needs case and the project assessment (eg if the needs for a project case had already been considered by Ofgem in a previous piece of work, then we could agree with the TO to reduce or omit that stage).We will also consider these timings alongside the development of the regime for third party delivery of onshore transmission assets.



1.47. We propose to consult on each proposal submitted by a TO under the SWW arrangements. We will follow the model used in TII, such that we will consult during our project assessment. We would consult on the TO's proposal, our views based on our assessment to date, and on the issues to consider in our ongoing assessment. We have found in TII that there is sufficient information available at this point for stakeholders to reach informed views about the details of the proposed projects, and that there is sufficient time left in the assessment process for us to take their views into account when reaching our decisions.

1.48. Based on our experience of assessing large projects under the TII framework we consider up to one year for the entire assessment process, from the initial submission to a decision on SWW outputs and funding allowances, would be appropriate in most cases. Our preference, where possible, would be to make final decisions in time to input changes to funding allowances into the financial model, to conduct the statutory consultations on the licence changes, and to modify the licence for outputs and allowances in time for the next financial year. This would allow for greater predictability of network charges, to the benefit of network users. For this preferred timeline, we would need to take the final decision by November before the financial year in which the TO would incur delivery costs. However, we recognise that the timings of some projects would mean that this preferred SWW timeline might not be appropriate.

1.49. It may be appropriate for there to be a different timeline for any particular assessment. Similarly, if a TO believes that there is justification for a different timeline for a particular assessment, then the TO should explain its reasoning and set out a clear proposition for us to consider at the earliest possible opportunity. We would work with the TOs to determine the optimal timeline in those cases, and the TO would then proceed with submitting its proposal in line with the agreed timeline.

1.50. For projects that were suited to our preferred timeline, the TO would need to submit its initial request by November of the year before a decision was to be made, which is about one and a half years before the start of the financial year in which the TO would start incurring construction costs. This timescale would allow Ofgem to investigate all of the relevant issues, narrowing down on the key questions at the same time as the TO was refining its plans and arriving at a position on the costs and risks.

1.51. We recognise that this preferred timeline could result in decisions for some projects being made further in advance (eg where costs were to be incurred from late in a financial year) than for others (eg where costs were to be incurred from early in a financial year. This could be acceptable in some cases (eg when the need case was clear, and the TO is confident about the costs), but there could be cases in which it was not possible (or desirable) to make a decision too far in advance of the TO incurring delivery costs.

1.52. In those cases in which timings differ to our preferred timeline, such that we could not make a final decision by the November prior to the financial year in which the TO started incurring delivery costs, then we may, where appropriate make a funding allowances in the following financial year. We will seek to agree with each TO the most appropriate approach for assessments that could not follow our preferred timeline.

1.53. In all cases, the timings will depend upon the TOs submitting information to us at the agreed times (including additional information that we might request during our assessment), in order to enable us to reach decisions at the required times.

Appendix 3 – Supporting tables on Load-Related Expenditure for NGET (TO)

Table A3.1: Movement of Outputs within Baseline

		FROM				
		LE (Entry-Shared Use)	LE (Exit – Sole Use)	LE (Exit – Shared Use)	Wider Works (Entry)	Wider Works (General)
TO	LE (Entry-Shared Use)				Connection of Sizewell : (Reconducting of Bramford-Sizewell circuit, Circuit breaker work at Rayleigh Substation) Voltage Support for East Anglia-Norwich : (Quadrature Boosters at Pelham substation) £100.1m	Ironbridge Closure : (Installation of SGTs and switchgear workat High Marnham substation) Mechanically switched capacitors at Feckenham substation £45.5m
	Wider Works (Entry)					East Coast strategic work 275kV to 400kV uprating at West Weybridge and Chessington £87.3m
	Wider Works (General)	Tees Crossing: (Work on Lackenby-Saltholme-Tod Point circuit) £25.1m	New 132kV Switchgear in Norwich Transfer of assets with Western Power Distribution (formerly Central Networks West) £0.2m	New circuit breakers at New Cross, Whitson and Lackenby South Manchester Autoclose SGT replacement at Willington substation £38.5m	Easements Ross Cable Uprating Cellerhead-Macclesfield Reconductoring Walpole 400kV Rebuild Capenhurst SGT Humber Smartzone SouthWales Operational Intertrip Undergrounding Provision Grain-Kemsley Uprate Thames Crossing Barking-West Ham Reconductoring £730.3m	

Table A3.2 - Recategorisation of schemes between LRE categories

LRE CATEGORY	EXPENDITURE OUT	£m	EXPENDITURE IN	£m
LE (Exit - Sole Use)	[redacted]	-5.8	[redacted]	15.5
			[redacted]	35.9
			[redacted]	10.8
			[redacted]	13.6
			[redacted]	
LE (Exit - Shared Use)	[redacted]	-13.6	[redacted]	17.6
	[redacted]	-10.8	[redacted]	5.9
	[redacted]	-15.5	[redacted]	7.7
	[redacted]	-0.2	[redacted]	10.0
	[redacted]		[redacted]	0.3
	[redacted]		[redacted]	0.6
	[redacted]		[redacted]	
LE (Entry - Shared Use)	[redacted]	-35.9	[redacted]	
	[redacted]	-17.6	[redacted]	
	[redacted]	-1.9	[redacted]	
	[redacted]	-13.5	[redacted]	
	[redacted]		[redacted]	
WW (Entry)	[redacted]	-0.6	[redacted]	1.9
	[redacted]	-10.0	[redacted]	13.5
	[redacted]	-7.7	[redacted]	
	[redacted]	-0.3		
TOTAL		**-133.2**		**133.2**

Appendix 4 - Business support cost assessment

1.1. The purpose of this appendix is to explain the methodology we have used in setting our proposed allowances for the seven business support activities (IT & telecom; property management; finance, audit & regulation; HR & non-operational training; procurement; CEO & group management and insurance). It sets out the results of our analysis and explains variations between our allowances and network companies' submitted forecasts. The following table summarises the allowances for NGET and NGGT.

Table A4.1 – Ofgem proposed allowance for business support costs

Average per year £m 2009/10 prices (incl. RPEs)	Transmission				
	Electricity		Gas		Total
	NGET TO	NGET SO	NGGT TO	NGGT SO	
TPCR4+R* Forecasts	56.5	29.9	20.5	18.7	125.6
RIIO-T1 Forecasts	53.2	41.6	18.7	20.8	134.3
Initial proposals	40.0	32.7	14.2	17.1	103.9
Difference: forecasts to IP	-24.8%	-21.4%	-24.4%	-18.1%	-22.6%

* TPCR4+R: four years actuals + 2 years forecasts

1.2. We have primarily used benchmarking analysis of all UK energy network companies (transmission, gas distribution, electricity distribution) against each other and against external benchmarks developed in collaboration with the Hackett Group in assessing business support costs. This benchmarking assessment covered all business support activity costs with the exception of insurance costs, which were assessed separately and added to the benchmark assessed costs.

1.3. Where a network company is part of a group its operating costs are generally derived from central group functions with costs allocated to the individual network. The assessment of business support costs has been carried out at an overall group level with allowances allocated to networks in the same group in proportion to their forecasts.

1.4. The RIIO-T1 and RIIO-GD1 assessments were carried out as a single process and therefore this appendix is identical to an appendix to the RIIO-GD1 Supporting Document on cost efficiency.

Overview of assessment process

1.5. Our main aim in assessing business support costs was to set appropriate allowances for business support as a whole and we designed and applied our assessment methodologies accordingly. While we benchmarked costs at an activity level, certain adjustments and additions have been applied at a total business support level. It is therefore not appropriate to detail the results of our assessment on a disaggregated activity basis.

1.6. With the exception of insurance costs, each activity was benchmarked separately. Insurance costs were excluded from the benchmarking exercise as differences in risk appetite and appropriate levels of coverage between companies and sectors make it difficult to ensure a like-for-like comparison.

External benchmark development

1.7. The external benchmarks were provided by the Hackett Group based on current data held in its database. We worked closely with Hackett to select appropriate benchmarks that we are confident provide good comparators against which network companies' costs can be compared.

1.8. Hackett's database contains data collected and validated by Hackett using robust and consistent processes. The database is kept up to date and is held at sufficiently granular level to enable Hackett to calculate metrics that align with our business support activity cost definitions.

1.9. The same comparator group was used for each activity. Our objective when designing the comparator group was to enable us to calculate benchmark metrics that as closely as possible reflect the costs of an efficient company operating in a competitive market environment. For this reason we excluded any government owned or operated organisations, any charitable organisations, and any price control regulated companies. To improve comparability with network companies we restricted the comparator group to companies with revenues of less than £2 billion and with fewer than 20,000 FTEs.

1.10. The comparator group contained 85 companies across 9 sectors[64]. The companies are within the UK and overseas. We have specifically verified that the geographical differences have no effect on the overall benchmarks.

1.11. For each activity Hackett provided one headline cost metric plus two to three supplementary metrics in order to aid our analysis. The headline metrics cost drivers were chosen on Hackett's advice on the basis that (of the cost drivers they have examined) they have the highest statistical relationship to total cost for the relevant activities and they are regularly used by Hackett and its clients for cost efficiency assessment purposes.

[64] Sectors were defined in accordance with the Global Industry Classification Standard (GICS). The GICS separates organisations into ten sectors in total. The only sector not represented in our comparator group was the utilities sector. The reason for this is that most companies in this sector are either government owned or are highly revenue regulated.

Networks benchmark

1.12. In addition to the Hackett benchmarks, we calculated equivalent metrics for the nine network company/groups[65] using 2010/11 data submitted by the companies in their RIIO-T1/GD1 data tables and in their annual regulatory returns. These metrics were calculated based on gross costs. Where a company has allocated a proportion of its business support costs to direct opex, capex, or repex or to non-network businesses then these are added back to the submitted net costs as pre-benchmark normalisations. This is reversed at the end of the assessment to return to net costs. The reversal (gross to net conversion) is done in the same proportion as in the companies/groups submitted forecasts.

Table A4.2 – Gross to net conversion ratios

RIIO-T1/GD1 weighted average gross to net conversion ratio	
National Grid	4.4 %
NGN	8.0 %
SSE	20.1 %
WWU	17.2 %

1.13. Other pre-benchmark normalisations were applied to 2010/11 (base year) submitted costs where a network company identified movements in any of its activity costs over RIIO-T1/GD1 or where the 2010/11 costs contain elements that would not be continued throughout RIIO-T1/GD1. We applied judgement on the proportion of costs that should be applied as pre-benchmark normalisations based on the information provided by the companies. Table A4.3 below details the pre-benchmark normalisations we applied.

[65] National Grid, Northern Gas Networks, Scottish & Southern Energy, Wales and West Utilities, Northern Powergrid, UK Power Networks, Western Power Distribution, Electricity North West, Scottish Power

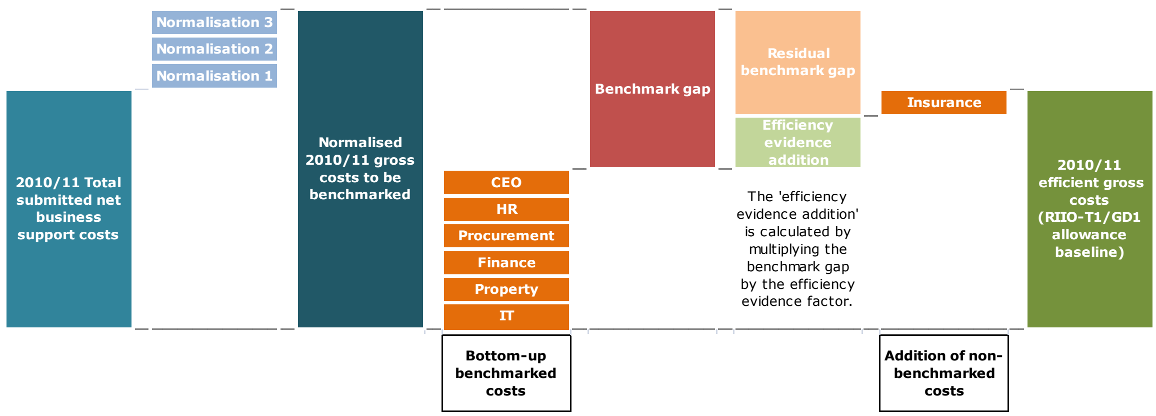
Table A4.3 – Pre-benchmarking normalisations (£m 2009/10 prices)

National Grid	**2010/11**
Net to gross add-back costs	+25.51
IT: GDFO support costs	+1.80
IT: Tactical Reversal	+0.83
IT: Non-regulated scope change	+1.05
Property: Timing Workload (R&M increases)	+0.92
Procurement: Stores & logistics	-2.02
Total	+28.09
NGN	**2010/11**
Net to gross add-back costs	+1.35
Net pain/fee (various activities)	+0.30
Finance: pensions deficit and actuarial review	+0.10
Procurement: Stores & logistics	-
IT: New system support	+0.40
Property team recruitment	+0.10
CEO: Stakeholder/community awareness	+0.20
Total	+2.45
SSE	**2010/11**
Net to gross add-back costs	+10.14
Procurement: Stores & logistics	-0.67
Total	+9.47
WWU	**2010/11**
Net to gross add-back costs	+3.76
Finance: Grade changes	+0.10
HR: Grade changes	+0.10
Procurement: Stores & logistics	-0.44
IT cost increase Offset by reduction in Asset SOMSA costs	+0.55
IT & Telecom: Support costs	+1.07
Property: Facilities maintenance annual workload fluctuations	+0.60
CEO: Staff vacancy not filled	+0.10
CEO: Recruitment of strategy manager	+0.10
Total	+5.94

1.14. It should be noted that identified cost movements were applied as pre-benchmark normalisations only where the company provided sufficient justification for them and where they affect business as usual costs. Where a company identified and justified exceptional costs over RIIO-T1/GD1 then these were applied post benchmarking as justified above benchmark increases.

Application of benchmarks to cost assessment

Figure A4.1– Process for calculating allowance baseline



1.15. A network company's 2010/11 benchmarked total business support cost was built up by calculating and aggregating the individual activity benchmarked cost components plus non-benchmark assessed insurance costs. These costs were then projected forward on a flat line over RIIO-T1/GD1 as the baseline.

1.16. In order to calculate the 2010/11 activity benchmarked cost (component of allowance baseline) for each company, the value of its relevant 'activity cost driver' was multiplied by the appropriate 'benchmark comparator' (e.g. for IT & telecom the 'activity cost driver' is the number of end-users and the 'benchmark comparator' is the networks upper quartile total cost per employee metric). The benchmark comparator used was either the 'networks upper quartile' or the 'external benchmark upper quartile'. For consistency with benchmarking in other areas the network upper quartile was used for all activities as default except for those activities where the external benchmarking indicated cost inefficiency in the UK networks industry as a whole. The actual benchmark used for each activity is shown in the benchmarking results charts at the end of this appendix.

1.17. The result of this analysis is that for activities where the benchmark comparator is higher than a network company's equivalent metric value (indicating cost efficiency) then the company's benchmarked cost will be above its actual 2010/11 cost and conversely where the benchmark comparator is lower than the equivalent company metric (indicating cost inefficiency) the benchmarked cost will be lower than 2010/11 actual.

Post benchmark additions

1.18. We added additional costs following the benchmarking for the years in which they apply, eg to cover additional insurance cost. We added these at group level prior to allocation of costs to individual networks. The only exception to this is increases to NGET SO and NGGT SO to reflect additional costs associated with transmission system operation. These were added after the allocation to the individual network's allowances (see 1.21 below).

Efficiency evidence additions

1.19. Where a company has provided robust evidence of cost efficiency, through for example its own benchmarking studies, we have assessed the quality of the evidence and have made allowance for it through an upward only 'efficiency evidence addition'. Our quality of evidence assessment took account of (1) the results/conclusions of the evidence ie the extent to which the study/evidence indicates cost efficiency, (2) the robustness of the methodology employed, (3) the quality and reliability of the data used in the study (4) the extent to which the results of the study can be verified or whether the study was carried out by a reputable independent third party. By scoring against each of these criteria we derived an efficiency evidence factor score (of between zero and 100 per cent) for each activity and a total efficiency evidence factor by taking the cost weighted average activity score. The total efficiency evidence factor was then multiplied by the calculated benchmark gap (see Figure A4.1 above) to give the efficiency evidence addition and our overall view of the 2010/11 efficient costs. The efficiency evidence addition is calculated for each year of RIIO-T1/GD1 and added to the baseline.

Table A4.4 – Efficiency evidence factors and efficiency evidence additions

Efficiency evidence factor	**Company activity factors**			
	National Grid	**NGN**	**SSE**	**WWU**
IT & telecom	21.8%	4.6%	10.8%	14.2%
Property management	32.1%	3.6%	0.0%	68.9%
Finance, audit & regulation	0.0%	4.6%	0.0%	0.0%
HR & non-operational training	0.0%	4.6%	0.0%	0.0%
Procurement	0.0%	5.5%	0.0%	0.0%
CEO & group management	0.0%	2.7%	0.0%	0.0%
Overall (cost weighted average)	**14.5%**	**4.0%**	**4.7%**	**17.7%**
RIIO-T1/GD1 efficiency evidence addition, £m 2009/10 prices				
Gross efficiency evidence addition	113.87	2.68	7.63	13.54
Net efficiency evidence addition	**108.86**	**2.47**	**6.10**	**11.22**

Other justified movements

1.20. Where a company identified and justified exceptional costs over RIIO-T1/GD1 then these are also added to allowance baseline.

Table A4.5 – Post benchmark additions (£m, 2009/10 prices)

Post benchmark additions to baseline allowance £m 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021
National Grid								
Transmission insurance increases	3.61	3.68	3.88	3.88	3.89	3.91	3.86	3.82
Gas distribution: stores and logistics	1.82	1.83	1.84	1.85	1.86	1.86	1.86	1.88
PPA Assessment of SO costs (applied to NGET_SO only)	1.94	2.21	2.17	1.64	1.31	1.41	1.79	1.92
PPA Assessment of SO costs (applied to NGGT_SO only)	1.53	1.92	1.89	1.65	1.47	1.53	1.77	1.91
NGN								
CEO: change in governance	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SSE								
Stores & logistics	1.31	1.31	1.32	1.32	1.32	1.32	1.32	1.32
SHETL fast track increases (applied to SHETL only)	1.50	2.50	3.30	3.70	4.60	5.10	5.40	5.70
WWU								
Recruitment of independent director	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Stores & logistics	1.31	1.31	1.32	1.32	1.32	1.32	1.32	1.32

1.21. While National Grid's transmission system operator businesses were included in our overall assessment, they were also subject to an independent detailed assessment by consultants PPA Energy. As PPA's assessment represents the total package for the SO business and recognises the IT intensive nature of system operation we expected it to come out above our benchmarked assessment. We are therefore proposing allowances to NGET SO and NGGT SO in accordance with PPA's assessment.

Allocation of allowance to individual networks

1.22. The calculated net allowances have been allocated to individual transmission and gas distribution networks in proportion to submitted cost forecasts for RIIO-T1/GD1 period. Table A4.6 below gives the percent split between transmission (T), gas distribution (GD), and electricity distribution (ED) networks for submitted costs and allocated allowances. The differences between the two sets of percentages are due to:

- Fast track allowances to SHETL: SHETL's fast-track allowances were subtracted from SSEs calculated allowance with the remaining allowance allocated to the other SSE network companies.
- Post benchmark increases to NGET SO and NGGT SO (PPA assessed increases), which are added post allocation.

1.23. The percentages shown for ED networks are notional amounts. An assessment will be carried out on electricity distribution networks' business support costs as part of RIIO-ED1.

Table A4.6 – Network split of group business support costs

Network		Group							
		National Grid	NGN	SSE	WWU	National Grid	NGN	SSE	WWU
		RIIO-T1/GD1 Submitted cost % split				RIIO-T1/GD1 calculated total allowance % allocation			
T	NGET TO	24.29%				23.78%			
	NGET SO	18.74%				19.42%			
	NGGT TO	8.59%				8.41%			
	NGGT SO	9.31%				10.14%			
	SHETL			8.65%				10.45%	
GD	East of England	13.11%				12.83%			
	London	8.43%				8.25%			
	North West	10.13%				9.91%			
	West Midlands	7.41%				7.26%			
	Northern		100.00%				100.00%		
	Scotland			14.31%				14.03%	
	Southern			26.08%				25.57%	
	Wales & West				100.00%				100.00%
ED	SSE Hydro			21.39%				20.96%	
	SSE Southern			29.58%				28.99%	

Activity cost drivers

Table A4.7 – Business support benchmarking cost drivers

2010/11 business support benchmarking cost drivers				
	National Grid	NGN	SSE	WWU
Revenue (£m 2009/10 prices)	3,719.3	314.6	1,470.5	294.0
End-users (number)	10,618.1	1,075.1	8,479.1	1,824.7
Employees (number)	7,605.3	1,070.1	4,962.2	1,363.0
Spend (£m 2009/10 prices)	3,266.0	160.9	856.0	173.2

Revenue

1.24. Revenue was used as the cost driver for three activities: Finance, audit & regulation; property management; CEO & group management.

1.25. Network companies' 2010/11 revenue figures have been calculated as follows: we included base revenue and incentive revenue but excluded income adjusting events, pass through costs and adjustments relating to prior years.

End-users

1.26. End-user numbers were used as the cost driver for IT & telecoms.

1.27. For this purpose an end-user was defined as "an individual (typically either an employee or contractor) that spends at least 10 per cent of his or her time using company provided, funded, supported computing devices that are part of the company's IT infrastructure (i.e. desktops, laptops, hand held devices, etc.) to support his or her business function. The user must have direct access to internal applications/systems to execute specific transactions on behalf of the company".

1.28. Where we do not have precise 2010/11 end-user figures we have estimated them based on FTE and employee numbers.

Employees

1.29. Employee numbers were used as the cost driver for HR & telecoms.

Spend

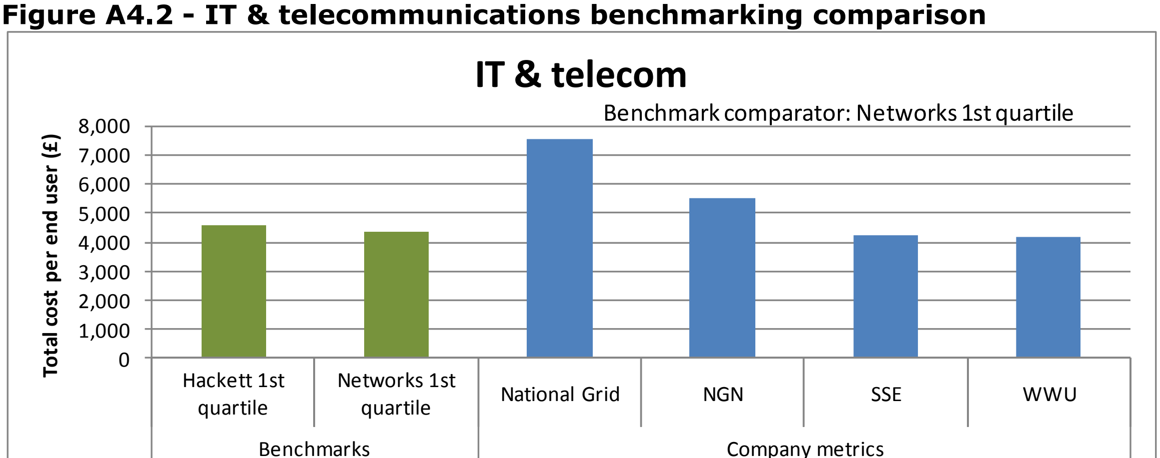
1.30. Total spend was used as the cost driver for procurement.

1.31. 2010/11 total spend has been calculated by adding total opex and capex and deducting related party and employee costs.

Business support benchmarking results

1.32. The following figures (A4.2 to A4.7) show the business support benchmarking results for different activities.

Figure A4.2 - IT & telecommunications benchmarking comparison



	Hackett 1st quartile	Networks 1st quartile	National Grid	NGN	SSE	WWU
Metric	4,603	4,343	7,528	5,516	4,219	4,181

Figure A4.3 - Property management benchmarking comparison

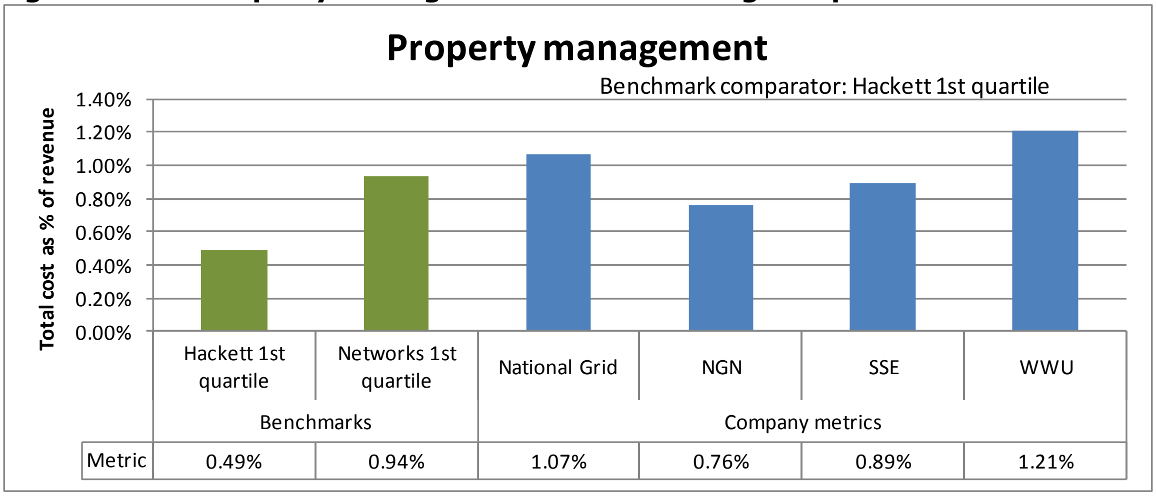


Figure A4.4 - Finance, audit & regulation benchmarking comparison

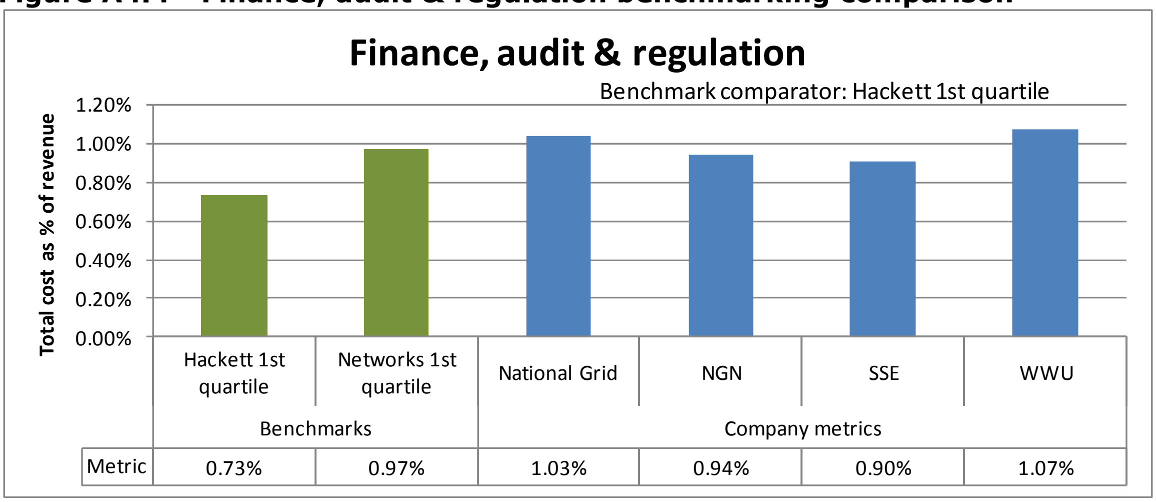


Figure A4.5 - HR & non-operational training benchmarking comparison

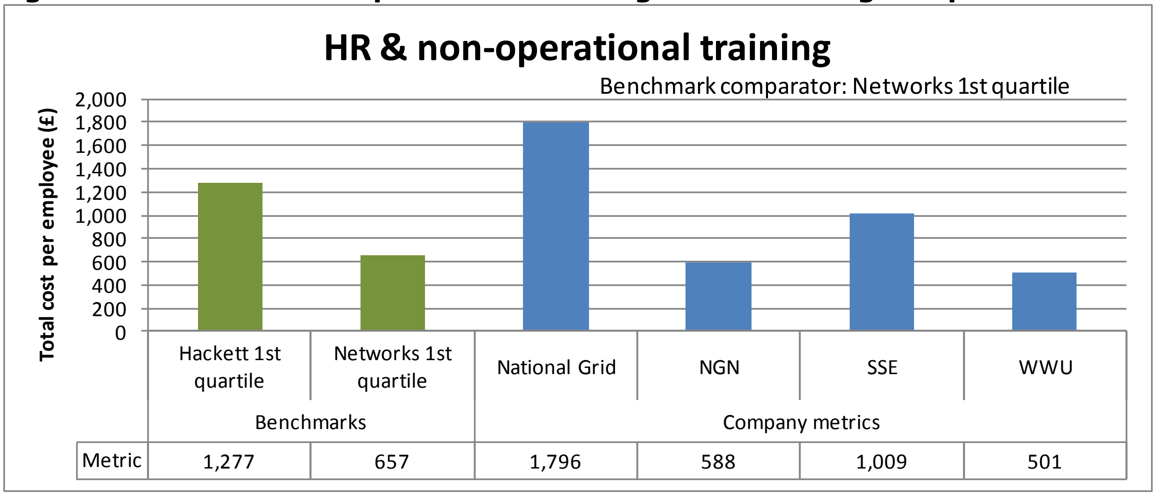
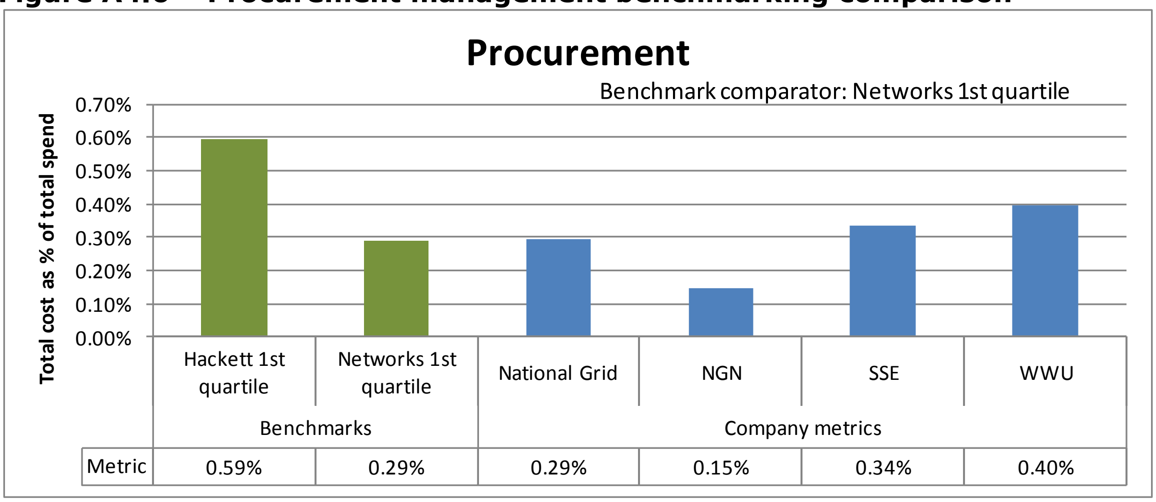


Figure A4.6 – Procurement management benchmarking comparison



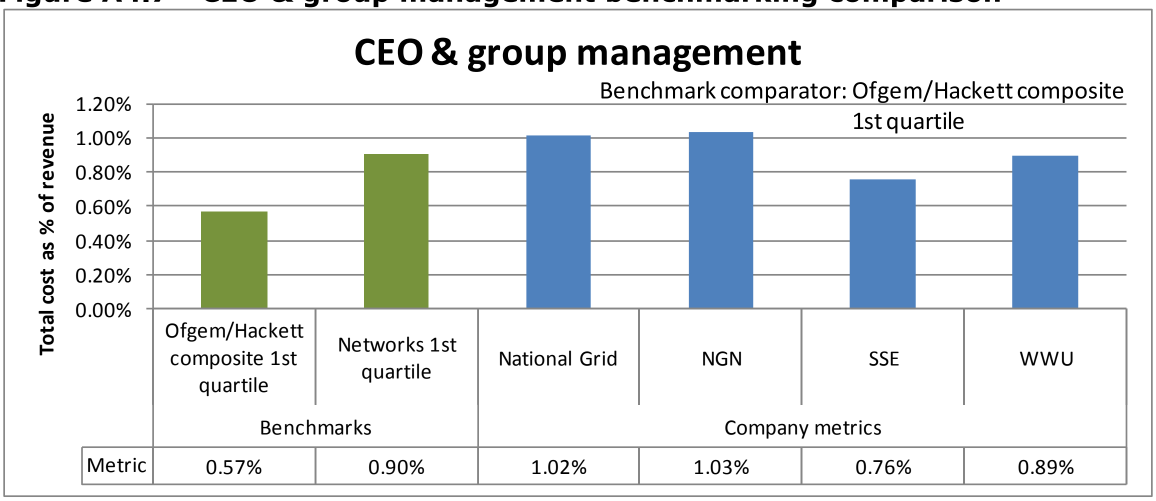
1.33. GDNs' business support costs include stores and logistics, which transmission treats as a direct cost. Procurement, stores and logistics was a single activity in GDPCR1 and GDNs reported these costs in aggregate. GDNs have not separated costs on a consistent basis: NGN and WWU have placed all costs into procurement, while SGN have placed them all in stores and logistics. For benchmarking we assumed a split as shown in Table A4.8 below.

Table: A4.8 – Procurement, stores and logistics cost split

Procurement stores & logistics assumed cost split								
	NGG				NGN	SGN		WWU
£m 2009/10 prices	East of England	London	North West	West Midlands	Northern	Scotland	Southern	Wales & West
2010/11 actual costs								
Procurement	0.59	0.43	0.50	0.35	0.19	0.22	0.45	0.44
Stores & logistics	0.63	0.46	0.54	0.38	0.00	0.22	0.45	0.44
Total	1.23	0.90	1.04	0.73	0.19	0.45	0.90	0.87
RIIO-GD1 forecast average								
Procurement	0.65	0.47	0.54	0.38	0.20	0.28	1.03	0.42
Stores & logistics	0.59	0.42	0.49	0.35	0.00	0.28	1.03	0.42
Total	1.24	0.89	1.03	0.73	0.20	0.57	2.06	0.84

1.34. The above stores and logistics costs were removed as pre-benchmark normalisations and then added back as post-benchmark additions to the allowance baseline.

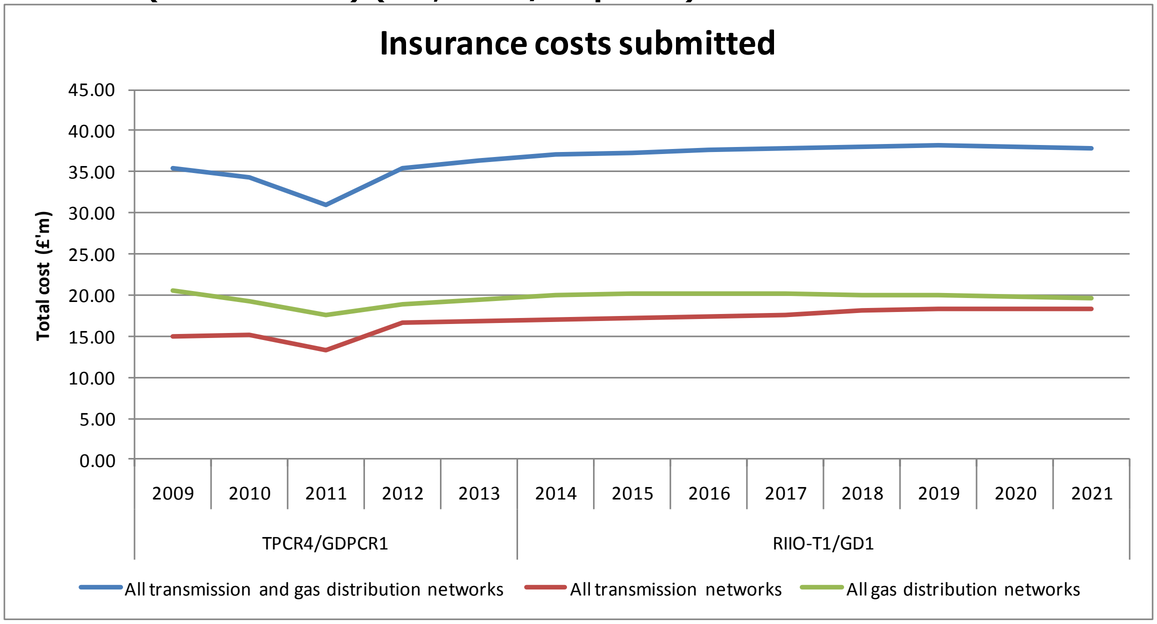
Figure A4.7 - CEO & group management benchmarking comparison



1.35. The benchmark comparator group excludes revenue regulated organisations and therefore, in order to reflect the possible increased cost associated with meeting regulatory burdens on network companies relative to the comparator, we constructed a composite upper quartile metric using data provided by Hackett as well as our own analysis of network company costs. The composite benchmark was constructed by summing the total cost as % of revenue upper quartile for corporate communications and for legal from Hackett with the networks upper quartile for executive office.

Non-benchmarked costs: Insurance

Figure A4.8 – Insurance costs actuals (2009-2011) and network company forecasts (2012 – 2021) (£m, 2009/10 prices)



1.36. Insurance costs were excluded from the benchmarking exercise as differences in risk appetite and appropriate levels of coverage between companies and sectors make it difficult to ensure like-for-like comparison.

1.37. Our assessment of insurance looked at overall industry trends over TPCR4/GDPCR1 and RIIO-T1/GD1. We have seen a general decrease in insurance costs for transmission and gas distribution networks in the first three years of GDPCR1 for which we have actual data. Over RIIO-T1/GD1 forecast costs are approximately flat for gas distribution networks and show moderate increases for transmission. The increase in transmission costs is justified on the grounds of increasing value of asset requiring insurance cover over RIIO-T1.

1.38. We therefore propose baseline allowances at 2010/11 actual cost levels for all networks with additions for National Grid's transmission business in line with forecast increases.