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RIIO T1
RIIO GD1

Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues

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Target audience: Customers and their representatives, distribution network operators, independent distribution network operators, independent transmission operators, owners and operators of distributed energy schemes, generators, gas shippers and suppliers, transmission owners, electricity suppliers and other interested parties.

Overview:

The next transmission and gas distribution price controls, RIIO-T1 and GD1, will be the first to reflect the new RIIO 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 for delivery.

We are now consulting on the strategy for the two price control reviews. This supplementary annex to the main consultation documents sets out our proposed approach to financial issues. This document is aimed at those want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the main consultation documents.

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Main consultation papers

- 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
- Consultation on strategy for the next gas distribution price control - RIIO-GD1 Overview paper (160/10) http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/RIIOGD1%20overview.pdf

Links to supplementary annexes

- Consultation 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/T1%20Outputs%20incentives.pdf
- Consultation 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/T1%20Cost%20assessment.pdf
- Consultation on strategy for the next gas distribution price control - RIIO-GD1 Outputs and incentives http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1%20outputs%20and%20incent.pdf
- Consultation on strategy for the next gas distribution price control - RIIO-GD1 Tools for cost assessment http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1%20costs%20assess.pdf
- Consultation 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/T1%20and%20GD1%20BP%20prop.pdf
- Consultation 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/T1%20and%20GD1%20uncert.pdf
- Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Impact Assessment http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1%20and%20GD1%20IA.pdf

Links to other associated documents

- Handbook for implementing the RIIO model - Ofgem, October 2010 http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf
- RIIO: A new way to regulate energy networks: Final decision http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Decision%20doc.pdf

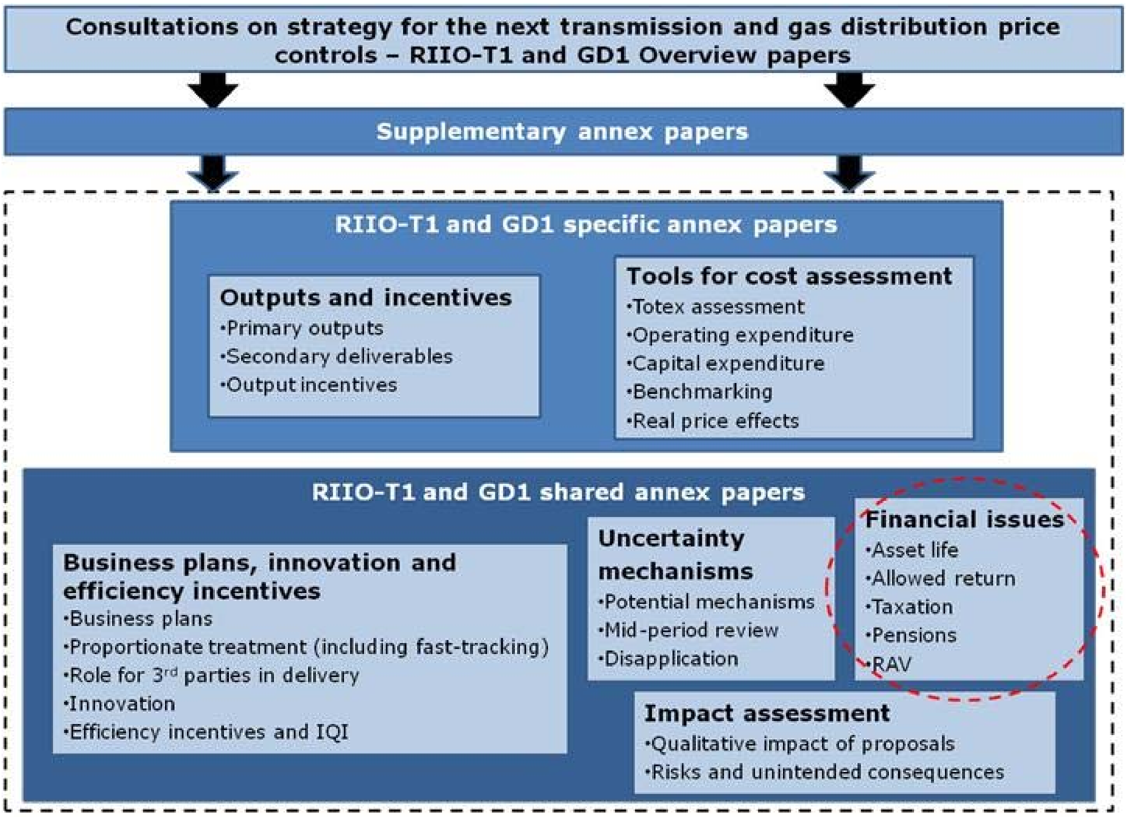
- Approach and timetable for TPCR5: decision document (21/10)
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR5/Documents1/TPCR5%20Approach%20and%20Timetable%20-%20Decision%20Document%20-%20FINAL.pdf
- Price Control Treatment of Network Operators Pension Costs under Regulatory Principles (76/10)
  http://www.ofgem.gov.uk/Networks/Documents1/Price_Control_Treatment_of_Pension_Costs_final.pdf
- Electricity Distribution Price Control Review Final Proposals - Allowed Revenue and Financial Issues (147/09)
  http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_5_Financial%20Issues.pdf
- The Economic Lives of Energy Network Assets – Report by CEPA/SKM/GL on behalf of Ofgem
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/CEPA%20Econ%20Lives.pdf
- The Weighted Average Cost of Capital for Ofgem's Future Price Control – Report by Europe Economics on behalf of Ofgem
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/Europe%20Economics%20Final%20Report%20-%20011210.pdf
- Establishment of pension deficit funding rate of return - Report by Ernst & Young on behalf of Ofgem
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/EY%20pension%20deficit%20funding.pdf

Table of Contents

1. Introduction

The next transmission and gas distribution price controls, RIIO-T1 and GD1, will be the first to reflect the new RIIO model. We are now consulting on the strategy for the two price control reviews. This supplementary annex, to the main consultation documents, sets out our thinking for both RIIO-T1 and GD1 on those elements of the price control collectively referred to as financial issues. These are asset lives and associated depreciation, cost of capital, financeability, taxation, pensions and regulatory asset value (RAV). This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the RIIO-T1 and GD1 Overview Papers. Figure 1.1 below provides a map of the documents published as part of the consultations.

Figure 1.1 - RIIO-T1 and GD1 Supplementary appendix document map*



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

1.1. This is a detailed technical supporting paper that expands upon the issues set out in Chapter 8 of the documents RIIO-T1 Overview paper and RIIO-GD1 Overview paper. It is structured as follows.

1.2. Chapter 2 provides a summary of the technical and economic asset life review that has been undertaken for us by a consortium comprising CEPA, SKM and GL Noble and provides our proposed economic asset life ranges and depreciation profiles for consultation.

1.3. Chapter 3 explains our approach to setting the allowed return and sets out our views on cost of debt indexation and initial ranges for the cost of equity; as well as summarising the report provided to us on the subject by our consultants, Europe Economics.

1.4. Chapter 4 shows how we will assess financeability and the main factors we will take into consideration.

1.5. Chapter 5 highlights the areas where we have decisions to take affecting the allowance we provide for taxation and Appendices 2 and 3 provide details on the tax methodology and the proposed tax trigger.

1.6. Chapter 6 discusses the pension issues that are the subject of the consultation, while Appendix 4 provides details of our pension methodology and Appendix 5 sets out our pension principles and notes for guidance.

1.7. Chapter 7 sets out the issues that affect our determination of the regulatory asset value (RAV) including our approach to capitalisation (i.e. additions to the RAV) for consultation and Appendix 6 provides the full RAV methodology.

2. Asset lives and depreciation

Chapter summary

In this chapter, we summarise the results of our consultant's review of technical and economic asset lives. We set out, for consultation, our views on the regulatory asset lives and depreciation profile for gas and electricity transmission and distribution networks.

Questions

Question 1: Do you agree with our proposed economic asset lives for gas and electricity transmission and gas distribution?
Question 2: Do you agree with our proposals for the depreciation profile?
Question 3: We invite views on our proposed approach to transition.

Asset lives

RIIO context and different types of asset life

2.1. Included within the annual revenue allowance for network operators is an amount for depreciation of the regulatory asset value (RAV), calculated using regulatory asset lives. There are a number of different ways of defining the life of a network asset. Each asset will have a design life, a technical life (the expected life of an asset from commission until it falls below minimum technical and/or safety performance levels); and an economic life (the life it is expected to be active on the network). Through good maintenance and management of an asset, its technical life will often exceed its design life. The economic life of an asset will be no longer than its technical life but may be shorter.

2.2. Under the RIIO model, we established the principle that the regulatory asset lives should reflect the average expected economic life of the related network assets. Adopting this principle balances the interests of existing and future customers as it spreads the cost of network assets over the time they are in use.

2.3. We contracted a consortium led by CEPA[1] to assess the following:

1. the technical lives for the assets of the four energy network sectors
2. the economic lives of the assets in each case

[1] The CEPA consortium comprises Cambridge Economic Policy Associates (CEPA), Sinclair Knight Martz and GL Noble Denton.

3. to identify the appropriate depreciation profile to be used, taking into account any uncertainty around the expected economic life.

We have published their full report in parallel with this document.[2]

2.4. Their report covers transmission and distribution for both gas and electricity. Although the electricity distribution businesses are not part of the current price control reviews, this report also provides views on the asset lives of electricity distribution assets. We include summary data from the consultants' report and our view on the appropriate technical and economic asset lives for consultation. We will issue a short separate consultation specific to the electricity distribution economic asset lives in January 2011. However, in responses to this consultation, we are interested in views on the proposed electricity distribution as well as transmission and gas distribution asset lives. We welcome views from all interested parties.

Summary of current regulatory treatment

2.5. The current regulatory asset lives vary by sector and have developed over time into a number of variations. These are set out below.

- **Electricity transmission:** post-vesting assets (those added after privatisation) have an asset life of 20 years. The pre-vesting assets will be fully depreciated by end 2010 in National Grid Electricity Transmission (NGET) and Scottish Power Transmission (SPTL) and 2012 in Scottish Hydro Electric Transmission (SHETL). Once the pre-vesting assets are fully depreciated a smoothing depreciation adjustment relating to the post vesting assets is set to be released creating supplemental depreciation for an additional period (15 years for SPTL, 30 years for SHETL and 50 years for NGET) on a straight line basis.
- **Electricity distribution:** all post-vesting assets have a regulatory asset life of 20 years. The date on which pre-vesting assets became fully depreciated varied by Distribution Network Operator (DNO), with the last being fully depreciated by the end of 2010. From the date that each individual DNO's pre-vesting assets became fully depreciated, we introduced a smoothing adjustment over 15 years, on a straight-line basis.
- **Gas transmission and gas distribution:** pre-2002 assets have an asset life of 56 years and will be fully depreciated (on a sum of digits basis) by 2058. Post-

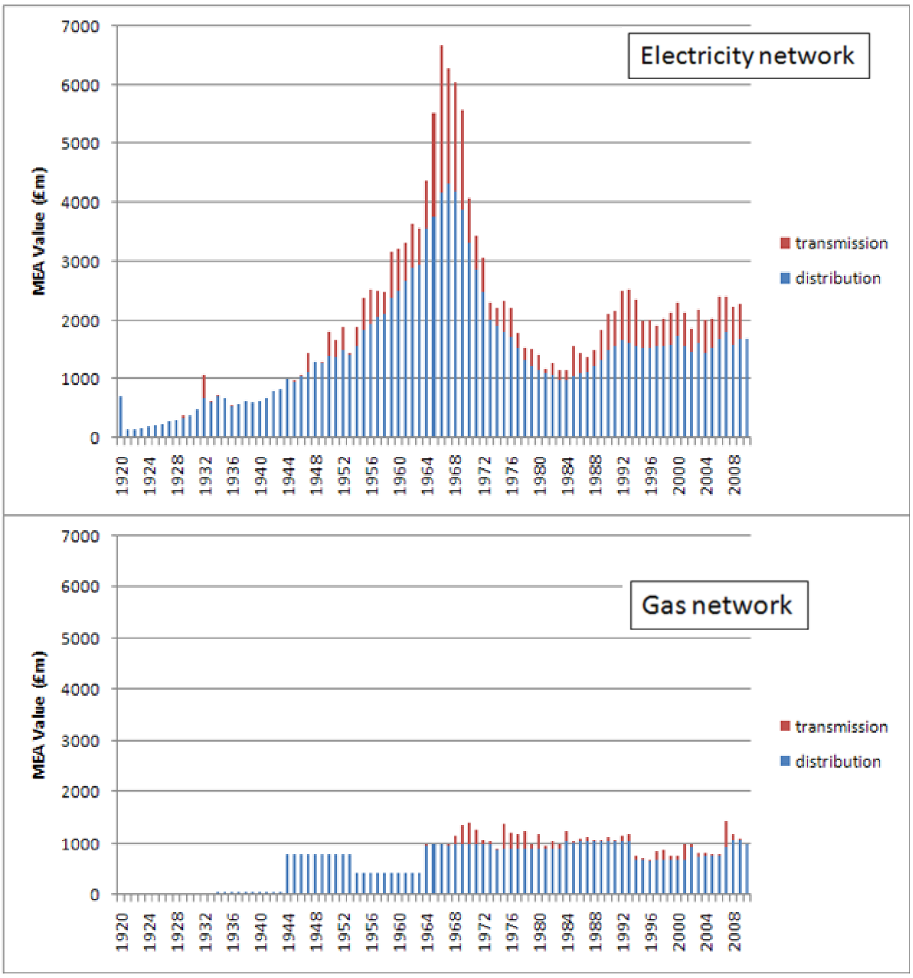
[2] The Economic Lives of Energy Network Assets – Report by CEPA/SKM/GL on behalf of Ofgem http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/CEPA%20Econ%20Lives.pdf

2002 assets have regulatory assets lives of 45 years and are depreciated on a straight-line basis.

Existing age of the energy networks

2.6. Figure 2.1 below shows the age profile of the current energy network assets. The values used in these graphs are modern equivalent asset (MEA) values or replacement values. The figure highlights the relative replacement costs of each network and the peak of electrification activity undertaken in the 1950s and 1960s. The weighted average age of each of the networks from the graph below is: 39 years for electricity distribution, 33 years for electricity transmission, 33 years for gas distribution, and 27 years for gas transmission.

Figure 2.1 Age and MEA replacement cost for the electricity and gas networks



Source: CEPA

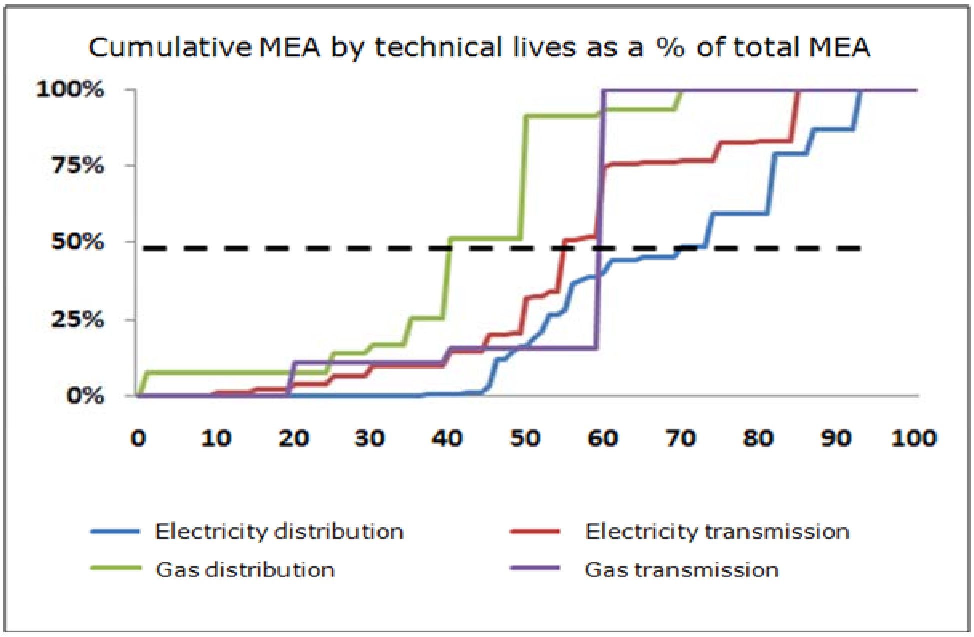
2.7. An overview of the existing gas and electricity networks as they exist today, including geographic maps of the each network is found in chapter 3 of the CEPA report on energy network assets.

Technical asset lives

2.8. Engineers base the technical life of an asset on an assessment of the number of years of use that they expect will derive from that asset. The number of years will be a factor of an asset's design life, its wearing out through use and the policy for its maintenance, including safety considerations.

2.9. The cumulative MEA for each of the networks based on the technical lives of the network assets and the weighted average technical asset lives for each sector are shown in figure 2.2 below. In summary the weighted average technical asset lives are: 54-60 years for electricity transmission, 60-75 years for electricity distribution, 60 years for gas transmission and 40-50 years for gas distribution.

Figure 2.2 Cumulative percentage MEA for the electricity and gas networks



Source: CEPA

2.10. There are uncertainties around the technical lives of certain asset categories used in the above chart. Where there is uncertainty, CEPA have used more conservative assumptions. For example, the design lives for polyethylene (PE) pipes is 50 years whereas there is a view in the industry that the actual technical life for these assets will be longer than this, with estimates of 150 years not being unusual. The weighted average technical life for the gas distribution assets increases to around 80 years if a longer, 150-year assumption is used. Another example of conservative technical life assumptions are those applied to underground cables. The technical lives used are no longer than existing ages in use even though these cables appear to have many years of use left.

2.11. We recognise that we are entering a period of innovation in networks, which may impact on how they are operated in the future. However, we have taken this into account in setting out our proposed range for economic asset lives and do not think that this will have a material impact on the usefulness of the vast majority of the existing network assets.

Statutory asset lives

2.12. Network operators use an expected useful economic life for their network assets as part of their depreciation accounting policy disclosed in their statutory and regulatory accounts.

2.13. Figure 2.3 summarises the ranges of asset lives used in statutory accounts compared with the technical lives set out above and the current asset lives (for new investment) used for regulatory purposes. The technical asset life range for gas distribution uses the lower estimate for PE pipes.

Figure 2.3 Summary of asset lives

Network		Asset Life range			
		Regulatory	Accounting	Technical	
				Full Range	Weighted Average
Electricity	Transmission	20	10-80	10-90	54-60
	Distribution	20	2-100	30-140	60-75
Gas	Transmission	45	30-100	20-60	60
	Distribution	45	10-100	0-70	40-50

2.14. The accounting policies detailed in figure 2.3 cover wide ranges due to the different types of assets that are part of the network. The technical lives in this figure are within the range of the accounting policies. The maximum economic asset lives to be used would in a steady network state tend to the technical lives. However, energy networks face considerable uncertainty over the next fifty years that might lead to technical lives being curtailed by economic factors. Therefore, in order to assess the expected economic life of the gas and electricity networks, it is necessary to consider how these networks may be used in the future.

The uncertainty of the future use of energy networks

2.15. There are two important national targets that will impact upon the future use of each of the energy networks. The first is the UK's target to meet 20 per cent of its primary energy demand from renewables by 2020[3]. The second is to achieve or exceed the UK's 80 per cent reduction in greenhouse gas emissions by 2050.

2.16. CEPA have identified a number of potential developments that could be significant drivers of the future need for, and structure of energy networks. Figure 2.4 sets out a summary of these uncertainties and their impact on average asset lives.

Figure 2.4 Summary of uncertainties influencing the future use of energy networks.

Event	Impact on average asset life	Rationale
Smart grids/ information technology	Decrease	Information technology tends to have a short asset life. Unlikely to be material.
New technology	Unclear	The impact could go in either direction depending on the cost benefit analysis associated with the new approach/technology.
Increase in cost of raw materials	Increase	More expensive assets could justify increased maintenance to extend the technical life or change the cost benefit analysis underlying health and safety limits on asset lives.
Policy decisions	Decrease	Government decisions on decarbonisation could lead to a wholesale change in approach or technology beyond that suggested by a simple cost-benefit analysis. Shifting between gas and electricity based space heating would be an example that could have a significant impact on asset lives.

Source: CEPA

2.17. In order to assess these uncertainties and their impact on the energy networks, many organisations have prepared projections of the future development of the energy markets in the UK. We asked CEPA to consider these scenarios as part of their work is assessing the expected economic lives for energy networks.

[3] The EU has a 20 per cent renewables target by 2020; the UK's legally binding target is 15 per cent.

2.18. CEPA elected to use Ofgem's Project Discovery[4] to provide the scenario framework for their analysis. CEPA extended the four scenarios to 2050 and cross-checked them with other published scenarios including the recent Redpoint report.[5] In addition, they drew upon our Long Term Electricity Network Scenarios. The scenarios result from consideration of either rapid or slow economic recovery (ER) coupled with rapid or slow environmental action (EA). These scenarios are named as follows:

- Dash for Energy (rapid ER and slow EA)
- Green Transition (rapid ER and rapid EA)
- Green Stimulus (slow ER and rapid EA)
- Slow Growth (slow ER and slow EA)

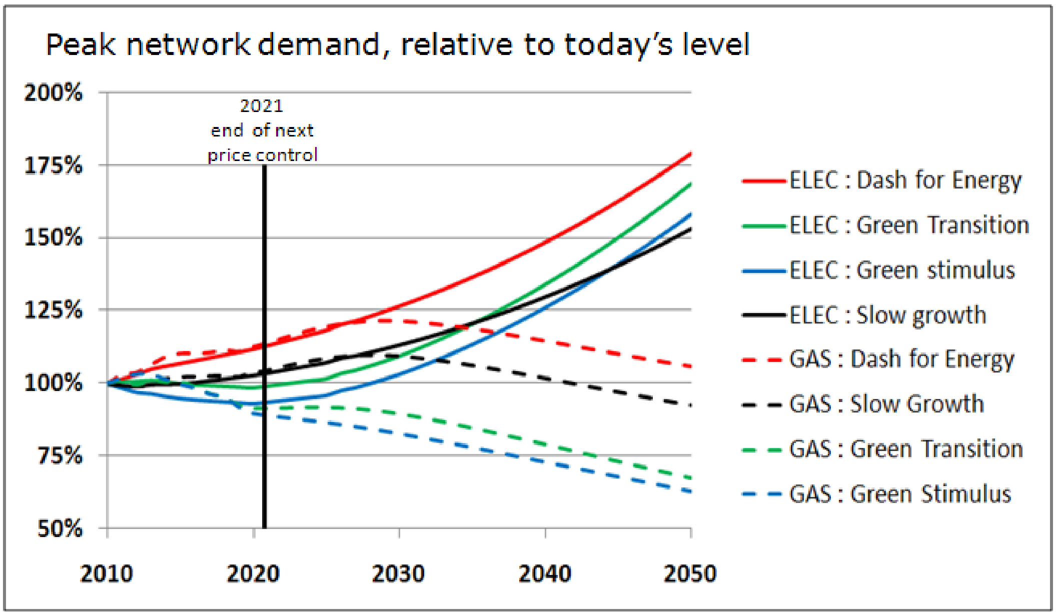
2.19. The analysis of the various scenarios shows that total annual gas demand will fall as the UK decarbonises to meet its 2050 carbon emission targets. Carbon capture and storage (CCS) on gas generation would effectively remove the barrier to continued use of the gas network in the power sector although it is currently an unproven technology at scale. If this were proven at a reasonable cost, however, then this significantly changes the scope for future use of the gas network.

2.20. Although the total demand for gas is falling, the use of gas in meeting peak demand (particularly for space heating demand) becomes an important factor in forecasting the use of the gas network. CEPA have examined the impact on peak electricity and gas demand under the four different scenarios. Figure 2.5 shows the ranges of differing levels of peak demand for both gas and electricity.

[4] Project Discovery - Energy Market Scenarios, Oct 2009 (122/09) http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Documents1/Discovery_Scenarios_ConDoc_FINAL.pdf

[5] Gas Future Scenarios - A report on a study for the Energy Network Associations Gas Futures Group, November 2010 http://www.ofgem.gov.uk/Networks/PriceControls/WebForum/Documents1/ena_gas_future_scenarios_report.pdf

Figure 2.5 Peak network demand relative to today's level



Source: CEPA

2.21. This graph shows electricity peak demand rising significantly under each scenario (between 150 per cent-175 per cent of today's levels) and the gas peak level being at or lower than today's levels (between 60-100 per cent). This outturn seems to be broadly consistent with the majority of other published future scenarios – although there are some scenarios where the gas network is significantly smaller.

Our proposals

Electricity networks

2.22. Our consultants' reports have demonstrated that technical asset lives are considerably longer than the current regulatory electricity asset lives of 20 years. It is also clear from the scenario analysis that under all future scenarios the use of the electricity networks, including peak demand is expected to increase.

2.23. Projecting forward, the mix of electricity assets is likely to change. This could mean greater volumes of short-life technology assets for monitoring and controlling the network. The introduction of smart grid technology could also impact on the need for and location of network capacity. However, this is unlikely to make a material difference to average technical asset lives. This may be balanced if the proportion of underground cables increases as existing infrastructure is replaced.

2.24. Recognising the uncertainties that still exist over the how the electricity network will develop into the future, particularly in light of the potential application of smart grid technology, our view is that average economic asset lives for both electricity transmission and distribution should be between 45 and 55 years. We discuss transitional arrangements later.

Gas networks

2.25. The gas networks have assets with average technical lives that are close to or longer than the current regulatory lives of 45 years.

2.26. There is significant uncertainty around the future use of the gas network with annual load and future peak demand likely to be no higher than currently. In some scenarios, gas usage could be much lower. The future use of the gas network depends upon the successful development of a number of technologies including CCS and high use of bio-methane. It seems likely that the path of gas usage should be clearer by the end of RIIO-GD1.

2.27. Our view is that it would be premature to reduce asset lives given that there are scenarios, where gas will remain an important element of the energy market. We therefore propose to retain the existing asset life of 45 years for post 2002 assets.

2.28. We invite views on our suggested ranges for economic asset lives, as set out in the figure 2.6 below.

Figure 2.6 Summary of asset lives and depreciation profiles

Network		Economic Asset Life
Electricity	Transmission	45-55
	Distribution	45-55
Gas	Transmission	45
	Distribution	45

Source: CEPA

2.29. We propose that, given the complexity of the arrangements that are currently in place, we will not change the assets lives in place for pre-2002 assets for gas transmission and gas distribution. Due to the front loaded nature of the depreciation method, by the start of the next price control, nearly one-third of the value of these assets will have received a depreciation allowance. The end of the 56 year depreciation period for these assets is also 45 years from the start of the new price controls, which is the proposed economic asset life for gas transmission and depreciation.

2.30. We will consider the smoothing arrangements for electricity transmission and distribution as part of the transitional arrangements.

2.31. Our proposals for revised regulatory asset lives therefore only apply to the assets covered by the current 20-year depreciation period in electricity transmission and distribution and those covered by the 45-year depreciation period in gas transmission and distribution.

Other regulatory practices

2.32. The economic asset lives recommended for electricity distribution and transmission by CEPA, in figure 2.6 above, are significantly higher than currently used for regulatory purposes. We have considered other regulatory sectors and highlight, in figure 2.7 below, examples of the use of longer asset lives. We also note that the Commission for Energy Regulation (CER), in Ireland, mention in their 'Decision on 2011-15 distribution revenue for ESB Networks Limited' that 'internationally in recent years that there had been a general trend towards extending the lifetimes of electricity distribution assets'.

Figure 2.7 Examples of recent regulatory decisions

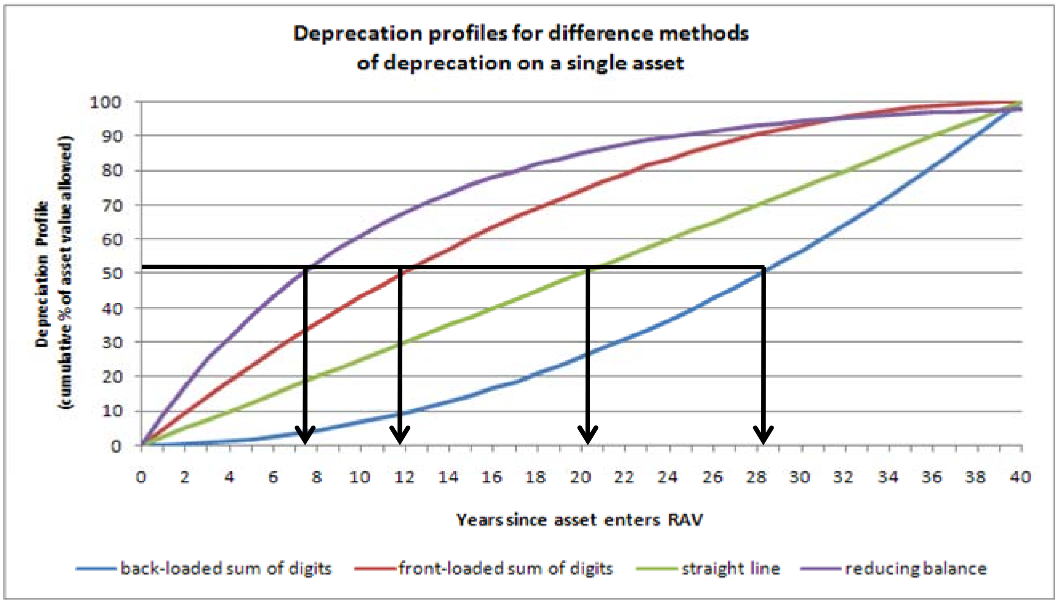
Country	Network	Practice
Victoria (Australia)	Electricity Distribution (Nov 2010)	Uses asset lives as follows: Sub-transmission: 44.7-60 years Distribution systems: 35.6-51 years SCADA/Network control 5-13 years
Republic of Ireland	Electricity Transmission 2011-15 (Nov 2010)	Re-iterates asset life of 50 years for High Voltage Network assets. This had been extended to 50 years (from 40 years) under the price control 2005-2010
Republic of Ireland	Electricity Distribution 2011-15 (Nov 2010)	Re-iterates asset life of 45 years for High Voltage/Medium Voltage/Low Voltage Network assets. This had been extended to 45 years (from 40 years) under the price control 2005-2010
GB	Water	Capital charges are included every year representing two elements: i) a current cost depreciation charge for above ground assets, e.g. treatment works; and, ii) an infrastructure renewals charge (IRC) for underground assets, such as pipes. The IRC is calculated using a 15 year average of infrastructure renewals expenditure Under historical cost convention, Severn Trent uses economic lives for its infrastructure assets of between 80 and 250 years. The higher end relates to reservoirs and aqueducts.

Depreciation

Depreciation profile

2.33. In considering the appropriate depreciation profile, our aim is to choose a methodology which reflects the speed at which assets are consumed by users. Figure 2.8 illustrates the impact of different deprecation profiles on a single asset with a 40-year asset life. Superimposed on this chart is a line at the 50 per cent level which shows the different speed at which an asset would fall to 50 per cent of its original value. This shows a reducing balance profile (9 per cent reducing balance is used) would reach the 50 per cent level in just under 8 years, a front-loaded sum of digits profile takes about 12 years, a straight line profile takes 20 years and a back-loaded sum of digits profile takes over 28 years.

Figure 2.8 Illustration of different depreciation profiles



2.34. We consider it is important that any depreciation profile is easy to calculate and understand. For this reason, we have historically tended to select a straight-line depreciation profile, although for pre 2002 gas assets we use a sum of digits approach.

2.35. However, it might be more appropriate to use a non straight-line depreciation profile in certain circumstances. For instance, by the time of the next gas distribution price control (RIIO-GD2), around 2020, the uncertainty over the future use of gas and electricity networks (as highlighted in figure 2.5) may be reduced. For the gas distribution network, it might be appropriate to use a front-loaded profile for RIIO-GD1 so as to avoid a more rapid write off in RIIO-GD2 and beyond, if the use of gas distribution network is likely to diminish significantly after RIIO-GD1.

2.36. The opposite argument may apply to the electricity network. In this case a back-loaded depreciation profile may be more appropriate for RIIO-T1.

2.37. We asked CEPA to consider this question and their recommendations are summarised in Figure 2.9.

Figure 2.9 CEPA's proposals for depreciation profiles

Network		Depreciation profile
Electricity	Transmission	straight line or back-loaded
	Distribution	straight line or back-loaded
Gas	Transmission	straight line or front-loaded
	Distribution	straight line or front-loaded

Source: CEPA

Our proposals

2.38. For electricity, transmission and distribution, our initial view is that there is no need to use a back-loaded profile; we propose to retain the current straight-line approach. Although there is likely to be growing demand for electricity, we also expect assets to be added gradually and so utilisation of individual assets is unlikely to be particularly back-loaded.

2.39. In gas, we are concerned that there is a possibility that by the end of RIIO-T1 and GD1 we could be entering one of the scenarios where gas becomes less important in the energy market. In such circumstances, there may be insufficient annual throughput or customer numbers to absorb the accelerated depreciation that would be required. We think this risk is greatest for gas distribution. We therefore propose to maintain straight-line depreciation for gas transmission but to apply a front-loaded depreciation profile to gas distribution for new investment. We propose to continue to depreciate existing gas distribution assets on a straight-line basis.

Transitional arrangements

2.40. We are committed to ensuring that efficient network companies are able to raise the finance they require, both debt and equity, in a timely manner. Where the adoption of a new approach to depreciation in a single step would cause excessive disruption to capital markets and/or raise concerns about financeability, we will adopt appropriate transition arrangements. The onus will be on the network companies to demonstrate to us in their well-justified business plans why transitional arrangements are necessary and to propose a suitable methodology.

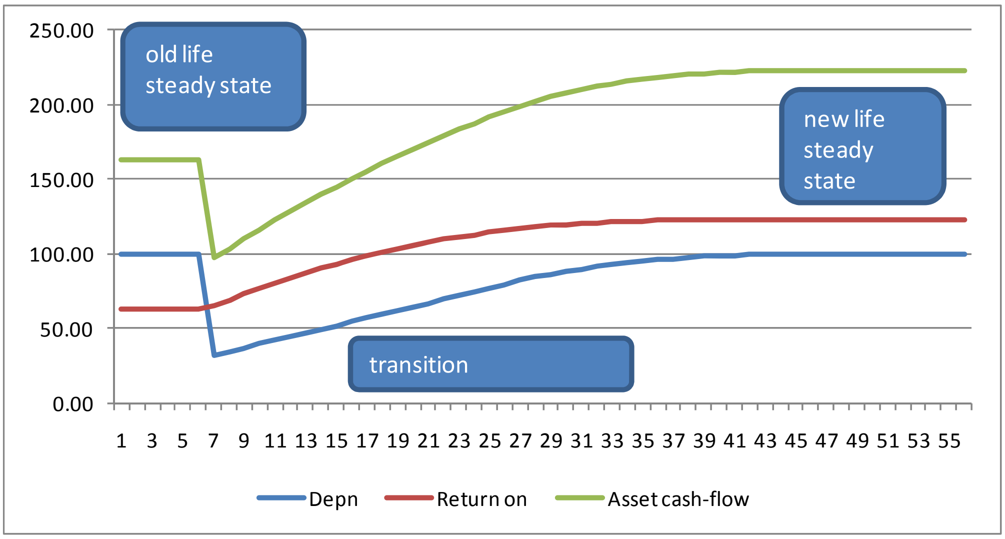
2.41. This section examines the impact of extending regulatory assets lives and considers the potential transitional arrangements.

The impact on allowed return of increasing regulatory asset lives

2.42. As described above we are proposing to increase the regulatory asset life for the electricity networks. There are two cashflow effects of this on allowed revenue. The first is to reduce the annual depreciation charge. The second is that the allowed return on RAV increases (as the RAV value increases).

Figure 2.10 shows a simple hypothetical scenario of the impact on cashflow. This stylistic approach assumes a constant annual investment and a change in asset lives, applicable to all assets, from 20 to 40 years. This shows that total asset cashflow (return plus depreciation) falls from the steady state position whilst the new policy takes effect, and then grows to reach a new higher steady state.

Figure 2.10 Stylised example of the impact of extending asset lives on depreciation, the return on RAV and the combined cashflow



Source: CEPA

2.43. The size and duration of the temporary fall in asset cashflow will vary according to the length of the increase in asset life, the depreciation profile that is used and the investment profile the network operator is forecasting.

2.44. Under the RIIO model, we are committed to introducing appropriate transitional arrangements where moving to the use of economic asset lives in a single step would cause excessive disruption to financial markets and/or raise concerns over financeability.

Potential transitional arrangements

2.45. We see a number of benefits from the provision of transitional arrangements. They:

- avoid any increased perception of regulatory risk that could arise from a sudden deferral of cashflows
- provide time for businesses to re-organise their financing arrangements as immediate equity injections are not practical

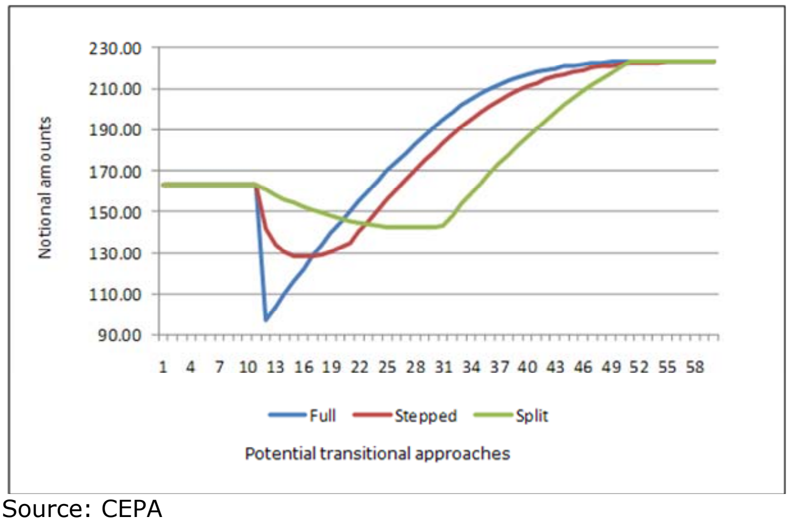
- allow firms to increase equity through retained earnings, rather than by new rights issues, which may reduce the transaction cost to firms of altering their capital structure
- reduce the likelihood that businesses need to engage in rights issues at a time when equity market conditions may not be ideal
- avoid any increased tax liabilities, which might arise in the short term if companies had to reduce their short-term reliance on debt finance significantly

2.46. As we set out in RIIO, our preference is to manage the transition over one price control period of eight years. This period, combined with the extensive period of consultation preceding it, should provide a sufficient time to allow companies to adapt their financing approach and to avoid any financeability concerns. Our prime driver for the length of transition is the need to ensure companies are financeable.

2.47. Some network companies have suggested that any changes to asset lives should only affect new investment. They argue that we would be adversely affecting the legitimate expectation of investors. We are not convinced by this argument as we have signalled for some time that the 20-year regulatory asset life was subject to review. In addition, individual investments in network assets are not ring-fenced. However, we recognise that it is a possible transitional arrangement.

2.48. CEPA have modelled the impact of two specific transitional options from their 'full' scenario. The full scenario assumes changes are made to new and existing assets. They have looked at a split implementation of change in asset lives where the change is applied to new assets only with existing assets keeping their current regulatory lives. They have also modelled a stepped implementation of asset lives where the change to asset lives is made in a series of steps. Figure 2.11 below illustrates the different options.

Figure 2.11 Illustrative cashflow impact of different approaches to transition



Source: CEPA

2.49. CEPA have applied this approach to some high-level scenario modelling at a sector level to highlight areas where the change in asset life may result in financeability issues and to assess the impact on consumer bills. CEPA's analysis suggests that the most significant impact will be in the electricity distribution sector and that the proposed change in asset lives will not have a material impact on consumer bills in the period to 2050. Whilst informative, CEPA's high level approach does not provide full information on which to base our decisions. It will be for network companies to highlight and demonstrate any financeability concerns they may have and to suggest the most appropriate transitional arrangements in their business plans. We welcome views from interested parties.

3. Allowed return

Chapter summary

This chapter outlines our approach for setting the allowed return for RIIO-T1 and GD1. In particular, it sets out the new approach for setting notional gearing, our initial thoughts on options for the cost of debt indexation mechanism, and an initial range for the cost of equity.

Questions

Question 1: Is our approach for setting the allowed return appropriate, particularly in the context of an eight-year price control?
Question 2: What impact do our proposals for RIIO-T1 and GD1 have on the companies' cashflow risk, and does this have a material impact on how the allowed return should be set?
Question 3: What considerations do we need to take into account when setting the notional gearing level?
Question 4: Is our proposed approach to setting the notional equity wedge appropriate?
Question 5: Is our proposed mechanism for indexing the cost of debt assumption appropriate?
Question 6: How should we account for the costs of issuing debt?
Question 7: Is our range for the equity beta appropriate for the network companies? What factors might mean that we should use different equity betas for the different sectors and/or companies within a sector?
Question 8: Does our overall range for the cost of equity capture probable range for RIIO T1 and GD1?
Question 9: Is the ex ante approach to the cost of raising equity, with a true-up at the next price control review appropriate for RIIO T1 and GD1?

Context

A WACC-based allowed return

3.1. The cost of capital is the return expected by investors on their investment. Regulators have typically made an allowance for the efficient financing of the companies they regulate that is set by calculating a return on the value of the capital employed in the business (the regulatory asset value or RAV) that is at least equal to the notional company's estimated cost of capital.[6] As part of the RIIO-T1 and GD1

[6] We set the allowed return such that a notional efficient company is able to raise the necessary level of capital to finance its investment programme and, therefore, achieve its required regulatory outputs.

price controls we will consider the main factors affecting the cost of capital and the issues surrounding the required calculations.

3.2. We are committed to ensuring that efficient companies are able to finance themselves (both through debt and equity). Consistent with this, the RIIO proposals outlined four key principles regarding our approach for setting the cost of capital allowance as part of future price controls:

- We will continue to take a real weighted average cost of capital (WACC) based approach to setting the allowed return;
- the cost of debt component of the WACC will be based on a long-term trailing average and updated mechanistically each year;
- the cost of equity component of the WACC will continue to be set by reference to the capital asset pricing model (CAPM), sense-checked by other approaches; and
- we will take a principles-based approach to the calculation of notional gearing, with the size of the notional equity wedge reflecting the company's risk exposure and potentially varying within and between sectors.

3.3. Under the RIIO proposals, we will need to balance and ensure consistency between three elements: the riskiness of the cashflows (including incentive schemes), the size of the equity wedge (and, therefore, notional gearing) and the equity beta and hence cost of equity. This balance will depend on the particular circumstances of the companies and we will therefore not be able to determine the appropriate level of notional gearing until we have seen and assessed companies' business plans.

3.4. Once we have evaluated the consistency between the riskiness of the cashflows in the business plans and the level of notional gearing we will have the opportunity to either adjust the level of gearing and/or the riskiness of the package by altering uncertainty mechanisms.

3.5. In light of the new approach for setting the allowed return, we do not consider it appropriate to include a range for notional gearing at this stage. We focus instead on setting out the approach we will use to determine appropriate notional gearing. Consequently, we do not include in this document any estimates for the weighted average cost of capital. We do however, set out our approach to cost of debt indexation and the cost of equity range. It will be for the companies to assess the overall risk of their business plans in the first instance and to make realistic bids for notional gearing if they wish to be fast-tracked.

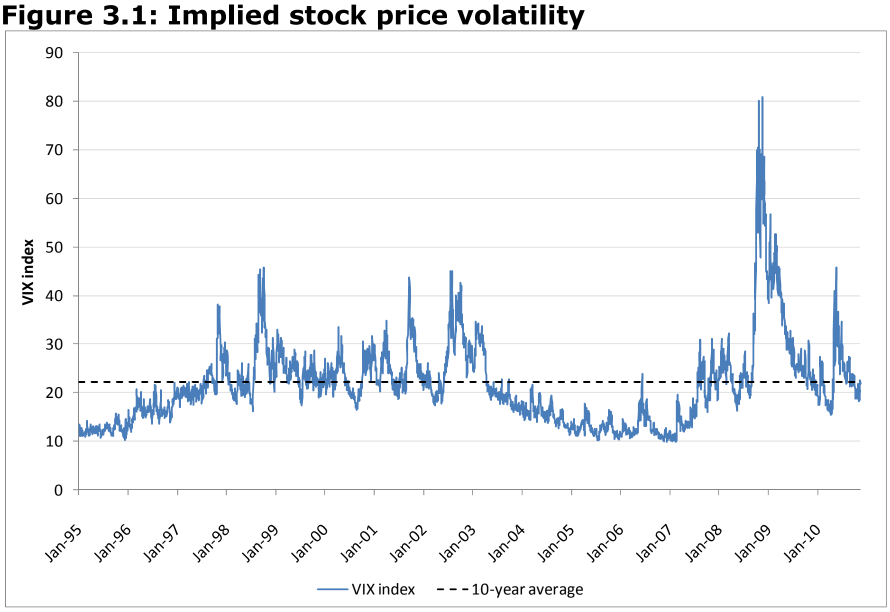
3.6. We contracted Europe Economics to advise us on a number of aspects of estimating the cost of capital. We summarise their recommendations in this chapter, which sets out our proposals as they apply to implementing the RIIO framework with regard to the RIIO-T1 and RIIO-GD1 price controls. We have published Europe Economics' report alongside this document.[7]

The current economic climate

3.7. The current state of the UK economy is more favourable than the last time we considered the cost of capital, which was at the time of the DPCR5 Final Proposals in December 2009. Recovery in both the UK and global economies has continued, with positive GDP growth in the fourth quarter of 2009 and in the first two quarters of 2010. Meanwhile, inflation has risen sharply, with the year-on-year rate of the RPI spiking from 0.3 per cent in November 2009 to 4.7 per cent in November 2010.

3.8. Stock price volatility, as measured by the VIX index, has declined since the financial crisis and is now back in line with its 10-year average (see Figure 3.1). Nevertheless, there remains a significant amount of uncertainty around the outlook for the coming years. A number of analysts have argued that the government budget cuts, proposed in the October Spending Review, together with the tax increases announced in June, could push the economy back into recession or a period of slow growth. This is reflected in the return of concerns about debt in Ireland, although we note that the UK economy is on more solid ground.

Figure 3.1: Implied stock price volatility



Source: Bloomberg

[7] The Weighted Average Cost of Capital for Ofgem's Future Price Control – Report by Europe Economics on behalf of Ofgem
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/Europe%20Economics%20Final%20Report%20-%20011210.pdf

3.9. The RIIO framework provides a number of important measures that we believe will help mitigate uncertainty, thus ensuring that companies are able to finance their activities efficiently and that consumers are protected against sharp price rises. The key mechanisms are: indexing the cost of debt, relying on long-term historical trends to set the cost of equity, setting notional gearing levels that reflect the cashflow risk companies face, and carrying out financeability testing (described in Chapter 4) to ensure that the overall regulatory package can be delivered and financed by an efficient company.

Notional gearing

Approach

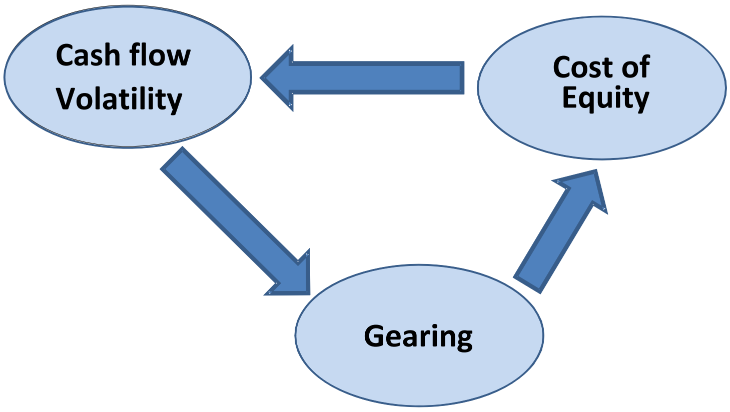
3.10. Under the RIIO model, we will adopt a principles-based approach to notional gearing,[8] with the size of the notional equity wedge reflecting the company's risk exposure and potentially varying within and between sectors. In the context of the current price control reviews, this is reflected not only in the fact that we may adopt different notional gearing assumptions for the concurrent RIIO-T1 and RIIO-GD1 reviews, but also that within each review individual companies may have a different notional gearing assumption where there is a significant difference in the cashflow risk they face.

3.11. This may be of particular relevance for RIIO-T1, where we expect SHETL and SPTL to carry out a substantially larger investment programme (relative to their RAV) than National Grid.

3.12. In setting the level of notional gearing, we will need to balance and ensure consistency between three elements – the riskiness of the cashflows (including incentive schemes), the size of the equity wedge and notional gearing and the equity beta and hence cost of equity. We illustrate this in Figure 3.2.

[8] We define gearing as net debt/RAV, expressed as a percentage.

Figure 3.2: Process for setting the allowed revenue



3.13. The notional gearing value for the WACC calculations cannot be set until we have the networks' final business plans and until we calibrate the incentives so we know the network companies risk exposure. We will also need to take into account the scale of the investment programmes envisaged for both RIIO-T1 and RIIO-GD1 and any implications these might have for cashflow risk. We are currently developing a set of approaches, including the use of Return on Regulatory Equity (RoRE), to set the notional equity wedge.

3.14. We note that the majority of network companies have been able to retain a 'comfortable investment grade' credit rating, while holding a larger proportion of net debt to RAV than assumed in our determinations. Gearing is typically around 70 per cent versus regulatory assumptions of 60 per cent in TPCR4, 62.5 per cent in GDPCR and 65 per cent in DPCR5 (although we note the Scottish transmission networks have a lower gearing).

Cost of debt

Indexing the cost of debt

3.15. Under the RIIO model, we have been clear that we will base the cost of debt component of the allowed return on a long-term trailing average of the yield on sterling-denominated bonds. We will adjust the revenue allowance mechanistically each year to reflect movement in the index. Setting the cost of debt component of the allowed WACC in such a way should provide comfort to companies and their investors that efficiently incurred new debt - even at levels higher than the level of the index at the time - will be fully funded in the future.

3.16. Some of the network companies have argued that in its review of Bristol Water, the Competition Commission (CC) has suggested that debt indexation is not appropriate. We do not agree with this interpretation. The CC suggested that regulators should focus on ensuring that the assumed cost of debt is appropriate to the price control period. We believe that our proposals for the cost of debt are fully consistent with this aim. In addition, we note that the CC highlighted that use of long-term indices would be relevant:

- in the case of regulated companies who finance long-life assets by issuing fixed-rate debt with long maturities; and
- where yields have a tendency to revert to a long-term average and, hence, past levels are relevant to estimating the expected level over the relevant period.[9]

3.17. We consider that both of these conditions apply. As Europe Economics' analysis shows, the network companies typically finance their activities with more than two-thirds fixed-rate debt. We also consider that, given the current low levels of the cost of debt, the historical average better represents likely levels during RIIO-T1 and GD1.

3.18. One of the concerns expressed by the companies has been that indexation would require the companies to re-structure their debt profile such that it tracks the index, to avoid the risk of underperforming it. The companies have argued that such a move may be costly and inefficient from a corporate financing perspective. How companies choose to finance themselves is a matter for their management.

3.19. We expect that companies will continue to issue debt of mixed tenor that reflects to some extent the economic lives of their assets. A parallel can be drawn with gearing - while we set a notional gearing, companies have been gearing above or below the notional level, as they deem appropriate. We expect that network companies will continue to be able obtain debt finance, over the period of the price control, in line with our cost of debt allowance.

3.20. We will continue to monitor issues such as the introduction of the Basel III banking supervision accords to ensure that the index will be robust to potential changes that might affect the bond market. However, since the network companies are primarily financed through existing fixed-rate debt, their cost of debt is less likely to be materially impacted by such changes.

3.21. Indexation protects the companies should the cost of debt increase markedly during the price control period. Conversely, indexation ensures that consumers do not pay excessively if the cost of debt were to fall in a sustained manner (as has been the case for the majority of the past decade). The benefits of indexation can be illustrated with extreme examples of rises/falls in the cost of debt, as shown in Figures 3.3 and 3.4.

[9] Bristol Water plc, a reference under section 12(3)(a) of the Water Industry Act 1991 – a report by the Competition Commission
http://www.competition-commission.org.uk/rep_pub/reports/2010/fulltext/558_final_report.pdf

3.22. Our analysis assumes that a notional company annually issues debt at the market rate. Figure 3.3 shows that, should the cost of debt rise throughout RIIO-T1 and RIIO-GD1 (1 April 2013 to 31 March 2021), indexation would better protect the companies than a fixed allowance (set at the observed cost of debt at the start of the price control). Conversely, Figure 3.4 shows that, should the cost of debt decline in a sustained manner throughout the price control, indexation would allow the savings to be passed on to consumers.

Figure 3.3: Illustration of rising cost of debt scenario

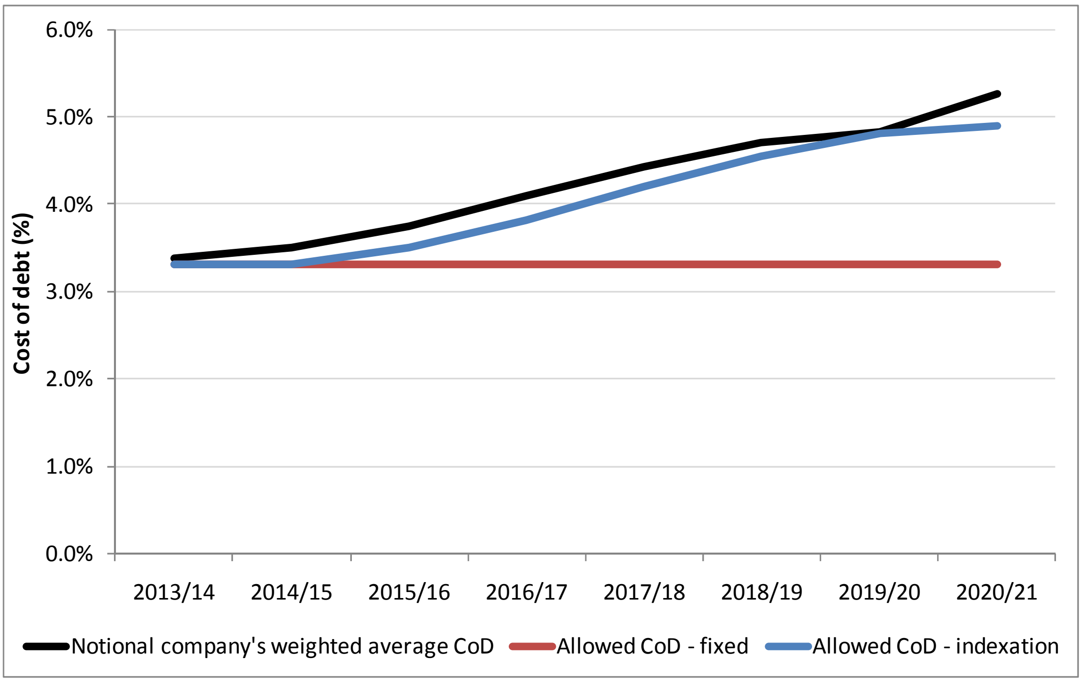
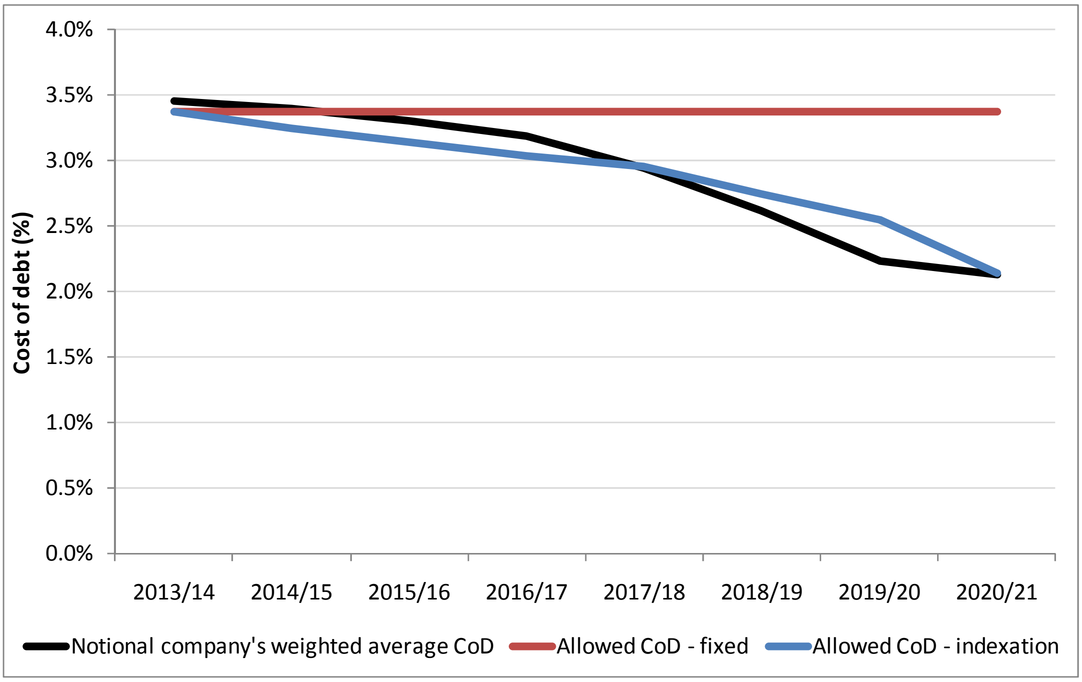


Figure 3.4: Illustration of falling cost of debt scenario



3.23. We asked Europe Economics to evaluate a range of options for how cost of debt indexation might work in practice. This involved identifying different options for the indexation mechanism, developing a set of criteria under which the options could be evaluated, and advising on a preferred option.

3.24. Europe Economics identified the following evaluation criteria:

- *Accuracy:* The index should accurately reflect the cost of debt for an efficient company, taking account efficiently incurred embedded debt. This criterion carries a high weight.
- *Simplicity:* The indexation mechanism needs to be simple to understand and acceptable to stakeholders. Since calculations will have to be carried out on an annual basis, the method of calculation should not be onerous and data should be readily available.
- *Transparency:* The indexation mechanism needs to be based on data and calculations that can be replicated by stakeholders.
- *Credibility:* The indexation mechanism needs to be based on credible data sources and calculations.
- *Fully mechanistic:* The indexation mechanism should not require any regulatory judgment in its application.
- *Cannot be manipulated:* The data used should be such that the regulated companies cannot manipulate the outcome of the calculations (eg by their own financing decisions).
- *Preserves efficiency incentives:* The indexation mechanism should preserve incentives for companies to raise their finance in an efficient way (ie if costs are high due to poor financing decisions, this should not feed through into a higher cost of debt through the indexation mechanism).

3.25. Europe Economics examined the following features of the indexation mechanism:

- the tenor of the bonds included in the index;
- the length of time for the trailing average;
- the credit rating/s of debt included in the index; and
- whether a simple average should be used or whether different time periods should be weighed so as to match better the index to companies' observed behaviour in financial markets.

Evaluation of options for indexation

3.26. With regard to the tenor of bonds used, Europe Economics recommended an index of 10-year maturities. This approach provides consistency with our past reference points when setting the cost of debt and analysis has shown that it provides a reasonable proxy for the cost of debt of network companies. An alternative proposed by Europe Economics is an index of 10+ years maturity, as published by iBoxx. Such an index has the benefit of reflecting the fact that a large proportion of bonds issued by utilities have a very long maturity. (Figure 3.5 shows that the average tenor of bonds issues by the network companies is close to 20 years.) However, the cost of debt for 10-year bonds and longer issues do not tend to be materially different from each other.

Figure 3.5: Tenor of network company debt issuances

	Weighted Average Tenor
NGET	20.8
NGG	20.2
SHETL	9.6
SPTL	11.8
Transmission	**20.0**
Northern Gas	21.3
Scotia - Scotland	19.6
Scotia - Southern	15.6
Wales & West	10.4
Gas Distribution	**15.8**
TOTAL	***18.6***

3.27. With regard to the length of the trailing average, Europe Economics recommends an eight year window. This is chosen as the shortest acceptable window since it matches the length of a RIIO price control. However, Europe Economics also notes that a longer trailing average (assuming sufficient historical data) would be appropriate in light of the fact that utilities have typically issued mostly fixed rate debt.

3.28. We note that Europe Economics link the length of the trailing average to the proposed length of the RIIO-T1 and RIIO-GD1 controls. However, we do not see any need to link the length of the trailing average to the proposed length of the price control as it is intended to continue from period to period. With that in mind, we prefer a 10-year window, which is consistent with our previous practice, provides a good match with companies actual cost of debt and provides for greater stability.

3.29. Europe Economics recommends an index of either A-rated debt or BBB-rated debt, or an average of the two. According to its analysis, a single-rating index performs better under the selection criteria of simplicity and transparency. We prefer a blend of ratings because we seek a comfortable investment grade rating and leave management free to develop their own financing strategy. We note that licensees as a whole are roughly equally divided between a broad A rating (covering A+/A/A-) and a broad BBB rating (including BBB+).

3.30. As far as the approach for averaging the index, Europe Economics notes that a weighted average based on RAV additions as a proxy for the timing of debt raised is preferable on a theoretical basis. However, concerns about the availability of data on RAV additions, and the added complexity of a weighted average lead it to conclude that using a simple average is preferable in practice.

3.31. We agree with Europe Economics' analysis and note the following concerns with regard to the weighted average approach:

- there is a time delay with regard to when RAV data is made available, which means that we would not be able to use the latest index values.
- weighting by past actions opens the index to influence by the companies' actions; and
- weighting would require calculating different indices for transmission and gas distribution (and, eventually, electricity distribution) and for individual companies.

3.32. In light of the above, we propose to apply a simple average to our preferred index.

Preferred option for cost of debt index

3.33. In light of the above, our proposal is to use a 10-year trailing simple average. We identified four options to deliver this:

- Average of Bloomberg 10-year BBB and 10-year A GBP corporate bonds[10]
- Average of iBoxx 10+ years BBB and 10+ years A GBP non-financial bonds
- Bloomberg 10-year BBB rated GBP corporate bonds on its own
- iBoxx 10+ years BBB rated GBP non-financial bonds on its own.

3.34. We carried out sensitivity analysis on the Bloomberg indices. Figure 3.6 shows the results of this analysis (as of 30 September 2010).

Figure 3.6: Sensitivity analysis of proposed indexation options

	Bloomberg 10-year bonds rated BBB	Bloomberg 10-year bonds rated A	Average of BBB and A
8-year average	3.16%	2.68%	2.92%
10-year average	3.32%	2.88%	3.10%

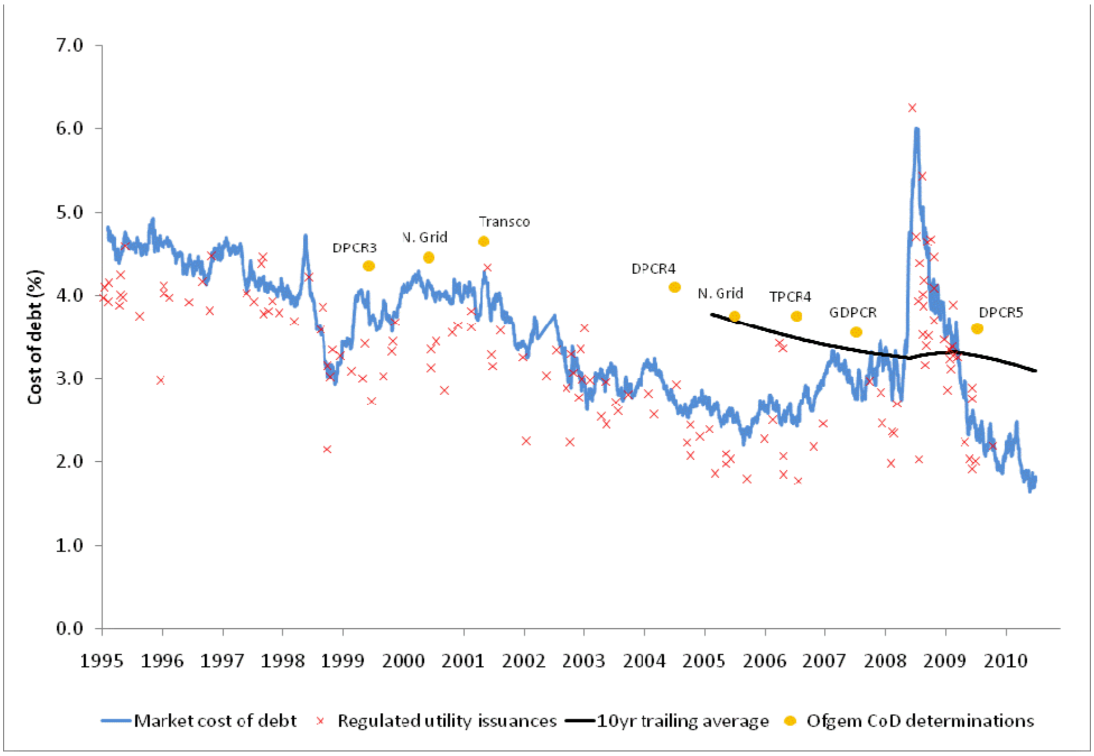
3.35. Our preference is to use the average of Bloomberg 10-year BBB and 10-year A GBP corporate bonds.

[10] We are aware that the Bloomberg A rated index only commenced in 2003. Prior to this date we have used data provided to us in the past by Grant Thornton - this data has been verified as part of the Smithers report and will be published should we decide to adopt this series for the cost of debt index.

3.36. Setting the cost of debt in line with the 10-year average of the above indices ensures a consistency with our approach in previous controls, as indicated by Figure 3.7.

3.37. Network operators have suggested that the index does not cover the transaction costs associated with issuing new debt. However, as shown in Figure 2.7, network companies have consistently outperformed the index by an average of 30bps. Based on our analysis of transaction costs relating to bond issuance, this is sufficient in our view to cover these costs. We would welcome views on this approach.

Figure 3.7: Illustration of our preferred option for cost of debt indexation



Source: Bloomberg

Initial estimate of the cost of debt

3.38. Figure 3.8 summarises recent regulatory decisions on the cost of debt by Ofgem and other UK regulators. It is important to note that, as regulators have typically set a fixed cost of debt, they have tended to aim up from observed market rates in order to account for the risk of the cost of debt rising during the price control period. The introduction of indexation removes the need for such so-called 'headroom' in the cost of debt allowance.

3.39. In addition to removing the need for headroom, our proposed indexation approach has the added benefit of capturing the cost of debt that the companies are likely to have on their books relating to existing assets.

Figure 3.8: Past regulatory precedent on the cost of debt

Determination	Year	Cost of debt (%)
Ofgem:		
DPCR5	2009	3.60
GDPCR	2007	3.55
TPCR4	2006	3.75
Other UK regulators:		
CC Bristol Water	2010	3.90 [2]
CAA NATS[1]	2010	3.60
Ofwat PR09	2009	3.60
CC/CAA Stansted	2008	3.4 - 3.7
ORR CP4	2008	3.25 - 3.5
CC/CAA Heathrow & Gatwick	2007	3.55

[1] From May 2010 Proposals

[2] Note that this consists of a 3.5% cost of embedded debt (uplifted by 30bps to account for Bristol Water's liquidity requirements and cost of issuing debt) and a 4.0% cost of new debt

3.40. We note that, were the current value from our proposed index to be used, the cost of debt would be 3.1 per cent. However, this value can be expected to change between now and when RIIO-T1 and GD1 come into effect, as well as changing annually during the price control period to reflect movements in the index.

Implementation issues

3.41. We are proposing to make the adjustment for changes in the cost of debt index through the addition of a component to the Base Demand Revenue formula in the licence special conditions. This component will be set annually according to a direction by the Authority.

3.42. Our intention is to use the index as at March 2012 to set the initial allowed revenues and to update annually from that date. Although this is after the due date to finalise fast-track businesses we would update the allowed revenues in the licence for any fast-tracked businesses before the licence comes into effect in April 2013.

3.43. There has been some concern that annual indexation would result in charging volatility. We have analysed the performance of the trailing average and note that the average annual movement over the last five years would only impact revenues by about 0.4 per cent, and by no more than 0.8 per cent in the most volatile year. The period over which we performed our analysis includes the credit crisis, where the cost of debt rose significantly.

3.44. We consider these to be small variations in the allowed revenue and, therefore, do not think that logging-up or caps and collars are needed in order to smooth the impact on consumer charges.

Cost of equity

Approach

3.45. We are committed to ensuring that efficient companies are able to finance themselves (both through debt and equity).

3.46. Under the RIIO model we will continue to estimate the cost of equity using CAPM sense-checked against other approaches where appropriate.

3.47. As mentioned earlier, in our new approach we will need to balance the riskiness of the cashflows with the notional gearing and the cost of equity. Our review of the cost of equity is therefore on the basis of existing regulatory risk and may change following the assessment of the companies' business plans.

3.48. The cost of equity can either be assessed by determining the risk-free rate, an equity risk premium for the market and an equity beta (which represents the systematic risk variability of a company relative to the market as a whole), or by an aggregate return on equity. Work carried out for Ofgem in 2003 and 2006 has demonstrated that betas for utility networks vary, to some extent,; but also noted that regulated utilities face lower cashflow risk relative to the market average. Europe Economics' analysis consisted of assessing the equity beta for listed UK energy networks, and then sense-checking the outcome against a range of comparators and regulatory precedent.

3.49. While our analysis here is focused on the components of the CAPM (the risk-free rate, equity risk premium and equity beta), we note that ultimately it is the overall cost of equity that matters. For this purpose, we will consider additional evidence as it becomes available over time (for example, analysis on future network transactions).

Duration of cashflows

3.50. Our proposal, to move away from accelerated depreciation for electricity transmission and distribution companies would result in investment being remunerated, through the depreciation charge, over a longer period. In our RIIO decision document, we recognised that there are arguments that lengthening/reducing the time over which capital is remunerated (taken in isolation) could raise/reduce the riskiness of cash flows and therefore of cost of capital. Oxera, advising the ENA, argued that there is a positive relationship between the duration of cashflows and the cost of capital.[11] They argued that Ofgem should therefore increase the allowed WACC by setting a higher equity beta and a lower notional gearing level. On the other hand, Ofgem's advisers CEPA argued that the longer duration of cashflows does not have a material impact on the cost of capital.[12] We asked Europe Economics to examine empirical evidence.

3.51. Europe Economics looked at cases where the duration of cashflows has been changed by regulatory intervention, and tested whether this resulted in an observed change in the equity beta. Europe Economics considered the introduction of accelerated depreciation in DPCR3 - in a sense the exact opposite of what is proposed under RIIO - and noted that the equity beta for companies that owned distribution networks at the time did not decline, as would be expected had Oxera's argument held true.

3.52. Europe Economics also considered four occasions when HM Treasury changed the capital allowance for oil companies (in 2002, 2004, 2006 and 2009) and noted that observed equity betas did not react to the changes.

3.53. Overall, Europe Economics concluded that its analysis shows no sign that equity betas respond to step changes that are intended to have material implications for the duration of cashflows. Further, Europe Economics' report states that, "We do not regard it appropriate for a regulator to entertain a large departure from corporate finance theory without having a clear alternative theoretical structure offer in its place, and a clear evidential rationale for preferring the latter framework".

3.54. Although the work carried out by Europe Economics does not support the view that changes in the duration of cashflows should affect the cost of equity, we remain open to arguments for and against this stance. We also note that if there is an impact, it would be significantly mitigated in these price controls by the transition arrangements that we will put in place.

Initial estimates of the cost of equity

3.55. Investors view the regulated energy networks as being of relatively low risk. This is because of their predictable revenue stream, anchoring of asset values to the RAV, and the stable and transparent regulatory regime in which they operate. The

[11] Oxera's arguments were made in the reports 'What is the impact of financeability on the cost of capital and gearing capacity?' (July 2010) and 'Cash-flow profiles and the allowed WACC - a response' (September 2010)
[12] RPI-X@20: Providing financeability in a future regulatory framework - a report by CEPA on behalf of Ofgem http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/Final%20CEPA%20RPI-X@20%20Financeability%20Report%20May%202010.pdf

result is that the networks have been able to access funds at a lower cost than the market average (as shown in Figure 2.7) and to attain a comfortable investment grade credit rating while having relatively high gearing.

3.56. RIIO introduces a new approach to setting the components of the allowed return, which means that direct comparison to past decisions by Ofgem (or other regulators) is not always appropriate. However, regulatory precedent does influence, to some extent, expectations about future regulatory decisions. With that in mind, Figure 3.9 summarises recent regulatory determinations on the cost of equity.

3.57. As Figure 3.9 shows, Ofgem's past decisions have not been out of line with other determinations. For example, the 6.7 per cent cost of equity allowed by Ofgem in DPCR5 is similar to the Competition Commission's determination as part of the Bristol Water investigation. Prior to DPCR5, we used an equity beta assumption of 1, whereas many other UK and European regulators have tended to apply a lower equity beta.

Figure 3.9: Regulatory precedents on the cost of equity

Determination		Year	RfR (%)	ERP (%)	β_e	CoE (%)
Ofgem:						
DPCR5		2009	2.0	5.25	0.9	6.73
GDPCR		2007	2.5	4.5	1	7.25
TPCR4		2006	2.5	4.75	1	7.00
Other UK regulators:						
CC Bristol Water		2010	2.0	5.0	0.92	6.60
Ofwat PR09		2009	2.0	5.4	0.94	7.08
CC/CAA Stansted	Low	2009	2.0	3.0	1	5.00
	High		2.0	5.0	1.24	8.20
ORR CP4	Low	2008				6.50
	High					7.00
European energy regulators:						
Ireland Electricity T&D[1]	Low	2010	1.6	4.5	0.4	3.40
	High		2.2	5.4	1	7.60
Austria Electricity Transmission		2009	2.97	5.0	0.89	7.42
Belgium Gas Transmission		2008	3.58	3.5	0.65	5.86
Germany Electricity and Gas T&D		2008	2.78	4.55	0.79	6.37
France Electricity Transmission		2007	2.2 [2]	4.5	0.66	5.17
Ireland Gas T&D	Low	2007	1.75	4.5	0.9	5.80
	High		2.25	5.0	0.9	6.75

[1] Europe Economics' range in Consultation document

[2] Regulator sets nominal risk-free rate, adjusted here by a 2% to reflect ECB inflation target

We asked Europe Economics to provide an analysis of the appropriate current range for the cost of equity. Their analysis and our views are summarised below. It is important to note that current ranges are broad and reflect existing precedent. The range should not be seen as constraining our final decision on the allowed return parameters. Through their business plans, we expect the network companies to provide evidence and make the case for the returns that they consider appropriate to their particular circumstances.

Risk-free rate

3.58. The risk-free rate is the rate of return that an investor would expect to earn on a "riskless" asset. Typically, government issued securities are considered the best available indicator of the risk-free rate due to the extremely low likelihood of the government defaulting on its obligations.

3.59. Europe Economics' preferred approach is to estimate a range for the risk-free rate from UK Index-Linked Gilts (ILGs) and sense-check the range against nominal Gilts, German and French sovereign bonds and past regulatory precedent.

3.60. Figure 3.10 plots the yield on ILGs of 5, 10 and 20-year maturities. A clear downward trend is observed over the last 10 years, which was temporarily disrupted by a spike in yields around the time of the financial crisis in late-2008. Similar trends are observed for nominal gilt yields, as well as for both index-linked and nominal bonds issued by the French and German governments.

Figure 3.10: Index-linked gilt yields

Source: Bank of England

3.61. Europe Economics note that the current low rates observed on ILGs are, in part, the result of the Bank of England's quantitative easing programme and its decision to hold the official Bank Rate at a record low level. ILG yields are expected to rise once the Bank of England reverses its policy and this should be taken into account when deciding on the risk-free rate range.

3.62. Considering past regulatory decisions, Europe Economics note that, while regulators have typically set a risk-free rate allowance that is above the market rates observed at the time, regulatory decisions over the past decade have mirrored the trend in ILGs and have gradually declined.

3.63. Figure 3.11 summarises the key estimates from Europe Economics' analysis of the risk-free rate.

Figure 3.11: Current spot and historical average yields on ILGs and Gilts

Measure	%
ILG spot rates (30 Sep. 2010)	
5 years	-0.35
10 years	0.43
20 years	0.64
Nominal gilts spot rates (30 Sep. 2010) delfated by inflation expectations	
5 years	-1.39
10 years	0.15
20 years	1.11
ILG 5-year average (Sep. 2005 - Sep. 2010)	
5 years	1.43
10 years	1.38
20 years	1.09

Source: Europe Economics

3.64. In light of the above, we propose to use an initial range for the risk-free rate of 1.4 - 2.0 per cent, where the lower bound represents a five-year average on 10-year ILGs and the upper bound corresponds to recent regulatory decisions including our position in DPCR5.

Equity risk premium

3.65. In the CAPM framework, the equity risk premium (ERP), as weighted by the equity beta, is a measure of the expected return, on top of the risk-free rate, that an investor would expect for a portfolio of risk-bearing assets. This captures the non-diversifiable risk that is inherent to the market.

3.66. Europe Economics' preferred approach is to rely on the well-established ERP estimates provided by Dimson, Marsh and Staunton (DMS). 13 This study assessed the excess return on equities relative to sovereign bonds in 16 developed countries over more than 100 years (since 1900). DMS estimate an ERP of 3.9 per cent when using the geometric mean, and 5.2 per cent when relying on the arithmetic mean of the historical series.

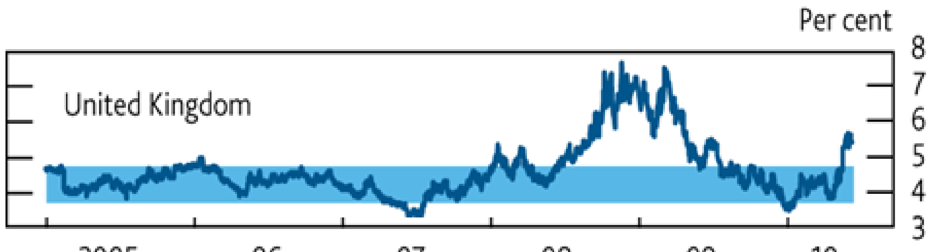
[13] These averages rise to 4.1 per cent and 5.3 per cent, respectively, if the impact of the financial crisis is removed by taking an earlier end-point for the series

3.67. While a number of academics have argued that the ERP rises at time of a financial crisis, Europe Economics note that both the UK economy and financial markets are expected to return to normal conditions by the start of RIIO-T1 and RIIO-GD1.

3.68. Europe Economics also notes that there has been no consensus in the debate about whether the arithmetic mean or geometric mean presented by DMS is more appropriate. With this in mind, Europe Economics advocates a range of 4.0 - 5.5 per cent for the ERP, with the bounds corresponding to the DMS estimates rounded to the nearest 0.5 per cent.

3.69. The Bank of England calculates the ERP based on a multi-stage dividend discount model (also known as a dividend growth model or DGM). Figure 3.12 shows that, since 1998, the ERP has tended to lie in the range 3.75 – 4.75 per cent. The Bank's latest estimate (from June 2010) of the ERP is around 5.5 per cent, although these figures can be expected to have returned to trend since, as financial markets have begun to settle.

Figure 3.12: Bank of England estimate of the ERP



* Figure adapted from Bank of England Financial Stability Report (June 2010). Shows the equity risk premium as implied by multi-stage dividend discount model. The shaded area shows interquartile ranges for implied risk premia since 1998 for United Kingdom.

Source: Bank of England

3.70. In light of the analysis above, we propose to use an initial range for the equity risk premium of 4.0 - 5.5 per cent. While we note that the upper end of the range is high relative to regulatory precedent for the ERP, we consider it is still an appropriate upper bound given the level of economic uncertainty.

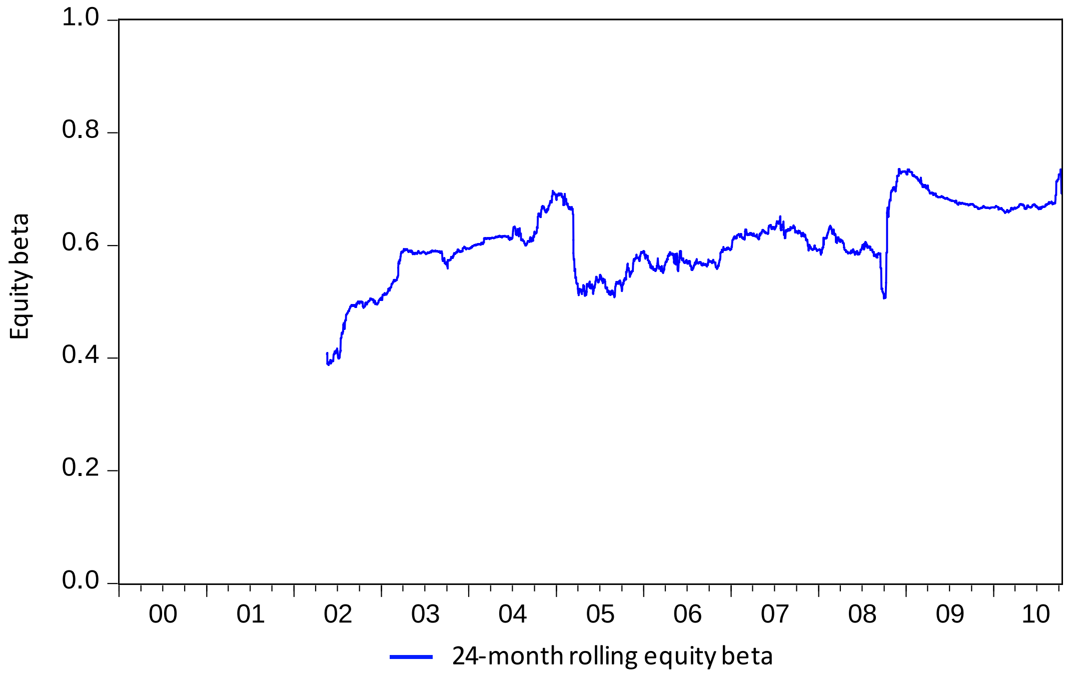
Equity beta

3.71. The equity beta measures the covariance of the returns on a stock with the market return. The weaker this co-variance, the greater the contribution that the stock could make to reducing the exposure to systematic risk, and hence the lower the required return.

3.72. Europe Economics calculate equity betas for the listed UK energy networks (National Grid, Scottish and Southern Electricity, and Scottish Power). The analysis focuses on a 2-year moving average of daily betas, in line with the recommendations of the Smithers Report.[14] Europe Economics averages the calculated betas to derive an estimate for the regulated energy networks sector.

3.73. Figure 3.13 plots Europe Economics' equity beta estimates for the regulated energy sector. A point estimate of 0.69 is derived from the most recent observation, with a 95 per cent confidence interval of 0.55 - 0.83.

Figure 3.13: Equity beta estimates for the energy sector



Source: Europe Economics

3.74. The above estimates are sense-checked in two ways:

- First, Europe Economics derives company-specific equity betas for the four transmission companies and five GDN groups. These are calculated by adjusting the asset beta for the sector (based on an equity beta of 0.69) by a factor corresponding to each company's share of revenue not accounted for by opex,

[14] A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K. - a report by Smithers & co on behalf of Ofgem
http://www.ofgem.gov.uk/Networks/Policy/Documents1/2198-jointregscoc.pdf

depreciation and tax, relative to the sector as a whole. This approach is in line with the Competition Commission's analysis on Bristol Water.

- Second, Europe Economics looks at the observed equity betas on UK water companies and European energy companies with actively traded shares. While these companies operate in different environments and are subject to different regulatory regimes than the companies we regulate, the approach provides a reasonable indication of systematic risk.

3.75. In light of the above, our initial range for the equity beta is 0.65 – 0.95.

Current range of the cost of equity

3.76. Figure 3.14 summarises our initial range for the cost of equity and compares it to Europe Economics' recommendations. We consider our range consistent with both observed market trends and recent regulatory precedent.

Figure 3.14: Initial range for the cost of equity

	Ofgem		Europe Economics[1]	
Cost of Equity component	**Low**	**High**	**Low**	**High**
Risk-free rate	1.4%	2.0%	2.0%	1.0%
ERP	4.0%	5.5%	4.0%	5.5%
Equity Beta	0.65	0.95	0.55	0.83
Cost of Equity (post-tax)	**4.0%**	**7.2%**	**4.2%**	**5.6%**

[1] Europe Economics combines the lower risk-free rate with the higher ERP and *vice versa*

Equity issuance costs

3.77. In setting price controls, we determine cost allowances consistent with a well-managed and efficient business. We recognise, however, that at times, companies may be subject to substantial investment requirements and consequently experience deteriorating credit ratios or apparent financial strain. We expect that network companies, as in any other sector, will need to raise additional equity to fund part of the investment. By putting in place our financeability principles as part of RIIO that provide longer term stability and clarity over our approach, companies should be able to raise the equity they require at efficient prices.

3.78. In TPCR4, we set out a mechanism by which the companies would be able to recover the cost of issuing new equity. This featured an ex ante allowance of five per cent of the equity value required to finance baseline capex, TIRG expenditure and half of the additional investment a company might incur during TPCR4 based on its FBPQ submission. The mechanism also included a true up at the following price control review, to reflect actual investment during TPCR4 and hence the required new equity.

3.79. As part of RIIO-T1 and RIIO-GD1 we are inviting views on whether the mechanism remains appropriate and should be continued for transmission and extended to gas distribution. Specifically, we are seeking views on whether the five per cent allowance remains reflective of regulated network utilities' cost of issuing new equity. As part of the RPI-X@20 review, CEPA produced a paper for us that noted a wide range of estimates for the cost of raising equity, with a comprehensive recent study by the Office of Fair Trading estimating the cost at three per cent.[15]

3.80. We are also interested in views on whether the approach remains appropriate for an eight-year price control and, if so, whether the true up should occur at the end of the eight years or earlier.

[15] Cost of raising equity - a report by CEPA on behalf of Ofgem http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/Cost%20of%20raising%20equity,%20CEPA%20(2010).pdf

4. Assessing financeability

Chapter summary

This chapter sets out initial thoughts on the approach to assessing financeability.

Questions

Question 1: Have we identified the correct equity and credit metrics?
Question 2: Do the rating agency levels quoted provide the most appropriate levels?
Question 3: We invite views on the approach to assessing the appropriate level of notional gearing.

Approach to assessing the financial impact of price control review proposals

Financeability ratios

4.1. In order to deliver the outputs that consumers expect, the network companies must be able to finance their activities (both through debt and equity). In order to ensure that our price control conditions allow this to happen, we will test the financeability ratios that the companies can be expected to achieve during the price control, assuming they operate efficiently.

4.2. In line with the RIIO model, when assessing financeability, we will take into consideration relevant equity metrics and the metrics that credit rating agencies focus on when determining a company's credit rating. We consider that the key equity metrics are:

- Notional RAV / EBITDA[16]
- Regulated Equity / Regulated Earnings

We consider the key credit rating metrics to be:

- Gearing: Net Debt / RAV
- PMICR[17]: (Cash From Operations - Capex) / Interest

[16] EBITDA is 'earnings before interest, tax, depreciation and amortisation'
[17] PMICR is 'post-maintenance interest cover ratio', also known as the adjusted interest cover ratio

4.3. Figure 4.1 summarises the gearing values and interest cover that are consistent with a 'comfortable investment grade' credit rating (ie in the range of BBB to A).

Figure 4.1: Relationship between key cashflow metrics and credit ratings

Metric	Ofgem DPCR5	Fitch[1]		Moody's[2]	
		A	BBB	A	Baa
Gearing	≤ 65%	60%	> 70%	45-60%	60-75%
PMICR[3]	N/A	1.75x	1.5x	2.0-4.0x	1.4-2.0x

[1] Fitch: 'Rating EMEA Regulated Utilities', 13 July 2010

[2] Moody's: 'Regulated Electric and Gas Networks', August 2009

[3] Fitch and Moody's have slightly different definitions for this ratio

4.4. We will also consider other metrics including funds from operations (FFO) interest cover and retained cashflow (RCF)/net debt. In DPCR5, we used benchmark values of 3x for FFO interest cover and 9% for RCF/net debt.

4.5. It is important to note that our financeability analysis will focus on the medium to long term. In line with the RIIO model recommendations, we will not advance cashflow in light of apparent short-term dips in the cashflow metrics. While we will seek to understand the reason behind such shortfalls, the onus will be on the company to resolve the situation. However, where a company demonstrates that application of any of the RIIO principles in a single step would cause an efficient company financing difficulties, we will implement transitional arrangements.

Return on regulated equity (RoRE) analysis

4.6. In DPCR5, we presented the concept of RoRE as an approach by which we analysed DNOs' actual returns during DPCR4, as well as a tool for checking that the expected outcomes from DPCR5 are financeable. The analysis takes a holistic view of all elements of the price control settlement to ensure that together they provide a fair balance of risk and reward for customers and shareholders. The RoRE analysis was well received among stakeholders.

4.7. Under the RIIO model, we intend to continue using RoRE analysis to check the overall implications of the regulatory settlement. We will also combine it with our review of equity and credit metrics to ensure that the notional equity is at an appropriate level.

4.8. Credit metrics will also play a key part in our assessment of the appropriate time period over which to transition any changes to asset life (or changes in the capitalisation treatment of replacement expenditure which is described in Chapter 7). We have said that we will aim to transition over a single price control period. We will, however, consider the option to transition over a longer period if required to maintain credit ratios.

4.9. Ensuring that the notional gearing is appropriate both for the riskiness of the cashflows and to provide appropriate equity and credit metrics may be an iterative process.

4.10. As we note in Chapter 3, we intend to use RORE analysis of cashflow volatility to establish the level of notional gearing that would allow an efficient company to achieve good returns and ensure sufficient cover given expected downside risks.

4.11. The notional gearing level that is commensurate with the risk of the package will also need to provide equity and credit metrics that are appropriate to ensure that the package as a whole is financeable. If the credit ratios are insufficient to meet the requirements for a comfortable investment grade credit rating, there are a number of factors that will need to be considered, and may be adjusted to achieve the desired overall balance.

4.12. These include the level of notional gearing, the volatility of the cashflows (through amendments to incentive schemes, trigger events etc), levels of equity injection, the period of transition and the cost of equity.

4.13. A key task for the companies in preparing their business plans next summer will be undertaking an assessment of the volatility of the cashflows and proposing appropriate, well justified and balanced views on notional gearing, levels of equity injection, transition arrangements (where appropriate) and the cost of equity. This will provide companies with a degree of flexibility (within certain constraints) and the opportunity to set out their preferred approach in their business plans.

5. Taxation

Chapter summary

This chapter examines a number of options for the implementation of our taxation methodology. We indicate our preferred treatment.

Questions

Question 1: Do you agree with modelling tax based on the proposals in the June 2010 Budget?
Question 2: Do you agree with modelling tax under UK GAAP pending adoption of IFRS reporting with any changes to be subject to the tax trigger?
Question 3: We invite views on the size of the dead-band
Question 4: Do you agree that clawback of the tax benefit of excess gearing in TPCR4 and GDPCR1 should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?
Question 5: Do you agree that clawback of the tax benefit of excess gearing should be updated every three years during the price control period?
Question 6: Do you agree that the tax treatment of new incentives should be calculated using vanilla WACC?

Introduction

5.1. The proposed methodology for taxation for RIIO-T1 and RIIO-GD1 follows that applied at DPCR5. This includes the introduction of a DPCR5-style tax trigger. It takes into consideration specific transmission and gas distribution issues and, as appropriate, the treatment in TPCR4 and GDPCR1. The methodology is set out in Appendix 2. This chapter deals with issues for consultation.

Modelling taxation on existing legislation or proposals

5.2. In the previous three price controls, we have modelled tax based on the existing tax rates and legislation. However, the June 2010 Budget set out a clear path of proposed corporation tax (CT) rate reductions and a change in the rates of capital allowances (CA). These will reduce the rate of CT from the current 28 per cent to 24 per cent from 1 April 2015. The rate on the plant and machinery pool would reduce to 18 per cent from 20 per cent and that on the Special Rate pool to 8 per cent from 10 per cent, both effective from 1 April 2012. The reduction in capital allowances and reduction in the CT rate for 2011-12 to 26 per cent have been confirmed in the Finance Bill 2010, published on 9 December 2010. We anticipate that those changes to capital allowance rates will pass into legislation before final proposals. The other CT changes will remain proposals. If we apply the extant CT and CA rates coupled with the introduction of the DPCR5 style tax trigger, licensees would get a windfall benefit (and conversely customers lose) were the June 2010 Budget proposals to materialise. Conversely, if we use the forecast rates and the reductions do not occur then licensees would actually pay additional tax (and customers would gain).

5.3. We consider that there are four options:

a. Use June 2010 Budget tax rates with the DPCR5 type tax trigger and dead-band
b. Use June 2010 Budget proposed tax rates and adjust the DPCR5 tax trigger to treat any differences between the Emergency Budget proposed rates and outturn rates as a pass through
c. Use extant rates but automatically pass-through any changes to CT and CA rates without any dead-band. This has the benefit that both customers and licensees are shielded from any upside or downside exposure
d. Use extant rates and introduce the DPCR5 style tax trigger with a dead-band, customers and network companies share the risk and reward within the dead-band

5.4. We invite views on these options. Our preference is for option a. In selecting this option we note the Competition Commission's comments in their report on Bristol Water plc, that changes in the tax rate is a normal business risk. We are aware that there will be a further budget in March 2011 before we conclude any fast-track proposals and a further budget in March 2012 before final proposals. We will reflect any changes in these budgets that affect CT and CA rates.

Impact on tax trigger from proposed move to IFRS based reporting

5.5. The Accounting Standards Board (ASB), in its October 2010 Exposure Draft 43: Application of Financial Reporting Standards proposes that entities that have public accountability apply EU-adopted International Financial Reporting Standards (EU-IFRS). For entities without public accountability and for small publicly accountable entities that are prudentially regulated, it proposes that they apply Financial Reporting Standard for Medium-sized Entities (FRSME)[18]; or, alternatively may apply EU-adopted IFRS. The ASB is proposing an effective date of accounting periods beginning on or after 1 July 2013, with earlier application permitted. It is seeking comments on its proposals by 30 April 2011. The timing of the move to either EU-IFRS or FRSME reporting is now clearer; although it is still subject to the ASBs post consultation final decision.

5.6. Some network companies already report under IFRS; and for the others there is the option of earlier application. For the first year of the price control, some companies may continue to report under UK GAAP. To allow for the uncertainty on timing of adoption of IFRS and the finalisation of the ASB proposals, we will model tax under UK GAAP. Accordingly, the tax treatment of opex, capex and repex will

[18] The draft FRSME is based on the International ASB's IFRS for SMEs but adapted to comply with UK and European legal requirements

follow the existing UK GAAP treatment. Any subsequent changes will fall within the scope of the tax trigger.

5.7. We invite views on whether this approach deals equitably with any change in the accounting (and consequent tax) treatment of any specific item of expenditure from the adoption of IFRS based financial statements during the price control period.

Tax trigger calibration of the dead-band

5.8. The trigger point is modelled as a change or changes that yield a greater than a set per cent increase or decrease in the total base revenue of an individual regulated business, on the basis of the aggregate effect over the remainder of the price control period. It is proposed that this percentage will be calibrated around a given per cent change in the mainstream rate of corporation tax. This was calibrated around a one per cent change in the CT rates in DPCR5. This factor remains our preferred option. We invite views on the quantum calibration of the dead-band.

Timing of tax clawback

5.9. Where the tax clawback for excess gearing is triggered, the options are to apply the adjustment in either:

a. the first year of the subsequent price control review (PCR) which, dependent on the quantum, may result in a significant increase in costs for customers compared with the last year of the TPCR4 and GDPCR1 PCRs
b. for TPCR4 and GDPCR1 adjustments, spread evenly over the first five years of RIIO-GD1 and RIIO-T1. This smoothes revenues and impacts customers less than (a) above
c. to spread evenly over the price control period, eg for RIIO PCRs over eight years.

5.10. We invite views on which is the most appropriate option. Our preferred option is c. All adjustments will be NPV neutral.

Timing of tax clawback adjustment to revenues in RIIO PCRs

5.11. We will set allowed revenues for RIIO-T1 and RIIO-GD1 before we have actual figures for all years of the existing controls and the TPCR4 adapted rollover year. We consider that waiting until the end of the eight-year control to apply the tax clawback is too long. We propose to update this more frequently. Annual data reporting in the regulatory reporting pack (RRP) will allow us to do this. Our preference is to update allowed revenues every three years during the RIIO controls.

5.12. We invite views on this proposal.

Tax treatment of incentives

5.13. Certain expenditure[19] is subject to various incentive mechanisms (eg TIRG, logged up costs and SO capex on gas entry and exit capacity) and often held outside the RAV. It is remunerated through additional revenue using a standard pre-tax WACC because these rates are not reflective of indexing the cost of debt under our RIIO model. In our view, this over compensates network companies. We consider that we should move to calculating additional revenues using the vanilla WACC plus the estimated incremental tax effects for new incentive mechanisms. Existing mechanisms that are not subject to any update, for example, TIRG will not be affected.

5.14. We invite views on the above proposal.

Business rates

5.15. We treat business rates as non-controllable operating costs (together with our licence fee) at past controls. The Valuation Office Agency (VOA) in England and Wales and Scottish Assessors Association (SAA) in Scotland have completed a revaluation of the assets of the transmission and gas distribution networks in 2010 for the purposes of determining rates until 2015. Broadly, these new rates have been agreed. During RIIO-T1 and RIIO-GD1, further revaluations in 2015 and 2020 are expected. Each network company is able to influence the valuation that is given and hence the business rates that it will incur in the future.

5.16. We recognise that for the ratings valuation that will occur in 2015, there is uncertainty regarding the future level of business rates that the network companies all incur. In our view, it is important that network companies should have appropriate incentives to minimise their business rates. We have concerns that the existing mechanism might not provide a strong enough incentive on the network companies to protect the interests of consumers as part of ratings revaluations. However, we have not identified an alternative mechanism to address these concerns. Therefore, for the purposes of setting the base price control revenue allowances, business rates are those from the 2010 valuations. For the period from 1 April 2013 up to 31 March 2015, we will maintain the previous (TPCR4 and GDPCR1) mechanism that enabled companies to recover the difference between the actual and assumed costs. After that time, we will switch-off this mechanism pending the outcome of the next revaluation exercise. Where network companies can demonstrate that they have taken reasonable actions to minimise the rating valuations, we will then reactivate the cost adjustment mechanism for the remainder of the period, (ie from 1 April 2015 up to 31 March 2021). We will deal with the 2020 valuation on similar basis.

[19] See chapter 7 on the RAV methodology

5.17. We consider that this approach provides incentives on network companies to minimise costs, whilst recognising that once the rating valuations are concluded the costs that they incur will be non-controllable.

6. Pensions

Chapter summary

This chapter examines a number of options for the implementation of our pension methodology and in the guidance on the application of our principles in the context of RIIO price controls. We indicate our preferred treatment.

Questions

Question 1: Do you agree that the timing of true up adjustments for existing controls should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?
Question 2: Do you agree that updated valuations for non fast-tracked companies should be the same as fast-tracked companies, ie 31 March 2011 unless no network company is fast-tracked, in which case updated as at September 2012 in time for final proposals?
Question 3: Do you agree that the deficit funding rate of return should be derived from the range of benchmarked pre-retirement real discount rates? If not, which alternative option do you prefer?
Question 4: Do you agree that same rate should apply to the calculation of the net present value of the true up adjustments?
Question 5: Do you agree that deficit funding allowances and the true up to date in a RIIO price control period should be every three years rather than truing up at the next eight-year price control?
Question 6: Do you agree that PPF levies should be part of benchmarked total costs? If not, which should be the alternative option?
Question 7: We invite views on whether the revised guidance to our pension principles is comprehensive and adequate for licensees and stakeholders to understand how the principles will be applied in RIIO controls and for network companies to prepare their business plan?

Introduction

6.1. The methodology for RIIO-T1 and RIIO-GD1 follows that set out in our 22 June 2010 Pension paper[20] and in the DPCR5 final proposals. The detailed methodology is in Appendix 4. This chapter considers issues that are not covered by our existing policy or require decisions to implement policy in the context of a RIIO price control.

6.2. Our pension principles under RIIO remain the same as previously set out in our June document. We have updated the implementation guidance notes to apply our methodology to RIIO price controls and the items that are being consulted on - see Appendix 5.

[20] Price Control Treatment of Network Operators Pension Costs under Regulatory Principles (76/10) http://www.ofgem.gov.uk/Networks/Documents1/Price_Control_Treatment_of_Pension_Costs_final.pdf

Timing of true up adjustments for existing controls

6.3. We need to set the period of time over which pension true up adjustments (arising from TPCR4, TPCR4 roll over and GDPCR1) are applied. We make the adjustments on an NPV neutral basis. They cover both ongoing service costs and deficit funding payments. We invite views on the following options:

a. one year, ie first year of RIIO controls, which could, dependent on the quantum, result in a significant increase in costs for customers compared with the last year of the TPCR4 roll over and GDPCR1 price control reviews (PCRs)
b. five years being the remainder of the previous price controls' ten year notional funding period (four years for transmission as the first year of the adjustment will be made in the adapted rollover year
c. Period of RIIO price control, eg eight years
d. For deficits only 15 years, so as to spread the true up to match the notional funding period for deficits in RIIO PCRs.

6.4. To alleviate significant spikes in revenue (and charges to customers) our preference is to spread the true up over the period of the subsequent price control (option c) including the rollover year for transmission.

Timing of updated valuations

6.5. In accordance with our pension principles, deficit funding allowances for the RIIO price controls are determined using the latest updated valuations. Given the timing of setting allowances for fast-tracked companies, all licensees are being required to provide an update as at 31 March 2011 in their business plans. For non fast-track companies there is the option to use later updated valuations in order to base the allowances on the most recent data.

6.6. There are three options for which valuation to use:

a. same as fast-tracked companies above, ie 31 March 2011
b. updated as at March 2012 in time for initial proposals, and/or
c. updated as at September 2012 in time for final proposals.

6.7. The advantage of updating is that the most up to date valuation is used. However, the downside is that fast-tracked companies may have lower funding if the updated valuations show larger deficits or, conversely too high funding should deficits be lower. This would also be inconsistent with our statement that fast-tracked companies will not be disadvantaged.

6.8. Our preference is for option a, unless in any sector no network company is fast-tracked in which case we prefer option c.

6.9. We invite views on which option is the most appropriate and equitable.

Notional deficit repair period

6.10. As set out in our 22 June 2010 document, the deficit will be funded over the notional 15-year deficit funding period. We will apply a flat profile over the deficit funding period allowing a rate of return. We do not reset the 15-year period at each subsequent control. The intention is that the deficit at the cut-off dates for each control will fully funded over the following 15 years.

6.11. We see no reason to change from a 15-year notional period set at the completion of our Pension Review. Our view is that given the monopoly status of the licensees, our financing duty and the strong commitment to funding the deficits, these provide a strong employer covenant and, we believe, a long notional recovery period is appropriate. This is a much stronger commitment to fund deficits than has been given by other regulators (eg Ofcom and Ofwat). It is supportive that the Competition Commission set funding at 15 years in their recent review of Bristol Water plc.

Deficit funding rate of return

6.12. Prior to DPCR5, the WACC was used to annuities deficit funding. At DPCR5, we considered that this was not appropriate and amended the basis to use a pre-retirement real discount rate.

6.13. In 2010, we appointed Ernst & Young to review this approach and to advise us on the pension deficit funding rate of return. Their report is available on our website[21].

6.14. Ernst & Young considered a number of options in their report:

a. continue benchmarking on pre-retirement discount rates
b. benchmark to develop a weighted average of the pre and post retirement discount rates over the term of the recovery period
c. derive a rate independently of the discount rates used in the network companies actuarial valuations
d. continue to use a 2.6 per cent real discount rate for future price reviews, or
e. use a scheme-specific rate.

6.15. Ernst & Young's recommendation is to continue with our DPCR5 methodology. Our preference for RIIO controls is therefore option a, which is to apply a funding

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[21] Establishment of pension deficit funding rate of return - Report by Ernst & Young on behalf of Ofgem http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/EY%20pension%20deficit%20funding.pdf

rate of return derived the range of benchmarked pre-retirement real discount rates in licensees' schemes. We invite views on this approach.

Resetting allowances during the price control period

6.16. In our view, it is inappropriate to leave established deficit funding unaltered for an eight-year price control. There could be two or three triennial reviews in that period, albeit at varying dates for different companies. To protect both customers and companies a mechanism to update the funding is necessary.

6.17. We consider that the options for a subsequent reset of allowances are:

a. at the mid-period review, which is not proposed to be equivalent to a full price control review, but a strictly limited review of outputs
b. every three years to coincide with the timing of the majority of triennial valuations
c. annually to accommodate disparate triennial valuation dates.

6.18. Our preference is for every three years. In our view, this is a sensible balance and avoids building the mid-period review of outputs into a full review (although from time to time it will coincide with the mid-period review). Prior to each re-set we propose to undertake a fresh efficiency review.

6.19. We invite views on the timing of subsequent reset of established deficit funding allowances.

The efficiency review

6.20. We introduced a two-stage efficiency review process as part of our revised approach to pensions last year. The first review using the new approach, which will inform setting allowances for TPCR4 roll over, RIIO-T1 and GD1, is currently underway by the Government Actuary's Department (GAD), using March 2010 data wherever possible. They are due to report in March so that companies can be aware of the outcome of the first stage of the review in preparing their business plans.

6.21. Network companies have disparate triennial valuation dates, these are currently:

- WWU, Scotia, Scottish network companies schemes and two DNOs schemes - 31 March 2009, then 2012, etc
- NGG, NGET and five DNO group schemes - 31 March 2010, then 2013, etc
- NGN is 31 December 2011, then 2014, etc.

6.22. For NGG and NGET (as well as a number of DNO schemes, which are used to provide panel data) GAD will be using draft data as they have not yet completed their March 2010 triennial valuation. We will therefore update the review once data is finalised if any data is significantly different from the draft.

True up in future periods

6.23. With longer price control periods, leaving the true up adjustment for pensions deficit costs until the end is in our view too long a period; given changing market conditions and the need to ensure network companies are financeable. In our view the options are:

a. to true up for actuals at each three year reset of pension funding, one year after the triennial valuations and amend revenues accordingly, or
b. leave to the subsequent price control.

6.24. We consider that truing up and amending revenues over the remaining years, during the price control period is preferable. Logically, this follows the proposed timing of resetting intra-period allowances and of subsequent efficiency reviews.

6.25. We invite views on the options for the timing of truing up pensions costs in the longer RIIO price control periods.

Pension Protection Fund (PPF) levy

6.26. Under our methodology, these levies are part of ongoing pension service costs and included in the benchmarking of total costs. As such, they are subject to the same incentives as all other costs. Licensees, as scheme sponsors or co-sponsors, have some influence over the quantum of the levy and some scope to mitigate the costs.

6.27. The PPF are consulting[22] on changes to the methodology on which they assess the risk-based element of the levy. Network companies have suggested that this could result in a material increase in the levy they pay. In their view, the levy is substantially a non-controllable cost, similar to business rates and the Ofgem licence fee. To mitigate the increase they have proposed to treat the levy as a cost pass through. An alternative may be to exclude PPF levies from the benchmarking and subject them to an efficiency review. They would then have a specific ex ante allowance and, by extension be subject to true up.

6.28. It is clear is that, under the PPF's proposals, a strongly funded scheme with a high Dun & Bradstreet failure score would expect to pay a higher levy than at

[22] The Pension Protection Fund Levy: A New Framework
http://www.pensionprotectionfund.org.uk/DocumentLibrary/Documents/levy_consultation_oct10.pdf

present, although this will also depend on the mix between risky and less risky assets a scheme invests in. As such, the amount of the levy is highly dependent on the characteristics of each individual scheme.

6.29. At present the future amount of the levy cannot be forecast with reasonable certainty, as there are too many unknown variables, including the outcome of the PPF consultation process. We have not received definitive computations from each licensee of the potential magnitude, or range, in the change in their levy assuming the PPF's proposals are adopted unchanged.

6.30. In our view, the current levies are not a material cost to network companies, current average annual cost of £6.8m (0.08 per cent of base demand revenues); and, for example, a doubling or tripling in the levy would not cause the network companies serious hardship. Our preference is to continue with our existing treatment as set out in our June 2010 decision document.

6.31. Views are invited on:

a. retaining our existing approach (ie to include PPF levies in the total cost (totex) benchmarking with no specific allowance and no true up)
b. set specific allowances, with either a true up or be subject to the same incentives as all other costs
c. the specific circumstances that moving to cost pass-through approach could be justified as equitable to both network companies and customers?

Determining the established deficit

6.32. NGG have raised an issue over the timing of establishing the deficits at the end of TPCR4 and GDPCR1. They have one scheme covering their four gas distribution networks and the gas transmission network. Under the current methodology, they will have two different cut-off dates, 2012 and 2013. NGG have requested that we determine the established deficits for both TO and GDNs at 31 March 2013. This would also coincide with a triennial valuation.

6.33. TOs had already made representation that we true up at the end of TPCR4 and commence true up adjustments in the adapted rollover year, ie 2012-13. We stated in the Transmission Price Control 4 - Rollover (2012/13) Scope Decision and Consultation document that we would do so. A change now would affect that decision, which is outside the scope of this consultation. We are not convinced that having two cut-off dates for the same scheme is an insuperable issue for either NGG or ourselves. We confirm our previous position as set out in our June Decision document, ie two separate cut-off dates to maintain the integrity of each price control.

Implementing the proposals through licence conditions

6.34. We propose to introduce a term in the Charge Restriction licence conditions to give effect to the true up of pre-RIIO pension adjustments and resetting of allowances and, as appropriate, other issues consulted on.

Pension principles

6.35. Our pension principles, as set out in our 22 June 2010 document, included guidance on how we implement them in price controls. It is necessary and appropriate to revise the guidance to ensure that it is relevant for RIIO price controls. The revised guidance is set out in Appendix 5. Our pension principles remain unaltered.

6.36. We invite views on whether the revised guidance is comprehensive and clear enough to allow licensees and stakeholders to understand how the principles will be applied in RIIO controls, and for network companies to prepare their business plans.

7. Regulatory Asset Value

Chapter summary

This chapter examines a number of options for the implementation of our methodology for calculating additions to regulatory asset value (RAV). We indicate our preferred treatment.

Questions

Question 1: How should we calculate the percentage of totex allowed into RAV?
Question 2: The proposed totex approach includes repex, business support costs and non-operational capex as part of totex.
Views are invited on whether totex should include:

a) Repex
b) Business support costs
c) Non operational capex

Question 3: Should the definition of related parties include captive insurance companies?
Question 4: In GDPCR1, we allowed GDNs to retain the proceeds of asset disposals in RAV for five years to incentivise GDNs to dispose of assets at competitive prices. We invite views on whether we should we now remove this treatment, or extend it to electricity distribution operators and transmission operators so that we deal with all licensees on a similar basis.

Introduction

7.1. The RAV methodology for RIIO-T1 and RIIO-GD1 is similar to that introduced for DPCR5. In the DPCR5 review, we undertook a fundamental review of the means by which costs are included in the RAV as this is a key element in our approach to equalising incentives for the DNOs. We now propose to adopt a similar approach into transmission and gas distribution, however, we are proposing to make a significant change to the RAV additions relating to overspend or underspend.

7.2. For DPCR5, we added a set percentage of total costs (totex) into RAV. For that review, we defined totex as total costs excluding business support costs and non-operational capex. A generic capitalisation of totex into RAV was set at 85 per cent, with the balance treated as fast money. Business support and non-operational capex were treated as fast money.

7.3. The rationale for this modified approach to determining RAV additions was to help equalise the incentives on capex and opex, which previously had different incentive rates applied to them, potentially distorting decision making. In DPCR5, all of the costs included in totex were subject to a single incentive rate although the rate varied by licensee group depending on the outcome of the information quality incentive (IQI).

7.4. Our proposal for RIIO T1 and GD1 is to remove any remaining boundary issues between categories and treat all costs (including business support and non-operational capex but excluding certain specific items detailed in Appendix 6) relating to the licensed entity for its licensed activities as totex. This is a change from the DPCR5 approach since we now recognise that this provides a simpler approach.

7.5. We will add a fixed proportion of costs to the RAV, with the rest remunerated in the year in which we expect the companies will incur them. The percentage that we will add to the RAV will be set at the price control review to strike a fair balance between existing and future consumers, in light of the proportion of capex-like costs expected during the price control period. Our approach will be consistent with our objective to equalise incentives between opex and capex in the overall control.

7.6. We recognise that there are various options for calibrating the percentage of totex allowed into RAV. In particular, we consider that the following approaches have merit and welcome views on these:

- treat all expenditure with an asset life of three years or less as fast money with the balance as slow money. Within this approach, indirect costs should follow the asset to which they relate.
- review company capitalisation levels in their regulatory accounts over the past five years and use the average capitalised as RAV additions with the balance being fast money.
- using network company business plan projected capitalisation rates, using an average over the eight-year business plan period.
- use a blended average of historical and future projected levels of capitalisation.

7.7. Our preferred method is a blend of all these approaches which, we consider, will produce a balanced approach. We propose to review the level of costs, company commentaries on their capitalisation policy and the recent history of capitalisation to arrive at a specific capitalisation level for each licensee. Where, within a sector (eg gas distribution), these fall in a closely defined range we will look to set an average level for the sake of simplicity. We will also consider and test this against our assessment of the overall financeability of licensees.

7.8. One area where there will be a conflict between the first bullet point above and the others is the treatment of repex, where companies do not capitalise the expenditure in their accounts although it relates to long life assets. In GDPCR we added 50 per cent of repex to the RAV. Under RIIO-GD1 we propose to base the calculation of the overall totex percentage allocation to RAV on the basis that 100 per cent of repex is added to RAV. If this treatment causes any financeability concerns, we will apply the transitional arrangements outlined in chapter 2). Our intention is to complete the transition over one price control subject to any financeability restrictions.

What does totex include?

7.9. Totex will broadly include all costs relating to licensees regulated activities, with the exception of pension deficit repair payments relating to the established deficit (which will be funded as fast money as set out in chapter 6), related party margins, some specific scheme exemptions (see Appendix 6) and some other minor exceptions.

7.10. We describe in Chapter 6 of the RIIO-T1 and GD1 Business plans, proportionate treatment, innovation and efficiency incentives, our proposed approach to the implementation of the efficiency incentives, including the interactions with the RAV.

7.11. Under our proposals, the calculation of the net additions to the RAV will reflect two parameters which will be set at the price control review:

- first, the efficiency incentive rate. The higher the efficiency incentive rate, the smaller the proportion of actual totex that is passed on to consumers, including through net additions to the RAV.
- second, the fixed percentage of totex to be added to the RAV. This is discussed above and effectively determines the extent to which the revenue and RAV adjustments made in light of actual totex rate are split between fast and slow money adjustment.

7.12. This approach will affect our definition of totex in that we will treat the portion of costs that consumers and licensees share as totex. This means that:

- where companies overspend, the actual spend less the amount shared will be treated as totex
- where companies underspend, the actual spend plus the amount shared will be treated as totex

7.13. Table 7.1 below illustrates this approach, where the RAV additions rate is 80 per cent and the efficiency sharing factor is 50 per cent.

Table 7.1 Illustration of the impact of the sharing mechanism on RAV additions

Forecast at price control	
Totex allowance	£100
Assumed RAV additions	£80
Actual reported in period	
Actual totex costs	£150
Sharing amount	£25
Totex post sharing	£125
RAV additions	£100

7.14. The full definition of totex is included in Appendix 6.

7.15. In previous price controls, we defined RAV additions in detail to avoid double funding and to enable the incentive mechanisms to operate effectively. The proposed approach will also have clear rules but will lead to a simplification of the overall reporting requirements and reduce debate about precise definitions and interpretation of rules.

7.16. In particular, some licensees treat business support costs as partly capital and partly as operating costs. In some instances, we have funded non-operational capex in the year the network company incurs it, rather than over the life of the assets created (normally 3-7 years).

7.17. At GDPCR1, repex was treated as a 50 per cent addition to RAV with the remainder being funded in the year in which incurred. We now propose to include repex, business support costs and non-operational capex in the totex calculation and we will reflect their inclusion in the overall totex percentage into RAV. This avoids the need to define these types of spend in detail and potential debate on the allocation of overheads to the RAV additions. The impact of the proposed change in treatment of repex is likely be to increase the allocation to RAV for the sector as a whole from around 35 per cent of total costs to 52 per cent (indicative numbers).

7.18. Views are invited on whether totex should include:

- Repex
- Business support costs
- Non operational capex

7.19. Under the revised approach to pensions, (see chapter 6) we have undertaken to fund established deficits. Future deficits arising after that time are referred to as incremental deficits and the cost of these will be included in future as part of the overall benchmarking of costs. We will therefore include any incremental deficits within totex.

7.20. We propose to exclude related party margins from costs added to totex unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers.

7.21. This causes an issue for the treatment of captive insurance companies, which fall within the scope of related party margins. Network companies generally establish these as a way of managing a company's insurance costs in a more efficient manner. Whilst profits in the insurance company may occur, over time these should be available to meet the company-insured risks. This provides a benefit to both network companies and customers.

7.22. We could exclude the captive insurers' dividends as super-profits but this ignores the fact the shareholders may be required to fund future risks.

7.23. We consider that the options are:

- exclude captive insurance companies from the related party clause whilst not allowing any excess losses (to the extent they are covered by the captive insurers) to be funded by consumers
- exclude dividends as super-profits and treat as excess cash not expected to be required to fund future liabilities/risks
- exclude all margins.

7.24. We consider that excluding captive insurance companies from the related party clause protects consumers whilst allowing network companies to act efficiently, provided any losses are borne by the captive insurers. This is a continuation of the TPCR4 treatment.

7.25. We invite views on these options.

Adjustments for 2011-12 and 2012-13 actual spend

7.26. The RAV additions used in determining prices for RIIO-T1 and RIIO-GD1 will rely on company forecasts for 2011-12 and 2012-13. In the event that actual RAV additions for these years turn out to be materially different to the estimates, we propose to restate the RAV and alter revenues two years after the close of the TPCR4 roll over or GDPCR1. We will claw back the benefits of any under-spend in 2011-12 and 2012-13 relative to the estimate used in the final proposals at this time and alter the revenue accordingly.

7.27. We will make any adjustment relating to the future review of the TPCR4 or GDPCR1 capex efficiency following those reviews. We shall also restate the RAV to take into account any over or under spends relating to the previous price control periods for both the GDNs and for the TOs where RAV additions have to date been based on forecast expenditure. We shall adjust revenue as necessary to reflect any over or under funding that may have occurred.

Other RAV additions specific to transmission operators

7.28. Transmission has a number of different funding mechanisms in addition to the manner in which we fund normal forecast business costs. Where specific scheme funding is applicable (eg TIRG projects) we will continue to deal with these in accordance with the conditions under which they were established. Where we revise or introduce new incentives, we expect these to be on a totex basis so that existing incentives will be appropriate. If we consider that there are good reasons why applying the totex approach to incentive funding will cause unintended consequences, we will either not use this approach or will restate the percentage allocation to totex.

7.29. For reference, we summarise the existing other funding mechanisms in Appendix 6.

Transmission SO RAV

7.30. The Transmission system operators have their own RAV calculations. These will continue, but in future, we propose to consider additions on a totex basis with specific recharge percentages. This will be consistent with the approach for the TO operation.

7.31. Where an SO spends capex on gas entry and exit capacity, we remunerate the additions as if we add them to an SO RAV. In fact, they remain outside of TO RAV until some time later (scheme dependent) (see Appendix 6 for further details).

Other RAV issues specific to gas distribution

7.32. In GDPCR1, we agreed that the proceeds of asset disposals will not be removed from RAV for five years to incentivise GDNs to dispose of assets at competitive prices. In both electricity distribution and gas and electricity transmission, we deduct the proceeds from RAV as received.

7.33. The GDNs will have enjoyed this deferral for five years by the end of GDPCR1. From the information we have received to date the total net proceeds from which consumers will benefit is shown in Table 7.2:

Table 7.2 - Total disposal proceeds reported by GDNs in GDPCR1 to date

£m - nominal	2007-08	2008-09	2009-10
Total disposal proceeds falling out of RAV	11.9	4.5	1.4
Year removed from RAV	2012-13	2013-14	2014-15

7.34. We show these values net of clean up costs for any land disposed of. From the figures given it is difficult to conclude that this incentive has particularly benefitted customers.

7.35. We invite views on whether we should we now remove this treatment, or extend it to electricity distribution operators and transmission operators so that we deal with all licensees on a similar basis.

7.36. Gas distribution licensees have been logging up costs relating to Fuel Poor Network Extensions since July 2009. The scheme allows us to add a combination of cost and / or the NPV of 45 years future revenue per connection to RAV at the following price control. This addition remains in RAV for five years following which we remove it and replace it by the actual cost.

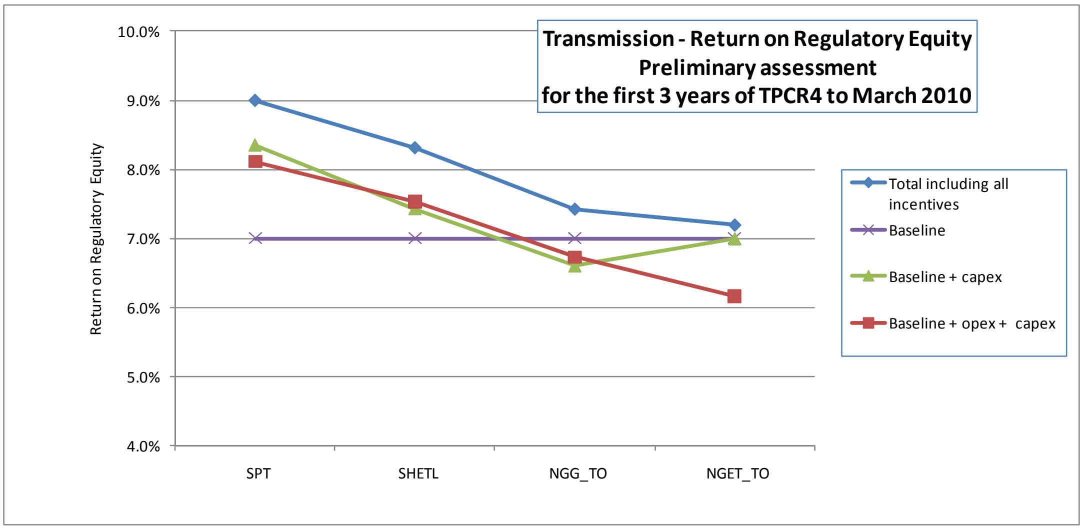
7.37. As this is a cost recovery mechanism it should arguably be partly adjusted through revenue with the capex addition alone entering RAV. We will consult on this issue in the RIIO-GD1 - Outputs and incentives supplementary annex document. In our view, the addition to RAV should be purely the capex addition, whilst allowing a return on the 45 year NPV of transportation revenues through a revenue adjusting item for a five year period.

8. Historical return on regulated equity (RoRE)

8.1. The two charts below include the draft preliminary actual RORE from each of the current transmission and gas distribution price controls for the period up to March 2010. This is only for the first three years (transmission) and two years (gas distribution) of a five year price control and it is not unusual to see companies under spending in the early years of the control and for their expenditure to catch up in the later years of a control period.

8.2. Figure 8.1 shows the RoRE data for the current transmission price control (TPCR4). This data relates only to the transmission operator part of the business, ie it excludes any performance relating to the system operator. Please note that we base these calculations upon initial regulatory reporting submissions that have not been adjusted by Ofgem. We will publish any adjustments and final figures in March 2011.

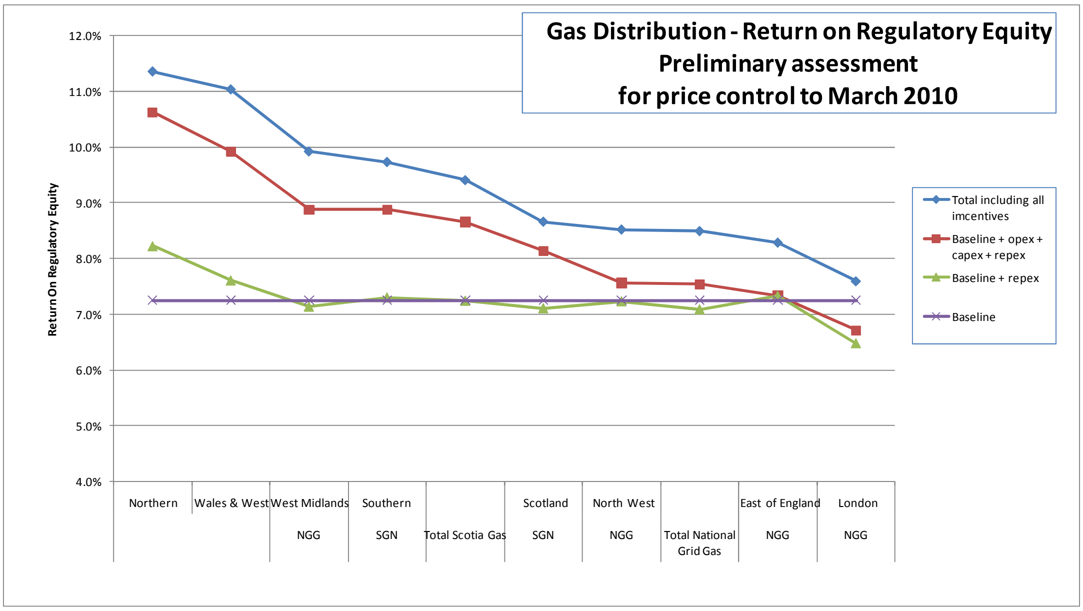
Figure 8.1 Preliminary draft RoRE for gas and electricity transmission operators



8.3. The charts compare the baseline allowed cost of equity to the returns on regulated equity earned by the relevant TOs. Separate lines are included to show the performance relating to capex alone (baseline + capex) and capex plus opex (baseline + capex+ opex). The difference between these two lines shows the impact of opex alone.

8.4. Figure 8.2 shows the RoRE data for the current gas distribution price control (GDPCR1). Please note that these calculations are based upon initial regulatory reporting submissions and have not been adjusted by Ofgem. We will publish any adjustments and final figures in March 2011.

Figure 8.2 Preliminary draft RoRE for gas distribution operators



8.5. The charts compare the baseline allowed cost of equity to the returns on regulated equity earned by the relevant Network Operators. Separate lines show the performance relating to repex (baseline + repex) and repex, capex and opex (baseline + repex + capex+ opex).

8.6. This shows that operators have in general made limited improvements in the repex spend (with the exception of Northern Gas who have deferred a LTS project) and more significant returns when opex and capex are taken into account. All companies have also benefited interest rate and tax differentials compared to the price control allowances.

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Question 2: Do you agree with modelling tax under UK GAAP pending adoption of IFRS reporting with any changes to be subject to the tax trigger?

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Question 1: Do you agree that the timing of true up adjustments for existing controls should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?

Question 2: Do you agree that updated valuations for non-fast tracked companies should be the same as fast tracked companies, ie 31 March 2011 unless no network company is fast-tracked, in which case updated as at September 2012 in time for final proposals?

Question 3: Do you agree that the deficit funding rate of return should be derived from the range of benchmarked pre-retirement real discount rates? If not, which alternative option do you prefer?

Question 4: Do you agree that same rate should apply to the calculation of the net present value of the ex post true up adjustments?

Question 5: Do you agree that ex ante deficit funding allowances and the true up to date in a RIIO price control period should be every three years rather than truing up at the next eight-year price control?

Question 6: Do you agree that PPF levies should be part of benchmarked total costs? If not, which should be the alternative option?

Question 7: We invite views on whether the revised guidance to our pension principles is comprehensive and adequate for licensees and stakeholders to understand how the principles will be applied in RIIO controls and for network companies to prepare their business plan?

CHAPTER: Seven

Question 1: How should we calculate the percentage of totex allowed into RAV?

Question 2: The proposed totex approach includes repex, business support costs and non-operational capex as part of totex.

We invite views on whether totex should include:

a) Repex
b) Business support costs
c) Non Operational capex

Question 3: Should the definition of related parties include captive insurance companies?

Question 4: In GDPCR1 GDNs were allowed to retain the proceeds of asset disposals in RAV for five years to incentivise GDNs to dispose of assets at competitive prices. We invite views on whether this treatment should continue.

Appendix 2 - Tax methodology

Overriding principle

1.1. We model each regulated business for price control purposes as a standalone entity. We treat all expenditure as incurred directly by the regulated business. For this purpose, we consider each transmission business, GDN and, for National Grid, each of the gas and electricity transmission owner and system operators and each retained gas distribution network to be individual regulated businesses.

Applicable tax regime and accounting regime

1.2. We are consulting on whether to apply the UK standard tax rules that have passed into legislation by the time of the final proposals, or to apply the changes proposed in the June 2010 Budget. Our preference and working assumption is the latter. For the preparation of Business Plans, licensees will be advised which will apply in the March 2011 Strategy paper. We are introducing the DPCR5-style tax trigger mechanism. This will deal with uncertainty from future changes in the tax regime over the these price controls.

1.3. We are consulting on the effect of the proposed change to IFRS reporting in the RIIO period. Subject to the outcome of that consultation, the tax treatment of opex, capex and repex will follow the existing UK GAAP treatment. Any subsequent changes from adopting IFRS will fall within the scope of the tax trigger.

1.4. We will assume that all capital allowances are claimed at rates in line with these intentions and in the year that the expenditure is incurred.

Tax losses

1.5. Tax losses have not been an issue for transmission companies in the past. We consider that this is not an issue for RIIO-T1. In line with our treatment in GDPCR, where tax losses arise we do not propose to give affected network companies negative tax allowances, but we will log up any tax losses as calculated on a regulatory basis and deduct them from expected tax allowances when the timing differences that led to the loss reverse.

1.6. In computing regulatory losses, we will ignore and reverse any surrender by a network company of losses to a group company, so that customers benefit from the full amount of the losses as they reverse.

Modelling of expenditure allocations to capital allowance pools

1.7. We will use the following capital allowance pools:

- Plant and Machinery (for this purpose this includes vehicles, cars and short life assets)
- Special Rate Pool (for long life assets) - and the relevant rates of annual writing down allowance
- Deferred Revenue Expenditure, for costs capitalised in the financial statements and allowed as deductible when charged to revenue.

1.8. These pools reflect the relevant legislation in place and take into account the legislative changes to the capital allowances regime since previous reviews.

1.9. We will collect data on expenditure under the old industrial buildings allowance (IBA) but, reflecting the phasing out of IBAs, set no allowances for these in RIIO-T1 and RIIO-GD1. We will also identify expenditure that does not qualify for capital allowances (principally interests in land), or is not deductible for computing taxable profits.

1.10. We will allow for specific expenditure which qualifies for research and development allowances, environmentally beneficial technologies, and for environmental remediation allowances at the relevant rates.

1.11. We will treat all other expenditure not qualifying for capital allowances or treated as non-qualifying, as revenue, which will attract a 100 per cent deduction.

1.12. We will derive the allocation of expenditure to individual capital allowance pools, revenue and expenditure non-qualifying for tax deduction from the regulated businesses' attributions in each allocation table.

1.13. We will require electricity and gas transmission entities to identify expenditure (which we funded on a pre-tax basis at previous controls) to project-specific capital allowance pools. This also applies to expenditure which is initially funded in the SO control and which is subsequently transferred to the TO control. This includes TIRG, logged up costs and other incentive mechanisms. We will model these as separate CA pools, so that we transfer the correct tax written down value on transfer to the TO control.

Allocations to capital allowance pools

1.14. For RIIO-GD1, we will apply a common approach to allocate allowed expenditure to capital allowance pools. This relies on an 'average' actual allocation based on the information we received from the GDNs. We have adopted this basis as all GDNs have similar allocation profiles.

1.15. For RIIO-T1, we will retain the company specific approach from TPCR4 to allocate allowed expenditure to capital allowance pools. This relies on the actual allocation forecasts based on the information we have received from the licensees with review and potential challenge based on our view of where capex should go for consistency with standard tax rules.

1.16. The basis of allocation of the key building blocks to the capital allowances pools for RIIO-GD1 is set out in table A2.1 below. This is an example based on the 2009-10 cost reporting submissions (RRP). It is for illustrative purpose only and is subject to review following submission of network companies business plans.

Table A2.1 – Cost allocation to capital allowance pools - RIIO-GD1

	General Pool	Long Life Pool	IBA	Deferred Revenue	Revenue	Non-Qualifying	Total
LTS (Local Transmission System) pipelines	0%	**99%**	0%	0%	**1%**	0%	100%
NTS (National Transmission System) Outtakes	0%	**100%**	0%	0%	0%	0%	100%
PRSs (Pressure Reduction Systems)	0%	**100%**	0%	0%	0%	0%	100%
LTS (Local Transmission System) Storage	0%	**100%**	0%	0%	0%	0%	100%
Other Storage	0%	**100%**	0%	0%	0%	0%	100%
Mains Reinforcement	0%	**100%**	0%	0%	0%	0%	100%
Governors	0%	**100%**	0%	0%	0%	0%	100%
Connections - Mains and Services	0%	**100%**	0%	0%	0%	0%	100%
Connections - Governors	**48%**	**52%**	0%	0%	0%	0%	100%
Other Plant & Equipment, Land & Buildings	**65%**	**26%**	0%	0%	0%	**9%**	100%
Gross Replacement Expenditure	0%	0%	0%	**0%**	**100%**	0%	100%

Opening capital allowance pool balances

1.17. The opening capital allowance pools will be determined from the latest RRP received, updated to the price control base year by addition of forecast spend by pool types from the Business Plans to 31 March 2013.

1.18. For licensees with a 31 March year-end, we expect to receive the CT600 corporation tax returns and supporting computations (CT600 information) for the year ended 31 March 2010 with the annual regulatory cost reporting pack (RRP) return due by 31 July 2011. For network companies with a 31 December year-end, we will require CT600 information for the year ended 31 December 2009.

1.19. We will review the closing pools (as shown in the RRP) for consistency with the CT600 information, and for any adjustments made to exclude non-regulated activity allowances.

1.20. When the capital allowances pools per the tax returns have been adjusted, so that they are on a comparable basis, we will identify outliers. We will then take a view as to whether to accept the balances as they stand, or amend them.

1.21. We will roll forward the pools using the allocation methodology described above.

Capitalised indirect costs

1.22. We will use individual licensee-specific capitalisation policies to determine the treatment of indirect costs and to these we apply the allocation rates to capital allowance pools set out above.

Modelling the tax deductibility of pension costs

1.23. The cash payments made by a licensee into a pension scheme are 100 per cent deductible in the year incurred, except where there are large irregular payments. In accordance with the irregular payments rules, we spread the latter over the current and up to three future years in accordance with the legislation, dependent on their magnitude.

1.24. For modelling and allowance setting, we assume that all pension payments attributable to the individual regulated business are paid in the year in which the allowance is given (to take account of the spreading of deficit repair costs). Pension adjustments relating to earlier price control periods are computed net of tax and will not attract any further tax relief.

Modelling cashflows of Corporation Tax (CT) payments

1.25. We treat all licensees and the regulated business segments as large companies. Under tax legislation, they are required to pay their tax liabilities for any given year in instalments commencing in the current year. We will assume that half the annual charge to CT is paid in the regulatory year, and half in the subsequent year, regardless of the actual timing of payments by businesses (which could be affected by a statutory year end different from the regulatory year end of 31 March, for example) and ignore subventions for surrendered tax losses. We take no account of additional payments (or receipts) from settling earlier years' tax liabilities. For the first year of the price control, we include 50 per cent of the businesses' estimated tax liability for the previous year, which will be the subject of a review for reasonableness.

Interest (payable and receivable)

1.26. We model interest receivable and payable by applying the nominal rate of interest (the assumed cost of debt plus modelled RPI estimate) to net debt as determined by the financial model, on an accruals basis year-on-year. We treat interest for tax purposes as fully deductible/taxable in the period in which it arises, subject to the tax clawback. We will ignore the forecast movement, if any, in derivative financial instruments in our modelling as these cannot be predicted with certainty.

Tax treatment of incentives

1.27. In previous Transmission price control reviews, some expenditure has been subject to various incentive mechanisms, held outside, and not remunerated through base demand revenues. Subject to the proposals for these mechanisms, all incentive revenues or penalties are to be on a vanilla WACC plus incremental tax effect basis. This primarily affects adjustments in respect of capital expenditure incentives but excludes agreed schemes such as TIRG.

Tax clawback of impact of excess gearing

1.28. Consistent with our existing policy we will apply an ex post adjustment to claw back from licensees the tax benefit they obtain from gearing above our notional gearing level.

1.29. The clawback will operate when in any year: (i) actual gearing exceeds notional gearing and (ii) interest costs exceed those modelled at the relevant price control. In the case where both of these conditions are satisfied, we will clawback the tax benefit which results from the difference between actual and modelled interest costs in that year. The specific methodology is set out in our open letter of 31 July 2009[23]. Where notional interest varies from that initially modelled at final proposals, due to changes to the cost of capital, we will consider this when undertaking these trigger tests.

1.30. To calculate the adjustment in the previous price controls ending on 31 March 2013, we will use actual data when available together with that forecast in network companies business plans. If the actual amounts are different, we reserve the right to make a further ex post adjustment, if required.

1.31. The timing of the clawback when applicable is subject to consultation.

1.32. In accordance with the July 2009 methodology, we will treat hybrid financial instruments that have the characteristics of pseudo equity as debt if the coupon is tax deductible, or proportionally if not 100 per cent deductible.

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[23] Tax gearing clawback letter July 2009
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=49&refer=Networks

Appendix 3 - Tax trigger

Tax trigger mechanism

1.1. The trigger mechanism protects licensees from material effects on their cashflows of legislative changes and is symmetrical for both licensees and customers. It fulfils the following key criteria, in that it:

- is unambiguously clear when a trigger event has occurred
- is measurable by Ofgem with minimal recourse to licensees, (subject to ex post adjustment for those that cannot be determined until tax returns are agreed by Her Majesty's Revenue and Customs (HMRC)
- is simple and transparent to apply.

1.2. We will calculate these changes by re-running the price control financial model (without profiling, if adopted) to assess the impact on the tax allowance component of revenues based on the aggregate effect over the remainder of the price control period of changes in relevant legislation, whether introduced in a Finance Act, other Act of Parliament, Statutory Instrument or other legislative instrument.

1.3. In accordance with our tax methodology, we model the regulated business for price control purposes as a standalone entity. We treat all expenditure as if it is incurred directly in the regulated business. The trigger is only applicable to the activities for which base demand revenues are set, ie the regulated gas distribution, TO or SO business. We will not apply the tax trigger to expenditure logged up or held outside of RAV, until it transfers into RAV.

Scope of the trigger

1.4. The trigger will specifically include effects arising from:

a. changes in the relevant legislation whether introduced in a finance act, other act of parliament, statutory instrument or other legislative instrument, or

b. changes in, or clarifications to, HMRC interpretation of legislation, or

c. new precedents set under case law, or

d. any changes in accounting standards that have a knock-on effect on the quantum or timing of taxation,

providing companies have demonstrably taken all requisite steps to reduce their tax liabilities.

1.5. The trigger will specifically exclude effects arising from any changes that alter the cash tax charge for the regulated business that arise specifically because the licensee is a member of a group of companies. We will apply tax legislation to the regulated business as if it was a standalone entity. For example, the potential restriction of interest as deductible because of the licensee being a member of any group of companies or partnerships will not be a trigger event.

Trigger point

1.6. The trigger point is a change or changes that yield a greater than a given per cent increase or decrease in the total base revenue of an individual regulated business, measuring it separately for each remaining year (including the year in which the trigger activates) in the price control period. We will calibrate this percentage around a set per cent change in the mainstream rate of corporation tax. The quantum calibration of the dead-band is the subject of consultation.

1.7. The trigger point is set at a per cent of total base revenue (as shown in the financial model and in the charge restriction licence conditions at the relevant term[24]). The measurement of this will be the aggregate effect on the tax charge (as shown by the financial model) of an individual regulated business of all legislative changes at A above within a regulatory year; and whether these in total breach the trigger. The adjustment will be on the excess over the trigger point, ie the deadband.

Measurement of changes

1.8. We will re-run the price control financial model to calculate whether the new outcomes from the prescribed legislative changes above, activate the trigger. We will not adjust any other assumption in the model, including for the cost of debt indexation[25]. We do this to ensure that we calculate all changes on a like-for-like basis.

1.9. We do not consider that the changes at B, C and D above, are easily measurable by us without recourse to licensees. Neither we, nor the licensee, can accurately quantify those changes until (a) the licensee has prepared and submitted its annual corporation tax return to HMRC; and (b) HMRC agrees that return.

1.10. We will agree the quantum of the effects at B, C and D and, if necessary, we will require it to be certified by an appropriate auditor[26]. Licensees must notify us in writing once they have quantified the effects setting out their supporting calculations. We will ignore B, C and D trigger events that have not been notified in writing prior to the end of price control period. We will log up the annual aggregate amount of these items and adjust these after HMRC has agreed and closed the relevant tax return. Licensees should notify us in writing within 30 days of that event. At that point, the financial model will be re-run as above. This

[24] PR in electricity transmission, Z in gas distribution, and TOZ in gas transmission
[25] Although interest may change overtime the effect on the tax burden will be adjusted through the indexation mechanism within the charge restriction conditions
[26] An appropriate auditor will be as defined in the relevant Regulatory Accounts licence condition

will include the effects arising at A above to re-measure the total of all effects. All ex post adjustments will be NPV neutral.

1.11. Where the effect of changes in B, C and D can be easily measured, they will be dealt with when known, or as if they were a change defined in A above. We will deal with these on a case-by-case basis. Licensees may apply in writing for these items to be adjusted in the period, and will need to:

- demonstrate that the effects of the changes are quantifiable
- provide evidence that the treatment has been agreed by HMRC or, in the case of items at B, C and D above, their appropriate auditor
- provide evidence of mitigation as far as practicable.

Timing of revised revenues

1.12. When the trigger is activated, changes to each regulated businesses' revenues from A will take effect from the regulatory year subsequent to that in which the trigger event or events occurred. Those from B, C and D as ex post adjustments as and when determined (as above) in the subsequent price control period(s). We will gross up the additional revenue at the applicable rate of corporation tax for each year so that regulated businesses do not suffer tax on tax and obtain the net additional tax burden or, if a reduction in the tax charge, the benefit to customers is net of the tax saved.

1.13. The two following tables illustrate the activation of the trigger and the timing of revised revenues, firstly for the adjustment of A effects, and secondly for the ex post adjustment where B, C or D effects cannot be quantified until tax submissions are agreed with HMRC.

In both examples the deadband trigger point is 0.33 per cent; the CT rates (based on the June 2010 Budget proposals); and the cost of capital (DPCR5), are for illustrative purposes only.

Table A3.1: Example of trigger in period straight forward from A effects

Trigger with restriction to adjust only the excess over the trigger point										
2010/11 prices		RIIO-1								RIIO-2
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
		£m	£m	£m	£m	£m	£m	£m	£m	£m
Impact on accounting tax charge:										
Year 1		(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	
Year 2			(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	
Year 3				15.0	15.0	15.0	15.0	15.0	15.0	
Year 4					2.0	2.0	2.0	2.0	2.0	
Year 5						(10.0)	(10.0)	(10.0)	(10.0)	
Year 6							2.0	2.0	2.0	
Year 7								1.0	1.0	
Year 8									2.5	
Sub total		(2.0)	(5.0)	10.0	12.0	2.0	4.0	5.0	7.5	
Adjustment for base amount		2.0	3.3	(3.3)	(3.3)	(2.0)	(3.3)	(3.3)	(3.3)	
Impact		0.0	(1.7)	6.7	8.7	0.0	0.7	1.7	4.2	
Additional tax on additional revenue		0.0	(0.4)	1.6	2.1	0.0	0.2	0.4	1.0	
Impact on subsequent year's revenue		0.0	(2.1)	8.3	10.8	0.0	0.9	2.1	5.2	
Trigger at	0.33%	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	
Trigger exceeded		NO	YES	YES	YES	NO	YES	YES	YES	
CT rate		25%	24%	24%	24%	24%	24%	24%	24%	
		RIIO-1								RIIO-2
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
		£m	£m	£m	£m	£m	£m	£m	£m	£m
Modelled Base Revenue		1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	
Impact on revenues			0.0	(2.1)	8.3	10.8	0.0	0.9	2.1	5.2
Total adjusted Base Revenue		1000.0	1000.0	997.9	1008.3	1010.8	1000.0	1000.9	1002.1	5.2

Table A3.2 Example of trigger to show the deferral working

Trigger with restriction to adjust only the excess over the trigger point

		RIIO-1								RIIO-2							
2010/11 prices	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
		£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Impact of tax legislation on accounting tax charge:																	
Year 1		(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)								
Year 2			20.0	20.0	20.0	20.0	20.0	20.0	20.0								
Year 3				4.0	4.0	4.0	4.0	4.0	4.0								
Year 4					2.0	2.0	2.0	2.0	2.0								
Year 5						(16.0)	(16.0)	(16.0)	(16.0)								
Year 6							(10.0)	(10.0)	(10.0)								
Year 7								(5.0)	(5.0)								
Year 8									(15.0)								
Deferred settlement		0.0	0.0	25.0	50.0	40.0	0.0	0.0	(25.0)								
Sub total		(3.0)	17.0	46.0	73.0	47.0	(3.0)	(8.0)	(48.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjustment for base amount		3.0	(3.3)	(3.4)	(3.5)	(3.6)	3.0	3.3	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Impact		0.0	13.7	42.6	69.5	43.4	0.0	(4.7)	(44.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additional tax on additional revenue		0.0	3.3	10.2	16.7	10.4	0.0	(1.1)	(10.7)								
Total impact on base revenue		0.0	17.0	52.9	86.2	53.8	0.0	(5.8)	(55.5)								
Deferred settlement				25.0	50.0	40.0	0.0	0.0	(25.0)								
(Value of total less amount settled in following year)																	
Corporation Tax rate		25%	24%	24%	24%	24%	24%	24%	24%								
Years to settlement				5	5	5			4								
Year in which revenues adjusted				8	9	10	0	0	12								
Deferred settlement (NPV at Cost of Capital)				31.5	62.9	50.3			(30.0)								
Trigger at	0.33%	3.3	3.3	3.4	3.5	3.6	3.5	3.3	3.3								
Trigger exceeded		NO	YES	YES	YES	YES	NO	YES	YES								
Revised Revenue		RIIO-1								RIIO-2							
	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
		£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Base Revenue		1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0								
Impacts of change from:																	
Year 1			(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)							
Year 2				20.0	20.0	20.0	20.0	20.0	20.0	20.0							
Year 3					4.0	4.0	4.0	4.0	4.0	4.0							
Year 4						2.0	2.0	2.0	2.0	2.0							
Year 5							(16.0)	(16.0)	(16.0)	(16.0)							
Year 6								(10.0)	(10.0)	(10.0)							
Year 7									(5.0)	(5.0)							
Year 8										(15.0)							
Deferred settled			0.0	0.0	25.0	50.0	40.0	0.0	0.0	(25.0)							
Adjustment for base amount			3.0	(3.3)	(3.4)	(3.5)	(3.6)	3.0	3.3	3.3							
Tax on tax impact			0.0	3.3	10.2	16.7	10.4	0.0	(1.1)	(10.7)							
Total adjusted revenue for calculating trigger		1000.0	1000.0	1017.0	1052.9	1086.2	1053.8	1000.0	994.2	(55.5)							
Actual phasing of adjusted base revenues:		1000.0	1000.0	1013.7	1017.6	1019.5	1003.4	1000.0	995.3	(19.7)							
Revenues deferred									31.5	62.9	50.3	0.0	(30.0)	0.0	0.0	0.0	0.0
Tax on tax allowed									7.5	15.1	12.1	0.0	(7.2)	0.0	0.0	0.0	0.0
Total Revenues									1034.3	58.3	62.4	0.0	(37.3)	0.0	0.0	0.0	0.0

1.14. In the example in above table A3.2, this shows when B, C and D amounts cannot be readily quantified and the revenue adjustment is deferred until tax computations are agreed. In the example, these are in years 8, 9, 10 and 12 with settlement made for each of years - 8, 9, 10 and 12. The amount settled is the calculated additional (or reduction in the) tax effect plus any change that this would make to the trigger, adjusted to be NPV-neutral to the year of settlement.

1.15. We propose to introduce a term in the Charge Restriction licence conditions to give effect to the tax trigger.

Appendix 4 - Pension methodology

Scope

1.1. We set out the pension methodology that companies should apply it in their fast-track business plan submissions for RIIO-T1 and RIIO-GD1; and as to how we will set allowances. These methodologies cover:

- GDPCR one year price control and GDPCR1 true up for pension costs
- allowances for deficit funding
- Regulatory fraction
- Early retirement deficiency contributions
- RIIO-T1 and RIIO-GD1 pension deficit true up.

1.2. The RIIO-T1 and RIIO-GD1 methodology follows that set out in the 22 June 2010 pension paper27 and the DPCR5 final proposals.

1.3. TPCR4 pension costs are subject to adjustment at TPCR4 roll over. We will reflect these adjustments in revenues in 2012-13 and subsequent years.

1.4. We will not fund any pension costs that relate to unregulated activities of the licensee, including the cost of repairing the relevant proportion of any deficit.

True up for GDPCR one year price control and GDPCR1

1.5. We committed at the one-year price control, and in GDPCR1, to restore companies to the position they would have achieved if their actual efficient pension deficit payments had been used to set allowances. The adjustments for the one-year control were set out in an open letter dated 10 September 2009.28

Ongoing service costs

1.6. The calculation will take the actual costs for GDPCR1 (including 2011-12 and 2012-13 forecast) and compare them to the allowed funding (all in constant prices). The actual numbers will include payments relating to the PPF levies - fixed and risk based.

1.7. For GDPCR1 the impact of the adjustment for ongoing service costs is limited to changes in contribution as shown in the actuarial valuations only, ie

[27] Price Control Treatment of Network Operators Pension Costs under Regulatory Principles (76/10)
http://www.ofgem.gov.uk/Networks/Documents1/Price_Control_Treatment_of_Pension_Costs_final.pdf
[28] GDPCR pensions open letter
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/Open%20letter%20to%20GDNs%20re%20pensions%20090909.pdf

(Actual DB cash contribution) – (Actual DB pensionable salary * allowed contribution rate)

1.8. The allowed contribution rates were set out in Table 3.2 to the GDPCR1 final proposals[29].

1.9. We will true up adjustments for ongoing service costs matching the GDPCR1 treatment in each of opex, capex and repex. Where this adjusts additions to RAV, we will recalculate regulatory depreciation and return on RAV; and adjust future revenues on a NPV neutral basis.

1.10. These adjustments are both funded in the first year of RIIO-GD1[30]. We calculate these net of corporation tax to avoid double counting the tax benefit / burden experienced by GDNs. We will apply a 30 per cent rate of CT, being the amount applicable when the GDPCR1 allowances were set.

Deficits

1.11. We will subject the true up adjustment of deficit funding contributions to an efficiency review, in accordance pension principle 1. We will add the cash amount of the true up of the deficit payments on a NPV neutral basis to revenues in RIIO-GD1.

True up for forecast years

1.12. The true up is based on actual expenditure and a forecast for 2011-12 and 2012-13. In the event that actual costs in 2011-12 and 2012-13 turn out to be materially different to the estimate, we would expect to alter revenue in the next price control; or, dependent on consultation at an earlier point in the 8-year control period. If the difference was due to genuine efficiencies that were reasonably foreseeable at the time the forecast was provided, there will be a clawback of the benefits of any under-spend relative to the estimate used in these proposals in RIIO-T2/RIIO-GD2. We will do likewise if the forecast for the TPCR4 roll over year is materially different from the estimate.

Timing of adjustments

1.13. The timing in revenue of the true up adjustments, arising from TPCR4, TPCR4 roll over and GDPCR1 is subject to consultation. This will be advised in the March 2011 Strategy Paper.

[29] GDPCR1 Final Proposals
http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/final%20proposals.pdf
[30] We are consulting on the period over which the true up funding will be spread; our preference is for 8 years

Defined benefit schemes - deficit repair costs

Established deficits – regulatory funding commitment

1.14. Our policy is that customers will fund the established deficit for each network company as at the end of the current price controls (ie TPCR4 and GDPCR1). The established deficit means the difference between assets and liabilities attributable to pensionable service up to the end of each respective price control period set out below and relating to the regulated business under pension principle 2:

- for GDNs – the price control period ending on 31 March 2013
- for transmission operators – the price control period ending on 31 March 2012.

1.15. This approach is consistent with our pension principles and it will achieve fairness between different network companies and their stakeholders.

1.16. In accordance with pension principle 5, subject to an adjustment for the regulatory fraction, the funding commitment covers changes, positive or negative, in the amount of the established deficit at the end of the price control period (for example caused by a fall in the value of stock markets or changes in longevity assumptions) provided that the scheme or schemes have been efficiently managed in accordance with principle 3 and costs are efficient and economic in accordance with principle 1, even if there has been an interim period during which a funding surplus has been reported.

1.17. Conversely, the funding commitment does not cover any element of deficit falling outside the scope of the deficit (eg non–regulated activities and bulk transferees) at the end of the price control period (the established deficit) or future service of those employees still active in the scheme after the relevant cut-off date. We will not make any future allowance for such deficit elements, other than through the benchmarking process, ie the incremental deficit.

1.18. We will treat any deficit payments that arise because of service after the relevant cut-off date as part of benchmarked totex and subject to the same incentive as totex in general.

Setting of established deficit repair allowances

1.19. As set out in our 22 June 2010 document, we are committed to funding the repair of established deficits, provided they satisfy pension principles 1 and 3, ie the relevant scheme, or schemes', costs must be efficient and there has been no material failure of stewardship. This is to ensure that the costs of addressing the deficit are not higher than they reasonably need to be. For setting allowances and true up adjustments, all actual deficit costs will be subject to an independent efficiency review.

1.20. Our approach is to set allowances based on up to date actuarial valuations of the assets and liabilities attributable to the established deficit. The methodology for the attribution between established and incremental deficit, is currently the subject of a review by both licensees and other interested stakeholders. Subject to the outcome, we plan to publish the final methodology in the March 2011 Strategy Paper.

1.21. We will base allowances on the latest updated valuations in accordance with our pension principles. Given the timing of setting allowances for fast tracked companies, all licensees will be required to submit an update as at 31 March 2011 for the business plan. We are consulting on whether non-fast track companies should submit later valuations to inform setting their allowances.

1.22. Network companies submit scheme valuations in nominal prices. We will rebase the deficit into 2010-11 prices used in setting price control reviews allowances by the relevant average RPI factors.

1.23. We apply the regulatory fraction (see below) to give the regulated element of the deficit funded by demand revenue customers.

Notional deficit repair period

1.24. We will fund the established deficit over a notional 15-year deficit funding period (from the respective cut-off dates), and will apply a flat profile over the deficit funding period allowing a rate of return. It is not our intention to reset the funding period at each subsequent price control review.

Pension deficit funding rate of return

1.25. Subject to consultation, we will continue with our current methodology first used at DPCR5. That is applying a funding rate of return derived the range of benchmarked pre-retirement real discount rates as applied in network companies valuations.

Determining the established deficit

1.26. The valuations used to inform setting allowances will pre-date the cut-off date for determining the established deficits. We will finalise the actual amounts during the RIIO price control period and true up at some stage. The exact timing is subject to consultation.

1.27. Where there is a difference in the size of a network company's deficit between the updated valuations (used to set allowances) and that shown by either a full triennial valuation at 31 March 2013, or updated valuations at that date (for those with an earlier full valuation date), these will be adjusted in revenue allowances at the next price control. If true ups are undertaken more frequently then this will be at the first one in the period. All true up adjustments will be NPV neutral, using the same discount rate as for setting allowances. We will spread the true up of this difference over the remaining years of the 15-year notional funding period.

Resetting allowances during the RIIO price control period

1.28. We are consulting on whether we should introduce a mechanism for a subsequent reset of allowances during a RIIO price control period. Our preference is every three years starting 31 March 2013 to be undertaken in summer 2014 and every three years thereafter. In addition, we will undertake future efficiency reviews in advance of any reset (subject to the timing of other price controls) and at the same time true up the RIIO controls.

1.29. Subject to this consultation, we will introduce a mechanism in the charge restriction conditions to adjust revenues for all adjustments.

Regulatory fraction

1.30. The regulatory fraction represents the element of licensee's pension deficits that relates solely to the activity of the distribution business (ie the licensed business) and which, ultimately, under the pension principles, is funded by customers.

RIIO-GD1 regulatory fractions

1.31. For GDNs, we include the pension deficit funding costs of employees engaged in the metering business. Normally, we treat this as an excluded service. We do this, as there are no dedicated metering employees within the licensees; and, this activity is performed by staff primarily employed in the gas transportation business. Subject to review of the pension data and their business plans, the regulatory fraction for Northern Gas Networks and Wales and West Utilities will be 100 per cent less liabilities for any staff engaged solely in de minimis and unregulated activities (excluding metering). Similarly, we will set a regulatory fraction for each of Scotland Gas Networks and Southern Gas Networks as a fraction of the total Scotia Gas Networks pension scheme. We will derive the fraction for NGG's RDNs, from attributing liabilities in the National Grid Gas pension scheme (NGUKPS) to its business segments and legacy Centrica liabilities. The NGUKPS legacy deficit relating to the NTS[31] will continue to be on the basis adopted in GDPCR1, and as pass-through costs in the GDNs. All regulatory fractions will be subject to review for structural changes to schemes, in accordance with principle 2.

RIIO-T1 regulatory fractions

1.32. For TOs', structural changes, if any, that occurred in TPCR4 and movements in unfunded early retirement deficiency contributions (ERDCs) are reviewed to determine the allowed proportion (regulatory fraction) of each company's pension costs applicable in RIIO-T1. In TPCR4, these were set out as a percentage of the deficit costs attributable to each TO irrespective of whether that TO was part of a larger scheme. For NGET, SPTL and SHETL, we will calculate the allowed proportion as a percentage of the wider scheme to which each TO is a sponsoring employer. For NGET an element will be attributable to the SO. We will make adjustments from that starting point to take account of scheme restructuring (mergers, and bulk transfers in and out) in the price control period to arrive at a new fraction.

[31] This includes the liability for the pensioners and deferred pensioners of the GDN businesses sold by NGG in 2005. GDNs only took on the active members and set up new schemes for these

1.33. At TPCR4, the Scottish TOs[32] pension schemes were in surplus and no regulatory fraction was determined. Since then the schemes have moved into deficit. These schemes are multi-employer schemes and at DPCR5, fractions were set for the electricity distribution businesses. This work also identified the indicative fraction relevant to the transmission business. These are for SPTL 4.8 per cent and for SHETL 7.1[33] per cent of their respect schemes deficits, subject to potential adjustment for ERDCs.

'Centrica liability'

1.34. This concerns the liabilities relating to non-regulated business activities carried out in NGG's predecessor companies. These include, in particular, those relating to the gas trading and supply activities de-merged in 1997 to form Centrica plc. As at TPCR4, we will only provide an allowance to cover the economic and efficient deficit repair costs relating to businesses that remain regulated, ie we will disallow the Centrica liability.

Periodic review of regulatory fractions

1.35. We will review the regulatory fraction at each reset of pension deficit allowances in the RIIO price control period.

Early Retirement Deficiency Contributions (ERDCs)

1.36. In accordance with pension principle 6, since 31 March 2004, ERDCs whether fully funded, partially funded or fully unfunded, are a matter solely for shareholders. In accordance with the principle, we will adjust the allowances in future price controls to exclude the impact of ERDCs resulting from redundancy and re-organisation. These have been offset by use of past surpluses, rather than being funded by increased contributions.

1.37. In TPCR4, we provided an allowance for 70 per cent of unfunded ERDCs arising in respect of relevant retirement dates between privatisation and 1 April 2004.

1.38. These unfunded ERDCs still exist for RIIO-T1 in NGET and NGG although they will reduce over time. That reduction is from the balance of TO and SO funding payments in excess of the regulatory fraction that fund them. We accept that where schemes are subsequently taken over and deficits paid off in full at that time, this may also include the ERDCs. We will review these on a case-by-case basis. We understand that SPTL and SHETL have no unfunded ERDCs.

[32] SP Transmission Limited (SPTL) and Scottish Hydro Electric Power Transmission Limited (SHETL)
[33] These percentages are indicative and subject to review

Computation of unfunded ERDCs

1.39. To arrive at the closing unfunded ERDCs we will:

a. Take the TPCR4 position and rebase using RPI to prices at the beginning of the control (ie 2007-08 prices)
b. Adjust where the scheme deficit has been cleared, by for example a take-over and subsequent funding in total of the deficit
c. Roll forward the revised sum each year to create a forecast position at the end of the price control by:
    - adding expected returns (using the cost of capital for each control as a proxy for the nominal return that might have been expected). The expected return is used (rather than actual returns) since this is the amount on which the original ERDC valuation was based; and
    - deducting the proportion of the deficit payments (in nominal prices) that were disallowed in TPCR4 and assumed to, in part, fund the ERDCs unfunded.
d. Compare the resulting values of ERDCs at 2013 (in nominal prices) to the deficits that are being used as the March 2013 position (again in nominal prices) and convert to a percentage of the total scheme deficit. We use this to reduce the regulatory fraction.

Table A4.1 Illustrative ERDC reduction calculation

£m	2005-06	2006-07	2007-08	2008-09	2009-10
B fwd	60.0	53.3	47.3	43.9	40.3
Return	3.3	3.0	2.6	2.4	2.2
Payments	(10.0)	(9.0)	(6.0)	(6.0)	(6.0)
C fwd	53.3	47.3	43.9	40.3	36.6

Deficit assumed at 31 March 2010 £m	Reduction in Regulatory Fraction
1214	3.0%

Movements in regulated fraction in closed pipes and wires only schemes

1.40. The ERDC movement calculation will in practise, only apply to the NGET ESPS (the National Grid section of the electricity supply pension scheme). It is not applicable to the NGG NGUKPS, as the scheme is not a pipes only business. The NGG NGUKPS also encompasses significant active and legacy members in non-regulated activities, eg NTS legacy members recharged to GDNs and the Centrica liability. Nor does it apply to SPTL and SHETL whose schemes have members in generation, supply and retail in addition to electricity distribution.

1.41. In a closed pension scheme for a predominantly wires or pipes only business, the non-regulated component of pension liabilities should logically reduce over time. The allowed regulated fraction should increase. We will calculate this by determining the liabilities attributed to the active scheme members in the regulated business and the movement from the position determined at the previous price control. For TOs this will, over time, move the fraction to their actual attribution (where supported by the necessary records) from the split applied at TPCR4 for NGET. We will review the regulatory fraction to reflect this. We will calculate the revised fractions by determining the liabilities attributed to the active scheme members in the regulated business and the movement from the position determined at the previous price control.

1.42. Table A4.2 shows an example of the calculation applied at DPCR5. This calculates the updated fraction for DPCR5 by taking the 80:20 split of liabilities at DPCR4 as the starting point. It then applies the current split of total liabilities and the current split of active members to calculate the updated fraction for DPCR5. We consider the methodology is still appropriate for RIIO controls.

Table A4.2 Movements in regulated fraction in closed wires only schemes

Pension liabilities						
		DPCR4			DPCR5	
		2004	2004		2010	2010
		£m	%		£m	%
Actives (plus retirees from actives after 2004)		150	21.4%		250	25.0%
Pensioners & deferreds (less retirees from actives since 2004)		550	78.6%		750	75.0%
Total liabilities		700			1000	
At DPCR4 split 80/20 attributable as follo		DPCR4			DPCR5	
Actives - allowed	90%	135	19.3%	92%	230	23.0%
Actives - disallowed	10%	15	2.1%	8%	20	2.0%
Pensioners & deferreds-allowed	77%	425	60.7%		580	58.0%
Pensioners & deferreds-disallowed	23%	125	17.9%		170	17.0%
		700	100.0%		1000	100.0%
Regulatory fraction:						
Allowed		560	80%		810	81.0%
Disallowed		140	20%		190	19.0%

1.43. To the new percentage will be deducted the residual balance on the unfunded ERDCs from pre 1 April 2004 (see below) which value will be expressed as a percentage of the total scheme deficit.

1.44. We will reset this element of the regulatory fraction at each reset of ex ante allowances in the RIIO price control period. It does not apply in the calculation of any ex post adjustment. As noted above, this mechanism is not applicable in gas distribution networks as their schemes only had active members transferred from NGG.

1.45. We expect relevant companies to maintain appropriate records to enable this assessment. In the absence of detailed records, we will apply our own judgement. We will revise the allowed proportion and apply it within a price control period for computing the true up adjustments. We will review a company's position on its merits and would expect a company to approach us at an early stage to discuss the possible impact on their true up adjustments.

1.46. We will not specifically require an actuarial assessment and valuation at each trigger point above to determine the revised allowed proportion, as we recognise that it is not necessarily cost effective for a company to have an annual actuarial assessment of this split. If one exists, we will use it to inform the assessment.

Efficiency review

1.47. We will carry out periodic efficiency reviews of network companies pension costs to inform truing up of price control ex ante allowances, setting and updating deficit allowances. The review will be in two stages:

a. an initial reasonableness review of energy network company's DB pension schemes and specifically their funding costs; and
b. where the initial review indicates that there are grounds to believe the company’s pension costs fall outside of the expected range, this will trigger a further in-depth examination to determine whether the company should retain any, or a proportion of, the apparent efficiency savings if outturn costs are lower than the allowances.

1.48. The second stage in-depth review will take place after completion of the initial report. If any network company triggers a second stage review, we will determine separate terms of reference for any subsequent consultancy support, as appropriate.

Objectives of initial review

1.49. The objectives of the initial review are to highlight those network company DB schemes:

- where the movement in the deficit (reviewing separately the movement in underlying assets and liabilities) appears to be out of line with the general market
- to identify whether any schemes’ benefits, investment strategies, funding methodologies, funding assumptions, funding levels or standard contributions fall outside of the expected range compared to:
    a. their industry peers, and
    b. publicly available information on other UK private sector DB pension provision.

1.50. The process should identify any scheme (and thus network company’s pension costs) that fall outside any of the expected ranges. If so, the initial review will inform Ofgem’s determination of whether or not the network company’s pension costs should be subject to a second stage in-depth examination.

Objectives of second stage in-depth review

1.51. The second stage review will ascertain whether:

- increased balances on deficits should be funded going forward
- over-spends against allowances should be made good
- under-spends against allowances should be clawed back.

1.52. If any network companies trigger an in-depth review, the detailed methodology will be determined at that time.

Ongoing service pension contributions

1.53. As set out in the 22 June 2010 decision document, for the RIIO controls, we will treat ongoing service pension costs as a component of overall total costs (albeit separately identifiable) and consequently include these in the efficiency benchmarking of total costs. This will mean that:

- pension costs (as part of employment costs) will be subject to any incentive mechanism applied to employment costs (or total costs), but there will be no specific pension cost adjustment
- scheme administration and PPF levy costs[34] will be included in the total cost benchmarking treatment (subject to the costs put forward by network companies being pro-rated with regard to the attribution between regulated and non-regulated activities)
- employment costs associated with the provision of non-regulated activities, eg excluded services, metering, LNG storage (subject to not being part of the main transmission price control) and de minimis business, are not part of base revenue allowances and so the same treatment will automatically apply to their ongoing pension service contribution elements.

Pension deficit true up

1.54. The following methodology is subject to the true up of funding to the 31 March 2013 final valuation. This is the difference in the deficit between the updated valuations (used to set allowances) and the deficit shown by either a full triennial valuation at 31 March 2013, or updated valuations (for those with an earlier valuation date). We will adjust this amount in revenue allowances during the next RIIO price control on an NPV neutral basis. We will spread this over the remaining period of that price control review period.

1.55. We are proposing to introduce a periodic 3-year cycle of efficiency reviews, at which time we will true up to date and reset allowances for the remainder of the control. This will be a two-stage efficiency review to determine whether a network company’s pension costs are efficient so that the network company can recover its economic and efficient pension costs, subject to our commitment to fund the opening established deficit. Where that initial stage of the review indicates that the company’s pension costs may be inefficient this may trigger a further in-depth examination to determine whether the company should retain any, or a proportion of, the efficiency savings if outturn costs are lower than the allowances. Similarly, a review may be triggered to determine the level of any additional funding if either the outturn costs are higher than the allowances or where the deficit has increased and either is demonstrably due to inefficiency. If the outturn costs are higher due to accelerated funding, which at the time of a

[34] And subject to the outcome of the consultation on this as described in chapter 5

efficiency review, results in a surplus then we will consider whether all of the cost are funded and the timing of that funding.

1.56. At each reset using the methodologies set out above, any under or over recovery of efficient pension costs against the allowance in the previous price control or reset as determined above, will be adjusted in future revenues over the remaining years of the initial notional 15-year notional funding period. These will be NPV neutral and (subject to this consultation) we will apply the same discount rate as used for annuitising the ex ante deficit allowances. We do this, so that customers are unaffected by the actual funding period used by companies.

Examples of deficit funding true up

1.57. We will deal with the element of the deficit that relates to regulated activities as illustrated in the examples below. In the March 2011 strategy paper we will update the tables if the outcome of the consultation on the timing of subsequent efficiency reviews is not to have in-period true ups.

1.58. In all the example tables, we assume that the network company's scheme has a 10-year deficit recovery plan and we use a 15-year notional funding period:

Table A4.3 shows the impact of a company choosing to repair the deficit over a shorter period than the 15 years over which the price control funding has been set. This example assumes no resetting of network company funding or of allowances at subsequent revaluations. In this example the company has chosen 10 years as an appropriate repair period and, subject to the "economic and efficient" test, the accelerated repair payments will be funded (including the time value of money) over the remaining 7 year period in RIIO-2. We fund the £400 additional payment in Period 1 over 7 years (£57 in each of the following 7 years in RIIO-2). We fund the opening RIIO-2 (£300) over the remaining 7 years of the 15-year notional funding period.

Table A4.3: Different repair period - all costs efficient and no subsequent revaluation changes to deficit

		RIIO period 1 (2013-21)								RIIO period 2 (2021-29)								Total
PCR start (1 Apr) & end date (31 Mar)	Yrs	2013							2021	2021							2029	
Reset dates 1 April			2014			2017 reset-next review due						2023			2026			
Movements in year ended 31 March		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Opening established defict to be funded		(1,500)	(1,350)	(1,200)	(1,050)	(900)	(750)	(600)	(450)	(300)	(150)	0	0	0	0	0	0	
Change in deficit																		
Actual repair payments over	10	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	(1,500)
Inefficient deficit not funded																		
Future regulatory funding over	15																	0
Notional Deficit allowance		100	100	100	100	100	100	100	100	43	43	43	43	43	43	43	0	1,100
Additional allowance from reset			0	0	0	0	0	0	0									0
Balance of overfunding in period 1										57	57	57	57	57	57	57	0	400
Total regulatory funding		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	1,500
Inefficiency borne by shareholders																		0

Table A4.4 illustrates the possible outcome if at a subsequent revaluation, an efficiency review triggers a second stage in-depth review and we deem £100 is inefficient. If deemed efficient the funding would continue as shown. If judged inefficient there would be a reduction in the funding from the year after the valuation as shown. In this example, we consider £100 as inefficient and is clawed back over the residual notional funding period of 13 years (together with the time value of money). The performance in RIIO-2 is not subject to adjustment, since the deficit has moved in line with the implied deficit band. We fund the £346 additional payment in Period 1 over 7 years (£49 in each of the following 7 years in RIIO-2). Likewise, we fund the opening deficit in RIIO-2 (£300m) over the remaining 7 years of the 15-year notional funding period.

Table A4.4: Efficiency review suggest a smaller deficit

	Yrs	RIIO period 1 (2013-21)								RIIO period 2 (2021-29)								Total
PCR start (1 Apr) & end date (31 Mar)		2013							2021	2021							2029	
Reset dates 1 April			2014			2017 reset-next review due						2023			2026			
Movements in year ended 31 March		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Opening established defict to be funded		(1,500)	(1,350)	(1,200)	(1,050)	(900)	(750)	(600)	(450)	(300)	(150)	0	0	0	0	0	0	
Change in deficit																		
Actual repair payments over	10	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	(1,500)
Inefficient deficit not funded			100															
Future regulatory funding over	15																	0
Notional Deficit allowance		100	100	92	92	92	92	92	92	43	43	43	43	43	43	43	0	1,054
Additional allowance from reset			0	0	0	0	0	0	0									0
Balance of overfunding in period 1										49	49	49	49	49	49	49	0	346
Total regulatory funding		100	100	92	92	92	92	92	92	92	92	92	92	92	92	92	0	1,400
Inefficiency borne by shareholders																		(100)

Table A4.5 illustrates the outcome if subsequently the deficit increases because of, for example changes in longevity. We allow the additional revenue of £100 over the residual notional funding period of 14 years at £7 per annum in RIIO-1, which we subsume within the opening deficit at RIIO-2. The performance in RIIO-2 is not subject to adjustment, since the deficit has moved in line with the implied deficit. The £475 additional Period 1 payment in is funded over 7 years (£68 in each of the following 7 years in RIIO-2). We fund the opening RIIO-2 (£325) deficit over the remaining 7 years of the 15-year notional funding period.

Table A4.5: Subsequent review shows deficit has increased (eg due to longevity) and all costs are considered efficient

	Yrs	RIIO period 1 (2013-21)								RIIO period 2 (2021-29)								Total
PCR start (1 Apr) & end date (31 Mar)		2013							2021	2021							2029	
Reset dates 1 April			2014			2017 reset-next review due						2023			2026			
Movements in year ended 31 March		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Opening established defict to be funded		(1,500)	(1,350)	(1,300)	(1,138)	(975)	(813)	(650)	(488)	(325)	(163)	0	0	0	0	0	0	
Change in deficit			(100)															
Actual repair payments over	10	150	150	163	163	163	163	163	163	163	163	0	0	0	0	0	0	(1,600)
Inefficient deficit not funded																		
Future regulatory funding over	15																	0
Notional Deficit allowance		100	100	100	100	100	100	100	100	46	46	46	46	46	46	46	0	1,125
Additional allowance from reset			7	7	7	7	7	7	7									50
Balance of overfunding in period 1										61	61	61	61	61	61	61	0	425
Total regulatory funding		100	107	107	107	107	107	107	107	107	107	107	107	107	107	107	0	1,600
Inefficiency borne by shareholders																		0

1.59. Whilst normal contribution rates are set at a level to secure future liabilities, it is likely that new deficits will arise for many different reasons. In this eventuality, we will look to fund this new deficit in accordance with the established pension principles.

Appendix 5 – Price Control Pension Principles under RIIO

1.1. Under RIIO, our pension principles remain the same as previously set out. These revised guidance notes for each principle take into account how we intend to apply them to defined benefit pension schemes under RIIO price controls.

Principle 1 - Efficient and Economic Employment and Pension Costs

Customers of network monopolies should expect to pay the efficient cost of providing a competitive package of pay and other benefits, including pensions, to staff of the regulated business, in line with comparative benchmarks.

1.2. We should not expect customers to pay the excess costs of providing benefits that are out of line with the wider private sector practice, nor for excess costs avoidable by efficient management action. We will, unless inappropriate, benchmark total employment costs within total costs, to ensure companies have correct incentives to manage their costs, including pension costs, efficiently.

Funding Commitment

1.3. For each network company, customers will fund the established deficit as at the end of the relevant price controls (ie DPCR4, TPCR4 and GDPCR1). The established deficit means the difference between assets and liabilities attributable to pensionable service up to the end of each respective price control period set out below and relating to the regulated business under principle 2:

- for DNOs – the price control period ending on 31 March 2010
- for GDNs – the price control period ending on 31 March 2013
- For Transmission owners and system operators – the price control period ending on 31 March 2012.

1.4. In accordance with principle 5, subject to an adjustment for the regulatory fraction, the funding commitment covers:

- The quantum of the established deficit at the respective cut-off dates in 1.3 above
- Changes in the amount of the established deficit at the end of the price control period (for example caused by a fall in the value of stock markets or changes in longevity assumptions) provided that the scheme or schemes have been efficiently managed in accordance with principle 3 and costs are efficient and economic in accordance with this principle 1, even if there has been an interim period during which a funding surplus has been reported

1.5. Conversely, the funding commitment does not cover any element of deficit falling outside the scope of the deficit (eg non–regulated activities and bulk transferees) at the end of the price control period (the established deficit) or future service of those employees still active in the scheme after the relevant cut-off date. We will not make any future allowance for such deficit elements, ie the incremental deficit, other than through the benchmarking process.

1.6. We will treat any deficit payments that arise because of service after the relevant cut-off dates above, as part of the benchmarked employment (or total) costs. These are subject to the same incentive as employment costs in general.

Notional deficit repair funding period

1.7. The deficit will be funded over the notional 15-year deficit funding period. We will apply a flat profile over the deficit funding period allowing a rate of return. We do not reset the 15-year period at each subsequent control. The intention is that the deficit at the cut-off dates for each control will be fully funded over the following 15 years.

Pension scheme administration costs

1.8. We will standardise the treatment of pension scheme administration costs paid directly by licensees compared to those funded through increased employer contributions to the scheme in setting allowances. These costs form part of the ongoing pension costs subject to benchmarking and to the same incentive mechanisms as other costs. There is no ex post adjustment in RIIO price controls.

Pension Protection Fund Levy

1.9. The quantum of the levy may change when the PPF's methodology is revised from 31 March 2012. Its magnitude is partly outside the control of sponsors and trustees. The levies form part of the ongoing pension costs subject to benchmarking and to the same incentive mechanisms as other costs. There is no ex post adjustment in RIIO price controls.

Stranded surplus

1.10. In the event that a surplus arises (ie assets exceed the full buy-out cost of accrued liabilities as shown by an appropriate actuarial valuation), only the trustees have the power to decide whether it is in the interests of scheme members to repay it to the employer (in accordance with the scheme rules and other legal requirements). Trustees' have obligations to protect scheme members. Network companies schemes are generally closed mature schemes with the majority of members either pensioners or deferred and with the average age of active members around 47. As such, we understand that they are generally looking to match their assets and revenues to their liabilities, which are becoming easier to forecast. In doing this their investment strategies will move from riskier to less risky assets, and they will likely use hedging strategies. Any potential for a surplus is very unlikely to arise. If this is the case, customers may indirectly benefit as investing in less risky assets to protect them from increased deficits on riskier assets, which are subject to market movements.

1.11. We will monitor each scheme's position on an annual basis. In the event that a scheme was in surplus for a given period, we consider that there is a reasonable expectation for symmetry in the treatment for funding of deficits and use of a surplus. We would therefore expect to share the benefit across members and customers. We would consider our options when setting allowances such that customers would benefit and the shareholders would cover the cost in the event that contribution levels remain the same. We will review each instance on a case-by-case basis.

Buy-ins and buy-outs of pension schemes liabilities

1.12. These currently fall within the scope of principles 1, 2 and 5. Buy-ins and buy-outs are effectively a de-risking of future liabilities. It will be necessary to determine how such de-risking be shared between customers and shareholders, to facilitate efficient management of the schemes and to remove uncertainty as to the regulatory treatment. It is difficult to be prescriptive as to how they should be spread between different generations of customers. For guidance, an equitable option is to spread these costs over the same deficit repair period used to set ex ante allowances. We will deal with these, if they occur, applying these existing pension principles on a case-by-case basis.

Principle 2 - Attributable Regulated Fraction Only

Liabilities in respect of the provision of pension benefits that do not relate to the regulated business should not be taken into account in assessing the efficient level of costs for which allowance is made in a price control.

1.13. It is for shareholders, rather than customers of the regulated services, to fund liabilities associated with businesses carried on by the wider non-regulated group. This includes businesses that were formerly carried on by the same ownership group and have been sold, separated and/or ceased to be subject to the main price control review. In principle this may include costs related to self-financing excluded services, distributed generation, metering, de minimis activities of the network company and of unregulated businesses in the same scheme in the context of a transportation and/or distribution price control. These will be dealt with on a case-by-case basis as in some cases the costs of such businesses are not readily separable from the regulated business.

1.14. At DPCR4, there was a general assumption of a 20 per cent disallowance for non-regulated activities for most licensees. For DPCR5, we retained this split as a starting point. At TPCR4, we disallowed the proportion of ongoing contributions and existing deficit that related to unregulated activities.

1.15. The regulatory fraction determined in setting ex ante allowances will be reviewed to assess the ex post adjustment when there have been structural changes to a scheme within a price control period. We will also review and adjust for movements, including cash funding by sponsors to the previously unfunded ERDCs.

1.16. Structural changes may occur when:

- schemes merge or demerge
- members are transferred in or out in bulk
- there is a change of ultimate controller
- there is a buy-in/buy-out of any part of the scheme membership.

1.17. The non-regulated component of pension liabilities should logically reduce over time in a closed pension scheme for a predominantly wires or pipes only business. Thus, the allowed regulated fraction should increase. We will calculate this by determining the liabilities attributed to the active scheme members in the regulated business and the movement from the position determined at the previous price control. For example, for DNOs and this will over time, move the fraction to their actual attribution (where supported by the necessary records) from the 80:20 pragmatic split adopted at DPCR4. We will calculate the revised fractions by determining the liabilities attributed to the active scheme members in the regulated business and the movement from the position determined at the previous price control. The methodology is set out in Appendix 4.

1.18. For DPCR5 and RIIO price controls, it is necessary to attribute scheme assets and liabilities separately to the established deficits at the respective cut-off dates and the incremental deficits attributable to active member's service and bulk transfers after the cut-off dates. In effect, this attribution may update the regulatory fraction. Guidance on the mechanism is subject to consultation.

Bulk transfers

1.19. During a price control period, there may be bulk transfers of members in or out of a DB scheme through corporate activity. These transfers are usually only accepted when the transfer value finances the deficit, if any, of the transferees. Bulk transfers in to a scheme require approval by trustees and as specified by the Pensions Regulator (TPR), they must be fully funded (in all but exceptional circumstances). TPR guidance states: "There is no statutory obligation for a trust-based scheme to accept transfers-in and provide benefits in exchange. Some schemes do offer defined benefit transfer credits, typically in the form of added years counting for benefits on the scheme's normal formula. Other schemes offer money purchase benefits in exchange for transfers, in which case no issues arise as to assumptions for determining benefits". It also states, "A transfer credit should not be expected to require additional funding from the employer in the long term unless agreed by the employer in advance”.

1.20. Under our commitment to fund the established deficits, movements in deficits arising from bulk transfers[35] that result from corporate transactions, whether fully funded or not, are a risk for shareholders and not customers. This applies even where the transferred protected person’s pension liability is underfunded where it arises from a corporate transaction.

1.21. Trustees may accept bulk transfers in to a scheme. These may include protected persons who may or, may not, be considered part of the regulated activities. We consider that these are not part of the established deficit and therefore shareholders, not customers, will fund any increase related to the transferees at future price controls.

1.22. This clarification covers only bulk transfers where individuals or groups of individuals (but not whole, or substantially, whole schemes) are transferred as part of a smaller transaction to acquire an activity rather than a licensee. We exclude a full merger between two existing DB schemes because of a corporate transaction. We will deal with this as a structural change (see above).

[35] Even if they include members other than active members

1.23. We cannot predict whether this treatment will be equitable to all situations. If we are satisfied that there are exceptional circumstances, we retain the option to deal with these on a case-by-case basis.

Principle 3 - Stewardship - Ante/Post Investment

Adjustments may be necessary to ensure that the costs for which allowance is made do not include excess costs arising from a material failure of stewardship.

1.24. We will disallow any excess costs arising from material failure in the responsibility for taking good care of entrusted pension scheme resources. Examples might include items such as recklessness, negligence, fraud or breach of fiduciary duty. We will review stewardship and reserve our position to make adjustments to allowances if we observe, for example, any of the following:

- poor investment returns over a long period, eg greater than a single price control
- whether the scheme investment managers are underperforming against their peers or the market and expectations and their performance has not been reviewed or benchmarked at appropriate intervals
- not matching investment/returns to fund future liabilities as they fall due
- material increase in deficits and need for increasing the funding
- maintaining a higher balance of investments in riskier assets compared to investment returns which do not match future liabilities
- accepting transfers in at under value
- making transfers out at over value.

1.25. In determining whether pension costs are reasonable, we may compare the level of funding rate recommended by periodic actuarial valuations to the actual funding rate adopted by the licensee. As long as a funding valuation uses actuarial assumptions, which are in line with best practice the costs will be included without adjustment in the benchmarking of employment (or total) costs and be subject to any incentivisation adjustment and the efficiency review set out in principle 1. This is one potential indicator of whether there has been a material failure in stewardship. We reserve our position to examine investment and administration costs to see whether these are materially out of line with industry figures.

1.26. The choice of investment strategy is one for trustees and necessarily involves the exercise of judgement, which, for any particular scheme and at any particular point in time, the trustees are best placed to make. These pension principles make clear that we do not think it is appropriate, given our statutory remit, for us to make judgements about investment strategies. In particular, the success or otherwise of any particular strategy can only be measured in hindsight, whereas trustees must make ex ante choices. Moreover, the strategy, which optimises outcomes over the whole life of a scheme, may produce inferior results over any particular shorter period (and vice versa). Therefore, it would be inappropriate for us to make judgements about investment strategies based on outcomes over the period of one price control.

Principle 4 - Actuarial Valuation/Scheme Specific Funding

Pension costs should be assessed using actuarial methods, on the basis of reasonable assumptions in line with current best practice.

1.27. We expect the level of scheme funding to be assessed on the basis of forward looking assumptions regarding long-run investment returns and other key variables. Licensees are required to provide up-to-date actuarial calculations (including the most recent formal actuarial valuation of the relevant schemes) to support their business plan estimates. During an 8-year price control period, licensees are required to provide annual up-dated valuations and triennial valuations to enable resetting of ex ante and truing up ex post of opening adjustments.

1.28. We would not expect substantial differences between companies. However, if an efficiency review identified an outlier, we will investigate as part of the second in-depth stage of the efficiency review the reasons for this. If these investigations reveal evidence of material differences, and these differences have contributed to an increase in funding required we might adjust the recommended funding rate for the purposes of setting the price control.

Principle 5 - Under Funding/Over Funding

In principle, each price control should make allowance for the ex ante cost of providing pension benefits accruing during the period of the control, and similarly for any increase or decrease in the cost of providing benefits accrued in earlier periods resulting from changes in the ex ante assumptions on which these were estimated on a case-by-case basis.

1.29. We will not make specific ex ante allowances or ex post adjustments for ongoing pension service costs, which include scheme administration costs and PPF levies. Instead, they form part of the overall benchmarking of costs and as such are subject to the same incentive mechanisms for sharing under- or over-spend.

1.30. Typically, actuarial valuations of pension funds are carried out triennially. In contrast, RIIO price controls are typically set for periods of eight years. It is likely that funding rates will change during the period of a price control. It is inappropriate to leave deficit funding unaltered for an 8-year period. We will reset ex ante allowances in 2015 based on full triennial (where available) or updated valuations as at 31 March 2013 and every three years thereafter. At the same time, there will be a two-stage efficiency review to inform the quantum of the costs and adjustments to deficit funding but not ongoing service costs.

1.31. The funding of any incremental deficit in excess of the established deficit at the end of the DPCR4, TPCR4 and GDPCR1 price controls would be subject to the same incentive mechanism as all other costs (including ongoing pension service costs). In principle we will apply the following guidelines to the funding of the established deficit:

a. An attribution must be made of the deficit and its constituent assets and liabilities between the established deficit and the incremental deficit.
b. During and at the end of the control period, there will be efficiency reviews and the resetting of ex ante allowances and ex post true ups. The efficiency review will inform us as to whether a company's pension costs are efficient, so that under principle 1, the network company can recover its economic and efficient deficit funding costs irrespective of the allowance set at the start of the control. Where that initial review indicates that the company's costs may be inefficient this may trigger a further in-depth examination. That will determine the level of any additional funding if either the outturn costs are higher than the allowances, or where the deficit has increased and either is demonstrably due to inefficiencies. Conversely, where outturn costs are lower than the ex ante allowances it will determine whether the licensee should retain any, or a proportion of, the savings.
c. At each subsequent price control, deficit funding allowances will be reset based on the methodologies set out above.
d. Any under or over recovery of efficient pension costs against the allowance in the previous price control as determined above, will be adjusted in future revenues over the remaining years of the initial notional 15 year funding period and be NPV neutral using the same discount rates as used for spreading the ex ante deficit allowances. Customers will be unaffected by the actual funding period used by companies.
e. As noted under principle 2, we will apply a revised regulatory fraction where there have been structural changes to a scheme in the price control period on a case-by-case basis. We will only change the element of the fraction related to movements in unfunded ERDCs at a subsequent price control, except where through structural changes network companies demonstrated unambiguously that they have been fully funded.

Unexpected lump sum deficit payments

1.32. These tend to occur in instances of change in corporate control, or through corporate activity within the network company's wider group. Whilst the trustees may take the opportunity to repair the deficit faster, it is not clear why customers should pay an accelerated profile.

1.33. We will review the payment of the lump sum compared to what the position would have been if the deficit was spread over a number of years. This is to ensure that customers have either positively benefited from, or have not been disadvantaged by the accelerated funding. Where a company cannot satisfy us that the accelerated payment has been in the interests of customers (as opposed to shareholders or scheme members), we will treat the payment as having been made over the remaining period of the 15-year notional deficit funding period.

Principle 6 - Severance - Early Retirement Deficiency Contributions

Companies will also be expected to absorb any increase (and may retain the benefit of any decrease) in the cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.

1.34. Since 31 March 2004, Early Retirement Deficiency Contributions (ERDCs) whether fully funded, partially funded or totally, unfunded, are a matter solely for shareholders.

1.35. The principle requires that an adjustment be made to the allowances for future price controls to exclude the impact of ERDCs resulting from redundancy and re-organisation, which have been offset by use of surpluses, rather than being funded by increased contributions.

1.36. This provides for consistent treatment with other restructuring and rationalisation costs. For this purpose, it will be necessary to roll forward the previously agreed amounts of unfunded ERDCs arising prior to 1 April 2004. The methodology is set out in Appendix [*4*]. That methodology does not apply to GDNs or NGG.

Appendix 6 - RAV methodology

Computing the RAV

1.1. The RAV is a key building block of the price control review. RAV is a financial construct for providing funding for costs over a prolonged period and represents the value upon which the companies earn a return in accordance with the regulatory cost of capital and receive a depreciation allowance. In DPCR5, as a key element in our approach to equalising incentives, we made a fundamental review of the means by which costs are included in the RAV. We will follow this approach for all network companies. The speed of money will be as follows:

- an agreed percentage of totex will be funded as slow money and added to the RAV
- the remainder will be funded as fast money which is expensed and funded in the year of expenditure

1.2. At the end of each year of a price control, we will publish an indicative updated RAV for each network company with a view to confirming the effective RAV at the end of the period (March 2021). In ascertaining these values it is important that the treatment of expenditure that network companies incur in this period is consistent with the principles and specific issues set out in the final proposals – that is, the same constituents of costs are added to the RAV (ie in the slow pot). We add all costs on a normal accruals basis. This excludes provisions, except for the actual cash utilisation thereof. The definition of normal accruals will be set out in the Reporting Instructions, prepared and amended in accordance with the licence conditions.

Definition of totex

1.3. The annual net additions to RAV will be calculated as a percentage of the totex. Totex consists of all the expenditure relating to a licensees regulated activities with the exception of:

- all costs relating to de minimis activities
- all costs relating to excluded services activities
- pension deficit repair payments relating to the established deficit (see chapter 6) and for the avoidance of doubt, all unfunded early retirement deficiency costs (ERDC) post 1 April 2004
- costs associated with specific incentive schemes (eg TIRG see below)
- all statutory or regulatory depreciation and amortisation
- profit margins from related parties (except where permitted as defined below)
- all additional costs relating to rebranding a company's assets or vehicles following a name or logo change
- fines and penalties incurred by the network company (including all tax penalties, fines and interest)
- compensation payments made in relation to standards of performance
- traffic management costs (including any associated fines or penalties)
- bad debt costs and receipts (subject to an ex post adjustment to allowed revenues)

- any asset revaluation amounts
- costs related to the SF6 incentive
- reversing, where appropriate, any cost reporting which is not on a normal accruals basis as referred to in paragraph [1.2] above
- costs in relation to pass-through items, including business rates (except for business rates on non-operational buildings), and Ofgem licence fees
- interest, other financing and tax costs[36] (except for business rates on non-operational buildings and stamp duty land tax)

1.4. In addition, the incentive payment given under the IQI sharing mechanism where licensees have spent less than their allowance is included in totex.

1.5. For avoidance of doubt, in each case normal ongoing pension service costs (which include pension scheme administration costs and PPF levies) will follow employment costs in each activity to RAV. As with all categories of costs (and their component activities) are intended to be mutually exclusive.

1.6. Costs added to RAV are all intended to refer to costs incurred by the licensee or a related party of the licensee undertaking regulated business activities where those costs are recharged to the licensee, but do not include any internal profit margins of the licensee or related party margins, except where permitted. The treatment of related party margins is set out in paragraphs [1.12] to [1.22] below.

1.7. Costs that are eligible for logging up or reopener mechanisms will follow the totex treatment as set out above. However, there will also be a separate table in the Reporting Instructions so that the value of these items are separately recorded to facilitate any adjustment to revenue as part of the review of logged up costs or any reopeners that have been triggered.

Deductions from RAV

1.8. The following items are not included in the costs added to the RAV but are netted off additions to the relevant cost categories in carrying out the RAV roll forward calculation:

- cash proceeds of sale (or market value of intra-group transfer) of operational assets – by netting off the relevant cost category
- cash proceeds of sale of assets as scrap – by netting off the relevant cost category
- amounts recovered from third parties in respect of damage to the network – by netting off the relevant cost category

[36] Tax costs include corporation tax, capital gains tax, payroll taxes, recoverable valued added tax and network rates

Spend not included as RAV additions

1.9. For the avoidance of doubt expenditure relating to the following areas is not added to RAV:

- LNG storage
- Metering

Other RAV requirements

Efficient costs

1.10. Ofgem reserves the option to disallow costs from the RAV for any of these categories if they do not relate to the regulated business or are demonstrably inefficient or wasteful. We will specifically review all costs in relation to restructuring of a company's business or operations in relation to corporate transactions, including the associated redundancy costs to satisfy ourselves that these costs are efficient and will deliver future savings for the benefit of the consumer.

Restated costs

1.11. For all costs, in whatever category, activity or exclusion, where a company makes any restatement of costs, we will apply these in to the year in which they were originally incurred rather than in the year of the restatement.

Related party costs

1.12. Costs are only included to the extent they represent the cost of services required by the licensees business. Costs for services recharged to the licensee by a related party[37] will only be admissible if the licensee would otherwise have needed to carry out the service itself or procure it from a third party. We will expect these services and associated costs to be itemised and justified. Such costs are only included to the extent that they satisfy the criteria regarding the prohibition on cross-subsidy in the relevant standard or standard special licence condition. Where licensees already hold derogations to cover the charging and reporting of specified shared services between two or more licensees under common ownership, then the derogations have preference over these requirements.

1.13. All companies and related parties charging the licensee should be able to demonstrate they have a robust and transparent framework governing the attribution, allocation and inter-business recharging of revenues, expenses, assets and liabilities. There should be documented procedures to demonstrate

[37] A related party is a term used to cover both Affiliate and Related Undertakings as defined in Standard Licence Condition 1 for electricity transmission and standard special licence condition for gas transportation

compliance with EU Procurement directives and implementing national legislation where these apply.

1.14. We would expect the network company to be able to justify the charge by reference to external benchmarking, or by reference to market-related testing, or tendering. We would expect related parties to be able to support their charges by either service level agreements or contracts; and that such contracts would be finalised on a timely basis and not remain in draft for an unreasonable period[38].

1.15. The attribution of costs relating to shared services must be on a demonstrably objective basis, not unduly benefiting the regulated company or any other company or organisation and be based on the levels of service or activity consumed by each entity. We expect licensees to document the basis on which they approve these at board level and provide evidence of this together with details of how the continuing assessment and challenge, annually takes place.

1.16. The basis should be consistent from year to year and where there are changes the licensee should both document and justify them.

1.17. The method used to attribute costs from the related party to the licensee and to activities should be transparent and the revenues, costs, profits, assets and liabilities separately distinguishable from each other.

Related party margins

1.18. We will exclude related party profit margins from costs added to RAV unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers. For this purpose, an entity we consider a related party if it is an Affiliate or Related Undertaking or if that entity and the network company have any other form of common ownership. A key indicator of entities being in common ownership is that they are affiliates of the Ultimate Controller (or controllers where there is more than one). We are consulting on the treatment of margins for captive insurance entities and will deal with this when the policy is confirmed.

1.19. When an entity ceases to be a related party, for example on a change in ultimate controller, then from the time it ceases to be a related party its margins will be allowable, if it meets the following requirement. There must be an unambiguous demonstration that its charges to the distribution business (in the original or amended contract) remain competitive and are in line with market rates, or the contract was re-tendered and that there was more than one bidder.

1.20. Whilst not precluding other demonstrations of competiveness, we consider that an open competitive tender is likely to be the clearest indicator. In the

[38] Whilst not defined, we expect licensees to demonstrate to our satisfaction why a period in excess of 6 months was reasonable

absence of an open competitive tendering exercise, we will seek strong evidence that the terms of any contract are competitive.

1.21. Irrespective of whether the network company demonstrates competition and they no longer disallow margins, the licensee must arrange to comply with the requirements of the relevant standard or standard special licence condition (on the maintenance and provision of information). It must continue to report the former related party's costs and margins as if it were still a related party for the remainder of the price control period. The data is required in order for us to be able to monitor performance against the price control and carry out cost analysis to inform future reviews.

1.22. Where a principal related party resource provider[39] ceases to be a related party during a price control period, for example on the restructuring of a group, we shall continue to treat them as a related party until the end of that price control period and we will continue to disallow the margins charged. At the next price control period the margins will be allowed provided that there is unambiguous demonstration that the charges to the distribution business (in the original or amended contract) remain competitive and are in line with market rates, or that the contract is re-tendered and that there is more than one bidder.

RAV calculation 2011-12 and 2012-13

1.23. The RAV additions used in determining prices for RIIO-T1 and RIIO-GD1 will rely on company forecasts for 2011-12 and 2012-13. The companies provide this in their business plan forecasts.

1.24. In the event that actual RAV additions for these years turn out to be materially different to the estimates, we will restate the RAV and alter revenues two years after the close of the TPCR4 roll over or GDPCR1. We will claw back the benefits of any under-spend in 2011-12 and 2012-13 relative to the estimates used in the final proposals at this time and alter the revenue accordingly.

1.25. An assessment of the efficiency of any capex spend will be carried out as part of the Price Control review work. We will make adjustments relating to TPCR4 and GDPCR1 at that time, if appropriate.

1.26. We shall also restate the RAV to take into account any over or under spends relating to the previous price control periods for both the GDNs and for the TOs where RAV additions have to date been based on forecast expenditure. We shall adjust revenue as necessary to reflect any over or under funding that may have occurred.

[39] A principal related party resource provider is one that has a contract to operate or manage a substantial part of a licensee's day-to-day operations, and that the licensee entered into the contract before or as part of the arrangements for a change in ultimate controller, or controllers, where there is more than one

Gas Distribution specific RAV items

1.27. This section details issues specific to Gas Distribution licensees.

1.28. We are consulting within the policy document (see RIIO-GD1 Outputs and incentives document) on the future approach to the Fuel Poor Network Extensions scheme. The additions to RAV under the existing arrangement are logged up and we deal with these at the end of the price control. In certain cases, an additional amount is given in addition to costs as an incentive addition to RAV. This incentive amount falls out of RAV after five years.

1.29. We are consulting within the policy section on the future of Xoserve. We will deal with the costs relating to Xoserve in a consistent manner with the totex approach. We will detail this when the policy approach is confirmed.

Transmission specific RAV items

1.30. Within transmission, there are various schemes that deal with the funding of costs that are considered uncertain at the time of the last price control. Where specific scheme funding is applicable (eg Transmission Incentive for Renewable Generation (TIRG) projects) we will continue to deal with these in accordance with the conditions under which they were established. Where we revise or introduce new incentives we expect these to be on a totex basis so that existing incentives will be appropriate. If we consider that there are good reasons why applying the totex approach to incentive funding will cause unintended consequences we will either not use this approach or will restate the percentage allocation to totex.

1.31. Transmission Incentive for Renewable Generation (TIRG) covers a finite number of schemes for which licensees report the expenditure separately, where the scheme allows efficiently incurred expenditure into RAV five years after completion of construction, and the agreed outputs delivered. In the interim, we consider the costs to be in a shadow RAV. We will add the capex under this scheme to RAV as already established (subject to the efficiency review).

1.32. TO Incentive expenditure is a scheme that provides funding for agreed major schemes between price controls. In RIIO-T1, we will add the efficiently incurred capex for these schemes to RAV on a totex basis.

1.33. Regulatory work in progress (WIP) relates to spend in NGET only, where the company incurs revenue driver expenditure but the project is incomplete and the outputs are yet to be delivered. To avoid penalising non-delivery of outputs, we match the addition of the capex to RAV upon delivery of the outputs and this we will make this on a totex basis.

1.34. We treat some costs, which may be uncertain in nature and size at the price review, as logged up for RAV purposes (subject to agreement). Network companies report these costs separately and we will review them prior to the next price control period for efficiency. In the interim, we will add the assessed values on a totex basis to RAV, two years in arrears on an NPV neutral basis.

1.35. Critical national infrastructure expenditure is added to RAV for NGG and NGET on completion of the work subject to the agreement of DECC. This will be on a totex basis. For SHETL and SPTL we will add this expenditure to RAV on a totex basis in the year of expenditure subject to compliance with the terms of this scheme.

1.36. Revenue drivers refer to a scheme for electricity TO load related capex. For SHETL and SPTL we treat the expenditure under these schemes as an immediate addition to RAV with a full efficiency review at the end of the price control. The allowed revenue of the licensees is uplifted each year by the additional return and depreciation allowable. In these circumstances, no further adjustment to RAV should be necessary.

1.37. The scale of generation capacity added or removed complicates revenue drivers for NGET. To date the additions to RAV have therefore been determined at the end of the price control period. The treatment of revenue drivers is discussed within the policy document and the RAV treatment will be clarified according to the outcome of that review.

1.38. The gas capacity investment incentive scheme relates only to NGG. Under this scheme, RAV additions occur relative to the date of release of capacity. Where projects already exist under this scheme, we will deal with them in accordance with the existing RAV arrangements. We will treat future schemes in RIIO-T1 on a totex basis for RAV additions.

SO RAV

1.39. The two system operators (NGET and NGG) have their own RAV addition rules. We will use a totex approach for RIIO-T1 calculating the percentage allocation to RAV on the same basis as for the TO licensees.

1.40. The existing SO gas revenue driver incentive sees capital investment taking place for Entry and Exit revenue drivers, remuneration initially being funded through the SO price control, and with the capex then being transferred to the TO RAV, with funding being then made in the TO price control. This approach will continue for TPCR4 schemes.

1.41. Notwithstanding the above, there is a disallowance from the RAV for items of expenditure that are demonstrably inefficient or wasteful.