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RIIO-T1: Final 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 Final Proposals for the next transmission price control for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT) from 1 April 2013 to 31 March 2021.

The document sets out the results of our assessment of each element of NGET's and NGGT's costs and our Final 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 Final Proposals for mechanisms to manage efficiently 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 Final Proposals. Stakeholders wanting a more high-level overview should refer to the Final Proposals Overview document.

Contents

Associated documents

Main consultation paper

RIIO-T1: Final Proposals for NGET and NGGT- Overview
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf

Supporting Documents

RIIO-T1: Final Proposals for NGET and NGGT – Outputs, incentives and innovation
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/2_RIIOT1_FP_OutputsIncentives_dec12.pdf

RIIO-T1: Final Proposals for NGET and NGGT – Finance
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/4_RIIOT1_FP_Finance_dec12.pdf

RIIO-T1/GD1: Final Proposals – Real price effects and ongoing efficiency appendix
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/5_RIIOT1_FP_RPE_dec12.pdf

Associated documents

RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=214&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Other Relevant Documents

RIIO-GD1: Final Proposals – Overview
http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/1_RIIOGD1_FP_overview_dec12.pdf

RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd
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 Final Proposals for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT).

Purpose of this document

1.1. This document sets out further detail on efficient costs and uncertainty mechanisms for our Final Proposals for NGET and NGGT for the next transmission price control, RIIO-T1. This price control will cover the eight-year period from 1 April 2013 to 31 March 2021.

1.2. Under the RIIO process, network companies are required to take into account the needs and views of stakeholders in order to submit well-justified business plans to us. Our March 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?

1.3. This document aims to provide further detail to support the Final 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.

1.4. Alongside this document we have published an Overview Document[2] and three other Supporting Documents:

[1] Decision on strategy for the next transmission price control: RIIO-T1 – Ofgem, 31 March 2011 Ref:46/11
[2] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

- RIIO-TI: Final Proposals for NGET and NGGT – Outputs, incentives and innovation[3]
- RIIO-T1: Final Proposals for NGET and NGGT – Finance[4]
- RIIO-T1/GD1: Final Proposals – Real price effects and ongoing efficiency appendix.

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

1.6. This document sets out our Final Proposals for the outputs to be delivered and the associated incentives that will apply around delivery for NGET and NGGT for the next transmission price control, RIIO-T1. This price control will cover the eight year period from 1 April 2013–31 March 2021. This document also outlines the proposed arrangements to support innovation by the companies.

Assessment process

1.7. Our Final Proposals build on the assessment and analysis we presented in Initial Proposals, published in July 2012. We developed these Proposals using a range of qualitative and quantitative tools to assess the business plans submitted by NGET and NGGT for their Transmission Owner (TO) and System Operator (SO) functions. We also engaged extensively with NGET and NGGT, and sought external information in order to come up with our Initial Proposals.

1.8. NGET and NGGT provided substantial responses to our Initial Proposals. A number of third parties also commented on cost and uncertainty relating to NGET and NGGT. These views are addressed in the relevant chapters of this document.

1.9. Since publication of Initial Proposals, we have continued to engage with NGET and NGGT in order to clarify our position, understand its responses and develop our proposals. We have taken into consideration further evidence and clarification provided in their responses and at a number of bi-lateral meetings, as well as the responses to a significant number of supplementary questions raised by us. We have also factored in responses from third parties to our consultation on Initial Proposals.

1.10. We have been supported by a consortium led by Pöyry Management Consulting as engineering consultants. 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. PPA Energy

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[3] RIIO-T1: Final Proposals for NGET and NGGT – Outputs incentives and innovation http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/2_RIIOT1_FP_OutputsIncentives_dec12.pdf
[4] RIIO-T1: Final Proposals for NGET and NGGT – Finance http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/4_RIIOT1_FP_Finance_dec12.pdf

provided engineering consultancy support in the development of Initial Proposals for the SO functions.

Structure of this document and associated documents

1.11. The remaining chapters provide further detail on the cost and uncertainty elements of the price control package.

1.12. The layout of this document is as follows:

- Chapter 2 summarises our Final Proposals for the efficient costs and uncertainty for NGET and NGGT
- Chapter 3 sets out our Final Proposals for the uncertainty mechanisms that will apply across NGET and NGGT
- Chapter 4 provides more details on the efficient costs and uncertainty mechanisms for NGET in relation to load-related capital expenditure
- Chapter 5 provides more details on the efficient costs and uncertainty mechanisms for NGET in relation to non-load-related capital expenditure
- Chapter 6 provides more details on the efficient costs and uncertainty mechanisms for NGET in relation to opex and non-operational capex
- Chapter 7 sets out the efficient costs and uncertainty for NGGT
- Chapter 8 sets out the efficient costs and uncertainty for both System Operators.

1.13. The appendices contain our Final Proposals in relation to the Information Quality Initiative (IQI), supporting tables on load-related capex and additional information on business support costs.

1.14. 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.

1.15. Chapter 2 sets out the adjustment to our baselines arising from the IQI interpolation.[5] In subsequent Chapters, baseline numbers are stated before the IQI adjustment.

1.16. We do not intend to make any further amendments to our Final Proposals to correct any inaccuracies identified after publication, as we consider our approach to applying the IQI interpolation already adequately accounts for the possibility of residual error.

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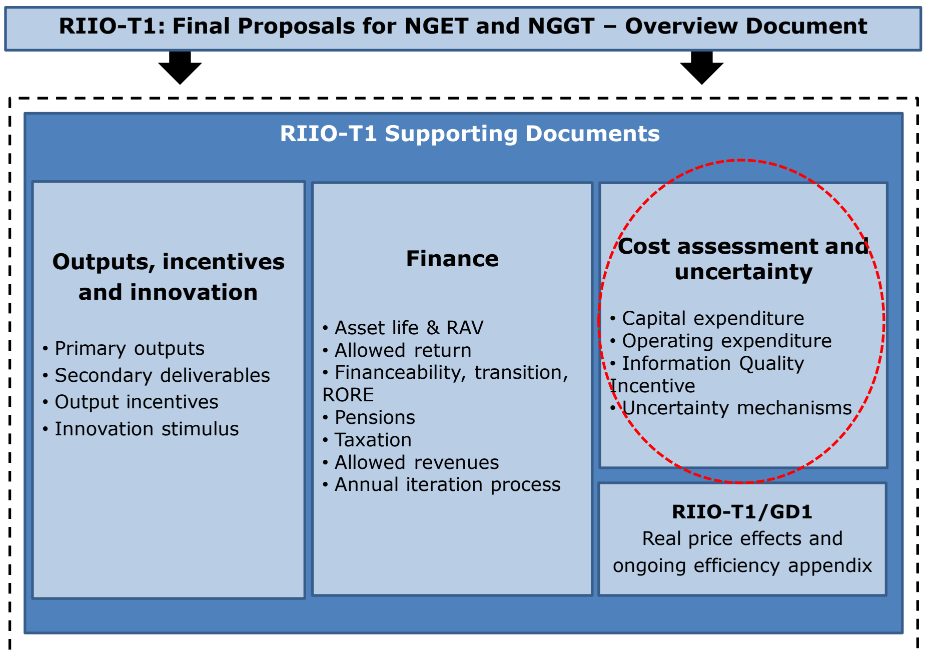
[5] This is explained further in Appendix 1.

1.17. Figure 1.1. provides a map of the RIIO-T1 Final Proposals documents.

Figure 1.1: RIIO-T1 Final Proposals document map



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

2. Final Proposals on cost and uncertainty for NGET and NGGT

Chapter Summary

This chapter summarises our Final Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for NGET and NGGT to deliver the associated outputs over the RIIO-T1 period.

Introduction

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

Overview

2.2. Three key terms used in this document are baseline, best view and uncertainty mechanism. These are described below.

- Baseline is the amount of allowed expenditure we set at the start of the price control for each year of RIIO-T1. Baseline typically includes expenditure for outputs where there is a reasonable degree of certainty over their need and cost.
- Best view is an estimate of total expenditure based on a central scenario of the generation and demand changes as well as connection activity. Best view is made up of baseline funding and additional funding adjustments through the operation of uncertainty mechanisms.
- Uncertainty mechanism funding is either adjusted automatically where outputs 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 us of needs case and costs.

Final Proposals for efficient expenditure for NGET and NGGT

2.3. Tables 2.1 and 2.2 set out our Final Proposals for NGET and NGGT for their TO function. Final Proposals for the internal SO elements of NGET and NGGT are set out in Chapter 8. The first part of each table outlines 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. The second part sets out our proposals for the best view forecast.

Table 2.1: Final Proposals for NGET baseline and best view expenditure

Baseline

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	916.1	1,035.6	952.8	865.9	513.9	367.9	150.5	56.7	**4,859.3**
NLRE	469.5	456.3	444.3	443.7	562.9	646.4	696.3	617.8	**4,337.2**
Non-operational capex	27.9	27.5	20.0	18.2	16.8	9.9	12.4	7.3	**139.9**
Customer contributions	-45.1	-33.4	-29.6	-37.3	-31.2	-26.3	-11.9	-1.4	**-216.3**
Opex	187.2	189.0	193.2	192.0	191.3	188.8	187.8	185.3	**1,514.6**
RPEs	-8.9	10.5	28.7	45.0	52.9	64.8	67.9	66.3	**327.2**
Sub-total	**1,546.8**	**1,685.4**	**1,609.4**	**1,527.5**	**1,306.5**	**1,251.5**	**1,103.0**	**932.0**	**10,962.0**
Non Controllable Opex and Excluded Services	101.6	93.9	93.3	91.0	91.0	90.8	90.8	90.7	**743.2**
Total Expenditure before IQI	**1,648.4**	**1,779.3**	**1,702.6**	**1,618.5**	**1,397.6**	**1,342.3**	**1,193.7**	**1,022.7**	**11,705.2**
IQI	35.9	39.9	40.9	42.7	41.1	43.4	42.9	42.3	**329.2**
Total Expenditure	**1,684.3**	**1,819.2**	**1,743.6**	**1,661.3**	**1,438.7**	**1,385.7**	**1,236.7**	**1,064.9**	**12,034.4**

Best view

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	1,021.0	1,273.3	1,276.5	1,238.1	889.7	805.6	449.3	278.1	**7,231.5**
NLRE	469.5	456.3	444.3	443.7	562.9	646.4	696.3	617.8	**4,337.2**
Non-operational capex	27.9	27.5	20.0	18.2	16.8	9.9	12.4	7.3	**139.9**
Customer contributions	-45.1	-33.4	-29.6	-37.3	-31.2	-26.3	-11.9	-1.4	**-216.3**
Opex	192.5	195.3	199.7	198.7	197.6	195.2	194.1	191.6	**1,564.7**
RPEs	-9.4	12.4	35.3	57.3	70.0	90.3	89.3	85.2	**430.6**
Sub-total	**1,656.5**	**1,931.4**	**1,946.2**	**1,918.6**	**1,705.7**	**1,721.1**	**1,429.5**	**1,178.6**	**13,487.7**
Non Controllable Opex and Excluded Services	101.6	93.9	93.3	91.0	91.0	90.8	90.8	90.7	**743.2**
Total Expenditure before IQI	**1,758.1**	**2,025.3**	**2,039.5**	**2,009.7**	**1,796.8**	**1,811.9**	**1,520.3**	**1,269.3**	**14,230.8**
IQI	35.9	39.9	40.9	42.7	41.1	43.4	42.9	42.3	**329.2**
Total Expenditure	**1,794.1**	**2,065.2**	**2,080.4**	**2,052.4**	**1,837.9**	**1,855.3**	**1,563.2**	**1,311.5**	**14,560.1**

Table 2.2: Final Proposals for NGGT baseline and best view expenditure

Baseline

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	39.1	40.3	79.0	163.2	145.1	28.3	1.0	-	**496.0**
NLRE	90.8	103.0	99.4	110.7	120.0	100.3	84.6	73.6	**782.4**
Non-operational capex	10.2	9.5	6.5	6.0	5.4	4.0	6.0	4.1	**51.7**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	62.7	62.8	67.0	74.6	78.5	78.1	73.9	69.9	**567.6**
RPEs	-4.3	-2.8	-1.2	1.3	4.6	5.3	5.8	6.6	**15.5**
Sub-total	**198.6**	**212.8**	**250.7**	**355.8**	**353.7**	**216.1**	**171.3**	**154.3**	**1,913.2**
Non Controllable Opex and Excluded Services	109.8	110.0	110.0	110.0	110.0	110.0	110.0	110.0	**879.6**
Total Expenditure before IQI	**308.4**	**322.8**	**360.6**	**465.8**	**463.7**	**326.0**	**281.2**	**264.3**	**2,792.8**
IQI	3.0	3.1	14.0	16.8	23.4	15.7	12.7	14.7	**103.3**
Total Expenditure	**311.4**	**325.8**	**374.6**	**482.6**	**487.1**	**341.7**	**293.9**	**279.0**	**2,896.1**

Best view

£m - year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	RIIO-T1
LRE	45.8	50.5	155.6	322.4	449.7	370.1	455.6	506.4	**2,356.1**
NLRE	90.8	103.0	101.7	114.0	138.1	116.0	100.2	87.8	**851.6**
Non-operational capex	10.2	9.5	6.5	6.0	5.4	4.0	6.0	4.1	**51.7**
Customer contributions	-	-	-	-	-	-	-	-	**-**
Opex	71.0	70.7	74.8	82.6	86.2	85.7	81.4	77.4	**629.7**
RPEs	-4.5	-3.0	-1.8	1.6	7.9	12.2	19.3	26.4	**58.2**
Sub-total	**213.3**	**230.7**	**336.9**	**526.5**	**687.3**	**588.0**	**662.4**	**702.1**	**3,947.2**
Non Controllable Opex and Excluded Services	109.8	110.0	110.0	110.0	110.0	110.0	110.0	110.0	**879.6**
Total Expenditure before IQI	**323.2**	**340.6**	**446.8**	**636.5**	**797.3**	**698.0**	**772.4**	**812.1**	**4,826.8**
IQI	3.0	3.1	14.0	16.8	23.4	15.7	12.7	14.7	**103.3**
Total Expenditure	**326.1**	**343.7**	**460.8**	**653.3**	**820.7**	**713.7**	**785.1**	**826.8**	**4,930.2**

Uncertainty mechanisms

2.4. The range of uncertainty mechanisms in Final Proposals to allow NGET and NGGT to manage the potential uncertainty it has identified during the eight year price control period is described in the Chapter 3.

3. Uncertainty mechanisms

Chapter Summary

This chapter sets out our Final Proposals in relation to uncertainty mechanisms for NGET and NGGT. We also summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Summary of Initial Proposals

3.1. In Initial Proposals we identified a number of costs which we considered could be more efficiently accommodated through an uncertainty mechanism as opposed to an ex ante allowance. The mechanisms proposed reflected our policy set out in the March Strategy Document and also reflected additional areas of uncertainty identified by NGET and NGGT in their business plans.

3.2. We also set out our assumptions for real price effects (RPEs) and ongoing efficiency and the associated ex ante allowances.

3.3. For our RPE assumptions, we used outturn data for 2011-12, and an independent forecast of real wage growth for 2012-13 and 2013-14, the years when the chosen independent forecast was available. For all other inputs, and for our labour RPE beyond the forecast period, we based our RPE assumptions on the historical long-term real average for the relevant input price indices. Overall, we calculated an RPE assumption of 0.8 per cent and 0.7 per cent per year for totex for NGET and NGGT respectively.

3.4. In Initial Proposals, we proposed an ongoing productivity improvement of 1 per cent per year for opex, and 0.7 per cent per year for capex, resulting in an assumption of 0.7 per cent per year for totex in NGET and NGGT. Our assumptions were based on historical growth rates in total and partial factor productivity over a 30-year period, drawn from evidence for comparator sectors from the EU KLEMS dataset.[6]

Summary of respondents' views

3.5. National Grid (NG)[7] raised a number of points in relation to our proposed uncertainty mechanisms. We set out below responses to mechanisms common to both NGET and NGGT. For responses to uncertainty mechanisms related to capex allowances see the relevant chapters.

[6] EU KLEMS data: http://www.euklems.net/index.html
[7] Where we refer to NG we are referring to National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT).

3.6. Suppliers and their representative bodies noted their concerns about the volatility in allowed revenues, and therefore network charges, which may arise from the use of uncertainty mechanisms. Additionally an industry body noted concerns that the increase in funding available through uncertainty mechanisms for NGGT may lead to increases in commodity charges.

Reopener mechanism

3.7. NG did not agree with our proposed materiality thresholds, of 1 or 2 per cent of average annual forecast revenue,[8] that will need to be reached to trigger the reopener mechanism. It considered the threshold too high and not justified. It also stated that we did not clearly explain in Initial Proposals whether the threshold would apply on an annual basis and whether it would include incurred and forecast costs. It noted that our financial modelling must take account of the restrictions the proposed mechanism imposes on changes in revenues.

3.8. NG was also concerned that restricting requests to reopen to specific periods or 'windows', proposed in 2015 and 2019, may delay investment. NGGT specifically referenced costs that may arise from complying with the Industrial Emissions Directive (IED).[9] It considered it was appropriate to provide an ex ante allowance for design phase work and therefore only construction work will be subject to the reopener mechanism. Conversely, an industry body supported the inclusion of IED compliance costs as an uncertainty mechanism, rather than an ex ante allowance, given that the Directive has not yet been transposed into UK law.

3.9. A number of responses noted concerns that the proposed reopener mechanism removes the current provision (through the income adjusting event mechanism) for network users to propose changes to allowances. Additionally, NGET and NGGT considered that a more general reopener was still appropriate (if not more appropriate given the extension of the Price Control Period) as costs may arise that could not have been predicted now.

3.10. An industry body, representing gas shippers and suppliers, welcomed the removal of the current income adjusting event provision and the inclusion of criteria in order to trigger a reopener. It specifically noted that it considered providing potentially excessive allowances for market facilitation should be avoided.

The mid-period review

3.11. NG sought clarification of our intended approach and scope of the mid-period review. For a number of potential uncertain costs, namely market facilitation and flood and erosion protection, it considered that it would be more appropriate to utilise a reopener mechanism rather than the mid-period review, because of the difficulty in quantifying outputs in these areas. It also sought clarification on whether

[8] By this we mean the best view allowances, after the application of the efficiency incentive rate.
[9] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:en:PDF

contributions to the Environment Agency and tower flood protection costs will be included.

3.12. NG requested that the mid-period review also provide an opportunity to request additional allowances for the SO, related to requirements that may arise from either the transition to a low carbon economy or European interactions.

Xoserve (Central Agent) review

3.13. NGGT considered there was a lack of information provided in Initial Proposals in relation to the review of Xoserve funding. It questioned whether the review would consider retrospective or prospective changes.

RPEs and ongoing efficiency

3.14. The majority of responses to our proposed RPE assumptions were in relation to our real wage assumptions. In particular, respondents considered that we should use labour indices specific to the energy sector, and that our use of comparator sectors understated wage growth in an industry experiencing skills shortages. They also considered that we should use, as the basis for our short-term forecast, a private sector wage growth forecast, as opposed to the HM Treasury consensus forecast for the whole economy.

3.15. NG noted in particular that our proposal would result in increases in attrition rates and make it more difficult to recruit, particularly given the different assumptions proposed for it versus the fast-tracked TOs. NG also commented on the choice of indices used to construct the RPE assumptions for capex materials and equipment and plant.

3.16. NG raised a number of concerns with our conclusions on ongoing efficiency. In particular, it argued that we had failed to consider the declining economy and, in relation to NGGT, the decline in the gas industry, the impact of investment efficiency on opex and regulatory precedent in drawing conclusions. It considered that all these factors suggested lower productivity improvements. By contrast, one supplier considered that our assumptions understated the prospects for improvement in productivity.

ONS review of the RPI

3.17. A number of responses to Initial Proposals noted the announcement that the Office for National Statistics (ONS) was considering conducting a review of the methodology used to calculate the retail prices index (RPI). Respondents noted that this could impact on a number of areas of the price control settlement and therefore an uncertainty mechanism should be considered. We had not discussed this in Initial Proposals as the ONS announcement was made following publication.

Final Proposals

3.18. We summarise in table 3.1 the Final Proposals on the uncertainty mechanisms that will operate in RIIO-T1 for NGET and NGGT. In coming to our decision, we have considered the materiality and volatility of the uncertain costs, and which parties (companies or consumers) are best placed to manage the uncertain cost risk. Where applicable we have included reference to where further details of the mechanism can be found elsewhere in our Final Proposals.

3.19. In finalising the design of the uncertainty mechanisms outlined below, we have implemented our recent decision on mitigating network charging volatility arising from the price control settlement.[10] We set out below the changes we have made to specific mechanisms to accommodate our charging volatility decision.

[10] See option 4 set out in 'Decision on measures to mitigate network charging volatility arising from the price control settlement' (Oct 2012): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=404&refer=Networks/Policy

Table 3.1: Summary of uncertainty mechanisms for NGET and NGGT

Mechanism	Applicable to	Area covered	Chapter ref.
Efficiency incentive rate	All	-	3, Appendix 1
Indexation	All	Inflation, cost of debt[1]	3
Pass through	NGET TO and NGGT TO	**NGGT TO/NGET TO**: Licence fees, business rates[1] **NGET TO**: Inter-TSO scheme, temporary physical disconnection, termination of bilateral agreements **NGGT TO**: policing costs related to security at sites, conveyance of gas to independent systems	3
Reopener (restricted to two windows)	All	**All**: Enhanced security, innovation roll-out[2] **NGGT TO**: industrial emissions, legacy pipeline diversions, quarry and loss development claims, one-off asset health shocks	3,7
Reopener (annual)	NGGT TO	Network flexibility (1 in 20 obligation)	7
Potential reopener	NGET	Delivery role for Electricity Market Reform (EMR), east coast integrated network pre-construction costs	3,4
Review	All	**All**: ONS review of the RPI **NGGT SO**: Xoserve funding	3,8
Mid-period review	All	Changes in outputs, or introduction of new outputs	3
Volume driver	NGET TO	Wider works, local generation connections, new demand connections, planning requirements of new infrastructure	4
Within period determinations	NGET TO	Strategic wider works	4
Revenue driver	NGGT TO	Incremental entry and exit capacity	7
Trigger	All	Tax legislation[1]	-
Reset	All	Pension deficit repair[1]	-
Disapplication	All	Enables price control parameters to be reset if TO experiences financial distress	-

Note (1) See 'Finance Supporting Document' for further details on these mechanisms. (2) See 'Outputs, Incentives and Innovation Supporting Document' for further details.

Efficiency incentive rate (as set by the Information Quality Incentive (IQI))

3.20. Details of the efficiency incentive rate are set out in Appendix 1 of this document.

Indexation for inflation

3.21. Protection against economy wide inflation is provided through annual indexation of revenues using the RPI. Our approach to indexation for inflation was explained in our decision of July 2011.[11] In summary, allowed revenues will be indexed by forecast RPI for 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.

3.22. We provide an ex ante allowance for real price effects (RPEs), which represent the expected change in input prices (eg wages) relative to economy wide inflation. We discuss RPEs in more detail below.

The ONS review of the RPI

3.23. We published a consultation on 30 October (ie following our IP publication) on how we should address any changes to RPI arising from ONS review of its RPI methodology.[12]

3.24. Following our review of responses, we have considered whether we should set out a commitment within Final Proposals to consult on this issue in the event that the ONS makes a change to the way it calculates RPI or set out this commitment in a licence condition. We note that network companies' responses to our consultation indicated mixed views on the preferred approach.

3.25. We have decided to set out a commitment within Final Proposals rather than introduce a licence condition. The reasons for our approach are that the effect of any change on network companies is difficult to assess at this stage, and as a consequence it is difficult for us to write a complete licence condition which captures the range of potential changes that we might need to make to the Price Control Financial Model to implement changes to the price control settlement. By setting out a commitment in Final Proposals, we also ensure that we can deal with all network companies at the same time, rather than waiting for the individual licensees to make applications to reopen.

3.26. Our review of potential changes to the price settlement following the ONS decision on the RPI methodology will be subject to the following process:

- Following the announcement of any change to the RPI index by ONS, we intend to publish a consultation in relation to the impact of the ONS decision on the price settlement (taking into account our statutory duties, including our principal objective to protect consumers' interest and our duties to have regard to the need for licensees to finance their regulated activities and to promote efficiency and economy on their part). We expect to publish our consultation within 6 months of any decision by the ONS to change the RPI methodology. That is, assuming the ONS publishes its decision by January 2013, we would expect to

[11] Decision on the RPI indexation methodology (Jul 2012): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes
[12] RIIO-T1 and GD1: ONS review of Retail Prices Index methodology (Oct 2012): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=329&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

publish a consultation document by August 2013. If we do not publish a consultation within 6 months of a decision by the ONS, we will write to the companies setting out our revised timetable for consultation.

- Consistent with the definition of RPI in the Special Conditions of each licence, following any change to the methodology for calculating the RPI, we will use the ONS' (revised) RPI to set allowed revenues. For the avoidance of doubt, we will use the (revised) RPI even in the event that the ONS continues to publish an RPI measure based on its existing methodology. However, we will consider within our consultation the option of retaining the use of an RPI based on the existing methodology (for the period for which it is available).
- We expect the consultation will consider, inter alia, the implications of the ONS change on the allowances for real price effects (RPEs) set at the price control review compared to any effect on companies' expected costs in relation to RPEs, the implications for our cost of debt and equity allowances and companies' debt and equity costs, as well as indexation of the Regulated Asset Value (RAV).
- Our review could result in an increase or decrease in companies' allowed revenues. That is, if, following consultation, we determine the outcome of the ONS change to its RPI methodology results in the over recovery (or the expectation of over recovery) of costs then we may consider reducing allowed revenues relative to those included in the price control settlement.
- We will only make changes to the price control settlement if we determine, following consultation, the impact on companies' net revenues over the price control period is greater than one per cent of average annual allowed revenue. Our calculation of the net revenue impact of the change in RPI will include the effect on the value of the RAV at the end of the Price Control Period, ie we will consider the difference between the value of the RAV under the revised RPI methodology compared to the value of the RAV if the existing RPI were retained.
- The purpose of the materiality test is to avoid making trivial changes to allowed revenues, and thus minimise regulatory costs. The proposed materiality test is consistent with the materiality test associated with other uncertainty mechanisms.
- The review will only consider changes to companies' net revenues arising from the ONS decision in relation to its review of RPI. We will not take into account other factors, notably, we will not have regard to companies' financial performance against the price control within the context of this review.

Pass through costs

3.27. Those costs treated as pass through costs are outlined in Table 3.1. In relation to the pass through of costs for conveyance of gas to independent systems we have made some changes.

3.28. The current NGGT licence (Special Condition C26 (Conveyance of Gas to Independent Systems)) allows NGGT to recover the costs associated with the supply of gas to Independent Undertakings[13] from all shippers. Independent Undertakings

[13] Independent Undertakings (IUs) comprise eight communities and around 10,000 customers connected to independent gas networks, ie not directly connected to the national gas network. The IUs are supplied by either Liquefied Natural Gas (LNG) or Liquefied Petroleum Gas (LPG). SGN operates/owns the largest IUs, comprising around 7,700 households in remote areas of Scotland: Campbletown; Stornoway; Wick; Thurso (all supplied with LNG), and Stornoway (LPG). WWU has independent networks in Llanfyllin; and,

are subsidised by GB gas customers in accordance with a direction from the Secretary of State dated 19 March 2008[14]. This direction ensures customers in the Independent Undertakings are charged no more than the average GB transportation charge and the commodity price charge for gas is equal to a GB reference commodity price.

3.29. NGGT recovers the transportation costs for Independent Undertakings through its charges, and pays these amounts to Southern Gas Networks (SGN) and Wales and West Utilities (WWU) for their respective independent systems. The total payments in 2012-13 were £17.2 million.[15] In relation to the commodity charge, NTS recovers the difference between the actual liquefied petroleum gas (LPG) or liquefied natural gas (LNG) cost and a GB reference commodity price, and pays these amounts to shippers. In 2012-13, the total amount paid to shippers was around £2 million.

3.30. As set out in the RIIO-GD1 Finance and Uncertainty Supporting Document, DECC has confirmed to us that it intends to continue with the current subsidy arrangements, and it expects to issue a direction by the start of the Price Control Period, ie 1 April 2013. In order to ensure that the arrangements can be in place for the start of the Price Control Period, we will publish the requisite licence condition as part of our statutory consultation on licence conditions, with the licence condition activated once the DECC direction is in place.[16]

3.31. For pass through costs, we are introducing a two year delay between the time that the adjustment value is known and the actual adjustment to revenues as a result of our decision in relation to mitigating network charging volatility. The proposed time delay or lag is designed to improve the predictability of charge changes. We will set out in the licence the forecast costs of the pass through items for the eight year Price Control Period. The lag on the pass through cost allows the network companies to recover the actual cost incurred relative to the forecast cost two years later, and thus provides up to two years notice of expected charge changes in relation to such provisions.

Reopener mechanism

Areas of cost covered

3.32. Through the reopener mechanism we are providing NGET and NGGT the opportunity to recover additional costs, if they arise, in a number of areas as set out in Table 3.1 above. These additional costs will be recovered through allowed revenues which set the level of network charges to consumers.

Llanwrtyd Wells. Source: GDN responses to DECC questionnaire on IU subsidy; 2007.
[14] This direction expires on 31 March 2013.
[15] As set out in Special Condition C26. Source: http://www.ofgem.gov.uk/Networks/Trans/GasTransPolicy/LNGPriceControl/Documents1/120206_GM_noticetomodify.pdf
[16] Recovery of transportation charges through NTS charges, and the payment to the relevant GDN, requires an amendment to statute. Thus, the relevant conditions in the licence will be subject to both a direction and statutory change.

3.33. The reopener mechanism is symmetric meaning that we can also propose changes to allowed revenues, ie we can reduce ex ante allowed revenues where there is evidence that TOs are no longer required to deliver outputs which funding was provided for. We note those responses that raised concerns that our proposal removed the current provision for third parties to request changes in NG's allowed revenues. We consider this point is addressed by the provision for us to trigger the mechanism, having been informed by third parties. We are also committed to consulting on any changes to revenues which will provide an opportunity for all interested parties to feed into the process.

3.34. When NGET or NGGT make a request for additional revenue it will need to provide evidence of the efficiency of the costs incurred, or expected to be incurred. The submissions will then be subjected to an efficiency assessment and we will undertake a consultation to allow all interested parties to comment. This follows the process set out in our March Strategy Document.

3.35. In relation to enhanced security costs, the TO will be required to provide evidence that project costs are efficient. Part of this evidence will be a requirement to provide details of the auditing process that projects have gone through. We outlined this approach in our March Strategy Document. There are likely to be two stages to the audit process, ie an audit prior to work commencing and an audit after work is completed. The audits will include information on whether the work meets the operational requirements for physical security and recommendations on whether the costs of the work represent value for money.

3.36. If the reopener mechanism is triggered we will consider making provision for expenditure yet to be incurred, as well as reimbursing the network company for efficient costs already incurred. Our ex post assessment to determine the efficiency of the costs incurred will take account of the recommendations in the audits submitted by the network companies and, where appropriate, we will benchmark costs across the network companies. In providing an ex ante allowance we will consider the certainty of the work commencing, which will require the network company to provide the initial audits that have been undertaken, and the efficiency of the expected costs.

Restriction of adjustments

3.37. In the case of all cost areas subject to the reopener mechanism, except network flexibility (1 in 20 obligation) in NGGT, a reopener can only be triggered during two defined windows.[17] To trigger the reopener NGET or NGGT will be required to submit to us, during the specified reopener windows, a notice stating the additional costs that have or are expected to be incurred.

3.38. It will also need to demonstrate that the costs incurred, and expected to be incurred over the remaining years of the price control, pass a materiality threshold. The materiality threshold is set at 1 per cent of average annual forecast revenue

[17] There will be two opportunities, in May 2015 and May 2018, to request changes to allowed revenues. This may result in allowed revenue changes from April 2016 and/or April 2019.

after the application of the efficiency incentive rate for the majority of costs subject to the reopener. The exceptions are one-off asset health shocks and network flexibility for NGGT where we are applying a higher materiality threshold of 2 per cent of average annual forecast revenue after the application of the efficiency incentive rate.

3.39. We are restricting the timing of reopeners and applying a materiality threshold to limit the impact on volatility in allowed revenues. NG was concerned that these restrictions put too much risk on it or may delay investment. We consider that providing two opportunities adequately balances the cash-flow risk of the network companies with the impact to consumers of changes in the charges which they pay as part of their energy bill. We do not agree that such restrictions will delay investment. NG will still be required to deliver its agreed outputs. An adjustment through the reopener mechanism will take account of both efficient costs already incurred and those that may be incurred in the future.

3.40. In relation to NGGT's reopener for network flexibility investment relating to its 1 in 20 peak day obligations, NGGT will be able to trigger a reopener at any time, provided the materiality threshold has been reached. The trigger event in this area is defined as investment required to meet future peak day requirements. Given the uncertainty in future requirements, the potential materiality and the importance of the obligation to security of supply, we consider it appropriate to provide more flexible arrangements. However, we do not expect that NGGT will need to trigger this mechanism in the early years of the price control as we would expect NGGT's business plan, and the allowances provided, to reflect requirements in the shorter-term.

3.41. If costs have not reached, or are not forecast to reach, the materiality threshold by the second reopener window we will assess additional costs as part of the next price control review.

Xoserve (Central Agent) review

3.42. We have not made changes to our approach to the Xoserve review which we set out in Initial Proposals, however NGGT sought clarity on the intended approach which we provide below.

3.43. Following our decision on changing the way Xoserve is funded[18] an implementation project has begun. It is likely to conclude in late 2013 and therefore any necessary changes to NGGT's revenues will be from April 2015 at the earliest. We have provided an ex ante allowance to NGGT based on the current funding arrangements. When a final decision on new funding arrangements is reached we will then conduct a review of allowances and propose any necessary adjustments. The adjustment will take account of any differences in the costs incurred by NGGT and

[18] Open letter review of Xoserve (Jan 2012): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=345&refer=Networks/GasDistr/RIIO-GD1/ConRes

the ex ante allowances provided, as well as resetting allowances going forward to ensure they reflect new funding arrangements.

The mid-period review

Structure of the mid-period review

3.44. We set out the broad structure and timetable for the mid-period review in our March Strategy Document. We are not making any changes to this proposed structure therefore, in summary:

- The review will be to address material changes in existing outputs justified by changes in government policy, or the introduction of new outputs to meet the changing needs of network users.[19]
- The review will start with the publication of a consultation setting out potential issues that may be relevant for triggering the review.
- Based on responses we will decide whether there are grounds for reviewing output requirements. If we decide to proceed then the review goes into assessment phase.
- We will consult on any changes to outputs or introduction of new outputs, as well as consulting on any consequential changes to cost allowances.
- Any changes in outputs, and associated changes in allowances, will take effect from April 2017.

Scope of the mid-period review

3.45. For the mid-period review to progress NG will be required to provide evidence that requested changes in allowances are supported by the introduction of new outputs, or changes to existing outputs. We expect evidence to be informed by stakeholders views.

3.46. NG proposed an uncertainty mechanism for a number of areas in its business plans where we have decided that the mid-period review provides adequate protection against the risk of changing costs in these areas. The mid-period review will therefore consider new or changed outputs in the following areas:

- GB and EU market facilitation: for changes imposed on NG through government or EU legislation, or network codes.
- Flood and erosion protection: for changes in government legislation that require NG to pay additional contributions to schemes.
- Network flexibility: for changes in commercial capacity obligations (other than changes to peak day (1 in 20) requirements covered through the reopener mechanism).

[19] We have not defined materiality as a quantitative threshold for such changes. Our view of materiality will be guided by responses to the consultation.

3.47. This is not an exhaustive list. The mid-period review will also provide an opportunity for other stakeholders, not just the network companies, to propose changes.

3.48. If NGET or NGGT can demonstrate that they have efficiently incurred costs in relation to any agreed changes to outputs prior to April 2017, we would also consult as part of the mid-period review on whether we should allow it to recover such costs on an NPV neutral basis.

Delivery of Electricity Market Reform (EMR) measures for NGET

3.49. NGET may incur costs during RIIO-T1 if it assumes responsibility for the delivery of EMR measures. We note that a proportion of these costs are likely to be on NGET as the internal electricity SO.

3.50. In the event that NGET assumes this role then we consider it is appropriate for it to recover the efficient costs it will incur through price control revenue allowances. Costs may be incurred in delivering new services or functions as a result of decisions taken by the Government in relation to EMR. To enable this we would amend NGET's licence and the Price Control Financial Model (PCFM) to allow us to adjust NGET's cost allowances where necessary.

3.51. The adjustment would be triggered by NGET providing notice to Ofgem that, as result of decisions by the Government under its EMR policy, it is necessary for the company to undertake new or enhanced activities to those taken into account for the final settlement of the RIIO-T1 price control. In the notice to Ofgem, NGET will need include supporting evidence including:

- a description of the new undertakings NGET is responsible for under EMR
- potential measures of the outputs from these new undertakings
- a description of how NGET intends to carry out the new functions or activities
- the costs that NGET expects to incur as a result
- an explanation of why the relevant costs cannot otherwise be recovered under the revenue allowances provided under the RIIO-T1 price control settlement.

3.52. We expect NGET to bring forward this information at the earliest possible opportunity.

East Coast integrated network pre-construction costs for NGET

3.53. As stated in our July open letter,[20] NGET submitted a request to us for funding through RIIO-T1 to undertake preliminary works related to potential integrated network investment off the east coast of England.

[20] Offshore Transmission: update on coordination policy developments (Jul 2012) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=49&refer=Networks/offtrans/pdc/cdr/2012

3.54. We are still developing our overall policy in this area and recently published a further consultation on our proposals to support the delivery of coordinated networks.[21] One of the proposals we are consulting on is for onshore TOs to undertake preliminary works for network developments between offshore and onshore where these have wider network benefits.

3.55. As we are consulting on the framework we are not in a position to confirm funding in Final Proposals for the East Coast proposal. We are therefore providing a mechanism by which additional funding, up to NGET's forecast of £25.3m, can potentially be triggered. Any adjustment will be subject to the outcome of the consultation and NGET's justification for these costs and proposed outputs. A decision to provide NGET with additional funding will require a licence modification and Price Control Financial Model change which will be triggered once the outcome of the consultation has been considered and a decision has been taken. For the avoidance of doubt, this process is only applicable for additional funding for the proposed East Coast project. Any further funding of preliminary works related to integrated network investment will be subject to review as part of the mid-period review.

Disapplication

3.56. We are not introducing any change to the current policy for disapplication which was set out in our guidance document published in 2009.[22] We consider that the current policy provides adequate and clear guidance for an efficient and economic network company that finds itself in financial distress.

RPEs and ongoing efficiency

3.57. The RPE assumption, and associated ex ante allowance, reflects the expectation that there will be a difference between the change in the RPI measure of inflation and the change in the price of inputs that the TOs will purchase over the price control, most notably labour. The ongoing efficiency assumption reflects the expectation that even the most efficient network company can make productivity improvements, for example by employing new technologies. This assumption represents the potential reduction in input volumes that can be achieved whilst delivering the same outputs.

3.58. We summarise our decision on assumptions for RPEs and ongoing efficiency below. For further details of our decision and the reasons for the decision see the supplementary appendix 'RIIO-T1/GD1 Real price effects and ongoing efficiency appendix'.

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[21] Consultation on proposed framework to enable coordination of offshore transmission (Dec 2012): http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Consultation_on_a_proposed_framework_to_enable_coordination_of_offshore_transmission.pdf&refer=Networks/offtrans/pdc/cdr/2012

[22] Arrangements for responding in the event that an energy network company experiences deteriorating financial health (Oct 2009): http://www.ofgem.gov.uk/Networks/Policy/Documents1/GUIDANCE%20DOCUMENT%20-%20FINAL%20OCT%2009.pdf

RPEs

3.59. We consider that the approach taken to estimate RPEs remains valid and we have decided not to make any methodological changes relative to our Initial Proposals. As we explain below we have updated our analysis to reflect the latest available data.

3.60. We have updated our real wage assumption for 2011-12 to take account of comparator sectors, therefore ensuring a consistent approach to setting allowances beyond the forecast period, based on historical real wage growth in a range of comparator sectors. This results in minimal change since Initial Proposals.

3.61. We have updated our short-term real wage forecast for the latest available forecasts published by the HM Treasury.[23] We have also incorporated outturn data for 2012-13 for materials and equipment input prices. Our approach is consistent with the principle that we use outturn or independent forecast data where available, and beyond use historical real averages.

3.62. The overall effect is marginally lower allowances for NGET, but a more marked reduction in allowances for NGGT reflecting the inclusion of the fall in steel prices in 2012-13. Our RPE assumptions are summarised in Table 3.2.[24]

Table 3.2: Average annual RPE assumptions (2011-12 to 2020-21)

	Opex	Capex	Totex
NGET TO	0.5%	0.8%	0.8%
NGGT TO	0.6%	0.4%	0.4%
NGET SO	0.4%	0.0%	0.3%
NGGT SO	0.4%	0.0%	0.2%

Ongoing efficiency

3.63. We do not consider that the responses to Initial Proposals raised any material issues to support a change to our overall conclusions. We examined NG's arguments in relation to the declining economy, capital substitution effects, and the potential for the double-count of catch-up, which it considered supported a lower productivity assumption. However, for the reasons we set out in the supplementary appendix, we do not consider that we need to change our assumptions.

3.64. Our ongoing efficiency assumptions for Final Proposals remain at 1 per cent per year for opex and 0.7 per cent per year for capex for NGET and NGGT.

[23] HM Treasury, Forecasts for the UK Economy (October 2012), Table 2 and 5: http://www.hm-treasury.gov.uk/d/201210forcomp.pdf
[24] Annual RPE assumptions can be found in the supplementary appendix.

4. Final Proposals for Load-Related Capex for NGET

Chapter Summary

This chapter sets out our Final Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for load-related expenditure for NGET to deliver the associated outputs over the RIIO-T1 period. We also summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Introduction

4.1. Load-related expenditure (LRE) is the investment required to connect new generators and customers to the transmission network, to upgrade the existing network and to cater for growth in demand.

4.2. LRE is driven by the capacity requirements and location of new customers (particularly new generation customers) and changes to existing customers' requirements (demand and generation). There is significant uncertainty about the load-related capex that will be required over the coming price control period and beyond. To help manage this uncertainty efficiently and without jeopardising delivery timescales we propose a combination of different mechanisms to fund NGET's LRE. This comprises baseline funding ex ante (upfront funding) for each year of RIIO-T1 and uncertainty mechanisms to adjust baseline allowances if LRE turns out to be more or less than the baseline.

4.3. LRE is split into three broad categories of work. Where relevant we set out changes since Initial Proposals by these categories. They can be described as follows:

- local enabling works - the minimum transmission works needed to connect a customer to the transmission network
- wider works - reinforcement or extension of the main interconnected transmission system to meet security and quality of supply standards
- transmission system support - activity carried out by a transmission network owner at the request of the System Operator in order to ease constraints on the network.

4.4. The layout of this chapter is as follows:

I. *Summary of Final Proposals*
We summarise allowances for Final Proposals to highlight the changes in proposed allowances. We also set out the Final Proposals baseline outputs that NGET will be responsible for delivering in RIIO-T1.

II. *Summary of Initial Proposals*
This section summarises what we said in Initial Proposals. We then outline views from parties who responded to our consultation on Initial Proposals.

III. *Issues affecting baseline allowances*
We set out our views on the key issues raised by stakeholders on baseline allowances in Initial Proposals and our decisions in relation to these for Final Proposals.

IV. *Issues affecting baseline outputs*
Wider Works boundary capabilities are discussed in this section.

V. *Issues affecting uncertainty mechanisms*
We consider the key issues raised by stakeholders on the uncertainty mechanisms in Initial Proposals and set out our decisions in relation to these for Final Proposals.

4.5. Figures presented in this chapter are in 2009-10 prices and exclude Real Price Effects (RPEs) but where it is relevant, reference to RPE adjustments are stated. The figures are also stated before any IQI adjustment. Background information set out in Initial Proposals is not repeated here and this chapter should be read in conjunction with the *Cost assessment and uncertainty supporting document* in Initial Proposals.

Summary of Final Proposals

4.6. Our Final Proposals take account of views from stakeholders and additional evidence provided by NGET since the publication of Initial Proposals. There is an 8.1 per cent increase in baseline funding arising from changes to the amount of disallowed funding and a movement of allowances from uncertainty mechanisms into baseline funding. Our Final Proposals also deal with additional funding requested by NGET and rectify an error in outputs.

4.7. The issues affecting baseline and uncertainty mechanisms are dealt with in dedicated sections, with each section containing a summary of Initial Proposals for that issue, respondents' views and our Final Proposals.

4.8. Table 4.1 sets out our Final Proposals for NGET's LRE in RIIO-T1 and summarises the changes to allowances we have made since Initial Proposals and the difference from NGET's forecast in March 2012.

Table 4.1: Final Proposals and changes from NGET's business plan and Initial Proposals (£m)

LRE category	NGET's business plan (March 2012)	Initial Proposals (July 2012)	Final Proposals (December 2012)	Change from Initial Proposals to Final Proposals
Local Enabling (Entry - Shared Use)	1,313.4	794.2	1,042.6	31.3%
Local Enabling (Exit - Sole Use)	485.8	492.0	511.9	4.1%
Local Enabling (Exit - Shared Use)	508.9	227.5	263.3	15.7%
Wider Works (Entry)	3,695.7	2,558.7	2,551.2	-0.3%
Wider Works (Exit)	0.0	0.0	0.0	0.0%
Wider Works (General)	230.0	413.8	483.0	16.7%
Transmission System Support (TSS)	7.3	7.3	7.3	0.0%
Baseline LRE	**6,241.2**	**4,493.5**	**4,859.3**	**8.1%**
Strategic Wider Works	1,257.7	1,679.8	1,617.0	-3.7%
Outputs funded by UMs	0.0	555.0	731.2	31.8%
East coast integrated network Preconstruction Request*	0.0	0.0	23.9	-
Best View LRE	**7,498.9**	**6,728.3**	**7,231.5**	**7.5%**
Real Price Effects (RPEs)	564.4	282.7	214.3	-24.2%

***Subject to the outcome of our consultation on a proposed framework to enable coordination of offshore transmission. Please refer to the Uncertainty mechanisms chapter for more information.*

4.9. Outputs that NGET is funded to deliver in Final Proposals and therefore accountable for over the price control period are summarised in Table 4.2.

Table 4.2: Final Proposals for baseline outputs

LRE categories	Outputs
Local Enabling (Entry –Shared Use)	33.21 GW of Generation connected and 0.52GW of Embedded Generation
	21.12 GW of Generation closures
	215.0 km of Overhead Line
Local Enabling (Exit - Sole Use)	1 x GSP enabled [redacted]
	275kV circuit breakers installed at 1 x site [redacted]
	2 x SGT installed [redacted]
Local Enabling (Exit - Shared Use)	Completion of 1x Tunnel [redacted]
Local Enabling (Exit - Sole Use ***and*** Shared Use)	72 SGTs installed
	27km of Overhead Line
Wider Works (Entry)	Increases in transfer capability across system boundaries (NGET have identified potential 29.4GW*), see section on issues affecting baseline outputs: wider works requirements.
	287 x 132kV towers removed
	5 x 132kV bays created
	1 x 132kV overhead line (km) erected
	10% underground cabling in new transmission routes
Wider Works (General)	9 sites protected against rising fault levels
	11 Shunt Reactors installed
Transmission System Support	1 x 4 Switch Mesh GIS Substation [redacted]

***** *Any boundary with a transfer capability at the end of RIIO-T1 which is lower than its capability at the start of RIIO-T1 as a result of forecast thermal, voltage or stability constraints are not reflected in this output figure.*

Summary of Initial Proposals

4.10. In our Initial Proposals we proposed a reduction of £1,747.7m to NGET's forecast baseline expenditure. This comprised £977.1m of expenditure we proposed to move out of baseline allowances into uncertainty mechanisms and £770.6m we proposed to disallow from the plan. The overall difference in best view between NGET's business plan and our Initial Proposals was £770.6m.

4.11. Expenditure we proposed to move from baseline to uncertainty mechanisms included:

- costs associated with overhead line (OHL) connections in RIIO-T1 (£246.1m)
- a number of small to medium sized wider works schemes (£308.9m)
- reinforcement work associated with Hinkley Point nuclear power station (£422.1m in RIIO-T1).

4.12. Expenditure we proposed to disallow from the plan were:

- efficiency savings identified across all LRE categories (£290.5m)
- expenditure associated with DNO mitigation measures (£18.1m)
- expenditure in RIIO-T1 for outputs forecast for delivery in RIIO-T2 (post March 2021) (£462.0m).

4.13. Prior to the publication of our Initial Proposals, NGET responded to our request to identify outputs for some non-boundary work by suggesting reallocation of some expenditure between LRE categories.[25] We accepted these proposals and reflected them in our Initial Proposals. The margin of difference in some LRE categories between NGET's plan and our Initial Proposals is attributable to this reallocation.

4.14. The differences in uncertainty mechanisms between NGET's March 2012 Business Plan and Initial Proposals are summarised in Table 4.3.

[25] Details can be found in Appendix 3 of the *Cost Assessment and Uncertainty supporting document* in Initial Proposals

Table 4.3: Uncertainty mechanisms in Initial Proposals

Uncertainty mechanism	Constituent parts	NGET March 2012 business plan	Ofgem July 2012 Initial Proposals
Local Generation Connection (Volume Driver)	Substation Costs	National substation volume driver (£23/kW)	Single national driver (£26.8/kW)
	Within-Zone Costs	Zonal 'within-zone' works driver (£2.7/kW to £36.8/kW)	
	Overhead Lines Costs	£1.2m/cct km	£1.1m/cct km
	Cable Costs	Matrix of costs from IET Electricity Transmission Costing Study 2012	(Same as NGET business plan)
Demand-Related Infrastructure (Volume Driver)	Substation Costs	£4.6m/SGT	£3.7m/SGT
	Overhead Line Costs	£1.2m/cct km	£1.1m/cct km
	Cable Costs	Matrix of costs from IET Electricity Transmission Costing Study 2012	(Same as NGET business plan)
Wider Works Requirements (Volume Driver)	Network Development Policy (NDP) and Boundary Specific Reinforcement Costs	Boundary specific; banded for below Gone Green (GG) and above GG; Range between £33/kW to £155/kW	Boundary specific; banded for below GG and above GG. Sub-bandings for above GG on certain boundaries where there is material variance in forecast scheme unit costs; Weighted mean of reinforcement schemes on all boundaries proposed for boundaries where no reinforcements have been identified by NGET
	Undergrounding Costs	Matrix of costs from IET Electricity Transmission Costing Study 2012	(Same as NGET business plan)
	DNO Mitigation Measures	Various volume drivers for undergrounding DNO OHL, tower dismantling, erecting OHL and switchbays based on DPCR5 Initial Proposals	Same types of volume drivers with changes to account for modifications by NGET, our assessment and recommendations made by our consultants.
Strategic Wider Works (Within Period Determination)	Outputs with a potential to cost >£500m or that do not meet NDP criteria	Eastern HVDC Wylfa-Pembroke HVDC	Eastern HVDC Wylfa-Pembroke HVDC Hinkley-Seabank Overhead Line Project

Issues affecting baseline allowances: unit cost efficiencies

Initial Proposals

4.15. The assessment of LRE asset unit costs carried out by our engineering consultants focussed on main primary plant - transformers, switchgear and cables. The distinction between primary and non-primary assets is explained in the next chapter. Details of their findings are published in a final assessment report published alongside Initial Proposals.[26]

4.16. Their assessment produced two cost reduction scenarios which are summarised below:

- Scenario 1 (Low Reduction): gives NGET credit for construction efficiency.
- Scenario 2 (High Reduction): assumes further efficiencies are available and that a utility delivering a work programme of this size should be able to derive economies of scale. Also assumes uncertainty mechanisms should hedge factors such as RPEs.

Table 4.4: Cost reduction scenarios

	Cost reduction scenario 1 (low reduction)	**Cost reduction scenario 2 (high reduction)**
Transformers	4.8%	11.1%
Switchgear	21.8%	27.3%
Cables	1.0% (weighted average of 15% reduction for unsanctioned schemes and no cut for sanctioned schemes)	1.0% (weighted average of 15% reduction for unsanctioned schemes and no cut for sanctioned schemes)

4.17. Our consultants used these cost reduction scenarios to carry out a top-down estimation of the scope of possible reductions in ex ante funding for LRE. The assessment report noted that NGET's own benchmarking was generally credible, but may not have taken recent price volatility into account.

4.18. In Initial Proposals we estimated reductions to NGET's LRE based on the following unit cost reductions to switchgear, transformers and cables :

- 11.1% transformers (Scenario 2 applied)
- 21.8% switchgear (Scenario 1 applied)
- 1.0% cables (same percentage in both scenarios).

Respondents' views

4.19. NGET expressed the view that our selection of Scenario 2 for transformers does not take into account forecast construction efficiencies built in at scheme level and effectively double-counts these efficiencies.

[26] Ofgem Initial Proposals published July 2012 (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20Stage%204%20NGET%20Final%20Assessment.pdf)

4.20. NGET also had reservations regarding the quality of our consultants' analysis which it categorised into errors and poor process. Both issues are explained further in Chapter 5 (*Final Proposals for non-load-related capex for NGET*).

Final Proposals

4.21. For Final Proposals we have decided to use consistent cost reduction scenarios and align LRE reductions with Final Proposals on non-load-related capex (NLRE). For both transformers and switchgear we have chosen the application of Scenario 2 as a common starting point. We then take into account specific factors for transformers and switchgear (such as in-built construction efficiencies) and adjust the percentage reduction accordingly to arrive at Final Proposals. We consider this to be a more accurate approach to recognising efficiencies and other factors NGET had already taken into account, rather than simply adopting Scenario 1.

4.22. Our consultants' unit cost assessment on LRE is based on unit cost benchmarking of NLRE capex. Final Proposals for LRE therefore uses NLRE as a proxy for unit cost reductions which is broadly in line with the approach taken in Initial Proposals. We have applied similar percentage reductions as for NLRE because we consider this to be appropriate since the assets involved are identical.

4.23. The decision to use NLRE as a proxy is due to the nature of LRE schemes. LRE schemes with new transformers are typically accompanied by new switchgear so most LRE schemes with transformers are mixed with switchgear costs. This is unlike NLRE where there is a clear separation between transformer replacement and switchgear replacement schemes by cost and volumes. The derivation of separate LRE unit cost reductions and weighted construction efficiencies using LRE schemes would require approximations and data manipulation, which in our judgement will offer no greater precision to an NLRE proxy. Therefore using NLRE as a proxy avoids the added complexity and risk of errors of trying to arrive at LRE unit cost reductions from LRE schemes.

Transformers:

4.24. Following Initial Proposals, NGET provided evidence to demonstrate the efficiency of its unit costs and why it felt these unit costs reflected market prices (more is said about this in the NLRE chapter).

4.25. In Initial Proposals for LRE we adopted a pure Scenario 2 reduction (11.1 per cent) for transformers but in Final Proposals we propose to recognise NGET's in-built construction efficiencies in proportion to the expenditure on the asset over the total cost of the scheme.

4.26. We estimate the construction efficiency weighted by equipment cost to be 5.1 per cent and so the reduction in transformer unit costs proposed for Final Proposals LRE falls from 11.1 per cent to 6.0 per cent.

Switchgear

4.27. At Initial Proposals we set a 21.8 per cent reduction, in line with Scenario 1. Similar to the approach taken above we start from Scenario 2 (27.3 per cent) and apply a weighted construction efficiency (3.5 per cent) to give us a reduction of 23.8 per cent. Next, we correct for the relative volumes of Air Insulated Substation (AIS) switchgear to Gas Insulated Substation (GIS) switchgear which drops the reduction further from 23.8 per cent to 18.2 per cent.

4.28. Following submission of further information from NGET we acknowledge that LRE switchgear forecasts contain sections of Gas Insulated Busbar (GIB) which inflate unit costs by approximately 2.1 per cent. Adjusting for these three factors brings Final Proposals for switchgear reduction down to 16.1 per cent.

Cables

4.29. We do not propose to make any changes to the 1 per cent reduction set at Initial Proposals for cables.

Summary

4.30. Starting from Scenario 2 and factoring in the changes set out above, we arrive at the unit cost percentage reductions shown in Table 4.5 for Final Proposals.

Table 4.5: Unit cost efficiency reductions by primary plant

	Scenario 2	Construction efficiency weighted by equipment	AIS/GIS spit	GIB	Final Proposals
Transformers	11.1%	-5.1%	-	-	**6.0%**
Switchgear	27.3%	-3.5%	-5.6%	-2.1%	**16.1%**
Cables	1.0%	-	-	-	**1.0%**

4.31. The impact on baseline and best view relative to the position at Initial Proposals is that the reduction applied to NGET's baseline falls from £281.4m to £209.5m, a difference of £71.9m. This is set out in Table 4.6. Table 4.7 shows the split of this £71.9m by LRE category.

Table 4.6: Reduction applied to NGET's Baseline by LRE category

LRE category	Reduction applied in Initial Proposals (£m)	Reduction applied in Final Proposals (£m)	Change since Initial Proposals (£m)	% Change
Local Enabling (Entry – Shared Use)	107.7	79.8	27.9	26%
Local Enabling (Exit – Sole Use)	62.9	42.9	20	32%
Local Enabling (Exit – Shared Use)	35.1	24.9	10.2	29%
Wider Works (Entry)	52.7	45.3	7.4	14%
Wider Works (General)	23	16.6	6.4	28%
TSS	0	0	0	-
TOTAL	**281.4**	**209.5**	**71.9**	**26%**

Table 4.7: Change in reduction to unit cost efficiency relative to Initial Proposals

	baseline (£m)	best view (£m)		LE (Exit - Sole Use)	LE (Entry)	LE (Exit)	WW (Entry)	WW (General)
Unit cost efficiency	+71.9	+71.9		20.0	27.9	10.2	7.4	6.4

Issues affecting baseline allowances: overhead lines

Initial Proposals

4.32. In Initial Proposals we excluded overhead line (OHL) and cabling works for generation and demand connections from baseline expenditure. Instead we proposed to remunerate NGET for the OHL component of connections when these are delivered using a volume driver to make an adjustment of allowed expenditure for OHL and cables.

Respondents' views

4.33. NGET expressed the view in its response that removing the OHL costs from the baseline without adjusting up the baseline allowances for the generic cost of connecting new generation capacity in effect means that the volume driver would only operate upwards.

Final Proposals

4.34. It is our intention that volume drivers for connections works operate in a symmetrical manner around baseline allowances. We have therefore decided to amend our proposal in Initial Proposals to include expenditure for OHLs within the baseline allowance. In Final Proposals we have included NGET's best view of OHL to connect new generators and new demand connections into baseline expenditure. For the price control period the baseline allowances will be adjusted each year if the amount of OHL NGET delivers for new connections is more or less than baseline. The adjustment will be made using the respective volume drivers for generation connections and demand-related infrastructure.

4.35. As a result of the above change, baseline allowances in Final Proposals increase by £246.2m in total relative to Initial Proposals, split by Local Enabling (Entry) and Local Enabling (Exit) as shown below. There is no change to best view.

Table 4.8: Change in baseline for overhead lines relative to Initial Proposals

	baseline (£m)	best view (£m)		LE (Entry) (£m)	LE (Exit) (£m)
Overhead lines	+246.2	0.0		+220.5	+25.7

Issues affecting baseline allowances: DNO mitigation measures

Initial Proposals

4.36. For Initial Proposals we proposed to reduce forecast expenditure for DNO Mitigation measures from £26.1m to £8.0m on the basis that £8.0m is the expenditure derived when applying NGET's proposed volume driver (or unit cost allowance, 'UCA') to the outputs stated in NGET's plan. Furthermore in the absence of a justification or clear outputs for the remaining £18.1m we proposed in Initial Proposals to disallow this amount.

Respondents' views

4.37. NGET did not agree with the proposed reduction of £18.1m. It provided clarification on these costs, which related to non-unit items such as substation civil costs.

4.38. NGET stated that its forecast represented a trade-off between transparency and accuracy, and a baseline allowance for non-unit items was a pragmatic and proportionate approach.

4.39. NGET provided additional information which clarifies that the majority of the £26.1m baseline is associated with a proposed new 400kV transmission route between [redacted]. The DNO Mitigation measures consists of building a new grid supply point for UK Power Networks (UKPN) and work to connect the 132kV circuits to the new DNO substation.

Final Proposals

4.40. We agree that there is likely to be non-unit cost items in the scope of these works but do not feel it would be in consumers' interests to introduce a volume driver for non-unit costs.

4.41. We accept NGET's explanation that £18.1m accounts for non-unit costs and we propose to restore £18.1m back into baseline for Final Proposals.

4.42. Therefore baseline and best view in Final Proposals increase by £18.1m relative to Initial Proposals as WW (Entry) baseline is increased by £18.1m.

Table 4.9: Change in baseline (and best view) for DNO mitigation relative to Initial Proposals

	baseline (£m)	best view (£m)		WW (Entry) (£m)
DNO mitigation	+18.1	+18.1		+18.1

Issues affecting baseline allowances: treatment of Hinkley-Seabank

Initial Proposals

4.43. Hinkley-Seabank is a proposed Wider Works (WW) output under NGET's best view to reinforce the transmission system in western England and Wales, driven primarily by potential new nuclear generation at Hinkley Point. In Initial Proposals we proposed that it was not suitable for NGET to advance this particular WW output through its Network Development Policy with baseline funding because the total forecast cost of the scheme (including pre-RIIO-T1 expenditure) exceeded £500m. We also noted uncertainty of new nuclear development, which is the primary driver for this reinforcement. In light of this, we proposed that it was more appropriate for NGET to submit this project for funding consideration through the Strategic Wider Works (SWW) uncertainty mechanism.

Respondents' views

4.44. In its response, NGET stated that it preferred the project be removed from the SWW mechanism and funded through baseline and the WW volume driver. NGET proposed to disaggregate the Hinkley-Seabank WW output by subdividing it into three discreet reinforcements with alternative triggers and differing outputs.

Final Proposals

4.45. Given the uncertainty surrounding nuclear development and the nature of this project being fairly binary (ie the decision to go ahead with the project is mainly driven by whether or not new nuclear generation connects at Hinkley Point) we propose to retain the overhead line and re-conductoring elements within the SWW funding mechanism. This is despite the total cost of these elements being below the £500m threshold for SWW projects.

4.46. We have decided to move the third element of works making up the Hinkley Seabank scheme, Aust substation and the installation of Quadrature Boosters (QBs) at Nursling, into baseline Wider Works (General). This is because there does not appear to be a strong enough association with the delivery of specific boundary outputs on B13. These works are driven by Negative Phase Sequence considerations and off-peak transfers respectively and do not provide any specific boundary capacity output on the boundary.

4.47. Therefore baseline in Final Proposals increases by £62.8m relative to Initial Proposals as WW (General) baseline is increased by £62.8.m. SWW reduces by the same amount.

Table 4.10: Change in baseline for Hinkley-Seabank overhead line project

	baseline (£m)	best view (£m)		Wider Works (General) (£m)	Uncertainty Mechanisms (SWW) (£m)
Aust Substation Works and Nursling QBS	+62.8	0.0		+62.8	-62.8

Issues affecting baseline allowances: Western HVDC (WHVDC)

Initial Proposals

4.48. The Western HVDC link is being developed jointly by NGET and SP Transmission Ltd (SPTL). Both companies requested funding for construction works on the Western HVDC link under our Transmission Investment Incentives[27] (TII) framework. In Initial Proposals we set out our decision that Western HVDC link would be a baseline output for NGET to deliver in RIIO-T1 with baseline allowances, in line with the July 2012 decision letter[28] on funding arrangements for this project for both NGET and SPTL and under both TII and RIIO-T1. We also noted that the forecast cost and outputs used in Initial Proposals for WHVDC had been based on the assumptions in NGET's business plan submission and would therefore need to be updated to reflect that decision.

[27] All documents related to TII that are referred to in this section can be found: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Pages/InvestmentIncentives.aspx
[28] July 2012 Decision Letter http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Jul12_WHVDC_decision_FINAL.pdf

Respondents' views

4.49. No respondents commented on WHVDC.

Final Proposals

4.50. In calculating the baseline costs for Final Proposals we have updated the assumptions used in Initial Proposals to reflect the funding decision for WHVDC. This results in NGET's share of baseline costs under RIIO-T1 being reduced from £682.5m to £621.1m, ie a reduction of £61.4m.

4.51. Therefore baseline and best view in Final Proposals decreases by £61.4m to reflect the reduction to WHVDC set out in our decision letter. WHVDC is categorised as WW(Entry).

Table 4.11: Change in baseline (and best view) reflecting final allowances for WHVDC

	baseline (£m)	best view (£m)		WW (Entry)
Reduction to WHVDC	-61.4	-61.4		-61.4

Issues affecting baseline allowances: preconstruction work

Initial Proposals

4.52. For Initial Proposals we proposed 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 prospective SWW outputs.

4.53. We allowed preconstruction funding for projects in baseline (£54.2m) and for SWW (£46.0m) but not for projects in neither category (£24.4m).

4.54. Our decision was taken on the basis that this amount was not part of NGET's March 2012 Business Plan and we held the view that the expenditure was to cover pre-construction activities for outputs delivered in RIIO-T2 and was not accompanied by supporting information.

Respondents' views

4.55. In its response to Initial Proposals NGET highlighted that we have incorrectly assumed this expenditure is related to outputs in RIIO-T2. NGET clarified that this amount is for expenditure beyond baseline but in uncertainty mechanisms. Since UCAs do not include pre-construction NGET believed that it may be underfunded.

4.56. NGET's response also identified additional projects which require preconstruction funding, increasing the total amount of preconstruction funding requested over the RIIO-T1 period.

Final Proposals

4.57. We acknowledge that this preconstruction expenditure reflects the development engineering associated with projects that are delivering RIIO-T1 outputs above baseline and funded by volume drivers.

4.58. Since UCAs for this category of expenditure do not include preconstruction funding we have decided to fund this amount in baseline.

4.59. As stated in Initial Proposals, NGET submitted a request for funding through RIIO-T1 to undertake pre-construction activities related to potential integrated network investment off the east coast of England. The proposal includes investments that would support wider network developments offshore.

4.60. We are currently developing and consulting on a framework to enable the investment needed for efficient coordination in offshore transmission.[29] As a result, we are reserving any decision on NGET's proposal (more details in the *Uncertainty mechanisms* chapter).

4.61. However, in the interest of preventing any unnecessary delay to the development of the project, NGET is commencing some early system and technical study work. We consider that such work will be of value to customers and could assist future development regardless of the results of this ongoing work.

4.62. To enable NGET to carry out this early system and technical study work we consider that £1.5m of the £28.5m of preconstruction allowance we are restoring to NGET's baseline will be sufficient for this purpose. The LRE category affected is WW (Entry).

[29] Consultation on the framework to enable coordination of offshore transmission http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=101&refer=NETWORKS/OFFTRANS/PDC/CDR/2012

Table 4.12: Change in baseline (and best view) for Pre-construction Work

	baseline (£m)	best view (£m)		WW (Entry) (£m)
Preconstruction Work	+28.5	+28.5		+28.5

Issues affecting baseline allowances: RIIO-T2 outputs

Initial Proposals

4.63. In Initial Proposals we proposed to disallow the baseline allowances NGET requested £463m in its March 2012 Business Plan for potential works in RIIO-T1 to deliver generation and demand connection outputs in RIIO-T2. We did not consider it appropriate to include baseline allowances for this potential spend in view of the uncertainty about what outputs might turn out to be required in RIIO-T2. We considered this to be in line with the RIIO principle of matching expenditure to outputs.

4.64. Instead, we proposed that any expenditure made by NGET in RIIO-T1 for outputs in RIIO-T2 would be treated initially as apparent overspend and would be covered by the totex incentive mechanism. We also set out the principle that NGET would be remunerated for the total efficient costs it incurred in RIIO-T1 for outputs delivered in RIIO-T2. We proposed that this would be assessed as part of setting the price control for next period, taking into account any prior adjustment through the totex incentive mechanism.

Respondents' views

4.65. NGET and one other stakeholder had concerns about the approach set out in Initial Proposals. The third party stakeholder said the renewables industry would like to see early grid development to overcome barriers and uncertainties for renewable projects. In their view we should include some allowance for preparatory activity for RIIO-T2, noting that the RIIO Handbook sets out the importance of looking beyond just one price control period.

4.66. In its response to Initial Proposals, NGET said that under these arrangements it could incur significant costs in advance of funding, and that these costs did not seem to be reflected in our financeability modelling. In addition, NGET highlighted that the potential adjustments to its allowances arising from the proposals in Initial Proposals could cause instability of customer charges. NGET also noted that the RIIO handbook says that expenditure for the delivery of outputs in future price control periods could be included provided that this delivers long-term value for money. In their response NGET put forward three options to address this issue (these are discussed in the next section).

Final Proposals

4.67. In response to NGET's concerns we have further assessed the financial implications of the RIIO-T2 expenditure as per our Initial Proposals under different scenarios. We set out in the Financial issues Supporting Document the assumptions we used in these stress tests. Overall, we find that our proposals are robust to a range of downside scenarios, including expenditure relating to outputs delivered in RIIO-T2.[30]

4.68. Although our financial analysis confirms that that the approach set out in Initial Proposals is financially sustainable for NGET we have also considered the potential implications of our approach on NGET's incentives and for consumers. One concern we have is that there is a risk that in the absence of clarity about the efficient costs of these works, NGET may defer load-related projects into RIIO-T2 as it could seek to fund more expensive projects through the baseline. We also noted NGET's argument surrounding volatility of charges.

4.69. We consider it is in existing and future consumers' interests that we provide greater certainty about how the essential work required in RIIO-T1 to deliver outputs in RIIO-T2 is funded, and set strong incentives for NGET to efficiently deliver these customer-driven outputs in a timely manner.

4.70. Therefore we are changing our proposals in this area compared to our position in Initial Proposals. To inform our decision for Final Proposals we have reviewed the three policy options put forward by NGET in its response to Initial Proposals to fund RIIO-T2 outputs. These were:

(1) a continuation of the 'work in progress' arrangements in the current transmission price control (this is NGET's preferred option)
(2) a within-period determination by us on the expenditure for RIIO-T2 outputs as and when this become more certain
(3) using the volume drivers to adjust the company's regulatory asset value at the end of RIIO-T1 for the works it has undertaken for outputs to be delivered in the next price control period.

4.71. We do not consider option 1 of continuing with the 'work in progress' arrangements in TPCR4 is appropriate. The absence of agreed parameters on efficient costs would risk NGET delaying outputs to the next price control period and inefficient spend being added to RAV at the end of the price control period. It is also a much less transparent adjustment mechanism for consumers to predict the likely impact on transmission charges.

4.72. We also do not consider option 2 of a within-period determination is appropriate (and note this is NGET's least preferred option). This would not be a

[30] Further detail of our analysis is set out in the Finance Supporting Document.

proportionate response to the likely scale of the generation and demand connection works in question and could lead to delays.

4.73. Our preferred approach for Final Proposals is a variant on option 3 to allow NGET to trigger a funding adjustment to cover this expenditure. This will work through the respective volume drivers in each load-related area using the unit cost allowances agreed for RIIO-T1 and the generic spend profile that is also included as part of the volume drivers. The benefit of this approach is that there will be a much clearer link between the costs NGET incurs in the RIIO-T1 period and outputs that the company can be held to account to deliver during the next price control period.

4.74. Specifically, we propose that NGET trigger an adjustment by providing, in year 6 of the price control (2018-19), evidence-backed forecasts of the load-related outputs it will deliver in the first two years of RIIO-T2. The volume driver for each output will automatically calculate a funding adjustment based on the unit cost allowances agreed for RIIO-T1 and apportion this using the construction spend profile that is part of the volume drivers. For example, if NGET forecast that it would deliver 100MW of new generation connection capacity in year 1 of RIIO-T2 and the volume driver has a four-year spend profile with 25 per cent of spend occurring in each year, the volume driver would make an adjustment to allocate 25 per cent of the efficient costs in year 6, 7 and 8 of RIIO-T1 and the final 25 per cent would go into the baseline for RIIO-T2. Similarly, if NGET forecast a further 100MW for year 2 of RIIO-T2 the volume driver would calculate an adjustment for 25 per cent of the efficient costs of the outputs in year 7 and 8 of RIIO-T1 with the remaining 50 per cent going into the baseline for RIIO-T2.

4.75. More information about the process for triggering the adjustment is set out in the LRE Uncertainty Mechanism section below.

4.76. The impact on best view is set out in Table 4.13. We have reduced NGET's original forecast of £463m to £422.3m to reflect unit cost efficiencies.

Table 4.13: Change in baseline (and best view) for RIIO-T2 outputs

	baseline (£m)	best view (£m)		LE (Exit - Sole Use) (£m)	LE (Entry) (£m)	LE (Exit) (£m)	WW (Entry) (£m)
T1 Expenditure for T2 Outputs	0.0	+422.3		+0.7	+221.2	+166.7	+33.8

Issues affecting baseline outputs: wider works requirements

Initial Proposals

4.77. In Initial Proposals we set out that NGET's WW (Entry) outputs would be measured as the maximum transfer capability across system boundaries defined by the National Electricity Transmission System Security and Quality of Supply Standard. 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.

4.78. In Table 4.12 of the *Cost assessment and uncertainty supporting document* in Initial Proposals we proposed several baseline WW outputs for which NGET would be accountable for delivering by the scheduled date. The table also shows the indicative WW outputs that NGET might be required to deliver on the system boundaries in its transmission area for which we also proposed to set NGET baseline funding. We also proposed in Initial Proposals that it would be for NGET to further determine the requirements for these indicative WW outputs through its Network Development Policy processes. Through this process NGET would, in effect, confirm which WW outputs were in the best interests of existing and future consumers for it to deliver. We also proposed that NGET's baseline allowances would be adjusted if it delivered more or less WW outputs than those set out in by a WW volume driver.

Respondents' views

4.79. NGET said that some of the information presented in Initial Proposals did not entirely reflect the boundary capabilities of the WW outputs identified in its March 2012 Business Plan submission. For instance, NGET pointed out that WW outputs on boundary B14 had been stated incorrectly and did not include an increase that might occur in 2015-16.

4.80. NGET also stated that we had made the assumption that the Western HVDC link will provide 2.4GW of additional capacity from 2015-16, which is incorrect for two reasons:

1. 2.4GW is only the short-term rating; the long-term capability of the link is 2.2GW
2. the link will not provide boundary capacity for the winter peak of 2015-16 so it is more appropriate to show the increase in boundary capacity in 2016-17.

Final Proposals

4.81. We have corrected the error on WW outputs for boundary B14 which stems from a spreadsheet submitted by NGET during the Supplementary Questions (SQ) process. This contributes 800MW of additional transfer capacity across B14 from 2015-16.

4.82. The transfer capacity across Boundaries B6, B7 and B7a will increase upon completion of WHVDC. Our decision on funding arrangements for WHVDC was published on 27th July 2012 and in that decision letter we stated that the *"planned 600kV design would provide a continuous rating of 2.25GW and a short-term (6 hour) rating of 2.4GW."*

4.83. We do not agree with NGET that the continuous rating of WHVDC is 2.2GW on the basis it contradicts our decision letter. The boundary capabilities of B6, B7 and B7a shown in the table are based on the continuous rating for WHVDC to be consistent with how other boundaries are represented in this table. However the transfer capability across these boundaries should demonstrate WHVDC's short-term rating of 2.4GW.

4.84. The profile of expenditure for the WHVDC WW output in the aforementioned decision letter indicates £20.1m expenditure in 2016-17. Therefore we have revised the scheduled delivery date of the baseline WW outputs across B6, B7 and B7a to show the contribution from WHVDC taking effect from 2016-17 onwards.

4.85. As a result of the above changes we have updated the WW outputs in Table 4.14 below. These are shaded in grey.

Table 4.14: WW outputs for baseline allowances in Final Proposals

Outputs	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
B6 (MW)	3,300	**4300[2]**	4,300	**6,550[1]**	6,550	6,550	6,550	6,550
B7 (MW)	2,000	**3400[2]**	3,400	**5,650[1]**	5,650	5,650	5,650	5,650
B7a (MW)	4,900	5,300	5,300	**7,550[1]**	7,450	7,450	7,450	7,450
B8 (MW)	11,300	11,300	11,300	11,500	11,500	10,600	10,600	10,600
B9 (MW)	12,600	12,600	12,600	11,500	11,500	11,500	11,500	11,500
B10 (MW)	5,800	5,800	5,700	5,700	5,700	5,700	5,700	5,700
B11 (MW)	9,900	9,900	10,000	10,000	10,000	10,000	10,000	10,500
B12 (MW)	5,800	5,800	5,100	5,100	5,100	5,100	5,100	5,200
B13 (MW)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
B14 (MW)	9,600	9,600	10,400	10,400	10,400	10,400	10,400	10,400
B14e (MW)	8,700	8,700	9,400	10,150	10,150	10,150	9,950	9,950
B15 (MW)	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,500
B16 (MW)	15,200	15,500	15,500	15,500	15,500	15,500	15,500	15,500
B17 (MW)	5,200	5,200	5,200	5,200	5,200	5,200	5,200	5,200
NW1 (MW)	1,800	1,800	1,800	1,800	4,400	4,400	4,400	4,400
NW2 (MW)	1,500	1,500	1,500	4,600	4,600	4,600	4,600	4,600
NW3 (MW)	2,900	2,900	2,900	2,900	**4400[2]**	4,400	4,400	4,400
NW4 (MW)	6,000	6,000	6,000	6,000	6,000	6,000	6,500	6,500
EC1 (MW)	4,100	4,100	4,100	4,100	4,100	7,000	7,000	7,000
EC3 (MW)	3,200	3,200	**4300[2]**	4,300	4,300	4,300	4,300	4,300
EC5 (MW)	2,600	2,600	**3600[3]**	3,600	6,800	6,800	6,800	6,800
SC1 (MW)	5,600	5,600	5,600	5,600	6,100	6,100	6,600	6,600

Notes:
1. Maximum transfer capability of the WHVDC is deemed to be 2,400MW (short-term, 6 hour rating). But the boundary transfer shown for B6, B7 and B7a reflects the continuous rating of 2.25GW.
2. Transfer capability increases from delivery of scheduled baseline WW outputs. See Table 4.13 in Initial Proposals.
3. Baseline WW output delivers 1,700MW increase in thermal capability. However, due to the boundary stability constraint actual increase in transfer capability only increases by 1000MW.

4.86. We confirm in Final Proposals it is for NGET to further determine on the need for WW outputs that are additional to the baseline WW outputs through its Network Development Policy processes. Through this process NGET would determine the requirements for additional WW outputs that are in the best interests of existing and future consumers and advance these into its forward investment programme for delivery. For more information on our Final Proposals regarding the Network Development Policy see the Outputs, incentives and innovation Supporting Document.

Issues affecting LRE uncertainty mechanisms

Initial Proposals

4.87. In Initial Proposals we proposed several uncertainty mechanisms, summarised in Table 4.15, to manage the uncertainty associated with the costs and volumes in each of the main LRE categories.

4.88. We proposed that the volume drivers would automatically adjust revenues each year to remunerate NGET for the efficient costs of the outputs actually delivered. To ensure flexible funding and efficient risk sharing arrangements with consumers we proposed that these would operate both up and down from the baseline level of outputs and expenditure. For example, if 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 exceeded the baseline level the volume driver would increase NGET’s allowed expenditure for the efficient costs of delivery.

4.89. We also proposed another type of uncertainty mechanism for large reinforcements of the transmission system known as Strategic Wider Works (SWW) outputs. This would entail further assessment by us, known as a within-period determination, of the needs case and efficient costs of the proposed SWW output and a project specific revenue adjustment for the specific output. We proposed these arrangements would be triggered by NGET bringing forward requests during the price control period.

Table 4.15: 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) not in baseline 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.

Respondents' views

4.90. NGET and four other stakeholders commented on the proposed uncertainty mechanisms set out in our Initial Proposals consultation. Overall, third party respondents supported the proposed uncertainty mechanisms. Two respondents made specific reference to the undergrounding uncertainty mechanism for new infrastructure. NGET raised issues in relation to the Wider Works (WW) and Local Generation uncertainty mechanisms. We give further detail of the specific points raised in the relevant sections below.

Final Proposals

4.91. We welcome stakeholders' general support for the uncertainty mechanisms set out in Initial Proposals. We have largely retained the uncertainty mechanism in the form proposed but have made some adjustments and refinements to these to address the substantive issues raised by stakeholders in the consultation. We provide further detail on the uncertainty mechanisms in Final Proposals in the following sections.

Issues affecting uncertainty mechanisms: volume driver for generation connections

Initial Proposals

4.92. In Initial Proposals we set a volume driver to calculate NGET's allowed expenditure for new generation connections in each year of the price control. We based it on the output of additional generation capacity connected in megawatts and the circuit kilometres of overhead line and underground cabling needed in connection works.

4.93. Based on our assessment of NGET's proposed volume driver in its March 2012 Business Plan, we proposed the following adjustments to improve the overall efficiency of the volume driver:

- Merging 'within zone' works and substation costs and taking a national average to derive a single unit cost allowance (UCA) to connect one megawatt of new generation capacity anywhere in NGET's licence area.
- Removal of some complexities, such as the demand and closures assumptions, where the assumptions did not seem to be linked to costs.
- Incorporating non-boundary works, where appropriate, in schemes that were subject to the local generation volume driver.
- Applying cost efficiency reductions to the UCA, reflecting the outcome of the unit cost assessment.

4.94. One part of the analysis that we carried out for Initial Proposals was to test NGET's proposed mechanism with our own in relation to cost recovery outcomes under different scenarios. This analysis had originally indicated that our proposed volume driver was more accurate in all three scenarios. Since publication we found a small error which, when corrected, meant that NGET was slightly more accurate in two of the three scenarios for the particular projects identified.

Respondents' views

4.95. From the consultation responses received on Initial Proposals only NGET provided specific feedback on our proposed generation connections volume driver. The points made by NGET were:

- While recognising that their March 2012 Business Plan proposal for the local generation connection uncertainty mechanism was complex, NGET thought our proposed mechanism was too simplistic.
- NGET was also concerned that we reached our conclusions regarding the accuracy of our proposed mechanism based on a limited number of scenarios.

- NGET acknowledged our concerns about the sensitivity of the 'within zone' UCA to demand changes and generation closures. Although NGET believed these factors have the potential to impact the cost of connections for new generators, it did not have direct evidence to link 'within zone' costs and these outputs for the majority of zones.
- NGET also acknowledged that zonal 'within-zone' costs had some scheme specific elements, which had resulted in the zonal driver being more scheme specific than zonal.

4.96. Taking on board our comments and concerns, NGET set out in its response an alternative mechanism that removed a number of complexities from its original proposal (see Table 4.16). NGET carried out a deterministic assessment, to support its argument of the mechanism representing a lower risk option for both itself and consumers.

Table 4.16: NGET's alternative proposal

Volume Driver 2009/10 prices	NGET Alternative Proposal
Zonal UCAs (Revenue Driver zones RD2 to RD22) (£/MW)	£3.0k/MW to £111.5k/MW
Overhead lines (£/cct km)	1.2m
Cables	Matrix of additional costs for undergrounding from 31 January, 2012 IET[31] report

4.97. The most significant changes between NGET's March 2012 Business Plan and the alternative volume driver in its response to Initial Proposals are:

- Zonal UCAs would now cover both the substation and 'within zone' costs.
- Zonal UCAs would be based on the connection of new generation only (demand changes and closures have been removed from mechanism).
- For mid-Wales (Zone 22) and the North East (Zone 2) the UCA would also adjust for new embedded generation.
- Base funding for [redacted] closure and the inclusion of the full mid-Wales costs (including embedded generation costs).

4.98. In addition NGET proposed to use either a re-opener or the national average for three zones that do not currently have any new generation connection data. NGET also considered that a more appropriate unit cost allowance was needed for

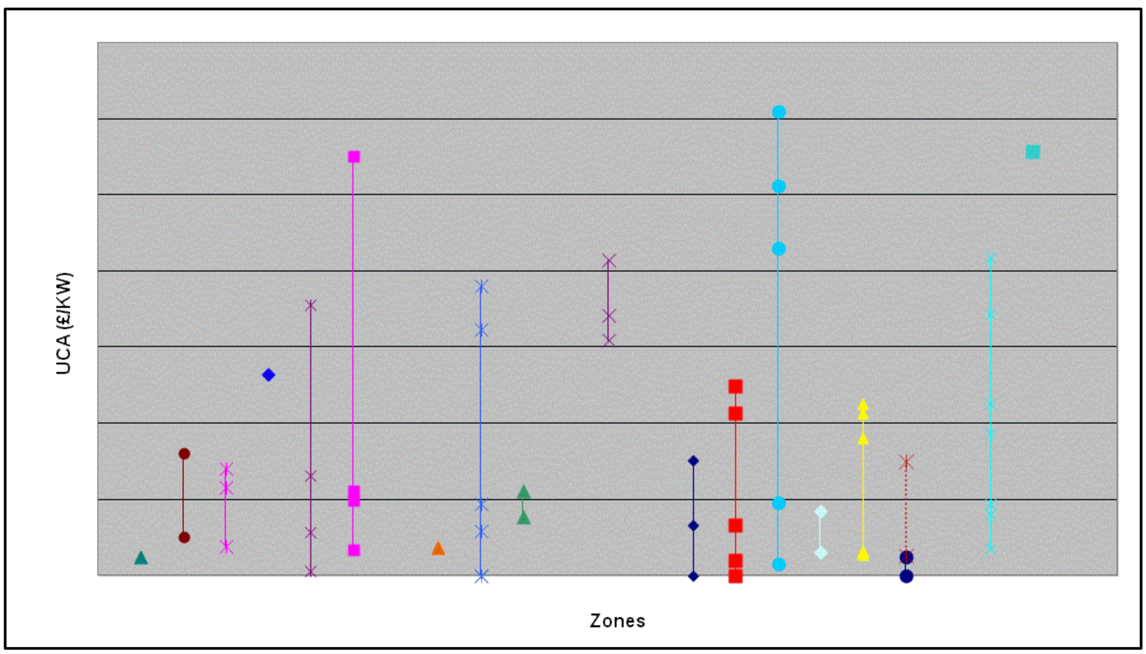
[31] Link to IET report (http://www.theiet.org/factfiles/transmission.cfm)

zone 19 as this zone as well as some other zones have a particularly low unit cost allowance and are based on a limited number of schemes.

Final Proposals

4.99. Our main concern is that NGET's proposed zonal unit costs are not representative of the costs of connecting generation in the particular zone but are more representative of the specific projects being considered in that zone. The graph below shows that there is a high spread of unit costs across the potential connection projects within most zones. It also shows how the zonal unit costs are very sensitive to the specific projects included and may change significantly during the period. For example, new information provided by NGET suggests that costs for connection projects in one particular zone may increase(shown on the diagram as red crosses, with red dashed lines linking the points) leading to project unit costs 6.7 times greater than the zonal unit costs NGET proposed.

Figure 4.1: Local generation project unit costs within each zone



4.100. NGET highlighted in its March 2012 Business Plan that out of the 58GW of contracted generation, it expects only 25GW to connect during the price control period. And in the period since March 2012, there have been a number of project substitutions with several new projects coming forward and developed by NGET as well as others terminating their connection contract. This suggests that the zonal UCAs could result in a large difference between the unit cost allowance and actual cost if there are a lot of project substitutions over the price control period. In our view, this would be less of an issue overall by adopting a national UCA.

4.101. NGET argued that zonal UCAs were superior to a national UCA because the scenario testing and deterministic assessment show NGET's zonal UCAs were more accurate than a single national rate. NGET's probabilistic assessment also indicated that NGET's alternative mechanism has a lower standard deviation between allowances and costs of £46.8m versus £69.9m for our proposed uncertainty mechanism. However, NGET's modelling does not take into account that new schemes may materialise during the price control period. We consider that this is a material shortcoming in their assessment, given the large uncertainty around which connections will proceed, and the impact it could have on actual costs.

4.102. NGET is concerned that some of the zonal unit costs are too low, especially zone 19, which NGET consider might not be representative, as the zone is only based on a limited number of schemes. Although zone 19 is based on two schemes, this is fairly common in other zones. Currently just over half of the zones have two or fewer schemes associated with them, including three zones with no schemes. We consider there is the same risk that these other zones will also not reflect NGET's proposed UCA, including a zone, which currently is set at a very high UCA and based on only one scheme.

4.103. NGET also requested a re-opener or application of the national rate to three zones which have no unit cost associated with it. Its request along with zone 19 and its concerns over low UCA zones seems inconsistent to its original proposal for having zonal UCAs. We are concerned that these requests will cause an imbalance in risk between consumers and NGET. NGET has only raised concerns and requests for adjustments to zones that could result in a loss to NGET and not to those zones that have a high UCA and could lead to consumers paying more than is necessary for connections.

4.104. Given the concerns listed above and the lack of justification by NGET beyond the deterministic probability assessment and scenarios, we do not propose to move away from the national UCA rate for Final Proposals. We consider the national UCA, being based on a much larger pool of schemes is better placed to deal with the large uncertainty during the period than zonal UCAs that are based on limited number of schemes. It also represents a more balanced risk approach between NGET and consumers and ensures that NGET has funding for those zones that currently have no schemes associated with them.

Embedded generation & closures

4.105. NGET has requested that the local generation uncertainty mechanism adjusts for embedded generation for mid-Wales (zone 22) and North East (zone 2). NGET has demonstrated that embedded generation will result in further costs being incurred in each of these zones. As a result we will amend the uncertainty mechanism to include embedded generation in zones 2 and 22 using the national rate.

RIIO-T2 outputs

4.106. As part of Final Proposals we are including a provision in the generation connections volume driver to fund NGET for works required in RIIO-T1 for generation connections in RIIO-T2. As discussed above, we consider that it is in existing and future consumers' interests to set clear parameters and incentives for NGET to deliver these customer-driven outputs in an efficient and timely manner. Therefore, our Final Proposals includes a mechanism for this.

4.107. Under our proposed mechanism, NGET will need to provide evidence in year 6 of RIIO-T1 (2018-19) of new generation connection capacity it will deliver in year 1 and year 2 of RIIO-T2 ie Bilateral Connection Agreements with generators for connection dates in 2021-22 and 2022-23. The adjustment will take effect in 2019-20 allowances, retrospectively for works in 2018-19 and concurrently for works in 2019-20, and again in 2020-21 allowances for works in that year.

Table 4.17: Ofgem's Final Proposals for Local Generation volume driver

Ofgem Final Proposal 2009/10 prices	**Parameters**
Generation Volume (national rate) (£k/MW)	27.1
Overhead lines (£m/cct km)	1.1
Cables	Matrix of additional costs for undergrounding from 31 January, 2012 IET report
Construction expenditure profile for yr1/yr2/yr3/yr4 (% of total efficient costs)	16.0%/31.5%/31.5%/21.0%
RPEs	0.8% per annum

4.108. Our Final Proposals for the local generation volume driver UCAs are set out in Table 4.17, which consist of the following adjustments made since Initial Proposals.

- Applying smaller cost efficiency reductions to reflect changes made to the cost efficiency assessment, set out in the *Issues affecting baseline – Unit Cost Efficiencies* section.
- Adjusting the mechanism so that the UCA will now remunerate NGET for embedded generation in Zones 2 & 22.
- Reducing the annual RPE adjustment from 0.9 per cent to 0.8 per cent as a result of the updated RPE assessment, set out in the uncertainty mechanisms chapter and the RPE annex.

Operation of volume driver

4.109. In Initial Proposals we set out in detail how the volume driver will operate. We further clarify in Final Proposals that the efficient costs of the delivered output in a given year as calculated by the volume driver would be profiled over the relevant price control years using the four-year construction expenditure profile in Table 4.17.

Issues affecting uncertainty mechanisms: volume driver for demand-related infrastructure

Initial Proposals

4.110. At Initial Proposals we proposed setting a volume driver for shared use infrastructure to provide the necessary flexibility, accountability and efficiency safeguards for consumers. The form of our proposed volume driver was broadly consistent with NGET's March 2012 Business Plan proposals. Based on our efficiency assessment of NGET's proposed volume driver in its March 2012 Business Plan, we proposed to adjust the UCAs downwards to reflect the cost efficiency adjustments identified through the unit cost analysis.

Respondents' views

4.111. There was no specific feedback on the Local Demand Volume Driver from stakeholders other than NGET, who supported the inclusion of the mechanism.

Final Proposals

4.112. Our Final Proposals for the local demand volume driver are set out in Table 4.18. Since Initial Proposals we have made the following adjustments:

- Applying smaller cost efficiency reductions to reflect changes made to the cost efficiency assessment, set out in the *Issues affecting baseline – Unit Cost Efficiencies* section.
- Reducing the annual RPE adjustment from 0.9 per cent to 0.8 per cent as a result of the updated RPE assessment, set out in the uncertainty mechanisms chapter and the RPE annex.

Table 4.18: Ofgem's Final Proposals for Demand-Related Infrastructure

Ofgem Final Proposal	Parameters
Substation Costs (national rate) (£m/SGT)	3.9
Overhead lines (£m/cct km)	1.1
Cables	Matrix of additional costs for undergrounding from 31 January, 2012 IET report
Construction expenditure profile for yr1/yr2/yr3 (% of total efficient costs)	44.5%/44.5%/11.0%
RPEs	0.8% per annum

RIIO-T2 outputs

4.113. Similar to generation connection outputs we are including a provision in the demand connections volume driver to fund NGET for works required in RIIO-T1 for demand connections in RIIO-T2. NGET will need to provide evidence in year 6 of RIIO-T1 (2018-19) of new demand connections it will deliver in year 1 and year 2 of RIIO-T2 ie customer agreements or DNO requests for new connections in 2021-22 and 2022-23. The efficient costs will be allocated to annual allowed expenditure under RIIO-T1 years using the three-year construction expenditure profile in Table 4.18. The adjustment will take effect in 2019-20 allowances concurrently for works in 2019-20, and again in 2020-21 allowances for works in that year.

Operation of volume driver for output delivery

4.114. In Initial Proposals we set out in detail how the volume driver for demand-related infrastructure will operate. We further clarify in Final Proposals that the efficient costs of the delivered output in a given year as calculated by the volume driver would be profiled in the relevant price control years using the three-year construction expenditure profile in Table 4.18.

Issues affecting uncertainty mechanisms: wider works volume driver

Initial Proposals

4.115. At Initial Proposals we proposed a volume driver to adjust NGET's baseline allowances for incremental WW outputs that increase transfer capacity over system boundaries but are not subject to the SWW mechanism or specified as a baseline WW output. We proposed that NGET would identify and phase the development of these outputs in accordance with its Network Development Policy (NDP) which is subject to approval by us (for more information on the NDP please see the Outputs, Incentives and Innovation Supporting Document).

4.116. We assessed the efficiency of NGET's proposed volume driver in its March 2012 Business Plan, which resulted in the following proposed adjustments:

- Reducing the baseline to a level with a more equal likelihood of downward or upward adjustments in allowances. This would result in a number of small to medium sized WW outputs in the Gone Green scenario to move out of baseline into a uncertainty mechanism.
- Incorporating non-boundary works, where appropriate, in schemes that are subject to the wider works volume driver.
- Introducing south coast system boundary, SC1, so that further non-boundary works would have defined outputs associated with them.
- Introducing unit cost bandings for two boundaries, B14e and EC5, where the spread of project unit costs on those boundaries are significantly different.
- Applying a weighted average of all WW project unit costs for boundary B13 UCA to ensure the boundary has a UCA (this is necessary because as a result of our proposed re-categorisation of Hinkley Seabank to SWW it has no schemes related to it).
- Applying the cost efficiency reductions, identified through the unit cost assessment.

Respondents' views

4.117. There was no specific feedback on the WW volume driver from stakeholders other than NGET.

- NGET did not agree with our proposal to apply a weighted average UCA derived from all WW projects on boundary B13. NGET considered that this was inappropriate because there was no relationship between the reinforcement costs and the different boundaries. Alternatively, NGET proposed to use elements of the Hinkley Seabank scheme to derive the UCA for boundary B13.
- NGET did not consider that the introduction of bandings for boundaries EC5 and B14e based on the £k/MW meets the RIIO-principles, as this is an input measure. NGET proposed using thresholds based on output levels as an alternative. NGET was also concerned that we proposed thresholds based on our judgement.
- NGET identified three additional schemes for boundary SC1, which it proposes to use to adjust the 'above' the baseline UCA for the boundary.

Final Proposals

Boundary B13 UCA

4.118. In NGET's response to Initial Proposals, NGET proposed moving the Hinkley Seabank scheme into the WW volume driver, using elements of the scheme to derive the UCA for Boundary B13. In the earlier section of this chapter relating to Hinkley Seabank we outlined our decision to retain the new overhead line and reconductoring works components of the scheme within the SWW mechanism, resulting in no projects forecast to deliver outputs on this boundary.

4.119. NGET has not come forward with any other potential schemes associated with the boundary B13 that can be used to inform our decision on the UCA to apply on boundary B13. In the absence of any better information, and to ensure that NGET has access to funding should the need arise we will retain our Initial Proposals position to apply the weighted average UCA for boundary 13.

Bandings for boundaries B14e and EC5

4.120. In NGET's response to Initial Proposals, NGET proposed to use a stepped approach to 'above the baseline' reinforcements for both boundaries B14e and EC5 with thresholds based on the output delivered, as opposed to cost. It proposed to use the following threshold levels and UCAs for both of these boundaries.

Table 4.19: NGET's proposed thresholds for boundaries B14e and EC5

Boundary	Below the baseline		Above the baseline	
	UCA (£k/MW)	Capability Threshold (MW)	Threshold (MW)	UCA (£k/MW)
B14e	107.9	9,950	<10,850	53.2
			>10,850	298.5
EC5	72.7	6,850	<8,300	25.4
			>8,300	155.1

4.121. We have considered NGET's alternative proposal using MWs delivered as the threshold capacity. However, NGET's alternative proposal does not address the issue of the large range of unit costs in boundary EC5, which ranges between £31.1k/MW and £569.3k/MW. In the event only a proportion of the schemes are required during the period, NGET could be over remunerated by over £100m. Our proposed mechanism, being based on unit cost, reduces the risk of customers over paying for incremental WW output on this boundary during the period.

4.122. NGET was also concerned that we based our UCA thresholds on judgement. In boundaries EC5 and B14e, there are distinct clusters of schemes. We worked out thresholds that were sufficiently spaced between these clusters to ensure that there was less risk that schemes would be pushed up or reduced down into an adjacent UCA category.

4.123. NGET's NDP will help to reduce the risk that NGET inflates project costs to benefit under the different cost thresholds. NGET will need to demonstrate to its wider stakeholders that its proposed outputs deliver long term value for consumers. If costs change significantly from its business plan it would need to justify the changes and whether the proposed outputs still fulfil the objectives of its NDP. Failure to demonstrate compliance with the NDP would render it ineligible for automatic funding under the WW volume driver. In this case we would determine the efficient costs incurred by the company and allow only those costs to be recovered. We note that NGET's proposed mechanism does not give us the opportunity to challenge it if we found that it had only delivered the lower unit cost schemes.

4.124. Our Final Proposals are that we retain our original proposal at Initial Proposals to have thresholds based on unit costs.

Adjustment to SC1 'above' baseline UCA

4.125. In response to Initial Proposals NGET proposed to adjust the 'above' baseline UCA to reflect three new schemes identified by NGET since the publication of Initial Proposals, increasing the 'above' baseline UCA from £100.4k/MW to £115.4k/MW.

4.126. Our assessment of the information NGET provided to us, shows that NGET's proposal is reasonable and therefore we propose to amend the 'above' baseline to reflect NGET's new estimate. The SC1 boundary was created late in the assessment process, as a means of easily monitoring non-boundary outputs. NGET has since carried out an assessment on possible reinforcement work that may be required over the boundary, which led to the identification of these three new schemes, which are required in relation to the possible connection of an interconnecting scheme.

Summary of wider works mechanism

4.127. Table 4.20 below sets out our Final Proposals for the wider works volume driver, which consist of the following adjustments made since Initial Proposals.

- Applying smaller cost efficiency reductions to reflect changes made to the cost efficiency assessment, set out in the *Issues Affecting Baseline – Unit Cost Efficiencies* section.
- Increasing the 'above' baseline UCA for boundary SC1 to reflect three new schemes identified by NGET.
- Reducing the annual RPE adjustment from 0.9 per cent to 0.8 per cent as a result of the updated RPE assessment, set out in the uncertainty mechanisms chapter and the RPE annex.

Table 4.20: Final Proposals wider works volume driver UCAs

Below Baseline			Above Baseline		
Boundary	Final Proposals UCA (£k/MW)	Incremental capex of baseline schemes (MW)	Boundary	Thresholds (£k/MW)	Final Proposals UCA (£k/MW)
B6	81.4	1000	**B6**		90.3
B7	62.4	1400	**B7**		61.8
B7a	51.6	400	**B7a**		76.3
B8	0.0	0	**B8**		14.4
B9	9.7	1000	**B9**		57.0
B13	0.0	0	**B13**		67.9
B14	106.3	800	**B14**		34.7
B14e	100.8	2050	**B14e (1)**	<250	50.8
	0.0	0	**B14e (2)**	>250	290.1
NW1	52.8	2600	**NW1**		26.8
NW2	51.8	3100	**NW2**		44.0
NW3	63.9	1500	**NW3**		44.0
EC1	88.0	2900	**EC1**		88.0
EC3	42.3	1100	**EC3**		42.3
EC5	69.9	4200	**EC5 (1)**	<125	36.5
	0.0	0	**EC5 (2)**	125<x<400	149.2
	0.0	0	**EC5 (3)**	>400	553.4
SC1	97.4	1000	**Sc1**		112.2

Table 4.21: Construction expenditure profile for WW outputs

Construction expenditure profile	% of total efficient costs
Year 1	16.0%
Year 2	26.0%
Year 3	37.0%
Year 4	21.0%

RIIO-T2 outputs

4.128. Similar to other customer driven outputs we are including a provision in the WW volume driver to fund NGET for works required in RIIO-T1 for WW outputs in RIIO-T2. NGET will need to justify through its NDP processes in year 6 of RIIO-T1 (2018-19) the new WW outputs it will deliver in year 1 and year 2 of RIIO-T2. The efficient cost will be allocated to annual allowed expenditure under RIIO-T1 years using the four year construction expenditure profile in Table 4.21. The adjustment will take effect in 2019-20 allowances concurrently for works in 2019-20, and again in 2020-21 allowances for works in that year.

Operation of volume driver for output delivery

4.129. Only WW outputs that NGET determines and delivers in accordance with its NDP will be subject to the WW volume driver. The volume driver will be triggered on every boundary that a WW output provides additional capacity. An adjustment will be made to NGET's allowed expenditure if it delivers more or less WW outputs for which the baseline allowance has been determined in Final Proposals.

4.130. The below baseline UCAs will adjust NGET's allowed expenditure downwards if capacity is less than the WW outputs assumed in setting baseline allowances; the above baseline UCAs will increase NGET's allowed expenditure if NGET determines and delivers additional WW outputs through its NDP to those assumed in setting the baseline allowance in Final Proposals. We will use the four year construction expenditure profile (see Table 4.21) to derive annual allowed expenditure for the amount of WW output delivered in a given year. This will be compared to NGET's baseline annual allowed expenditure.

Issues affecting uncertainty mechanisms: planning requirements for the undergrounding of new transmission cables

Initial Proposals

4.131. In Initial Proposals we proposed to use an uncertainty mechanism to adjust the baseline revenues to reflect the actual volume of undergrounding that was needed to meet planning requirements.

4.132. Our consultants had assessed the information NGET provided to us on the mechanism and assessed the proposed UCAs and concluded that NGET's approach to converting from lifetime cost in the IET report to capital cost for UCA was reasonable.

Respondents' views

4.133. Two respondents as well as NGET commented on the Undergrounding uncertainty mechanism.

- One respondent agreed with having an undergrounding volume driver, which could be adjusted for planning decisions on a case by case basis.
- Another respondent wanted confirmation that the unit costs for the undergrounding uncertainty mechanism reflected the full cost of an actual undergrounding project.

- NGET supported the inclusion of the mechanism.

Final Proposals

4.134. We considered respondents' comments on the Undergrounding Uncertainty Mechanism. NGET's business plan currently assumes that routes will be constructed using overhead lines and have been funded on this basis. The UCAs set out in Table 4.22 are the additional costs needed to underground these routes and therefore all additional costs should be captured within the UCAs.

Table 4.22: 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

4.135. We are not proposing to make any further adjustments to the uncertainty mechanism or the UCAs.

4.136. We will use the UCAs set out in Table 4.22 to adjust NGET's revenue to reflect decision made by the planning authorities on the length of cable circuits that are to be undergrounded. An adjustment will be made to their allowed expenditure if NGET is required to deliver more or less than the length of circuit assumed in the baseline allowances. We will use a four year construction expenditure profile to derive annual allowed expenditure (see Table 4.23).

Table 4.23: Construction expenditure profile for underground cabling

Construction expenditure profile for yr1/yr2/yr3/yr4	% of total efficient costs
Year 1	20.0%
Year 2	50.0%
Year 3	20.0%
Year 4	10.0%

Issues affecting uncertainty mechanisms: planning requirements for DNO mitigation measures

Initial Proposals

4.137. In Initial Proposals we proposed to use an uncertainty mechanism to adjust the baseline for actual DNO mitigation activities that NGET would need through planning requirements.

4.138. We assessed the efficiency of NGET's proposed volume driver in its March 2012 Business Plan, which resulted in the following proposed adjustments:

- 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.
- Applying the cost efficiency reductions, identified through the unit cost assessment.

Respondents' views

4.139. There was no specific feedback on the DNO mitigations measures from stakeholders other than NGET.

4.140. NGET disagreed with the reduction of the £18.1m from the uncertainty mechanism baseline as it reflected non-unit items. This issue is discussed in the *Issues affecting baseline allowances: DNO Mitigation measures* section, as it relates to baseline funding rather than the uncertainty mechanism design of UCA.

Final Proposals

4.141. Table 4.24 sets out our Final Proposals for the DNO mitigation measure UCAs, which consist of the following adjustments, made since Initial Proposals:

- Increasing the UCA for the DNO switchgears to reflect changes made to the cost efficiency assessment, set out in the *Issues Affecting Baseline – Unit Cost Efficiencies* section.
- Reducing the annual RPE adjustment from 0.9 per cent to 0.8 per cent as a result of the updated RPE assessment, set out in the uncertainty mechanisms chapter and the RPE annex.

Table 4.24: Final Proposal of UCAs for DNO mitigation activities

Volume Driver	Final Proposals
Undergrounding of DNO overhead line (based on 132kV underground cable) (£m/ single circuit km)	1.1
DNO tower dismantling (£k/tower)	[redacted]
New DNO overhead line(based on reconductoring of 132kV tower line and assuming three towers per km) (£m/ single circuit km)	0.7
New DNO double circuit overhead line (based on reconductoring 132kV tower line and three towers per km) (£m/double circuit km)	0.8
New DNO switchbays (based on NGET unit cost – average of air-insulated and gas-insulated switchgear) (£m/bay)	[redacted]
RPE's	0.8% per annum

Issues affecting uncertainty mechanisms: Strategic Wider Works

Initial Proposals

4.142. In Initial Proposals we proposed reopener arrangements for NGET to request us to make a within-period determination on delivering large reinforcements of the transmission system. Consistent with NGET's March 2012 Business Plan we said that SWW provisions would apply to reinforcement works that cost more than £500m or other WW outputs that did not meet the criteria under the NGET's NDP. We also included the Hinkley-Seabank reinforcement in SWW because of the size of the project and its relationship to uncertain new nuclear generation.

4.143. We also said that as part of its determination, we would assess the needs case and the efficient costs of delivery. It would then set out its decision in relation to new SWW outputs approved for delivery and the amount of funding adjustment to NGET's allowances and other provisions as necessary.

Respondents' views

4.144. NGET's response did not express any views in relation to the general proposals we set out in Initial Proposals about the SWW arrangements. It raised a specific issue on our proposed re-classification of the Hinkley-Seabank reinforcement into SWW. We have set out above why we have decided to continue with this approach for Final Proposals.

4.145. One other stakeholder responded on the proposed SWW arrangements noting that it is important that these do not create barriers or delays. The stakeholder also asked for further clarification as to what comfort can be provided to investors, whose generation projects depend on SWW outputs, that we would release the funding for these works.

Final Proposals

4.146. A key principle of the SWW arrangements is that the regulatory framework does not act as a barrier to the efficient delivery of wider works outputs. We included guidance in Initial Proposals on the SWW arrangements that would apply for NGET seeking within period determination from the Authority on additional funding and outputs to deliver wider system reinforcements. We have not made any further amendments to this guidance for Final Proposals. We consider this guidance provides useful information to the industry as a whole on the key aspects of the arrangements to consider SWW outputs. However, we will further consider if further external guidance is necessary to set out in more detail the assessment and decision making stages, information requirements on the TOs and the arrangements for ensuring timely delivery of wider works outputs.

5. Final Proposals for Non-Load-Related Capex for NGET

Chapter Summary

This chapter sets out our Final Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for non-load-related expenditure (NLRE) for NGET to deliver the associated outputs over the RIIO-T1 period. We also summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Introduction

5.1. NLRE is primarily driven by asset health conditions, the risk of asset failure and its impact on the transmission network. TOs need to invest to make sure their existing assets are in good condition to provide secure, efficient and reliable network services to consumers.

5.2. We split the NLRE into two categories of investment, namely:

- Primary plant-type assets. This includes the expenditure on the replacement and refurbishment of transformers, switchgears, overhead lines, underground cables. Cable tunnels are also included in this category.
- Non-primary plant-type assets. This includes including the expenditure on the replacement of reactors, meters, protection and control systems, flooding protection and other miscellaneous assets.

5.3. The remainder of this chapter provides the details of our Final Proposals and is structured as follows:

- summary of Final Proposals
- details of NLRE for primary plant-type assets
- details of NLRE for non-primary plant-type assets
- mid-period review for NLRE
- TPCR4 asset renewal performance review.

5.4. Figures presented in this chapter are in 2009-10 prices and exclude physical security expenditure and RPEs but where it is relevant, references to RPE adjustments are stated. The figures are also stated before any IQI adjustment. Background information set out in Initial Proposals is not repeated here and this chapter should be read in conjunction with Initial Proposals and the associated supporting document on cost assessment and uncertainty.

Summary of Final Proposals

5.5. We set an ex ante baseline of £4,337.2m for NLRE in our Final Proposals. Table 5.1 outlines the details of this and the changes from NGET's forecast and our Initial Proposals.

5.6. Our Final Proposals represent a 6.8 per cent reduction compared to NGET's forecast £4,654.1m. In comparison with Initial Proposals, we have increased the baseline by £166.9m (4 per cent), reflecting new evidence provided by NGET and the correction of errors in our Initial Proposals.

5.7. We also include our Final Proposals for physical security expenditure and RPEs for NLRE in Table 5.1. The details of physical security are set out in Chapter 6 of this document, and for RPEs we set out further details in the supporting document 'Final Proposals – Real price effects and ongoing efficiency appendix'.

Table 5.1: Final Proposals for NLRE and changes from NGET's forecast and Initial Proposals

NLRE - Asset Categories	NGET's forecast (£m)	Ofgem Initial Proposals (£m)	Ofgem Final Proposals (£m)	Changes in Final Proposals from Initial Proposals (per cent)	Change in Final Proposals from NGET's forecast (per cent)
Primary Plant-type Assets	**3,797.0**	**3,456.2**	**3,556.6**	**2.9%**	**-6.3%**
Switchgear	1,180.4	1,028.8	1,061.5	3.2%	-10.1%
Overhead Lines	763.7	733.6	733.6	0.0%	-3.9%
Transformers	573.7	510.6	539.1	5.6%	-6.0%
Underground Cables	827.3	738.2	777.4	5.3%	-6.0%
Cable Tunnels	452.0	444.9	444.9	0.0%	-1.6%
Non-Primary Plant-type Assets	**857.1**	**714.2**	**780.6**	**9.3%**	**-8.9%**
Protection & Control	361.0	300.5	334.3	11.3%	-7.4%
Weather-Related Resilience	116.1	104.9	104.9	0.0%	-9.6%
Substation Other (Not requiring asset replacement)	173.1	137.1	168.5	22.9%	-2.7%
Other TO	99.9	71.4	71.4	0.0%	-28.5%
BT21CN	38.1	38.1	38.1	0.0%	0.0%
Reactors	33.4	29.7	31.0	4.4%	-7.1%
Substation Other	27.7	24.6	24.6	0.0%	-11.0%
Metering	7.7	7.7	7.7	0.0%	0.0%
Total NLRE	**4,654.1**	**4,170.3**	**4,337.2**	**4.0%**	**-6.8%**
Physical Security	146.2	0.0	0.0	N/A	N/A
RPEs	452.4	237.2	188.7	-20.4%	-58.3%

Primary plant-type assets

Initial Proposals

5.8. For Initial Proposals we agreed with NGET's forecast on asset replacement volumes, but reduced baselines from NGET's forecast through capex efficiency savings.

5.9. We set out the cost reductions between 1.6 per cent and 12.8 per cent based on our consultants' analysis from a range of evidence including unit cost benchmarking, review on sample schemes and asset management system.

Respondents' views

5.10. Only NGET commented on our NLRE Initial Proposals. NGET expressed general concerns regarding two aspects of our consultants' capex assessment process:

- Errors – NGET said that the analysis contained a number of mistakes and inconsistencies, and that our consultants' unit cost comparison with historical unit costs did not appear to take account of changes in definition of the scope of unit costs since TPCR4 and Rollover. It also said that there were inconsistencies between the bottom-up assessment of scheme costs and the 'Ofgem level' unit cost comparisons for the same schemes.
- Poor process – NGET said that the benchmarking approach adopted did not meet Ofgem's own stated requirements for transparency and robustness. It had concerns that our consultants' unit cost comparisons with other TOs were not based on the same scope, that the different nature and size of their business made the comparison not statistically robust, and that our consultants' bottom-up assessment of scheme costs was not transparent. It also had reservations about the quality of Ofgem's consultants' benchmark database because of the rounded nature of the consultants' benchmarks.

5.11. We summarise the asset-specific comments from NGET by asset categories below.

Switchgear

5.12. NGET made the following comments with regards to switchgear:

- Our consultants' benchmarks did not differentiate between the costs of Gas Insulated Substation (GIS) and Air Insulated Substation (AIS) high voltage switchgear.
- Our consultants did not review a proper set of sample switchgear replacement schemes in the bottom-up assessment.
- Our consultants' comparisons with historical unit costs did not reflect accurate volume weightings between AIS and GIS switchgears.

5.13. In addition to the above, NGET provided evidence to justify how its unit costs were inflated by the inclusion of Gas Insulated Busbar (GIB) costs in the scope of GIS costs.

5.14. NGET also provided its own unit cost benchmarking analysis against the 'Offshore Transmission Technology Report[32]' from the European Network of Transmission System Operators for Electricity (ENTSO-E).

Overhead lines

5.15. NGET was broadly content with our Initial Proposals for overhead lines, but argued that the cost reduction to the baseline for overhead line tower steelwork should take account of its built-in construction efficiency.

Transformers

5.16. NGET challenged that the cost reduction in our Initial Proposals double-counted its built-in construction efficiency for transformer replacement schemes.

5.17. NGET provided its own unit cost benchmarking analysis against the 'Offshore Transmission Technology Report' from the ENTSO-E to justify their unit costs as efficient.

5.18. NGET also provided further evidence to justify that its transformer unit costs reflected current market prices. It also provided an analysis of unit costs in its transformer replacement schemes to demonstrate that it had not inflated the unit costs for the future schemes planned in the later part of RIIO-T1.

Underground cables and tunnels

5.19. NGET argued that the sample schemes reviewed by our consultants were very atypical to the rest of cable replacement schemes. It challenged that the cost reduction to cable replacement in our Initial Proposals suggesting it was not appropriate.

5.20. NGET provided further evidence to demonstrate the difference between sample schemes and the rest of schemes for cable replacement. It also provided its own analysis on all of the cable replacement schemes by following the same approach used by our consultants. This analysis revealed a cost reduction of £34.9m for cable replacement schemes.

5.21. NGET also requested an increase in baseline of £14.5m to cover cable installation costs that were omitted from its business plan.

32 https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/SDC/European_offshore_grid_-_Offshore_Technology_-_FINALversion.pdf

Final Proposals

5.22. We have reviewed the comments and new evidence from NGET and come to the following conclusions for Final Proposals:

- We propose to increase the baselines for switchgear, transformers and underground cables by £32.7m, £28.5m and £39.2m, respectively, from our Initial Proposals.
- We do not propose to adjust the baselines for overhead lines and cable tunnels from our Initial Proposals.

5.23. We consider our consultants' analysis and methodology to be robust and transparent. They have been engaged in the benchmarking process alongside the electricity TOs from the outset of the development of unit cost definitions for RIIO-T1. As a result, they have a very clear understanding of unit cost definitions and the scope of work included within these costs. They have ensured that their benchmarks are comparable to the RIIO-T1 unit cost definitions. Where there are differences between their benchmarks and the RIIO-T1 unit cost definitions, they have given reasonable consideration in their analysis. Our consultants' recommendations for Initial Proposals were based on a range of evidence including unit cost benchmarking and scheme assessment. We believe their conclusions reflect a balanced view taking into account a combination of bottom-up and top-down analysis. The consultants' approach was set out in a summary report published alongside Initial Proposals.

5.24. We set out the details of our reasoning for our Final Proposals below.

Switchgear

5.25. We propose a baseline allowance of £1,061.5m for switchgear replacement. Our proposal represents a 3.2 per cent increase from our Initial Proposals and is 10.1 per cent lower than NGET's forecast.

5.26. The change from our Initial Proposals recognises the following aspects:

- Our consultants have updated the switchgear unit cost benchmarking to reflect the difference between AIS and GIS high voltage switchgear unit costs. This results in an increase of 5.6 per cent in switchgear replacement costs.
- We apportioned NGET's built-in construction efficiency (which is calculated from total scheme costs) to the value of the switchgear component in switchgear replacement schemes. This leads to a decrease of 2 per cent in switchgear replacement costs.

5.27. We consider that NGET's argument for the inclusion of GIB costs in the switchgear unit costs is not relevant to the switchgear replacement expenditure, because we have not found any evidence to support that NGET's switchgear replacement schemes may include the scope of GIB replacement. Therefore we discount the impact of GIB costs on switchgear replacement.

5.28. We acknowledge that the comparison between the RIIO-T1 unit costs and historical unit costs for switchgears were not made entirely on the same basis. However, our consultants confirmed that this comparison was only used to provide a sense-check on the RIIO-T1 unit costs, and therefore it did not impact on their conclusions on cost adjustments.

5.29. We noted that the purpose of the 'Offshore Transmission Technologies' report from ENTSO-E was to provide an overview of offshore electricity transmission technologies and that unit costs for high voltage assets in the report were indicative. While NGET's unit cost comparison against this report provided further information, we did not regard this evidence to be sufficiently accurate or comparable for us to be able to put significant weight on it in Final Proposals.

Overhead lines

5.30. We set out a baseline allowance of £733.6m for overhead line replacement. Our proposal remains the same as Initial Proposals and represents a 3.9 per cent reduction to NGET's forecast.

5.31. For overhead line tower steelwork, we note that NGET did not provide sufficient evidence to justify its built-in construction efficiency. We believe our Final Proposals for overhead lines provide an efficient allowance for NGET to deliver its outputs.

Transformers

5.32. We set out a baseline allowance of £539.1m for transformer replacement. Our proposal represents a 5.6 per cent increase from our Initial Proposals and is 6 per cent lower than NGET's forecast.

5.33. We consider that NGET has provided sufficient evidence to address our concerns in Initial Proposals. We therefore propose to increase the baseline to reflect NGET's built-in construction efficiency in transformer replacement schemes and remove the double counting of cost efficiency savings. In reaching our Final Proposals, we apportioned the built-in construction efficiency to the value of the transformer component in transformer replacement schemes. This results in an increase of 5.1 per cent in transformer replacement costs.

5.34. For similar reasons as stated for switchgear, we decided not to adjust Final Proposals with regards to the comparison with historical unit costs and NGET's comparison against the 'Offshore Transmission Technology Report' from ENTSO-E.

Underground cables and tunnels

5.35. We set out a baseline allowance of £777.1m for underground cable replacement and a baseline allowance of £444.9m for cable tunnel replacement. For underground cables, our proposal represents a 5.3 per cent increase from our Initial Proposals and is 6 per cent lower than NGET's forecast. For cable tunnels, our proposal remains the same as Initial Proposals and is 1.6 per cent lower than NGET's forecast.

5.36. We agree with NGET's analysis on cable replacement schemes and our Final Proposals are to increase the baseline allowance by £39.2m from our Initial Proposals. This change takes account of additional evidence provided by NGET to illustrate how Initial Proposals have overstated the cost reduction based on sample schemes.

5.37. We do not agree with NGET's late request to include an omitted cable installation cost in our Final Proposals because there was insufficient evidence presented to us to justify the expenditure.

Non-primary plant-type assets

Initial Proposals

5.38. For Initial Proposals we proposed to accept NGET's forecast on expenditure for BT 21st Century Network and meter replacement. For the other categories we set out cost reductions between 9.6 per cent and 28.5 per cent based on our consultants' review on sample schemes and capex efficiency savings.

Respondents' views

5.39. Only NGET commented on our NLRE Initial Proposals. The key points from NGET are summarised below.

5.40. NGET said that we had double-counted efficiency savings by not recognising its built-in construction efficiencies in replacement schemes for protection and control systems, low voltage alternative current equipment, batteries and reactors.

5.41. NGET challenged our Initial Proposals for stand-alone control system replacement costs on the basis that our consultants' assessment had not fully recognised the engineering challenges associated with undertaking this type of work in existing substations. NGET also provided a counter argument to our consultants' assessment on the unit cost and replacement volume. It explained that the mismatch between its forecast and our estimates was caused by differences in unit cost definition and scope.

5.42. For strategic spares, NGET disagreed with our Initial Proposals and requested full funding. It provided further evidence to clarify its approach to strategic spares and how the costs were captured in its capex and opex programmes.

5.43. For the cost of weather-related resilience NGET requested further clarification on whether the disallowed tower flooding protection cost could be revisited at the mid-period review.

5.44. NGET did not comment on our Initial Proposals for the other types of expenditure in this category.

Final Proposals

5.45. We reviewed the comments and new evidence from NGET and propose three changes from Initial Proposals:

- We propose to increase the baseline allowance for protection and control system replacement by £33.8m and set the total allowance as £334.3m.
- We propose to increase the baseline allowance for the Substation Other category (not requiring asset replacement) by £31.4m and set the total allowance as £168.5m.
- We propose to increase the baseline allowance for reactors by £1.3m and set the total allowance as £31m.

5.46. We do not propose to adjust the baseline allowances from our Initial Proposals for the other types of expenditure for non-primary plant-type assets. Further details of our changes are set out below.

5.47. For protection and control systems, although NGET explained its approach to using high complexity and engineering factors during the scheme cost estimation process, the new information did not allay our concerns. There appears to be a tendency to adopt overly conservative complexity and engineering assumptions, which are reflected as high complexity and engineering factors. We take the view that looking at each aspect of a scheme design individually may have the unintended consequence of layering (pancaking) complexity assumptions to a level that may be inefficient compared with making such assumptions when considering the scheme as a whole. For Final Proposals we therefore maintain our position in Initial Proposals.

5.48. However, we have increased the baseline allowance for protection and control system replacement to recognise costs that are not strictly attributable to the unit cost definition in stand-alone control replacement schemes, but should reasonably be included within non-primary plant-type expenditure.

5.49. We propose to fully fund the cost of strategic spares totalling £31.4m because NGET's new evidence explains the cost of strategic spares sufficiently and addresses our concern regarding the risk of double counting this cost in the other types of investment.

5.50. We noticed that NGET did not provide sufficient evidence to justify its built-in construction efficiencies in replacement schemes for assets in the Substation Other category. We believe our Final Proposals for substation other provide an efficient allowance and therefore for Final Proposals maintain our position in Initial Proposals.

5.51. We propose to review the disallowed cost of tower flooding protection during the mid-period review and adjust the allowance for weather-related resilience where necessary.

Mid-period review

Initial Proposals

5.52. For Initial Proposals we did not propose an uncertainty mechanism to review Network Output Measures (NOMs) and adjust the baseline allowance for NLRE. We also outlined our approach to assessing the performance of NOMs at the end of RIIO-T1.

Respondents' views

5.53. LRE is a customer-driven activity, but NLRE work is more flexible and can be organised around peaks and troughs of LRE activity. NGET commented on the need to introduce an uncertainty mechanism to cover financing costs associated with advancing NLRE activity if LRE occurs more slowly than forecast. NGET estimated that the potential financing cost could exceed the effective materiality threshold proposed for other uncertain costs.

Final Proposals

5.54. In recognising that NLRE would be affected by the progress of LRE, we propose to review NOMs at the mid-period review. If NGET can justify material changes to the delivery of NOMs and provide evidence to justify the changes in the best interest of consumers, we will make necessary adjustments to its allowance to reflect financing costs. Further information on the assessment of NOMs is set out in the Outputs, incentives and innovation Supporting Document.

TPCR4 asset renewal performance review

5.55. We reviewed NGET's asset renewal performance during TPCR4 in our Initial Proposals based on the information updated on 31 March 2012. This review provided us with a holistic view for assessing its NLRE forecast in the RIIO-T1 business plan.

Initial Proposals

5.56. For Initial Proposals we expressed our concern about the under delivery of 132kV switchgear replacement and estimated that the costs associated with under delivery could be in a range between £50m and £122m. As our estimate was based on partial forecast information available at the time, we recommended a final reconciliation be carried out during an efficiency review after the completion of TPCR4 and the TPCR4 rollover year.

Respondents' views

5.57. NGET commented that the statistics on their TPCR4 asset renewal performance should be updated to reflect the latest information in their 2011-12 regulatory reporting pack (RRP).

5.58. NGET also requested that Ofgem should recognise the over delivery of other asset types, such as transformers, which were excluded from the TPCR4 rollover allowances.

Final Proposals

5.59. Our review of TPCR4 asset renewal performance has given due consideration to the trade-off between over delivery and under delivery across asset classes and operating voltages.

5.60. We updated our assessment of the under delivery in volumes of 132kV switchgear using the information submitted by NGET in its 2011-12 RRP. We calculated an under delivery in volume of 64 units of 132kV switchgear based on a comparison with the forecast produced by our age-based modelling using NGET's 2009-10 asset life estimation. We estimated that the cost associated with the under delivery is likely to be in the range of £48m to £75m. Should this under delivery continue to the end of the TPCR4 and its rollover period we would retrospectively reduce the TPCR4 allowance to avoid duplicating funding in RIIO-T1. After applying a sharing factor of 25 per cent (applicable for TPCR4), we estimate a provisional reduction from £12m to £19m to the TPCR4 allowances.

5.61. We recognise that any claw-back needs to be based on actual figures after the completion of TPCR4 and the TPCR4 rollover. Therefore the above analysis does not form part of our Final Proposals as we can only complete such review once the TPCR4 and its rollover period is complete.

6. Final Proposals for Non-operational Capex and Opex for NGET

Chapter Summary

This chapter sets out our Final 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 summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Non-operational capex

6.1. Non-operational capex is expenditure on new and replacement assets which are not system assets. This includes:

- IT and telecoms
- vehicles including mobile plant and generators
- land and buildings used for administrative purposes.

Initial Proposals

6.2. In our Initial Proposals we proposed that NGET's forecasted expenditure on vehicles and land and buildings should be allowed in full.

6.3. Our consultants provided two scenarios for setting baselines – case 1 representing a higher reduction and case 2 a lower reduction. For IT and telecoms expenditure, we proposed to follow the case 1 scenario for two specific projects: Transmission Front Office (TFO), and Strategic Asset Management (SAM). In respect of all other IT expenditure on systems and projects we proposed a 50 per cent reduction from what has been requested by NGET.

Respondents' views

6.4. NGET's comments concerning IT and telecoms expenditure were as follows.

- It argued that the arbitrary cut of 50 percent in other IT expenditure was inappropriate and based upon unsupported assumptions.
- It also argued that this will put safety and reliability outputs at risk and will increase totex as embedded efficiencies will no longer be deliverable.

- It said that the proposed reductions in expenditure were inconsistent with the assumption of lower direct opex allowances arising from benefits from TFO and SAM.

- It also said that the reductions in IT costs ignored the flexibility of National Grid's Information Systems (IS) delivery model using external resources.

Final Proposals

6.5. We have reviewed the IT and telecoms baselines proposed in Initial Proposals and further evidence provided by NGET in its response. As a result we have increased the baselines for Final proposals as shown in the Table 6.1.

Table 6.1: Comparison of Initial and Final Proposals for NGET non-operational capex

£m 2009/10 prices	NGET Forecast Total Expenditure over RIIO-T1	Initial Proposals Total Expenditure over RIIO-T1	Final Proposals Total Expenditure over RIIO-T1	Change Initial Proposals to Final Proposals	Change Initial Proposals to Final Proposals
Non-operational capex					
TFO	62.8	43.8	47.6	3.8	8.7%
SAM	32.7	26.5	27.5	1.0	3.8%
Other	43.9	21.9	32.9	11.0	50.0%
Total IT Expenditure	**139.4**	**92.2**	**108.0**	**15.8**	**17.1%**
Vehicles	13.9	13.9	13.9	0.0	0.0%
Land and Buildings	18.1	18.1	18.1	0.0	0.0%
Total	**171.3**	**124.2**	**139.9**	**15.8**	**12.7%**

6.6. In respect of TFO and SAM we have increased the allowances to reflect the case 2 low reduction scenario suggested by our engineering consultants. This recognises the importance of these projects to the delivery of reductions in direct opex.

6.7. For other IT expenditure we have increased the baseline. As a result of NGET's further explanations, we accept that most of this expenditure is on-going IT capex necessary to maintain and enhance existing systems. We have decided to maintain a reduction of 25 per cent from NGET's forecast. While NGET has provided more evidence, we still consider that some savings will be achieved as not all system refreshes will go ahead in RIIO. Nevertheless we consider NGET will be able to achieve its agreed outputs with this increased baseline.

Opex

6.8. Operating costs are 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 indirect costs and business support.

6.9. Direct opex represents the inspections, maintenance and fault repair costs associated with maintaining NGET's transmission network. Closely associated indirect costs (CAI) represent the back office functions that support the inspections and maintenance teams work on the network. 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).

6.10. 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; and CEO and other corporate functions.

6.11. Table 6.2 shows our Initial and Final Proposals. All numbers are quoted on a best case scenario.

Table 6.2: Initial and Final Proposals for Total NGET opex

£m 2009/10 prices (excluding RPEs)	NGET Forecast Total Expenditure over RIIO	Initial Proposals Total Expenditure over RIIO	Final Proposals Total Expenditure over RIIO
Direct opex	1,001.6	843.0	769.4
Closely associated Indirect Costs	530.0	467.5	477.6
Business Support	405.7	318.3	317.7
Sub - Total Opex	**1,937.3**	**1,628.8**	**1,564.7**
Non Controllable and Excluded Service costs	743.2	743.2	743.2
Total	**2,680.5**	**2,372.0**	**2,307.9**

Direct opex

Initial Proposals

6.12. To help us assess NGET's opex we used engineering consultants for expert advice. Our consultants developed a methodology for assessing NGET's business plan which re-modelled costs to provide recommendations on baselines. The re-modelling took into consideration changes in the network, asset condition, and asset diversity and complexity challenges faced over the RIIO-T1 period. We subsequently adopted these recommendations for Initial Proposals.

6.13. This led to a proposed overall reduction of 16 per cent to NGET forecasts. The biggest areas of reduction were fault repairs and planned inspections and maintenance.

Respondents' views

6.14. NGET expressed concern at the reductions being proposed. It said that the analysis made by our consultants failed to take into consideration factors such as:

- whole life costing
- efficiencies already embedded within the plans
- one-off benefits in base years.

6.15. NGET said that our opex assessment had been conducted independently to the capex review. It also said that the assessment contained errors including the double counting of efficiencies. It claimed that it ignored benchmarking evidence and the totex benefits whereby higher maintenance allowances reduced capex costs over the long run.

6.16. NGET raised, amongst other concerns, the following specific points:

- **Asset painting**: NGET argued that the allowances set were inappropriately low, and as a consequence assets will not achieve their anticipated technical lives. It provided further evidence about the whole life costing modelling and greater clarifications regarding its business plan.
- **Efficiencies double counted**: NGET argued that approximately £40m was double counted in our calculations of efficiency savings made for planned maintenance.
- **One off 2010-11 benefits**: NGET argued that a one-off receipt of an insurance payout has artificially reduced its opex for the base year of our cost assessment. This in turn has artificially reduced baselines for the RIIO period.
- **Physical security expenditure**: NGET argued that this should be set as an ex ante allowance.

Final Proposals

6.17. We have reviewed in detail NG's response to Initial Proposals. In broad terms we believe that the approach adopted by our engineering consultants was appropriate. Although NGET submitted a large commentary, only limited modelling under pinning the plan has been provided. In the absence of this detail the consultants' methodology remains, in our view, the most appropriate means of assessment. We have only departed from this methodology where a case for change is clearly justified, for example greater clarifications or errors that have been identified.

6.18. We are proposing a £75.2m increase from Initial Proposals This is offset by Allowed Innovation costs which have been removed and treated as an adjustment to revenue. The direct opex baselines for Final Proposals are £769.4m for the RIIO-T1 period. We set out the reasons for our changes in more detail below.

6.19. Table 6.3 below shows the changes from Initial Proposals to Final Proposals.

Table 6.3: Comparison of Initial and Final Proposals

£m 2009/10 prices	NGET Forecast Total Expenditure over RIIO-T1	Initial Proposals Total Expenditure over RIIO-T1	Final Proposals Total Expenditure over RIIO-T1	Change Initial Proposals to Final Proposals	Change Initial Proposals to Final Proposals
Fault Repairs	264.9	213.8	229.1	15.3	+7%
Planned Inspections & Maintenance	387.3	300.4	360.3	59.9	+20%
Vegetation Management	26.9	23.1	23.1	-	0%
Operational Property Management	123.6	106.8	106.8	-	0%
Physical Security Expenditure	50.1	50.1	50.1	-	0%
Allowed Innovation Costs (incl. IFI)	148.8	148.8	-	-148.8	-100%
Total	**1,001.6**	**843.0**	**769.4**	**-73.6**	**-9%**

6.20. Allowed Innovation costs have now been removed and treated as an adjustment to revenue.

Fault repairs

6.21. In their assessment methodology our consultants took 2010-11 actual opex as a starting point. However, in that year NGET received a one-off insurance payment of £2.6m from incidents relating to cable tunnels and floods. The effect of this is to suppress the ongoing cash costs on which our Initial Proposal baselines were based. We accept that these proceeds should not be included in our assessment, and so have increased baselines by £15.3m for Final Proposals.

Planned maintenance – asset painting

6.22. NGET has argued the asset painting baselines set out in our Initial Proposals would mean that assets would not be able to achieve their technical lives. It provided further supporting evidence, including benchmarking data and greater detail about the whole life costing model it has adopted.

6.23. In our view the benchmarking information portrays NGET as an average performer in terms of costs compared to its peers. NGET remarked that the benchmarking data does exclude environmental considerations to which the UK is particularly susceptible such as coastline and lichen impacts. Although we are sympathetic to these arguments to an extent we do not think that it fully accounts for the performance gap.

6.24. NGET also acknowledged under delivery of asset painting over the TPCR4 period. In its response it said that it followed an 18-year cycle for tower painting, but had not been able to achieve its full outputs in TPCR4 owing to supplier and financial constraints.

6.25. Despite NGET's view above, the evidence provided in respect of the whole life costing demonstrates that spending on asset painting during RIIO-T1 will avoid higher capital costs going forward. We have therefore increased opex baselines by £28m covering both plant and tower assets, which is lower than NGET's forecast.

Planned maintenance – double count of efficiencies

6.26. NGET argued that efficiencies were double counted in the Initial Proposals. We investigated its concerns and found that there was a double-count. This was caused by NGET's classification of continuous improvement and capitalisation, with the two adjustments being aggregated. We have revised our Final Proposals to correct this.

Physical security

6.27. NGET has argued that costs associated with physical security should be funded through ex ante baselines. Although we agreed with the need for expenditure in this area, the uncertainty around the extent and efficient cost of work meant for the purposes of Initial Proposals we placed them in an uncertainty mechanism.

6.28. We have considered the points raised in NGET's response, but have decided to retain this expenditure within an uncertainty mechanism. The scope of work and efficient costs remain unclear. The uncertainty mechanism will ensure NGET are appropriately remunerated for efficient physical security expenditure.

6.29. For capex no further allowances have been granted on an ex ante basis. £150m of funding was provided in the TPCR4 Rollover, and NGET's workplan remains behind schedule. Given this, and significant uncertainties around scope and efficient delivery of work, we consider that no further ex ante funding is required, and we will consider remunerating NGET's efficient costs at the first re-opener window in 2015.

Closely associated indirect opex

Initial Proposals

6.30. As with direct opex we used our consulting engineers to help with the assessment and again they used their methodology to assess costs. In short their approach, combined with the limited information provided by NGET, resulted in a reduction of £62.5m being applied to forecast baselines.

Respondents' views

6.31. NGET considered that the level of disallowed expenditure was excessive and unjustified. It also raised concerns with operational training, and linkages between opex and capex workloads.

6.32. Other respondents were concerned that, given the shortage of specialist skills in the energy sector both in the UK and globally, our Initial Proposals may not be sufficient to enable network companies to meet their workforce renewal requirements.

Final Proposals

6.33. We have reviewed the allowances set in light of NGET's and other stakeholder comments and our Final Proposals have increased Initial Proposals by £10.1m to reflect the arguments made about operational training, in line with its forecast. We propose a baseline of £477.6m for the RIIO-T1 period.

6.34. The Table below shows the changes from Initial Proposals to Final Proposals.

Table 6.4: Comparison of Initial and Final Proposals

£m 2009/10 prices	**NGET Forecast Total Expenditure over RIIO-T1**	**Initial Proposals Total Expenditure over RIIO-T1**	**Final Proposals Total Expenditure over RIIO-T1**	**Change Initial Proposals to Final Proposals**	**Change Initial Proposals to Final Proposals**
Operational IT & Telecoms	153.4	132.1	132.1	-	0%
Project Management	14.4	14.5	14.5	-	0%
Network Design & Engineering	41.9	35.6	35.6	-	0%
Engineering Management & Clerical Support	40.5	34.8	34.8	-	0%
Network Policy (incl. R&D)	21.1	17.6	17.6	-	0%
Health, Safety & Environment	44.6	37.4	37.4	-	0%
Operational Training	134.4	124.3	134.4	10.1	8%
Stores & Logistics	8.2	5.9	5.9	-	0%
Vehicles & Transport	24.5	24.4	24.4	-	0%
Market Facilitation	9.2	6.9	6.9	-	0%
Network Planning	37.8	34.0	34.0	-	0%
Total	**530.0**	**467.5**	**477.6**	**10.1**	**2%**

6.35. In setting these allowances we make the following comments.

Operational training

6.36. Our consultants considered different possibilities but nevertheless we adopted a baseline of £124.3m at Initial Proposals. Our reasons for this was that NGET had proposed a significant increase from its current expenditure levels and we took a view that it could achieve greater efficiencies.

6.37. Following clarifications from NGET including its response to Initial Proposals, we no longer consider this reduction to be appropriate. In light of this we have decided to fund operational training at the level proposed by NGET. We will nevertheless closely monitor NGET's level of spend and if they under spend during of RIIO-T1 then we will want to understand the reasons for this and ensure that future outputs are not jeopardised.

6.38. For all other areas we have maintained the baselines set at Initial Proposals, as we have not seen any substantive new evidence to support a change. We note NGET's comments that CAI was not appropriately linked to the capex programme. However, there was an increase in capex activity which is captured in the 2010-11 base year used to set baselines.

Business support costs

6.39. The Final Proposals for business support costs are discussed in detail in Appendix 3.

7. Final Proposals on cost and uncertainty for NGGT

Chapter Summary

This chapter sets out our Final Proposals for efficient levels of baseline expenditure and uncertainty mechanisms for NGGT to deliver the associated outputs over the RIIO-T1 period. We also summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Introduction

7.1. This chapter sets out our Final Proposals for an efficient level of expenditure for NGGT, and the arrangements for addressing risk and uncertainty around those costs. Our proposals are informed by our assessment of NGGT's forecasts for baseline capex and opex and for incremental capex for the purposes of Initial Proposals. Additionally, our proposals are informed by further assessment of information, evidence and data provided by NGGT within the context of its response to the consultation following the publication of Initial Proposals. We have also considered responses from other stakeholders.

7.2. The chapter is divided into a number of sections. The overview presents a summary of our proposals, and subsequent sections address unit costs, load-related capex, non-load-related capex and opex. Figures are stated before any IQI adjustment.

Overview

7.3. In this section we provide an overview of respondents' views to Initial Proposals. We then set out a summary of our Final Proposals and major changes made since Initial Proposals.

Respondents' views

7.4. NGGT provided a detailed response to Initial Proposals. It raised a number of concerns, particularly regarding pipeline and compressor station unit costs. NGGT also brought forward a considerable level of new information during the consultation period and following its response. We summarise these concerns and the new information in the sections below. Several other respondents provided their views on our Initial Proposals. An industry body was the only respondent to provide specific input regarding our proposed uncertainty mechanism in relation to the Industrial Emissions Directive (IED). It suggested that it was reasonable to move IED compliance costs to an uncertainty mechanism given that the legislation is yet to be transposed into UK law and there remains some ambiguity over its application. However, no respondent, other than NGGT, provided specific input in relation to our cost assessment. Respondents' views on other areas such as constraint management can be found in the Outputs, Incentives and Innovation supporting document.

Final Proposals and changes from Initial Proposals

7.5. Table 7.1 sets out how our Final Proposals differ from NGGT's forecast expenditure, as set out in its March 2012 business plan. It includes non-controllable opex of £0.9bn[33], which comprises items such as licence fees or business rates. In total we have reduced NGGT's forecast best view costs by around £2.0bn and have moved £0.1bn from NGGT's baseline into uncertainty mechanisms.

Table 7.1: Key cost parameters for NGGT

£m 2009/10 prices	NGGT Forecast Total Expenditure over RIIO-T1	IP Total Expenditure over RIIO-T1	FP Total Expenditure over RIIO-T1	Change IP to FP	Change IP to FP %
Load-related capex	3,471.6	2,177.0	2,356.1	179.1	8.2%
Non-load-related capex	1,432.0	951.9	851.6	-100.3	-10.5%
Non-operational capex	64.0	44.7	51.7	7.0	15.7%
Total capex	**4,967.7**	**3,173.6**	**3,259.4**	**85.8**	**2.7%**
Customer contributions	**-**	**-**	**-**	**-**	**-**
Total Capex (net of customer contributions)	4,967.7	3,173.6	3,259.4	85.8	2.7%
Total Opex (incl. non controllable)	1,498.0	1,493.4	1,509.3	15.9	1.1%
Total expenditure (Totex) exc RPEs	**6,465.7**	**4,666.9**	**4,768.6**	**101.7**	**2.2%**
RPEs	422.5	146.9	58.2	-88.7	-60.4%
Totex before IQI adjustment	**6,888.3**	**4,813.9**	**4,826.8**	**12.9**	**0.3%**
IQI adjustment	n/a	69.8	103.3	33.6	48.1%
Totex after IQI adjustment	**6,888.3**	**4,883.7**	**4930.2**	**46.5**	**1.0%**

7.6. This reflects the outcome of our assessment of NGGT's business plan and subsequent information ahead of the Initial Proposals and the analysis of our engineering consultants, Pöyry. Additionally, it reflects the consultation responses

[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.

from Initial Proposals. Our Final Proposals address the concerns expressed regarding both load and non-load-related expenditure projects and take into account the additional information received from NGGT and other respondents.

7.7. The highlights of our Final Proposals and changes from Initial Proposals are:

- We have modified our views regarding the volume of incremental capex included in the best view.
- We maintained our view that NGGT's Avonmouth projects are included within the baseline. The projects' ex ante funding has been increased to £153.7m, reflecting updated pipeline costs.
- We have modified our Initial Proposals for both baseline projects and the relevant uncertainty mechanisms regarding the emissions expenditure. These reflect updated compressor unit costs and additional information regarding NGGT's options to deal with the Industrial Emissions Directive.
- We have maintained our views as set in Initial Proposals for the asset health expenditure.
- We have broadly accepted NGGT's comments around opex and the evidence provided in response to our Initial Proposals, and have changed the baseline accordingly.

Unit costs

7.8. This section relates to allowances for the primary assets of the National Transmission System (NTS), ie compressor stations and pipelines. In our Initial Proposals we did not have a specific section on unit costs. However, for clarity, and as a result of significant new information from NGGT, we consider it appropriate to include a separate section to set out our Final Proposals for unit costs for compressor stations and pipelines.

Initial Proposals – Compressor Station Unit Costs

7.9. For Initial Proposals we deemed that NGGT's forecast unit costs were not efficient. Following extensive assessment of NGGT's historic project costs and using additional international data, we proposed different unit costs for gas turbine and electric Variable Speed Drive (VSD) compressor units.[34] The unit costs proposed were based on the relationship we established between the output (in MWs) and the cost for single units for gas turbine-driven compressor units and for electric VSD compressor units.

7.10. The outturn costs provided by NGGT were adjusted for a number of errors and inaccuracies.[35] Additionally, NGGT's original data did not separate the cost of specific bundled works undertaken in compressor stations (such as re-wheels and

[34] The term "electric Variable Speed Drive (VSD) compressor units" is used interchangeably with "electric driven compressor units".
[35] Examples of these are (i) contradicting information regarding the cost of long HV connections at Hatton and Felindre compressor stations, (ii) the actual size of the compressor trains installed in Felindre and St. Fergus, (iii) inclusion of HV substation costs not required in future projects.

flow modifications) which would not form part of compressor replacements driven by emissions legislation. We note that NGGT, when forecasting future incremental projects, includes these as separate projects to the installation of compressor units. We therefore removed costs relating to these activities so as not to double count or over-estimate the unit cost of compressor replacement.

7.11. Our proposed unit costs did not reflect the installation of compressor units on greenfield sites, because NGGT's outturn data primarily related to brownfield projects. The only greenfield compressor site installation was for Felindre, which has gas and electric-driven compressors. However, NGGT did not separate data between the gas turbine-driven units and the electric VSD unit, with the exception of compressor trains. Therefore, we could not assess greenfield site data and so we did not use this to inform our proposed UCA for gas turbine-driven units.

7.12. Therefore, we explored other data sources for gas turbine-driven units, such as the information relating to an Alaskan compressor station. The data from the Alaskan compressor station contained a series of gas turbine compressor train costs. We used these to complement the gas turbine compressor train data provided by NGGT for Felindre station. Also, general station data was utilised, only after we verified their close fit with a top-down analysis of Felindre compressor station data.

Respondents' views – compressor station unit costs

7.13. NGGT expressed concerns regarding our proposed compressor unit costs. It provided extensive comments on our methodology, suggesting it was simplistic and non-representative. Within its response NGGT also provided us with additional cost data. This data was gathered through the Gas Transmission Benchmarking Initiative (GTBI), a study undertaken by the Juran Institute of 67 new gas transmission compressor units in Europe.

7.14. NGGT provided additional data from costing exercises, quotes from Original Equipment Manufacturers (OEMs) and publicly available compressor construction costs. NGGT also provided a new cost methodology which calculated compressor unit costs depending on the scope of works and referencing an internal library of unit costs.

Final Proposals – compressor station unit costs

7.15. Following the publication of our Initial Proposals, we engaged extensively with NGGT regarding our proposed unit costs. NGGT had the opportunity to present its concerns at a number of face-to-face meetings. We also held several meetings to understand and challenge the new information presented by NGGT, and asked a large number of supplementary questions. We took all of this evidence into account when deciding on our Final Proposals.

7.16. NGGT's response included a number of criticisms of our methodology and the data used to derive Unit Cost Allowances (UCAs). We note that NGGT provided only limited information to support its forecasts in its business plan, and it was unable to provide more detailed information (such as its cost data in a Work Breakdown Structure (WBS) format) to us before Initial Proposals. As a result, our proposed unit costs were based on the information NGGT could provide at Initial Proposals, and other third party unit cost information that was available to us.

7.17. We undertook a detailed analysis of the compressor unit and station data provided in the GTBI study. We consider that this data represents good evidence, although we note that there are limitations which are discussed in more detail below. Having taken these into account, we have based the UCAs in Final Proposals on the GTBI data. We have also verified these UCAs by cross-checking them against the outturn costs of recently delivered projects. Below we set out our analysis in more detail.

7.18. The GTBI study consisted of compressor station and unit data[36], which was provided by six European gas transmission companies. These related to projects undertaken from 2007 to date. The compressor unit data in the GTBI study included costs for design/engineering, main works contractors and compressor train[37] works. Where extraordinary factors (such as long HV connections or complicated design specifications) were present, these costs were reported separately, but included within the cost of compressor units. We have included these extraordinary factors in our proposed UCA, so as to reflect possible extraordinary factors that NGGT might face.

7.19. The data also included the costs of bundled works undertaken alongside the installation of compressor units, such as flow modifications and/or asset health expenditure. Since these bundled works are not a prerequisite to the installation of compressor units, we excluded them from our UCA. This is consistent with our approach at Initial Proposals.

7.20. In view of the above, and that NGGT will be installing compressor units for both its emissions and LRE incremental capex, we proceeded with analysing the compressor unit data. The aim was to (i) derive meaningful relationships for compressor outturn costs and outputs; (ii) understand the impact of specific project items, eg design costs; and (iii) assess the deliverability of compressor projects.

7.21. We found several issues with NGGT’s submitted data to the GTBI study. These included misclassification of flow modification costs, exchange rate errors, inclusion of inefficient delays in project delivery dates and compressor units’ output. The influence of these errors was to inflate the cost and delivery time of NGGT’s compressor units.

7.22. We found some limitations in the GTBI data. We were unable to review all the participants’ originally submitted data for reasons of commercial confidentiality. Also,

[36] The data related to a total of 67 compressor units in 33 compressor stations (18 brownfield and 15 greenfield).
[37] Compressor train includes typically the motion generator (gas generator and power turbine, or electric motor) and the compressor and/or the unit control system.

several compressor unit data points included only the total figure, without any further breakdown, despite that being requested by the Juran Institute.

7.23. Through our analysis we identified relationships between compressor output and cost for:

a. electric driven compressor units installed in existing sites
b. electric driven compressor units installed in new sites
c. gas turbine-driven compressor units.[38]

7.24. We were unable to establish separate costs for specific items such as design costs and HV connections. As a result, we included these elements within our total unit cost.

7.25. We also used the GTBI data to provide a benchmark to assess NGGT's forecast construction time. In terms of delivering compressor projects, we note that:

a. the average delivery time is around four years, which is considerably faster than the delivery time proposed by NGGT for the compressor projects in RIIO-T1
b. NGGT has been fairly consistent in delivering projects required for load-related purposes in 3-4 years. In contrast, projects driven by environmental obligations have lagged considerably, despite being of the same or simpler project scope.

7.26. In addition to our analysis using the GTBI data, we examined the other evidence and analysis submitted by NGGT.

7.27. NGGT provided two pricing exercises for a hypothetical compressor project at an existing site that had been submitted to it by Main Works Contractors (MWCs). We welcome NGGT's efforts in sourcing this information. However, the two quotes diverged significantly in terms of costs, were subject to further negotiation and detailed clarification[39], and were presented with a significant range of costs around the proposed price.[40]

7.28. We note that NGGT informed one MWC that the quote would be used for the purposes of setting UCAs. We consider that knowledge of this information may have affected the MWC's incentive to submit competitive pricing for the relevant projects. As a result, we put very limited weight on this evidence.

7.29. We reviewed NGGT's new methodology. This consisted of two constituent parts. The first part calculated the costs for a simple project and the second for a

[38] We could not establish meaningful relationships separately for gas turbine driven units installed in existing sites and those installed in new sites. The reason was that no reliable conclusions could be drawn from the data available.
[39] As explained by NGGT.
[40] One MWC quoted a range -5%/+10% and the other +/-30%.

limited number of complexity factors. However, this was based on the same data set (recent NGGT compressor projects) that was submitted to GTBI. As a result, we identified the same errors in the data as we had found in NGGT's GTBI submission. We also found that the granular nature of the methodology, and the large number of unit cost options, many of which were based on limited data, meant that it would be difficult to determine an efficient output level. As a result, we chose to place more weight on the GTBI report, after correcting for NGGT's errors, in determining unit costs.

7.30. In view of our assessment described above and where installing a compressor unit is justified, we propose the following unit costs for compressor units.

Table 7.2: Final Proposals – compressor Unit Cost Allowances

2009/10 prices **Unit type**	**Fixed costs (£m/unit)**	**Variable costs (£m/MW)**
Electric (New site)	[redacted]	[redacted]
Electric (Existing site)	[redacted]	[redacted]
Gas (New/Existing site)	[redacted]	[redacted]

7.31. We note that these unit costs are the outcome of outturn project costs. As such, NGGT will benefit from lessons learned through past projects and the ability to streamline the delivery of compressor projects. Also, sharing of best practice among the participants of the GTBI study will enhance NGGT deliverability.

7.32. As explained above, specific sub-items, such as design costs or HV connection for electric VSD units, are included within the unit costs. The difference between the fixed costs on electric and the gas units is attributed to the different nature of the two types of installations.[41]

7.33. Additionally, we have verified these unit costs by applying them to recent NGGT projects, after taking into account separate major bundled works undertaken by NGGT on those sites, such as asset health expenditure or flow modifications. Modelled project costs, using these unit costs, were comparable to outturn costs.

7.34. For the avoidance of doubt, project works bundled with installation of compressor units relating to:

- load-related expenditure (LRE), such as re-wheels, reverse flow modifications
- asset health, such as rebuilding/renovating civil assets, replacement of control units

[41] For example the requirement to house the VSD – which is typically bigger to a gas turbine - increases the scope of civil and/or electromechanical works. Also, the requirement to have an HV connection is also contributing to higher fixed costs.

are funded separately either through the revenue drivers identified for such projects, or through the asset health expenditure identified below. This will ensure that our UCAs will provide NGGT with the appropriate level of expenditure for compressor unit installation projects.

Initial Proposals – Pipeline Unit Costs

7.35. In our Initial Proposals we provided specific unit costs only for the projects included in the baseline. More specifically, we used our engineering consultants' data, which was part of a feasibility study conducted for an overseas client. These unit costs were based on sample data of 36 pipelines.

7.36. Unit costs were provided for the following terrain types for pipelines of diameters of 600mm, 915mm and 1220mm. Three broad classifications were considered:

- 'Normal' – which includes farmland and rolling hills
- 'Difficult' – which includes roads, railways, suburban, marsh, rock
- 'Overall' – which is a combination of normal and difficult terrain.

7.37. For the baseline projects and in the absence of specific route information we applied the relevant unit costs for the 'normal' type of pipeline.

Respondents' views – Pipeline Unit Costs

7.38. In its response to our Initial Proposals, NGGT said that our proposed unit costs were based on a feasibility study rather than actual project outturn costs. It also said they did not take into account circumstances representative to the construction of pipelines in GB, such as design codes. It said that our choice of the 'normal' classification ignored the presence of 'difficult' terrain at project sites, and that as a result our unit costs should be based on the 'overall' classification. Furthermore, it said that unit costs did not take appropriate consideration of RPEs when converting the original data into 2009-10 prices.

7.39. NGGT also identified and provided in its response various North American pipeline data. Additionally, NGGT provided us with additional sub-project item data for its own pipeline projects. This included the outturn cost of rail crossings, river crossings, horizontal directional drilling (HDD), linepipe costs, etc.

Final Proposals – Pipeline Unit Costs

7.40. Following the publication of our Initial Proposals, we engaged extensively with NGGT regarding our proposed pipeline unit costs. NGGT had the opportunity to present its concerns at a number of face-to-face meetings. We noted NGGT's remarks on our proposed pipeline unit costs. We evaluated our pipeline UCAs in light of this information.

7.41. We consider that NGGT's suggestion of using the 'Overall' classification is well founded, as this represents better the mix of circumstances found in GB when building pipelines. Therefore, on the basis of the new evidence provided, we propose to use the 'Overall' unit cost for pipeline costs for ex ante and incremental capex. We have also converted unit costs into 2009-10 prices by applying the relevant RPE and RPI indices.[42]

7.42. We considered NGGT's comments regarding different design codes between GB and foreign gas networks. However, our consultants confirmed that the impact of different design codes had already been taken into consideration in setting their advised unit costs.

7.43. In relation to the North American data, we welcome NGGT's effort to source this. However, we propose to give greater weight to our consultants' analysis, as this was based on a greater number of data points and a more detailed examination of data. Also, no visibility of the specific circumstances and efficiency of delivery of the North American projects could be provided.

7.44. Table 7.3 shows the pipeline unit costs for Final Proposals. These unit costs are higher than those used at Initial Proposals.

Table 7.3: Final Proposals - Pipeline Unit Costs

Diameter (mm)	Final Proposals (£m/km)
610	[redacted]
915	[redacted]
1220	[redacted]

7.45. As a cross-check, we compared these against TPCR4 pipeline unit costs used for revenue driver calculations and verified the impact of RPEs on such costs. We also checked our proposed unit costs against NGGT's detailed forecasts for its Avonmouth pipelines project. These checks showed that our proposed unit costs are appropriate.

Load-related capex

7.46. As mentioned in our Initial Proposals, load-related capital expenditure (LRE) is the investment required to:

- ensure that the NTS is able to cope with the changing pattern of flows on the network (network flexibility capex)
- connect new loads coming from customers (CCGTs, storage facilities, etc.) to the NTS (incremental capex).

[42] We acknowledge that RPEs were not taken into consideration when uplifting the 'normal' data. However, its application leads to a lower figure than the one provided in Initial Proposals.

7.47. Below we explain our Final Proposals for the individual subcategories of LRE, ie network flexibility, ex ante entry/exit/bi-directional capex and incremental capex. We note that, for projects currently in progress, or that have been forecast with sufficient accuracy, these are funded through ex ante baselines and/or from previously set revenue drivers.

Initial Proposals – Network flexibility

7.48. Network Flexibility capex is a new category of expenditure which NGGT suggested in its business plan and is driven by changing network flows. This expenditure is difficult to forecast accurately over the whole RIIO-T1 period. Our Initial Proposals dealt with this through an ex ante allowance for the projects to maintain the 1-in-20 obligations in Scotland. The remainder was proposed to be largely funded through uncertainty mechanisms where evidence of need becomes available. This meant that other forecast baseline projects, such as the one for additional compression at Lockerley, were put into the pool of projects considered within the uncertainty mechanisms provided in the Initial Proposals. These UMs differentiate network flexibility expenditure between investment necessary to meet future peak day requirements, and expenditure required to meet more dynamic commercial capacity obligations.

7.49. We also provided allowances for NGGT in order to undertake additional analysis on the changing pattern of flows.

Respondents' views – Network flexibility

7.50. NGGT welcomed our inclusion of the Scottish 1-in-20 projects, although it said that we had been unclear in explaining the minor efficiency reductions. Additionally, NGGT expressed concerns about the reduced level of allowance compared to its forecast and the placement of one ex ante project into the set of projects within the uncertainty mechanisms. However, no additional evidence was provided to support these concerns.

Final Proposals – Network flexibility

7.51. Having considered all evidence provided within the original business plan and given that no additional information was provided in the context of the Initial Proposals consultation, we are maintaining our views in terms of the allowances and the uncertainty mechanism for network flexibility.

7.52. Additionally, we note that the allowance put forward for the Scottish 1-in-20 projects reflected recent outturn project costs. Specific projects, such as re-wheels and flow modifications, were delivered at a lower cost than the ones proposed in NGGT's business plan. As a result, we do not propose to make any adjustments for Final Proposals.

Initial Proposals – Entry/exit/bi-directional

7.53. Load-related capex entry/exit/bi-directional refer to schemes which provide respectively entry/exit/bi-directional capacity to the NTS.

7.54. In our Initial Proposals we included baseline funding for the construction of two pipelines (915mm in diameter) to support the NTS following the planned decommissioning of the Avonmouth Liquefied Natural Gas (LNG) storage facility.

7.55. These projects were originally included within NGGT's load-related incremental capex forecast. However, given the merits of NGGT proposals we deemed it appropriate to fund the pipeline solution ex ante. Our ex ante allowance was based on our engineering consultants' comparator 'normal' pipeline cost data. In view of this we proposed an allowance of £112.3m.

7.56. One more project was identified (pipeline environmental monitoring & aftercare) and was funded as forecast in NGGT's business plan.

Respondents' views – Entry/exit/bi-directional

7.57. In its response to our Initial Proposals, NGGT agreed with our approach to include the pipeline solution within the ex ante allowance, but argued that the costs were not reflective and would underfund these projects. This was attributed to the low pipeline unit costs.

7.58. NGGT justified its views and provided specific reasons, as explained in the unit cost section above. Also, NGGT undertook a desktop exercise to assess the routing of the Avonmouth pipelines and more specific costs.

Final Proposals – Entry/exit/bi-directional

7.59. Following NGGT's response we reassessed the cost of the baseline projects, using the 'overall' pipeline unit cost. As mentioned above, given the additional evidence provided by NGGT, we consider the 'overall' unit cost is more representative of conditions found in GB.

7.60. Additionally, we assessed the cost of the Avonmouth pipelines following a detailed bottom-up approach. As mentioned, NGGT provided us with the cost of specific sub-projects costs, such as river crossings, linepipe[43], etc. We combined these with the information provided following NGGT's desktop routing exercise, to estimate the total pipeline costs.

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[43] The steel pipeline itself.

7.61. The two different approaches resulted in similar project costs.[44]

7.62. In light of the above, we consider it appropriate to set the ex ante allowance for the pipeline solution[45], following the planned decommissioning of the Avonmouth LNGS facility, to £153.7m.

Initial Proposals – Incremental

7.63. The amount and location of incremental capex is dependent upon customer signals at entry capacity auctions or through the exit capacity application process. These signals cannot be accurately forecast.

7.64. In light of that, we proposed that incremental capex, other than that relating to flexibility, will be derived from revenue drivers. These will be calculated upon receipt of the relevant signals and based primarily on efficient unit costs for pipelines and compressor stations. We recognised that NGGT's proposal was based on the information on costs and phasing which was available to them. However, we expressed our concerns about the number of projects that were suggested by NGGT, but were not yet backed by user commitment. Based on past experience and for the purposes of informing our best view, we assumed 25 per cent attrition in such projects and the remainder of those being on average deferred by two years. Also, we were concerned about the level of underlying pipeline and compressor station unit costs for the anticipated incremental capex. Although specific revenue drivers had not yet been calculated, we estimated them to result in a 20 per cent reduction in incremental capex.

7.65. We also included expenditure relating to already signalled projects of £309.3m, relating to Fleetwood and the South West Quadrant. These were based on previously calculated revenue drivers.

Respondents' views – Incremental

7.66. No specific views were provided by the respondents with respect to our assumptions regarding the attrition or deferral of incremental capex projects. However, NGGT expressed their view that pipeline and compressor station unit costs were not appropriate.

[44] The bottom-up approach resulted in slightly lower costs, but we are minded that there may be variances occurring during the project's execution. Thus, we consider that the top-down approach estimation through the pipeline unit costs as appropriate.
[45] The pipelines to be installed will be of 915mm in diameter.

Final Proposals – Incremental

7.67. In light of the respondents' views, additional information that has been assessed since Initial Proposals and unit costs proposed for compressor stations (as seen above in Table 7.2) and for pipelines (as seen above in Table 7.3), we have recalculated the level of incremental capex for our best view.

7.68. We also sought to recognise the uncertainty around the UK's future energy mix and the consequences for investment in the NTS over the RIIO-T1 period. The recent publication of the Energy Bill and announcement of the UK Government's gas strategy has led to an increased probability of incremental investment above that set out in Initial Proposals. We have added £400m to our best view forecast to reflect this. The final outcome of these adjustments is an increase to our best view forecast of incremental capex of £166m.

7.69. We have reclassified the already signalled projects of £309.3m[46] based on previously calculated revenue drivers and included them in the baseline.

Funding & Associated Outputs

7.70. In light of the above we propose to set a LRE baseline of £186.7m. This will fund the projects in Scotland, and the further analysis and installation of the pipeline sections proposed in the pipeline solution in time for the planned decommissioning of the Avonmouth facility.

7.71. Table 7.4 below shows our proposal for NGGT's load-related capex allowance.

Table 7.4: NGGT Load-related allowance (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Total
Flexibility, Entry & Exit LRE Baseline	24.6	13.8	8.9	54.8	76.4	7.9	0.2	-	**186.7**
Previously triggered revenue drivers	14.6	26.5	70.1	108.4	68.7	20.4	0.8	-	**309.3**
Incremental capex	6.7	10.2	76.6	159.2	304.6	341.8	454.6	506.4	**1,860.0**
Total	**45.8**	**50.5**	**155.6**	**322.4**	**449.7**	**370.1**	**455.6**	**506.4**	**2,356.1**

[46] These include projects in Fleetwood and in the Southwest quadrant of the NTS. Fleetwood is a location where the need for a new entry point was triggered by the long term capacity auction in 2006 and at the time of Initial Proposals commercial rights to future capacity were held at the site. Our understanding is that these capacity rights have been lost. At the present time it is unclear whether the future capacity as signalled will be needed. We will continue to monitor the situation and should circumstances 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 may have implications for base revenue and 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.

7.72. In terms of outputs for LRE baseline, we maintain our views as per the Initial Proposals and set specific outputs. Table 7.5 below lists these projects in terms of LR area, project scheme, output, start date, delivery date and costs.

Table 7.5: 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	2014	2020	26.4
Entry	Pipeline environmental monitoring & aftercare	Satisfaction of permit obligations	2014	2018	6.6
Exit	Avonmouth decommissioning	Pipeline solution	2014	2018	153.7

7.73. We note that the delivery date for the pipeline solution has been brought one year forward, compared to Initial Proposals, to 2018. This reflects commissioning of the pipeline solution in time, prior to the planned decommissioning of the Avonmouth LNG storage facility. Relevant funding to allow post-commissioning activities will be available to NGGT up to 2019, as it was originally foreseen in Initial Proposals.

7.74. Including the two pipelines in the baseline provides clarity to NGGT, compared to other projects subject to the Planning Act requirements. Therefore, we expect NGGT to expedite its activities and apply earlier than 2017, to warrant commissioning of the pipelines' operation in 2018. We will be reviewing the progress of these actions through the annual reporting progress and the mid-period review.

Non-load-related capex

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

7.76. The emissions-related expenditure refers to the allowances for projects aimed at the mitigation and abatement of direct gaseous emissions resulting from the operation of gas turbines required for the operation of compressor stations. It does not include expenditure in relation to methane venting. Our incentives in relation to methane venting will be set out in a future document relating to the gas SO external incentives.

7.77. The asset health expenditure refers to schemes which maintain the condition of primary assets on the NTS (entry points, pipelines, multi-junctions, compressor sites and exit points). This is achieved by managing, maintaining and replacing the secondary assets within the primary assets to achieve a defined level of network risk.

Initial Proposals - emissions

7.78. In our Initial Proposals we considered NGGT's business plan in relation to:

(1) the needs case for the two directives driving the expenditure - the IPPCD[47] (Integrated Pollution Prevention and Control Directive) and the IED[48] (Industrial Emissions Directive)
(2) the cost of the projects included in the business plan in terms of proposed unit costs, choice of technology and size of compressor unit proposed.

7.79. For Initial Proposals we considered that NGGT had proved the needs case for Peterborough and Huntingdon compressor stations regarding the IPPCD. Similarly we agreed with the needs case regarding Aylesbury compressor station with respect to the IED. Therefore, we proposed to provide ex ante allowances for these projects.

7.80. However, we considered that projects for Peterborough and Huntingdon were oversized and also that NGGT's proposed costs were not justified. Thus, we set allowances based on our UCAs for gas turbine-driven and electric VSD-driven compressor units. Additionally, we considered that some of the proposed projects were not aligned with other load-related projects. Hence, these were disallowed. As a result of the above, the baseline was set at £119.5m. For projects where we considered that the needs case had not been made, we included them in an uncertainty mechanism and proposed to revisit the needs case in the mid-period review. Therefore, the amount included within the uncertainty mechanism was £320.6m.

7.81. While our Initial Proposals figures were based on replacement of compressors, we noted that other European Transmission System Operators (TSOs) have considered more cost-efficient solutions to deal with the impact of the IED, such as Dry Low Emissions (DLEs) retrofits and exchange of non-compliant gas turbines with compliant ones.

Respondents' views - emissions

7.82. NGGT provided responses with respect to our Initial Proposals for the emissions expenditure. More specifically, NGGT provided input in three broad areas.

7.83. The first related to the uncertainty around the transposition of the IED into UK law and the risk of misalignment between legislative requirements and the availability of reasonable funding for existing legislation. NGGT sought legal advice on the potential transposition of the IED into UK law and broadly maintained the view that it will not be able to benefit from the exemption under the IED. However, due to the uncertainty around the transposition, NGGT agreed in principle with our approach

[47] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2008:024:0008:0029:EN:PDF
[48] Link provided earlier in the Uncertainty chapter of this document

to have an uncertainty mechanism around the sites related to projects driven by the IED. In order to enable delivery of the relevant projects, NGGT requested an ex ante allowance for Front End Engineering Design (FEED) work.

7.84. The second area related to our proposed mechanism to trigger investment for IPPCD Phase 4 projects (following commissioning of IPPCD Phase 3 projects). NGGT suggested that the proposed mechanism did not allow NGGT to align the requirement to commence these Phase 4 projects soon after the start of Phase 3.

7.85. The third area related to the proposed costs. More specifically, NGGT disagreed with our application of the IQI mechanism with respect to projects included within the uncertainty mechanism. This is addressed in Appendix 1.

7.86. As mentioned above, NGGT provided comments on our proposed unit costs for gas turbine and electric drive compressors. It provided us with additional compressor site specific evidence relating to the emissions projects.

7.87. NGGT also provided us with Original Equipment Manufacturer (OEM) quotes relating to retrofitting Dry Low Emissions (DLE) equipment to existing gas turbines. Retrofitting provides an alternative means to replacement in order to comply with emissions legislation. These quotes indicated that there were significant savings compared to full replacement.

Final Proposals - emissions

7.88. Following the publication of our Initial Proposals, we engaged extensively with NGGT and also the Environment Agency (EA) and the Scottish Environment Protection Agency (SEPA), to discuss and understand further the evolution of environmental legislation and its application in GB.

7.89. Having assessed all the relevant information, including the changing pattern of flows, we consider that the NTS will go through a transition period throughout RIIO-T1. Therefore, while investment in order to tackle the NTS's direct emissions can be forecast with reasonable accuracy on some sites, on other compressor sites future utilisation is unpredictable and may decline significantly.

7.90. Furthermore, NGGT considers that some compressor sites, especially in Scotland, enjoy more compression capability than required. This is due to the faster than expected decline in quantities of gas landing at St Fergus. Other sites may no longer be required upon commissioning of new compressor units on adjacent sites.

Projects disallowed

7.91. Further to our views as expressed in Initial Proposals regarding sites where projects were disallowed (eg Wormington and Hatton), we consider that the projects at Kirriemuir and St. Fergus should also be disallowed.

7.92. The reason for this is that both sites will benefit from the commissioning of the VSDs installed for the purposes of the IPPCD Phases 1 and 2. The VSDs installed have been sized to undertake the bulk operation of the stations once commissioned. There have been no additional capacity requirements at those sites arising from incremental signals. Moreover, NGGT has advised of the diminishing flows of gas coming from the St. Fergus terminal. Thus, we do not consider it efficient to provide funds for compressors in Scotland, when NGGT has pointed to the future lack of gas.

Ex ante allowance & uncertainty mechanisms

7.93. We maintain our view that the projects at Peterborough and Huntingdon relating to IPPCD Phase 3 should be funded ex ante. Having set out our position to NGGT regarding the size of the compressor units, we received no evidence contradicting this. Therefore, we maintain our views that the size of the compressor units should be 24MW for both stations and have set the allowances accordingly.

7.94. We also maintain our view on the projects at Aylesbury relating to the IED, which we consider as the first phase of IED-related works.

7.95. Therefore, we set ex ante allowances for IPPCD Phase 3 and IED Phase 1 for the aforementioned sites, using our Final Proposal UCAs, at £142.7m. We note that the relevant funding for these projects is moved to the early years of RIIO-T1 to prioritise their delivery.[49]

7.96. In setting the baseline for Final Proposals, we considered the uncertainty around the actual sites targeted for investment under IPPCD Phase 4 and the transposition of the IED into UK law, which is due to occur in January 2013. We also expect the competent authorities[50] to follow with issuing specific guidance on technical aspects of the IED. These will provide clarity regarding NGGT's future obligations.

7.97. Furthermore, evidence reviewed following NGGT's response to our Initial Proposals indicates that NGGT has been considering a wide range of options to deal effectively with the IED. Some of these options are listed below:

(1) Decommissioning of compressor sites – this was indicated for two sites due to the evolution of the NTS
(2) Retrofitting DLE equipment on existing gas turbines – NGGT has experience of such works and similar gas turbines have been operating at other installations
(3) Exchange of non-compliant gas turbines with compliant ones and use existing facilities

[49] As already mentioned in our section on Unit Costs, we expect that NGGT is able to deliver these ahead of its original forecasts and our phasing forecasts.
[50] The Environment Agency for England and Wales and the Scottish Environment Protection Agency for Scotland

(4) Installation of additional compliant compressor units in parallel with the operation of existing units – this resembles the principle followed for investment under IPPCD
(5) Decommissioning of existing units and replacement with new compliant ones.

7.98. We also consider that NGGT may be able to make use of the emergency derogation as provided within the IED[51] for existing sites, where compression capability allows such options, and subject to EA and SEPA guidance.

7.99. We welcome NGGT's revised approach to consider potentially more cost-effective solutions in order to deal with the environmental legislation, similar to those considered by its European counterparts. We recognise that there is no "one solution fits all" principle. We also acknowledge that NGGT will still be required to undertake works for both IPPCD Phase 4 and the remaining sites considered within the IED (second phase) and optimise its portfolio of options.

7.100. Mindful of future circumstances regarding flow patterns, and consistent with our approach for future flexibility capex, we propose a baseline of £9m for emissions abatement optioneering. This will enable NGGT to develop an integrated and cost-effective plan to comply with the requirements of IPPCD Phase 4 and IED Phase 2).

7.101. Additionally, we are including £269.3m in the baseline for the IPPCD Phase 4 and IED Phase 2 projects, to recognise NGGT's obligation to incur expenditure to comply with this legislation. The level of this baseline is based on the currently available information, where capex projects are forecast. If NGGT's planned expenditure is different to this amount, we will adjust the baselines up or down. We expect that NGGT's integrated plan may include opex solutions as well as capex projects. As a result, we have divided the baseline between capex (75 per cent or £202.0m) and opex (25 per cent or £67.3m).

7.102. Table 7.6 below shows the baseline profile.

[51] If the emergency derogation requires a narrow definition, whereby a gas turbine needs to be classified as emergency and being operated less than 500 hours, then we expect NGGT to classify gas turbines in sites with multiple units as such to avoid unnecessary investment.

Table 7.6: NGGT Emissions mitigation capex baseline (excluding RPEs)

£m – year to 31 March 2009/10 prices	2014	2015	2016	2017	2018	2019	2020	2021	Total
IPPCD Phase 3 & IED Phase 1	29.2	47.4	21.3	21.1	20.9	1.4	1.4	0.0	**142.7**
Emissions abatement optioneering	4.0	3.0	2.0	-	-	-	-	-	**9.0**
IPPCD Phase 4 & IED Phase 2	-	1.2	12.0	36.1	48.1	47.7	33.2	23.7	**202.0**
Total	**33.2**	**51.6**	**35.4**	**57.2**	**68.9**	**49.1**	**34.6**	**23.7**	**353.7**

7.103. Table 7.7 below lists the Outputs related to baseline allowances in terms of the project group, output, start date, delivery date and costs.

Table 7.7: Outputs of Emissions mitigation baseline (excluding RPEs)

Project Scheme	Output	Start date	Delivery date	Cost (£m)
IPPCD Phase 3 & IED Phase 1	Peterborough Huntingdon Aylesbury	2013	2020	142.7
Emissions abatement optioneering	Development of emissions abatement integrated plan[52]	2013	2015[53]	9.0
IPPCD Phase 4 and IED Phase 2	Integrated plan to set outputs	2015	-	269.3[54] Subject to re-opener

7.104. We require NGGT to use the baseline expenditure related to the emissions abatement optioneering to develop an integrated plan of investment to comply with IPPCD Phase 4 and IED Phase 2. This plan will need to demonstrate comprehensive cost-benefit analysis of all the engineering and commercial options available to NGGT. The plan will need to consider compression requirements on the network as a whole, not just at individual sites, as well as performance against other incentives such as venting. It will also take into account any guidance on IED issued by the EA and SEPA, as well as finalised IPPCD Phase 4 requirements. We will evaluate the proposals included in this plan and adjust the relevant part of the baselines upwards or downwards if necessary.

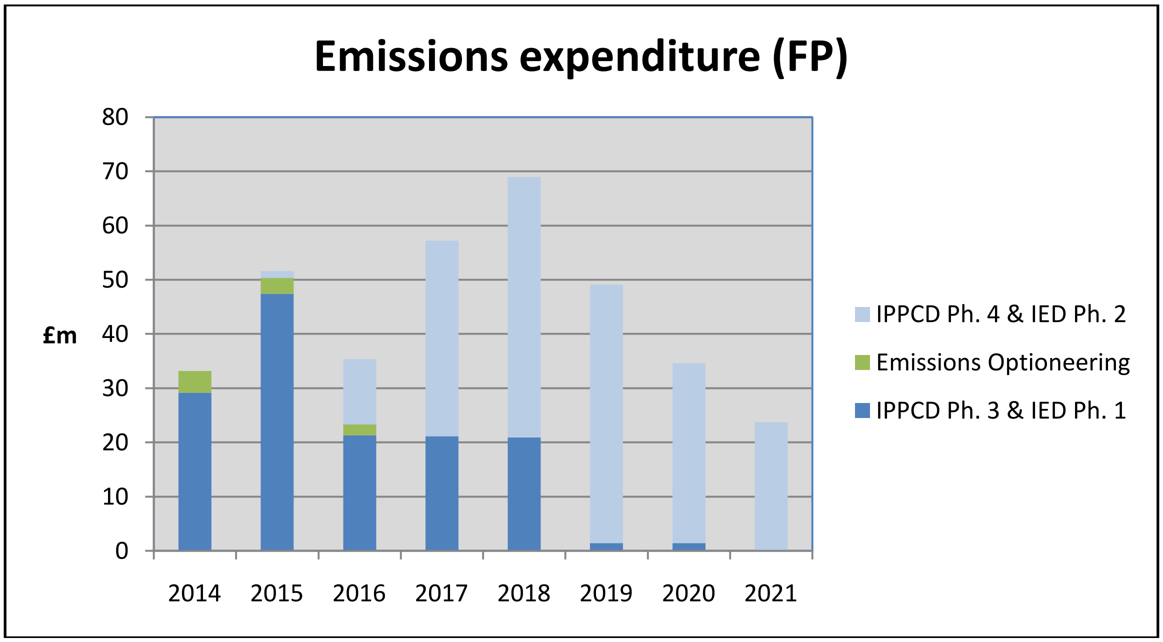
7.105. We will also continue to engage with all relevant stakeholders to assess all options available and ensure an efficient programme of works.

[52] Please refer to the uncertainty mechanism for IED below for further details.
[53] This year is set indicatively, given the timing of the current circumstances.
[54] This is the total expenditure (capex and opex) related to the compliance with IPPCD phase 4 and IED phase 2.

7.106. We also reviewed NGGT's plan to identify if there was a relationship between emissions expenditure and levels of venting from the NTS. No such evidence was identified. As a result our Final Proposals for emissions are not expected to impact on NGGT performance in relation to the venting incentive scheme.[55]

7.107. Figure 7.1 shows the profile of the emissions expenditure.

Figure 7.1: Profile of baseline emissions capex in RIIO-T1



Initial Proposals – asset health

7.108. For Initial Proposals we separated our treatment of asset health expenditure into two broad areas. The first area related to the Feeder 9 project, replacing an existing pipeline across the Humber River. The second area related to the asset health expenditure for the secondary assets within the NTS.

7.109. For the Feeder 9 project we provided an ex ante allowance to enable NGGT to undertake preliminary engineering and licensing activities. Given the uncertainty and range of expected costs, we considered it appropriate that the remainder be funded (with the costs to be evaluated) via an uncertainty mechanism. The trigger for the uncertainty mechanism was NGGT being granted the appropriate planning approval.

7.110. In relation to the other areas of asset health expenditure, we compared forecast replacement volumes and unit costs against TPCR4 allowances and expenditure for the primary and secondary asset groups. Our engineering

[55] Please refer to our Final Proposals on Gas System Operator incentive schemes for more details.

consultants also assessed the volume of works forecast, the justification and the underlying costs of secondary assets.

7.111. Based on our assessment, we proposed to set a baseline for asset health at £418.4m.

Respondents' views – asset health

7.112. In response to our Initial Proposals, NGGT argued that the proposed reduction to its allowance would impact upon their ability to meet their Network Output Measures (NOMs) targets. It provided further detail on below ground pipe and coating, impact protection and civil assets.

7.113. Further comments suggested that the funding for Feeder 9 pre-consent work was insufficient and requested that long-delivery procurement items be considered in the uncertainty mechanism.

7.114. NGGT indicated that there will be a consequential impact from the reduction of the emissions investment programme, as this is foreseen in the business plan and that the asset health investment plan and Network Output Measures (NOMs) will be impacted by decisions taken on their compressor replacement strategy, ie if a compressor unit is not replaced, this will lead to higher asset health costs.

7.115. Despite not being strictly classified within the asset health expenditure, NGGT provided specific comments regarding expenditure relating to the rationalisation of Bacton terminal. In subsequent engagement with NGGT, they provided cost estimations and requested the inclusion of such expenditure within RIIO-T1.

Final Proposals – asset health

7.116. Below we provide our thinking on the areas mentioned above.

Feeder 9

7.117. We revisited the cost data provided in the business plan, and reviewed additional information relating to NGGT's activities for acquiring the necessary permits.[56] As a result, we maintain our view that our proposed funding is sufficient for the purposes of preliminary engineering and application for the relevant consents.

7.118. NGGT has not provided us with data to prove that the tunnelling solution and the respective linepipe will pose difficulties due to procurement costs and long delivery timelines. We therefore do not propose to change the phasing of the expenditure.

[56] NGGT provided us with information on the necessary permitting activities for the pipelines solution related to the Avonmouth LNGS facility decommissioning.

7.119. In view of the above, we maintain our position as set out in Initial Proposals, where we will assess the relevant costs upon NGGT having received the necessary permits and providing us with specific cost evidence.

NOMs and reduced level of expenditure for secondary assets

7.120. We consider that NGGT's suggestion that the reduced level of expenditure will impact its ability to meet its Network Output Measures (NOMs) targets has not been justified. NGGT acknowledges that the NOMs methodology is complemented by other approaches when considering the best way forward. NGGT has also advised that the NOMs have not included the secondary assets of at least one major terminal. Furthermore, having reviewed the additional information provided in NGGT's response with our engineering consultants, we consider that our baseline will allow the necessary works to achieve its NOMs target.

Bacton rationalisation

7.121. We assessed the information provided by NGGT, including the forecast expenditure as provided in several stages (July 2011 & March 2012 Business Plans), the accompanying justification, pre-works sanction papers and feasibility studies.

7.122. We consider that NGGT's approach to potential works at Bacton terminal has been inconsistent. More specifically, NGGT classified and proposed such works under different justifications, initially within ex ante LRE, then as LRE to be triggered under the network flexibility uncertainty mechanism and then under asset health.

7.123. As mentioned above, NGGT has not included some of the secondary assets at Bacton within its NOMs methodology. Additionally, NGGT's forecasts relating to the scope of works and claimed costs have changed. Even evidence provided following the end of the consultation period for Initial Proposals indicated that NGGT explored scenarios whereby the configuration of the site would change. We were concerned that some of these scenarios seemed inconsistent with other information. We were also concerned at the wide range of cost estimates and the significant late increase in cost estimates from an initial range of £12m - £30m to a later one of £57m - £87m.

7.124. We note that we disallowed funding related to Bacton terminal in the TPCR4 Rollover. From the evidence presented to us for RIIO-T1 there still appears to be no clear investment driver or accurate forecast of likely costs. As a result, we do not propose to fund this project.

Compressors asset health

7.125. We reviewed NGGT's argument regarding the potential impact of a reduced replacement programme on the condition of its compressor stations. We note that NGGT did not provide any substantive data to support this. Furthermore, NGGT's business plan forecast significant volumes of work through the emissions-related expenditure.

7.126. NGGT's business plan has not taken into consideration that compressor stations will be operated on average 40 per cent less than in previous years. The level of asset health expenditure required on average for compressor stations in TPCR4 was approximately £200 per actual fleet operating hour. On the assumption that NTS compressors operate on average around 50,000 hours per year, our baseline asset health expenditure relating to compressor stations, as set out in Initial Proposals, is higher on a per hour basis than TPCR4. We also note that the emissions uncertainty mechanism will cover all non-compliant compressors.

7.127. In view of the above, we maintain our views on the baseline as it was set in Initial Proposals.

7.128. Table 7.8 below shows the asset health baseline.

Table 7.8: NGGT asset health baseline (incl. Feeder 9 – exc. 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

Non-operational capex

7.129. Non-operational capex is expenditure on new and replacement assets which are not system assets. This includes:

- IT and telecoms
- vehicles including mobile plant and generators
- land and buildings used for administrative purposes.

Initial Proposals

7.130. In our Initial Proposals we considered that NGGT's forecast expenditure on vehicles and land and buildings should be allowed in full.

7.131. For IT and telecoms expenditure, we proposed reductions for two specific projects in line with NGET - Transmission Front Office (TFO) and Strategic Asset Management (SAM) - following a review by our engineering consultants. In respect of all other IT expenditure on systems and projects we proposed a 50 per cent reduction from what has been requested by NGGT.

Respondents' views

7.132. NGGT's comments concerning IT and telecoms expenditure were as follows:

- It argued that our cut of 50 percent in other IT expenditure was inappropriate and based upon unsupported assumptions.
- It also argued that this will put safety and reliability outputs at risk and will increase totex as embedded efficiencies will no longer be deliverable.
- It said that the proposed reductions in expenditure were inconsistent with the assumption of lower direct opex allowances arising from benefits from TFO and SAM.
- It also said that the reductions in IT costs ignored the flexibility of National Grid's IS delivery model using external resources.

Final Proposals

7.133. We have reviewed the IT and telecoms baselines included in Initial Proposals and further evidence provided by NGGT in its response. As a result, we have increased the baselines for Final Proposals as shown in Table 7.9.

Table 7.9: Comparison of Initial and Final Proposals for NGGT direct opex

£m 2009/10 prices	NGGT Forecast Total Expenditure over RIIO-T1	IP Total Expenditure over RIIO-T1	FP Total Expenditure over RIIO-T1	Change IP to FP	Change IP to FP %
Non-operational capex					
TFO	22.5	15.7	17.1	1.4	8.9%
SAM	12.0	9.7	10.1	0.4	4.1%
Other	20.3	10.2	15.3	5.1	50.0%
Total IT Expenditure	**54.8**	**35.6**	**42.5**	**6.9**	**19.4%**
Vehicles	2.7	2.7	2.7	0.0	0.0%
Land and Buildings	6.5	6.5	6.5	0.0	0.0%
Total	**64.0**	**44.8**	**51.7**	**6.9**	**15.4%**

7.134. For TFO and SAM we have increased the allowances in line with the increases for the same projects for NGET. This recognises the importance of these projects to the delivery of reductions in direct opex.

7.135. For other IT expenditure we have increased the baseline. As a result of NGGT's further explanations, we accept that most of this expenditure is on-going IT capex necessary to maintain and enhance existing systems. We have decided to maintain a reduction of 25 per cent from NGGT's forecast. While NGGT has provided more evidence, we still consider that some savings will be achieved as not all system refreshes will go ahead in RIIO. Nevertheless we consider NGGT will be able to achieve its agreed outputs with this increased baseline.

Opex

7.136. Operating costs are 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 indirect costs and business support.

7.137. Direct opex represents the inspections, maintenance and fault repair costs associated with maintaining NGGT's transmission network. Closely associated indirect (CAI) costs represent the back office functions that support the inspections and maintenance teams' work on the network. 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).

7.138. 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; and CEO and other corporate functions.

Initial Proposals

7.139. For direct opex we applied a general reduction of 0.2 per cent to NGGT's forecast. This increased the efficiency assumption proposed by NGGT from 1.3 per cent to 1.5 per cent. We proposed specific reductions in fault costs as we consdiered there would not be an increase in these costs due to the effects of Coal Tar Enamel (CTE) coating on pipelines. NGGT's forecast for inspections and maintenance costs was reduced as we did not accept the argument from NGGT that costs would rise if the independent GDNs withdraw from the pipeline emergency repair service. Operational property costs were reduced by a further 1 per cent (removing the real increase in property costs assumed by NGGT).

7.140. For CAI costs we proposed to increase the efficiency assumption to 1.5 per cent as for direct opex above. We also reduced NGGT's forecast of increases in operational IT costs due to increases in support costs.

Respondents' views

7.141. For direct opex NGGT argued that the calculation used to reduce costs for CTE deterioration overstated the impact of these costs on overall faults costs. NGGT also presented new evidence to support the increase in fault costs due to the CTE costs.

7.142. With respect to CAI costs NGGT argued that the reduction in operational IT costs was not in line with Ofgem's engineering consultants' views. They also provided new evidence to support the increase in IT support costs as a result of the investment in SAM. NGGT also claimed that we had arbitrarily imposed additional efficiencies on its forecasts, which already included efficiencies.

7.143. Other respondents were concerned that, given the shortage of specialist skills in the energy sector both in the UK and globally, our Initial Proposals may not be sufficient to enable network companies to meet their workforce renewal requirements.

Final Proposals

7.144. Table 7.10 shows the Final Proposals for NGGT opex. These proposals represent best view and not the baseline and therefore include uncertain costs,

Table 7.10: Initial and Final Proposals for NGGT opex

£m 2009/10 prices (excluding RPEs)	NGGT Forecast Total Expenditure over RIIO	IP Total Expenditure over RIIO	FP Total Expenditure over RIIO
Direct Costs	518.0	491.5	394.7
Closely Associated Indirect Costs	123.6	117.7	121.9
Business Support	144.4	112.6	113.1
Sub total	**786.0**	**721.8**	**629.7**
Non Controllable and Excluded Services	771.6	771.6	879.6
Total	**1557.6**	**1493.4**	**1509.3**

Direct opex

7.145. With respect to direct costs, we have considered the arguments put forward in respect of CTE costs. Whilst we do not accept that the new evidence concerning CTE coating justifies an increase in baseline, we found a mistake in our calculation of the effect of these costs on overall faults costs. We have therefore changed the reduction in fault costs due to CTE from £2.1m per annum to £0.6m. This increases the baseline for fault costs. We have also reversed the additional 1 per cent reduction on operational property as this was a mistake. The original forecast of operational property costs did not include an additional 1 per cent increase as this was part of the RPE adjustments.

7.146. We have added an allowance of £67.3m for emissions expenditure relating to compliance with the IPPCD Phase 4 and IED Phase 2 directives through operational measures (see emissions capex section above for further detail). Physical security and quarry and loss costs have not been changed from NGGT's own forecast as they are subject to an uncertainty mechanism.

7.147. Despite the changes above direct costs are lower than in our Initial Proposals. This is because some costs have been moved out of direct opex. Security (armed guards) has been moved into non-controllable costs. Allowed innovation costs have been removed as they will be remunerated through innovation incentives.

7.148. Table 7.11 below shows the effect of all the changes.

Table 7.11: Comparison of Initial and Final Proposals for NGGT direct opex

£m 2009/10 prices (excluding RPEs)	**IP Total Expenditure over RIIO**	**FP Total Expenditure over RIIO**	**Change IP to FP £m**	**Change IP to FP %**
Direct Costs				
Fault Repairs (excluding Decommissioning)	38.0	49.8	11.8	31.2%
Planned Inspections & Maintenance	177.9	177.9	0.0	0.0%
Operational Property Management	35.3	37.6	2.3	6.6%
Emissions Uncertainty Mechanism	0.0	67.3	67.3	
Physical Security	41.9	41.9	0.0	0.0%
Security (Armed Guards)	108.0	0.0	-108.0	-100.0%
Quarry and Loss Development	20.2	20.2	0.0	0.0%
Allowed Innovation Costs (incl. IFI)	70.3	0.0	-70.3	-100.0%
Sub total	**491.5**	**394.7**	**-96.8**	**-19.7%**
Non Controllable and Excluded Services	771.6	879.6	108.0	14.0%
Total	**1263.1**	**1274.3**	**11.2**	**0.9%**

Closely associated indirect costs

7.149. For CAI costs we accept NGGT's additional evidence provided in respect of operational IT support costs and have therefore increased operational IT baselines. However, we do not accept NGGT's contention in respect of the additional efficiency savings of 0.2 per cent being applied to all CAI costs. We consider there will be further efficiencies to be gained particularly through the implementation of new IT systems and this is reflected in our proposals.

Table 7.12: Comparison of Initial and Final Proposals for NGGT closely associated indirect costs

£m 2009/10 prices (excluding RPEs)	IP Total Expenditure over RIIO	FP Total Expenditure over RIIO	Change IP to FP £m	Change IP to FP %
Closely Associated Indirect Costs				
Operational IT & Telecoms	17.3	21.6	4.2	24.4%
Network Design & Engineering	7.0	7.0	0.0	0.0%
Engineering Management & Clerical Support	21.8	21.8	0.0	0.0%
Network Policy (incl. R&D)	15.2	15.2	0.0	0.0%
Health, Safety & Environment	6.7	6.7	0.0	0.0%
Operational Training	19.8	19.8	0.0	0.0%
Vehicles & Transport	4.7	4.7	0.0	0.0%
Market Facilitation	21.7	21.7	0.0	0.0%
Network Planning	3.4	3.4	0.0	0.0%
Total	**117.7**	**121.9**	**4.2**	**3.6%**

Business support

7.150. Final proposed expenditure for business support costs are discussed in detail in Appendix 3.

Non-controllable costs

7.151. The figures proposed by NGGT for non-controllable costs have been used in both the Initial Proposals and Final Proposals. The change in Final Proposals is due to the move of security (armed guards) from direct opex to non-controllable costs.

8. Final Proposals on cost and uncertainty for NGET and NGGT system operator internal costs

Chapter Summary

This chapter sets out our Final Proposals for efficient levels of baseline expenditure for internal costs for NGET and NGGT to deliver the associated outputs over the RIIO-T1 period in their System Operator roles. We also summarise responses to Initial Proposals and highlight changes made for Final Proposals.

Introduction

8.1. This chapter sets out our Final Proposals for the internal System Operator (SO) costs to be recovered by NGET and NGGT 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 SO and for which they seek to recover revenue through their price controls. The main cost areas are capex (primarily related to investment in IT systems) and opex (covering the ongoing costs of running the business, including support for IT systems).

8.3. Ofgem have also published initial proposals on the external costs and incentives applying to NGET and NGGT in their System Operator roles.[57]

Initial Proposals

Approach to assessment

8.4. For Initial Proposals we used engineering consultants to assist us in our review. Our consultants reviewed NGET and NGGT's forecasts and business plans in depth and considered this in the context of future system operation requirements. They provided two scenarios for setting baselines – case 1 being the higher reduction

[57] Electricity System Operator incentive schemes from 2013: disallowing costs and efficiency in system operations reward scheme (Ref: 136/12).http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=319&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent
System Operator incentive schemes from 2013 Initial Proposals (Ref: 106/12) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=306&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

scenario and case 2 the lower reduction scenario. They also recommended that an uncertainty mechanism be used to cover expenditure towards the end of RIIO-T1.

8.5. We did not consider all the forecasts put forward by NGET and NGGT to be well justified. As a result we adopted the case 1 higher reduction scenarios. For NGET this reduced overall expenditure by £222.0m and for NGG overall expenditure was reduced by £130.4m. We did not propose an uncertainty mechanism as we considered that NGET's and NGGT's risk was covered by baselines and other uncertainty mechanisms.

NGET SO

NGET's response

8.6. NGET said that its baselines had been reduced due to uncertainty but that we had not included any mechanism to manage that uncertainty, against what our engineering consultants recommended. It also said that our consultants had incorrectly assumed a linear relationship between opex and capex. To assist its arguments NGET provided further information clarifying its position.

Final Proposals

8.7. We have considered NGET's response to Initial Proposals in detail, including its additional information. After further consideration we have decided to move to case 2 – lower reduction scenario of the consultants range. This represents an increase of £74.4m from Initial Proposals baselines and a total baseline of £830.1m across the RIIO-T1 period.

8.8. Table 8.1 shows Final Proposals for NGET SO internal costs.

Table 8.1: Comparison of Initial and Final Proposals for NGET internal SO opex and capex

£m 2009/10 prices	NGET Forecast Total Expenditure over RIIO-T1	IP Total Expenditure over RIIO-T1	FP Total Expenditure over RIIO-T1	Change IP to FP	Change IP to FP
SO Capex	312.4	203.2	230.1	26.9	13%
SO Opex	665.2	552.5	600.0	47.5	9%
Sub Total	**977.6**	**755.7**	**830.1**	**74.4**	**10%**
Adjustment for RPEs	34.3	3.8	5.5	1.7	45%
Adjustment for IQI	-	-	37.0	37.0	-
Total	**1011.9**	**759.5**	**872.6**	**113.1**	**15%**

8.9. In setting these allowances we make the following comments:

Uncertainty mechanism

8.10. NGET stated in its business plan that there would be greater uncertainty over investments towards the end of the RIIO-T1 period. An important feature of the RIIO process was that licensees would provide plans which were robust throughout the eight year period. It remains our view that NGET's business plan contains some investments without sufficient justification.

8.11. We also note that our consultants were not aware of the other uncertainty mechanisms put forward in our Initial Proposals. These uncertainty mechanisms, such as the efficiency incentive rate, mid-period review and specific re-opener relating to EMR, are set out in Chapter 3. We remain of the view that the funding mix and balance of risks remains appropriate and so do not propose an additional uncertainty mechanism.

Capex allowances

8.12. NGET re-iterated its business plan justification in its response to our Initial Proposals. It also provided further detail and clarification on its investment plans. In some cases the emphasis of the investment has changed, for example the stability control system where the benefits of enhanced monitoring capability has been stressed.

8.13. In light of the new information and clarification provided by NGET, we propose to move to the case 2 lower reduction scenario which equates to a capex baseline of £230.1m, an increase of £26.9m over our Initial Proposals.

8.14. The baseline includes an allowance of £12.6m for data centre costs; this is unchanged from Initial Proposals.

Linkages between opex and capex

8.15. NGET argued that the linear link assumed between opex and capex was wrong. It provided evidence that some of its opex activities have no relationship with capex programmes.

8.16. As a result, we have refined our analysis with our engineering consultants. Consequently operating cost baselines have been increased. For certain elements of these costs, the new methodology splits them between a fixed and variable component. For example, NGET has indicated that within the business support category certain costs are fixed including the market facilitation and the cost of membership of a number of important international transmission co-ordination groups (such as ENTSO-E, and CORESO). The revised allowances for operating costs take account of these costs. For variable costs, which fluctuate in line with changes in the size of the capital programme, these have continued to be scaled accordingly but now take account of the increase in the baseline for capital expenditure.

8.17. Based on this revised methodology we are proposing a new opex baseline of £600.0m, an increase of £47.5m over Initial Proposals.

NGGT SO

NGGT response

8.18. NGGT provided similar arguments to those in the NGET response. It also provided more clarification in relation to capability enhancements, asset health and EU Regulatory Requirements.

Final Proposals

8.19. Table 8.2 shows Final Proposals for NGGT SO internal costs.

Table 8.2: Comparison of Initial and Final Proposals for NGGT internal SO opex and capex

£m 2009/10 prices	NGGT Forecast Total Expenditure over RIIO-T1	IP Total Expenditure over RIIO-T1	FP Total Expenditure over RIIO-T1	Change IP to FP	Change IP to FP
SO Capex SO Opex	263.9 324.5	197.7 260.3	159.4 293.8	-38.3 33.5	-19% 13%
Sub Total	**588.4**	**458.0**	**453.2**	**-4.8**	**-1%**
Non-Controllable Costs	60.9	71.2	134.0	62.8	88%
Sub Total	**649.3**	**529.2**	**587.2**	**58.0**	**11%**
Adjustment for RPEs	15.9	1.6	1.8	0.2	13%
Adjustment for IQI	-	43.4	14.7	-28.7	-66%
Total	**665.2**	**574.2**	**603.7**	**29.5**	**5%**

Uncertainty mechanisms

8.20. There is no change in our position from Initial Proposals regarding uncertainty mechanisms, for the same reasons set out in the section for NGET (SO) above.

NGGT capex

8.21. The further clarifications provided by NGGT (SO) helped us to understand better its planned expenditure. As a result, we have set our Final Proposals using the case 2 lower reduction scenario. This provides a capex baseline of £159.4m, an increase of £24.5m above our Initial Proposals, once the re-classification of Xoserve costs referred to below has been taken into account.

8.22. The baseline includes an allowance of £12.6m for data centres; the figure is unchanged from Initial Proposals.

Linkages between Opex and Capex

8.23. We have applied the same approach for setting NGGT's opex allowances that was discussed for NGET above. Based on this revised approach our Final Proposals show a new baseline of £293.8m, an increase of £33.5m from Initial Proposals.

Non-Controllable Costs

8.24. Non-controllable costs are the opex and capex relating to Xoserve. The change in Final Proposals is due to the re-classification of £62.8m Xoserve capex from SO capex to non-controllable costs. The costs include the £10.7m referred to in Chapter 7.

Appendices

Index

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.[58]

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 SHETPLC 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.

Summary of Initial Proposals

1.5. For Initial Proposals we used the same IQI matrix that we had set out in our Strategy Decision document. The incentive rate was considered to be post-tax.

1.6. NGET and NGGT's IQI scores are set out in Table A1.1 below:

[58] See: Ofgem (March 2011) http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf

Table A1.1: Initial Proposals 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 %

Respondents' views

1.7. NGGT said that it should not be penalised for volume differences under the IQI where Ofgem had moved ex ante funding to uncertainty mechanisms for specific reasons such as future planning or legislative requirements. It gave two examples of the Feeder 9 replacement and expenditure to comply with IED. It also said that this approach was inconsistent with our Strategy Decision.

Final Proposals

1.8. We noted NGGT's comments, and have ensured that the effect of moving funding into uncertainty mechanisms is excluded from the IQI.

1.9. We propose to use the same IQI matrix as at Initial Proposals. This is set out in table A1.2 below:

Table A1.2: 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

1.10. At Initial Proposals we made a number of adjustments to exclude certain costs from the IQI calculation. For Final Proposals we are making the same adjustments.

Because our Final Proposals baselines have changed from those presented in Initial Proposals, the IQI scores have also changed.

1.11. The IQI scores are set out in Table A1.3.

Table A1.3: Proposed IQI scores, income reward/penalty and sharing factor

	NGET	NGGT
IQI Score	112.4	122.6
Income reward /penalty as per cent of base Totex	0.85%	-0.64%
Incentive Rate	46.9%	44.4%

Appendix 2 – Supporting tables on Load-Related Capex for NGET

Profile of Load-Related Expenditure

Table A2.1: Summary of RIIO-T1 LRE expenditure

(£m, 2009/10 prices)

	2014	2015	2016	2017	2018	2019	2020	2021
Baseline (excl. RPEs)								
LE (Entry - Sole Use)	-	-	-	-	-	-	-	-
LE (Exit - Sole Use)	98.2	86.4	80.6	94.8	80.2	54.8	15.6	1.4
LE (Entry)	162.0	196.7	186.7	220.7	117.4	96.0	42.5	20.7
LE (Exit)	54.4	38.4	32.4	32.8	50.6	41.4	12.5	0.9
WW (Entry)	510.1	621.9	583.6	448.3	209.0	111.7	54.8	11.8
WW (Exit)	-	-	-	-	-	-	-	-
WW (General)	84.1	92.2	69.6	69.3	56.8	64.0	25.2	21.9
TSS	7.3	-	-	-	-	-	-	-
Uncertainty Mechanisms (excl. RPEs)								
Demand-Related Infrastructure (volume driven)	-	0.1	1.6	5.2	24.2	26.1	40.4	69.7
Local Generation Connections (volume driven)	4.3	45.4	62.9	16.1	11.0	8.2	35.2	38.2
Wider Works (volume driven)	67.0	96.1	56.3	35.7	18.2	22.1	23.4	23.8
Strategic Wider Works (within period determinations) *Integrated Network Preconstruction (triggered funding)	33.7	72.3 *23.9 (max., subject to consultation)	202.9	315.1	322.4	381.3	199.8	89.6
Best view (excl. RPEs)	**1,021.0**	**1,273.3**	**1,276.5**	**1,238.1**	**889.7**	**805.6**	**449.3**	**278.1**
Total RPEs	**- 3.9**	**10.4**	**26.0**	**40.4**	**40.1**	**46.5**	**31.7**	**23.2**

Subject to the outcome of our consultation on a proposed framework to enable coordination of offshore transmission. Please refer to the Uncertainty mechanisms chapter for more information.

Appendix 3 – Business support costs

1.1. Business support costs cover the following activities: non-operational IT and telecoms; property management; finance, audit and regulation; HR and non-operational training; insurance; procurement; stores & logistics (gas distribution only); and CEO and group management[59].

1.2. Please note that, with the exception of Table A3.2, this appendix is common to both RIIO-T1 and RIIO-GD1 Final Proposals documents.

Initial Proposals

1.3. For Initial Proposals we assessed transmission and gas distribution network companies' costs and set baseline allowances by reference to external benchmarks developed in collaboration with the Hackett Group and to network benchmarks, which were calculated using data from all UK transmission, gas distribution and electricity distribution companies. We assessed networks within the same ownership group together and allocated allowances to the individual networks in proportion to their forecasts.

1.4. We also carried out qualitative assessments of the efficiency evidence submitted by the companies and made additions to baseline to reflect the results of this assessment.

1.5. Other baseline additions were applied for non-benchmarked activities (insurance) and where companies had justified additional costs not captured in the benchmarking.

1.6. GDNs' insurance costs were allowed at 2010-11 levels, while NGET's and NGGT's were allowed in full.

Respondents' views

1.7. While we received some support for the overall approach taken to assessing business support costs, a number of respondents felt that the external benchmark was unsuitable for comparing network companies against and that some of the chosen activity cost drivers, specifically those used for IT and telecoms and property management, were inappropriate.

1.8. A number of respondents disagreed with the decision to select the lower of the Hackett (external) benchmark and the networks benchmark for individual activities.

[59] Business support does not include R&D. R&D costs are covered under the Network Innovation Allowance (NIA).

1.9. Some respondents expressed concern that the analysis was too focused on the base year 2010-11, did not fully recognise some additional costs that network companies will face over T1 and GD1 (for example increased IT support costs), and did not sufficiently factor in differences between the benchmarking comparator group and network companies.

1.10. One respondent expressed concern that the methodology employed was "cherry-picking" companies' costs for individual activities and suggested that in order to mitigate this problem we should:

- use the networks upper quartile for all activities rather than a mixture of external and networks upper quartiles, and

- either apply the efficiency evidence addition in a way that ensures it results in allowances that are more representative of network companies' position against other industries, or uplift individual activities to the opex allowance (middle up).

1.11. SGN did not agree that it should be treated as part of the SSE group for benchmarking business support costs.

Final Proposals

1.12. Our Final Proposals for network company business support costs are set out in Table A3.1 below. The sections after the table provide further detail on the changes we have made from Initial Proposals.

Table A3.1: Business support group Final Proposals (excluding RPEs except where stated)

£m, 2009/10 Prices	National Grid	NGN	SGN	WWU	Total
RIIO-T1/GD1 Forecasts	1,705.3	141.7	271.9	150.7	2,269.6
Ofgem Initial Proposals	1,338.8	117.3	220.4	134.0	1,810.6
Total movement from Initial Proposals	+65.9	+15.9	+65.7	+17.1	+164.6
Ofgem Final Proposals	**1,404.8**	**133.2**	**286.1**	**151.1**	**1,975.1**
Indicative breakdown of movements from Initial Proposals					
Policy decisions					
Move to top-down benchmarking[60]	-33.3	+7.9	+35.5	+18.3	+28.4
SGN-SSE relationship	+1.8	+0.3	-3.8	+0.3	-1.4
Additional baseline adjustments	+63.2	+2.7	+3.6	+2.6	+72.1
Efficiency evidence review	+23.1	-	-	-	+23.1
PPA SO revised assessment	+48.1	-	-	-	+48.1
New data/ error corrections					
Normalisations and activity cost drivers	-20.3	+14.0	+22.2	-1.3	+14.6
Other	-6.0	+1.1	+3.2	+1.1	-0.6
Factor combination effect[61]	-10.7	-10.2	+5.0	-3.9	-19.8
Total movement from Initial Proposals	+65.9	+15.9	+65.7	+17.1	+164.6
Ofgem Final Proposals (incl. RPEs)	**1,418.5**	**134.6**	**289.1**	**152.7**	**1,994.9**

[60] All values are the impact of removing the individual change versus the Final Proposals top down benchmarking scenario, ie the figures shown assume that the individual change was the last one applied. If changes are applied in a different order then the individual effects will be different.
[61] The costs shown in this table are the impact of the individual changes if applied in isolation. 'Factor combination effect' is the residual impact of applying these changes in combination.

Table A3.2: Business support transmission network Ofgem Final Proposals (excluding RPEs)

Total RIIO-T1 £m 2009/10 prices	Transmission					
	NGET TO	NGET SO	NGGT TO	NGGT SO	NGGD	National Grid
RIIO-T1 Forecasts	405.7	320.8	144.4	157.5	676.9	1,705.3
Ofgem Initial Proposals	318.3	260.0	112.6	135.7	512.2	1,338.8
Ofgem Final Proposals	317.7	292.4	113.1	151.4	530.1	1,404.8
Difference: Initial Proposals to Final Proposals	-0.6 -0.2%	32.4 12.5%	0.4 0.4%	15.7 11.6%	18.0 3.5%	65.9 4.9%
Difference: forecasts to Final Proposals	-88.0 -21.7%	-28.4 -8.8%	-31.3 -21.7%	-6.1 -3.8%	-146.8 -21.7%	-300.5 -17.6%

Move from bottom-up to top-down benchmarking

1.13. While we consider that our bottom-up benchmarking approach for business support costs in Initial Proposals was robust, we wanted to be more consistent with other activity assessments and to address concerns around cherry-picking. As a result, we have moved to a top-down benchmarking assessment, where network companies are compared against an upper-quartile benchmarking metric only at total business support level. As in Initial Proposals we excluded insurance from this assessment.

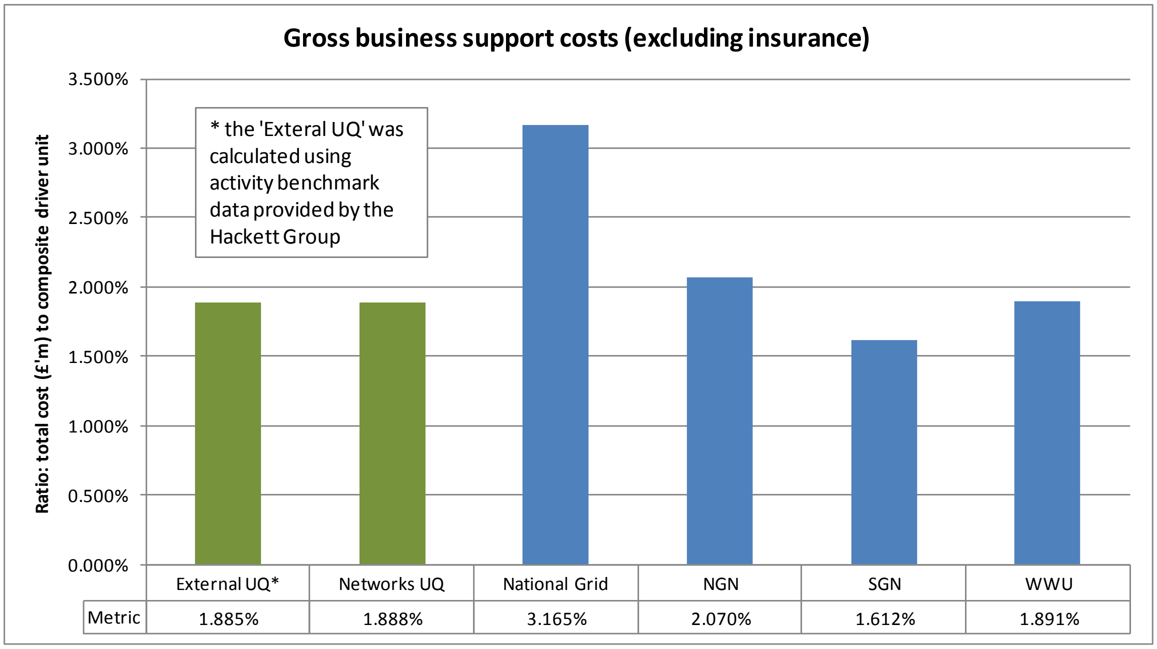
1.14. For this top-down assessment we have used a composite cost driver, the value of which was derived from the same bottom-up activity drivers used in Initial Proposals, and taking an average weighted by activity cost of each bottom-up activity driver value[62].

1.15. In order to calculate the comparator metric (ie the equivalent upper-quartile against which the network companies were compared) we took the Hackett upper-quartile metric for each activity except CEO and group management.[63] Then, using the aggregate networks industry[64] activity driver values as representing a proxy-company, we calculated the total efficient business support costs of this proxy-company. We also calculated its composite driver value as explained in paragraph 1.14 above.

[62] The bottom up activity drivers are: revenue (for finance, audit, and regulation; property management; CEO and group management), end-users (for IT and telecom), employees (for HR and non-operational training), and spend (for procurement).
[63] For CEO and group management, as in Initial Proposals, rather than using the Hackett upper quartile we calculated an Ofgem/Hackett composite upper quartile. The Ofgem/Hackett upper quartile is higher than the raw Hackett value.
[64] Transmission, gas distribution, electricity distribution

1.16. The top-down benchmarking methodology results in external and network upper-quartile metric values that are almost identical. This is shown in Figure A3.1 below. We are satisfied that the revised methodology and these results largely resolve respondents' issues over inappropriate drivers and non-comparability of the external comparator group to network companies.

Figure A3.1: Business support top-down benchmarking comparison



Change in treatment of SGN's relationship to SSE

1.17. We agreed with SGN that it should not be treated as part of the SSE group for benchmarking purposes as doing so distorts the benchmarking. However, as SGN is 50 per cent owned by SSE and approximately 25 per cent of its business support costs are allocated from SSE, we do not agree that it is appropriate to entirely separate SGN from the SSE group. For this reason we have separated SGN and SSE for initial benchmarking before combining their separate benchmarking results. This means there are ten rather than nine network company/groups (leading to small changes in other companies' assessment as well as SGN's). SGN's baseline allowances were then set by taking a weighted average of SGN's baseline and SSE's baseline (scaled to SGN's level of 2010-11 actual costs). We used a 50:50 baseline weighting to reflect SSE's 50 per cent ownership of SGN. As this ratio is approximately equal to the cost weighting between SGN and SSE used in Initial Proposals the resultant change in SGN's allowances is small.

Additional baseline adjustments

1.18. Additional baseline adjustments, leading to a net increase £72.1m, have been added to the network companies' baselines. These include the following:

- To reflect the operational growth in NGET TO, we added £53.4m (pre-capitalisation adjustment) to National Grid's baseline. This is equivalent to approximately two per cent per annum growth on NGET TO's allocation of National Grid's baseline business support allowance.

- To take account of the higher regulation costs of network companies versus the Hackett benchmarking comparator group, we added 15 per cent of network companies' submitted finance, audit and regulation costs to baselines.

- PPA's reassessment of transmission SO costs resulted in an increase of £48.1m in SO business support cost assessment. As in Initial Proposals this was applied to NGET SO and NGGT SO post allocation and not at group level.

1.19. We also reviewed network companies' submitted efficiency evidence, which included some National Grid evidence previously omitted in error. This resulted in National Grid's efficiency evidence factor increasing from 14.5 per cent to 19.9 per cent. Other network companies remained as in Initial Proposals.

1.20. We are satisfied that we have made sufficient baseline adjustments to take account of any non-comparability between network companies and the benchmark comparator group and to reflect any justifiable additional costs that network companies will face over RIIO-T1 and RIIO-GD1. No additional adjustments were made for:

- Property: we consider that regional variations in property costs are not a relevant factor as network companies are not tied to a particular geographic location for their non-operational property, which comprises the majority of their property management costs.

- Additional IT support costs: the benchmark sets efficient levels of costs for all business support activities, including IT and telecoms, and therefore no additional adjustment is required.

- Other forecast cost increases should be managed within network companies' efficient cost levels.

Normalisations and cost driver updates

1.21. National Grid transmission, NGN, and SGN submitted new information in relation to their end-user count. We also corrected double counting errors relating to SGN's employee numbers and NGET and NGGT's spend. The corrected driver values are given in Table A3.3 below.

Table A3.3: Business support benchmarking costs drivers

	National Grid	NGN	SGN	WWU
Revenue (£m 2009/10 prices)	3,719.3	314.6	746.4	294.0
End-users (number)	10,204.2	1,356.1	3,418.2	1,824.7
Employees (number)	7,922.6	1,070.1	1,808.1	1,363.0
Spend (£m 2009/10 prices)	2,092.8	163.4	474.8	179.4
Composite driver (unit)	**6,191.5**	**744.1**	**1,884.6**	**967.7**

1.22. Normalised costs have been adjusted to remove costs related to non-regulated entities and other non-formula costs. The final normalised 2010-11 costs for benchmarking are shown in Table A3.4 below.

Table A3.4: Business support 2010-11 normalised gross costs

£m, 2009-10 prices	National Grid	NGN	SGN	WWU
Finance, Audit & Regulation	36.1	3.0	5.1	3.1
HR & Non-operational training	12.6	0.6	0.9	0.7
Procurement	7.8	0.2	0.9	0.7
IT & Telecom	68.5	5.9	12.7	7.6
Property Management	35.1	2.4	6.0	3.5
Insurance	21.7	3.5	3.9	2.9
CEO & Group Management	35.8	3.2	4.8	2.6
Business support total	217.7	18.9	34.3	21.2