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Transmission Price Control Review: Updated Proposals

Document type: Consultation

Ref: 170/06

Date of publication: 25 September 2006

Deadline for response: 24 October 2006 to tpcr.responses@ofgem.gov.uk

Target audience: Transmission licensees, Gas transporters, users of the transmission networks, consumer groups and other interested parties

Overview:

This document sets out our updated proposals for the transmission price controls that will apply from 1 April 2007. It sets out our further thinking on the allowances that we intend to provide to fund efficient expenditure of the transmission licensees over the period 2007 - 2012.

Our updated proposals are based on extensive consideration of historic and forecast cost assessments of the transmission companies, which, together with our initial financial assumptions, allow us to calculate revenue allowances for each company. We have also set out further thoughts and more detailed proposals in relation to price control and incentive design.

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Context

This document sets out our updated proposals for the electricity and gas transmission licensees' price controls for the five years from 1st April 2007.

Since the existing price controls were set, there have been a number of changes in the external environment, such as changing patterns of gas supply, changes in the electricity generation mix, as well as changes in wider energy policy, especially in relation to the environment. In our initial proposals document in June, we set out our thoughts on how the price controls could be designed to meet these objectives and challenges. We also set out our initial views on the allowances for capital and operating expenditure which would be required to allow the companies to operate their networks efficiently.

Since June, we have worked with the industry to develop an updated suite of proposals which address the issues of replacing and refurbishing aging network assets, uncertain demand for network capacity, financial issues such as the rate of return, the depreciation cliff edge, pensions and tax, as well as incentive design issues in electricity and gas.

Associated Documents

- TPCR 2007-2012 Updated Proposals - Appendices, September 2006 (Ref No. 170/06a)
- TPCR 2007-2012 Initial Proposals, June 2006 (Ref No. 104/06)
- TPCR 2007-2012 Initial Proposals, Main Appendices, June 2006 (Ref No. 104b/06)
- TPCR 2007-2012 Initial Proposals, Appendix: Offtake Revenue Drivers and Baselines for NGG NTS , June 2006 (Ref No. 104c/06)
- TPCR 2007-2012 Initial Proposals, Draft Enduring Offtake Impact Assessment, June 2006 (Ref No. 104d/06)
- Access Reform in Electricity Transmission: Working group report and next steps, May 2006 (Ref No. 83/06a)
- A framework for considering reforms to how generators gain access to the GB electricity transmission system: A report by the Access Reform Options Development Group April 2006, May 2006 (Ref No. 83/06b)
- TPCR 2007-2012: Third Consultation, March 2006 (Ref No. 51/06)
- TPCR 2007-2012: Third Consultation, Supplementary Appendices, March 2006 (Ref No. 51/06b)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)

Copies of the consultant's reports and responses to the Ofgem consultation documents can also be found on the Ofgem website (www.ofgem.gov.uk).

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Summary

The Transmission Price Control Review (TPCR) will set revised price controls for the electricity and gas transmission licensees to apply from 1 April 2007. It will set the amount of revenue that each licensee will be allowed to recover from its customers. This is the first time that we have set price controls for all of the four transmission licensees at one time.

This document provides an update to the initial proposals which we published in June. It sets out revised revenue allowances which reflect our current assessment of historic and forecast data as provided to Ofgem by the licensees. The key themes of our proposals are:

- ***Investment to support new sources of gas and electricity*** - the transmission networks are facing a period of change driven by a number of external factors, such as the increasing reliance on gas imports and the growth in renewable generation. These changes will require significant investment in new network infrastructure. We are also taking steps to improve the ease of access to networks, especially for renewable energy.

- ***Investment to support high levels of network performance*** - while the networks consistently perform at a very high level of reliability, there is a need to replace network assets so that high levels of reliability can be maintained. This is particularly the case for the electricity transmission networks.

- ***Flexibility to respond to new developments*** - much of the new investment will be driven by the needs of network users. The outcome of the Government's energy review is also likely to have an impact. We are establishing a regulatory regime which is flexible to a changing environment and can respond effectively to events, but is sufficiently robust to remain in place for a five year period.

- ***The right allocation of risk*** - in delivering funding for investment in the transmission networks we need to ensure that there should be an appropriate balance of risk between the transmission companies, network users and consumers. Our proposals seek to allocate the risks so that they can be managed effectively, and seek to provide rewards for the companies commensurate with the risks they face.

- ***A continuing focus on efficiency*** - in delivering investment and operating their networks we expect the licensees to operate in an efficient and effective manner, thereby ensuring that consumers continue to benefit from a high standard of performance at an efficient cost.

The main features of our updated proposals are:

- We have adjusted our allowances for capital investment from £4.25 billion (in 2004/5 prices) over the next five years to £4.5 billion. This represents an increase of 76 per cent over the allowances set during the last major price control reviews and a 6 per cent increase over our initial proposals. It also includes our

current view of the investment required to maintain the existing network, and undertake the investment required to connect new sources of gas and electricity;

- We have completed the work on the form of mechanisms to adjust the revenue allowances automatically, either up or down, in response to the actual needs of users of the system. These will provide for a closer alignment between revenue allowances and the cost of investment to meet the changing needs for capacity;

- We have also adjusted our proposed allowances for operating costs. These allowances ensure the benefits of efficiency savings achieved by the companies since the last review are passed through to consumers and they assume further improvements in efficiency in the next price control period;

- We have revised our allowances for pension costs and, where relevant, have made adjustments to regulatory depreciation to smooth the impact of the ending of depreciation on pre-vesting assets; and

- The initial proposals allowed a real post tax return of 4.2 per cent on the regulated asset value of the companies. We have not changed that assumption at this stage and will make our final decision on the appropriate allowed return in our final proposals.

- To encourage more sustainable network development we are considering a new incentive to target the reduction of leakage of sulphur hexafluoride, a very potent greenhouse gas

- Because of the limited output performance measures in transmission, we are considering measures to safeguard consumers in the event that companies' investments fall significantly below their allowances.

Meeting the challenges that the sector faces will involve increased costs, especially for new investment. There are also outside pressures on costs, particularly in the case of pensions, business rates and taxation. If we assume fixed revenue streams in real terms for the next five years, our initial proposals provide a total fixed revenue allowance for transmission owner activities across the four transmission licensees of £1,754 million per year. This will represent an increase of 6 per cent against the current allowances for 2006/07. The eventual change in revenues over the five-year period will also depend on the impact of the revenue drivers which will fund any necessary additional expenditure. However, transmission charges currently only represent around 3 per cent of a domestic consumer's bill so the impact on prices should be minimal.

Next steps

We will continue with work to refine the proposals between now and publication of final proposals in December. We will also start the consultation process on the licence modification to give effect to our proposals. Informal consultations will be published in mid October 2006 and early January 2007, with the final proposals consultation taking place in February 2007. The new licence conditions, if accepted by the licensees, will take effect from 1st April 2007.

1. Introduction

Chapter Summary

This chapter sets out the background to the updated proposals and summarises the main developments since publication of our initial proposals in June 2006. It also explains how this document is structured.

Questions

There are no questions in this chapter.

Background

1.1. The TPCR will establish price controls for each of the transmission licensees in their role as transmission owners (TOs) to apply from April 2007 onwards. This will comprise a set of fixed revenue allowances for the period until March 2012 supplemented by additional mechanisms (revenue drivers) which will allow revenues to be adjusted automatically as the requirements of network users become known.

1.2. In June we published our initial proposals for these allowances. We have now reached a stage in the process where we can update our initial view on these allowances in the light of further analysis and responses to the June consultation. We are seeking wider views on these findings ahead of the final proposals in December.

1.3. The allowances are built up from allowances for operating costs, depreciation and return on the Regulatory Asset Value (RAV). The RAV takes into account our assessment of past capital expenditure and our proposed allowances for capital expenditure over the course of the next price control period. In setting these allowances we have considered whether any deductions should be made for inefficient expenditure during the current price control period.

Structure of this document

1.4. The focus of this document is our updated assessment of the levels of costs for each of the companies that would be consistent with the efficient operation of their networks. The structure of the document is as follows:

- Chapter 2 sets out an overview of the approach that we have taken in developing the revenue allowances presented in this document;
- Chapters 3 to 6 set out our updated findings for each of the four transmission companies in turn;

- Chapter 7 discusses a number of policy issues considered in establishing our proposed allowances for capital expenditure and operating costs, as well as the general framework of price control incentives. These are largely common to all companies;

- Chapter 8 discusses financial issues, including the important issue of cost of capital;

- Chapters 9 and 10 set out our proposed package of incentives and adjustment mechanisms for electricity and gas respectively. This covers the issue of how revenues should flex as demands for network capacity change over time (particularly, given the level of uncertainty regarding network requirements during the next five years); and

- Chapter 11 sets out how we have considered the issue of sustainable development in the context of the TPCR, and explains how these considerations are reflected in developing our updated proposals.

1.5. There are a number of supplementary appendices which provide more technical detail on our updated proposals. In addition, Appendix 3 sets out how we have responded to the many individual points made by respondents to the Initial Proposals and Appendix 4 provides a glossary of terms relevant to this document.

1.6. References to Ofgem in this document and the appendices should be interpreted as including references to the Gas and Electricity Markets Authority (the Authority) as appropriate.

System operator incentives

The June Initial Proposals set out our high level thoughts on how we propose to set price controls for NGG and NGET as system operators for the gas and electricity transmission systems. We are publishing a consultation document separately, which will set out detailed thinking on allowances and incentives for internal and external SO costs.

2. Overview of the updated proposals

Chapter Summary

This chapter provides an overview of the approach that we have taken in developing the revenue allowances for each of the transmission licensees. It also outlines the main features of our proposals, together with the potential impact of these proposals on consumers.

Questions

There are no questions in this chapter.

Introduction

2.1. In establishing revenue allowances for each transmission licensee, it is necessary for us to form a view on the level of costs that we would expect an efficiently run business to incur during the price control period. Our view has been informed by an analysis of the cost submissions provided by each licensee, but also reflects a number of assumptions on pension costs, tax, depreciation and the allowed rate of return. We have also undertaken an assessment of whether historic capital expenditure has been efficiently incurred. These views have been informed by work undertaken by external consultants for Ofgem. We intend to publish the reports of these consultants in due course.

2.2. Our assessment of companies' costs and other price control assumptions is ongoing in a number of areas and we intend to refine our proposals in the light of this further work. In doing so, we expect that the proposed revenue allowances will change, either up or down, in light of our revised conclusions. These updated proposals represent the final iteration in the consultation process before publication of our final proposals in December.

2.3. Our approach to cost assessment and a summary of our proposed revenue allowances are set out in this chapter. Chapters 3 to 6 describe the application of these approaches to each of the licensees in more detail and set out company-specific proposals for the revenue allowances.

Summary of the proposed revenue allowances

2.4. Our updated calculations of revenue allowances for the transmission companies are set out in table 2.1[1]. The revenue allowances are not profiled over the five years

[1] In the interest of clarity figures have been rounded to the nearest million pounds, where appropriate.

to match the profile of costs but are set in terms of an allowance for the initial year which is then left unchanged in real terms over the 5 year period (i.e. in the RPI-X formulation, X is assumed to be zero).

Table 2.1 Revenue allowances 2007/08 to 2011/12

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)	Change from 2006/07 allowance
2006/07 allowance	442	1005	160	51	1657	-
2007/08 allowance						
- Initial Proposals	471	940	136	49	1595	-4%
- September Update	474	1081	150	49	1754	6%
Change from Initial Proposal	***3***	***141***	***14.4***	***0.4***	***159***	***-***

2.5. Overall, our initial proposals represent an overall increase in annual transmission revenues of around 6 per cent relative to 2006/07 allowances. It should be noted that these revenue allowances will vary to a degree depending on actual demand for capacity relative to the demand for capacity assumed in setting the allowances - through the operation of the adjustment mechanisms.

Capital Expenditure

2.6. In setting revised price controls, it is necessary for us to form a view on the likely level of "baseline capital expenditure" required for the coming five year period and the efficiency of past capital expenditure. Our view has been informed by a detailed efficiency and performance review of each licensee's capital expenditure programme and associated asset management practices. Our analysis has included:

- An efficiency review of historical capital expenditure up to 2004/05, which has now been extended to include an assessment expenditure in 2005/06; and
- An assessment of forecast capital expenditure for 2005/06 to 2011/12.

2.7. The outcome of our updated assessment of forecast capex over the course of the consultation to date is summarised in table 2.2 below. This table sets out the following capex movements:

- **Licensee original forecast** - this is the initial bid submitted in December 2005;
- **Licensee adjusted forecast** - this is an alternative representation of December 2005 forecasts after adjustments were made by Ofgem to remove load related expenditure covered by automatic revenue drivers; and
- **Initial Proposals (June 2006) and Updated Proposals (September 2006)** - These reflect Ofgem's view on the appropriate allowances. It is important to note that these figures may have changed to accommodate new capital expenditure

information provided by the companies and are not directly comparable with the original and adjusted forecasts.

Table 2.2 Capex allowances 2007/08 to 2011/12 (5 year totals)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)	change from adjusted forecast
Capex allowance (last 5 year price control)	889	1453	152	71	2565	-
Licensee original forecast	1346	3816	717	834	6713	-
Licensee adjusted forecast	938	3660	674	182	5455	-
Initial proposals (IP)	737	2790	555	164	4246	-22%
September Update	**797**	**2953**	**576**	**178**	**4503**	**-17%**
Change from IP	60	163	21	13	257	-
September Update – change from last price control	**-92** (-10%)	**1500** (+103%)	**423** (+278%)	**107** (+151%)	**1938** (+76%)	-

1. The adjusted forecast includes only cost items that fit within our definition of baseline capex

2.8. In the light of significant uncertainty regarding the level and timing of investment necessary to accommodate new loads, we have proposed adjustment mechanisms which flex revenues automatically as the transmission licensees respond to the needs of users. For the purposes of determining the fixed revenue allowances for each licensee, we have therefore excluded those uncertain user-driven investments. The remaining investment proposals, other than the projects already provided with funding under the Transmission Investment for Renewable Generation (TIRG) project, have been considered as part of our cost assessment work.

2.9. Our analysis of the companies' investment proposals has identified scope for significant cost reductions, particularly in the area of non-load related expenditure for the coming five year period. Our view is that the fixed revenue allowances should provide appropriate funding for some £4.5 billion of capital expenditure over the next five years.

Operating expenditure

2.10. Our view on the appropriate allowances for operating expenditure has been informed by a detailed assessment of the efficiency of the controllable operating expenditure for each licensee. This assessment has three elements:

- We have 'normalised' 2004/05 (our base year) operating costs by removing, amongst other things, non-recurring and atypical cost items. We have also made adjustments for different accounting treatments of certain types of expenditure;
- We have considered the scope for efficiency improvements during the next price control period against the normalised level of base year controllable costs, and
- We have considered upward cost pressures for some elements of operating cost and the need for additional allowances in respect of new categories of cost.

2.11. Our analysis of the companies' forecasts of controllable operating costs has identified scope for savings in a number of areas. Our updated view is to allow funding commensurate with £2.13 billion of total operating expenditure over the next five years. This represents an increase of around £61 million relative to our initial proposals but a reduction of £193 million relative to the companies' forecasts.

Table 2.3 Total opex allowances 2007/08 to 2011/12 (5 year totals)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)	Change from Company Forecast
Company forecast	717	1402	157	52	2327	
Initial Proposals	675	1216	137	46	2074	-11%
September Update	686	1260	141	46	2134	-8%
Change from Initial Proposal	***12***	***44***	***4***	***0***	***61***	

Pension, depreciation and tax costs

2.12. In setting allowances for pension costs we have developed the principles applied in the context of the recent electricity distribution price control review (DPCR4). In our updated proposals we have modified our approach to allow for recovery of 70 per cent of the costs related to unfunded ERDCs arising prior to April 2004. We have also made adjustments to allowances in respect of future service to reflect the latest actuarial estimates of required contribution rates.

Table 2.4 Pension costs 2007/08 to 2011/12 (5 year totals)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)
Initial Proposals	131	181	6	4	322
September Update	187	247	6	8	448
Change from Initial Proposal	***56***	***66***	***0***	***4***	***126***
Percentage change	**43%**	**37%**	**3%**	**103%**	**39%**

2.13. The main adjustment to depreciation since Initial Proposals relates to the position which arises when pre-vesting assets become fully depreciated within the price control period. In line with the approach we adopted at DPCR4, we propose to bring forward depreciation allowances for post vesting assets, in order to smooth the companies' income streams.

Table 2.5 Depreciation costs 2007/08 to 2011/12 (5 year totals)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)
Initial Proposals	520	1546	254	90	2410
September Update	529	2002	320	91	2942
Change from Initial Proposal	***9***	***455***	***66***	***1***	***532***
Percentage change	**2%**	**29%**	**26%**	**1%**	**22%**

2.14. Our allowances for tax have also increased since Initial Proposals, largely due to the increase in depreciation allowances for the electricity transmission companies provided to the companies as described above. The tax allowance for NGG has been reduced significantly due to the re-gearing of the balance sheet as part of our financial modelling and changes in the starting point for the capital allowances.

Table 2.6 Tax costs 2007/08 to 2011/12 (5 year totals)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)
Initial Proposals	282	363	68	26	738
September Update	190	547	76	24	838
Change from Initial Proposal	***-92***	***185***	***9***	***-2***	***100***
Percentage change	**-33%**	**51%**	**13%**	**-7%**	**14%**

Impact on consumers

Electricity transmission charges account for around 3 per cent of domestic consumers' final bills, and gas transmission charges for around 2 per cent. We therefore expect the impact of our proposals on domestic energy bills to be small. However, we recognise that some larger consumers may be exposed to a greater proportion of transmission charges and the impact may be more significant.

3. National Grid Electricity Transmission (NGET)

Chapter Summary

This chapter sets out our updated proposals for the revenue allowances of NGET for the period 2007 to 2012. The chapter quantifies the changes that we have made to our initial proposals and sets out the reasons for those changes in the light of consultation responses, further analysis and discussions with stakeholders.

Questions

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

Summary

3.1. NGET owns and maintains the network of electricity transmission assets in England & Wales and is also the System Operator (SO) of the GB electricity transmission system. This chapter sets out our updated proposals for NGET in relation to its role as transmission owner (TO). It does not set out any SO costs or allowances, which will be covered in a separate consultation document to be published shortly.

3.2. Table 3.1 below summarises our updated proposals for NGET (all prices are 2004/05, £m). We have continued to profile revenues to hold them constant in real terms from 2007/08 onwards (i.e. X=0):

Table 3.1 NGET updated proposals summary

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		327	338	353	384	403
- load (base case)		259	167	210	261	252
Operating costs						
- Controllable		158	152	147	148	149
- Non-controllable		102	101	101	101	101
Depreciation		383	398	411	397	413
Pensions		38	37	37	37	36
Current Tax		118	116	113	105	96
Revenue allowances	1,005	1,081	1,081	1,081	1,081	1,081

3.3. There are five main areas where we have made changes to our initial proposals. They are summarised below (expressed as a total change relative to our initial

proposals, over the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of £163 million resulting from changes to refurbishment costs, overhead line and switchgear costs, input costs, plus a delay in applying procurement efficiency savings until 2007/08;
- **Operating costs:** an increase of around £45 million arising from changes to the treatment of high engineering costs, efficiency savings, upward and downward cost drivers and other miscellaneous costs;
- **Depreciation:** we have brought forward revenues of around £420 million to address the shortfall in revenues caused by the depreciation "cliff edge" (the ending of depreciation on pre-vesting assets from 2010/11 onwards). Further details are given in chapter 8;
- **Pensions:** an increase of £66 million, primarily due to allowing 70 per cent of the cost of deficit recovery relating to unfunded ERDCs to be recovered from customers; and
- **Tax:** an increase of £184 million, reflecting the adjustments set out above; principally the increase in depreciation allowance.

Capital expenditure (Capex)

Historical capital expenditure (2000/01 to 2004/05)

3.4. Our initial proposals noted that NGET had over-spent its allowances of £1,601 million for capital expenditure by 4 per cent, after adjusting actual capex to exclude non-operational capex according to the definition under the price control.

3.5. Since publishing initial proposals we have been made aware by NGET of a case of employee fraud affecting levels of past capital expenditure. We consider that the costs associated with this fraud should not be borne by consumers and have consequently removed £2.5 million from historical expenditure. We have also made adjustments to allocations of non-operational capex, and to address a small price base error, which also reduces historical capital expenditure by a further £13.6 million. Each of these adjustments reduces the opening value of the RAV for 2007/08, which is discussed in paragraphs 3.14 to 3.16.

Forecast capital expenditure (2005/06 to 2011/12)

3.6. Our approach to our assessment of forecast expenditure has been to evaluate the total expenditure needed for the seven year period 2005/06 to 2011/12, and established an assumed profile of annual expenditure for that period consistent with the total capex requirement.

2005/06 to 2006/07

3.7. In setting the last five year price control, we provided a capital expenditure allowance of £251 million in respect of 2005/06[2]. Since the initial proposals, we have assessed the actual costs of £464 million incurred by NGET in 2005/06.

3.8. While we consider that a lower level of expenditure in 2005/06 might be more consistent with our proposed seven year total of forecast expenditure, we have found no evidence to suggest that the additional expenditure incurred by NGET is inefficient. We consider that the additional expenditure reflects a different view on the timing of capital expenditure over the seven year period.

3.9. For the purposes of rolling forward the RAV, we propose to reflect the actual level of expenditure incurred by NGET in 2005/06, although we have adjusted our profile of capital expenditure for 2006/07 to 2011/12 downwards consistent with different assumptions in respect of the timing of expenditure. We have also re-profiled our allowances to more closely reflect the shape of NGET's proposed profile of capex for the seven year period. Together, these adjustments have resulted in a scaling back of allowances of £110 million over the period 2007/08-2011/12.

3.10. A summary of our Updated Proposals of capex for the period to 2006/07 is set out in table 3.2 below:

Table 3.2 – NGET updated forecast capital expenditure (2005/06-2006/07)

NGET Bid & Allowances (2005/06 - 2006/07)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure	450	370	338	426	88
Non Load Related Expenditure	601	580	424	547	123
Total	**1052**	**950**	**762**	**974**	**211**

3.11. In our Initial Proposals, we also identified a 5 per cent capital expenditure procurement efficiency saving to commence from 2005/06. Several respondents to the Initial Proposals commented that there would be a lead time for implementation of changes necessary to achieve the procurement savings that we had proposed. We have reviewed further relevant evidence and we have decided to delay the application of this procurement saving until 2007/08 rather than 2005/06.

[2] In the one year extension of NGET's price control we reflected £364 million of expenditure in relation to 2005/06.

2007/08 to 2011/12

3.12. Our initial proposals provided for an allowance for capital expenditure of £2,790 million over the five year price control period commencing on 1 April 2007. We have now updated this allowance to £2,953 million, around £707 million below the licensee's adjusted forecast, as set out in table 3.3 below:

Table 3.3 – NGET updated forecast capital expenditure (2007/08-2011/12)

NGET Bid & Allowances (2007/08 - 2011/12)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure					
Sole-use & infrastructure	1332	1161	1077	1204	127
Input cost increase	25	25	0	38	38
Procurement efficiency	0	0	-53	-57	-5
Adjustment for 05/06 actual	0	0	0	-36	-36
Sub total	**1356**	**1186**	**1024**	**1149**	**125**
Non Load Related Expenditure					
Transformers & reactors	226	226	161	161	0
Switchgear	556	556	405	441	36
Overhead Lines	615	615	409	459	50
Underground Cables	515	515	471	437	-34
Other non-load related	433	447	413	409	-4
Input cost increase	115	115	0	64	64
Procurement efficiency	0	0	-92	-91	1
Adjustment for 05/06 actual	0	0	0	-75	-75
Sub total	**2460**	**2474**	**1766**	**1805**	**39**
Total	**3816**	**3660**	**2790**	**2953**	**163**

3.13. The major changes set out in table 3.3 above are:

- **Load related - Baseline infrastructure**: We have amended our view slightly on the appropriate baseline assumptions for generation and demand growth (£22 million) and increased provisions for general infrastructure (£105 million).
- **Non load related - Switchgear**: We have updated our estimated volume and unit costs of switchgear replacement based on new information from NGET. We have also made a minor arithmetic correction (+£36 million).
- **Non load related - Overhead lines**: We have updated our estimated volume of overhead line replacement and also updated our assumed unit cost in the light of new information from NGET (+£50 million).
- **Non load related - Underground cables**: We have reduced the assumed volume of cabling installed in tunnels reflecting our estimated cable replacement profile (-£34 million).

Other changes have been made to factors which apply across both load related and non load related expenditure. These include:

- **Input cost increases**: We have made a provisional allowance for higher input costs for both load and non-load related expenditure, based on cost indexation evidence provided by NGET (+£102 million). We will give this further examination ahead of our Final Proposals.

- **Adjustment to 2005/06 actual**: The information originally provided by the companies was in the form of forecast capital expenditure from 1 April 2005 to 31 March 2012. Since publishing our initial proposals we have reviewed the data on actual expenditure in 2005/06. Because the level of actual expenditure is higher than we assumed in setting our initial proposals, we have scaled back allowances in later years accordingly (-£110 million over the 5 year period from 1 April 2007).

Regulatory Asset Value

3.14. Table 3.4 below sets out how we have reached our updated proposals for the opening RAV on 1 April 2007. Our proposed opening RAV for 1 April 2007 reflects the depreciated value of actual expenditure incurred by NGET in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07.

Table 3.4 NGET Regulatory Asset Value 2000/01 to 2006/07

NGET	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Opening value bf	5,113	5,019	5,047	5,046	5,025	5,046	5,289
Depreciation	-317	-320	-329	-337	-345	-358	-370
RAV additions	342	349	329	316	320	464	505
Adjustments	-119	0	0	0	46	137	0
Closing value cf	5,019	5,047	5,046	5,025	5,046	5,289	5,424
Average RAV	5,066	5,033	5,047	5,036	5,036	5,168	5,357

Note:
1) RAV additions includes capitalised pensions; and
2) Adjustments reflect asset disposals, transfers, BETTA related adjustments and TSS expenditure.

3.15. Our Updated Proposals therefore establish an opening RAV in 2007/08 of £5,424 million relative to our initial proposals of £5,199 million. The main factors influencing the movement between our Initial Proposals and these Updated Proposals are:

- The updated allocations of non-operational capex;
- The removal of expenditure relating to the fraud by NGET employees;
- The inclusion of 2005/06 actual costs;
- The delay in applying procurement efficiency savings until 2007/08; and
- The downward adjustment to capital expenditure allowances for 2006/07 onwards described above.

3.16. In addition to the movements set out above we recognise that there are differences between the RAV calculations set out above and those outlined as part of the one year price control extension. A reconciliation of these differences is set out in Appendix 11.

Controllable operating expenditure (Opex)

3.17. In the initial proposals document we proposed an opex allowance of £709 million for NGET for the five year period between 2007/08 and 2011/12, compared with NGET's forecast of £896 million. As set out in table 3.5 below, we propose to increase this by £44.9 million, for the following reasons:

- **Normalisation:** an increase of £28.7 million resulting from inclusion of engineering costs which had previously been excluded as atypical;
- **Efficiency savings:** an increase of £12.7 million from a change in our assumptions on the scope for future efficiency savings on engineering opex, IS costs, insurance and corporate costs;
- **Upward/downward cost drivers:** a reduction of £3.9 million from the removal of a separate allowance for upward/downward cost drivers given that these are now factored into the generality of the opex allowance; and
- **Miscellaneous expenditure:** an increase of £7.4 million.

Table 3.5 – NGET updated opex forecast (5 year totals, £m 2004/5 prices)

	NGET Forecast	Initial Proposals	September Update	September update - change from NGET
NGET Forecast	**896**			
Ofgem Allowance - Initial Proposals		709	709	
Changes for Sept Update				
Normalisation adjustments			29	
Efficiency savings			13	
Cost drivers			-4	
Misc. opex			7	
Total increase from Initial Proposals			***45***	
Total	**896**	**709**	**754**	**-142**

3.18. These adjustments reduce the gap between Ofgem and NGET on the forecast level of costs, but a gap of some £142 million remains.

4. Scottish Hydro-Electric Transmission Limited (SHETL)

Chapter Summary

This chapter sets out our updated proposals for the revenue allowances of SHETL for the period 2007 to 2012. The chapter quantifies the changes that we have made to our initial proposals and sets out the reasons for those changes in the light of consultation responses, further analysis and discussions with stakeholders.

Questions

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

Summary

4.1. SHETL owns and maintains the network of electricity transmission assets in northern Scotland. Table 4.1 below summarises our updated proposals for SHETL (all prices are 2004/05, £m). We have continued to profile revenues to hold them constant in real terms from 2007/08 onwards (i.e. X=0):

Table 4.1 - SHETL updated proposals summary

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		11.0	13.0	14.7	9.9	9.9
- load (base case)		37.0	21.6	16.2	24.8	19.8
Operating costs						
- Controllable		5.9	6.2	5.7	5.5	5.6
- Non-controllable		3.5	3.5	3.5	3.5	3.5
Depreciation		16.6	17.6	18.3	19.0	19.7
Pensions		0.7	0.8	0.8	0.8	0.8
Current Tax		6.0	5.2	4.9	4.4	4.0
Revenue allowances	50.8	49.7	49.5	49.2	49.3	49.3

4.2. There are five main areas where we have made changes to our initial proposals. They are summarised below (expressed as total £m changes relative to our initial proposals, over the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** we are proposing an increase of around £14 million to accommodate updated information on transformer replacement, an additional cost item falling under TSS, and a moderate increase in input costs;

- **Operating costs:** a small increase of £0.4 million to account for real wage growth;
- **Depreciation:** an increase of £1 million as a result of changes to the opening RAV;
- **Pensions:** a small increase of £1 million based on revised ongoing contribution rates and attributable pensionable salaries; and
- **Tax:** a reduction of around £2 million.

Capital expenditure (Capex)

Historic capital expenditure (2000/01 to 2004/05)

4.3. We have identified no adjustment from the initial proposals to SHETL's historical capex.

Forecast capital expenditure (2005/06 to 2011/12)

4.4. Our approach to our assessment of forecast expenditure has been to evaluate the total expenditure needed for the seven year period 2005/06 to 2011/12, and established an assumed profile of annual expenditure for that period consistent with the total capex requirement.

2005/06 to 2006/07

4.5. In setting the 2 year price control extension, we provided a capital expenditure allowance of £24 million in respect of 2005/06. Since the initial proposals, we have assessed the actual costs of £19 million incurred by SHETL in 2005/06.

4.6. Our analysis of the seven year expenditure profile suggests a potentially lower level of expenditure in relation to 2005/06 than actually incurred by SHETL. We believe that this difference can be explained by the assumptions regarding the timing of investment and as such the actual expenditure incurred by SHETL may be consistent with the bringing forward of expenditure that we have identified in relation to later years.

4.7. For the purposes of rolling forward the RAV, we propose to reflect the actual level of expenditure incurred by SHETL in 2005/06, although we have adjusted our proposed profile of capital expenditure for 2006/07 to 2011/12 downwards to reflect the adjusted view on timing of expenditure. This adjustment has resulted in a scaling back of allowances of £2 million over the period 2007/08-2011/12. This calculation has been applied in accordance with the methodology adopted for NGET. This will be subject to review for our Final Proposals.

4.8. A summary of our Updated Proposals of capex for the period to 2006/07 is set out in Table 4.2 below:

Table 4.2 – SHETL updated forecast capital expenditure (2005/06-2006/07)

SHETL Bid & Allowances (2005/06 - 2006/07)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure	25	21	19	21	2
Non Load Related Expenditure	25	25	24	25	2
Total	**50**	**45**	**43**	**47**	**4**

2007/08 to 2011/12

4.9. Our Initial Proposals provided for an allowance for capital expenditure of £164 million over the five year price control period commencing on 1 April 2007. We have now updated this allowance to £178 million, around £4 million below the licensee's adjusted forecast, as set out in Table 4.3 below. However, it should be noted that SHETL has provided additional information on rising input costs which were not reflected in the initial and adjusted bid.

Table 4.3 – SHETL updated forecast capital expenditure (2007/08-2011/12)

SHETL Bid & Allowances (2007/08 - 2011/12)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure					
Sole-use & infrastructure	778	126	113	116	3
Input cost increase	0	0	0	5	5
Adjustment for 05/06 actual	0	0	0	-2	-2
Sub total	**778**	**126**	**113**	**119**	**6**
Non Load Related Expenditure					
Transformers	14	14	9	14	5
Other non-load related	42	42	42	42	0
Input cost increase	0	0	0	3	3
Adjustment for 05/06 actual	0	0	0	0	0
Sub total	**56**	**56**	**51**	**58**	**7**
Total	**834**	**182**	**164**	**178**	**13**

4.10. The major changes set out in Table 4.3 above are:

- **Transformer replacement volume:** increase of £5 million based on updated information from SHETL regarding the need for replacement based on asset condition;

- **Investment to support system operation:** increase of £3 million following further review of information submitted by the licensee and also including the estimated impact of market price movements;

- **Outturn spend above profile:** reduction of £2 million reflecting the inclusion in the RAV from 2007/08 to 2011/12 of outturn expenditure relative to our assumed profile for 2005/06; and

- **Input costs:** increase of £8 million associated with forecasts of future input cost movements.

Regulatory Asset Value

4.11. Table 4.4 below sets out how we have reached our updated proposals for the opening RAV on 1 April 2007. Our proposed opening RAV for 1 April 2007 reflects the depreciated value of actual expenditure incurred by SHETL in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07.

Table 4.4 - SHETL Regulatory Asset Value 1999/00 to 2006/07

SHETL	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Opening value bf	247	253	250	244	238	233	234	276
Depreciation	-13	-13	-14	-14	-14	-14	-16	-16
RAV additions	19	10	7	8	9	14	19	27
Adjustments	0	0	0	0	0	0	38	0
Closing value cf	253	250	244	238	233	234	276	287
Average RAV	250	252	247	241	236	234	255	281

Note:
1) RAV additions includes capitalised pensions; and
2) Adjustments reflect changes in connection change and BETTA related adjustments.

4.12. Our Updated Proposals establishing an opening RAV for 2007/08 of £287 million relative to our initial proposals of £282 million. The main factors influencing the movement between our Initial Proposals and these Updated Proposals are:

- The inclusion of 2005/06 actual costs;
- The delay in applying procurement efficiency savings until 2007/08; and
- The downward adjustment to capital expenditure allowances for 2006/07 onwards described above.

Controllable operating expenditure (Opex)

4.13. In our initial proposals document we set out our five year allowances for operating expenditure of £28.5 million. We propose to increase this by £0.4 million, to £28.9 million, to allow for real wage growth.

Table 4.5 SHETL updated opex forecast (5 year totals, £m 2004/5 prices)

	SHETL Forecast	Initial Proposals	September Update	September update - change from SHETL
SHETL Forecast	33.8			
Ofgem Allowance - Initial Proposals		28.5	28.5	
Changes for Sept Update				
Cost drivers			0.4	
Total increase			***0.4***	
Total	**33.8**	**28.5**	**28.9**	**-4.9**

4.14. These adjustments reduce the gap between Ofgem and SHETL on the forecast level of costs, but a gap of around £4.9 million remains.

5. ScottishPower Transmission Limited (SPTL)

Chapter Summary

This chapter sets out our updated proposals for the revenue allowances of SPTL for the period 2007 to 2012. The chapter quantifies the changes that we have made to our initial proposals and sets out the reasons for those changes in the light of consultation responses, further analysis and discussions with stakeholders.

Questions

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

Summary

5.1. SPTL owns and maintains the network of electricity transmission assets in southern Scotland. Table 5.1 below summarises our updated proposals for SPTL (all prices are 2004/05, £m). We have continued to profile revenue to hold them constant in real terms from 2007/08 onwards (i.e. X=0)

Table 5.1 SPTL updated proposals summary

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		50	57	59	60	61
- load (base case)		68	42	38	84	57
Operating costs						
- Controllable		16	15	16	16	16
- Non-controllable		13	13	13	13	13
Depreciation		63	66	68	58	65
Pensions						
- allocated to opex		0	0	0	0	0
Current Tax		18	17	16	14	12
Revenue allowances	160	150	150	150	150	150

5.2. There are four main areas where we have made changes to our initial proposals. They are summarised below (expressed as total £m changes relative to our Initial Proposals, over the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of around £21 million based on revised information on overhead line replacement, switchgear replacement, increased reinforcement to accommodate additional demand, and moderate amendments to input costs and treatment of procurement efficiency;

- **Operating costs:** an increase of £4.3 million in our allowance based on clarification of the submission relating to engineering opex;
- **Depreciation:** an increase of around £66 million as a result of bringing forward revenue recovery for accelerated depreciation; and
- **Tax:** an increase of £9 million.

Capital expenditure (Capex)

Historic capital expenditure (2000/01 to 2004/05)

5.3. For SPTL, we have made a small adjustment to its historical capital expenditure. This adjustment reduces the capex figure by around £1.7 million. This reduction reflects a reallocation of corporate costs.

Forecast capital expenditure (2005/06 to 2011/12)

5.4. Our approach to our assessment of forecast expenditure has been to evaluate the total expenditure needed for the seven year period 2005/06 to 2011/12, and established an assumed profile of annual expenditure for that period consistent with the total capex requirement.

2005/06 to 2006/07

5.5. In setting the 2 year price control extension, we provided a capital expenditure allowance of £74 million in respect of 2005/06. Since the initial proposals, we have assessed the actual costs of £45 million incurred by SPTL in 2005/06.

5.6. Our analysis of the seven year expenditure profile suggests a potentially greater level of expenditure in relation to 2005/06 than actually incurred by SPTL. We believe that this difference can be explained by the assumptions regarding the timing of investment and as such the actual expenditure incurred by SPTL may be consistent with the bringing forward of expenditure that we have identified in relation to later years.

5.7. For the purposes of rolling forward the RAV, we propose to reflect the actual level of expenditure incurred by SPTL in 2005/06, although we have adjusted our proposed profile of capital expenditure for 2006/07 to 2011/12 upwards to reflect the adjusted view on timing of expenditure. This adjustment has resulted in an increase of allowances of £2 million over the period 2007/08-2011/12. This calculation has been applied in accordance with the methodology adopted for NGET. This will be subject to review for our Final Proposals.

5.8. A summary of our Updated Proposals of capex for the period to 2006/07 is set out in Table 5.2 below:

Table 5.2 – SPTL updated forecast capital expenditure (2005/06-2006/07)

SPTL Bid & Allowances (2005/06 - 2006/07)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure	61	55	49	52	3
Non Load Related Expenditure	112	109	90	94	4
Total	**173**	**164**	**139**	**146**	**7**

2007/08 to 2011/12

5.9. Our initial proposals provided for an allowance for capital expenditure of £555 million over the five year price control period commencing on 1 April 2007. We have now updated this allowance to £576 million, around 98 million below the licensee's adjusted forecast, as set out in Table 5.3 below. However, it should be noted that the adjusted forecast does not include any additional costs associated with rising input prices. This was provided separately.

Table 5.3 – SPTL updated forecast capital expenditure (2007/08-2011/12)

SPTL Bid & Allowances (2007/08 - 2011/12)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure					
Sole-use & infrastructure	350	310	282	288	6
Input cost increase	0	0	0	14	14
Procurement efficiency	0	0	0	-14	-14
Adjustment for 05/06 actual	0	0	0	1	1
Sub total	**350**	**310**	**282**	**289**	**7**
Non Load Related Expenditure					
Switchgear	53	53	42	44	2
Overhead Lines	126	126	101	112	11
Other non-load related	187	184	130	130	0
Input cost increase	0	0	0	14	14
Procurement efficiency	0	0	0	-14	-14
Adjustment for 05/06 actual	0	0	0	1	1
Sub total	**367**	**364**	**273**	**287**	**14**
Total	**717**	**674**	**555**	**576**	**21**

5.10. The major changes set out in Table 5.3 above are:

- **Exit triggered infrastructure project:** an increase of £6 million based on evidence of a demand increase requiring network reinforcement;

- **Overhead line replacement volume:** an increase of £11 million based on additional information from SPTL on prioritisation amongst asset categories based on condition and importance to the system;
- **Switchgear:** an increase of £2 million based on a further review of the interaction between specific projects and overall switchgear replacement volume;
- **Outturn spend below profile:** an increase of £2 million reflecting the inclusion in the RAV from 2007/08 to 2011/12 of outturn expenditure relative to our assumed profile for 2005/06;
- **Procurement efficiency savings:** reduction of £29 million associated with applying a 5 per cent procurement efficiency savings from 2007/08 onwards; and
- **Input costs:** increase of £28 million associated with forecasts of future input cost movements.

Regulatory Asset Value

5.11. Table 5.4 below sets out how we have reached our updated proposals for the opening RAV on 1 April 2007. Our proposed opening RAV for 1 April 2007 reflects the depreciated value of actual expenditure incurred by SPTL in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07.

Table 5.4 - SPTL Regulatory Asset Value 2000/01 to 2006/07

SPTL	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Opening value bf	681	654	629	594	579	574	554	714
Depreciation	-49	-50	-50	-51	-52	-53	-59	-61
RAV additions	22	25	15	36	47	33	45	100
Adjustments	0	0	0	0	0	0	175	0
Closing value cf	654	629	594	579	574	554	714	754
Average RAV	668	642	612	587	576	564	634	734

Note:
1) RAV additions includes capitalised pensions; and
2) Adjustments reflect changes in connection change and BETTA related adjustments.

5.12. Our Updated Proposals establishing an opening RAV for 2007/08 of £754 million relative to our initial proposals of £746 million. The main factors influencing the movement between our Initial Proposals and these Updated Proposals are:

- The inclusion of 2005/06 actual costs;
- The delay in applying procurement efficiency savings until 2007/08; and
- The upward adjustment to capital expenditure allowances for 2006/07 onwards described above.

Controllable operating expenditure (Opex)

5.13. In the Initial Proposals document, we proposed an opex allowance of £74.7 million for the five year period between 2007/08 and 2011/12. We propose to increase this figure to £79 million to take account of an increase in the engineering opex of £4.3 million.

Table 5.5 SPTL updated opex forecast (5 year totals, £m 2004/5 prices)

	SPTL Forecast	Initial Proposals	September Update	September update - change from SPTL
SPTL Forecast	93.5			
Ofgem IP		74.7	74.7	
Changes for Sept Update				
Efficiency savings			4.3	
Total increase			***4.3***	
Total	**93.5**	**74.7**	**79.0**	**-14.5**

5.14. These adjustments reduce the gap between Ofgem and SPTL on the forecast level of costs, but a gap of around £14.3 million remains.

6. National Grid Gas NTS (NGG NTS)

Chapter Summary

This chapter sets out our updated proposals for the revenue allowances of NGG for the period 2007 to 2012. The chapter quantifies the changes that we have made to our initial proposals and sets out the reasons for those changes in the light of consultation responses, further analysis and discussions with stakeholders.

Questions

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

Summary

6.1. NGG NTS is Transmission Owner (TO) and System Operator (SO) of the GB gas transmission system. This chapter sets out our updated proposals for NGG in relation to its role as transmission owner (TO). It does not set out any SO costs or allowances, which will be covered in a separate consultation document to be published shortly.

6.2. Table 6.1 below summarises our updated proposals for NGG NTS (all prices are 2004/05, £m). We have continued to profile revenues to hold them constant in real terms from 2007/08 onwards (i.e. X=0):

Table 6.1 NGG NTS updated proposals summary

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		99	62	43	36	36
- load (base case)		365	144	5	5	1
Operating costs						
- Controllable		59	58	59	58	60
- Non-controllable		79	79	79	78	78
Depreciation		97	106	109	109	108
Pensions		38	38	37	37	37
Current Tax		36	31	36	41	45
Revenue allowances	442	474	474	474	474	474

6.3. There are five main areas where we have made changes to our initial proposals. They are summarised below (expressed as total £m changes relative to our Initial Proposals, over the period 2007/08 to 2011/120 and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of £60 million, accounting for more recent information on the Milford Haven pipeline, procurement efficiency, asset relocation, outturn spend above profile and other miscellaneous costs;

- **Operating costs:** an increase of £11.6 million arising from reallocating R&D costs, alterations to efficiency savings assumptions and adjustments for upward and downward cost drivers;

- **Depreciation:** an increase of £9 million;

- **Pensions:** an increase of £56 million based on allowances for unfunded ERDCs and an adjustment for the regulatory treatment of the historical Centrica surplus. It also reflects a reduction in the expected deficit as at 31 March 2007; and

- **Tax:** a reduction of £116 million due to the re-gearing of the balance sheet as part of our financial modelling, changes in the starting point for the capital allowances and changes to capital allowances due to the Millford Haven pipeline project.

Capital expenditure (Capex)

Historic capital expenditure

6.4. In our Initial Proposals, £75m of NGG's historical capex was initially disallowed from the RAV based on our assessment of it having been inefficiently incurred. This included the investment with a weak need case for increasing the entry capacity at St Fergus (£73m), and other costs that could have been avoided by a more efficient contracting strategy (£2m).

6.5. In its response to the Initial Proposals, NGG argued for the full allowance of £75m. The arguments for the £73m for increasing St Fergus entry capacity centred on the obligation that the last price control put on NGG to offer the baseline capacity all year round. NGG pointed out that, as baseline capacity has been booked by users, there would have been potentially significant buyback costs if the investment had not been undertaken.

6.6. We have reviewed in more detail the requirements for entry capacity at St Fergus. We do not believe that NGG has demonstrated the need case for the £73m of expenditure incurred to increase the entry capacity at St Fergus and have concluded that it would be inappropriate to allow this investment to enter the RAV in full. We recognise however that while the investment is not currently justified, both now and for the foreseeable future, it might at some stage become used. In light of this, we might want to provide some future funding for the expenditure incurred.

6.7. We have identified two options for dealing with the RAV relating to this investment:

- Option 1 – Full disallowance of the expenditure until such time as the investment becomes used and useful (i.e. no change from the initial proposals); and

- Option 2 – Allowing a discounted value of the expenditure to enter the RAV.

6.8. Supporting arguments for Option 1 are:

- We still believe that, based on the information available to NGG at the time of its committing to the investments, the need case for the £73 million investment was weak.
- The value of the added capacity has been little so far. The actual physical flow at St Fergus has been continually below the capacity level even without the investment. We are not convinced that the increased capacity has avoided significant buyback costs, since it is not clear that expensive buyback should have been required in the first place. NGG seems to have taken an over-pessimistic estimate of the buyback costs when justifying the value of this investment, without taking full account of other operational measures.
- There is no strong evidence from available market information to suggest that flows to St Fergus could increase in the foreseeable future.

6.9. Supporting arguments for Option 2 are:

- The increased capacity at St Fergus could help to reduce buyback costs when such costs do actually arise. In situations where NGG cannot be certain of the real physical flow at St Fergus, and where there is lack of liquidity and depth of capacity market, buyback costs could reach a level that is detrimental to consumers' interests.
- The increased capacity at St Fergus could be beneficial for future needs from users. A total disallowance now might lead to undue complexity for future regulation, for example in considering when and how the assets are accepted back into RAV.

6.10. On the remaining £2m costs, which were deemed to be inefficient in our Initial Proposals, we still believe that they could have been avoided if NGG had adopted an efficient contracting strategy.

Forecast capital expenditure

6.11. Our approach to our assessment of forecast expenditure has been to evaluate the total expenditure needed for the seven year period 2005/06 to 2011/12, and establish an assumed profile of annual expenditure for that period consistent with the total capex requirement.

2005/06 to 2006/07

6.12. In setting the last five year price control, we provided a capital expenditure allowance of £112 million in respect of 2005/06[3]. Since the initial proposals, we have assessed the actual costs of £251 million incurred by NGG in 2005/06, which includes £120 million of expenditure in relation to the Milford Haven pipeline. For the purposes of rolling forward the RAV, we propose to reflect the actual level of expenditure incurred by NGG in 2005/06.

6.13. A summary of our Updated Proposals of capex for period to 2006/07 is set out in Table 6.2 below:

Table 6.2 – NGG updated forecast capital expenditure (2005/06-2006/07)

NGG Bid & Allowances (2005/06 - 2006/07)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure	571	541	531	614	83
Non Load Related Expenditure	133	133	120	117	-3
Total	**704**	**674**	**651**	**731**	**80**

Licensees adjusted bid does not include NGG's revised cost projections for Milford Haven which are reflected in our proposals for updated allowances.

2007/08 to 2011/12

6.14. Our Initial Proposals provided for an allowance for capital expenditure of £737 million over the five year price control period commencing on 1 April 2007. We have now updated this allowance to £797 million, around £141 million below the licensee's adjusted forecast, as set out in Table 6.3 below:

[3] Excluding Milford Haven.

Table 6.3 – NGG updated forecast capital expenditure (2007/08-2011/12)

NGG Bid & Allowances (2007/08 - 2011/12)	Licensee Initial Bid	Licensee Adjusted Bid	Ofgem Initial Proposals (IP)	Ofgem Updated Proposals (UP)	Change from IP to UP
Load Related Expenditure					
Baseline load related	632	243	243	251	8
Milford Haven Project	224	224	224	280	56
Input cost increase	41	41	0	0	0
Procurement efficiency	0	0	-12	-13	-1
Adjustment for 05/06 actual	0	0	0	3	3
Sub total	**898**	**508**	**454**	**520**	**66**
Non Load Related Expenditure					
Compressor - emissioin reduction	180	180	115	115	0
Asset relocation costs	0	0	-70	-59	11
Other non-load related	268	251	251	231	-20
Input cost increase	0	0	0	0	0
Procurement saving	0	0	-14	-15	-1
05/06 actual adjustment	0	0	0	3	3
Sub total	**448**	**431**	**282**	**277**	**-6**
Total	**1346**	**938**	**737**	**797**	**60**

6.15. The major changes set out in Table 6.3 above are:

- **Updated baseline projects and Milford Haven project costs:** increase of £64 million (£8 million and £56 million respectively) as more up to date forecast is considered efficient;
- **Costs relating to relocating assets:** increase of £11 million;
- **Procurement efficiency savings:** reduction of £1 million associated with applying procurement efficiency savings from 2007/08 onwards, rather than from 2005/06;
- **Rising input costs:** increase of £0.5 million based on forecasts of future input costs; and
- **Removing excluded costs to be dealt with by flexible revenue mechanism:** reduction of £20 million.

Regulatory Asset Value

6.16. Table 6.4 below sets out how we have reached our updated proposals for the opening RAV on 1 April 2007. Our proposed opening RAV for 1 April 2007 reflects the depreciated value of efficient expenditure incurred by NGG in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07. Consequently, we have not included any expenditure in relation to the increase of entry capacity at St Fergus.

Table 6.4 - NGG NTS updated proposals RAV profile

NGG	2002/03	2003/04	2004/05	2005/06	2006/07
Opening value bf	2,328	2,375	2,395	2,370	2,537
Depreciation	-82	-83	-84	-84	-88
Net capex additions	129	103	59	251	480
Closing value cf	2,375	2,395	2,370	2,537	2,929
Average RAV	2,351	2,385	2,382	2,453	2,733

6.17. Our Updated Proposals establishing an opening RAV for 2007/08 of £2,929 million relative to our initial proposals of £2,873 million. The main factors influencing the movement between our Initial Proposals and these Updated Proposals are:

- The transfer of above ground installations from the NTS to the DNs;
- The inclusion of 2005/06 actual costs;
- The delay in applying procurement efficiency savings until 2007/08; and
- The downward adjustment to capital expenditure allowances for 2006/07 onwards described above.

Controllable operating expenditure (Opex)

6.18. In the Initial Proposals document we proposed an opex allowance of £281.5 million for NGG for the five year period between 2007/08 and 2011/12, compared with NGG's forecast of £324 million. As set out in table 6.5, we propose to increase our Initial Proposals by £11.6 million to £293 million, for the following reasons:

- **Normalisation:** reduction of £5.6 million arising from removing R&D costs in 2004/05;

- **Efficiency savings:** increase of £2.5 million as a result of revised views of engineering opex, IS costs and insurance; and

- **Upward/downward cost:** increase of £14.7 million as a result of including all increasing and decreasing costs that we consider appropriate.

Table 6.5 NGG updated opex forecast (5 year totals, £m 2004/5 prices)

	NGG Forecast	Initital Proposals (IP)	September Update (UP)	September update - change from NGET
NGET Forecast	**324**			
Ofgem Allowance - Initial Proposals		282	282	
Changes for Sept Update				
Normalisation adjustments			-6	
Efficiency savings			3	
Cost drivers			15	
Misc. opex			12	
Total increase from Initial Proposals	**324**	**282**	***293***	-31
Total				

7. General price control policy and cost assessment issues

Chapter Summary

This chapter sets out our updated thoughts on a number of policy issues associated with setting the price control allowances and form of price controls. These tend to be issues relating to the principles to be adopted in treating particular types of costs.

Questions

Question 7.1: Do you agree with our proposed incentives for efficient capital expenditure, including a 25 per cent incentive rate?

Question 7.2: What do you think about our proposals to address significant capex under spend? In particular:
(1) What action should we take if this happens?
(2) At what level should we trigger this response?
(3) Should this response apply to load related and non load related capex?

Question 7.3: Do you agree with our proposed approach for dealing with uncertain costs including future input price changes, specific cost uncertainties, and wider regulatory developments?

Question 7.4: What do you think regarding the proposed regulatory treatment of NGG's use of affiliated LNG?

Capex incentives

7.1. For some of the companies, particularly NGET, we are proposing allowances for non load related capital expenditure that vary significantly from the company forecasts. The allowances we propose represent our best view, in the light of all available evidence, of a level of expenditure consistent with protecting consumers by funding efficient levels of capital expenditure. An important element of the overall regime is how the companies are rewarded or penalised if, for whatever reason, they spend more or less than the allowances we set.

7.2. While there is a wide range of possible incentive structures, in essence they all address the question of how much of the cost or benefit arising from differences between allowed capex and actual capex should be attributable to the company or to consumers. We have termed this sharing factor the 'incentive rate'. It should be noted that the difference between allowance and outturn expenditure could be positive (if the company spends less than the allowance) or negative (if the company spends more than the allowance).

7.3. We are proposing to set an incentive rate of 25 per cent for each of the four transmission licensees. This is broadly consistent with the average incentive rate

faced by the transmission companies under the current price controls (17 to 27 per cent)[4].

7.4. The sliding scale approach adopted in DPCR4, in effect, tailored the incentive rate to each company's approach to forecasting its capex requirements and its attitude to the risk of variations relative to allowance. A company could, in effect, choose a lower incentive rate in return for a less challenging allowance. In part the DPCR4 approach relied on information provided from a comparative assessment of the various DNO groups. This is not possible to the same extent for transmission, because of the smaller number of companies and the substantial differences between them. We therefore propose to set the same incentive rate for all four companies.

7.5. An incentive rate of 25 per cent is comparable to the average incentive rate under a standard 5-year RPI-X form of control (with 40 year asset lives) - but avoids the weakness inherent in the standard RPI-X model of the incentive rate falling with the passage of time within the price control period. By way of comparison, a five-year rolling incentive, with a 40 year depreciation life represents an incentive rate of around 35 per cent, while a five-year rolling incentive for NGET or SPTL, taking into account the proposed acceleration of depreciation allowances would represent an incentive rate of about 45 per cent in the latter years of the price control. Details of how the mechanism might work are set out in Appendix 10.

7.6. One of our reasons for proposing this form and strength of incentive is the limited availability of output measures for transmission. In principle, output measures provide a framework for discerning over time whether a company has undertaken the level of investment required to deliver the desired level of network performance. They also allow us to assess whether genuine efficiency savings have been made or whether investment has been inappropriately or inefficiently deferred, at a cost of a deteriorating service to network users. However, transmission networks are, quite appropriately, designed and operated to be secure under a wide range of circumstances and output measures based on network performance are therefore difficult to identify. In the absence of such output measures, and in view of the resulting genuine uncertainty in estimates of the level of investment required, we feel it would be inappropriate to increase the incentive rate above 25 per cent.

7.7. To date, the companies have not developed either short or long term output measures for the transmission system that are robust and could be used to monitor that levels of capital expenditure are not too low to maintain adequately the quality and integrity of the system. This raises the question of how incentives should be structured if, in practice, a company is spending substantially below its allowance for capital expenditure; e.g. as a result of a step change in the investment planning approach adopted by the company. Given the limitations of transmission output measures compared with distribution, we are considering whether we should provide for a review point in such circumstances specifically for transmission companies, with

[4] The current price controls have different rates of return and regulatory depreciation periods which impacts upon the incentive rates currently faced by each of the transmission companies.

the option of adjustments being made to the allowances. Any review would consider whether the significant reduction in expenditure against the company's forecasts and allowances reflected genuine efficiency savings or was potentially damaging to the short or long term integrity of the network.

7.8. Such an approach, if implemented, might be restricted to non load related expenditure since companies have more flexibility to reassess the need for such investment during the control period than in the case of load related expenditure, which is driven by customer requirements. Such adjustments could be made if, for instance, the cumulative under-spend at any stage in the five-year control period is more than 20 per cent of the cumulative capex allowance for non load related expenditure, and could involve either an automatic, pre-determined adjustment to the capital expenditure allowance for the balance of the five-year period or an opportunity for Ofgem to review the evidence and decide whether such an adjustment should be made. We would welcome views in relation to this issue, including:

- Whether there should be either an Ofgem review of evidence and decision on any adjustment, or an automatic adjustment in these circumstances;
- The level at which the trigger for such a measure should be set; and
- Whether it should apply to load related as well as non load related capex.

Cost Uncertainties

Input prices

7.9. The licensees have raised concerns about the potential upwards pressure on capital expenditure resulting from potential increases in input costs relating to materials and labour. We have reviewed these potential cost increases and, based on our preliminary analysis, have decided to include an ex ante allowance for these factors within our capex and opex allowances, rather than adopting alternatives such as linking allowances to price indices other than the RPI.

Specific cost uncertainties ('Known unknowns')

7.10. The initial proposals highlighted a small number of identifiable, discrete cost items which are dependent on external factors. Our current position on the possible treatment of these 'known unknowns' is:

BT 21st Century Networks

7.11. As set out in our initial proposals document, there is uncertainty regarding the timing of the roll out of BT 21st Century Networks, which could have an impact on the licensees' tele-protection systems. We have considered the licensees' submissions regarding the need for additional capex to address the issue. We are

not proposing to provide an ex-ante allowance given the uncertainty involved. Although we have not made a final decision on this matter, we believe that a more appropriate approach, in the interests of consumers, may be to permit a re-opening of the price control, or a logging up of such costs for consideration at the next review.

Quarry and loss of development claims

7.12. It has been brought to our attention that NGG NTS is potentially facing a number of claims from quarrying businesses where it is argued that the location of NTS pipelines prevents the further development of such businesses. At the present time it is not possible to forecast with any accuracy the number and magnitude of the claims that may arise.

7.13. Whilst we are still considering the options available to us, we believe whichever solution is adopted must ensure NGG NTS retains incentives to minimise the size of such claims.

Wider regulatory developments

7.14. There are two specific wider regulatory developments which have the potential to impact on the costs that NGET should potentially be permitted to recover. These relate to:

- UK participation in a European Union (EU) Inter-TSO compensation scheme; and
- The proposed independent systems cost recovery mechanism.

7.15. Currently, there are no costs to be allowed for under either of these developments. However, there is a reasonable expectation that this will change within the next price control period. We are therefore minded to insert relevant terms in NGET's revenue restriction to allow for costs to be recovered should the need arise.

UK participation in a EU Inter-TSO compensation scheme

7.16. There is currently a voluntary scheme operating at an EU level to provide for transmission system operators (TSOs) to contribute towards the costs of other TSOs in recognition of transit flows and the associated need for investment to accommodate such flows. The UK does not participate in the existing voluntary scheme.

7.17. If the scheme were to become mandatory (which is anticipated) or if the UK were to decide to participate in a voluntary scheme, then there could be cost implications for NGET. The extent to which the UK would make a net contribution, or receive a net payment, would be determined by the details of the scheme. This is currently subject to extensive debate at an EU level. While we are not responsible

for the decision to join a voluntary scheme or introduce a mandatory scheme, we think it is prudent to plan on the basis that such a scheme might be implemented in the next price control period - and that the price control should be flexible enough to accommodate such a development.

Independent systems cost recovery mechanism

7.18. Independent systems are small gas networks serving communities that are not connected to the main gas transportation system. The gas is currently supplied by road tanker or boat. Independent systems are more costly to operate than the main distribution network.

7.19. The Secretary of State for Trade and Industry has issued a series of determinations requiring arrangements to be in place to ensure that customers on these networks pay no more than the average GB gas distribution charge. This is currently given effect through an undertaking by each of the gas distribution companies. An alternative model being consulted on currently through the gas distribution price control review (GDPCR) is for these costs to be separately identified and passed on, for the purposes of cost recovery, to NGG NTS. This will enable a more consistent pattern of cost recovery across all GB gas consumers. More detail on this issue can be found in the Ofgem documents for the GDPCR.

7.20. We consider it prudent to plan on the basis that such a mechanism might be implemented, and therefore propose to insert an appropriate term in the licence of NGG NTS to allow for such a contingency. We will review this in the light of the GDPCR consultation.

Real Wage Growth

7.21. In the initial proposals we stated that we had not made any assumptions on real wage growth in setting our allowances. We would clarify that we have not adjusted the companies' own assumptions and numbers for real wage growth and we do not intend to adjust the allowances to reflect our view on real wage growth.

Capex allowances to connect windfarms

7.22. In the initial proposals we highlighted the issue of how much capex should be allowed to connect small, renewable generators in Scotland. We note the progress in the reform of the transmission charging which seeks to improve the cost signal to generators for them to choose economically efficient connection designs. We will further review the scope of customer choice relevant to the forecast baseline capex for the Scottish companies and update our views in the Final Proposals.

NGG NTS flow margins

7.23. The Initial Proposals document raised the need to review the application of the 5 per cent margin on the 1 in 20 scenario peak day flow when planning future network capacity. Having considered advice from our consultants and responses to the initial proposals, we believe that reforming the flow margins alone may not yield the best solution for consumers and network users. This should be considered as a major component of a wider ranging review of NGG's forecasting and network planning which will deliver greater transparency and clarity for system users and help to ensure better consistency, especially when faced with changing patterns of flow across the NTS network in future. It is planned to consult on these issues after the Final Proposals are published in December.

Non-controllable operating costs

7.24. In our initial proposals we proposed that the transmission network rates be treated as pass through up to 2009/10, and that the treatment of rates for 2010/11 and 2011/12 would depend on our view of the licensees' input into the 2010 rating valuations. We intend to reflect this in the licence modifications.

Rolling forward the RAV

7.25. The capex efficiency incentives discussed in this chapter are expected to encourage efficient capex against the allowance level. However, until we are able to establish a clear set of output performance measures against which to assess investment, we will continue to assess actual capex in the future for evidence of inefficient expenditure regardless of any over or under-spend against the original allowance. This will be confirmed in our final proposals.

Excluded and de minimis services

7.26. In order to set the revenue restrictions to implement the transmission price controls we must consider the scope of services being remunerated. In particular we will consider whether any activity or service provided by the transmission businesses should be classified as excluded services or de minimis. De minimis activities are those which are not related to running the transmission businesses, these activities are limited to 2.5 per cent of allowed revenue, the associated costs and revenues are excluded from the price control.

7.27. There are other services which are related to the transmission business but outside the definition of transmission (asset) owner activity e.g. NGET post vesting connections, NGET's optical fibre network leased to Cable & Wireless (formerly Energis). Where the costs of such services are separately identifiable they will be excluded from the price control, if the costs are indistinguishable the associated revenues will be netted off overall allowed revenues In the case of NGG NTS we must consider the services provided to the GDNs post DN sales. We will set out

views on de minimis or excluded services for each licensee in December and any associated adjustment to their price controls.

Regulatory reporting

7.28. In our initial proposals document, we set out that we were considering how to develop enhanced regulatory reporting arrangements. The purpose of these measures is to improve the quality of information on cost, revenue and incentive mechanisms, which we use to monitor performance and set future price controls and incentives.

7.29. At present, the information required is located in various conditions throughout the transmission licences. We are proposing to introduce revised licence conditions which detail enhanced reporting requirements and place them into dedicated locations in the licence. We expect this will have a demonstrable improvement on the transparency and consistency of information made available.

7.30. The licence drafting process will take place in parallel to the TPCR consultation process. We expect to publish an initial thoughts document on generic licence drafting issues in October, and will be picking up regulatory reporting.

NGG NTS's provision of services from National Grid LNG Storage Limited

7.31. NGG NTS has responsibility for the day-to-day operation of the gas transportation system. In this role it buys Operating Margins and System Support services from National Grid LNG Storage Limited. The price at which NGG NTS is permitted to buy these services is regulated. Any spare capacity once the necessary services have been provided is auctioned and sold to shippers as a commercial service[5].

7.32. NGG NTS had raised concerns about these arrangements. Investment is required in the facilities to enable the services to continue to be provided. NGG NTS does not think that the current arrangements provide sufficient revenue to fund the necessary investment. It has also indicated that these services are essential for system operation, and that (in the short term at least) there are no other service providers. NGG NTS has suggested that the necessary investment might be funded through an allowance in the main price control.

[5]http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3331_storage.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/gastrading

7.33. Since initial proposals we have undertaken further work to review the extent to which NGG NTS are reliant on these services, and how this might be expected to change in the medium term as other potential service providers enter the market. We have also examined the need for capital expenditure to facilitate (a) a relatively short extension to operating lives, and (b) longer term renewal of the facilities. We accept that the services are required in the short term and that this requires some investment. However, we should not assume that the services currently provided will be essential in the medium to long term, given the scope for Operating Margins and System Support to be provided in other ways, e.g. through agreements to interrupt large demand customers, or through contracts with other storage operators. We are not therefore minded to fund the investment through allowances in the main price control. We would, however, welcome views on this position.

7.34. If we do not include allowances for the investment in the main price control, then we need to increase the regulated prices that NGG NTS is permitted to pay for the services. The work we have undertaken to review the costs and revenues will inform how we do this. We will publish the consultants' report on this work in due course.

7.35. We believe that the approach set out above is more consistent with facilitating competition in these services over the medium term. In the transition to competition the prices will continue to be regulated as a means of ensuring that consumers pay a reasonable cost for Operating Margins and Transmission Support. These reasonable costs will be reflected in our initial proposals for NGG NTS's System Operator incentives, to be published in December. We are also currently minded to place a licence obligation on NGG NTS to develop tenders for the competition provision of these services to specified timescales as part of this package of reform to ensure that the transition to competitive provision of these services has a clearly defined path.

8. Financial Issues

Chapter Summary

This chapter sets out our views on a number of financing issues associated with setting the revenue allowances for each of the companies. This includes how we calculate the financial return (or cost of capital) to be allowed on past and future investments by the companies.

Questions

Question 8.1: Do you agree with the conclusions of the Smithers & Co cost of capital study, in particular the real cost of debt and equity?

Question 8.2: Do you agree with our proposed revised treatment of pensions costs?

Question 8.3: Do you agree with our proposed approach to the provision of new equity?

Cost of capital

8.1. Our decision on cost of capital will take account of a range of factors such as the investment focus of the review, our financeability assessments, the overall balance of risk the companies will face, our consultants' work on this issue, and consistency with past regulatory decisions, which have recognised the importance of providing stability in allowed returns. Our decision on the cost of capital will be published in our December Final Proposals.

8.2. For modelling purposes, and to provide a reference point for consultation responses, our June initial proposals adopted a real post tax rate of return of 4.2 per cent for all four of the companies, noting that the rate of return allowed in Final proposals may be higher or lower than this figure. We have retained this modelling assumption for the purposes of these Updated Proposals.

8.3. Our modelling assumption is consistent with the following factors:

- A real pre-tax cost of debt of 3.4 per cent, consistent with current 10 year trailing average data for gilt yields (2.3 per cent) and the current 10 year average spread of 'A' rated utility bonds with a ten year maturity (1.1 per cent);
- A cost of equity of 7 per cent, based on the midpoint of estimates of long run average total market returns that range between 6.5 per cent and 7.5 per cent; and

- A gearing level of 60 per cent (in line with the assumptions underlying the current controls),

8.4. It also reflects the continuation of the approach adopted in DPCR4 of taking a longer term view on appropriate returns rather than relying upon the snapshot provided by the latest market information.

8.5. DPCR4 outlined the difficulties of the CAPM approach to the cost of capital in determining the appropriate return to equity finance. We adopted an approach that emphasised long term averages for total equity market returns, which were on average in the range 6.5-7.5 per cent. In the final settlement, we adopted a value at the top of this range given the investment focus of the review.

8.6. The DPCR also adopted a relatively pragmatic approach to the cost of debt, given the lack of available information on the historical cost of debt more widely. In doing so, we modelled five year average spreads on a small sample of DNO corporate bonds with a range of maturities to determine the debt premium, which supported a real pre-tax cost of debt around 4.0 per cent. In the final settlement, we adopted a real pre-tax cost of debt of 4.1 per cent.

8.7. Responses to the initial proposals have been varied, although dominated by the companies and financing institutions, who have argued that a post-tax real rate of return of 4.2 per cent would be too low and would be an unjustifiable movement from DPCR4 when compared to market movements since November 2004. In contrast, some gas shippers have provided evidence to suggest that the cost of capital should be significantly lower than we have assumed (3.2 to 3.7 per cent), although they have also acknowledged that TO's face asymmetric risk which is not captured by the CAPM methodology they have used in deriving their estimates. In the past, Ofgem has implicitly allowed for such risks in its allowed rates of return to equity.

8.8. Since Initial Proposals, we have received a draft final report on the work on cost of capital undertaken by Smithers & Co. Some key features of the report are that it:

- Estimates that the long run risk free rate is 2.5 per cent;
- Estimates an equilibrium level for the real pre-tax cost of debt for A-rated utility companies within the range 3.5 – 4.25 per cent;
- Indicates that long term total equity market returns are within the range 6.5 – 7.5 per cent, dependent on the time horizon being considered; and
- Highlights that, statistically, network utilities represent lower than average market risk to equity investors. Smithers' central estimate is in the range 4.5 per cent to 6.25 per cent, based on a beta factor of 0.5, for a sample of listed UK water and energy utility companies. Statistical confidence intervals around these figures are, however, very large.

8.9. We are currently reviewing the content of the report, which is published alongside our September Update. We would welcome comments from interested parties.

Pensions

8.10. In calculating the appropriate allowances for pension costs, we have sought to apply the principles established through the Developing Network Monopoly Price Controls project and applied in DPCR4. Our proposed allowances for pension costs are made up of two components:

- An amount for ongoing contributions (in respect of future service); and
- An amount for future repair of current deficits, assuming that repair payments are calculated on an annuity basis over ten years.

Ongoing contributions

8.11. Each company has indicated they expect higher ongoing pension contributions for the next price control period as a result of changing actuarial assumptions (e.g. on future returns and longevity). Our consultants have reviewed the proposed level of contribution rates and have advised that they are conservative, but are within the range of current accepted market practice. Allowance has therefore been made in each year of the new control periods based on the current actuarially recommended funding rates.

Over/under funding

8.12. Prospectively, our approach provides for an adjustment for over or under-funding relative to the ex-ante pensions allowance as a result of changes to the actuarially recommended funding rate.

8.13. In respect of current deficit funding we need to decide whether to make any adjustment for past over or under-funding in arriving at the portion of the current deficit which should be recovered from customers in the future. The only case in which there is an explicit allowance for pension costs is NGG for the period 2002-2007. For the other licensees, and for NGG for periods before 2002, there is no explicit allowance for pensions and, indeed, it is not clear whether there was any specific consideration of pension costs other than as part of employment costs as a whole. While it would be possible to make an estimate of the level of pension cost allowance which could be inferred from the overall allowance for employment costs, we have concluded, as we did at DPCR4, that such estimates would not provide an adequate basis for an over or under-funding adjustment. We therefore do not intend to make any adjustment for over or under-funding other than for NGG in the period 2002-2007.

Deficit repair payments

8.14. The June initial proposals set out our initial conclusions regarding the level of deficit funding in relation to National Grid (NGET and NGG). The schemes of the two Scottish companies are in surplus.

8.15. There are two key issues in assessing the proportion of the deficit that is judged to be attributable to the licensee and funded by consumers:

- The treatment of unfunded Early Retirement Deficiency Contributions (ERDCs); and
- The impact of the Centrica legacy.

ERDCs

8.16. Our pension principles state that all ERDCs are for the account of shareholders and the June initial proposals applied this principle fully, thus disallowing 100 per cent of unfunded ERDCs. National Grid has argued that this approach is not consistent with the final outcome of DPCR4 in which only 30 per cent of the cost of unfunded ERDCs arising before 1 April 2004 was borne by shareholders.

8.17. The DPCR4 final settlement applied our pension's principles in a pragmatic fashion, reflecting that the appropriate treatment of pension costs (in particular, deficit repair costs) had not been an issue considered at previous reviews. In addition, this approach recognised several data quality issues which made it difficult to apply all of our principles fully in respect of past periods. While the transmission companies initially appeared to have more robust data upon which to apply our principles we have also considered the importance of regulatory consistency with regard to precedents set in DPCR4. Therefore, we propose to provide an allowance for 70 per cent of unfunded ERDCs arising in respect of relevant retirement dates between privatisation and 1 April 2004.

8.18. We propose to make no provision for funded ERDCs prior to 1 April 2004 and no allowance for ERDCs, whether funded or unfunded, after 1 April 2004.

Centrica

8.19. Our initial proposals reaffirmed the principle that it would be inappropriate for the regulated business to fund any pension costs that relate to unregulated activities, including the cost of repairing the relevant proportion of any deficit. In applying this principle we disallowed the Centrica element of the National Grid UK Pension Scheme.

8.20. National Grid accepts the principle that the regulated business should not fund deficits relating to unregulated activities. Nevertheless, they argue that when the Centrica pension liabilities for non active scheme members were retained by Lattice,

Centrica was a still a regulated business and the assets and liabilities cannot be disentangled. They suggest that this makes them different to the electricity DNOs and therefore warrant a different application of the pension principles.

8.21. We have considered these arguments and concluded that the circumstances are not sufficiently different to warrant a different treatment from the principles applied during DPCR4.

8.22. We have also considered the argument that past surpluses relating to Centrica may have been incorrectly reflected in setting past gas transportation price controls and have decided, for the period 2002 - 07, to make adjustments for the amount by which the 2002 - 07 allowance for pension costs could be argued to have been too low as a result of incorrect attribution of the Centrica surplus and for interest on that amount at the 2002 - 07 WACC. We do not propose to make any adjustment for the period prior to 2002, consistent with the decision to make no adjustment for over or under-funding in that period.

Pension cost allowances

8.23. The table below summarises our proposals for pension cost allowances.

Table 8.1 - Transmission pensions allowances for TO and SO (nominal terms)

	NGET	NGGT	SPTL	SHETL
Annual ongoing allowance	£18.9m	£20.3m	£1.4m	£1.7m
Total expected deficit	£406.0m	£372.0m	£0.0m	£0.0m
Non attributable element - (Centrica)		£(102.2)m		
Non attributable element - (other)	£(5.3)m	£(32.0)m	£0.0m	£0.0m
Unfunded ERDC's	£(42.8)m	£(49.7)m	£0.0m	£0.0m
Deficit for allowance	£358.0m	£188.1m	£0.0m	£0.0m
Annual Deficit Allowance Opex	£39.3m	£27.5m	£0.0m	£0.0m
Annual Deficit Allowance Capex	£13.0m	£0.0m	£0.0m	
Total Annual Deficit Allowance	£52.3m	£27.5m	£0.0m	£0.0m
Allowance Opex	£53.5m	£47.8m	£0.5m	£0.8m
Allowance Capex	£17.7m	£0.0m	£0.9m	£0.9m
Total Allowance	£71.2m	£47.8m	£1.4m	£1.7m
Change from Initial Proposals				
Opex	£18.5m	£23.2m	£(0.7)m	£0.1m
Capex	£6.1m	£0.0m	£(1.3)m	£0.1m
Total	£24.6m	£23.2m	£(2.0)m	£0.2m

8.24. Table 8.2 below shows the amounts of annual allowances apportioned to TO.

Table 8.2 Average annual allowance apportioned to the Transmission Owners (2004/05 prices)

	NGET	NGG
Allowance Opex	£37.1m	£37.3m
Allowance Capex	£12.3m	£0.0m
Total Allowance	£49.4m	£37.3m

Tax

Proposed approach

8.25. Our June initial proposals provide an allowance for the expected tax payments becoming due in respect of each year of the new price control reflecting our view of capital allowances and interest payments based on our assumptions about gearing. Consistent with the approach established for DPCR4 we intend to make ex post adjustments to reduce the tax allowance where actual gearing and actual interest expense exceed the level assumed in the financial model.

8.26. In our updated proposals we have reviewed our modelling of capital allowances and made some minor adjustments to the opening tax positions of the companies but the changes to our proposed allowances for tax primarily reflect our revised proposals for revenue allowances, particularly the acceleration of depreciation to offset the ending of depreciation of post-Vesting assets. (Further detail of this issue is set out later in this Chapter.)

Double funding of past tax liabilities

8.27. One respondent to the Initial Proposals expressed concern that the proposed change in approach, to set a post tax cost of capital together with a specific allowance for tax, will result in consumers effectively funding tax payments twice. The respondent observes that companies have been able to obtain deferred allowances for capital expenditure in past price control periods, thus benefiting from tax payments at less than the statutory tax rate. In contrast, previous price control settlements funded tax at the full statutory tax rate through the allowed pre-tax rate of return. To the extent that tax liabilities deferred from earlier periods will now fall due during the coming price control period the proposed approach to tax allowances will fund these liabilities fully.

8.28. We have considered these arguments carefully. However, we consider that the approach to tax in past reviews was clear to both the companies and the regulator. Adjusting the tax allowance to reflect deferred tax from past periods would therefore be inappropriate, as it would represent a re-opening of previous price controls. It would also be inconsistent with the approach adopted in DPCR4.

Financeability

8.29. We have analysed the impact of our updated proposals, incorporating a range of capital expenditure scenarios, in order to assess whether our proposals can be expected to allow the licensees to be able to maintain an appropriate credit rating. In the Initial Proposals document we suggested that, if this were not to be the case, the appropriate approach would be to assume that companies should be able to raise additional equity when necessary and to satisfy ourselves that the allowance for the cost of equity takes account of the marginal costs associated with such equity injections.

8.30. Our initial analysis suggests that the proposed baseline positions for each of the licensees (i.e. reflecting the baseline capex allowances but not any additional expenditure funded by revenue drivers) can be funded without any requirement for equity or any other "financeability adjustment". However, it appears that equity may be required should the requirement for capital expenditure reach the higher levels suggested by SHETL and, possibly, SPTL.

Cost of provision of new equity

8.31. We are considering how best to provide funding for the costs of new equity issuance. The options are:

- An ex-ante allowance for issuance costs based on an estimated quantum of equity required; or
- An ex-post adjustment taking into account the effect of outturn levels of capital expenditure, over and above the base-line allowed in setting the price control.

8.32. Our present view is that an ex post approach may be more practicable.

8.33. One way of making ex post provision at the next price control review would be to re-run the financial models used to calculate the final price control proposals for the 2007-12 period, adjusting for outturn levels of capital expenditure and calculating the notional addition to equity (if any) required to maintain gearing at or below a trigger level consistent with maintaining a suitable investment grade credit rating. An adjustment would be made to the level of revenues recoverable in the future to fund the expected issuance costs associated with this notional equity increment. This could take the form of an enhanced annual rate of return on the portion of the RAV represented by the notional equity increment, or of a lump sum (having the same net present value) recoverable in the first year of the following price control period.

8.34. We would welcome views on this topic and, in particular, on how such an allowance for equity issuance costs should be set.

Accelerated depreciation

8.35. The pre-vesting assets of NGET and SPTL become fully depreciated after 2009/10 (the so called “cliff edge”). At that time the companies would cease to receive depreciation allowances on these assets and their overall revenue allowances would fall by £435m and £78m respectively during the last two years of the price control period. For SHETL, pre-vesting assets do not become fully depreciated until after 2011/12. This issue does not arise in relation to NGG because of the different approach adopted for setting depreciation allowances in past price reviews.

8.36. For the electricity distribution companies, in DPCR3 and DPCR4, we concluded that an adjustment should be made to smooth the profile of depreciation and remove this "cliff edge" effect. This adjustment involved:

- A reduction in the asset life of post-vesting assets, thereby increasing the level of the depreciation allowance related to these assets; and
- A “smoothing adjustment” to spread over a defined future period the additional value of depreciation that would have been funded in the past had a shorter asset life been established at vesting.

8.37. We have adopted this approach in our updated proposals.

8.38. In the case of electricity distribution, post-Vesting regulatory asset lives were reduced to 20 years and the smoothing adjustment was applied over 15 years. We have adopted this approach for SPTL in our updated proposals. However, in the case of NGET and SHETL this approach provides more revenue than is necessary to offset the impact of the cliff edge when it occurs. In light of this, we propose to use longer smoothing periods (50 years for NGET and 30 years for SHETL) as this generates an income stream that, in each case, more closely matches the loss of depreciation.

8.39. In establishing the mechanism in respect of Transmission Investment for Renewable Generation (TIRG), we adopted a regulatory depreciation period of 40 years to maintain consistency with the approach adopted for other transmission assets. Given the proposals for accelerated depreciation, we now consider that it is appropriate to adopt a 20 year depreciation period in respect of the approved TIRG schemes.

9. Adjustment mechanisms and incentives: electricity

Chapter Summary

This chapter sets out how revenue allowances will flex for each of the three electricity transmission companies with changing patterns of demand for capacity on the network ('revenue drivers'). The chapter also provides an update on the design of incentive schemes for system performance, and to support innovation.

Questions

Question 9.1: Do you agree with our proposal that it is appropriate for NGET to have a different form of revenue driver from SPTL and SHETL?

Question 9.2: Do you agree with our proposed mechanism to deal with baseline and revenue driver sample risk?

Question 9.3: Do you agree with our proposed split of revenue recovery between pre-connection and completion?

Question 9.4: What are your views on the appropriate method of providing connections to the Scottish Islands?

Question 9.5: What additional output measures do you think Ofgem should capture when considering system performance?

Question 9.6: Do you agree with our view that an Innovation Funding Incentive is appropriate?

Introduction

9.1. In our initial proposals we set out the case for revenue drivers as a means of dealing with uncertainty over the future need for capital investment to accommodate changing patterns of network use. This is an important consideration in the current context of changing patterns of generation. Our updated proposals set out more detail on how these mechanisms will work in practice.

9.2. We also provided more detail on our proposals for incentives to promote efficient levels of expenditure on research and development (R&D), and incentives associated with system performance.

Revenue Drivers

9.3. In our initial proposals we set out a two-part design for the revenue drivers for NGET, SPTL and SHETL - with separate adjustment mechanisms for local connection costs and for 'deeper' reinforcement costs. Having reviewed the consultation responses and having had further discussions with the transmission companies we have concluded that this is the appropriate form for the revenue drivers.

9.4. The following sections set out how this form of revenue driver is proposed to operate for each of the three companies. The proposals are quantified, but still subject to further investigation and analysis. We are proposing for all three companies to use the concept of a 'Revenue Driver RAV'. If the any element of the revenue driver is triggered, then the relevant amount will be added to the relevant Revenue Driver RAV.

9.5. The revenue allowances will be based on depreciation and return on the Revenue Driver RAV. We believe that this approach improves transparency and helps ensure consistency between the revenue drivers and the main control. We are proposing the same strength of incentives across both aspects of the control. The use of a Revenue Driver RAV also provides a basis upon which the revenue drivers can be rolled in to the main control at an appropriate point in the future.

SHETL and SPTL

Local connection costs

9.6. The main source of uncertainty for SHETL and SPTL in relation to investment on the network locally to connect new generation projects is over the number and location of projects that proceed, given the range of possible projects in the queue for grid connections. For any given total number of MW connecting, the investment costs can vary significantly depending on which projects proceed.

9.7. The approach we are proposing will provide an allowance in return for connecting a specified volume of MW of new generation. This is in addition to the other changes we have proposed, such as changes to demand and generation closure assumptions. This volume of MW will be set at a level with a high probability of being connected before April 2012, based on the information currently available. The starting point will be the amount of generation connected on 31 March 2005. The proposals are summarised in Table 9.1 below:

Table 9.1: Baseline capex allowance for new generation connections, SPTL and SHETL

	Baseline new generation connected from 1 April 2005 onwards (MW)	Proposed load related capex allowance from 1 April 2007 (£m)
SPTL	1,734	289
SHETL	1,489	119

9.8. It should be noted that SPTL has provided updated data in respect of local infrastructure costs, which we are in the process of reviewing. We are also considering the impact of the planning inquiry on the proposed Beauly to Denny transmission line upgrade for the MW total for SHETL. These factors might influence our final proposals in this area.

9.9. While the baseline volumes of new generation connections might be considered to be relatively certain in aggregate, there is much more uncertainty over the individual projects that make up the total. The allowance proposed assumes, in effect, an average cost mix of projects. It is possible that in practice there is an atypically high (or low) cost mix. This is not a risk that SPTL and SHETL have a great deal of control over. By and large it depends on where the new generation projects are located.

9.10. We are proposing to address this issue by placing limits on the 'sample risk' faced by SPTL and SHETL. This will be done by limiting the difference between actual capital costs and allowed capital costs through a one-off adjustment once the specified volume of MW has been met. We are proposing that the adjustment should be such that the difference can be no more than 15 per cent either way.

9.11. Funding for connecting MW over and above the specified baseline level will be provided through a revenue driver mechanism. When this point is reached in the price control period will depend on the rate at which new generators are connected to the network. The mechanism we are proposing provides the additional funding in two stages:

- Pre-connection: Once the generator seeking connection has provided a sufficiently robust financial commitment to support its application for a grid connection, a mechanism will be 'switched on', enabling a proportion of SPTL's and SHETL's costs to be added to its Revenue Driver RAV on an 'as incurred' basis. We are proposing that this proportion should be 75 per cent.

- Completion: Once the local works have been completed by SPTL or SHETL, then an additional £/MW revenue allowance will be added to the Revenue Driver RAV. The £/MW amount will be set at a level consistent with, on average, recovering the remaining 25 per cent of capital costs (plus an allowance for financing costs during construction).

9.12. As with the baseline allowances set out above, there is a 'sample risk' that £/MW element to the revenue driver is significantly below (or above) what is required to fund 25 per cent of the costs over the portfolio of projects - even if the costs are being incurred efficiently. It depends in part on whether the projects coming forward are atypically high (or low) cost.

9.13. We a proposing to limit this risk for SPTL and SHETL in a similar way to that proposed for the baseline allowance. If, across the portfolio of projects funded through the revenue driver, the deemed capital costs calculated through the two elements of the local connection revenue driver are more than 15 per cent higher or lower than the actual capital costs, then an adjustment will be made to limit the difference to a maximum of 15 per cent.

Deep reinforcement costs

9.14. The second aspect to the revenue driver design question for SPTL and SHETL relates to deep reinforcement of the network to ensure that the system can accommodate the bulk transfers associated with the connection of additional generation locally.

9.15. For SPTL and SHETL these represent a discrete number of projects which will be required if particular volumes of new generation connect behind a particular network constraint. Given the uncertainties involved in setting revenue drivers for deep reinforcements, we propose to assign a £m value to each project, the revenues for which will begin to flow once certain triggers are met. Both the £m value and the triggers will be set ex-ante in order to provide transparency and an incentive for efficiency.

9.16. We continue to review the material provided by the companies in support of the definition of these projects and the associated trigger conditions, and will publish information separately in due course - ahead of our final proposals document.

9.17. In the initial proposals we flagged up the potential issue of efficient investment being provided in large discrete blocks, e.g. if a new 400kV line is built, and that this might sit awkwardly with a revenue driver that was a continuous function of megawatts seeking capacity. We flagged the idea of a Revenue Driver Adjusting Event (RDAE). We believe that the approach we now propose for deep reinforcement for SPTL and SHETL represents a more appropriate means of addressing the 'lumpiness' of transmission investment, hence the case for a formal RDAE process is less compelling.

9.18. However, for some of the large (but currently very uncertain) projects that are anticipated to be covered by the deep reinforcement driver for SPTL and SHETL the cost are at present very uncertain also. They could, for example, be influenced by planning consent condition - and might be subject to route changes. We would intend to recognise this in our final proposals through a mechanism to trigger a process for SPTL or SHETL to provide a further submission of costs in some

circumstances, which might in turn result in the revenue driver allowances being revised.

NGET

9.19. We are proposing a different structure of revenue driver for NGET as compared to SPTL and SHETL. This difference in approach reflects differences in the size and diversity of factors influencing load related investment for NGET as compared to SPTL or SHETL. It does however retain separate revenue drivers for local versus deep system reinforcement. It also retains the concept of a baseline level of funding consistent with an associated baseline view on new generation connections – with the revenue drivers providing (or holding back) funding for variations from the assumed baseline generation scenario.

9.20. The structure of revenue drivers we are proposing for NGET is based on separating its network into zones. The reference point for both parts of the revenue driver will be a definition of:

- Generation by zone;
- Demand by zone; and
- Transfers across zone boundaries.

9.21. The proposed definition of this revenue driver reference point is set out in appendix 8. This is, in our view, consistent with a proposed baseline capital expenditure allowance for load related expenditure of £1,149 million.

Local connection costs - generation

9.22. NGET will incur costs in providing local infrastructure if new generation connects. If the amount of generation connected in each zone varies from the level assumed in setting the baseline, then the revenue allowances should also vary. We are proposing that this should be on a £/MW basis - with scope for different £/MW values to be adopted for each zone. Indicative values for each of the £/MW revenue drivers for generation-triggered local infrastructure costs are provided in appendix 8.

9.23. As we noted in our initial proposals, this approach requires us to define when new generation should be counted as such for the purposes of triggering revenue adjustments. We propose to identify new generation in two stages, in a similar fashion as for SPTL and SHETL.

- Pre-connection: Once the connecting generator has provided a sufficiently robust financial commitment to support its application for a grid connection, then a mechanism will be 'switched on' enabling the addition of a proportion of costs to be added to NGET's revenue driver RAV on an 'as incurred' basis. We are proposing that this proportion should be 75 per cent; and

- Completion: Once the local works have been completed by NGET, then the £/MW allowance for the relevant zone will be added to the Revenue Driver RAV. The £/MW amount will be set at a level consistent with, on average, recovering (with an appropriate return) the remaining 25 per cent of capital costs.

9.24. The £/MW will be an estimate of 25 per cent of the capital cost of providing the additional local infrastructure to connect new generation, including an allowance to reflect likely financing costs for the lag between costs being incurred and the revenue allowance commencing.

Local connection costs - demand

9.25. Similarly if there are increases in the amount of electricity being taken off the transmission network, then costs will be incurred by NGET in providing the supporting local network infrastructure. The revenue allowances should reflect these variations. We are proposing that there should be a £/MW adjustment to cover differences between the assumed demand growth and actual demand growth - again with different £/MW values for each zone. Indicative values for each of the £/MW revenue drivers for demand-triggered local infrastructure costs are provided in appendix 8.

9.26. As with the generation-triggered local infrastructure costs, in implementing this scheme we need to define when new demand counts as such for the purposes of the revenue driver. Again, we propose a two-stage approach:

- Pre-connection: Once the DNO has signalled an increase in forecast demand to NGET, a mechanism will be 'switched on' enabling a proportion of actual costs to be added to the Revenue Driver RAV on an 'as incurred' basis. We are proposing that this proportion should be 75 per cent; and

- Completion: Once the local works have been completed by NGET, then the £/MW allowance for the relevant zone will be added to the Revenue Driver RAV. The £/MW amount will be set at a level consistent with, on average, recovering (with an appropriate return) the remaining 25 per cent of capital costs.

9.27. The £/MW will be an estimate of the capital cost of providing the additional local infrastructure to connect new demand, including an allowance to reflect likely financing costs for the lag between costs being incurred and the revenue allowance commencing.

Deep reinforcement costs

9.28. Changes in generation and demand will impact on the need for deeper network reinforcement to accommodate the consequent changes in the pattern of bulk flows across the network. We propose to adjust revenues to capture these investment drivers through the use of £/MW revenue drivers linked to changes in the 'surplus' or 'deficit' of generation in each zone. If there is more generation than demand in a

particular zone, then the zone is in 'surplus'. Conversely, if there is more demand than generation, then the zone is in 'deficit'.

9.29. We propose to set a £/MW adjustment linked to changes in the surplus or deficit for each zone. We will also define a starting point for allowances against which revenue adjustments can be made, consistent with the generation and demand patterns assumed in setting the baseline capital expenditure allowances. Our current view on this starting position is set out in appendix 8.

9.30. The mechanism for deep infrastructure costs will use the rules for recognising new generation and demand as for local infrastructure costs, i.e. at a pre-connection stage (when there has been a user commitment, or signal from a DNO) and at a connection stage when the works have been completed.

9.31. The £/MW will be an estimate of the capital cost of providing the additional deep infrastructure to accommodate the consequent network flows if a zone surplus or deficit changes. It will include an allowance to reflect likely financing costs for the lag between costs being incurred and the revenue allowance commencing. The revenue stream will be derived to permit the recovery of depreciation and return on the assumed capital costs.

Interactions with the baseline

9.32. The model set out above results in a Revenue Driver RAV being built up over time with changes in zonal generation and demand, and zonal surpluses or deficits. However, the baseline capital expenditure allowances already reflect one particular pattern of anticipated changes. The revenue drivers need to provide appropriate revenue allowances net of the allowances already provided for.

9.33. We think the simplest way to give effect to this interaction is to define a default negative value (or profile) for the NGET Revenue Driver RAV to mirror the allowance for the baseline pattern of generation and demand growth that has been included in the main NGET RAV. As the various revenue drivers are triggered there will be additions to the Revenue Driver RAV, which will reduce this negative balance over time - and might result in a net positive balance at some point. A positive balance means in effect, that the baseline allowance was too conservative and net additional revenues should be provided. Conversely, a negative balance means that the baseline allowance was too generous and allowances should be clawed back.

Transmission connections to the Scottish Islands

9.34. In the initial proposals document we noted that revenue drivers will not be designed to handle very large extensions to the transmission network (such as to connect Shetland, Orkney or the Western Isles) because of the considerable uncertainties over the technology used and design specifications.

9.35. We identified two possible ways of handling this issue. First, by re-opening the price control of SHETL when further information is available on the demand for capacity, and likely design and cost. Second, by opening up the provision of such transmission links to alternative providers. We set out that our proposal would be dependent on the position taken by SHETL and the extent to which we considered there would be material benefits to consumers.

9.36. There have been no firm developments in our position since initial proposals. We remain of the view that there is scope within the existing regulatory framework to facilitate competition in such transmission links - and will be undertaking further development work on such options outside the TPCR process. Since our initial proposals we have visited Shetland, Orkney, and the Western Isles to meet with stakeholders and discuss transmission issues. The feedback we received supports continuing this development work.

System performance

9.37. In respect of system performance incentives, we are not proposing changes to the position we set out in our initial proposals, at this stage. We remain of the view that output measures are an important part of the overall regime, and that there would appear to be merit in adopting an appropriately specified 'penalty only scheme'. However we are keeping this issue under review until final proposals.

Innovation incentives

9.38. In the June initial proposals document we proposed the introduction of an Innovation Funding Incentive (IFI) for electricity transmission, similar in form to the scheme introduced as part of the most recent DPCR. We remain of the view that this is appropriate, and we are taking forward the work to give practical effect to the scheme. We are working with the Energy Networks Association (ENA) to develop a work programme to ensure that we are in position to implement the scheme from 1 April 2007.

9.39. The parameters of the IFI scheme to be adopted in electricity transmission are not yet decided. However, we have sought views from the licensees and electricity DNOs to gain feedback on their experience of the scheme that applies to them. When developing our final proposals for IFI, we will accommodate lessons learned from electricity distribution.

Interactions with potential reforms to access arrangements

9.40. In parallel with the TPCR we have chaired an industry group to examine how access arrangements might be better structured, given the range of issues and challenges faced in seeking to develop efficient transmission networks in the context of significant changes in demand for capacity. This group, the Access Reform Options Development Group (ARODG) published its findings last Easter for consultation. Since then NGET has proposed changes on a voluntary basis for new

generators, and we understand that NGET intends to propose enduring changes shortly. We will track the development of these proposals carefully, and come forward with proposals for consequent changes to the incentives that NGET, SPTL and SHETL face in the light of any revised access arrangement if we consider such steps to be necessary.

10. Adjustment mechanisms and incentives: gas

Chapter Summary

This chapter sets out our proposals for the treatment of entry and offtake capacity release. We also provide our views on how revenue allowances will flex for NGG NTS with changing patterns of demand for capacity on the network ('revenue drivers'), for both entry and offtake. The chapter also provides an update on the incentive design for buy backs and to support innovation, as well as transitional incentives for offtake.

Questions

Question 10.1: Do you agree with our proposals for the treatment of entry and offtake capacity release obligations, and capacity substitution?

Question 10.2: Do you agree with our proposed approach in relation to revenue drivers?

Question 10.3: What are your views of our proposals on buy back incentives, in particular, in relation to investment lead times and caps on exposure?

Question 10.4: Is it appropriate to propose an incentive on NGG NTS to release additional incremental flexibility over and above the flexibility baseline?

Question 10.5: Do you agree with our view that an Innovation Funding Incentive is appropriate?

Question 10.6: What are your views on our proposals for transitional offtake incentives?

Introduction

10.1. The Initial Proposals package comprised a revenue allowance for NGG NTS plus mechanisms which provide for positive and negative adjustments around this amount. These mechanisms are intended to adjust revenues automatically as better information emerges over time on the volume of transmission capacity that is needed, and seek to provide additional incentives which reward strong performance and penalise weak performance.

10.2. There were six elements to our Initial Proposals for NGG NTS in respect of adjustment and incentive mechanisms:

- Obligations on NGG NTS to release capacity;
- Revenue drivers;

- Buy back incentives;
- Revenue from sales of non-obligated capacity;
- Funding for innovation; and
- Transitional incentives for offtake.

10.3. This chapter highlights where our current proposals differ from those in the Initial Proposals consultation. We consider that where possible it is desirable that consistent arrangements are developed for the price controls across both the entry and offtake regimes and as such both areas are considered in this chapter.

Context

10.4. Our Initial Proposals for the entry capacity arrangements represented an evolution of the existing entry capacity regime under which users are able to secure entry capacity rights at a range of entry points through a series of long and short term capacity allocations.

10.5. For gas offtake, we continue to consider that reform to booking arrangements can be developed and implemented such that exit capacity used from October 2010 is allocated within a 'user commitment' framework – which implies users being able to book exit capacity in advance under these arrangements during 2007.

10.6. Since the release of the Initial Proposals document, NGG NTS has raised Uniform Network Code (UNC) modification proposal 0116, 'Reform of the NTS offtake arrangements' in order to implement enduring offtake reform. This modification proposal provides for the implementation of enduring offtake arrangements from 1 October 2010 with initial capacity allocations occurring in July 2007.

10.7. We note that this modification proposal is currently the subject of UNC modification process and that nothing in this consultation can fetter the discretion of the Authority in considering this modification proposal. It remains our intention that a final impact assessment would accompany our decision on the modification proposal.

Capacity release obligations

10.8. In our Initial Proposals consultation, we proposed to retain the concept of baseline capacity release obligations defined for each entry point (and offtake point) but introduce formal mechanisms to enable baseline capacity to be reallocated. This reallocation mechanism was to be backed up by the release by NGG NTS of a populated network model. Our proposals remain unchanged in this regard, although work on the quantification of the baseline numbers continues and some indicative numbers are provided in Appendix 9 for entry and 7 for offtake.

Entry capacity

10.9. For entry, NGG NTS's network is capable of accommodating a wide range of different patterns of flows and baselines. This capability is precisely why Ofgem wishes to facilitate the transfer of capacity between different entry points. We would intend that the initial baselines be chosen from that sub-set of possible baselines wherein no baseline is less than the amount of obligated capacity NGG NTS has already sold in respect of that entry point.

10.10. In the current entry regime 20 per cent of the baseline capacity at an entry point is held back from the long term auctions. The intention behind this policy was to allow new entrants to gain access to capacity without having to wait until new capacity can be constructed. This remains an important objective. However, we should recognise that there is a potential cost to holding back capacity from the long term auctions, e.g. if it dilutes or distorts incentives to buy long-term capacity. Further, we need to recognise our proposals to extend the ways (through the transfer of capacity which is discussed in paragraphs 10.17 - 10.27 below) in which new entrants can gain access to capacity in the short term. Therefore Ofgem proposes reducing the proportion of capacity held back to 10 per cent, with an intention to remove the concept completely as part of the next price control review. There is no proposal to have any withheld capacity of this type in the exit regime.

Offtake capacity

10.11. Since the Initial Proposals NGG NTS has developed detailed proposals for product definition of flexible offtake rights during the enduring period. In particular, NGG NTS has now proposed the release of separate flat and flexible capacity products. As such it is now possible to provide indicative offtake baseline numbers for the enduring period.

10.12. In our Initial Proposals consultation, we noted that the baseline numbers should be consistent with the nodal baselines specified for the transitional period, with adjustments to reflect the proposed product definitions for the enduring period. Given NGG NTS's proposal to proceed with two separate offtake products, the flat capacity baseline numbers set out in the Initial Proposals document remain largely the same with only minor revisions undertaken at some nodes.

10.13. In our Initial Proposals we also proposed to adjust upwards the flat capacity baselines for a number of interruptible sites on the transmission network and that NGG NTS should be provided with an allowance to enter into contracts to buy back firm rights at these sites in order to manage any potential interruptions going forward. We continue to believe that this approach is appropriate.

10.14. We propose that the allowance should be based upon the costs of NGG NTS contracting for constrained LNG provision in the south west area, subject to 50 per cent sharing factors in the event of deviations from the target.

10.15. Given the development of proposals for the flexibility product by NGG NTS, we are proposing to set a flexibility baseline at the level of 22 mcm/day (238 GWh/day) for each year of the enduring offtake period.

10.16. Our proposals for enduring period baselines for both flat and flexibility capacity and allowances for south west interruption are presented in more detail in Appendix 7.

Substitution of capacity obligations and associated methodologies

10.17. In the Initial Proposals consultation we proposed the introduction of obligations on NGG NTS for the substitution of capacity between gas entry points and for the substitution of capacity between gas offtake points. Under these proposals unsold baseline capacity could be allocated to where it is most in demand after each long term capacity allocation.

10.18. The Initial Proposals consultation indicated that there would be an obligation on NGG NTS to carry out "all reasonable" transfers of capacity between entry points and between exit points before receiving additional remuneration for incremental capacity. This is known as the substitution obligation. We also proposed that baselines at offtake (entry) would be adjusted upwards to reflect relevant increases in entry (offtake) baselines.

10.19. We continue to propose a framework for the substitution and reallocation of baselines in the context of long term capacity allocations, including the introduction of a substitution obligation. In particular, we propose that:

- NGG NTS be obliged, under its licence to consult on and develop a transparent methodology for baseline revisions. This methodology would address processes associated with substitution and the upward revision of baselines to reflect developments at offtake and entry. The methodology would need to reflect NGG NTS's statutory and licence obligations with respect to efficient network development. NGG NTS will be obliged to use all reasonable endeavours to identify capacity transfers.

- NGG NTS will be required to offer capacity transfer exchange rates to shippers who request them to facilitate the transfer of sold and unsold capacity between entry points.

- Ofgem approval will be required before baselines are substituted or revised;

- NGG NTS will also be required as part of its application to revise baselines to set out the exchange rate that was applied in undertaking any substitution;

- NGG NTS will be required to publish a statement setting out revised baseline numbers reflecting any revisions that have been approved by Ofgem; and

- NGG NTS will be required to submit to the Authority an annual statement explaining the basis upon which it has reached the view that user demands signalled through long term allocations cannot be satisfied by substitution.

10.20. In addition to the proposals set out above for long term substitution at entry and offtake, we are also proposing a number of changes to the short term entry regime including:

- An obligation to offer capacity transfer rates to shippers who request them to facilitate the transfer of unsold capacity between entry points. This can be called transfer facilitation; and

- An obligation to offer capacity transfer rates to shippers who request them to facilitate the transfer of sold capacity between entry points. This can be called capacity trade facilitation.

10.21. We are aware that the discussions between NGG NTS and shippers are ongoing on how this approach would be implemented. This section of the document provides further thinking on this approach.

Transfer facilitation

10.22. Ofgem's preferred approach would be an obligation on NGG NTS to respond to any requests from any shipper, prior to an auction, for an exchange rate to operate in that auction between a pair of entry points. This would allow a shipper to participate in an auction at one point to purchase capacity for use at another point. NGG NTS would, after the auction, make the transfer of capacity in accordance with the established exchange rate.

10.23. Ofgem's current view is that NGG NTS be allowed to charge shippers its reasonable costs of producing an estimate of an exchange rate - which could then be refundable in the event that capacity is subsequently purchased. If more than one shipper is requesting the same exchange rate calculation NGG NTS should share the costs between them in a non-discriminatory fashion. One possible arrangement is that the charges made to a shipper for this capacity should be netted off the charges for any capacity sold to the shipper in an auction in accordance with this transfer rate.

10.24. In setting any exchange rates NGG NTS should act in accordance with a methodology which they will have to develop and maintain in a transparent fashion. This methodology will have the objectives of:

- Reflecting the physical possibilities of transferring capacity about the network;

- Facilitating competition between gas shippers, suppliers and others associated organizations;

- Being non-discriminatory, and

- Being transparent.

Capacity trade facilitation

10.25. Under this obligation NGG NTS would be obliged to respond to any request from any two (or more) shippers for the creation of an exchange rate for the transfer of capacity between any pair of entry points at which those shippers hold capacity, over a particular time period in the future. The exchange rates offered may be time limited (e.g. NGG NTS may provide an exchange rate for the transfer of capacity between point i and point j for the period 3 years out, but exchanges at that rate must be conducted within 1 month of the rate being issued). The exchange rates provided should be calculated in accordance with the methodology referred to in paragraph 10.24 above.

10.26. If the shippers that requested the exchange rate all indicate (within the time period for which the exchange rate is valid) that they wish to make such an exchange then NGG NTS shall exchange the capacity between the shippers in accordance with the exchange rate.

10.27. Our current view is that NGG NTS should be allowed to charge shippers its reasonable costs of producing an estimate of an exchange rate. In the event of more than one shipper requesting the same exchange rate calculation NGG NTS should share the costs between them in a non-discriminatory fashion.

Revenue drivers

10.28. In our Initial Proposals consultation, we proposed a revenue driver framework at gas entry and offtake. These revenue drivers would not necessarily be used, as they are at present, to set NGG NTS's prices for capacity, indeed we anticipate that this would rarely be the case. Our policy proposals remain unchanged in this regard, although work on the quantification of the revenue driver numbers continues. Similarly, the revenue drivers would not necessarily be used, as they are at present, in the user commitment test that NGG NTS applies to determine the release of permanent incremental obligated entry capacity. Instead, we anticipate that as a result of the de-linking of the charging regime from revenue drivers, the NPV test would be set as a function of the new gas transmission charges. For example, it may take the form of a commitment by shippers to pay transmission charges for a certain number of years). A similar user commitment test, running off transmission charges, is already in place for electricity.

10.29. Since the release of the Initial Proposals Ofgem has undertaken a further review of the offtake revenue drivers which has been informed by external consultant input. As a result of this review, several revisions have been undertaken to the offtake revenue drivers. In some cases the revenue drivers have increased whereas in other cases the allowances have been reduced reflecting our assessment of the efficient costs of delivering incremental capacity.

10.30. Our proposals for appropriate revenue drivers are discussed in Appendix 9 for entry and Appendix 7 for offtake.

10.31. In its response, NGG NTS raised concerns regarding its remuneration in situations where it was considered to be efficient to 'over-build' capacity relative to the immediate demand for capacity as revealed in the long-term capacity auctions. This might potentially be a relevant consideration if the cost of 'over-building' is very low as a by-product of the technical design identified by NGG NTS. In considering explicit revenue adjustments to accommodate such a situation we need to be mindful of the following:

- The rules for capacity release currently require shippers to cover just half of the anticipated costs of providing additional capacity through bids in the long term auctions in order to trigger the capacity release - which in turn might reduce the risk that shippers fail to signal the need for a level of capacity that consumers value;
- There can be scope within the existing arrangements, although possibly requiring UNC modifications (and potentially resulting in a longer overall auction process), for shippers to be given a second chance to book additional capacity through an 'open season' - which, with appropriate pricing, should be capable of reflecting the low cost of additional capacity if the circumstances arise;
- Our proposals to increase the flexibility with which capacity can be transferred between entry points might affect the perceived value to shippers of buying 'cheap' spare capacity at an entry point if the opportunity arises; and
- NGG NTS can be rewarded for anticipating future demand for capacity through the operation of the proposed revenue drivers - and these incentives should be allowed to operate as intended.

10.32. On balance we do not, therefore consider that a revenue adjustment mechanism to handle these circumstances should be codified as part of the price control regime. We would therefore propose handling any such applications from NGG NTS for additional funding to 'over-build' on an *ad hoc* basis. However, the hurdle for approval of such a price control 're-opener' is a high one, and NGG NTS would need to demonstrate why the factors cited above do not promote an efficient solution for consumers in each instance.

Buy-back incentives

10.33. Our Initial Proposals included proposals to amend the buy back regime so that there was a different treatment of buy-backs associated with the late delivery of investment to provide incremental capacity at a particular point, and buy-backs associated with the general operation of the network, e.g. the management of maintenance schedules. We remain of the view that this is a sensible and appropriate demarcation. However, the detail of our proposals for buy backs relating to incremental investments has changed in a number of areas. We propose that buy backs relating to incremental investment should be subject to:

- A default investment lead time of 42 months for entry and 38 months for exit, reflecting some evidence that the typical time taken to obtain planning consents has increased since the last price control review. The current default lead time for entry is 36 months;

- A mechanism to allow NGG NTS to vary the lead time for specific projects though the allocation to NGG NTS of a specified number of lead time extension 'permits' (e.g. in unit of 1 month for capacity at one ASEP) which NGG NTS would have discretion to 'play' in advance of the relevant long term capacity auctions. This would replace the current process of NGG NTS applying to Ofgem for lead time extensions on a case-by-case basis. We might wish to enable NGG NTS to 'buy' additional permits by declaring a shorter lead time for some projects;

- A cap on the price at which shippers can sell back incremental capacity rights to NGG NTS (which defaults to zero if capacity is not delivered within five years of the contractual delivery date); and

- The determination of an absolute cap on NGG NTS exposure to buy back costs in each formula year. For both entry and offtake we propose that separate caps be set at £36 million per year respectively.

10.34. We believe that the cap of £36 million per year is appropriate, on balance, given the increased discretion we are providing to NGG NTS to manage the risk of capacity not being delivered on time and the increased protection we are providing for NGET in respect of the costs it might incur if capacity needs to be bought back, through the administered price arrangements. The current cap for entry is £12.5 million each year.

10.35. Our proposals for the treatment of operational buy back actions have not changed since our Initial Proposals consultation.

Revenue from non-obligated capacity release

10.36. Proposals to incentivise the release of non-obligated capacity remain largely unchanged since the publication of the Initial Proposals consultation in June.

10.37. It is noted that in the light of NGG NTS's proposals to release a separate exit flexibility product we are proposing an incentive on NGG NTS to release additional incremental flexibility over and above the flexibility baseline.

10.38. Under our proposals, NGG NTS will receive a 50 per cent share of all of the revenues associated with the release of non-obligated offtake capacity including flexibility. We also consider that it would be appropriate to cap NGG NTS gains under such an incentive to £20m p.a.

Innovation incentives

10.39. In our initial proposals we sought views on whether there was a case to introduce an Innovation Funding Incentive (IFI) scheme for gas transmission. We have concluded that it is appropriate to introduce such a scheme as a means of promoting R&D for the benefit of consumers. We are taking forward work to give effect to the scheme in practice. We are working with the Energy Networks Association (ENA) to develop a work programme to ensure that we are in position to implement the scheme from 1 April 2007.

10.40. The parameters of the IFI scheme to be adopted in gas transmission are not yet decided. However, we have sought views from licensees and the electricity DNOs to gain feedback on their experience of the scheme that applies to them. When developing our final proposals for IFI, we will accommodate lessons learned from electricity distribution.

Transitional offtake incentives

10.41. As part of the sale by National Grid Gas plc of four of the gas distribution networks (GDNs), we implemented incentives on NGG NTS for the period to 30 September 2008 (the "interim" period). Offtake arrangements are now in place for the intervening, transitional period; however incentives on NGG NTS have not yet been determined for this period. As part of the TPCR it is therefore necessary to consider NGG NTS incentives for this period.

10.42. Our Initial Proposals for transitional incentives remain unchanged with the exception of the targets proposed for the CLNG incentive, which have been revised following the receipt of further information from NGG NTS. The proposed incentive targets which apply across both the enduring and transitional offtake periods are discussed in detail in Appendix 7.

11. Sustainable Development and the Environment

Chapter Summary

This chapter sets out our updated proposals on how the TPCR takes account of our sustainable development and wider environmental duties. It proposes the introduction of incentives to reward the electricity transmission companies for reducing leakage rates of SF6, an extremely potent greenhouse gas used as an insulating agent in high voltage switchgear, as a means of complementing the incentives provided through the EU Emissions Trading Scheme (ETS). It also sets out our view of other key environmental impacts associated with the operation of transmission networks - losses, noise and visual amenity. In particular, this chapter sets out our approach to the issue of under-grounding of electricity transmission lines.

Questions

Question 11.1: Do you agree that the licensees should be incentivised to reduce leakage of SF6? Do you agree the incentive should be set for 5 years?

Question 11.2: Do you agree with our proposal not to apply the DPCR approach to transmission undergrounding? Do you have views upon how we may best factor this in to our decisions?

Introduction

11.1. Our initial proposals highlighted the following areas as the key environmental impacts associated with the operation of the transmission networks. There was broad agreement from respondents that this represented a comprehensive list:

- Emissions;
- Losses;
- Noise; and
- Visual Amenity.

11.2. We provide funding through our cost allowances consistent with the companies complying with relevant statutory requirements in respect of the environment. Our updated proposals therefore relate to potential measures over and above the requirements of environmental legislation. These are discussed in turn below.

Emissions

11.3. We are proposing to introduce a system of rewards for the electricity transmission companies to reduce leakage rates of SF6, a gas used as an insulating

agent in high voltage switchgear. We would hope that the incentive scheme could be implemented in April 2007 alongside the other elements of the new price controls.

11.4. SF6 emissions are outside the scope of EU ETS. Therefore, the companies have weaker financial incentives to reduce emissions of SF6 relative to emissions covered by EU ETS. SF6 is, however, an extremely potent greenhouse gas and leakages from the electricity transmission network are material. In 2004/05, emissions from the three transmission licensees were around 15 tonnes, or 0.36 million tonnes of CO2 equivalent.

11.5. The design of the incentive needs to recognise that use of SF6 by the companies might be expected, other things being equal to increase over time, given that SF6 is used in preference to oil in new switchgear. The incentive also needs to be designed to make use where appropriate of existing monitoring and reporting procedures. We anticipate a relatively simple form of incentive, measured over the duration of the control period - rather than year-by-year. One such form is a one-off payment at the end of the control period if leakage rates are reduced by a specified amount.

Losses

11.6. Creating the appropriate incentive scheme to reward reductions in losses is significant from an environmental perspective. Total losses across the electricity transmission network represents, on average, some 1.7 per cent of the electricity generated, or 6 TWh. If losses were lower, then less electricity would need to be generated to meet any given level of demand. In turn this would reduce emissions associated with electricity generation.

11.7. We are proposing that NGET should have in place a losses incentive as part of package of system operator (SO) incentives. The form of this incentive is subject to separate consultation. We do not, however, think that additional incentive measures specific to each Transmission Owner are appropriate.

Noise

11.8. We are content with the existing regulatory protections for consumers in respect of noise pollution associated with the operation of the transmission networks, e.g. through existing planning and monitoring processes and environmental statutory requirements. We are not therefore proposing a separate incentive scheme to address noise pollution.

Visual amenity

11.9. It is generally accepted that transmission assets reduce visual amenity, and that visual amenity has a value to consumers. The existing electricity transmission

network has 26,550 kilometres of overhead line in GB, comprising 5,250 kilometres of 132kV, and 21,300 kilometres of 275/400kV.

11.10. On the gas transmission system, the visual amenity issues are primarily associated with compressor stations, terminals, and other above ground installations (AGIs). There are around 400 such installations, ranging in size from very large entry terminals to equipment similar in size to a small electricity sub-station. There are 25 compressor stations on the GB network, and 6 large entry terminals.

11.11. Since publication of our initial proposals we have undertaken further analysis of the costs and benefits of under-grounding electricity transmission lines, and we have met with key stakeholders.

11.12. As part of the DPCR we allocated additional funds for the distribution companies to underground a proportion of the network in environmentally sensitive areas. This allowance was limited in aggregate to around £60m over all fourteen companies over the five year period. We have considered the option of extending the DPCR policy to transmission, but have concluded that this may not be appropriate, for the following three reasons:

- Planning: The construction of new transmission lines generally requires planning consent, and for large projects this can involve a public inquiry. The planning consent process is an important vehicle through which the interests of consumers in terms of visual amenity are considered. This planning approval process is generally less involved for distribution;

- Costs: The costs of under-grounding transmission are significantly higher than for distribution - and a scheme capped as a proportion of allowed revenues along the lines of DPCR does not appear to be credible given the potential scale of the costs; and

- Benefits: While there are far fewer transmission lines in environmentally sensitive areas compared to distribution lines, the visual amenity issues are potentially significant - but in a much more specific, case-by-case manner. It is more difficult to generalise about consumers' average willingness to pay (which is implicit in the DPCR approach).

11.13. We recognise that the consumer benefits of visual amenity associated with investment in the transmission network should be taken into account, and that decisions affecting visual amenity should be informed by objective analysis. In transmission this will necessarily be more case-specific, due to the high investment costs involved in some projects. As such, we propose to consult further on how best to factor this issue into decisions that Ofgem might be required to make.

Appendices

Index

Index - Supplementary Appendices

Note that the Supplementary Appendices are found in a separate appendices document.

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.2. Responses should be received by 24 October 2006 and should be sent to:

Robert Hull
Director - Transmission
Office of Gas & Electricity Markets,
9 Millbank,
London,
SW1P 3GE

Tel: 020 7901 7050
email: tpcr.responses@ofgem.gov.uk

1.3. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.4. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.5. Any questions on this document should, in the first instance, be directed to:

Colin Green
Senior Manager - Transmission Price Control Review
Office of Gas & Electricity Markets,
9 Millbank,
London,
SW1P 3GE

Tel: 020 7901 7143
email: colin.green@ofgem.gov.uk

1.6. Having considered the responses to this consultation, Ofgem intends to publish final proposals for the price controls in December 2006. These will set out our revised views of the revenue allowances for each of the transmission businesses and

further quantify our proposals for the incentive framework that will apply to gas and electricity transmission.

CHAPTER: 1

There are no questions in this chapter.

CHAPTER: 2

There are no questions in this chapter.

CHAPTER: 3

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

CHAPTER: 4

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

CHAPTER: 5

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

CHAPTER: 6

There are no questions set out in this chapter. Questions relating to the substance of the updated proposals are set out in later chapters.

CHAPTER: 7

Question 7.1: Do you agree with our proposed incentives for efficient capital expenditure, including a 25 per cent incentive rate?

Question 7.2: What do you think about our proposals to address significant capex under spend? In particular:
(1) What action should we take if this happens?
(2) At what level should we trigger this response?
(3) Should this response apply to load related and non load related capex?

Question 7.3: Do you agree with our proposed approach for dealing with uncertain costs including future input price changes, specific cost uncertainties, and wider regulatory developments?

Question 7.4: What do you think regarding the proposed regulatory treatment of NGG's use of affiliated LNG?

CHAPTER: 8

Question 8.1: Do you agree with the conclusions of the Smithers & Co cost of capital study, in particular the real cost of debt and equity?

Question 8.2: Do you agree with our proposed revised treatment of pensions costs?

Question 8.3: Do you agree with our proposed approach to the provision of new equity?

CHAPTER 9:

Question 9.1: Do you agree with our proposal that it is appropriate for NGET to have a different form of revenue driver from SPTL and SHETL?

Question 9.2: Do you agree with our proposed mechanism to deal with baseline and revenue driver sample risk?

Question 9.3: Do you agree with our proposed split of revenue recovery between pre-connection and completion?

Question 9.4: What are your views on the appropriate method of providing connections to the Scottish Islands?

Question 9.5: What additional output measures do you think Ofgem should capture when considering system performance?

Question 9.6: Do you agree with our view that an Innovation Funding Incentive is appropriate?

CHAPTER: 10

Question 10.1: Do you agree with our proposals for the treatment of entry and offtake capacity release obligations, and capacity substitution?

Question 10.2: Do you agree with our proposed approach in relation to revenue drivers?

Question 10.3: What are your views of our proposals on buy back incentives, in particular, in relation to investment lead times and caps on exposure?

Question 10.4: Is it appropriate to propose an incentive on NGG NTS to release additional incremental flexibility over and above the flexibility baseline?

Question 10.5: Do you agree with our view that an Innovation Funding Incentive is appropriate?

Question 10.6: What are your views on our proposals for transitional offtake incentives?

CHAPTER: 11

Question 11.1: Do you agree that the licensees should be incentivised to reduce leakage of SF6? Do you agree the incentive should be set for 5 years?

Question 11.2: Do you agree with our proposal not to apply the DPCR approach to transmission undergrounding? Do you have views upon how we may best factor this in to our decisions?

Appendix 2 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[6]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[7].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[8]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[9]

[6] entitled "Gas Supply" and "Electricity Supply" respectively.
[7] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[8] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[9] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[10] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[11] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[10] or persons authorised by exemptions to carry on any activity.
[11] Council Regulation (EC) 1/2003

Appendix 3 - Summary of respondents' views

1.1. This appendix summarises the responses to the initial proposals document, and sets out our view of the issues raised. The following text sets out responses by each chapter of the initial proposals document, separated into licensees' views, other respondents' views and Ofgem's views.

Chapters 3 to 6 – Company chapters

Licensees' views

1.2. NGET believes that the initial proposals hugely underestimate the required capex, and disagreed with all the key areas of reductions, i.e. volume and unit cost of non-load related capex, project related reduction on load related capex, procurement savings, the exclusion of market price impact and the reduction on load-related projects.

1.3. NGET disputes the setoff of the normalisation adjustments and more generally believes allowances should be set on the basis of accounting costs and not Ofgem's view of cash costs. It disagrees with some aspects of the efficiency analysis, particularly insurance corporate costs and NGET engineering opex, and believe NG should be given "costs to achieve" such productivity gains.

1.4. The licensees were concerned that the required efficiency improvements were too large. SHETL believes that a shift in the frontier of 1.5 per cent would be difficult to achieve given SHETL's small cost base.

1.5. SPTL believes that the reduction in non-load related capex would lead to reduced safety and integrity of the network. Whilst welcoming the inclusion of the load related baseline, the licensee was concerned about commercial implications resulting from the reduction due to efficient connection designs for wind generation.

1.6. On the treatment of the capex associated with St Fergus projects, NGG NTS argues that it is inappropriate to disallow it. NGG NTS argues that due to the obligation that last price control put on NGG to offer the baseline capacity throughout the year, there would have been potentially significant buyback costs without these investments, as baseline capacity has been booked by users.

1.7. The licensees were concerned that the required efficiency improvements in the opex allowance were too large. SPTL also disagreed with the proposed efficiency adjustments to plant maintenance.

Other respondents' views

1.8. The majority of respondents that commented felt there was insufficient evidence to assess whether or not the capex spend associated with St Fergus should be disallowed. However, several respondents noted that if the capacity was provided in response to user commitment, it would be inappropriate to disallow it.

Ofgem's views

1.9. We have made various adjustments to our assumptions on capital expenditure and operating expenditure, as set out in chapters 3 to 6 of this document.

1.10. We are not convinced by NGG's arguments about the obligations of carrying out the investment and continue to believe that the investment was not efficiently incurred with best information available at the time. The consistently low physical flow through St Fergus terminal bears testimony to the lack of true requirements for the increased entry capacity.

1.11. We acknowledge there was insufficient evidence made available in our initial proposals document to assess the efficiency of the investment at St Fergus, and intend to publish our consultants' reports on our website.

Chapter 7 - Price control cost assessment and general policy issues

Licensees' views

1.12. All respondents agreed with the proposed treatment of non-operational capex and 'quasi-capex' or preferred a short life RAV of five years.

1.13. In relation to the issue of future input cost increases, two licensees supported the ex-ante approach whereas support for the indexation approach was expressed by the other licensee respondent and one other respondent.

1.14. With regard to the approach adopted to assess efficient connection design for wind generation, two licensees gave their comments. One supported Ofgem's approach in principle, on the proviso that the charging methodology provides a sufficient price signal, and that allowances are made for different choices made by the generators. The other licensee expressed concern about potential impacts on commercial arrangements, quality of supply and environmental issues. Seven other respondents gave their view on this issue, with six supporting Ofgem's approach and one expressing concern on potential consequence of low security connection becoming the default.

Other respondents' views

1.15. Several respondents expressed support for rolling capex incentives, as they provide consistent incentives across price control periods.

1.16. Most respondents supported the use of re-openers, specifically for BT 21st Century Networks. Other cases for re-openers that were cited included increases in construction prices and unforeseen investments.

Ofgem's views

1.17. In relation to efficient connection design, our preferred option is still for generators to make their own choice according to the allowance in the GBSQSS, i.e. without adverse impact on the level of security and costs to other users. We are still pursuing the more desirable outcome of restoring cost signal to generators for them to choose economically efficient connection designs and do not agree that the efficient connection design that our Initial Proposals were based on would create quality of supply and environmental issues.

1.18. Whilst we believe that in general re-opening the price control should be avoided, we recognise that there may be situations where it is unavoidable.

Chapter 8 – Financial Issues

Licensees' views

1.19. Responses to the initial proposals document on the cost of capital were varied. However, the licensees and financing institutions argued that our position of a post-tax rate of return of 4.2 per cent was either too low, represent an unjustifiable movement from DPCR4 when compared to market movements since November 2004, or both. In contrast, some gas shippers provided evidence to suggest that the cost of capital should be significantly lower than we have assumed (3.2 to 3.7 per cent).

1.20. The licensees supported our approach of bringing forward depreciation allowances from post vesting assets into the next price control period to address the depreciation cliff edge.

1.21. All the licensees considered that our pension principles should be consistent with those adopted in DPCR4.

Other respondents' views

1.22. Several respondents agreed with our position that allowances for tax payments should be set out on an ex-ante basis, in order to provide financial certainty, and to avoid having to re-open the price control with ex-post allowances.

1.23. Some respondents commented that whilst Ofgem states that it is the intention to apply the same criteria as in DPCR4 to pension costs, there appears to be a very different approach to the treatment of Early Retirement Deficiency Costs.

Ofgem's views

1.24. We are continuing to provide a return on equity, which is expected to provide 40 per cent of the funds despite the absence of any equity being provided to the transmission business since vesting. We continue to believe that our proposals for the overall return are appropriate and recognise the funding needs faced by the transmission businesses.

1.25. On the question of ERDCs we understand the need for regulatory consistency notwithstanding the divergence from pension principles and are therefore proposing to make an allowance for unfunded ERDCs in respect of the pension deficit in accordance with DPCR4.

1.26. We believe that the most appropriate mechanism of ensuring the licensees are able to fund their activities in an effective manner is to address the depreciation cliff edge by accelerating depreciation, such that additional allowances are brought forward into the price control period from 2007/08 to 2011/12.

Chapter 10 – Adjustment mechanisms and incentives: electricity

Licensees' views

1.27. NGET and SPTL expressed support for a system of locational revenue drivers, recognising that they would enable revenues to flex in response to actual demands for connection capacity. SHETL expressed reservations as they were concerned that revenue drivers would struggle to deal with lumpy investment with any degree of accuracy. All the transmission licensees supported disapplication of revenue drivers for large non-standard projects. The licensees were also concerned about financeability of investment if revenues only flow once capacity is delivered.

1.28. SHETL and SPTL were keen on using alternative 'step-release' revenue mechanisms for larger deep reinforcement projects.

1.29. The licensees recognised that the current reliability incentives were flawed. However they strongly opposed moving to a penalties only regime, arguing that this would have a material effect on the balance of risk and reward that they face.

1.30. All the licensees were in support of IFI in both electricity and gas, but considered that there would need to be a review of the parameters of the scheme in light of experience of the scheme in electricity distribution.

Other respondents' views

1.31. The majority of respondents recognised the benefits of tying investment to actual projects. There was also support for a two-part system of revenue drivers, given the different cost characteristics.

1.32. Some respondents were concerned over the accuracy of revenue drivers, and the scope for perverse incentives and unintended consequences. Other respondents were in support of disapplying the revenue drivers for large non-standard projects, but cautioned that such a mechanism would need to be clearly defined and set out in advance.

1.33. The majority of respondents expressed support for opening up to competition the provision of connections to the Scottish Islands. SHETL was strongly against competition in this area, and considers it best able to deliver the connections efficiently.

Ofgem's views

1.34. We believe that revenue drivers are the most appropriate way of dealing with uncertain demands for connections, and will on average provide an appropriate level of funding. Our proposals for a two-part revenue driver reflect the different cost drivers of a connection to the transmission system.

1.35. We are fully considering the treatment of exceptional projects such as the Western Isles and Shetland connections, including the potential to open them up to competition. However, in the event that these remain within SHETL's licensed area, if they cannot be included within a standardised framework, we believe that clear criteria for treating them should be determined ex-ante.

1.36. As set out in this document, we continue to believe that there appears to be merit in a penalties only reliability incentive scheme. However we are keeping this issue under review, in discussion with the companies - and in the light of consideration of the issue of output measure more generally.

Chapter 11 Adjustment mechanisms and incentives: gas

Entry – licensee's views

1.37. There was broad support for our proposed form of revenue drivers. Although detailed concerns were raised by NGG NTS on the network modelling undertaken to set the baselines and revenue drivers - and the potential for under-remuneration relative to costs.

1.38. NGG NTS expressed concern regarding its potential exposure under our proposals on buy-back. There was general support for our proposals to adopt separate arrangements for incremental and operational buyback.

Entry – other respondents' views

1.39. There was support from shippers on our proposal to continue to place NGG NTS under obligations to release specified amounts of capacity at each entry point – while there was general recognition that there needed to be more flexibility to transfer capacity between entry points.

1.40. A number of shippers raised concerns about the extent to which the proposals for baselines represented significant changes to how they understood the regime would work when it was first implemented.

1.41. One respondent questioned whether the current regime, which has only been in place for a single price control period, is sufficiently ineffective such that this level of radical change is required. This respondent would have expected the cost benefit analysis for the change to have been presented at this time.

1.42. Another expressed fundamental concerns about the existing gas entry regime. In its view, the existing regime has distorted competition, unnecessarily increased perceptions of regulatory risk of operating in the competitive gas market and has required frequent, unanticipated regulatory intervention to solve problems that have emerged from the complex auction arrangements.

1.43. Some respondents agreed that allowing capacity substitution between entry points may improve efficiency. However, they consider that the proposed changes transfer additional risk to shippers unless the reallocation methodology is clearly defined.

Entry - Ofgem's views

1.44. We welcome support for the use of revenue drivers. We believe that revenue drivers provide an appropriate mechanism for providing allowances for network investment that is uncertain. Work is ongoing to quantify the revenue drivers.

1.45. We continue to believe that it is appropriate to retain the concept of baseline capacity. However, we also believe that where capacity is substituted in the longer term it is sensible for baselines to be reduced to reflect the corresponding reduction in capacity.

1.46. Ofgem rejects the assertion that its proposed changes are radical. We believe that current regime requires minor changes of the type we are proposing.

1.47. We agree that the basis for any capacity substitution that occurs in the unconstrained period needs to be clearly defined. We believe that a substitution methodology and a clear framework underpinning any substitutions will need to be developed.

Exit – licensees' views

1.48. In general the licensees were broadly supportive of the transitional offtake arrangements.

1.49. The licensees and other respondents highlighted a number of key concerns with regard to the enduring offtake arrangements, which included: flexibility capacity release; treatment of CLNG; treatment of revenue drivers; form of buy back arrangements; and lumpy investment. Respondents noted the need for further policy development on the key elements of the proposed regime in order to provide detailed comments on the proposals.

Exit – other respondents' views

1.50. Some respondents were in support of our proposed revenue drivers, but cautioned the need to balance accuracy with simplicity.

1.51. Several respondents were in support of nodal allocation of capacity and basing enduring baselines on the transitional ones, with adjustments for firm incremental capacity.

1.52. A number of respondents agreed with our approach on buy backs of offtake capacity, but considered that there would need to be further thinking on investment lead times.

Exit - Ofgem's views

1.53. We continue to believe it is appropriate to push forward with offtake reform in order to ensure that non-discriminatory capacity allocation arrangements are put in place along with mechanisms for users to provide long term commitments to capacity.

1.54. Our view is that NGG NTS should have incentives to deliver incremental investment for the transitional period through the application of pre-specified revenue drivers.

1.55. We are considering the issues relating to investment lead times in the context of buy back of offtake capacity, and have proposed measures, as set out in chapter 10, which we believe are appropriate.

Chapter 12 – Environmental Considerations

Licensees' views

1.56. The licensees recognised that we had identified all the significant environmental impacts.

1.57. SPTL recommended that any innovation in support of environmental benefits should be addressed through the proposed IFI mechanism for transmission networks.

1.58. The licensees offered cautious support for an incentive on the release of SF6. One licensee stressed the importance of ensuring that any incentive would be based on a parameter that the licensees have operational control over. Any incentive scheme would also need to recognise the increase in the use of SF6 in switchgear and substations over the next price control period.

Other respondents' views

1.59. The majority of respondents recognised that we had identified all the significant environmental impacts, and welcomed our stance on drawing attention to the issues.

1.60. A number of interest groups raised concerns about our stance on allowances for under-grounding transmission lines for reasons of visual amenity.

1.61. Several respondents refuted our suggestion that an underground cable at 400kV really does cost around 15 to 20 times more than an overhead line.

1.62. There was general support for considering an incentive scheme for SF6 emissions – although some concerns were raised by the licensees about the practicalities and the potential for added complexity.

Ofgem's views

1.63. We continue to be unconvinced that there is a clear case for an undergrounding allowance. Our position has been informed by views on the costs and benefits of such an allowance. In addition, we recognise that the consents process for transmission infrastructure offers the public an opportunity to express its concerns.

However, we are considering our position, and will continue to conduct analysis prior to our final proposals in December.

1.64. When coming to a view of how much more expensive underground cables are rather than overhead lines, we were informed by NGET's charging model, which uses audited data of actual spend on projects. The range we used was at the lower end of the scale.

1.65. In the absence of incentivisation of leakage of SF6 via another means, such as EU ETS, it is appropriate for us to consider how to reduce its effect on the environment.

Appendix 4 - Glossary

A

Access Reform Options Development Group (ARODG)

Group set up by Ofgem which is intended to be a helpful pre-cursor to (and not substitute for) parties considering whether they wish to raise specific modification proposals to industry codes and is designed to stimulate debate and discussion. The group met weekly during March and April, and has published a report for consultation.

B

Baseline

Baselines define the reference levels of capacity that the transmission licensee is to release. Baselines also determine the levels above (or below) which incremental capacity is defined.

Baseline Capital Expenditure

Baseline capital expenditure is the total amount of capex required in association with the baseline. It includes both load related capex and non-related capex.

British Electricity Trading and Transmission Arrangements (BETTA)

BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system which came fully into effect at BETTA go-live (1 April 2005).

C

Capital Expenditure (Capex)

Expenditure on investment in long-lived transmission assets, such as gas pipelines or electricity overhead lines.

Compound Annual Reduction (CAR)

Also known as Compound Annual Growth Reduction (CAGR). The cumulative year on year rate applied to an investment or other part of a company's activities over a multiple-year period.

D

Distribution Price Control Review (DPCR)

The price control review for the electricity distribution network operators conducted in 2003 & 2004. The resulting price control covers the years 2005 to 2010.

Distribution Network Operators (DNOs)

Holders of electricity distribution licences. Licences are granted for specified geographical areas. Currently in Great Britain there are seven companies who own the fourteen licensed distribution areas.

E

Early Retirement Deficit Costs (ERDC)

ERDCs are the costs of providing the additional pension benefits payable to a scheme member who retires before normal retirement date as a result of re-organisation or redundancy, over and above the benefits to which such a member would be entitled if he retired voluntarily at the same date. The rules of both the ESPS and the LGPS provide for the automatic enhancement of benefits to which a member becomes entitled on taking early retirement as a result of re-organisation or redundancy. Principal employer companies have often in the past used a pension fund surplus to cover part or all of these additional costs, subject to agreement with the trustees of the scheme. In the absence of agreement by the trustees, the employer must make additional contributions to the pension fund to cover the additional liability.

Electricity Supply Pension Scheme (ESPS)

A Retirement Benefit Scheme based upon benefits paid as a proportion of final salary. The Scheme is an exempt approved scheme (ICTA'88) and is subject to a trust document. The "Group" has many principal employers and is organised and defined by a set of rules, trustees and produces accounts annually and actuarial valuations at least every 3 years (triennially). The scheme is principally for people working in the Electrical Utility Industries. This scheme is one of the 26 separate tranches each actuarially independent.

F

Final Sums Liability (FSL)

The level of financial security a generator seeking connection to the network is required to post to cover the costs of works completed to connect them.

Front Office Management Services Agreed (FOMSAs)

An agreement between the gas distribution business retained by National Grid Gas plc and the IDNs with regards to the provision of certain IT services.

Forecast Business Plan Questionnaire (FBPQ)

Expenditure information requested by Ofgem from the licensees relating to the period from 2005/06 to 2011/12.

G

Gas Distribution Networks (GDNs)

Gas Distribution Networks, of which there are eight, four of which are owned by National Grid Gas plc, and four of which were sold by Transco plc (now National Grid Gas plc) to third party owners on 1 June 2005.

Gas Distribution Price Control Review (GDPCR)

The review of the price control applying to gas distribution networks. The review will extend the existing price control for the year 2007-08 and reset the control for the period commencing 1 April 2008.

Gas Transmission Charging Methodology Forum (GTCMF)

A dedicated forum, established in January 2006, to allow National Grid NTS to provide information to the gas industry on its ongoing review of its Transportation Charging Methodology and other relevant charging methodologies and issues, and to provide an opportunity for users' views to be represented and discussed.

Great Britain System Operator (GBSO)

See SO.

H

Historical Business Plan Questionnaire (HBPQ)

Expenditure information requested by Ofgem from the licensees relating to the period from the year before their most recent five-year full price control until 2004/05.

I

Independent Distribution Networks (IDNs)

Gas Distribution Networks which were sold to third party owners by Transco plc (now National Grid Gas plc) on 1 June 2005. There are four such network companies, which are: Northern Gas Networks Ltd, Scotland Gas Networks plc, Southern Gas Networks plc and Wales & West Utilities Ltd.

Information Quality Incentive Mechanism

A form of incentive design adopted by Ofgem as part of the DPCR which provided companies with the potential for greater rewards if they chose more challenging cost targets.

Innovation Funding Initiative (IFI)

A mechanism to remunerate research & development expenditure by DNOs.

L

Lattice Group Pension Scheme (LGPS)

A Retirement Benefit Scheme based upon benefits paid as a proportion of final salary or for newer members contributions paid to the scheme. The Scheme is an exempt approved scheme (ICTA'88) and is subject to a trust document. The Scheme is organised and defined by a set of rules, trustees and produces accounts annually and actuarial valuations at least every 3 years (triennially). The Pension Scheme is principally for people working in the Gas Utility Industries.

Liquefied Natural Gas (LNG)

LNG consists mainly of methane gas liquefied at around -260 degrees Fahrenheit. Cooling and liquefying the gas reduces its volume by 600 times such that a tonne of LNG corresponds to about 1,400 cubic metres of methane in its gaseous state. LNG may be stored or transported by special tanker.

Load Related Capex

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

M

Monopolies and Mergers Commission (MMC)

The Competition Commission replaced the MMC on 1 April 1999. It is an independent public body. The CC conducts in-depth inquiries into mergers, markets and the regulation of the major regulated industries.

N

National Grid Gas (NGG NTS)

The licensed gas transporter responsible for the gas transmission system, and four of the regional gas distribution companies.

National Grid Electricity Transmission (NGET)

The electricity transmission licensee in England & Wales.

National Transmission System (NTS)

The high pressure gas transmission system in Great Britain.

Non-Load Related Capex

The replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

O

One in Twenty Obligation

A licence obligation imposed by Standard Special Condition A9 (Pipe-Line System Security Standards) upon both NGG NTS and the GDNs.

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overhead.

Operating Margin (OM)

In relation to gas the OM is gas in storage which is reserved by the NTS to ensure the supply of gas is maintained in the event of a network emergency.

P

Public Electricity Suppliers (PESs)

The fourteen successor companies to which were transferred the electricity distribution and supply undertakings of the former area boards at privatisation. Each PES was required to provide distribution services and connections, and to provide a supply to consumers, in the geographical area (the 'authorised area') formerly served by the area board to which it was the successor. The duty to supply was progressively removed as competition was introduced, and was eliminated entirely by the Utilities Act 2000 which converted each PES licence into separate distribution and supply licences. The duty to provide distribution services and connections within its authorised area remains an obligation of the EDNO which, in each of the fourteen areas, is the present successor to the relevant PES.

Pipeline Maintenance Centre (PMC)

Internal NG group providing specialised maintenance and emergency services for high pressure gas pipelines.

Plugs Model

A method used by NGET to classify network assets (for the purposes of charging) as either general infrastructure assets or connection assets. The plugs model identifies connection assets as excluding any assets which are shared or sharable by another user. The cost of connection assets are used to derive connection charges, while the cost of infrastructure assets is used to derive use of system charges. See Transmission Network Use of System charges.

R

Real Unit Operating Expenditure (RUOE)

A measure of operating performance calculated by dividing the real operating expenditure in a year by an appropriate output measure.

Registered Power Zones (RPZ)

A mechanism to encourage the DNOs to develop and demonstrate new and more cost-efficient ways of connecting and operating generators on their systems.

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated transmission or (as the case may be) distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

Renewables Obligation Certificates (ROCs)

A mechanism implemented by the Government to promote generation by renewable energy sources. Generators are given certificates depending on the volume they generate and suppliers are required to source a per cent of their energy from renewable sources or pay a buyout price.

Repex

In this consultation this term describes the use of an operating allowance to fund each year's expected non load related capital expenditure.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

Re-openers

A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances) under a price control before the scheduled next formal review date for the relevant price control.

Revenue Driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

Rolling Incentives

A measure which ensures licensees are able to retain the rewards of efficiency savings for a period of five years (consistent with the duration of the price control) irrespective of when the efficiency saving is made.

S

Security and Quality of Supply Standard (SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Scottish Hydro-Electric Transmission Limited (SHETL)

The electricity transmission licensee in northern Scotland.

Scottish Power Transmission Limited (SPTL)

The electricity transmission licensee in southern Scotland.

Sliding scale

This term is used generically to describe incentive schemes which involve profit (and loss) sharing around a fixed target costs, such as the current form of SO incentives in gas and electricity.

System Operator (SO)

The system operator has responsibility to construct, maintain and operate the NTS and associated equipment in an economic, efficient and co-ordinated manner. In its role as SO, NGG NTS is responsible for ensuring the day-to-day operation of the transmission system.

T

Theoretical Maximum Physical Capacity

An approach to determining the level of baselines which can be characterised as the maximum amount of gas that can be taken through a particular entry or offtake point by reducing supplies at other nodes in order to balance the network but not taking into account interactions with flows elsewhere on the network.

Transmission Connected Customer (TCC)

A customer directly connected to the gas or electricity transmission system.

Transmission Entry Capacity (TEC)

Defines a generator's maximum allowed export capacity onto the transmission system. The holder of the TEC has the right to export the specified number of megawatts onto the transmission system at any one time, and is eligible for compensation if NGET cannot accommodate this export on the network.

Transmission Investment for Renewable Generation (TIRG)

In the context of this document, this means the regulatory mechanisms developed before the start of the next main price control in 2007, to fund a number of specific network enhancement projects required to provide transmission capacity for new renewable generation plants.

Transmission Owners (TO)

Companies which hold transmission owner licenses. Currently there are three electricity TOs; NGET, SPTL and SHETL. NGG NTS is the gas TO.

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three

electricity transmission licensees, NGET, SPTL, SHETL and to the licensed gas transporter responsible for the gas transmission system, NGG NTS

Transmission Use of System Charges (TNUoS)

Charges levied by NGET on users of the GB electricity transmission network to recover the costs of providing and maintaining the general network infrastructure assets. TNUoS charges vary by location, and are different for generators and for suppliers.

U

Unit Cost Allowance (UCA)

A parameter of the current revenue restriction for NGG NTS. A UCA is set for each entry point, and is intended to reflect the cost of providing additional capacity at that point on the network. The actual additional revenue entitlement for NGG NTS if it releases such additional capacity at a particular entry point is a function of the UCA for that entry point. NGG NTS also uses the UCAs as reserve prices in its auctions of entry capacity.

Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced NGG NTS's network code as the contractual framework for the NTS, GDNs and system users.

V

Vesting Assets

Assets included in the RAV at the vesting date.

Vesting

The date at which the regulated gas and electricity transmission and distribution companies were privatised.

Appendix 5 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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Appendix 6 - Price Control Calculations

Introduction

1.1. This appendix sets out the way that the revenue allowances for each of the transmission licensees has been calculated for the period 2007/08 to 2011/12, including the key assumptions that have been adopted in order to derive price control revenue allowances.

1.2. We first provide an explanation of how the calculations are constructed. We then set out the calculations for each of the four companies in turn.

Explanation

1.3. Price controls provide a company with a level of revenue that is sufficient to finance an efficient business. This is based on an estimate of operating expenditure; capital expenditure; financing costs; and corporation tax for the period 2007/08 to 2011/12. The calculations of price control revenues include, for illustration, an amount that might be earned under the IFI. However, it should be noted that IFI revenue is provided on a partial pass-through basis depending on companies' expenditure in IFI activities.

The balance between 'R0' and 'X'

1.4. In setting the price control a decision needs to be made about the balance between the immediate change in revenues in the first year of the price control ('R0') and the path of revenues over the remaining years (or 'X'). There is no "right" answer on the appropriate balance between 'R0' and 'X', but there are two main considerations in coming to a decision, namely the financial profile of companies and the longer-term trend in revenues.

1.5. We have assumed, for modelling purposes, that revenues will be held constant in real terms over the entire five year period. For final proposals, we are minded to profile revenues more closely to the anticipated profile of costs.

Approach to the revenue calculations

Calculating the movement in the RAV

1.6. The calculation of the movement in the RAV is shown in lines 1 to 6. In each year total capital expenditure[12] (line 2) is added to the opening RAV (line 1) and the allowed level of depreciation (line 3) is subtracted from it to give a closing asset value (line 4). The closing value in any year (line 4) then becomes the next year's opening value (line 1).

1.7. The difference between the present values of the opening RAV in 2007/08 and the closing RAV in 2011/12 (are shown in line 5). The present value movement in the RAV is then derived by subtracting the present value of the closing RAV in 2011/12 from the present value of the opening RAV in 2007/08 (line 6).

Calculating allowed items

1.8. The allowed levels of costs and associated items are shown in lines 7 to 15. Line 7 shows the allowed level of operating expenditure (excluding pensions costs which have been considered separately) in each year. This is the sum of controllable and non-controllable operating cost allowances. The annual allowances for capital expenditure are given in line 8. Ofgem's proposed allowance for expensed pensions costs are then set out in line 9.

1.9. Ofgem's proposed allowances for corporation tax are set out in line 10 based upon the methodology set out in Chapter 8. The total annual cash costs that will be incurred by each licensee is calculated by adding together lines 7 to 10 in each year (line 11). The annual cost is then discounted to determine the present value equivalent cost (line 12). This is calculated by discounting the total allowed items figure by the vanilla WACC[13] of 4.84 per cent.

1.10. We then derive the total cost allowance for the five year period (line 14) by summing the present value of the annual cash costs (line 12) and adding the present value movement in the RAV (line 13).

Calculating annual revenue

1.11. To ensure that the price controls provide a company with a level of revenue that is sufficient to finance an efficient business, the total present value of annual revenues (line 19) must equate to the total present value of allowed costs (line 14).

[12] Total capital expenditure includes an allowance for capitalised pension.
[13] Calculated as the average of the pre-tax cost of debt and post-tax cost of equity weighted by the assumed gearing level. This is consistent with a post-tax cost of capital of 4.2 per cent.

We have profiled the present value total of base TO revenue according to our assumption that revenues will be held constant in real terms (i.e. X equal to zero). The present value of the base TO revenue line is then divided by the discount factor (line 16) to derive the total base TO revenue allowance (line 17). We have added an illustrative amount for IFI income (line 20) and, for the Scottish electricity transmission licensees, an adjustment in relation to the five year rolling capital expenditure incentives that applied in respect of their price controls in 2003/04 and 2004/05 (line 22) to derive total TO revenues.

NGET

1.12. The table below sets out how the revenue allowance proposals for NGET set out in Chapter 3 of the main document have been calculated.

Table A6.1: NGET revenue allowances

All prices are £m in 2004/05 terms

	Licensee = NGET TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		5,424.2	5,636.3	5,751.8	5,913.1	6,169.8
2	Total capital expenditure		594.9	513.3	571.9	653.9	663.3
3	Depreciation		-382.9	-397.7	-410.6	-397.1	-413.3
4	Closing asset value		5,636.3	5,751.8	5,913.1	6,169.8	6,419.8
5	Present value of opening/closing RAV		5,424.2				5,068.6
6	5 year movement in PV of RAV						355.6
	Allowed items						
7	Operating costs (excluding pensions)		259.6	253.5	248.5	248.9	249.9
8	Capital expenditure		594.9	513.3	571.9	653.9	663.3
9	Pensions allowance		38.0	37.4	37.0	36.9	36.4
10	Tax allowance		117.7	115.6	112.7	105.0	96.5
11	Total of allowed items		1,010.1	919.9	970.0	1,044.6	1,046.1
12	Present value of allowed items		986.6	856.9	861.9	885.4	845.7
13	5 year movement in PV of RAV						355.6
14	Total present value over 5 years						4,792.1
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Price control revenue		1,076.2	1,076.2	1,076.2	1,076.2	1,076.2
18	Present value of PC revenue		1,051.1	1,002.6	956.3	912.1	870.0
19	Total present value over 5 years						4,792.1
20	IFI revenue (0.4% of line 17)		4.3	4.3	4.3	4.3	4.3
21	Revenue driven revenue		0.0	0.0	0.0	0.0	0.0
22	Capex roller incentive		0.0	0.0	0.0	0.0	0.0
23	Total price control revenue		1,080.5	1,080.5	1,080.5	1,080.5	1,080.5

SHETL

1.13. The table below set out how the revenue allowance proposals for SHETL set out in Chapter 4 of the main document have been calculated.

Table A6.2: SHETL revenue allowances

All prices are £m in 2004/05 terms

	Licensee = SHETL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		287.0	318.3	335.3	347.8	363.5
2	Total capital expenditure		48.0	34.6	30.9	34.7	29.7
3	Depreciation		-16.6	-17.6	-18.3	-19.0	-19.7
4	Closing asset value		318.3	335.3	347.8	363.5	373.5
5	Present value of opening/closing RAV		287.0				294.9
6	5 year movement in PV of RAV						-7.9
	Allowed items						
7	Operating costs (excluding pensions)		9.4	9.7	9.2	9.0	9.1
8	Capital expenditure		48.0	34.6	30.9	34.7	29.7
9	Pensions allowance		0.7	0.8	0.8	0.8	0.8
10	Tax allowance		6.0	5.2	4.9	4.4	4.0
11	Total of allowed items		64.1	50.2	45.7	48.9	43.5
12	Present value of allowed items		62.6	46.7	40.6	41.5	35.2
13	5 year movement in PV of RAV						-7.9
14	Total present value over 5 years						218.8
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Price control revenue		49.1	49.1	49.1	49.1	49.1
18	Present value of PC revenue		48.0	45.8	43.7	41.6	39.7
19	Total present value over 5 years						218.8
20	IFI revenue (0.4% of line 17)		0.2	0.2	0.2	0.2	0.2
21	Revenue driven revenue		0.0	0.0	0.0	0.0	0.0
22	Capex roller incentive		0.4	0.2	-0.1	0.0	0.0
23	Total price control revenue		49.7	49.5	49.2	49.3	49.3

SPTL

The table below sets out how the revenue allowance proposals for SPTL set out in Chapter 5 of the main document have been calculated.

Table A6.3: SPTL revenue allowances

All prices are £m in 2004/05 terms

	Licensee = SPTL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		753.7	807.9	841.3	870.1	955.6
2	Total capital expenditure		117.2	99.4	97.3	143.6	118.0
3	Depreciation		-63.1	-66.0	-68.5	-58.2	-64.6
4	Closing asset value		807.9	841.3	870.1	955.6	1,009.0
5	Present value of opening/closing RAV		753.7				796.6
6	5 year movement in PV of RAV						-42.9
	Allowed items						
7	Operating costs (excluding pensions)		28.2	27.8	28.5	28.5	28.5
8	Capital expenditure		117.2	99.4	97.3	143.6	118.0
9	Pensions allowance		0.5	0.5	0.5	0.5	0.5
10	Tax allowance		18.5	17.0	15.7	13.7	11.6
11	Total of allowed items		164.4	144.7	141.9	186.3	158.5
12	Present value of allowed items		160.6	134.8	126.1	157.9	128.1
13	5 year movement in PV of RAV						-42.9
14	Total present value over 5 years						664.6
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Price control revenue	159.6	149.3	149.3	149.3	149.3	149.3
18	Present value of PC revenue		145.8	139.0	132.6	126.5	120.7
19	Total present value over 5 years						664.6
20	IFI revenue (0.4% of line 17)		0.6	0.6	0.6	0.6	0.6
21	Revenue driven revenue		0.0	0.0	0.0	0.0	0.0
22	Capex roller incentive		0.0	0.0	0.0	0.0	0.0
23	Total price control revenue		149.9	149.9	149.9	149.9	149.9

NGG NTS

1.14. The table below sets out how the revenue allowance proposals for NGG NTS set out in Chapter 6 of the main document have been calculated.

Table A6.4: NGG NTS revenue allowances

All prices are £m in 2004/05 terms

	Licensee = NGGT TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		2,928.9	3,296.1	3,396.5	3,335.7	3,268.3
2	Total capital expenditure		464.3	206.3	48.3	41.3	36.9
3	Depreciation		-97.1	-105.9	-109.1	-108.7	-108.1
4	Closing asset value		3,296.1	3,396.5	3,335.7	3,268.3	3,197.1
5	Present value of opening/closing RAV		2,928.9				2,524.2
6	5 year movement in PV of RAV						404.8
	Allowed items						
7	Operating costs (excluding pensions)		137.8	136.5	137.2	136.4	138.2
8	Capital expenditure		464.3	206.3	48.3	41.3	36.9
9	Pensions allowance		38.3	37.7	37.1	37.0	36.6
10	Tax allowance		36.1	31.4	35.9	41.1	45.2
11	Total of allowed items		676.4	411.9	258.4	255.7	256.9
12	Present value of allowed items		660.6	383.7	229.6	216.7	207.7
13	5 year movement in PV of RAV						404.8
14	Total present value over 5 years						2,103.2
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Price control revenue		472.3	472.3	472.3	472.3	472.3
18	Present value of PC revenue		461.3	440.0	419.7	400.3	381.8
19	Total present value over 5 years						2,103.2
20	IFI revenue (0.4% of line 17)		1.9	1.9	1.9	1.9	1.9
21	Total price control revenue		474.2	474.2	474.2	474.2	474.2