Decision on strategy for the next transmission price control - RIIO-T1 Tools for cost assessment

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Target Audience: Consumers and their representatives, transmission companies, generators, offshore gas producers/importers, suppliers, shippers, investors, environmental organisations, distribution network companies, government policy makers and other interested parties.

Overview:
This is the first transmission price control to reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model. RIIO is designed to drive real benefits for consumers; providing network companies with strong incentives to step up and meet the challenges of delivering a low carbon, sustainable energy sector at a lower cost than would have been the case under our previous approach. RIIO puts sustainability alongside consumers at the heart of what network companies do. It also provides a transparent and predictable framework, with appropriate rewards to promote timely investment in the networks.

Having consulted on our initial strategy for the next transmission price control, this supplementary annex to the main decision document sets out our current thinking on the tools that we will use for cost assessment. This document is aimed at those seeking a detailed understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the main decision document.

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Associated Documents

Main decision paper

- Decision on strategy for the next transmission price control - RIIO-T1
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Links to supplementary annexes

- Decision on strategy for the next transmission price control - RIIO-T1 Outputs and incentives
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionoutput.pdf
- Decision on strategy for the next transmission price control - RIIO-T1 Tools for cost assessment
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisioncosts.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionfinance.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Uncertainty mechanisms
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionuncert.pdf

Links to other associated documents

- Providing a greater role for third parties in electricity transmission: Early thinking and options
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/thirdpartyrole.pdf
- Decision letter on the regulatory asset lives for electricity distribution assets
http://www.ofgem.gov.uk/Networks/Policy/Documents1/assetlivedecision.pdf
- The Weighted Average Cost of Capital for Ofgem's Future Price Control (March 2011 update) – Report by Europe Economics on behalf of Ofgem
http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1WACC.pdf
- Onshore transmission assets and risks associated with renewable projects with potentially limited lives - Report by CEPA on behalf of Ofgem
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/ceparenewablelives.pdf
- Cost of debt index model for RIIO-T1 and GD1
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/costofdebtT.xls

- Consultation on strategy for the next transmission price control - RIIO-T1 Overview paper (159/10)
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1%20overview.pdf
- Handbook for implementing the RIIO model - Ofgem, October 2010
  http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf

A glossary of terms for all the RIIO-T1 and GD1 documents is on our website:
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisiongloss.pdf

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1. Introduction

Chapter Summary
This chapter sets out how cost assessment analysis contributes to the overall RIIO price control work, provides a summary of our latest thinking, and introduces the later chapters in this document.

Introduction

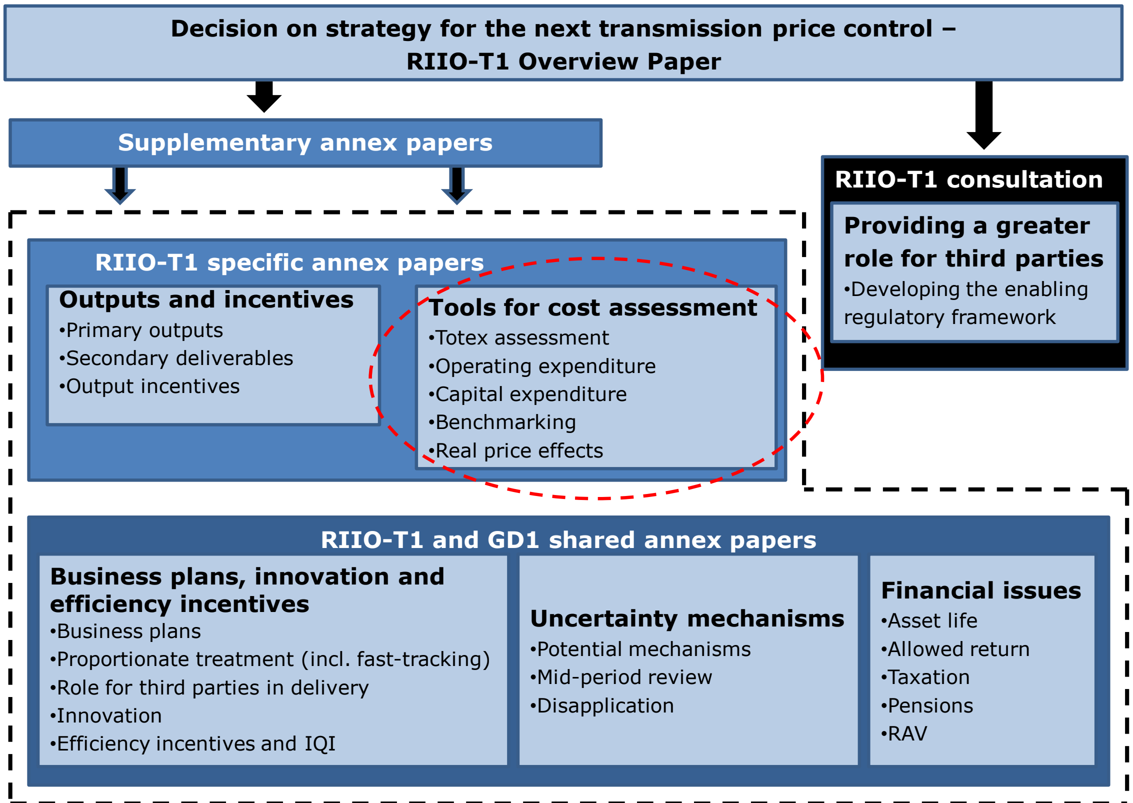
1.1. The next transmission and gas distribution price controls, RIIO-T1 and GD1, will be the first to reflect the new RIIO model. In December 2010, we consulted on our initial strategy for the two price control reviews. The overview document of our initial strategy for RIIO-T1[1] included a supplementary annex which set out the tools that we intend to use for cost assessment.

1.2. Following consideration of responses received to the initial strategy consultation, this document sets out our decision on the tools that we will use for cost assessment. This document is aimed at those seeking a detailed understanding of our decision. Stakeholders wanting a more accessible overview should refer to the RIIO-T1 main decision paper.[2] The price control will be set for an eight year period from 1 April 2013 to 31 March 2021.

1.3. Figure 1.1 below provides a map of the RIIO-T1 documents published as part of the suite of decision documents. We have also published a consultation setting out our early thinking on providing a greater role for third parties in electricity transmission.

[1] Consultation on strategy for the next transmission price control - RIIO-T1 Overview paper http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1%20overview.pdf
[2] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Figure 1.1 RIIO-T1: document map*



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

Summary of latest thinking

1.4. In this section we set out a summary of the latest thinking contained in each section of this document.

Cost assessment overview

1.5. We have decided that it is appropriate to apply a toolkit approach to the assessment of the cost requirements in the Transmission Owners' (TOs') business plans taking into account a mixture of high level and more disaggregated cost analysis.

1.6. Our assessment toolkit will include both international benchmarking and more TO-specific analysis. We will draw on a blend of analytical techniques from our toolkit to conduct our assessment of cost requirements, whilst recognising the limitations of international benchmarking options given that it is at a relatively early stage of development.

Real price effects and ongoing efficiency

1.7. When we assess the TOs' business plan forecasts we will consider whether they incorporate a reasonable level of productivity improvements which could be expected to be made by an efficient company (ongoing efficiency improvements). We will also assess whether they have a well-justified level of changes in input prices (e.g. wages) relative to the Retail Price Index (RPI) which we refer to as Real Price Effects (RPEs).

1.8. We consider that our proposal to set an ex ante allowance for RPEs remains appropriate. Our assessment of the TOs' forecasts will be informed by a range of evidence including the analysis of the relationship between RPI and relevant input price indices.

Total expenditure analysis

1.9. Total expenditure (totex) benchmarking is an important part of the overall toolkit. Before July, when we receive the companies' business plans, we will look to develop our benchmarking further, where appropriate, with the TOs, our academic advisor and the help of technical consultants. Stakeholders' views on totex are very mixed with some respondents supporting the high level approach, whilst others highlight that caution is needed in applying the totex approach. Given the mixed views raised by stakeholders, we will balance our approach to cost assessment across both totex assessment and disaggregated cost assessment techniques in RIIO-T1. We will not rely solely on just one technique.

1.10. We had hoped at this stage to publish some preliminary cost analysis based on our international benchmarking work. However, we have decided to do further work to refine our approach and will publish the results of our analysis at a later date.

Direct operating expenditure (opex) and closely associated indirect costs

1.11. Our assessment of the efficient direct operating expenditure required by TOs will primarily be based on our assessment of the forecasts in their business plans. This will require each TO to demonstrate that its forecasts are consistent, reliable and justifiable in terms of the volume of the planned work, the unit cost of delivery and the impact on the output measures.

1.12. We will employ a toolkit approach carrying out an initial assessment of the appropriateness of the TOs' forecasts including trend analysis, disaggregated benchmarking, volume and unit cost analysis as well as expert assessment by our technical consultants. In order to be able to carry out appropriate benchmarking analysis across networks and TOs, we are re-categorising some indirect costs that are closely associated with direct opex as closely associated indirect costs.

Business support costs

1.13. As proposed in our December document, we will use a toolkit approach to assess the TOs' forecasts of business support costs. Our assessment will be based on an analysis of historical and forecast costs for the various activities defined within business support. Where appropriate, we will compare the activities across gas distribution, electricity distribution and gas/electricity transmission companies, as well as other external comparators.

Capital expenditure (capex)

1.14. We will assess the efficient costs required by a network company largely based on our analysis of the forecasts in a company’s business plan. This approach will place an onus on the companies to demonstrate that their forecast costs are reasonable and are linked to the delivery of outputs.

1.15. For Load Related Expenditure (LRE), we will work closely with our engineering consultants to assess baseline expenditure based on TOs' future business plans and the parameters for revenue drivers. We will carry out a range of assessment approaches including disaggregated benchmarking between TOs, variance analysis, unit cost comparisons and spot-checks on selected schemes during our initial sweep.

1.16. For Non-load Related Expenditure (NLRE) we will expect the TOs' business plans to demonstrate that the planned volumes and unit costs of non-load related work are efficient. We will use historical trend analysis, age-based modelling and unit cost analysis to assess the TOs' plans.

1.17. Unit cost assessment remains a key element in our cost assessment and in particular for NLRE assessment. We will focus on unit costs of primary network assets and expect TOs to explain and justify any variations on unit costs between the current transmission price control (TPCR4) and RIIO-T1. Our views on efficient unit costs will be built on our analysis, expert views from engineering consultants and market intelligence.

System operator internal costs

1.18. We will use a range of techniques for assessing the System Operator (SO) internal capex and opex including trend analysis, benchmarking costs and expert review. We will assess the internal SO costs separately from external costs. The latter will be assessed as part of the Balancing Services Incentive Scheme workstream. However, we will ensure that there is consistency across the range of SO costs.

Structure of this document

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

- chapter 2 provides an overview of our position relating to our cost assessment toolkit and approach
- chapter 3 outlines our position on real price effects and ongoing efficiency
- chapter 4 summarises our position in respect of total expenditure analysis
- chapter 5 sets out our position on direct operating expenditure and closely associated indirect expenditure assessment
- chapter 6 provides our position in respect of business support cost assessment
- chapter 7 explains our position the assessment of capital expenditure
- chapter 8 details our proposed methodology for assessing System Operator (SO) internal costs.

2. Cost assessment overview

Chapter Summary
In this chapter we set out our latest thinking on our overall approach to cost assessment. In particular, we set out our proposed use of a toolkit approach incorporating a range of top-down and bottom-up assessment methods.

Summary of consultation proposals

2.1. We outlined in the December document our intention to make use of aggregated top-down approaches, such as totex[3] benchmarking, within our overall toolkit. This type of top-down assessment would be used alongside other more disaggregated analysis to inform our views on the reasonableness of the overall costs proposed in the business plans.

2.2. As in TPCR4, we would use a combination of top-down and bottom-up analyses within our overall assessment toolkit in order to obtain a balanced view of TOs' expenditure requirements.

1. **'Top-down'** – This approach would include comparing productivity to other companies in the same or related sectors of the industry, or benchmarking against international companies. An advantage of this approach is that it can capture economy–wide and sectoral factors such as technological development, labour, and other input costs that may be missed in a bottom up approach. Given adequate data, top-down approaches can be applied to a whole TO or to expenditure components such as opex or capex.
2. **'Bottom-up'** – This assessment splits the cost base into the key individual activities of the transmission companies and builds up the total costs by rolling up the work required from a zero base in order to identify the efficient level of costs that should have been incurred. Examples of the application of this approach include development of direct opex or replacement capex through multiplying efficient quantities by efficient costs, or by combining individual projects that have been subjected to project by project review.

2.3. There is some crossover between top-down and bottom-up approaches. For example, bottom-up approaches can use methods such as benchmarking TOs, and comparison to historical performance and trends in order to determine efficient unit costs and efficient quantities. Similarly, top-down approaches which focus on benchmarking may be supported by more detailed analysis such as expert review in order to identify likely cost drivers.

2.4. We highlighted that as this is the first time we are intending to make use of totex benchmarking techniques within our toolkit, the more disaggregated, bottom-up approaches remain critical elements of our assessment, helping to ensure that our

[3] Total expenditure refers to the total amount spent by a business each year, regardless of whether it is capital or operating expenditure. It is different to total cost, which refers to operating expenditure plus a measure of capital consumption (analogous to depreciation).

methodology is robust. They are also helpful in identifying and highlighting potential areas of efficiency and enabling a more informed discussion with the companies over their costs and allowing us to target those areas of business plans where we require stronger justification.

Summary of responses

Totex benchmarking

2.5. Stakeholders were broadly supportive of the methods and principles outlined for the proposed totex benchmarking. However, they expressed concern with the use of US Federal Energy Regulatory Commission (FERC) data as the international comparator data and emphasised the need to use mature benchmarking data and processes. Stakeholders also wanted any data used by us to be made available to them.

2.6. Stakeholders recognised that totex cost benchmarking is a better guide than disaggregated (eg opex or capex) benchmarking. They noted that any totex benchmarking must ensure consistency and normalisation of data. They argued that where it is difficult to separate the transmission and distribution businesses as in the FERC data, this could skew the benchmarking results.

Direct opex and closely associated indirect costs

2.7. Stakeholders generally supported our proposals but were keen to obtain a more detailed understanding of how our approach will work in practice. In general, respondents agreed with the proposed methods for assessing direct opex. However, diverse views were provided on the treatment of closely associated indirect opex. Some respondents raised concerns regarding the methods for setting allowances for closely associated indirect opex, stating that a non-linear relationship exists between direct and closely associated engineering opex, making it inappropriate to apply percentage uplifts or fixed sum adjustments.

Business support costs

2.8. We received a small number of comments in relation to our proposed approach for assessing business support costs. The responses received related to the techniques contained within our cost assessment toolkit.

2.9. Respondents highlighted the need to identify appropriate cost drivers for business support costs within the transmission businesses and to ensure that costs are consistent and normalised across networks to allow meaningful assessment to be undertaken between businesses. A number of respondents highlighted that differences in the definitions of business support activities in existing regulatory reporting structures would make cross-company comparison difficult.

Capex

2.10. We did not receive any particular comments from stakeholders regarding the cost assessment of load related capex. However, a general concern was expressed in relation to the use of historical cost information to assess the cost into an uncertain future with higher delivery rates.

2.11. Respondents generally supported our consultation proposals for the assessment of non-load related capex for the RIIO-T1 period. Some specific concerns were raised. There was a perception that there is a lack of comparable data to be used in benchmarking, which may compromise its value. This concern contributes to general support for the assessment to focus primarily on forecast volumes and unit costs. A further observation made was that care should be taken when using historical analysis to assess costs in an uncertain future.

Latest thinking

2.12. In the light of consultation responses, we intend to apply a toolkit approach to the assessment of the cost requirements in the TOs' business plans taking into account a mixture of high level and more disaggregated cost analysis. Our toolkit of approaches, and the areas in which we intend to apply them, are set out below:

Figure 2.1: Cost Assessment Techniques

Cost assessment techniques						
Resource Intensity		**Direct Opex**	**Indirect Opex**	**Load Related Capex**	**Non-Load Related Capex**	**Initial Sweep**
Lighter Touch	**Total Expenditure Benchmarking**	✓				Full
	Disaggregated Benchmarking	✓	✓	×	✓	
	Historical Trend Analysis	✓	✓	✓	✓	
	Unit Quantity Analysis	✓	×	✓	✓	
	Asset Unit Cost Analysis	✓	×	✓	✓	
	Output Unit Cost Analysis	×	×	✓	×	
	Expert Review	✓	✓	✓	✓	
More Detailed	**Project by Project Review**	×	✓	✓	✓	Sample

Total expenditure benchmarking

2.13. As mentioned above, we outlined in the December document our intention to include benchmarking of historical totex, using suitable cost drivers, within our cost assessment toolkit. We have undertaken further work to develop an international dataset of historical transmission related expenditure to enable comparison. This primarily focuses on US data from the FERC database. International comparison is necessary as in GB there are only three electricity TOs with significantly different scales of operation, and only one gas TO. We also intend to carry out benchmarking between the GB electricity TOs where this is feasible, but note the different scale of the three businesses.

2.14. We have carried out initial descriptive analysis of the US data compared with the GB TOs and we have found that a significant pool of potential comparators exists. Further details are set out in Appendix 1. We also have data for a range of key cost drivers. However, we have also identified a number of key concerns with the data including the integration of transmission with other electricity supply chain activities in the US, differences in the definition of costs drivers and economic and regional differences. We intend to work with the companies over the summer to improve the robustness of the data with a view to making a more informed assessment for the initial sweep. We also expect the TOs to put forward more aggregated or totex benchmarking as part of their business plan submissions.

2.15. We consider that this type of benchmarking is important as a starting point for asking questions in terms of the efficiency of the TOs' costs. Our updated position in respect of totex benchmarking is discussed in more detail in Chapter 4. However, given the maturity of the data and this analysis we intend to place greater weight on the disaggregated techniques discussed below.

Disaggregated and bottom up analysis

2.16. Bottom-up, disaggregated analyses remains an integral component of our analytical toolbox for cost assessment.

Direct opex and closely associated indirect costs

2.17. For direct opex and closely associated indirect costs[4] our approach will include:

- assessing the TOs' forecast total costs and comparing this to historical costs, trends and benchmark comparators
- assessing the TOs' forecast quantities and unit costs and comparing these to historical quantities and costs, trends and benchmark comparators
- conducting an expert review of key policies and practices, in particular those which form part of the TOs' asset management strategies.

2.18. Our direct opex and closely associated indirect costs assessment is discussed further in Chapter 5.

Business support costs

2.19. We will assess indirect costs that are closely associated with operating activities and capital works as part of our assessment of those activities. This creates a distinction between those costs that are required to support the overall business (business support) and those costs that support the operational activities (closely associated indirect costs).

2.20. Much of the analysis for business support costs will be the same for transmission and gas distribution. We intend to compare costs in transmission, gas distribution and electricity distribution where possible. We intend to benchmark these costs by group. We consider that there are three main groups of such costs: information systems (IS), property and other business support costs. Further detail is provided in Chapter 6.

[4] Closely associated indirect costs include activities related to managing and building the network, such as network design and engineering, engineering management and clerical, wayleaves administration, control centre and system mapping.

Capex

2.21. For capex we will carry out both load and non-load related modelling. Our view on the volume of asset replacement will also be informed by age-based modelling and information provided by the TOs on secondary deliverables relating to asset health, criticality and replacement priorities. Our view will also be informed by the risk and reliability outcomes proposed by the TOs in their business plans.

2.22. For LRE we will carry out modelling based on capacity requirements, but the nature of the expenditure means that we will be more focused on expenditure required at key boundaries and the costs of associated projects.

2.23. We will undertake unit cost analysis for the major asset types (eg in electricity transmission this might include transformers, switchgear, metering, control, overhead lines, underground cables, and other substation expenditure). We will seek expert advice on the appropriate levels of unit costs in these areas and on the efficient level of costs for a subset of representative schemes. Our approach to capex assessment is discussed further in Chapter 7.

SO internal costs

2.24. In both gas and electricity transmission, performance of the SO function (ie balancing the system in real time) creates a requirement for opex and capex by the relevant SO. This expenditure is largely related to labour and IT systems costs.

2.25. Our assessment of internal SO opex and capex will be based upon both historical trend analysis and consideration of future needs. This will reflect anticipated market developments and also any known or ongoing developments to the systems which interact with system operation. We are also likely to draw upon the services of external consultants, who offer expertise in respect of IT and market development issues. Further detail is provided in Chapter 8.

3. Real price effects and ongoing efficiency

Chapter Summary
This chapter sets out the type of analysis that we expect to carry out to assess the forecasts submitted by the TOs for input price inflation and ongoing efficiency improvements. It also outlines some of the issues that we expect the TOs to take account of in their business plans when justifying their proposals.

Summary of consultation proposals

3.1. Our December document outlined how we expect to reflect ongoing efficiency improvements and RPEs within our assessment of the forecasts submitted by the companies.

Ongoing efficiency

3.2. In order to capture expected efficiency improvements that can be made by frontier companies, it is necessary to include an assumption for ongoing efficiency improvements within RIIO-T1. As in previous price controls, we proposed that analysis of data from productivity datasets such as EU KLEMS growth and productivity accounts would be used to inform the ongoing efficiency assumption. This dataset contains input (capital (K), labour (L), energy (E), materials (M) and services (S)) and output data for the different sectors in the economy.

3.3. In addition, we suggested that we would refer to other sources such as:

- the Office of National Statistics (ONS) measures of productivity for the electrical, gas and water industries referenced in the 2010 Bristol Water inquiry by the Competition Commission
- output/tender price data for capital projects such as the construction output price index (COPI) used by Ofwat as part of its price controls.

Real price effects

3.4. Our suggested approach for reflecting input price inflation was to make an ex-ante allowance for RPEs based on forecasted differences between RPI and input price inflation, ie there would be no indexation of allowed revenues with respect to actual input price inflation. We proposed that our assumptions would be based on analysis of historical trends of relevant price indices relative to the RPI. Table 3.1 outlines the indices we had identified for consideration as part of our assessment.

Table 3.1: Data sources considered at recent price controls

Source	Description
ONS Average Weekly Earnings (AWE)	General labour cost index. Replaces the Average Earnings Index.
ONS Annual Survey of Hours and Earnings (ASHE)	Sector specific data on earnings and hours paid
ONS Producer Price Indices (PPI)	Input and output indices by sector
Joint Industry Board (JIB)	Labour costs for the electrical contracting industry
Building Cost Information Services (BCIS)	Various cost indices for the construction industry, eg Price Adjustment Formulae Indices (PAFI) (previously known as Baxter Indices), tender price indices
British Electrotechnical and Allied Manufacturers Association (BEAMA)	Labour and material cost indices for the electrical and mechanical engineering industries
Bloomberg	Commodity prices (historical and forward prices)
Royal Institute of Chartered Surveyors (RICS)	Commercial rent forecasts

3.5. We proposed that network companies could outline a case for implementing input price indexation of allowed revenues as part of their business submissions or they could set out an alternative uncertainty mechanism which we would consider against a set of defined criteria for inclusion in the price control. We considered that the onus was still on the companies to meet these criteria for input price indexation. We further discuss the possible inclusion of additional uncertainty mechanisms in 'Supplementary Annex - Uncertainty mechanisms'.

Summary of responses

Ongoing efficiency

3.6. One respondent emphasised the importance of using forward looking data alongside analysing past trends when conducting our assessment of future efficiency assumptions. They argue this is necessary because of the significant period of change the network companies face.

3.7. Two respondents raised the issue of possible "double counting" of the efficiency incentive, from both an ongoing efficiency assumption as outlined in this chapter and the efficiency target derived from using benchmarking techniques. They were concerned that expecting a company that is operating above the industry average efficiency (as identified using benchmarking) to improve their efficiency further by the industry average (as per the ongoing efficiency assumption) will result in double counting.

3.8. One respondent suggested that where industry specific data exists, eg ONS productivity data, it should be relied on more than economy wide indices or data for other European countries. Another respondent commented that we should be taking into account independent and factual studies when making our final proposals.

3.9. No further sources of data that we should investigate were identified by respondents.

Real price effects

3.10. Respondents questioned whether an ex ante allowance was the most appropriate mechanism for dealing with RPEs - this was argued in the context of current uncertainty over the path of the economy and the increase to an eight year price control both adding to the difficulty of forecasting. One respondent highlighted that they are already facing skills shortages with the increasing demand from renewable energy companies for similar skills and how the increased volatility in commodity prices is causing difficulties in forecasting. It was felt that more consideration should be given to managing this risk through an uncertainty mechanism. Suggestions included sharing large increases over and above the ex ante allowance with consumers or through a premium in the regulatory return.

3.11. One respondent commented on the importance of looking at forward contract rates along with historical trends in our analysis, but acknowledged that forward-looking data is not available in all areas and can be contradictory. They highlighted the difficulties they have faced over TPCR4 due to the volatility in commodity prices that would have been unforeseen based only on historical trend analysis.

3.12. There were comments made on setting the right input mix, including understanding how contractor rates play a part, and the correct pass through of oil and energy costs. One respondent suggested that reinstatement and street works costs, eg Traffic Management Act (TMA) costs, should be included as inputs.

3.13. Two respondents agreed with assessing forecasts on a notional structure but felt that there is a requirement to allow some variation due to regional factors. For example, labour costs may make up a larger proportion of costs in some areas.

3.14. Respondents noted that using indices that are closely related to the utilities sector and those that are based on UK data will be the most appropriate. One highlighted that relying on construction industry indices would not correctly identify cost pressures faced by the network companies due to the varying degree that the sectors have been impacted by the recession.

3.15. Further data sources suggested including forward prices for commodities and energy, and indices for labour in the renewable industries.

Latest thinking

Ongoing efficiency

3.16. Ongoing efficiency improvements are those expected by the more efficient network companies identified by our benchmarking. Benchmarking analysis will identify the efficiency improvements that we expect to be achieved by the relatively inefficient companies, in order to catch-up with those network companies identified as being more efficient. In addition to this catch-up we expect the industry as a whole to make efficiency improvements. We expect network companies, within their business plan submissions, to include an ongoing efficiency assumption for their cost forecasts. We encourage them to define within their submissions the data sets used to come to those assumptions. In assessing business plans, we will be analysing the growth and productivity accounts of the EU KLEMS dataset. We will use UK data from a range of industrial sectors that share similarities to the network companies. We believe it is necessary to look at industries outside of the energy sector due to the privatisation effect inherent in any data relating to the energy sector and other privatised utilities.

3.17. The EU KLEMS data set begins in 1970 and extends to 2007 for some sectors, and 2005 for others. We propose to examine data from 1970 onwards as we think using the longest time period available provides the best estimate of long-term trends.

3.18. The EU KLEMS dataset presents data on two different types of industry output that can be used to estimate productivity and unit cost trends:

- Gross output: This measures the value of the output in an industry, ie the combined turnover of the companies in that industry. Changes in the volume of gross output for an industry are calculated by examining changes in constant prices. The inputs for gross output are capital, labour, energy, materials and services.
- Value added: This is the value of gross output minus the value of intermediate inputs (energy, materials and services) required to produce the final output. The inputs for value added are therefore just labour and capital. Growth in the volume of value added is the change in value added at constant prices.

3.19. The value added approach and the gross output approach both have pros and cons. For example, the gross output measure would provide a measure of the productivity improvements from a combination of labour, capital and intermediate inputs whereas value added will only provide a measure for labour and capital. Changes in measures based on gross output may reflect changes that have occurred in the vertical structure of organisations within an industry, eg if there was a merger of firms within an industry the measure of gross output may reflect this, as well as productivity improvements and price changes. The value added measures of productivity are not affected by such reorganisations.

3.20. We intend to examine data using both approaches to come to our final conclusions.

3.21. The EU KLEMS dataset allows us to analyse both partial and total factor productivity measures. Partial productivity measures are most relevant when examining particular costs such as opex as they can capture the relevant component of the production process. When examining these partial productivity measures we propose to analyse productivity on the basis of constant capital input where appropriate. This is necessary to eliminate any capital substitution effect. For example, labour productivity growth within a sector may only have been possible due to substituting labour for capital inputs. We will also examine Total Factor Productivity (TFP) measures which will be more relevant to total expenditure measures.

3.22. We will also examine other productivity data where this complements the EU KLEMS data. For example, the Competition Commission examined ONS data on sectoral productivity which we will consider.

3.23. We will crosscheck our separate analyses of RPEs and ongoing efficiency with indices that combine the two effects. For example, the COPI will provide evidence on unit cost trends for capital projects which will be relevant to the assessment of capex activities.

3.24. We will review this evidence and any further information included in the business plan submissions in July when assessing ongoing efficiency improvements.

Real price effects

3.25. We propose to base our assumptions for RPEs on a range of evidence:

- analysis of historical trends of relevant price indices relative to the RPI
- historical correlation of price indices with RPI combined with forecasts of RPI to produce RPE forecasts (CEPA used this approach in their analysis for us at the last Distribution price control)
- examining analysts' forecasts of input price growth where available (eg the HM Treasury publication 'Forecasts for the UK Economy')
- any other well-justified evidence provided by the network companies as part of their business plan submissions.

3.26. The responses to our consultation did not identify any further sources of data; we will continue to look at sources as outlined in Table 3.1 for our analysis. We acknowledge that historical trends do not always accurately predict future movements, but we think that this is a sound approach particularly over an eight year horizon. Where forecast indices and future contract price data are available, for example for commodity and energy prices, we will examine this to help aid our decision process.

3.27. As set out in the December document, we will assess the forecasts received on a notional structure rather than the weights proposed by the individual companies. We will only revisit this assumption if the network companies present strong evidence as part of their business plans to suggest that an alternative approach is required. We are seeking to avoid setting allowances based on companies' individual structures that may be inefficient. For example, it may be justified to include a higher weighting for labour in the input mix in London where wages are higher than the rest of GB. We do not at this stage see any strong arguments for including regional RPE premium (eg assuming higher wage growth in some parts of GB).

4. Total expenditure analysis

Chapter Summary
This chapter sets out our latest thinking on our approach for conducting total expenditure benchmarking and how we expect to apply this analysis within our cost assessment.

Summary of consultation proposals

4.1. We outlined in our December document our intent to use total expenditure benchmarking within the RIIO-T1 process. Due to the limited number of transmission companies in GB, we proposed international benchmarking, with comparator data for this purpose to be obtained from databases maintained by the FERC and other internationally available sources, with appropriate adjustments being made to ensure comparability.

4.2. We identified three frontier-based methods for assessing the cost data: Corrected Ordinary Least Squares (COLS), Stochastic Frontier Analysis (SFA) and Data Envelopment Analysis (DEA). We proposed COLS as the principal form of analysis because it provides more reliable estimates than SFA when applied to small sample data. Further, unlike the DEA technique, the regression based approaches that underlie COLS have statistical tests that enable us to verify the reliability of the estimated results. We noted that we would use DEA to cross check our results.

4.3. The strength of conclusions from the benchmarking results would depend on the quality and comparability of the international data. We proposed using totex benchmarking to inform our overall assessment of the companies' forecasts rather than applying it mechanistically.

Summary of responses

4.4. Stakeholders were broadly supportive of the methods and principles outlined for this assessment tool. However, they expressed concern with the use of FERC data as the international comparator data and emphasised the need to use previously analysed benchmarking data and processes with appropriate adjustments for international differences and differences in the characteristics of the networks.

4.5. Stakeholders reflected that the impact of the potential growth in renewable energy generation on transmission system costs will be significant if the networks are to adapt to the required changes. As such they expressed concern that the benchmarking results that could be distorted by different levels of renewable generation penetration into transmission networks in different countries. They suggested that the reliability of networks should be considered as a separate cost driver as it was used by other international benchmarking studies. Stakeholders also responded that security of supply requirements and population densities of areas covered should be included as cost drivers because they drive the planning or construction techniques and methods. There were diverse views on the normalisation of costs with some respondents believing this is necessary, while others did not.

4.6. Stakeholders expressed concern that Ofgem did not build on other mature international benchmarking works such as e3Grid[5], ITOMS[6], ICTSO[7] and GTBI[8.] To demonstrate the transparency and credibility of proposed benchmarking, stakeholders requested that any data used by us should be made available to allow them to replicate the analysis.

Latest thinking

4.7. Under the RIIO regulatory framework, international benchmarking is a key element of the cost assessment toolkit, and we will continue developing our international dataset and totex benchmarking methods during this price control. We will also ask the TOs to put forward more international benchmarking analysis themselves at both an aggregate and disaggregated level. However, having considered the emerging issues such as availability and maturity of the data for international comparators and stakeholders' concern on the robustness of international benchmarking, we intend to rebalance the role of totex benchmarking in RIIO-T1. Although we will take the results of totex benchmarking into consideration when we assess cost efficiencies of network companies, we will focus more on disaggregated cost assessment approaches.

4.8. We are using an external academic advisor and technical consultants to improve the robustness of international benchmarking. This may include a range of approaches, such as asking our technical advisors to indicate the potential for bias in our results, and sensitivity analysis to minimise or quantify the impact of data uncertainties. We will be engaging further with network companies on our toolkit approach including different analytical methods in the period up to July 2011. This will include a workshop on the international benchmarking analysis. In the sections below, we highlight some of the further progress and thinking that we have made in respect of international benchmarking since December 2010.

[5] e3Grid is a regulatory benchmarking of European Electricity Transmission System Operators (TSO) on behalf of the Council of European Energy Regulators (CEER) Workstream Incentive Regulation and Efficiency benchmarking (WS EFB) 2008.

[6] ITOMS, the International Transmission Operations & Maintenance Study, is a consortium of international transmission companies that work together with UMS Group, comparing performance and practices and identifying best transmission industry practices worldwide.

[7] ICTSO, the International Comparison of Transmission System Operation, exchanges information on TSOs' current and future operating practices for the purpose of benchmarking. It is managed by a Steering Committee consisting of six selected members and supported by KEMA.

[8] GTBI, the Gas Transmission Benchmarking Initiative, was conducted independently by Juran, and consists of eight gas transmission companies in Europe.

Progress on international benchmarking

Benchmarking dataset

4.9. We appointed a team from the University of Cambridge to assist us in compiling an international dataset based on US data and information from other countries. The international dataset includes detailed information of major electricity and gas utilities in the US from 1994 to 2009 and some high level information on companies outside US in recent years, adjusted to reflect differences between countries such as foreign exchange rate, purchasing power parity etc.

4.10. In reviewing and carrying out initial descriptive analysis on the FERC dataset we have identified a number of general issues including:

- most US transmission network operators, unlike GB operators, are part of integrated businesses of generation, transmission, and distribution for gas and electricity. This vertically integrated structure creates difficulty in accurately identifying common costs attributable to gas or electricity transmission networks alone
- the electricity transmission network in the US is less clearly defined than it is in GB. For example, electricity networks of voltages lower than 132kV are part of the distribution networks in the GB, while in the US, there are no definite boundaries
- the measures of transmission network characteristics are different between US and UK. For example, pole miles instead of circuit miles are used to report the network length in the US.

4.11. For the non-US dataset, there are further issues in terms of gathering sufficient information with regards to network characteristics and activities across years as such information is rarely available from companies' websites or publications. This limits our effort to include non-US transmission companies in our analysis.

4.12. We are continuing to work to develop the dataset further, including having discussions with FERC. Our latest thinking in terms of the cost drivers to use as part of the international benchmarking is outlined below.

Cost drivers

4.13. We outline below a selection of the cost drivers that we consider to be important for purposes of gas and electricity transmission. Further detail on the work performed on cost drivers since our December document is set out in Appendix 1:

- length of pipeline/transmission circuit
- peak demand
- compressor capacity (gas only)
- energy delivered

- asset age.

4.14. We have prepared initial analysis to compare data between the international dataset and the GB dataset in respect of these cost drivers. This has highlighted areas where the international dataset needs to be enhanced or adjustments need to be made to ensure better comparability. For example:

- for gas, pipeline lengths ideally should be normalised with their respective pressure tiers or diameters in such cost assessments. However, the information on operating pressure tiers and diameter of transmission pipes is not directly available from the FERC data source
- for electricity, GB transmission network lengths are reported in circuit kilometres. Ideally we should convert the pole length measure in the US FERC data to circuit length. However, we are only able to convert the pole miles into circuit length for transmission lines at 132kV and higher voltages, and are unable to do the same conversion for the transmission lines below 132kV as the required information for this conversion is not available in the US FERC data.

4.15. We are continuing to develop our international dataset, with a review to removing/remedying these inconsistencies such that we are able to make robust international comparisons. We have appointed an external academic advisor, Melvyn Weeks from the University of Cambridge, to assist us in improving the benchmarking methodology and to provide advice on developing the international dataset. We will also continue to work with stakeholders to develop and refine our analysis.

5. Direct operating expenditure and closely associated indirect costs

Chapter Summary
This chapter sets out our latest thinking on the approach for assessing direct opex and closely associated indirect costs using our toolkit of assessment techniques.

Summary of consultation proposals

5.1. Our proposed approach for assessing direct opex contained a number of components. We proposed analysis of historical and future direct costs in the initial sweep using variance and trend analysis. We also proposed benchmarking direct opex between the GB TOs. We set out that we would also make use of DNO cost information and international comparators, where relevant and where there is data available.

5.2. We outlined our intent to take account of closely associated indirect costs, such as scheduling and planning costs, in our assessment of direct costs. Our intention was to apply a fixed overhead to either direct costs or to the quantity of activities in a particular area to recognise the indirect costs associated with that activity. This would be informed by our technical consultancy advice.

Summary of responses

5.3. Stakeholders generally supported our proposals but were keen to obtain a more detailed understanding of how our approach would work in practice. In general, respondents agreed with the proposed methods of assessing direct opex. However, there was a range of views on the treatment of closely associated indirect costs. In addition, clarification was sought on the review of internal opex incurred by the SO.

5.4. For closely associated indirect costs, some stakeholders supported our proposal, agreeing that the volume of these costs will be largely driven by the network activities. However, concerns were also raised by others regarding the methods that we intend to use in assessing closely associated indirect costs. These respondents believed that a non-linear relationship exists between direct and closely associated engineering costs, making it inappropriate to apply a percentage uplift percentages or fixed sum adjustments. They also considered that the proposal could put material issues in engineering support at risk of being ignored, such as arrangement of sufficient system access, obtaining planning consent and future transmission system design etc. They expressed concern regarding mapping historical data onto new definitions and suggested that there were significant costs associated with modifying their accounting and IT systems to allow them to record closely associated indirect costs.

Latest thinking

Direct opex

5.5. As proposed in our December document, we intend to assess the efficient direct opex required by a TO primarily based on our evaluation of the forecasts in their business plan. This requires a TO to demonstrate that their forecasts are consistent, reliable and justifiable in terms of the volume of the planned work, the unit cost of delivery and the impact on the output measures.

5.6. We will employ a toolkit approach to carry out an initial assessment of the appropriateness of the TOs' direct opex forecasts including trend analysis, disaggregated benchmarking, analysis of volumes, unit cost analysis and expert assessment by our technical consultants. This will allow us to identify whether there are any concerns with the companies' forecasts and decide the level of proportionate treatment. Where appropriate, we will drill down further in the companies' forecasts as part of ongoing analysis for both potential fast-track and non fast-track companies.

5.7. We have appointed a consortium of Pöyry, TNEI, PPA and GL Noble Denton to review the TOs' direct opex performance both in terms of key policies and practices and volumes of work and associated unit costs.

Closely associated indirect costs

5.8. We have carried out further work to develop the definitions of closely associated indirect activities and have discussed these with the TOs. We consider the appropriate activities are:

- Operational IT and Telecoms
- Operational Property Management
- Operational Training
- Health, Safety and Environment
- Control Centre
- Stores and Logistics
- Network Policy (including R&D)
- Engineering Management and Clerical Support
- Project Management
- Network Design and Engineering
- System Mapping
- Vehicles and Transport.

5.9. These costs are mainly driven by the volumes of network activities including both direct opex and capital activity. We consider it is appropriate to identify them separately and to assess them together with the relevant direct costs. A similar approach for assessing closely associated indirect costs was adopted in DPCR5. However, we note the issues raised by respondents in respect of the treatment of closely associated indirect costs and provide some further clarification of our approach below.

5.10. There may be a nonlinear relationship between some indirect costs and direct opex or capital activity, as a business may need to incur costs ahead of the relevant activity in order to deliver outputs in future years. For example, engineering support costs may be incurred in advance of a capital investment program in order to support delivery of network investment. This may suggest a smoothed cost allowance for those overheads over the period. Some costs may be fixed while others may vary more proportionately with the activity concerned.

5.11. Given the nature of closely associated indirect costs, we therefore intend to review categories of these indirect costs in association with possible cost drivers and seek to identify the relationship between the areas of costs. For example, closely associated indirect costs may be driven by direct opex, the asset base, the capital investment program or a mixture of factors. Some costs may be fixed, such as wayleave administration, and most appropriately dealt with through a fixed cost allowance. Some engineering support costs, such as network strategy, may be mainly driven by future investment and best handled by setting an allowance that is proportionate to the volumes of future investment.

5.12. Under the RIIO model our assessment of expected efficient costs will be largely based on our assessment of the forecasts in the company's business plan. There is an onus on the TOs to explain and justify the relationship between direct costs and closely associated indirect costs as part of their business plans.

5.13. Pöyry, TNEI, PPA and GL Noble Denton will also be assisting us in reviewing closely associated indirect costs and linking them with relevant cost drivers. We will discuss our proposals with the TOs and encourage them to provide accurate historical data of closely associated indirect costs.

6. Business support costs

Chapter Summary
This chapter sets out our latest thinking on the approach for assessing business support costs using our toolkit of analytical techniques.

Summary of consultation proposals

6.1. In our December document, we set out our proposed approach for assessing indirect opex. This made the distinction between those costs that are required to support the overall business (business support) and those costs that support the operational or capex activities (closely associated indirect costs). We outlined our intention to separate these cost categories and to assess closely associated indirect costs within direct opex.

6.2. Building on this separation, we proposed that the assessment of business support costs associated with transmission and gas distribution should be conducted in the same way to enable comparison across the group of transmission and gas distribution companies. In order to conduct the cost assessment, we proposed a combination of tools. These included:

- historical trend analysis to look at performance against price control baselines and movements in costs over time (eg it may be appropriate to compare the growth in such costs across sectors such as distribution and transmission)
- regression analysis using a combination of historical and forecast data from the transmission and distribution businesses in relation to a selection of cost drivers (eg customer numbers, length of network, modern equivalent asset value (MEAV), total direct costs and total fixed and current assets from the regulated accounts, and employee numbers)
- the use of expert review from recognised specialists, particularly in relation to costs linked to IT and property
- the use of standard metrics to benchmark against other external companies.

Summary of responses

6.3. We received a small number of comments in relation to our proposed approach for assessing business support expenditure. The responses identified no additional categories of business support costs. They suggested that identifying appropriate cost drivers for business support costs within the transmission businesses was the key priority. They raised some concerns on the appropriateness of some of the cost drivers we had proposed (eg customer numbers, employee numbers) on the basis that they may not enable suitable comparisons between companies. In addition, one respondent expressed the view that there is no reason why support costs per cost driver will be consistent across networks, affecting the ability to benchmark.

6.4. One respondent expressed concern regarding the consistency and normalisation of business support costs across networks, stating that robust processes are needed if meaningful comparisons are to be made between businesses. A number of respondents highlighted that differences in the definitions of business support activities in existing regulatory reporting structures would make cross-company comparison difficult.

6.5. There was general support for the proposal to engage specialist consultants to assist in the assessment of IT, telecommunications and property costs. The rationale for utilising specialist consultants to assess property costs was, however, questioned by one respondent. One respondent suggested for owned property an assessment of the notional rental on those buildings should be included for benchmarking purposes.

6.6. Another respondent questioned how SO business support costs, particularly those relating to IT and property, are to be assessed.

Latest Thinking

6.7. As outlined in Chapter 5, we intend to separate business support and closely associated indirect cost categories and to assess closely associated indirect costs together with direct opex and capex. This makes a distinction between those costs that are required to support the overall business (business support) and those costs that support the operational activities (closely associated indirect costs).

6.8. We have carried out further work to refine the business support activities set out in the December document. We consider the appropriate activities are:

- IT and Telecommunications
- Property
- Human resources and non operational training
- Finance and regulation
- Insurance
- Procurement (excluding stores and logistics)
- CEO and other corporate functions.

6.9. We have decided to move all operational training and stores and logistics to closely associated indirect costs as we believe these costs follow more closely the direct costs of the network business. This is also consistent with the treatment of these costs within DPCR5.

6.10. In the business plan template guidelines, we have set out clear definitions for each activity. To ensure that comparisons between network companies are valid we will collect all business support costs on a gross basis, ie before any capitalisation of costs and any other allocations. We have structured the business plan templates to collect business support costs in the required level of detail to perform the cost assessment.

6.11. We will adopt a similar approach for the assessment of business support costs for both transmission and gas distribution to enable comparison across the broader group of companies.

6.12. We will use a range of tools for both the initial fast-tracking analysis and the more detailed review. These tools are the same as those set out in the December document, namely:

- historical and forecast trend analysis
- regression analysis
- comparison of costs between networks
- expert review of IT and property costs - as part of this we will consider the use of notional rent, for comparison purposes only, where the property is owned.

6.13. With regard to cost drivers for business support activities, we accept the comments in relation the use of customer and employee numbers. We will therefore focus more on the use of total direct cost, total assets and MEAV.

6.14. We will also use external benchmarking information for the various business support activities where the use of such data will enhance and improve our assessment.

6.15. In DPCR5 an in-sourcing/out-sourcing adjustment was made to account for the fact that companies may have differing business models. These differing models may mean that some business support costs or closely associated indirect costs that are directly incurred in one company may be incurred within a charge for contactors in another. We will determine a methodology for collecting information from transmission and gas distribution companies to make similar adjustments.

7. Capital expenditure

Chapter Summary

This chapter sets out our latest thinking on the approach for assessing load and non load related capex, including unit cost assessment across both categories of capex.

Summary of consultation proposals

7.1. In the December document, we outlined our proposed approach for assessing both load related and non-load related capex. Our proposals are summarised in the sections below.

Load Related Expenditure

7.2. In order to assess LRE, we outlined our intention to carry out high level modelling based on capacity requirements, with more focus on expenditure required to deliver key boundary transfer capacities and the costs of associated projects. This would include a review of unit costs based upon comparison, benchmarking, market intelligence and expert advice. The assessment of incremental unit costs would be based on the analysis of the costs of projects that deliver the incremental capacity. The unit cost may differ for different entry, exit points and boundaries.

Non Load Related Expenditure

7.3. In our proposals, we outlined a range of techniques to assess the companies' forecasts in terms of the total level of NLRE required for the price control period and to establish an assumed profile of annual expenditure consistent with this. We indicated that our initial views would be informed by the outcomes of historical trend analysis, and by quantity and unit cost analysis.

7.4. We proposed the use of historical trend analysis in the initial sweep and in later detailed cost assessments. As with direct opex, our trend analysis proposed to look at expenditure incurred during prior periods, and any projected changes to historical expenditure. We also proposed to benchmark NLRE either as part of the initial sweep or in the later more detailed analysis.

7.5. For both gas and electricity transmission, we set out our intention to consider both the volume of asset replacement required, and the efficient level of unit costs. Additionally, we intended to draw on bottom-up analysis for projects of a sufficiently large scale.

7.6. For electricity transmission we would assess the:

- **volume of asset replacement required**: informed by age-based modelling, and, where material differences exist between volumes forecast by the model and

those proposed by the TOs, by information provided by the TOs on secondary deliverables relating to asset health, criticality and replacement/risk priorities
- **unit costs**: our approach would vary at each of the stages of assessment. During the initial sweep, the onus would be on the businesses to demonstrate the efficiency of their unit costs. For non-fast tracked companies, we proposed a comprehensive assessment of their unit cost information by interrogating the differences between forecast unit costs, historical performance, appropriate market intelligence, and expert advice

7.7. For gas transmission we would assess the:

- **volume of asset replacement required**: since we are not able to utilise an age-based model for volume assessment, we proposed greater emphasis on the companies' link between replacement volumes and asset condition and criticality.
- **unit costs**: we proposed unit cost analysis for the major expenditure areas. Initially, the emphasis would be on engagement with the TO to agree a consistent set of definitions of unit costs. Assessment of unit costs would include a combination of historical information, expert advice, and market intelligence. It might also be possible to benchmark project costs.

7.8. We proposed that our capex assessment would employ both advice from external consultants and project by project review where appropriate and useful. Furthermore, as with opex, we intended to take account of closely associated indirect costs, such as scheduling and planning costs, during our assessment of direct capex costs.

7.9. Our proposals for assessment of costs for the RIIO-T1 period included TPCR4 ex post reviews, whereby we intended to examine delays in asset replacement and deferments of capex. Significant deferment has occurred during the TPCR4 period to date, and TOs should benefit if deferment is efficient and can be justified as being in the interests of consumers. However, deferment that increases risk to consumers or results in outcomes not being delivered to the transmission network should not be rewarded through additional revenues in RIIO-T1.

7.10. Several issues pertinent to the subject of deferment are summarised below:

- **Lifetime extensions**: We would expect increasing levels of sophistication in asset management and targeting of particular failure modes to result, on average, in longer expected asset lives.
- **Increases in unit costs**: If cost increases are allowed on an ex ante basis, the associated risk would be allocated to the TOs and would not be passed on to consumers. Passing on the impact of additional cost increases is inconsistent with the ex-ante risk allocation, whereby the TOs have assumed price risk. In a similar vein, TOs should not be allowed to defer expenditure so that customers have to fund expected price increases.
- **Business/cycle costs**: Network operators should not be discouraged from efficiently deferring or bringing forward capex to take advantage of the business cycle, provided customers are not exposed to additional risk or costs.

- **Arbitrary deferrals**: Deferrals that deliver increased risk or cost to customers should not result in replacements being included again in future capex allowances. This is because the TO has already benefitted from the capital adjustment incentive, without delivering any actual efficiency benefit.

Summary of responses

Load Related Capex

7.11. We did not receive any particular comments from stakeholders regarding the cost assessment of LRE. However, a general concern was expressed in relation to the use of historical cost information to assess the cost into an uncertain future with higher delivery rates.

Non-Load Related Capex

7.12. We received responses related to NLRE assessment from network companies only. Respondents generally supported our consultation proposals for the assessment of non-load related capex for the RIIO-T1 period.

7.13. One respondent agreed that the use of historical analysis is useful, but cautioned that care should be taken when using it to assess costs into an uncertain future. It noted that linking cost changes to impacts on outputs is useful provided it can be done in the context of a changing workload.

7.14. In terms of benchmarking, there was a general concern regarding the potential lack of comparable data. One respondent stated that "endeavouring to benchmark capital costs against overseas comparators is unlikely to provide definitive results given the difficulty in collecting comparable data." This respondent also maintained that while it may be possible to benchmark the three TOs, the results are unlikely to be conclusive given the shortage of panel data. Another respondent supported the suggestion of using closely related industries for benchmarking purposes.

7.15. As a result of concerns regarding the utilisation of benchmarking for the assessment of capital costs, the network companies generally supported an approach "primarily undertaken from an assessment of forecast volumes and unit costs". One respondent considered that volume analysis relating to non-load related investment can only be reasonably performed using condition and appropriate criticality assessments (in place of our proposed age-based survivor model).

7.16. There was general support for the proposal to derive a consistent set of definitions of unit costs. However, one of the respondents voiced concerns over the assessment of unit costs for non-load related investment due to the small numbers and high variability of some of the asset types.

Latest thinking

Load Related Capex

7.17. In response to the feedback that requested for further clarification of our methodology, we present further details of our LRE cost assessment approach in the below sections.

7.18. We intend to adopt a common approach across all of the GB gas and electricity TOs in terms of the nature of data submissions, supporting information and accompanying narrative. However, whilst the framework will be consistent we will naturally expect the structure of the detailed content of TO business plans (via the tables and narratives) to vary to a degree across the TOs to reflect their specific drivers of investment costs. For electricity this will be both at both a local and wider system level, whereas for gas this will reflect the uncertainty about future supply and demand locations.

7.19. We will carry out a range of assessment approaches including disaggregated benchmarking between TOs, variance analysis, unit cost comparison and spot-check on selected schemes during our initial sweep. We will also seek expert views on the cost efficiency from engineering consultants to inform us the fast track decision. In determining whether this part of a business plan is well justified, we will place a strong emphasis not just on the quality of the data submission but the quality of the accompanying supporting information and narrative.

7.20. We accept that given the timeframe of the RIIO-T1 period out to 2020-21 and a number of market developments covering technology and policy, that there is considerable uncertainty of investment needs especially towards the later years. Consequently, we will be asking the TOs to provide data, supporting information and accompanying narrative to provide us with an understanding of the key drivers of this uncertainty and its potential impact on their LRE needs. The ability of the TOs to demonstrate a strong understanding of potential future LRE, and to be able to clearly present, explain and justify their forecasts for RIIO-T1, will be a key component of our assessment of whether TO business plans are well justified.

7.21. Consequently, within our data tables we will be asking the TOs to provide an upper and lower forecast of potential LRE under RIIO-T1 and to present clearly and explain, in the tables and accompanying narrative, what these forecasts are, how they have been derived, and how they relate to ranges of potential drivers and expenditures for individual aspects of the system[9]. We will expect the TOs to be able to demonstrate the different techniques they have employed as being relevant to determining an appropriate level for their baseline and explaining differences between baseline and upper and lower forecasts.

[9] For example, local connections and boundary reinforcements in the case of electricity transmission, and incremental entry and exit capacity in the case of gas transmission.

7.22. One aspect of this uncertainty will be the levels and patterns of generation and demand; and the impact on investment volumes under RIIO-T1. We will expect the TOs to be able to explain their assumptions and their impacts on investment needs for both their baseline forecast and the accompanying lower and upper forecasts. Whilst we do not necessarily expect the same level of detail for the latter part of RIIO-T1, nonetheless we will expect to see a structured methodical approach to forecasts for these later years utilising all available historical and future information that the TOs have at their disposal. The more this is in evidence the greater confidence we will have regarding the justification for the business plans.

7.23. The second aspect will be the potential variation in costs which the TOs may face. We accept that it will be difficult to set a single value of such costs for RIIO-T1 and thus we will provide the TOs with the opportunity in their data tables and accompanying narrative to explain for key asset types and for schemes in general to explain (i) how and why costs might vary and (ii) how they have determined the level of costs assumed to underpin their baseline forecast.

7.24. We encourage TOs to submit as much information as they can in their business plan and accompanying narrative, within the scope of our data tables and guidance notes, for our Stage 1 review. We appreciate that TOs will adjust and refine their business plans reflecting on further information - in particular under the non-fast-track process we would expect TOs to present any changes in their business plans in the context of our comments on their initial business plans.

Electricity Transmission

7.25. Our primary focus will be placed on the assessment of the baseline LRE in network companies' future business plans and the parameters for revenue drivers to manage uncertainty around these baselines. We expect TOs, in their business plans via both their data table submissions and accompanying narrative, to clearly present and justify their baseline LRE forecast with respect to (i) relevant investment drivers, (ii) determination of necessary schemes and their scopes, ie assets delivered; and (iii) underlying cost assumptions including overheads.

7.26. For the cost assessment of investment required under the uncertainty mechanism, we will expect the TOs to show costs relating to specific revenue drivers. We will also consider information from the baseline LRE cost assessment. Although the detail of revenue driver allowance is not determined yet, we will work with our policy team and TOs to set out the appropriate parameters for relevant revenue drivers. Our aim is to reflect the cost that TOs will face should they undertake additional investment outside the baseline scenario. For known future investment we will likely set out the allowance in the context of costs presented for equivalent activities seen historically and/or for which there are other comparable known future schemes to the extent possible. It is our intention to use the information we gather from the TOs regarding future uncertainty of investment volumes and costs to inform our assessment and determination of the appropriate structure and values for revenue drivers.

7.27. For both our cost assessment and examination of revenue drivers we intend to review LRE under three categories:

Sole use connections and local enabling investment

7.28. We will seek to understand the volumes and types of connections and the costs associated with them. However, our focus will be on assessing the local enabling investment for network entry and exit points. We will compare the forecast scheme costs with relevant historical scheme performance, and seek explanation and justification from TOs for any variations in future performance within their business plans. We will expect the TOs to provide a breakdown of local enabling schemes into different groups of connections reflecting their different investment needs. We will expect the TOs to be able to explain the basis of this breakdown and to demonstrate that to the best extent possible they have built up their forecast with reference to the experience of similar historical schemes and forward expectations to justify the volumes and cost assumptions.

7.29. We recognise there will be individual ranges of uncertainty for local enabling investment in different parts (zones, for example) of the TO networks and we expect this individual variation to be captured within relevant revenue drivers. However, within an overall lower and upper LRE forecast we would not expect these to be derived from a simple sum of individual ranges (for the zones) and we will be seeking TOs to demonstrate how they have determined an appropriate diversity of risk within their overall lower and particularly upper forecasts.

Wider infrastructure investment

7.30. Wider infrastructure investment relates to works carried out beyond the nearest Main Interconnected Transmission Substation (MITS) to a new connection. Considering the complexity of wider infrastructure investment, we will look to TOs to explain in their baseline how they set up wider infrastructure schemes in terms of scheme need, priority, cost drivers, investment uncertainty and network output measures. We expect TOs to define the critical system boundaries they consider for future wider infrastructure investment and present them in the data tables. This should be supported by necessary narrative to explain why these boundaries are critical and the potential range of investment needs which might be required under which circumstances and the impact this would have on LRE. To facilitate our assessment of the cost efficiency of delivering boundary transfer capability, we will expect TOs to inform us of the relationship between boundary transfer capacity and relevant wider infrastructure schemes.

Anticipatory investment

7.31. We will assess the cost efficiency for schemes currently funded under the Transmission Investment Incentive (TII). We expect TOs to report TII schemes' information in the data tables and break them down into the categories of pre-construction and construction phases. We will examine the efficiency of those funded costs and cost profiles for the future investment within the RIIO-T1 period with reference to the assessments already done in 2010-11. Our default expectation is that submitted costs will largely reflect those submitted as part of the TII assessment conducted in 2010-11. Where there are differences in the TO business plan submissions versus these costs, we will expect TOs to clearly explain and justify any variations in these costs from those previously submitted to Ofgem for assessment.

Gas Transmission

7.32. For gas transmission, given the current commercial regime we will be primarily focused on assessment of the appropriateness of NGG's proposed network flexibility requirements. We also intend to update the parameters for existing revenue drivers where there have been specific user commitments on entry or exit, or where there is a known case for introducing a new revenue driver.

7.33. Our primary focus will be on the assessment of the baseline LRE in the business plans, which will include network flexibility. We expect the TO to present and justify clearly the relevant investment drivers (including how the investment delivers value for customers), determination of necessary schemes and their scopes, and underlying cost assumptions, including overheads.

7.34. We will want to understand how future network flexibility requirements have been forecast, what assumptions have been made about the ability to use reasonable operational measures and both existing and potential new commercial mechanisms to meet these needs. We will require clarity on why such needs were not anticipated in response to the user commitment signals where they relate to existing users and why they can't be incorporated into the appropriate commercial arrangements and revenue drivers for new users. We will expect the TO to demonstrate the appropriateness and cost effectiveness of investments deemed necessary to address flexibility requirements not covered by operational measures and commercial mechanisms. Again we will also expect the TO to demonstrate effectively the uncertainty regarding future network flexibility needs and the impact on network investment.

7.35. Revenue drivers are used in gas transmission to manage uncertainty about the location and size of future user signals for network capacity. One aspect of this uncertainty will be the levels and patterns of supply and demand, and the impact on investment volumes under RIIO-T1 as a result of network reinforcement associated with such user signals. We will expect the TO to be able to explain the assumptions and their impacts on investment needs for its forecast, and to provide sufficient information to allow an assessment of the efficient level of cost (including unit costs) to be assessed.

Non Load Related Capex

General

7.36. We will continue to use historical trend analysis in our assessment of NLRE. Historical cost levels provide a reasonable baseline from which to scrutinise and evaluate proposed future expenditure. Significant deviations in cost trends will need to be explained and justified by the TOs, and may be accepted if there are clear arguments supporting the circumstances or scenarios which might result in such material increases (or decreases) in capex.

7.37. Where appropriate, we will benchmark NLRE expenditure, either as part of the initial sweep or in the later more detailed analysis. Benchmarking of any kind (whether between the GB TOs, or against DNO costs) will be carried out only if comparable data is available.

Electricity transmission

7.38. Although one of the TOs suggested that we should only use asset condition and criticality data to derive forecasts for NLR asset replacement volumes, we will continue to use a standard age-based model to inform our assessment of the companies' forecasts. This modelling is one of the key techniques available to Ofgem as we do not have detailed knowledge of the condition on individual assets. It is less resource intensive, minimises issues around information asymmetry, and is widely used for longer-term forecasting of asset replacement volumes.

7.39. It should, however, be emphasised that our view on the volume of asset replacements for electricity transmission will be informed by both age based modelling (our primary assessment tool, as indicated above) and information provided by the TOs on secondary deliverables relating to health, criticality and replacement/risk priorities. If age-based information is insufficient or inadequate, our reliance on the TOs' Network Output Measures (NOMs) for asset volume assessments may increase.

7.40. The model will continue to inform both our initial, high-level assessment of asset replacement volumes and any full and detailed analyses of business plans that take place thereafter. It will be useful in highlighting material discrepancies in the replacement volumes derived by us, and those proposed by the TOs. Where material discrepancies are found, we will seek to understand their causes and contexts. We will rely on detailed and robust asset condition and criticality information provided by the TOs, and will place an onus on the TOs to justify and explain significant volume differences in their business plans.

7.41. We consider the proposed age-based model to be a valuable tool in deriving asset replacement volume forecasts. However, we do acknowledge that models have limitations, particularly where defined technical asset lives do not fully take into account such factors as specific TO issues, type faults, equipment obsolescence etc. Additionally, we acknowledge that there may be particular circumstances which result in variability of the timing of asset replacement projects.

7.42. Following consultation with the TOs, we are considering the possibility of including certain load-related asset replacements in the non-load related replacement volumes that are used within the model for the purposes of forecasting the quantity of network assets that will reach the end of their technical lives in the

RIIO-T1 price control period. The inclusion of such load-related replacements for the purposes of calculations will be based on clearly-defined decision criteria which will consider the replacement priorities and ages of the assets that have been disposed of. Defined criteria will assist us in objectively including only those asset replacements that, while occurring as part of load-related capital projects, involve the disposal of an asset that was reasonably close to the end of its technical life.

7.43. We recognise that circumstances may lead to variability in the number of replacement projects that are undertaken by the network companies in any given year. Whether planned to ensure programme efficiency, or unplanned due to unexpected events (weather, cost changes, unfulfilled obligations by contractors), these variances in expected replacement volumes are often reasonable and explicable, and should be redressed by an increase or decrease in the number of asset replacement projects in subsequent years. As such, non-material variances should be imperceptible over a reasonable length of time.

7.44. Since modelled forecast replacement volumes will be summed over the eight year price control period (2013-2021) prior to comparison with a similarly summed total volume proposed by the TOs, year-on-year variances should have a minimal effect on the accuracy of the model’s outputs or applicability of the assessment methodology. However, we may choose to employ probabilistic methods to assess the effects of short-term variances on longer-term outputs.

7.45. These variances would be viewed as statistical features of the outputs of a model which utilises and operates on probabilistic inputs (the asset lives), some of which are non-symmetrical in shape. They will only become relevant to the modelled volumes, and the assessment methodology, if they are statistically material.

7.46. If there are material differences between previous forecast asset replacement volumes and those that have actually been carried out, we may adjust or tune the technical asset lives as defined by the network companies. In essence, we will be applying a tuning methodology that involves shifting distributions (functions). For practicality, we will seek to retain the overall shapes of these distributions, as defined by the TOs, although we will give the TOs an opportunity to put forward the case for varying the shape of the distribution.

7.47. Our view on deferment of asset replacements and non-load related capex remains unchanged. Any deferrals in expenditure that result in an increase in cost or risk to consumers will not be rewarded; nor will inefficient or unnecessary replacement deferrals be included in future capex allowances. Additionally, as part of the business plans, it is still our intention to request that TOs categorise their NLRE in terms of reduced expenditure and increased expenditure, with justified reasons for material changes.

7.48. As explained above, asset life extensions resulting from expenditure deferred with minimal or no increase in risk to consumers will be fed back into our age-based model to test the TOs' suggested asset life profiles against actual life extensions, and to tune the model for future price controls.

Gas transmission

7.49. Due to the general unavailability of age-based information for gas transmission assets, we will continue to assess proposed asset replacement volumes without the application of an age-based model. This decision is further supported by our view that there is a weaker correlation between age and condition (or need for replacement) for assets in gas networks than for those in electricity networks, largely because the effects of weathering are probably stronger in electricity.

7.50. Additionally, gas assets (both those that are buried and those that are above ground) are generally subjected to a wider range of influences, such as interference, external corrosion, internal corrosion, ground movement, vibration, mal-operation, excursions, number of operations, temperature cycling, and pressure cycling. Whilst some of these influences have a time-based property (eg number of operations), or may have some correlation with time (eg corrosion), others do not (eg ground movement). The strength of the influence will vary, depending on the type of asset, while the forecastability (eg for mal-operation) or the rate of change of the magnitude (eg for vibration) of the influence may be unknown. These factors indicate that an age-based model would have limited value in determining when gas transmission assets need to be replaced.

7.51. As a result, our view on the volume of assets will continue to place greater emphasis on the ability of the TO to articulate the link between replacement volumes and asset condition and criticality.

Unit cost assessment

7.52. Unit cost assessment remains a key element in our cost assessment and in particular for NLRE assessment. We will focus on unit costs of primary network assets, eg transformer, circuit breaker etc in electricity and compressor, pipe etc in gas. Our views on efficient unit costs will be built on our analysis, expert views from engineering consultants and market intelligence.

7.53. We will review the forecast unit costs against the historical information and seek to understand the movement of unit costs between TPCR4 and RIIO-T1. We recognise unit costs can vary due to circumstances eg locations of investment, advance of technology, supply and demand balance etc. As there is clearly greater uncertainty in the back end, we will seek details from the TOs of potential variations in unit costs for assets they will use over the RIIO-T1 period. For example, TOs need to put forward key drivers of unit costs and explain their impacts on unit cost variances between TPCR4 and RIIO-T1.

7.54. To help TOs preparing necessary information and facilitate our unit cost assessment, we will work with TOs to develop relevant data tables to collect appropriate unit costs information. For example, we may seek multiple mode unit costs in data tables for assets down to a threshold materiality level and expect TOs to explain of key drivers of unit costs and how they relate to assumed or derived unit costs from proposed investment in the baseline.

8. System Operator internal costs

Chapter Summary
This chapter sets out our views on the approach for assessing SO internal costs.

Summary of consultation proposals

8.1. In both the gas and electricity markets, performance of the external SO function creates a requirement for internal opex and capex by the relevant SO. This expenditure is largely related to labour and IT systems costs. The costs involved are generally not as significant as the equivalent costs for the TOs, but it is important that they are assessed appropriately.

8.2. We did not explicitly refer to SO internal costs in the December document. However, we consider that it is important to outline our views on this subset of costs at this stage.

8.3. Our assessment of internal SO opex and capex is likely to be based upon both historical trend analysis and consideration of future needs. This will reflect anticipated market developments (eg anticipated increases in the proportion of intermittent generation), which may in turn impact upon future cost requirements, and also any known or ongoing developments to the systems which interact with system operation (eg xoserve in gas and the Balancing Mechanism software in electricity). We are also likely to draw upon the services of external consultants, who offer expertise in respect of IT and market development issues.

Latest thinking

8.4. For SO internal opex, we will assess cost by key activities such as operational planning, real time operation, energy trading, business support etc. We will discuss this further with SO and seek expert views on the SO internal opex breakdown.

8.5. We intend to use a range of cost assessment techniques such as trending analysis, benchmarking etc. to assess the efficiency of SO internal cost requirements. We will also look for expert reviews on SO internal opex and capex from specialist consultants.

8.6. We have structured the business plan template to collect SO internal cost information in the required level of detail to perform the cost assessment and enable an effective review process. To assist with the review, we will require historical information on the new activity basis for 2009-10 and 2010-11 to enable comparison between future requirements and historical costs.

8.7. External SO costs will be assessed as part of the Balancing Services Incentive Scheme workstream by our Markets division. However, we will work together to ensure that there is consistency across both internal and external SO costs.

Appendices

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Appendix 1 - Progress on international benchmarking

Appendix Summary
This appendix provides further details regarding international benchmarking analysis undertaken to date, building on the information provided in Chapter 4.

Gas transmission cost drivers

1.1. We considered a set of cost drivers for gas transmission, and reviewed the comparability of their measures in between the US FERC and GB Regulatory Reporting Pack (RRP) data.

Length of pipeline

1.2. We consider the length of gas transmission pipelines is an important cost driver in establishing efficient level of costs. Pipeline lengths ideally should be normalised with their respective pressure tiers and diameters in such cost assessments. However, the information of operating pressure tier and diameter of transmission pipes is not directly available from the FERC data source. There are network designs from which the diameters can be obtained but normalisation of pipeline lengths using this data source is likely to be a complex process.

1.3. In addition to the issue of unobserved pipeline diameters in the FERC data, there is a greater distinction between the ownership and operation of gas pipelines. In some cases gas transmission companies only operate sections of their own pipelines (leaving the remaining sections to be operated by other transmission companies), in other cases sections of the pipeline are jointly owned. In totex benchmarking, as owners of the pipelines are likely to be responsible for replacement and expansion of their non-operated lines, varying levels of ownership are likely to distort how the capex element aligns with relevant cost drivers. .

Peak Demand

1.4. Maximum flow or peak demand, rather than annual flow or total energy delivered dictates a transmission system’s capacity requirements. The pipeline’s capacity is determined by its size and the capacities of installed compressors. Leaving peak demand unchanged and increasing the annual flow or total energy delivered will have a minimal impact on totex. However decreasing the annual flow and increasing the peak demand will lead to significant increases in totex as additional capacity would be required. This additional capacity will be in the form of increased compressor capacity and/or larger pipelines.

1.5. The measure of peak demand in the US FERC data is the energy flow delivered on the day of maximum flows. For NGG, peak demand is measured as the amount of flows delivered at the national transmission system’s offtake points on the system peak day. Peak demand in the FERC data is reported in dekatherms and we have converted it to gigawatt hours to make it consistent with the GB data.

Compressor capacity

1.6. The trade-off between pipeline diameter and compressors is the balance between higher capital costs of laying pipelines with larger diameter and lower operating costs in running low capacity compressors or vice versa. The pressure of gas transmitted through pipelines falls due to friction and intermolecular resistance. This is usually minimised by the use of pipelines with larger diameter and/or compressors especially specified for long transmission distances. Larger pipeline diameter increases the capacity of a pipeline because it suffers proportionately less frictional drag along its walls. Over long distances, however, there is limited scope in using larger pipeline diameters only. Compressors are necessarily required for some distances and so we have included total installed compressor capacity separately as a cost driver.

Energy delivered

1.7. Energy delivered is the total annual energy delivered to offtake points by the transmission network. Like peak demand, we converted units reported in the US FERC data from dekatherms to gigawatt hours to be consistent with energy units in the GB data. Although total annual energy delivered is a less important cost driver compared to peak demand, the size of NGG's annual energy flows and the extent of variability[10] in the data warrant its consideration as a cost driver.

Asset age

1.8. Asset age gives an indication of the number of years that pipelines have been in use. The causal relationship between asset age and totex is not clear. In general, older assets result in lower capital outlays, whilst operating costs associated with older assets tend to be higher. As we do not have information on the asset age profiles, we have used a financial proxy that we define as the ratio of accumulated depreciation at the end of the respective reporting years to the annual depreciation charge corresponding to the period.

Other cost drivers

1.9. Other factors such as population density or the number of road or river crossings also affect the costs of expanding and maintaining gas transmission pipelines. However, it is difficult to quantify all these factors in the international benchmarking because of the difficulty in obtaining such information. Differences in terrain and/or right of way are particularly important because of the very diverse environments in which pipelines are built. We are unable to quantify these differences in the analysis and so are considering whether to collect some qualitative environmental information

[10] Variability in the data is depicted by the standard deviation and also the difference between the minimum and the maximum.

on the identified frontier companies to understand the differences between NGG and those companies that come up on the frontier and the possible impacts of these differences on the benchmarking results.

Comparability of the data sets

1.10. We used data from 2007 to 2009 for NGG and 29 US companies. NGG is within the range of the FERC data companies in terms of pipeline length only. Its other cost drivers are potential outliers in the dataset. As we have noted in the earlier discussions of cost drivers, further inconsistencies lie in the absence of a definitive border between transmission and distribution pipelines, inadequate information to normalise pipeline lengths, and varying proportion of pipelines operated by the transmission companies.

Electricity transmission cost drivers

1.11. We considered a range of cost drivers for electricity transmission, and discuss how these measures in the GB data compare with the FERC data measure. We also provide the descriptive statistics in Table 1.2. The cost drivers considered are network length, peak demand, energy delivered, and asset age.

Network length

1.12. Transmission network length is an important cost driver in many international benchmarking studies. It could be measured in pole length (route length) or circuit length. The GB transmission network lengths are reported in circuit kilometres in the RRPs. Ideally we would wish to convert the pole length measure in the US FERC data to circuit length. However we are only able to convert the pole miles into circuit length for transmission lines at 132kV and higher voltages, and are unable to do the same conversion for the transmission lines below 132kV as the required information for this conversion is not available in the US FERC data.

1.13. The FERC data provides the pole length and the number of circuit on each transmission line of 132kV or higher voltages. So we can calculate the circuit lengths by multiplying the pole length by its corresponding number of circuits. However for voltages below 132kV, the pole lengths and the number of circuits are aggregated and reported at the respective voltage levels. It is therefore not possible to convert the pole length into the circuit length. For example, we have a single figure of 222,222 as reported pole length at 66kV with a total of 108 circuits. As different distributions of the number of circuits could yield different circuit lengths, we are unable to calculate circuit lengths of 66kV transmission lines. We therefore adopt two cost drivers for network length. For 132kV and higher voltages, we use the circuit length as the measure of network length and pole kilometres as the measure for network length for voltages below 132kV.

Peak Demand

1.14. Peak demand in the FERC data is defined as the maximum hourly energy that is delivered at exit points on a transmission network in a year. In the GB RRP data, peak demand is defined as the measured annual system peak demand based on the maximum half-hour average. The peak demand in the GB RRPs includes transmission losses and station demand but excludes interconnector exports. Peak demand is therefore inconsistently defined between the GB RRPs and the US FERC data. To make the comparison on a consistent basis, we define peak demand for GB companies in this analysis as peak demand as per the GB RRPs less transmission losses at system maximum demand also as per the GB RRPs. However, some differences still remain and are identified below:

- Peak demand in GB is the maximum half hour average in a year while it is measured as maximum hourly average in the US. As Great Britain peak demand averages over a shorter time horizon, this could result in a bias that makes the GB peak demand higher.
- GB peak demand, as defined in our international benchmarking analysis, also includes station demand. In GB station demand represents auxiliary demand supplied through the station transformers. It is unclear whether peak demand in the FERC data takes station demand into account or not. If not, it will lead to a bias that makes GB peak demand higher.

Energy Delivered

1.15. Peak demand, rather than total annual energy delivered, dictates transmission investment requirements. However, given a fixed transmission capacity, the higher annual energy delivered means the greater use of transmission assets. This may imply higher operating cost. We therefore decided to include the total energy delivered within our cost drivers.

1.16. To compare energy delivered consistently, we use energy throughput as a measure of total energy delivered in our analysis. In the GB data, energy throughput is calculated by summing together annual energy delivered at grid supply points, annual transmission energy losses and annual energy exported to external systems. For the US FERC data, this is done by adding together energy received by all means for a company.

Age of network Assets

1.17. Similar to the gas transmission network, we use an age proxy definition for electricity transmission network assets.

Other cost drivers

1.18. Other factors like population density, security standards and reliability performance also affect the costs of expanding and maintaining electricity transmission networks. However, it is difficult to quantify all these factors in the international benchmarking because of the difficulty in obtaining such information.

Comparability of the data sets

1.19. We limited the FERC data companies to those with transmission lengths higher than 2000 circuit kilometres. The US FERC data was also limited to those companies with information on cost drivers set out above. This gave us data from 2006 to 2009 for 30 US companies and the three GB TOs.

1.20. The relative size of NGET to the other GB companies suggests that whilst NGET is a potential outlier in this dataset, the other GB companies are most likely within the range of most cost drivers. As noted in the discussions on cost drivers, inconsistency of the peak demand measure, inadequate information to express network length at all voltages in similar units and the absence of a definitive border between transmission and distribution creates data comparability concerns in this analysis.