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Transmission Price Control Review: Initial Proposals

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

Overview:

This document sets out our initial proposals for the transmission price controls that will apply from 1 April 2007. It represents a key milestone in the Transmission Price Control Review (TPCR) as it sets out our initial thinking on the allowances that we intend to provide to fund efficient expenditure of the transmission licensees over the period 2007 - 2012.

We present our initial findings from our 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 information and more detailed proposals in relation to the design of the price controls and the incentives that we intend to provide to transmission companies.

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Context

Transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain. Timely investment in the networks is essential to ensure their efficient operation.

There have been a number of changes in the external environment since the current transmission price controls were set and there is significant uncertainty concerning the future development of the networks. This uncertainty arises, in particular, from:

- changing patterns of gas supply resulting from the decline of UK gas production and its replacement by imports;
- changes in the electricity generation mix, largely relating to the development of renewable generation; and
- changes in wider energy policy, especially concerning environmental issues.

Against this background, the objectives of the review involve developing incentives for investment in gas and electricity infrastructure, to promote efficient and timely investment in our transmission networks and to allocate risk appropriately.

Associated Documents

- TPCR 2007-2012 Initial Proposals - Appendices
- 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)

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. These price controls will determine 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 sets out our initial proposals, which have been developed following a process of public consultation that started in July 2005. The revenue allowances reflect our current assessment of historic and forecast data as provided to Ofgem by the licensees. The key themes of our initial 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 move from UK gas production to an increasing reliance on gas imports and the growth in renewable generation. These changes will require significant investment in new network access 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 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 deliver investment and operate their networks in an efficient and effective manner, ensuring that consumers continue to benefit from a high standard of performance at an efficient cost.

Initial proposals

The main features of our initial proposals are:

- We have made allowances for capital investment of some £4.25 billion (in 2004/5 prices) over the next five years, representing an increase of 65 per cent over the

allowances set during their last major price control reviews. This figure 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 are also introducing mechanisms to adjust the revenue allowances automatically, either up or down, in response to the needs of users of the system as these become known. As an illustration, if a reasonable proportion of the licensees forecast investments currently seen as uncertain do in fact occur, then capital investment of some £5.0 billion would be required, representing an overall increase of 95 per cent over the last reviews.

- The 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.

- The proposals allow a real post tax return of 4.2 per cent on the regulated asset value of the companies.

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 £1,595 million per annum. This will represent a reduction of around 4 per cent against the current allowances for 2006/07. The actual change in revenues will depend on the actual performance of companies under the current price controls and the effects of the revenue drivers.

We have developed these initial proposals following a detailed investigation of the information provided by the companies, and consideration of the associated financial issues. There is still work to do and our proposals should be expected to change. For example, adjustments in the timing of revenue allowances to maintain the ability of the companies to finance their activities are likely to cause allowances to increase relative to our initial proposals.

Implications for transmission charges

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 that the impact of these proposals on domestic energy bills to be small. For some larger industrial customers, however, the impact of changes in transmission charges might be more significant.

Next steps

We will undertake further cost analysis and price control development work which will be presented in the updated proposals in September 2006. We will then publish final proposals in early December 2006. The new controls, if accepted by the licensees, will take effect from 1st April 2007.

1. Introduction

Chapter Summary

This chapter sets out the background to the initial proposals and summarises the main developments since publication of our Third TPCR Consultation in March 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 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. We have now reached a stage in the process where we have formed an initial view on what these fixed allowances should be. This view is based on our analysis of each company's cost submissions, informed by work undertaken by our external consultants. The next stage is to seek wider views on these findings and to explore further with the companies some specific areas of costs.

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 initial findings on 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 initial findings for each of the four transmission companies in turn;
- Chapters 7 and 8 discuss those issues that are largely common to all companies which influence the level at which the revenue allowances are set. 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. Chapter 8 discusses financial issues, including the important issue of cost of capital;

- Chapter 9 provides an update on electricity and gas System Operator issues.

- Chapters 10 and 11 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);

- Chapter 12 sets out how we have considered environmental issues in the context of the TPCR, and explains how these considerations are reflected in the developing our initial proposals.

1.5. There are a number of supplementary appendices which provide more technical detail on our initial proposals, and which set out the different strands of our impact assessment work. Appendix 3 provides a glossary of terms relevant to this document, and appendix 15 sets out how we have responded to the many individual points made by respondents to the Third TPCR Consultation.

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.

2. Overview of the initial 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 including pension costs, tax, depreciation and the allowed rate of return. We have also assessed of whether historic capital expenditure has been efficient. These views have been informed by work undertake by external consultants for Ofgem. Subject to commercial confidentiality we intend to publish these reports in due course.

2.2. Our assessment of companies' costs and other price control assumptions is ongoing 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 changes will be set out in our subsequent documents.

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.

Capital Expenditure

2.4. 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 practises. Our analysis has two key elements:

- an efficiency review of historical capital expenditure up to 2004/05; and
- an assessment of forecast capital expenditure for 2005/06 to 2011/12.

2.5. In our March Consultation document, we highlighted that a key feature of the TPCR was the significant increase in capital expenditure proposed by the the transmission licensees. In particular, the four transmission licensees had submitted bids for some £6.7 billion for the period 2007 to 2012 compared to some £2.6 billion for the last 5 year review period.

2.6. 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 which we instead propose will be captured by the automatic adjustment mechanisms. 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.

2.7. 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. We have formed the view that the fixed revenue allowances should provide appropriate funding for some £4.25 billion of capital expenditure over the next five years. However, as an illustration, if a significant proportion of the investments currently seen as uncertain do occur, then this could result in a total expenditure requirement of £5.0 billion.

Operating expenditure

2.8. 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 (taken as our base year) operating costs by removing, amongst other things, non-recurring and atypical cost items. We have also made some adjustments for different accounting treatments of certain types of expenditure;
- We have considered the scope for efficiency improvements during the coming 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.

2.9. Our analysis of the companies' forecasts of controllable operating costs has identified scope for savings in a number of areas. We have formed a view that the fixed revenue allowances should provide appropriate funding for some £1.1 billion of operating expenditure over the next five years. This represents a reduction of £300m relative to the companies' forecasts.

Summary of the proposed revenue allowances

2.10. Our initial calculations of revenue allowances for the transmission companies are highlighted in the following tables. The revenue allowances are not profiled over the five years 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

(2004/05 prices)	2006/07 allowance (£m)	2007/08 - 2011/12 annual allowance (£m)
NGG	442	471
NGET	1005	940
SPTL	160	136
SHETL	51	49
Change (%)		**-3.7**

2.11. Overall, our initial proposals represent a reduction in annual transmission revenues of around 4 per cent relative to 2006/07 allowances. However, this outcome should be considered with a degree of caution. The table above reflects the annual fixed allowances for each of the transmission licensees before the impact of the automatic adjustment mechanisms. They might therefore be viewed as conservative estimates of total revenue allowances, in particular for SHETL and NGG NTS. Under one reasonable alternative scenario for NGG NTS and SHETL, where new investments that they propose are included to reflect a total £5.0 billion of capex i.e. some £750 million higher than is assumed in the baseline, then overall allowances would be £19 million per annum higher.

Impact of proposals 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 that the impact of our proposals on domestic energy bills to be small. However, we recognise that some larger customers may be exposed to a greater proportion of transmission charges and the impact of these proposals upon energy costs may be more significant. These impacts are explained further in Appendix 6.

3. National Grid Electricity Transmission (NGET)

Chapter Summary

This chapter sets out our initial proposals for the revenue allowances for NGET for the period 2007 to 2012. NGET is the System Operator (SO) of the GB electricity transmission system and owns and maintains the network of electricity transmission assets in England & Wales. The chapter also explains the outcome of our efficiency assessment of capital expenditure incurred during the last main price control period and the current one-year control, and sets out the adjustments we have made to the underlying estimates of future operating costs and capital expenditure provided by the companies.

Questions

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

Summary

3.1. The table below summarises our initial proposals for NGET (all prices are 2004/05, £m). We have profiled revenues to ensure that revenues are held constant in real terms from 2007/08 onwards (i.e. X=0):

Table 3.1 NGET Revenue allowances

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		322	338	341	355	385
- load (base case)		253	179	200	195	179
Operating costs						
- Controllable		150	141	138	140	141
- Non-controllable		102	101	101	101	101
Pensions		36	36	36	37	37
Current Tax		86	81	74	65	57
Revenue allowances	1,005	940	940	940	940	940

3.2. These initial calculations indicate that NGET's revenue allowance will fall by some £65m between 2006/07 and 2007/08.

3.3. The capital expenditure allowances for load related expenditure (i.e. new infrastructure investment) have been calculated assuming a baseline view on the forecast volume of new generation connections. The proposed revenue adjustment mechanisms will flex the allowances for load related expenditure depending on actual demands for capacity relative to this baseline. The detail of the revenue adjustment mechanisms is discussed in Chapter 10 and Appendix 11.

Capital expenditure (Capex)

Historical (2000/01 to 2004/05)

3.4. The relevant historic period for NGET is from 2000/01 (the last year for the previous price control period) to 2004/05 (the latest year for which there is actual data). As summarised in the table below, NGET has over-spent its allowances of £1,601m for capital expenditure by 4 per cent.

Table 3.2 NGET Historical Capex

NGET historical capex (04/05 prices)	**2000/01-2004/05**		
	Load related	Non-load related	Total
Allowance (£m)	807	794	1601
Reported actual (£m)	874	853	1727
Adjusted actual (£m)	874	798	1673
Overspend (£m)	67	4	71
(Overspend/allowance)%	8%	1%	4%
TSS			
Reported actual (£m)			35

3.5. The actual capex as reported by NGET has been adjusted to exclude non-operational capex according to the definition under the current price control. The figures above also include NGET's investment to improve system operational efficiency (TSS capex), which has been funded during this period by NGET's five year SO internal cost incentive. The terms of the SO incentive scheme allow for efficient TSS expenditure to be included within the TO RAV when the current SO internal incentive scheme expires.

3.6. While we consider that NGET could have managed its historic expenditure to remain within its allowance in this period without significant consequences in terms of system performance, we have found no evidence of inefficient spend. Therefore, our initial proposal is to include all the adjusted actual capex incurred in this period in the RAV opening value at 1 April 2007.

Forecast (2005/06 to 2011/12)

3.7. The table below summarises NGET's forecast of expenditure required for the remaining two years of the current price control period (2005/06 and 2006/7) and for the full five-year period of the next price control. It also sets out our initial view on the appropriate level of expenditure, informed by the analysis of our external consultants. This view excludes TIRG investments which are subject to a separate funding mechanism.

3.8. We have so far only assessed NGET's forecast for this seven year period and identified certain reductions in certain areas. Where the reduction is a result of top-down analysis, it has been profiled along NGET's own forecast cost profile. Work is ongoing to assess NGET's actual expenditure for 2005/06. The outcome of this assessment, together with any consequential changes to our view of the next six years, will be set out in our September Update.

Table 3.3 NGET Forecast Capex

NGET forecast capex (04/05 prices)	**2005/06 - 2006/07** Load related	Non-load related	2yr sub total	**2007/08 - 2011/12** Load related	Non-load related	5yr sub total	7yr total
Licensee forecast (£m)	441	601	1042	1337	2460	3797	4839
Adjusted forecast (£m)	360	573	933	1166	2449	3616	4549
Ofgem view (£m)	329	418	746	1006	1742	2747	3493
Change from forecast (£m)	-32	-155	-187	-161	-708	-869	-1056
(Change/forecast)%	-9%	-27%	-20%	-14%	-29%	-24%	-23%
TSS							
Licensee forecast (£m)			10			19	29
Ofgem view (£m)			9			18	28

3.9. NGET's forecast has been adjusted to include only cost items that fit within our definition of baseline capex. This adjustment includes:

- taking out costs relating to excluded activities for separate review; and
- re-categorising certain cost items between opex and capex.

3.10. As we have used a lower assumption than NGET for the increase in generation connecting to the system and the corresponding increase in system boundary flows, certain items of load-related expenditure have been taken out of the adjusted forecast. It should be noted that if our assumption proves to be incorrect, and a different outcome is confirmed by user commitments, the revenue drivers would allow the revenue allowance to flex in response to these developments.

3.11. In arriving at our own view of the required allowance for load related capex we have then made a number of further adjustments, including:

- removing double-counting between load-related and non-load-related capex;
- removing an estimated amount of avoidable early asset replacement;
- removing NGET's estimate of the impact of future increases in the real cost of labour and materials; and
- estimated savings due to improvements in procurement efficiency.

3.12. The issues of future cost increases and procurement efficiency are discussed in paragraph 3.14 below.

3.13. Non-load related capex comprises costs of maintaining the existing capability of the network - mainly the replacement or refurbishment of existing assets. Our proposed reduction in comparison with NGET's forecast is driven by the following adjustments:

- to reflect more appropriate levels of asset replacement and refurbishment, both in terms of volume of activity and unit cost. These adjustments are based on advice from our consultants, who have carried out in-depth assessments of NGET's asset base and management processes;
- to remove, pending further consideration, an item relating to a possible need for investment by NGET in response to a potential change of service level from BT's '21st Century' telecoms network; and
- to remove the estimate of future real cost increases and to reflect estimated savings due to improvements in procurement efficiency.

3.14. NGET assumed in their cost estimates an adjustment for future increases in the cost of labour and materials. We have yet to conclude on whether this is reasonable or not, and will update in September. For the purposes of initial proposals we have excluded this element of NGET's cost forecast. On procurement, we have assessed NGET's procurement policies and strategy and compared this to measures of best practice. On this basis, we have identified a potential range of savings and have assumed an overall 5 per cent reduction for the purposes of initial proposals. This is at the low end of our range of possible reductions, given the information available.

3.15. The treatment of future TSS capex is discussed in Chapter 7. Further detail of our cost assessment analysis that has informed our proposed capital expenditure allowances are given in Appendix 7.

Regulatory Asset Value

3.16. The table below sets out our initial proposals for the opening RAV in 2007/08, reflecting the outcome of our efficiency and performance review of capital expenditure for the period 2000/01 to 2006/07. This is based upon our consultants' estimates of expenditure for 2005/06 and 2006/07, and is pending the outcome of our further review.

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

	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Opening value bf	5,112.8	5,022.2	5,051.5	5,055.7	5,038.7	5,061.5	5,153.1
Depreciation	-317.4	-320.5	-329.2	-337.5	-345.5	-354.8	-366.8
Net capex additions	346.1	349.8	333.4	320.5	368.4	446.4	412.2
Adjustments for disposals	-119.3	0.0	0.0	0.0	0.0	0.0	0.0
Closing value cf	5,022.2	5,051.5	5,055.7	5,038.7	5,061.5	5,153.1	5,198.5
Company view capex	346.1	349.8	333.4	320.5	368.4	532.0	514.4

Controllable operating costs

3.17. The operating costs incurred by NGET reflect a mix of controllable and non-controllable items as well as atypical items and one-off costs. In determining appropriate cost allowances, it is necessary to distinguish between operating costs that are controllable by the licensee and those that are outside direct control, such as network rates and licence fees. We propose that ongoing non-controllable costs are treated as a pass-through item for price control purposes. Within this context, our analysis focuses upon controllable operating costs.

Normalisation

3.18. NGET's operating costs reflect the cost of performing the day-to-day functions of the transmission business, including atypical costs and the costs of dealing with one-off events. Our efficiency assessment requires that costs are considered on a normalised basis. This means that we should only consider the efficiency of those costs associated with performing recurring functions.

3.19. Table 3.5 below outlines the normalisation of NGET's controllable costs for our base year of 2004/05. Our starting point is NGET's assessment of 2004/05 controllable cash costs as set out in their historic business plan questionnaire (HBPQ). We have then made several adjustments to remove non-cash costs, atypical and non-recurring costs as set out below.

Table 3.5 Normalisation of NGET's controllable opex (£m, 2004/05 prices)

NGET Controllable Cash Costs (per HBPQ)	179.3
- Disallowed Costs	-3.2
- Non Cash Costs	-3.3
- Atypical and Non Recurring Costs	-22.9
NGET RCCC (Ofgem)	149.9

3.20. Our proposed adjustments for disallowed costs include the removal of onerous lease costs and the removal of related party margins. We have also removed the costs associated with an employee share option scheme (non cash cost adjustment). The most significant adjustment we are proposing is the removal of the costs associated with atypical and non-recurring items including:

- a refund of connection charges;
- restructuring and severance costs; and
- site clearance costs.

3.21. The remaining normalised costs represent the recurring cash controllable costs (RCCC) that will continue to be incurred in the next period in the absence of further efficiency improvements. The next stage in our analysis is to assess the scope for efficiency improvements over the coming period.

Efficiency Analysis

3.22. In projecting NGET's RCCC forward to 2012 we incorporate estimates of potential efficiency savings. We have identified a number of savings using both 'top down' and 'bottom up' methods of analysis of NGET's costs. These include the following (for further details see Appendix 8);

- Engineering opex - we have identified some scope for efficiency savings in inspections and maintenance activities (routine and unplanned);
- Information Technology - we have identified potential efficiency savings including system integrator rates and the rationalisation of applications and platforms;
- Insurance - we have used an extrapolation of market cycles to project future insurance costs. This gives a lower estimate than NGET's assumption of an increasing linear trend;
- Other shared services and corporate costs - we have made further adjustments based on benchmarking analysis of these costs. In addition we have removed any duplication between NG's corporate centre and the regulated business; and
- Ongoing efficiency - we have included an assumption of 1.5 per cent p.a. This is discussed further in Chapter 7.

Upward cost pressures

3.23. We have also considered evidence put forward by NGET in respect of costs expected to increase during the next price control period. The following issues were identified by NGET.

- Quasi-capex[1] - NGET highlighted a number of increasing costs between 2007 and 2012. We have removed £82.7 million of these costs for a separate efficiency assessment and these may be included in the capex allowance rather than in opex. This is discussed further in Chapter 7;
- Insurance - as discussed above we have used a lower forecast than NGET; and
- Real wage growth - in developing our proposals we have assumed that there is no growth in real employment costs. NGET has assumed that real employment costs will increase by around 2 per cent p.a. initially, declining to around 1 per cent at the end of the period.

[1] This includes decommissioning of substations , overhead line and cable, refurbishment of overhead lines and circuit breakers, and asbestos removal.

Additional opex allowances

3.24. We have also included an allowance for non operational capex (see chapter 7). Our proposed opex allowances include NGET's forecasts of additional costs without adjustment. We are currently assessing these cost projections and may make appropriate adjustments to the allowances in due course. Any changes will be set out in our September update.

Summary

3.25. The following table summarises our initial proposals for controllable operating costs for NGET. It is important to note that NGET's FBPQ numbers are not necessarily comparable with our allowances on a "like-for-like" basis given our normalisation and removal of quasi capex costs.

Table 3.6 Initial Proposals NGET Controllable opex

	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
	£m	**£m**	**£m**	**£m**	**£m**
NGET forecast Controllable Operating Costs	**179.3**	**177.2**	**178.8**	**177.5**	**182.9**
NGET RCCC 2004/05	**149.9**	**149.9**	**149.9**	**149.9**	**149.9**
Total Efficiency Adjustments	(13)	(18)	(21)	(24)	(26)
Efficient Cash Costs	**137.1**	**131.7**	**129.0**	**125.9**	**124.1**
Total Upward Cost Drivers	1.2	1.2	1.2	1.2	1.2
Ongoing Opex Allowance	**138.3**	**132.9**	**130.2**	**127.1**	**125.3**
Total Additional Opex allowances	11.6	7.6	7.4	12.8	15.9
Ofgem total Controllable Allowance	**149.9**	**140.5**	**137.6**	**139.9**	**141.2**

4. Scottish Hydro-Electric Transmission (SHETL)

Chapter Summary

This chapter sets out our initial proposals for the revenue allowances for SHETL for the period 2007 to 2012. SHETL owns and maintains the network of transmission assets in northern Scotland. The chapter also explains the outcome of the capital expenditure efficiency assessment during the current price control period the adjustments we have made to the underlying estimates of forecast operating costs and capital expenditure provided by SHETL.

Questions

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

Summary

4.1. The table below summarises our initial proposals for SHETL (all prices are 2004/05, £m). We have profiled revenues to ensure that revenues are held constant in real terms from 2007/08 onwards (i.e. X=0):

Table 4.1 SHETL Revenue allowances

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		10.0	11.7	13.1	8.3	8.3
- load (base case)		28.0	15.3	15.7	23.6	18.5
Operating costs						
- Controllable		5.8	6.2	5.6	5.4	5.4
- Non-controllable		3.5	3.5	3.5	3.5	3.5
Pensions		0.7	0.8	0.8	0.8	0.8
Current Tax		6.4	5.5	5.2	4.8	4.4
Revenue allowances	50.8	48.9	48.9	48.9	48.9	48.9

4.2. These initial calculations indicate that SHETL's revenue allowance will fall by about £1m between 2006/07 and 2007/8. A more detailed explanation of how the revenue allowance has been calculated is included in Appendix 5.

4.3. The capital expenditure allowances for load related expenditure have been calculated assuming a baseline view on the forecast volume of new generation connections. Our revenue adjustment mechanisms will flex allowances for load related expenditure depending on actual demands for capacity relative to this baseline. These adjustment mechanisms are discussed in Chapter 9 and Appendix 11.

Capital expenditure

Historical (1999/00 - 2004/05)

4.4. The summary table below shows that SHETL has under-spent its allowance by 21 per cent in the historical period.

Table 4.2 SHETL Historical Capex

SHETL historical capex (04/05 prices)	**1999/00-2004/05**		
	Load related	Non-load related	Total
Allowance (£m)	15	71	86
Reported actual (£m)	25	43	68
Adjusted actual (£m)	25	43	68
Overspend (£m)	10	-28	-18
(Overspend/allowance)%	68%	-40%	-21%

4.5. We have found no evidence of inefficient spend in this period, and therefore propose to include all the actual capex incurred in this period in the RAV opening value at 1 April 2007.

Forecast (2005/06 to 2011/12)

4.6. The table below summarises SHETL's forecast of expenditure required for the remaining two years of the current price control period (2005/06 and 2006/7) and for the full five-year period of the next price control. It also sets out our initial view on the appropriate level of expenditure informed by the analysis of our external consultants. This view excludes TIRG investments which are subject to a separate funding mechanism.

4.7. We have so far only assessed SHETL's forecast for this seven year period and identified certain reductions in certain areas. Where the reduction is a result of top-down analysis, it has been profiled along SHETL's own forecast cost profile. Work is ongoing to assess SHETL's actual expenditure for 2005/06. The outcome of this assessment, together with any consequential changes to our view of the next six years, will be set out in our September update document.

Table 4.3 SHETL Forecast Capex

SHETL forecast capex (04/05 prices)	2005/06 - 2006/07			2007/08 - 2011/12			
	Load related	Non-load related	2yr sub total	Load related	Non-load related	5yr sub total	7yr total
Licensee forecast (£m)	25	25	50	766	56	822	872
Adjusted forecast (£m)	21	25	45	114	56	170	216
Ofgem view (£m)	19	24	43	101	51	152	195
Change from forecast (£m)	-1	-1	-2	-13	-5	-18	-20
(Change/forecast)%	-7%	-4%	-5%	-11%	-8%	-10%	-9%
TSS							
Licensee forecast (£m)						12	12
Ofgem view (£m)						12	12

4.8. SHETL's forecast for load related expenditure has been adjusted to include only cost items that fit within our definition of baseline capex. This adjustment:

- Includes SHETL's request that some £626m of large investment schemes to accommodate forecast wind generation growth be taken out of the baseline consideration but be treated by flexible revenue allowance mechanisms; and
- reflecting a lower level of generation growth and corresponding level of system boundary flows included in the defined baseline.

4.9. SHETL's adjusted forecast of load related capex as included in the baseline relates to accommodating the generation and demand changes as part of the baseline definition. One reduction that we have made related to the assumed connection design for smaller wind farms (see Chapter 7 for further discussion).

4.10. SHETL's forecast of non-load related capex consists of costs for maintaining the existing capability of the network, including mainly the replacement or refurbishment of existing assets. We have made a minor adjustment to the forecast level of asset replacement.

4.11. TSS capex relates to investment to improve system operational efficiency. The historical TSS capex has been funded during this period by NGET's five year SO internal cost incentive. The terms of the SO incentive scheme allow for efficient TSS expenditure to be included within the TO RAV when the current SO internal incentive scheme expires. The treatment of future TSS capex is discussed in Chapter 7.

Regulatory Asset Value

4.12. The table below sets out our initial proposals for the opening RAV in 2007/08, reflecting the outcome of our efficiency and performance review of capital expenditure for the period 1999/00 to 2006/07. This is based upon our consultants' estimates of expenditure for 2005/06 and 2006/07 and is pending the outcome of our further review of these years.

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

	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Opening value bf	247.4	253.5	250.0	243.7	238.3	233.3	233.7	272.4
Depreciation	-12.9	-13.3	-13.5	-13.7	-13.9	-14.1	-15.6	-16.0
Net capex additions	19.0	9.9	7.2	8.3	8.9	14.4	54.4	25.7
Adjustments for disposals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing value cf	253.5	250.0	243.7	238.3	233.3	233.7	272.4	282.2
Company view capex	19.0	9.9	7.2	8.3	8.9	14.4	55.0	27.4

Controllable Operating costs

4.13. The operating costs incurred by SHETL reflect a mix of controllable and non-controllable items as well as atypical items and one-off costs. In determining appropriate cost allowances, it is necessary to distinguish between operating costs that are controllable by the licensee and those that are outside direct control, such as network rates and licence fees. We propose that ongoing non-controllable costs are treated as a pass-through item for price control purposes. Within this context, our analysis focuses upon controllable operating costs.

Normalisation

4.14. SHETL's operating costs reflect the cost of performing the day-to-day functions of the transmission business, including atypical costs and the costs of dealing with one-off events. Our efficiency assessment requires that costs are considered on a normalised basis. This means that we should only consider the efficiency of those costs associated with performing recurring functions.

4.15. Table 4.5 below outlines the normalisation of SHETL's controllable costs for our base year of 2004/05. Our starting point is SHETL's assessment of 2004/05 controllable cash costs as set out in their historic business plan questionnaire (HBPQ). We have then made adjustments to remove atypical and non-recurring costs as set out below:

Table 4.5 Normalisation of SHETL's controllable opex (£m, 2004/05 prices)

SHETL Controllable Cash Costs (per HBPQ)	5.4
- Disallowed Costs	n/a
- Non Cash Costs	n/a
- Atypical and Non Recurring Costs	-0.4
SHETL RCCC (Ofgem)	5.0

4.16. The adjustment of atypical costs represents implementation costs associated with the British Electricity Transmission and Trading Arrangements (BETTA) which was a one off event. The remaining normalised costs represent the recurring cash controllable costs (RCCC) that will continue to be incurred in the next period in the absence of further efficiency improvements. The next stage in our analysis is to assess the scope for efficiency improvements over the coming period.

Efficiency Analysis

4.17. We have projected SHETL's RCCC forward to 2012 to include an adjustment for ongoing efficiency improvements ("frontier shift") where we have included an assumption of 1.5 per cent p.a. This is discussed further in Chapter 7

Upward cost pressures

4.18. We have also considered the following cost increases put forward by SHETL in its FBPQ.

- Engineering opex – SHETL forecast an increase in operating costs linked to its forecast capex increase. We have adjusted these costs to be consistent with our allowance for SHETL's future capital expenditure;
- Insurance - SHETL forecast an increase linked to its forecast network expansion. We have made similar adjustments as with engineering opex;
- Real wage growth - we have presently assumed no growth in real wages. SHETL has assumed that wages will grow at around 1 per cent p.a. A key factor for consideration is the assessment of total employment costs (see chapter 7) which will be discussed in our September update.

Summary

4.19. The following table summarises our initial proposals for controllable operating costs for SHETL.

Table 4.6 Initial Proposals SHETL Controllable opex

	2007/08	2008/09	2009/10	2010/11	2011/12
	£m	£m	£m	£m	£m
SHETL Forecast Controllable Operating Costs	**6.0**	**6.4**	**6.8**	**7.1**	**7.5**
SHETL RCCC 2004/05	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
Total Efficiency Adjustment	(0)	(0)	(0)	(0)	(0)
Efficient Cash Costs	**4.9**	**4.9**	**4.8**	**4.7**	**4.6**
Total Upward Cost drivers	0.9	1.3	0.9	0.7	0.8
Ongoing Opex Allowance	**5.8**	**6.2**	**5.6**	**5.4**	**5.4**
Total Additional opex allowance	-	-	-	-	-
Ofgem total controllable allowance	**5.8**	**6.2**	**5.6**	**5.4**	**5.4**

5. Scottish Power Transmission (SPTL)

Chapter Summary

This chapter sets out our initial proposals for the revenue allowances for SPTL for the period 2007 to 2012. SPTL owns and maintains the network of transmission assets in southern Scotland. The chapter also explains the outcome of the capital expenditure efficiency assessment during the current price control period and sets out the adjustments we have made to the underlying estimates of forecast operating costs and capital expenditure provided by SPTL.

Questions

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

Summary

5.1. The table below summarises our initial proposals for SPTL (all prices are 2004/05, £m). We have profiled revenues to ensure that revenues are held constant in real terms from 2007/08 onwards (i.e. X=0):

Table 5.1 SPTL Revenue allowances

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		48.7	56.0	56.8	55.5	56.3
- load (base case)		65.7	38.3	37.5	82.6	55.4
Operating costs						
- Controllable		14.9	14.4	15.1	15.1	15.2
- Non-controllable		12.5	12.5	12.5	12.5	12.5
Pensions		1.2	1.2	1.2	1.2	1.2
Current Tax		16.8	15.3	13.9	11.9	9.7
Revenue allowances	159.6	135.5	135.5	135.5	135.5	135.5

5.2. These initial calculations indicate that SPTL's revenue allowance will fall by some £24m between 2006/07 and 2007/08. A more detailed explanation is provided in Appendix 5.

5.3. The capital expenditure allowances for load related expenditure (i.e. associated with the changing demands for network capacity) have been calculated assuming a baseline view on the forecast volume of new generation connections. Our revenue adjustment mechanisms will flex allowances for load related expenditure depending on actual demands for capacity relative to this baseline. The detail of these adjustment mechanisms is discussed in Chapter 10 and Appendix 11.

Capital expenditure

Historical (1999/00 - 2004/05)

5.4. The summary table below shows that SPTL under-spent its capex allowance by 4 per cent in the historical period.

Table 5.2 SPTL Historical Capex

SPTL historical capex (04/05 prices)	**1999/00-2004/05**		
	Load related	Non-load related	Total
Allowance (£m)	18	167	185
Reported actual (£m)	36	157	193
Adjusted actual (£m)	32	146	178
Overspend (£m)	14	-22	-8
(Overspend/allowance)%	79%	-13%	-4%

5.5. The actual capex as reported by the licensee has been adjusted to exclude non-operational capex and the profit margins charged by related parties as according to the definition under the current price control.

5.6. We have found no evidence of inefficient spend in this period, and therefore propose to include all the adjusted actual historical capex in the RAV opening value at 1 April 2007.

Forecast (2005/06 to 2011/12)

5.7. The table below summarises SPTL's forecast and our initial view of required capex for the remaining two years of the current price control period (i.e. including 2005/06) and for the full five-year period of the next price control. This view excludes TIRG investments which are subject to a separate funding mechanism. We have so far only assessed SPTL's forecast for this seven year period and identified certain reductions in certain areas. Where the reduction is a result of top-down analysis, it has been profiled along SPTL's own forecast cost profile. Work is ongoing to assess the actual capex incurred in 2005/06. The assessment of this, together with any consequential changes to our view of the next six years, will be reflected in our September Update.

Table 5.3 SPTL Forecast Capex

SPTL forecast capex (04/05 prices)	2005/06 - 2006/07			2007/08 - 2011/12			
	Load related	Non-load related	2yr sub total	Load related	Non-load related	5yr sub total	7yr total
Licensee forecast (£m)	61	112	173	347	367	713	886
Adjusted forecast (£m)	55	109	164	307	364	671	835
Ofgem view (£m)	49	90	139	279	273	553	692
Change from forecast (£m)	-6	-19	-25	-28	-90	-118	-143
(Change/forecast)%	-11%	-17%	-15%	-9%	-25%	-18%	-17%
TSS							
Licensee forecast (£m)						3	3
Ofgem view (£m)						2	2

5.8. SPTL's forecast has been adjusted to include only the cost items that fit our baseline capex definition. The adjustment is due to the following factors:

- re-categorising cost items between opex and capex; and
- reflecting the lower level of generation growth and corresponding level of system boundary flows included in the defined baseline. It should be noted that we will be putting in place mechanisms to allow revenues to flex around the baseline if new generation volumes vary from our assumptions.

5.9. SPTL's adjusted forecast of load related capex as included in the baseline relates to accommodating the generation and demand changes as part of the baseline definition. Our reduction in this cost category is driven by the following factors:

- adopting efficient connection designs for smaller wind farms; and
- removing avoidable/deferrable investment relating to demand growth

5.10. SPTL's forecast of non-load related capex consists of costs for maintaining the existing capability of the network, including mainly the replacement or refurbishment of existing assets. Our reduction is driven by the following factors:

- to reflect more appropriate levels of asset replacement and refurbishment and the efficient cost of doing so. This is based on advice from our consultants, who have carried out in-depth assessment of SPTL's asset management; and
- to remove, pending further assessment, the cost item relating to SPTL's expected need to accommodate the potential change of service level from BT's telecom network for carrying its operational telecoms signals.

5.11. TSS capex relates to investment to improve system operational efficiency. The historical TSS is under NGET's SO internal cost incentive, which allows depreciated value of efficient spend to be rolled into RAV at next price control. The treatment of future TSS capex has been discussed in consultation so far and our initial position is set out in Chapter 7. The reduction in our view reflects the more appropriate level of costs for the investment agreed between NGET as the GBSO and SPTL.

Regulatory Asset Value

5.12. The table below sets out our initial proposals for the opening RAV in 2007/08, reflecting the outcome of our efficiency and performance review of capital expenditure for the period 1999/00 to 2006/07. This is based upon our consultants' estimates of expenditure for 2005/06 and 2006/07, pending the outcome of our further review.

Table 5.4 SPTL Regulatory Asset Value 1999/00 to 2006/07

	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Opening value bf	681.4	654.0	629.1	596.1	581.9	576.8	557.0	712.5
Depreciation	-49.1	-49.6	-50.2	-50.7	-51.6	-52.7	-59.4	-60.5
Net capex additions	21.6	24.7	17.2	36.4	46.5	32.9	214.8	94.1
Adjustments for disposals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing value cf	654.0	629.1	596.1	581.9	576.8	557.0	712.5	746.1
Company view capex	21.6	24.7	17.2	40.8	51.7	37.2	224.4	111.5

Controllable Operating costs

5.13. The operating costs incurred by SPTL reflect a mix of controllable and non-controllable items as well as atypical items and one-off costs. In determining appropriate cost allowances, it is necessary to distinguish between operating costs that are controllable by the licensee and those that are outside direct control, such as network rates and licence fees. We propose that ongoing non-controllable costs are treated as a pass-through item for price control purposes. Within this context, our analysis focuses upon controllable operating costs.

Normalisation

5.14. SPTL's operating costs reflect the cost of performing the day-to-day functions of the transmission business, atypical costs and the costs of dealing with one-off events. Our efficiency assessment requires that costs are considered on a normalised basis. This means that we should only consider the efficiency of those costs associated with performing recurring functions.

5.15. Table 5.5 below outlines the normalisation of SPTL's controllable costs for our base year of 2004/05. Our starting point is SPTL's assessment of 2004/05 controllable cash costs as set out in their historic business plan questionnaire (HBPQ). We have then made adjustments to remove disallowed costs, non-cash costs, atypical and non-recurring costs as set out below:

Table 5.5 Normalisation of SPTL's controllable opex (£m, 2004/05 prices)

SPTL Controllable Cash Costs (per HBPQ)	18.1
- Disallowed Costs	-0.7
- Non Cash Costs	-0.2
- Atypical and Non Recurring Costs	-2.7
SPTL RCCC (Ofgem)	14.5

5.16. The adjustment for disallowed cost is the removal of a related party margin, the non cash adjustment is to remove profit on the sale of assets. The adjustment of atypical costs is primarily for implementation costs associated with the British Electricity Transmission and Trading Arrangements (BETTA).

Efficiency Analysis

5.17. We have projected SPTL's RCCC forward to 2012 for identified efficiency savings and to include an adjustment for ongoing efficiency ("frontier shift") where we have included an assumption of 1.5 per cent p.a. This is discussed further in Chapter 7. We have identified some scope for cost reduction within SPTL's forecast for engineering opex, mainly for tower painting and plant maintenance.

Upward cost pressures

5.18. We have also considered evidence for increasing costs put forward by SPTL in respect of costs expected to increase costs over time. The following were identified by SPTL:

- Engineering opex – SPTL said that it had to increase some of its activities driven by the condition of its aging asset base. While we have made some efficiency adjustments to these costs we have nevertheless recognised a certain level of volume increase;
- Insurance - SPTL forecast increased insurance costs between 2007 and 2012. For the same reasons discussed in relation to NGET in Chapter 3 we have not included this increase.

Additional opex allowances

5.19. We have also included an allowance for non operational capex (see Chapter 7) We have taken the numbers forecast by SPTL which we are assessing and may adjust accordingly. Any changes will be detailed in September.

Summary

5.20. The following table summarises our initial proposals for controllable operating costs for SPTL.

Table 5.6 Initial Proposals SPTL Controllable opex (2004/05 prices)

	2007/08	2008/09	2009/10	2010/11	2011/12
	£m	£m	£m	£m	£m
SPTL forecast Controllable Operating Costs	**17.7**	**18.3**	**19.0**	**19.3**	**19.2**
SPTL RCCC 2004/05	**14.5**	**14.5**	**14.5**	**14.5**	**14.5**
Total Efficiency Adjustments	(2)	(2)	(3)	(3)	(3)
Efficient Cash Costs	**12.3**	**12.1**	**11.9**	**11.8**	**11.6**
Total Upward Cost Drivers	1.2	2.0	2.8	3.0	3.2
Ongoing Opex Allowance	**13.5**	**14.1**	**14.7**	**14.8**	**14.8**
Total Additional Opex allowances	1.3	0.3	0.4	0.4	0.4
Ofgem total Controllable Allowance	**14.9**	**14.4**	**15.1**	**15.1**	**15.2**

6. National Grid Gas NTS (NGG NTS)

Chapter Summary

This chapter sets out our initial proposals for the revenue allowances for NGG NTS for the period 2007 to 2012. NGG NTS owns and operates the gas transmission network in Great Britain. The chapter also explains the outcome of the capital expenditure efficiency assessment during the current price control period, and the adjustments we have made to the underlying estimates of forecast operating costs and capital expenditure provided by NGG NTS.

Questions

Question 6.1: Do you think our proposed approach to the costs incurred in the current price control period in respect of increasing capacity at St Fergus is appropriate?

Summary

6.1. The table below summarises our initial proposals for NGG NTS (all prices are 2004/05, £m). We have profiled revenues to ensure that revenues are held constant in real terms from 2007/08 onwards (i.e. X=0):

Table 6.1 NGG NTS Revenue allowance

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		98	60	39	32	33
- load (base case)		114	107	5	5	0
- Milford Haven		206	18	0	0	0
Operating costs						
- Controllable		58	57	56	55	56
- Non-controllable		79	79	79	78	78
Pensions		24	25	26	27	28
Current Tax		58	53	54	57	59
Revenue allowances	442	471	471	471	471	471

6.2. These initial calculations indicate that NGG-NTS's revenue allowance will increase by some £29m between 2006/07 and 2007/08. Further details are provided in Appendix 5.

6.3. The capital expenditure allowance for load related expenditure (i.e. associated with the changing demands for network capacity) is based on a baseline view together with expenditure in relation to Milford Haven. Our revenue adjustment mechanisms will flex allowances for load related expenditure depending on actual demands for capacity relative to this baseline. The detail of these adjustment mechanisms is discussed in Chapter 10 and Appendix 11.

Capital Expenditure

Historical (2002/03 to 2004/05)

6.4. The summary table below shows that NGG NTS under-spent its TO capex allowance in the historical period by 50 per cent.

Table 6.2 NGG NTS Historical Capex

NGG NTS historical capex (04/05 prices)	2002/03-2004/05		
	Load related	Non-load related	Total
Allowance (£m)	696	20	716
Reported actual (£m)	312	47	358
Adjusted actual (£m)	312	47	358
Overspend (£m)	-385	27	-358
(Overspend/allowance)%	-55%	136%	-50%

6.5. Although total expenditure was well below allowance, our initial assessment has indicated some £75m of inefficient load related spend in this period, all associated with investment to increase entry capacity at St Fergus. When considered in the context of the information derived from the long term entry capacity auctions, we do not believe that NGG NTS has demonstrated a need from this investment. In forming this view we have had regard to the time at which information on the lack of demand for capacity was available, and the choices available to NGG NTS in terms of progressing the investment, or not, at the time. Our current view is that the case has not been made for including this investment in opening RAV value at 1 April 2007. We are, however, willing to consider any further arguments put forward on this issue ahead of our September Update document.

6.6. In addition to what is defined as TO capex, costs incurred in this period on the Milford Haven project amount to £5.7m, which is subject to a separate efficiency assessment to decide the appropriate amount to enter RAV opening value.

Forecast (2005/06 to 2011/12)

6.7. The table below summarises NGG NTS's forecast and our initial view of required capex for the remaining two years of the current price control period (i.e. including 2005/06) and for the full five-year period of the next price control. We have so far only assessed NGG NTS's forecast for this seven year period and identified certain reductions in certain areas. Where the reduction is a result of top-down analysis, it has been profiled along NGG NTS's own forecast cost profile. We are currently collecting information on the actual capex incurred in 2005/06. The assessment of this, together with any consequential changes to our view of the next six years, will be reflected in our September updates.

Table 6.3 NGG NTS Forecast Capex

NGG NTS forecast capex (04/05 prices)	2005/06 - 2006/07			2007/08 - 2011/12			
	Load related	Non-load related	2yr sub total	Load related	Non-load related	5yr sub total	7yr total
Licensee forecast (£m)	211	133	344	674	448	1122	1466
Adjusted forecast (£m)	181	127	309	284	411	695	1004
Ofgem view (£m)	171	114	285	230	263	493	779
Change from forecast (£m)	-10	-13	-23	-53	-148	-202	-225
(Change/forecast)%	-6%	-10%	-8%	-19%	-36%	-29%	-22%
Milford Haven							
Licensee forecast (£m)			360			224	584

6.8. NGG NTS's forecast has been adjusted to include only cost items that fit within our definition of baseline capex. This adjustment includes:

- reallocating a certain amount of costs from load related to non-load related capex; and
- re-categorising cost items between opex and capex.

6.9. We have also adjusted NGG NTS's forecast to reflect our definition of entry and offtake capacity baselines. It should be noted that we will be putting in place mechanisms to allow revenues to flex around the baseline if new entry capacity volumes vary from our assumptions.

6.10. NGG NTS's forecast of load related baseline capital expenditure includes investment to deliver the baseline entry capacity as defined for the current price control period. NGG assumed in their cost estimates an adjustment for future increases in the cost of labour and materials. We have yet to conclude on whether this is reasonable or not, and will update in September. For the purposes of initial proposals we have excluded this element of NGG NTS's cost forecast. On procurement, we have assessed NGG NTS's procurement policies and strategy and compared this to measures of best practice. On this basis, we have identified a potential range of savings and have assumed an overall 5 per cent reduction for the purposes of initial proposals. This is at the low end of our range of possible reductions, given the information available.

6.11. NGG NTS's forecast of non-load related capex concerns the costs to replace and refurbish existing assets for maintaining the existing capability of the network, and meeting safety and/or environmental requirements. Our reductions from NGG NTS's adjusted non-load related capex include:

- the reduction of a small proportion of forecast cost to replace compressors for emission reduction due to very low future utilisation of certain sites; and
- the relocation of currently under-utilised assets to reduce the need for new assets.

Regulatory Asset Value

6.12. The table below sets out our initial proposals for the opening RAV in 2007/08, reflecting the outcome of our efficiency and performance review of capital expenditure for the period 2002/03 to 2006/07. This is based upon our consultants' estimates of expenditure for 2005/06 and 2006/07, and is pending the outcome of our further review.

Table 6.4 NGG NTS Regulatory Asset Value 2002/03 to 2006/07

	02/03	03/04	04/05	05/06	06/07
Opening value bf	2,351.2	2,400.6	2,421.4	2,395.3	2,547.7
Depreciation	-79.2	-82.1	-84.9	-84.7	-88.5
Net capex additions	128.6	102.9	58.8	237.2	413.6
Adjustments for disposals	0.0	0.0	0.0	0.0	0.0
Closing value cf	2,400.6	2,421.4	2,395.3	2,547.7	2,872.7
Company view capex	137.5	134.7	91.9	245.6	428.3

Controllable Operating costs

6.13. The operating costs incurred by NGG NTS reflect a mix of controllable and non-controllable items as well as recurring cost, atypical items and one-off costs. In determining appropriate cost allowances, it is necessary to distinguish between operating costs that are controllable by the licensee and those that are outside direct control, such as network rates and licence fees. We propose that ongoing non-controllable costs are treated as a pass-through item for price control purposes. Within this context, our analysis focuses upon controllable operating costs.

Normalisation

6.14. NGG NTS's operating costs reflect the cost of performing the day-to-day functions of the transmission business, atypical costs and the costs of dealing with one-off events. Our efficiency assessment requires that costs are considered on a normalised basis. This means that we should only consider the efficiency of those costs associated with performing recurring functions.

6.15. Table 6.5 below outlines the normalisation of NGG NTS's controllable costs for our base year of 2004/05. Our starting point is NGG NTS's assessment of 2004/05 controllable cash costs as set out in their historic business plan questionnaire

(HBPQ). We have then made several adjustments to remove non-cash costs, atypical and non-recurring costs as set out below:

Table 6.5 Normalisation of NGG NTS's controllable opex (£m, 2004/05 prices)

NGG NTS Controllable Cash Costs (per HBPQ)	63.6
- Disallowed Costs	-0.1
- Non Cash Costs	-0.6
- Atypical and Non Recurring Costs	-2.9
NGG NTS RCCC (Ofgem)	60.0

6.16. The adjusted for disallowed cost was to remove related party margins, the adjustment for non cash costs was for an employee share option scheme. The atypical costs removed related to restructuring costs.

Efficiency Analysis

6.17. In projecting NGG NTS's RCCC forward to 2012 we incorporate estimates of potential efficiency savings. We have identified a number of savings using both 'top down' and 'bottom up' methods of analysis of NGG NTS's costs. These include the following (for further details see Appendix 8).

- Engineering opex - we have identified some scope for cost reductions mainly due to de-manning of non-operational compressor stations;
- Information Technology - we have identified savings for costs relating to system integrator rates, application and platform rationalisation;
- Insurance - we have used an extrapolation of market cycles to project future insurance costs, NG assumed an increasing linear trend;
- Other shared services and corporate costs - we have made further adjustment based on benchmarking analysis. In addition we have adjusted for any duplication between NG's corporate centre and the regulated business;
- Ongoing efficiency ("frontier shift") - we have included an assumption of 1.5 per cent p.a. this is discussed further in Chapter 7.

6.18. Aside from engineering opex, these adjustments are based on the same analysis as for NGET.

Upward cost pressures

6.19. We have also considered evidence put forward in respect of costs expected to increase costs over time. The following were identified by NGG NTS.

- Quasi-capex - NGG NTS highlighted a couple of items between 2007 and 2012. Of these costs £1.8 million has been removed and treated as capex of the remaining costs we have included £1.6 million over 2007-12. This is discussed further in Chapter 7
- Real wage growth - we have presently assumed no growth in real wages. NGG NTS has assumed growth of 2 per cent p.a. declining to 1 per cent at the end of the period. A key factor for consideration is the assessment of total employment costs (see Chapter 7) which will be discussed in our September update.

Additional opex allowances

6.20. We have also included an allowance for non operational capex (see chapter 7). We have taken the numbers forecast by NGG NTS for the purposes of initial proposals, and might adjust subsequently in the light of further analysis.

Summary

6.21. The following table summarises our initial proposals for controllable operating costs for NGG NTS. It is important to note that NGG NTS' forecast costs are not necessarily comparable with our allowances on a "like-for-like" basis given our normalisation and removal of quasi capex costs and the inclusion of non operational capex.

Table 6.6 Initial Proposals NGG NTS controllable opex allowance

	2007/08	2008/09	2009/10	2010/11	2011/12
	£m	£m	£m	£m	£m
NGG NTS forecast Controllable Operating Costs	**63.3**	**65.0**	**63.5**	**65.5**	**66.9**
NGG NTS RCCC 2004/05	**60.0**	**60.0**	**60.0**	**60.0**	**60.0**
Total Efficiency Adjustments	(5)	(7)	(10)	(10)	(9)
Efficient Cash Costs	**55.2**	**53.1**	**50.4**	**50.5**	**50.7**
Total Upward Cost Drivers	0.4	0.4	0.3	0.4	0.5
Ongoing Opex Allowance	**55.6**	**53.5**	**50.7**	**50.9**	**51.2**
Total Additional Opex allowances	2.5	3.2	5.5	3.4	5.0
Ofgem total Controllable Allowance	**58.1**	**56.7**	**56.2**	**54.3**	**56.2**

7. Price control cost assessment and general policy issues

Chapter Summary

This chapter sets out our current thinking on a number of cost assessment policy issues. It also discusses incentives for capital expenditure efficiency.

Questions

Question 7.1: Do you agree with our proposed treatment of non-operational capex and 'quasi capex'?

Question 7.2: Do you agree with our proposed approach to future input price changes and indexation? Is our assumption of a 1.5% annual efficiency saving for opex realistic and appropriate?

Question 7.3: Is our assumption on efficient connection design for wind generation, and the associated reduction to some of the company cost forecasts, appropriate?

Question 7.4: Do you think that we need to allow explicitly for the possibility of re-opening the price controls for specified single events where the timing and level of costs is uncertain and driven by third party decisions? If so, what might such events be and why?

Question 7.5: What do you think of our proposed options for setting incentives for efficient capital expenditure?

Introduction

7.1. The chapter set out our views on a range of cost assessment and general policy issues relating to our initial proposals. It describes how these policy issues have been reflected in our proposals, and seeks views on some outstanding issues.

Cost assessment policy issues

Cost allocation and capitalisation policy

7.2. The four TO licensees have adopted different approaches in capitalising their indirect costs (e.g. business and support overheads). The assessment of historical capex is consistent with the relevant rules underlying each individual licensee's previous price control. For the next price control, we consulted in the Third TPCR Consultation whether the individual approach should continue, or whether some alignment should be carried out across the TOs or between the Scottish TOs and their related DNOs.

7.3. Judging from the cost assessment carried out so far and the responses to the Third TPCR Consultation, it would be difficult to establish a common ground upon which to align across the TOs or within Scottish network operators. We will continue to adopt the individual approach, allowing for different levels of capitalisation across the TOs. The assessment of the total efficient Capex of each licensee will be a combination of its efficient direct costs and relevant proportion of efficient indirect costs.

Flow margins in gas transmission planning

7.4. NGG NTS has been applying a 5 per cent margin on the 1 in 20 scenario peak day flow when planning future network capacity. The impact on the size of the capex increment for providing this margin is getting greater as it is applied to an increasing overall base. It is worth noting the fact the flow margin is applied in addition to Operating Margins, and is quite separate from that. We consulted in the Third TPCR Consultation whether some adjustment should be made to this approach.

7.5. Based on the latest information and having considered the responses, we believe the continued application of the 5 per cent flow margin uniformly is no longer appropriate. We will explore with NGG NTS and other relevant parties (such as the Health and Safety Executive) more appropriate options, such as locational application of reduced flow margin.

Treatment of wind generation

7.6. We proposed in the Third TPCR Consultation to adopt a cost-benefit approach to determine relevant TPCR parameters influenced by wind generation, including the baseline capex and other flexible revenue arrangements such as revenue drivers. This involves identifying the network investment that would minimise the total transmission costs including capex and operational costs such as constraints.

7.7. The valuation of transmission constraints has a direct impact on the trade-off with transmission investment and hence can significantly influence the outcome of the efficient capex assessment. We consulted in the Third TPCR Consultation on the continued applicability of the set of constraint unit costs used in the TIRG project. These costs are essentially based on assessment of the fundamental economics of generation, rather than observable market prices.

7.8. Since the responses to our Third TPCR Consultation have presented no new information or arguments to persuade us otherwise, we have developed our Initial Proposals on the basis of cost benefit analysis using the same constraint unit costs as used in the TIRG project.

Efficient connection of wind generation

7.9. During the current price control period there has been a change to NGET's connection charging methodology to, in effect, reduce the scope of site-specific connection charges and increase the scope of general use of system charges. One consequence of this is a weakening of incentives on new generators to opt for a cheaper, but less secure, local connection design. Historically, smaller generators were generally content to opt for the less secure design because they saw the direct effect in terms of lower connection charges. At our request, NGET has recently proposed a number of options to address this issue through their charging methodology. It appears a realistic prospect that some short term temporary solution and a longer term permanent solution can be found to re-instate the incentives for some generators to opt for more efficient connection designs.

7.10. Having discussed this issue extensively with the relevant licensees and considered the responses to the Third TPCR Consultation, we have developed our Initial Proposals on the basis of the most efficient connection design. This has involved reductions to the costs forecasts provided by the companies in some instances.

Treatment of Capex for operational efficiency

7.11. One of the potential drivers for capital investment is efficient system operation. Following further analysis and discussion with the licensees we have identified a small number of specific investment schemes for STPL and SHETL that should be funded. Allowances have therefore been included in the initial proposals for SPTL and SHETL.

7.12. There is, however, uncertainty as to what additional investment might be needed for system operation reasons. For expediency, we think that an appropriate approach is to address such additional allowances in the context of NGET's SO price control. This would enable allowances to be re-set more frequently in the light of the most recent information. This arrangement would involve payments from NGET (as system operator) to SPTL and SHETL until the next TO price control review, when appropriate RAV adjustment could be made to relevant TO’s.

Cost uncertainty

Input prices

7.13. The licensees have raised the potential upwards pressure on capex resulting from likely increases in market prices for materials and labour. Some have included this as a separate item in their forecast costs. Pending further analysis, we have removed this element of the cost forecasts from our allowances. In principle our preferred approach is to include an ex ante allowance for such factors within the capex and opex allowances, rather than alternatives such as the greater use of input price indices. We will set out our updated views on the level of any such allowances in our September update.

Specific foreseeable events

7.14. In some instances the costs to be incurred by the transmission companies will be influenced by individual external events which are yet to happen. The impact of some such events has been included in the cost forecasts provided by the companies. Our preferred approach, limited to a very small number of exceptional items, is to set a fixed allowance once the magnitude of the relevant costs is known. This approach maintains the incentive properties and does not give the companies potential windfalls. In such cases we would agree in advance to a re-opener of the price control to agree the treatment of the specific costs concerned. A possible example of such a cost item might be costs potentially incurred by transmission companies as a result of the roll out by BT of its '21st Century Network'. We do not however propose to put in place mechanisms to adjust revenues during the next price controls for events that have not yet been identified. We will set out our position on the events that might be relevant to the transmission companies in our September Update.

Treatment of Non Operational Capex

7.15. In the Third TPCR Consultation we consulted on a number of issues relating to treatment of non operational capex e.g. IT, vehicles, property etc. In particular we discussed the treatment of historic and forecast expenditure.

Treatment of historic expenditure

7.16. Both the Scottish transmission companies and NGET received non operational capex as part of their opex allowances at their last price control reviews. NGET was given an explicit non-operational capex allowance for vehicles and IT at the price review in 2000. The following table sets out this allowance and shows the actual costs NGET has incurred to 2004/05 and forecast for the last two years.

Table 7.1 NGET Non Operational Capex (IT & Vehicles) Allowance vs. Actual

(£m 2004/05 Prices)	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Allowance	4.6	4.0	4.1	2.5	2.4	n/a
Actual/F'cast	5.1	13.2	19.6	18.6	8.7	13.0
Difference	0.4	9.3	15.6	16.1	6.3	13.0

7.17. This table shows that that NGET has effectively overspent its allowance from 2003/04. We are presently assessing the efficiency of NGET's expenditure to 2006/07 a significant proportion of these costs relate to work and asset management (WAM) systems and portable devices used by NGET's field operatives.

7.18. Given that the original allowance was included as part of NGET's controllable operating costs we regard all expenditure up to and including 2006/07 as operating expenditure and therefore NGET will not receive any further remuneration in respect to these costs. NGET had included the above non operational expenditure in its FBPQ as part of its historic capex, but we have removed these costs accordingly.

Treatment of forecast expenditure

7.19. In the Third TPCR Consultation we asked how such expenditure should be treated going forwards. We set out three options:

- Inclusion in the TO RAV (depreciated over 40-45 years)
- Inclusion in the RAV but depreciated over the economic lifetime of such assets (3-7 years) "short life RAV"
- inclusion of such expenditure as part of the opex allowance

7.20. Two licensees said that remuneration of such expenditure should reflect the period of time over which the benefits would be realised and favoured capitalisation of such expenditure One licensee suggested that the precedent of the GB System Operator price control should be applied, where shorter asset lives are applied.

7.21. The transmission licensees assume asset lives around 40 years in their RAVs. Applying the same lives to non-operational capex would be economically distortionary and place perverse incentives on the companies given that, over the period that such investment would earn a return, the same assets would be replaced several times over.

7.22. This leaves the latter two options. One disadvantage of adopting the "short life RAV" is the complexity it would introduce in monitoring overall capex expenditure given the great diversity of asset lives being applied. We note the comparison to the GB SO however we would distinguish the SO IT assets as truly "operational" given that they are integral to the real time operation of the transmission network, and as such genuinely warrant a short life RAV approach.

7.23. A key consideration here is the incentives on the licensees to incur such spend efficiently. Given that such investment is closely aligned with shorter term management strategy and objectives, remuneration of such spend as opex would seem to provide the appropriate incentives on efficiency. Furthermore the incentives on efficiency are stronger for opex particularly in relation to overspends.

7.24. Based on the company forecasts for non operational capex we believe the financial impact of including this expenditure in opex is not significantly different to the short life RAV approach. Therefore we propose to include non-operational capex allowances as part of the licensees' opex allowances. This is consistent with the approach we applied to the DNOs in DPCR4 We are presently assessing the companies' forecast non operational capex.

Quasi capex

7.25. In their cost forecasts NGET and NGG reclassified some types of operating costs as capital expenditure. An example is the costs of re-painting transmission towers (which has the effect of extending the life of the assets). We have assessed this treatment, and agree with the approach adopted by NGET and NGG. This position is therefore reflected in our initial proposals. We will monitor this treatment over time through our regulatory reporting requirements to ensure that this approach is consistently applied over time.

The scope for efficiency savings

7.26. In chapters 3 to 6 we discussed a number of potential efficiency savings we have included in our proposed controllable opex allowances. One of the assumptions we included was for ongoing efficiency improvement during the course of the price control period. We have assumed 1.5 per cent p.a. between 2007 and 2012

7.27. The assumption of 1.5 per cent is consistent with the assumption used itself by one of the companies. Further our detailed analysis of NGET and NGG has identified a number of potential areas for greater efficiency relative to the cost forecasts they have submitted to Ofgem. Collectively, these factors mean that a 1.5% reduction is in our view challenging but achievable.

Treatment of NG's offshore insurance captives

7.28. As part of our normalisation exercise we established that NG's offshore insurance captives charge the regulated businesses (NGET and NGG) significant margins as part of their insurance premiums. Furthermore in our assessment of insurance costs we ascertained that the offshore captives had paid out substantial dividends to NG Group. Our assessment of NG's insurance costs has shown them to be efficient and we are therefore not proposing to make any adjustments in respect of the captives' margins or dividends. However it is important to note that given our treatment of NG's captives we expect any excess losses (to the extent they are covered by the captives) will be funded by the captives and not the consumer.

Non controllable opex

7.29. The focus of our initial proposals has been on the appropriate levels of costs over which the companies exercise a significant degree of control. The total allowances, however, also include allowances for cost items over which the companies have only limited or no control. Examples include rates and licence fees. We will provide a more detailed explanation of these cost items, and our proposed treatments in our September Update.

TPCR Capital expenditure incentives

7.30. In order to assess efficient capital expenditure for the calculation of revenue allowances, we have undertaken a detailed assessment in this review of the historical and forecast capital expenditure efficiency of the companies. However, we are seeking to establish mechanisms that incentivise the companies to deliver efficient capital investment. Over recent years, we have developed and applied such additional incentives to the current RPI-X form of control.

7.31. The next price control period is expected to require significant increases in transmission capital expenditure, both to replace assets as their condition deteriorates, and to connect new sources of gas and electricity to the networks. The companies should be incentivised to carry out these network investments in an efficient manner. There is a high level of uncertainty in the future capex required. A key mechanism that will be introduced for this review is the use of 'revenue drivers' to vary revenue allowances automatically as requirements for load related expenditure change during the review period, while retaining the incentive for efficient delivery of the required transmission capacity.

7.32. However, it is still a challenge for us to set appropriate incentives for the non-load related expenditure for the transmission companies. This is due to the limited availability of comparable output performance measures or quantifiable simple drivers that we can use to assess the delivery of efficient investment through the evidence of acceptable standards of network performance. This is mainly because there are only three electricity transmission companies with major differences in scale, and only one gas transmission company. In addition transmission assets generally have long lives, and a high level of redundancy is built into the networks so that the link between investment and quality of supply is heavily lagged. Transmission investments may also be large projects that take place over a number of years.

7.33. As set out in our March document, we propose to introduce 'rolling incentives' for capital expenditure, where a company is allowed to keep (or bear) a fixed proportion of the difference between allowances and actual costs irrespective of when the difference occurs. This has the benefit of maintaining a consistent strength incentive over a period of time. Since substitution effects are reduced when incentives are applied across as wide a range of spend as possible, this incentive could be applied to all non-load related expenditure combined with the baseline load related expenditure.

7.34. A key issue to consider in setting this rolling incentive is the strength of the incentive to encourage efficient behaviour around a baseline point. In previous reviews, we have used high powered incentives to incentivise efficient behaviour. In the particular circumstances of this review, with a step change in investment volumes, and uncertainty about timing of investments, it may be more appropriate to use a lower powered incentive aimed at incentivising efficiency but not over-encouraging under-spend, as well as discouraging but not excessively penalising over-spend. We are currently considering a relatively shallow incentive rate of around 20%, e.g. for an amount of over/underspend, the company would lose/gain 20% of the value of this expenditure.

7.35. In our March document, we also considered whether it would be appropriate to introduce a 'sliding scale' (or 'information quality incentive') mechanism similar to that applied in DPCR4. Under this scheme, baseline capex allowances were set on the basis of a synthesis of Ofgem's and each company's views of the appropriate baseline level of expenditure, and the strength of the incentive rate set for each company varied inversely with the scale of the difference between the two views. It also included an additional income item which was adjusted to ensure the "incentive compatibility", i.e. for a particular level of actual spend, the company gets the highest rewards (or lowest penalty) if the spend agrees with its own forecast. This was developed so as to encourage and reward reasonable capital expenditure projections as well as to encourage efficiency.

7.36. We are currently considering the relative merits of two broad options for the approach to capital expenditure incentives. One is to adopt a mechanism similar to that applied in DPCR4 for this review. The other one is to rely on the in-depth analysis and detailed scrutiny that we have undertaken of the companies’ own forecasts to establish an appropriate allowance for baseline capex together with a rolling incentive at an appropriate incentive rate. We will provide an update on this issue in our September Update.

Rolling forward the RAV

7.37. The capex efficiency incentives discussed in the previous section 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 do not anticipate that they will eliminate the need to assess actual capex in the future for evidence of inefficient expenditure regardless of any over or under-spend against the original allowance. We will provide an update on this issue in September.

Regulatory Reporting

7.38. As part of our proposals for the transmission price controls we will introduce enhanced regulatory reporting arrangements. These will take effect from 1 April 2007, and will oblige the companies to report more frequently on a wider range of specified data items relating to performance under the price control. The purpose of these measures is to improve the quality of information (cost, financial, system performance, etc) which we use to monitor performance and to set future price controls and incentives. We will provide an update on the form of these requirements in September.

Excluded and de minimis services

7.39. The price control revenues do not cover all the activities of the licensees. They are permitted as part of their licensed activities to undertake specified services which are excluded from the price control. They are also permitted to undertake activities that do not relate to running the transmission business, but only if the scale of these operations remains within specified de minimis limits (2.5 per cent of allowed revenues).

7.40. We will set out our views in September on whether the current arrangements need to be changed in the light of our price control proposals. One particular issue is the provision of services to GDNs no longer owned by National Grid.

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: Should the licensees' revenue allowances for tax payments be set to avoid any need for ex post adjustments?

Question 8.2: Are there any other measures which could be taken to reduce perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plc's?

Introduction

8.1. In this chapter we discuss the following financial issues:

- Allowed rates of return on investment (cost of capital);
- Pensions
- Tax
- Financeability
- Financial Ring-fence

Cost of capital

8.2. In setting a price control allowance we have to set a figure for the allowed return on the Regulatory Asset Value. This should be set to be at least equal to the licensee's cost of capital – i.e. the level of return required by the financial markets, both debt and equity, in order to provide capital.

8.3. We will not finalise our view on the appropriate allowed rate of return until the Final Proposals in early December. However, our initial views are as follows:

- We will continue the approach adopted in DPCR4 of taking a longer term view on the appropriate return rather than relying on the snapshot provided by the latest market information;
- While we are aware that estimation techniques other than the Capital Asset Pricing Model (CAPM) are available, such as the Fama-French three factor model, we have found no evidence to suggest that they add materially to the robustness

of the estimates derived through CAPM. We are also aware that the CAPM approach can support a relatively wide range of possible estimates;

- Recent market evidence shows some recovery of real interest rates from levels which were historically very low. However, yields on index-linked gilts are still at a level below the DPCR4 assumption of 2.75%. Spreads on utility bonds have also narrowed somewhat since DPCR4. (The "spread" is the premium to gilt yields paid by a corporate borrower);
- In DPCR4 we took a conservative view on the required return on equity (7.5% post tax, real), at the high end of the range of estimates for historic long term average equity market returns. We are aware that regulated utilities might generally be expected to be lower risk than the long term market average, and we are aware of recent evidence on beta factors and on transaction prices in the UK regulated utility sector which confirm our view on the conservative nature of the DPCR4 approach;
- We believe that the same cost of capital should be applied to each of the transmission companies (previously, the Scottish TO's were given a premium to National Grid), given the absence of evidence to show that the Scottish TO's face a higher degree of risk;

8.4. We have engaged consultants to examine a range of issues associated with cost of capital estimation and their conclusions will inform our approach to the cost of capital debate in TPCR.

8.5. For modelling purposes, and to provide a reference point for consultation responses, we have adopted a real post tax cost of capital of 4.2% for all four of the companies in arriving at these Initial Proposals. This is consistent with the following assumptions:

- A real pre-tax cost of debt of 3.4%. This figure is consistent with current 10 year trailing average data for gilt yields (2.3%) and the average spread of 'A' rated utility bonds with a ten year maturity (1.1%;
- A cost of equity of 7%, based on the midpoint of estimates of long run average total market returns that range between 6.5% and 7.5%; and
- A gearing level of 60% (in line with the assumptions underlying the current controls).

8.6. Supporting information for our cost of capital analysis is set out in Appendix 9. It is important to note that the rate of return allowed in our Final Proposals may be higher or lower than this figure. In determining the appropriate rate to allow, we will need to take into account the results of our consultants' further work on cost of capital and of our financeability assessments, as well as the overall balance of risks the companies will face under the revised controls.

Pensions

8.7. Pension contributions by the companies are a significant cost item going forward. 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). These factors, together with requirements of the Pensions Regulator in respect of scheme specific deficit funding, result in higher allowances for pension costs. In addition, both National Grid and Scottish Power have indicated they expect to make additional payments to reduce the deficits in their schemes shortly.

8.8. In calculating the appropriate allowances we are seeking to apply the pension principles established through the Developing Network Monopoly Price Controls project and applied in DPCR4. In applying these principles to the transmission companies there are a number of specific issues that need consideration.

'Centrica liability'

8.9. This concerns the liabilities relating to non-regulated business activities carried out in NGG's predecessor companies including, in particular, those relating to the gas trading and supply activities de-merged in 1997 to form Centrica plc. We only intend to provide an allowance to cover the proportion of deficit repair costs that relate to businesses that are regulated now i.e. we will disallow the Centrica liability. We have not yet concluded our assessment of this figure. The figure shown in table 8.1 below is, therefore, provisional.

8.10. However, as previous price control allowances implicitly took account of scheme surpluses arising in part from past contributions relating to Centrica and other non-regulated activities, we also propose to assess the impact this surplus may have had on previous price control allowances and to allow for this when assessing the deficit funding (ie. past allowances probably should have been higher and we need to recognise that in calculating allowances for this control).

Treatment of ERDC's

8.11. Early indications are that up to £480 million of the deficits across all companies may arise from unfunded Early Retirement Deficiency Costs (ERDC's). Our pension principles state that all ERDC's are for the account of shareholders. We propose to apply this principle to the transmission companies and have not made allowance for any ERDCs, whether funded or not, for purposes of these Initial Proposals. In DPCR4, for the reasons explained below, we made adjustments for partial recovery of unfunded ERDC's.

Past over or under funding

8.12. Historically, the companies might have contributed to their pension schemes in a manner which differed from the assumed contributions on which past price control allowances were set. We need to assess how to treat such differences. In principle, where this occurs, we would adjust allowances for subsequent control periods to take account of the over- or under-funding of actual contributions provided by previous price controls.

8.13. However, due to data quality issues we did not apply this principle in DPCR4 – and, partly in consequence, also adjusted our application of the principle in respect of ERDCs. On balance, we formed a view that this was appropriate "in the round" given the impact on DNOs.

8.14. While such adjustments might also be appropriate in the context of the transmission companies, we have not yet finalised our view. In some cases the transmission companies would appear to have more robust data upon which we could apply our principles. Our intention is to apply our principles comprehensively if we can.

Summary of pensions treatment

8.15. The table below summarises the position on the pension schemes and our current provisional view on the allowances for pension costs.

Table 8.1 Summary of pensions allowances

Licensee(Scheme)	NGGT	NGET	SPT	SHETL
Number of Members	113,943	11,300	18,625	6,541
Assets at previous valuation	£11.9b	£1.2b	£1.7b	£0.8b
Deficit at previous valuation	£879m	£272m	£198m	£44m
Date of previous valuation	2004	2004	2003	2003
Employer contributions	30.2%	20.6%	23.0%	25.0%
Current actuarial valuation	Mar-06	Mar-06	Mar-06	Mar-06
Deficit at this valuation	£425m	£406m	Surplus	Surplus
	£m	£m	£m	£m
Total expected deficit - £m	425	406	Surplus	Surplus
- non attributable element (8.5% not TO)	36	5	n/a	n/a
- non attributable element (Centrica)	62	n/a	n/a	n/a
- unfunded ERDC's - £m	259	190	0	0
= Deficit for allowance - £m	68	211	0	0
Annual deficit allowance - £m	9	27	0	0
Annual ongoing allowance - £m	16	19	3	2
Total annual pensions allowance - £m	25	47	3	2
Capitalised portion of the allowance	0%	25%	64%	52%
	£m	£m	£m	£m
Opex portion of the allowance - £m	25	35	1	1

Tax

8.16. In our March document, we proposed to maintain the ex ante approach to tax adopted for DPCR. Under this approach, an allowance will be made for the expected actual tax payments becoming due in respect of each year of the new control based on our view of capital allowances and interest, based on our assumptions about gearing from the cost of capital. We will continue to make ex post adjustments in respect of interest where the actual gearing and actual interest expense exceed the levels assumed in setting the cost of capital. Further work will be required to establish tax allowances and put companies on a common starting gearing position.

Financeability

8.17. In setting price controls, we determine cost allowances consistent with a well managed and efficient business. We recognise, however, that over the lifecycle of the network, licensees will require substantial investment at times and may consequently experience periods of deteriorating credit ratios or apparent financial strain.

8.18. The transmission licensees are projecting a significant investment requirement relative to the size of their existing asset bases. We have examined carefully the impact these might have upon the ability of licensees to finance their networks whilst meeting benchmark levels for key financial indicators consistent with a comfortable investment grade rating.

8.19. While recognizing that the concurrent Ofwat/Ofgem Financing Networks consultation may shortly provide useful additional insights into approaches for funding major new network investments, our current view is that the appropriate approach is to assume that companies should be able to raise additional equity when necessary to meet funding requirements and maintain appropriate credit quality. This implies that we will need to be satisfied that the allowance we make for the cost of equity appropriately takes account of the marginal cost of equity injections required including transaction costs.

Depreciation cliff-edge

8.20. A separate financing issue relates to the loss of income from the cessation of regulatory depreciation on pre vesting assets. Our preferred approach is to use tilted depreciation to bring forward depreciation funding by shortening asset lives (as was adopted in DPCR 3 and 4). However we are currently assessing the nature of the required adjustment and at this stage we have not included this adjustment in our proposed revenue allowances. As a result, and all other things being equal, these Initial Proposals may understate the revenues required.

Financial ring fence

8.21. We have previously made clear our intention to modify the financial ring-fencing conditions of the electricity transmission licences to bring them into line with the current standard, as represented by the relevant conditions in the DNO, NGG-NTS and GDN licences.

The principal such modification will be to introduce the ‘cash lock-up’ mechanism, designed to protect against companies transferring cash and/or other valuable assets to affiliates where the licensee's ability to maintain an investment grade credit rating is threatened. We will propose this modification to a timescale consistent with application from 1st April 2008.

9. System Operator Costs

Chapter Summary

This chapter discusses how we propose to set allowances for NGG NTS and NGET in their roles as system operators of the gas and electricity transmission systems. It describes the nature of the costs and outlines our forward work plan.

Questions

There are no questions in this chapter.

Introduction

9.1. There are two types of possible role for transmission companies: 'System Operator' and 'Transmission Owner'. In broad terms, a System Operator is responsible for managing flows across the network in real time, while a Transmission Owner is responsible for building and maintaining transmission assets. These are complementary roles and there are clearly strong interactions between the two roles.

9.2. In gas, NGG NTS performs both roles for the whole of GB. In electricity, NGET is the System Operator for GB and the Transmission Owner for England and Wales. SPT and SHETL are the Transmission Owners for the south and the north of Scotland, respectively.

Electricity

9.3. NGET incurs a range of different types of costs in managing the network in real time. These include internal costs associated with the operation of the control rooms, and external costs incurred through contracts with network users to provide the necessary range of services. These include contracts with generators to maintain a capability to provide certain services (e.g. 'Black Start'), and contracts with generators and demand users to change their operating behaviour to resolve short term constraints on the network. These are managed through the Balancing Mechanisms and through longer term Ancillary Services contracts.

9.4. System Operator costs are subject to a different form of revenue regulation as compared to the RPI-X form of regulation used for Transmission Owner activities. The model of regulation is a form of profit/loss sharing, with a target level of costs being set periodically, with variations from this target level of costs being shared between NGET and consumers. The model has also involved setting caps and collars on maximum profits and losses for each year. It should be noted that the current incentive scheme lapsed on 31 March 2006, and has been replaced for an interim one year period with a scheme based on ex post assessment of efficiency.

9.5. The initial proposals set out in this document exclude all consideration of SO costs. However, our process of cost assessment includes what are currently classified as internal SO costs within its scope. We will publish our initial proposals for the SO incentives scheme in September 2006. Additionally, we plan to issue a separate 'open letter' consultation ahead of the September proposals.

Gas

9.6. The broad framework for the regulation of SO activities for NGG NTS is similar in structure to NGET. The range of activities covered is also similar, including internal functions such as the operation of the control room and external functions associated with the release of capacity to network associated with network investment and contracting with network users for services to support the day to day operation of the network. These activities are subject to profit/loss sharing incentives with cap and collars on maximum profits and losses in any given year.

9.7. The set of SO incentives in place currently for NGG NTS is wider in scope than for NGET. It includes:

- Internal costs incentive - This incentive covers areas such as staff costs and systems costs. It also covers capital expenditure associated with the operation of the SO;
- Incentives relating to the provision and management of entry and exit capacity - These include incentives relating to investment at entry and exit, as well as day to day network management incentives. These incentives are intended to facilitate efficient network management and cover capacity buy backs, as well as use of interruption and constrained LNG on the NTS. Our proposals in respect of these areas of NGG NTS's incentives are included in these initial proposals, in chapter 11;
- System balancing incentives - These are incentives covering the use of operating margins gas (system reserve), shrinkage, and gas which is used as compressor fuel;
- Gas balancing incentive - The current gas balancing incentive provides NGG NTS with a financial incentive to buy and sell gas efficiently and to reduce day on day linepack changes.

9.8. We will publish our proposals for the Internal Costs, Gas Balancing and System Balancing SO incentives in September 2006. Additionally, we intend to issue an 'open letter' consultation ahead of the September proposals.

9.9. One particular issue we are exploring currently is the treatment of NGG NTS's use, in its capacity as system operator, of its affiliated LNG storage. Currently the provision of these services is price regulated, and NGG NTS has raised concerns about the appropriateness of the current regime of price regulation given the forward looking cost of providing these services. We are progressing work to understand these costs, and to explore the scope for the competitive provision of these services. We will set out our views on this issue in our September Update document.

10. Adjustment mechanisms and incentives: electricity

Chapter Summary

This chapter sets out our initial proposals for the three electricity transmission companies for the package of incentives and adjustment mechanisms through which revenue allowances will depend on future events. The key element is how revenues flex with changes in demand for capacity from network users. It also covers funds made available to support innovation, and incentive schemes linked to system performance standards.

Questions

Question 10.1: Is our proposed two-part revenue driver design appropriate and proportionate to the issue it is seeking to address?

Question 10.2: What are the costs and benefits of seeking to facilitate greater competition between providers of transmission services, in respect of the prospective transmission links to the Scottish Islands?

Question 10.3: Is our proposed approach to funding for innovation appropriate and necessary?

Questions 10.4: Is our proposal to extend the existing performance incentive scheme appropriate?

Introduction

10.1. The initial proposals package comprises a fixed revenue allowance for each company plus a number of mechanisms which provide for adjustments around this fixed amount. These mechanisms are intended to adjust revenues automatically as better information emerges over time on the volume of transmission capacity that network users wish to buy, and seeks to provide additional incentives which reward strong performance and penalise weak performance.

10.2. This chapter sets out our initial proposals on these adjustment mechanisms for the three electricity transmission companies. Our proposals needs to recognise the different roles of each licensee and, in particular, the difference between NGET in its role as Great Britain System Operator (GBSO) and NGET, SPTL and SHETL in their roles as Transmission Owners. Our proposals cover three areas:

- Changes in demand for network capacity (‘Revenue drivers’);
- System performance; and
- Innovation.

Revenue Drivers

10.3. We continue to believe that uncertainty over future demands for network capacity in both gas and electricity is such that we need mechanisms which adjust revenue allowances as new information emerges during the next price control period. Setting a fixed revenue allowance in the prevailing circumstances represents an unnecessary risk for consumers (of revenue allowances being too high or too low relative to the need for investment).

10.4. When a new generator applies for a grid connection NGET is obliged to provide an offer of terms. This offer of terms currently identifies the works that need to be completed before the generator is permitted to use the network. These will be a combination of local work and, depending on network studies, reinforcement works on the main interconnected system. Our objective is to design a set of revenue drivers which are robust to a wide range of possible scenarios of demand for network capacity. They should seek to capture in a relatively simple and transparent manner all the key cost drivers.

10.5. Our analysis and discussions with the companies have demonstrated that the cost drivers are different for the local works and the deeper reinforcement works. We propose to reflect these differences in our revenue driver design, through a two-part revenue driver design for each licensee. The first part would cover local works associated with each new generation connection to the transmission system. The second part would cover the ‘deep’ reinforcement works that results from the aggregation of this connection (and, potentially, closure) activity on flows across the network.

Local connection works

10.6. The revenue driver for local works would adjust revenues separately for each new generation connection. The revenue driver should only provide additional funding where there is a clear and demonstrated need for the investment. It would not therefore be appropriate to trigger the revenues when a prospective new generator first applies for a connection, because not all applications are progressed to actual connection. There are two broad options for when revenues are triggered:

- When the capacity is contractually delivered (which currently is equivalent to when all works are completed); or
- At some point prior to contractual delivery, when the generator has made a strong enough financial commitment such that it is deemed efficient to undertake the investment.

10.7. The first option provides an incentive for the companies to deliver the investment on time, but does result in weaker cash flows in the short term. The second option more closely maps the timing of revenue allowances and actual costs. We have not yet finalised our views on this issue.

10.8. The detail of the adjustment mechanisms once it is triggered is still being developed. In summary, we think there are two viable approaches that need further development work with the companies. First, a revenue driver which is a (relatively complex) function of the different dimensions of each connection - being size, distance, voltage, and requirement for substation investment. Second, a simple £ per MW allowance plus a proportion of the costs being subject to cost pass-through. The first approach is likely to be more cost reflective on a scheme-by-scheme basis, while the second approach is likely to be more transparent. The second approach is similar in design to the Distributed Generation (DG) incentive introduced at the last DPCR.

10.9. Our initial views are presented in more detail in Appendix 10. We will set out firm proposals in our Updated Proposals document in September.

Deeper system reinforcement

10.10. The design of a revenue driver for deeper reinforcement work is more challenging because of the uncertainty over both future demands and over what constitutes efficient network design in any particular set of circumstances given the 'lumpy' nature of some forms of transmission investment.

10.11. The starting point is the baseline assumed in deriving the capex allowances set out in Chapters 3 to 5. This sets out one possible, realistic generation scenario and defines a programme of capex consistent with accommodating that scenario. If there are more generation connections than are assumed in the central case, then we might expect capex requirements to be higher. Conversely, if there are fewer generation connections than are assumed in the central case, then we might expect capex requirements to be lower (because some investment can be avoided). Revenue drivers will seek to adjust revenues consistent with the ways in which an efficient capex plan might change in the light of new information about demands for capacity being revealed.

10.12. We have only recently finalised our view on this baseline scenario and the associated capex plan for deep system reinforcement that would be required. The next stage in the process is to explore variations from this baseline in more detail with the companies. Appendix 10 sets out our initial thoughts given the information currently available, including on when the revenue drivers should 'trigger' and when the triggered revenues should be recoverable by the companies. We will update these proposals in September when we have completed this further analysis.

Future adjustments to revenue drivers

10.13. Once we have set the revenue drivers we do not anticipate changing them for the duration of the price control period. There is, however, one set of circumstances where we consider a limited re-opener might be appropriate – and arguably should be designed into the overall framework.

10.14. We recognise that in a very small number of instances involving very large investments where it might be efficient for companies to respond to the need for additional capacity by investing in a way which 'over-provides' capacity in the first instance. This is because efficient transmission investment can involve large 'lumps' of new capacity being provided, e.g. if a new line is needed.

10.15. In these circumstances there is a risk that the revenue adjustment might be too low if it is based on the amount of additional capacity required by users. There are a number of ways of addressing this issue. Our preferred option is to provide for a 'revenue driver adjusting event' (RDAE) mechanism to allow the companies to apply for the relevant revenue driver to be based on the additional capacity being provided rather than by the additional capacity being demanded by users.

10.16. There are, however, other ways in which the same issue might be addressed. One alternative is to retain the same structure of revenue drivers, but to apply them to a proportion of the costs – with the licensee being permitted to pass through the remaining proportion of costs (subject to the option for Ofgem to undertake an efficiency study). This approach is similar to the approach adopted by Ofgem in the context of incentives for DNOs to connect new generators - and similar to one possible approach for the local connection works revenue drivers discussed above.

Links to the Scottish Islands

10.17. It should also be noted that the revenue drivers will not be designed to handle very large extensions to the transmission network involving sub-sea links to the Scottish islands. These projects are too uncertain in terms of the technology to be used, and the appropriate design specification, for meaningful revenue drivers to be set at this stage.

10.18. We will however continue to monitor this situation, and engage constructively where we can help in facilitating a solution and protect the interests of consumers. One option is to re-open the price control of SHETL when information on the likely costs of such investment is more certain.

10.19. However, given the uncertainty over the efficient technology, design specification, and financial structure for undertaking this kind of investment, another option is to open up these large investments to extend the coverage of the transmission network to competition. Arguably, this represents a more effective way to generate information on efficient costs and designs. This would appear to be possible with the existing regulatory framework, but may require changes to SHETL's transmission licence. There are, however, some international precedents for this kind of arrangement.

10.20. We will take a pragmatic approach to this issue, and pursue the more complex options if the benefits to consumers of so doing are expected to be material. This, in part, depends on the role SHETL wish to take, and their response to the challenge of taking this issue forward. To date, SHETL has taken an active role in developing design options and has indicated that it is willing to take on such large scale investments - which represent a large shift in the nature of SHETL's regulated business.

System performance

10.21. Following the London and Birmingham transmission failures in 2004, we introduced reliability incentives in NGET's transmission licence. The rationale for introducing these incentives was to complement the existing framework through direct financial incentives to provide levels of system reliability consistent with the needs of consumers. In January 2006, we introduced a reliability incentive for SPTL and SHETL as well.

10.22. These measures were intended to be interim measures, given that we were then shortly due to start the process of reviewing the whole package of incentives for NGET, STPL and SHETL through the TPCR process.

10.23. The incentives set a target level of performance and penalise (or reward) performance below (or above) the target. There is a maximum penalty and a maximum reward in any given year. The performance measure for NGET is amount of energy lost through unplanned outages. The performance measure for SPTL and SHETL is the number of events that result in lost energy. This difference reflects NGET's role as system operator.

10.24. We continue to believe that explicit measures of system performance are an important facet to the overall regulatory regime. However, one limitation we face is the limited range of performance measures. Transmission networks are planned to very high levels of security, and our networks are very reliable. Statistics on system reliability only tell a small part of the overall story. To get a fuller picture of the performance of the transmission companies you therefore need to look behind the reliability measures. Unfortunately, we do not currently have the available output measures to do this. We therefore propose:

- to retain a performance incentive based on the current measures of reliability; and
- develop a more extensive range of output measures for the companies to report on in respect of system performance over the next price control period (such that we can revisit this question at the next price review)

10.25. In the light of the consultation responses to the Third TPCR Consultation we do, however, propose a different structure to the incentive. As part of a wider package of incentives, we think it is more appropriate for the reliability incentive to be re-characterised as a minimum standard rather than a target level of performance. As such, we propose to move to a 'penalties only' scheme.

10.26. The next stage is to review the data and parameters underpinning the current schemes to see if it needs to be updated. We will then publish our firm, quantified proposals in September. We will also set out proposals to develop a wide range of output measures to gather data on, and for the companies to report against.

Innovation incentives

10.27. As part of our proposals for the most recent DPCR we introduced a new incentive scheme to promote innovation by the licensees. The decision we made as part of DPCR was informed by analysis of the scope for innovation to be delivered and implemented commercially. We concluded that additional measures were needed to protect the interests of consumers. We believe that the reasoning behind our decision in the context of DPCR is equally applicable to the electricity transmission companies. We therefore propose to introduce a similar scheme for NGET, SHETL and SPTL.

10.28. The 'Innovation Funding Incentive' proposed for electricity transmission identifies a pot of funding for innovation for each company up to 0.5 per cent of TO allowed revenue, which can be accessed if the companies come forward with proposals that meet agreed criteria and comply with good practice for managing R&D projects. We propose that there should be open reporting of IFI activities, including the potential benefit to consumers.

10.29. We will provide an update on this issue, together with more information on how such a scheme might work in practice for NGET, SPTL and SHETL, in September.

Interactions with potential reforms to access arrangements

10.30. In our Third TPCR Consultation we highlighted the issue of access reform and the potential for the current arrangements through which generators gain access to use the transmission network to hinder competition and the efficient planning of network investment.

10.31. This work has been taken forward since the Third TPCR Consultation through an industry working group, the Access Reform Option Development Group (ARODG), chaired by Ofgem. ARODG published its findings for consultation in April. A key focus for the group were the requirements for financial security from new parties seeking connection to the network, and in particular the impact of the Final Sums Liability (FSL) regime in the context of large numbers of applications in the same areas of the network. We are pleased with the progress being made through the ARODG process, and will monitor next steps carefully and seek to facilitate further progress where we can.

10.32. As a first step, we are hosting workshops to review the responses to the ARODG report, and to consider next steps and any specific proposals from individual industry parties on 6 July in Glasgow and 7 July in London. As potential options for change are developed and proposed, we will separately ensure that interactions with the TPCR are identified and consulted on. This might require consultation through open letters, to the extent that the timing does not align with planned TPCR documents. Some of the potential interactions in terms of the design of revenue drivers, for example, are discussed in more detail in Appendix 10 of this document.

11. Adjustment mechanisms and incentives: gas

Chapter Summary

This chapter sets out our initial proposals for National Grid Gas NTS for the package of incentives and adjustment mechanisms through which revenue allowances will depend on future events. The key elements are defining NGG NTS's obligations to release capacity, setting out how revenues flex if users wish to buy capacity above these levels, and defining how allowances are set for buying back contracted capacity that is not available physically. It also sets out how efficiency savings or over-spend relative to allowances will be treated and how funding to support innovation will be made available.

Questions

Question 11.1: What do you think of our revised proposals for setting entry capacity release obligation baselines, and for the proposed mechanisms for enable such baselines to be re-allocated in some circumstances?

Question 11.2: Are our proposals for revenue drivers for entry and offtake appropriate and proportionate, given the issues they are seeking to address?

Question 11.3: Are our proposals for buy back for entry and offtake appropriate and proportionate, given the issues they are seeking to address?

Questions 11.4: Is there a case for an innovation incentive for NGG NTS?

Introduction

11.1. The initial proposals package comprises a fixed revenue allowance for each company plus a number of mechanisms which provide for adjustments around this fixed amount. The adjustments can be positive and negative. These mechanisms are intended to adjust revenues automatically as better information emerges over time on the volume of transmission capacity that is needed, and seeks to provide additional incentives which reward strong performance and penalise weak performance.

11.2. There are 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
- Transitional incentives for offtake

11.3. This chapter outlines our current thinking on these issues in the light of views expressed by respondents to the Third TPCR 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.

11.4. In this chapter we consider the introduction of incentives and revenue drivers across both the NTS transitional and enduring offtake periods as described in the Third TPCR consultation.

Context for entry and offtake

11.5. The proposals set out below for the entry capacity arrangements represent an evolution of the existing entry capacity regime under which shippers are able to secure entry capacity rights at a range of entry points through a series of long and short term capacity allocations.

11.6. For offtake capacity booking arrangements we continue to believe that wider ranging changes are required to ensure that the interests of consumers are protected and effective competition is promoted. This was identified as an issue in the context of NGG NTS's sale of four of its local gas distribution network (GDN) businesses where we indicated that all classes of users should have adequate and equal opportunities to gain access to the network through arrangements that provide NGG NTS with accurate and financially backed investment signals. We continue to believe that reform is overdue in this area.

11.7. A key issue arising from the Third TPCR Consultation was that several respondents commented that the case for the introduction of enduring offtake arrangements still needs to be made. In response to these concerns we have published a draft Impact Assessment. This is set out in Appendix 17 and seeks to elaborate on, and quantify where possible, why we think consumers will benefit from reform. The Impact Assessment estimates base case net benefits to customers of the offtake proposals to be £46m in present value terms.

11.8. We note the continuing process of industry engagement to develop the detail of practicable and fit-for-purpose models to implement, and are keen to ensure that Ofgem plays its part in developing a set of price control proposals consistent with these emerging models. The proposals set out in this chapter have been developed with this in mind.

11.9. At the core of the proposals is the notion that NGG NTS should be remunerated for providing additional capacity where there is a sustained demand for such additional capacity. We think the most robust way of demonstrating such a sustained demand is through a process of booking long-term capacity. This is what we mean by a 'user commitment' model.

11.10. We continue to believe that reform to booking arrangements for offtake capacity can be developed and implemented such that capacity used from October 2010 is allocated within a 'user commitment' framework – which implies users being able to book capacity in advance under these arrangement during 2007.

11.11. We recognise that aspects of the enduring offtake arrangements would require a Uniform Network Code (UNC) modification proposal to be raised and will ultimately need to be consulted upon through code modification processes. It is our intention to publish a final impact assessment with our decision on any such modification proposal.

Capacity release obligations

11.12. The current arrangements in gas entry oblige NGG NTS to make available specified volumes of capacity at each entry point. This has the benefit of providing certainty to shippers, but has also raised issues of inflexibility in practice – as it does not provide a framework for unsold baselines to be reallocated, including to new entry points that might be developed once the baselines have been set initially.

11.13. In our Third TPCR Consultation we consulted on an alternative model for entry which did not specify baselines in advance – but rather relied on the application by NGG NTS of an approved methodology. In the light of consultation responses and further consideration of how best to tackle the identified defect, we have revised our proposals. We now propose to retain the concept of baseline capacity release obligations defined for each entry point (and offtake point) but introduce formal mechanisms to enable unsold baseline capacity to be reallocated. This will enable existing capacity (which to some extent can be substituted between different points on the network) to be allocated to where it is most in demand.

11.14. We propose to apply this approach to entry and to offtake (under the proposed reformed arrangements). The baselines will be set at levels consistent with the physical capability of the network that is already built or funded to be built – as estimated using network modelling analysis. Initial estimates of the baseline levels (and the basis upon which they have been derived) are provided in Appendix 11 for entry and 16 for Offtake.

Reallocating baselines

11.15. The framework for reallocating capacity is anticipated to be as follows:

- After each long term capacity allocation NGG NTS will review demands for capacity relative to then current baseline levels;
- If there is an entry or offtake point where demand exceeds the baseline level of capacity and there is a 'reasonably substitutable' entry or offtake point with unsold baseline capacity, then NGG NTS will develop a proposal to transfer capacity between the relevant points;

- NGG NTS will consult and develop a methodology for identifying and proposing appropriate substitutions in these circumstances, and the methodology will be subject to Ofgem approval;
- NGG NTS will submit a report to Ofgem following each long term capacity allocation setting out how it proposes to re-allocate baseline capacity. Any reallocation of baselines will be subject to Ofgem approval. Once approved, the baselines will be changed with effect from the delivery date of the capacity bought in the relevant long term auction (normally three years in advance).

11.16. There will need to be modifications to NGG NTS's licence to give effect to this framework. We will progress any such licence changes in the light of responses to this consultation. For example, we would need to specify requirements for the methodology – which might include a requirement to explore fully 'reasonable substitution' opportunities, and a requirement to propose increasing baselines levels where additional offtake capacity is created through the release of any incremental entry capacity in excess of baseline levels, or vice versa.

Baseline definitions and gas offtake

11.17. In the transitional period, we do not propose to use baselines to define capacity release obligations, rather, the nodal baselines specified will provide high level separation between baseline funding and the remuneration of incremental capacity. Furthermore, it is our initial proposal that it would not be appropriate to specify separate baselines for the GDN flexibility product in this period.

11.18. Given that NGG NTS have yet to develop proposals for product definition that address the treatment of flexible offtake rights during the enduring period it has not been possible to provide indicative baseline numbers. However, it is our initial proposal 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. We also propose to adjust upwards the baselines for a number of interruptible sites on the transmission network. Given that these sites have historically had interruptible status but have been rarely interrupted, we consider these sites should be able to secure firm capacity rights. The NTS will also 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.

Revenue drivers

11.19. Where there is demand for additional capacity over and above baseline levels, NGG NTS should receive appropriate remuneration. However, in the absence of financially backed user commitments we do not know with an appropriate degree of certainty where additional capacity will be demanded – and it is not in our view appropriate to determine a fixed allowance for it in advance in the hope the investment will be needed. Experience over the current price control period indicates that new developments can have as significant impact on NGG NTS's investment plans. Revenue drivers seek to adjust revenue allowances consistent with the efficient provision of new capacity in response to demand.

11.20. The mechanisms for users revealing their demands for extra capacity are the long term capacity booking windows in entry, and being developed for offtake. The revenue drivers will be set at levels consistent with meeting bookings of new capacity under a wide range of different flow scenarios. This will ensure that the network is developed with an appropriate degree of flexibility. The revenue drivers are proposed to operate in the following manner for entry and under the enduring offtake regime:

- If there is sustained demand for capacity over and above the relevant baseline level of capacity, then NGG NTS will be entitled to recover additional revenue;
- The relevant baseline will reflect any re-allocations of baseline capacity that have been approved prior to the date at which the demand for extra capacity is signalled;
- A revenue driver will be set as a value per unit of additional capacity for each point (or group of points, in the case of offtake). These values are not anticipated to be changed for the duration of the price control.
- The revenue drivers will be set consistent with NGG NTS earning a standard rate of return on an estimate of the cost of investing to provided extra capacity at the relevant point on the network, and will include appropriate estimates of financing cost for the period before the revenues are recoverable;
- The revenue driver will determine an income stream for a period of five years from the point at which the additional capacity is contractually delivered, irrespective of actual out-turn costs;
- At the end of the five year period, the efficiently incurred actual costs will be included in the RAB – and as such NGG NTS will be permitted to earn a regulated return on the efficient cost of the investment for the remaining life of the relevant assets.

11.21. Further detail of how these mechanisms will work is provided in Appendix 11 for entry and Appendix 16 for enduring offtake. This also includes a discussion of how the offtake arrangements will work in the transitional period.

11.22. Under the transitional offtake regime it is proposed that the same revenue drivers will apply, again, for a period of five years. However, as the transitional arrangements represent a partial user commitment model, it will be necessary for incremental revenue to be triggered absent an explicit user commitment in some circumstances in order to recognise non-specific, load related reinforcement consistent with NGG NTS's assessment of its 1 in 20 obligation. However, we consider it appropriate for Ofgem to have some oversight of the case for such investments before they are remunerated through the application of revenue drivers.

Buy-back incentives

Entry

11.23. The current framework in entry and the prospective enduring framework at offtake places obligations on NGG NTS, in response to a sufficiently strong signal through the long term capacity bookings, to deliver capacity to a specified timetable.

The default at entry is three years, although there is scope for this to be extended with the Authority's approval.

11.24. In the Third TPCR Consultation we proposed modifications to this regime, which would create different incentives for different buy-back situations. Namely, to draw a distinction between 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, and propose that buy backs relating to incremental investment should be subject to:

- a default investment lead time (of 3 years for gas entry and which may be 3.5 years for gas offtake depending on the outcome of NGG NTS proposals in this area), although NGG NTS should be able to apply to the Authority to extend investment lead times
- an administered buy back price cap if NGG NTS does not deliver capacity by the contractually agreed date:
    - based on a function of historic gas prices
    - in relation to capacity sold after April 2007
    - that defaults to zero five years after the contractual delivery date assuming no capacity has been delivered
- income adjusting event provisions if NGG NTS is unable to deliver capacity for reasons outside its control
- scope for bilateral agreements to vary the buy back price, scope of work, timescales for delivery with NGG NTS with any additional revenue NGG NTS makes from the bilateral agreement treated as excluded revenue.

11.25. However, we propose to treat operational buy back actions differently at offtake and entry. For entry a sliding scale incentive is proposed for operational buy backs. We will set out our views on the target cost for this incentive, and the associated sharing factors, caps and collars in September. Some initial thoughts are set out in Appendix 11, which indicates our initial view that NGG NTS should face a greater exposure under this incentive than it does today, given the other refinements were are proposing for the regime as a whole, e.g. the separate treatment of incremental capacity buy back and the proposed basis for setting baselines.

Offtake

11.26. Following consideration of respondents' views and discussions of the Enduring Offtake Working Group (EOWG), we do not propose to introduce a sliding scale incentive for operational buy backs, but rather we propose to retain the current regime. As such:

- NGG NTS will be able to interrupt for maintenance purposes at zero cost provided that it remains within its agreed number of maintenance days, and
- any costs incurred by NGG NTS as a result of exceeding its allowed maintenance days or as a result of unplanned outages will be borne in full by NGG NTS.

11.27. This is discussed further in Appendix 16.

Revenue from non-obligated capacity release

11.28. It is our view that NGG NTS should be incentivised in relation to the release of non-obligated and interruptible capacity at both entry and exit. As stated above, at entry, it is proposed that such revenues should be netted off the costs of an operational buy back actions within the operational buy back incentive. As such, such revenues will be implicitly subject to 50 per cent sharing factors and a cap and collar.

11.29. With respect to gas offtake, it is our initial proposal that revenue generated from the sale of non-obligated and interruptible capacity should be subject to a separate sliding scale incentive. We propose a zero target for this incentive, with all revenues from non-obligated capacity and interruptible capacity subject to a 50 per cent sharing factor and a defined cap such that the potential cost to customers is limited.

11.30. It is our initial view that, in line with arrangements at entry, the obligation to release baseline capacity should continue up to and including the gas day. As such, non-obligated capacity would be capacity released above baseline in a constrained allocation for which a sustained demand signal had not been received.

11.31. It is currently assumed that the release of interruptible capacity will be on a use it or lose it (UIOLI) basis with the scope for additional discretionary release by NGG NTS. Before finalising the details of this incentive, it will be necessary to gain a greater understanding of the principles for such discretionary release and the way in which non-obligated and interruptible capacity are likely to be priced. As such, these proposals represent our initial view, and we do not believe that it would be appropriate to specify an incentive cap at this time.

Innovation incentives

11.32. Chapter 10 above sets out our proposal to introduce an innovation funding incentive for the electricity transmission companies. We have also considered the rationale for a similar scheme for National Grid NTS.

11.33. We consider that, on balance, the case for including such an additional measure is less compelling for NGG NTS than it is for the electricity transmission companies. There is more evidence of research and development being progressed in a commercial setting, e.g. through manufacturers and contractors used by NGG NTS, in collaboration with organisations such as Advantica. However, we also recognise that there might potentially be further longer-term benefits from innovation that might be unlikely to be realised without refinements to the funding of NGG NTS. We have yet to form a definitive view as to whether an IFI mechanism for gas transmission would deliver value to customers. We are actively developing our thinking on this and would particularly welcome views from parties close to this subject.

Transitional offtake incentives

11.34. 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.

11.35. NGG NTS has a series of incentives that currently apply to it within the interim period. In the Third TPCR Consultation we described these incentives in detail and set out our proposals. In summary we proposed simplifying the incentives that apply to NGG NTS for the transitional period relative to those that apply in the interim period. The proposals for the transitional incentives set out in the Third TPCR Consultation were supported by most respondents. Our initial proposals are consistent with those set out in the Third TPCR Consultation and are as follows:

11.36. **Foregone charges incentive**. We do not consider that it is necessary to continue with this incentive for the transitional period for reasons outlined in Appendix 16.

11.37. **Exit capacity investment incentive**. We do not consider that it is appropriate to continue with this incentive for the transitional period for reasons outlined in Appendix 16.

11.38. **Constrained LNG incentive**. We propose to retain this incentive in its current form, and to update the incentive target value. Furthermore, we propose to extend the application of this incentive into the enduring period such that it applies for the duration of the next price control period. Pending the receipt of further information from NGG NTS regarding expected constrained LNG costs, it is our initial proposal that the incentive target should remain at the 2008/9 level of £2.1m for the remainder of the next price control period.

11.39. **NTS buy back and 15 day interruptions incentive**. We propose to update the greater than 15 days interruption element of the incentive for the transitional period. NGG NTS have not responded to our requests to provide forward looking data on expected greater than 15 days costs. Pending further information in this regard, and given that costs in recent years have been zero, it is our initial proposal that the incentive target for 2009/10 and the first 6 months of formula year 2010/11 should be zero.

11.40. **NTS buy back incentive**. NGG NTS also has a capacity buy back incentive under the interim regime. We are not proposing to continue with this incentive for the transitional period for reasons outlined in Appendix 16.

12. Environmental considerations

Chapter Summary

This chapter sets out our initial proposals on the environmental aspects of the transmission price control review. It describes how the transmission companies impact on the environment, and sets out our policy proposals in this regard. It considers the issue of emissions, losses, visual amenity and noise.

Questions

Question 12.1: Do you agree with our assessment of the main impacts of the transmission system? What are the most important impacts from the perspective of consumers?

Question 12.2: Should emissions of SF6 be subject to a separate incentive scheme, given that they are currently outside the scope of the European Emission Trading Scheme (EU-ETS)

Question12.3: Should there be additional measures to promote innovation in support of environmental benefits, either as part of the proposed incentive scheme for innovation for NGET, SPT and SHET or as a separate measure?

Introduction

12.1. This chapter sets out our initial proposals on the environmental issues associated with the TPCR. It starts with a consideration of the range of impacts associated with the current operation of the transmission networks. This starting point reflects our statutory duties in respect of the environment, including our secondary duty under the gas and electricity acts to have regard to the effects on the environment and contribute to the achievement of sustainable development when we make decisions.

12.2. The transmission networks can be viewed as having the following broad types of environmental impacts:

- Emissions;
- Losses;
- Visual Amenity
- Noise

12.3. These are discussed in turn below.

Emissions

12.4. The operation of the transmission system results in emissions and leakages. The main emissions are Sulphur Hexafluoride (SF6) and oil in electricity, and CO2 and methane in gas compressor stations.

12.5. SF6 is used in substations and switchgear and is an extremely effective electrical insulator. It has significant advantages over alternative materials. It is non-flammable and takes up less volume than an equivalent insulating volume of oil. It can, however, leak.

12.6. SF6 is an extremely potent greenhouse gas, and is approximately 24 thousand times more damaging than CO2. In 2004/05, emissions from the three transmission licensees were 13.85 tonnes, 1.02 tonnes and 0.17 tonnes for NGET, SP and SHETL respectively. This sums to around 15.04 tonnes of SF6, or 0.36 million tonnes of CO2 equivalent.

12.7. Around 15 per cent of National Grid's greenhouse gas emissions are associated with the electricity and gas compressors used to pressurise the UK's national gas transmission system. Using 2004/05 data, greenhouse gas emissions from NGG NTS's gas compressors were around 1.8 million tonnes CO2.

12.8. Oil is used as an insulator in some cabling. Cabling is used in circumstances where it is not possible to install over-head lines, e.g. to span large distances across water. In total, around 64,808 litres of oil leaked from electricity transmission assets in 2004/05. Because of the prevalence of cabling in SHETL's transmission area, over 39,654 litres were lost from its transmission system.

Losses

12.9. The bulk transfer of electricity results in the loss of energy in transit. These losses are lower than on the distribution networks because the total length of transmission circuits is lower and the electricity is being transmitted at higher voltages. Total losses across the transmission network represents, on average, some 1.7 per cent of the electricity generated.

12.10. 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. The precise impact on emissions would depend on the marginal generation technology.

Visual amenity

12.11. It is generally accepted that transmission assets reduce visual amenity, and that visual amenity has a value to consumers. However, the value of enhancements of visual amenity will vary widely between different classes of customer.

12.12. The existing electricity network has 26,550 kilometres of overhead line in the GB electricity transmission, comprising 5,250 kilometres of 132kV (Scotland only), and 21,300 kilometres of 275/400kV.

12.13. 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. A large compressor station is similar in size to a small (100MW) power station. There are 25 compressor stations on the GB network, and 6 large entry terminals.

Noise

12.14. The main sources of noise pollution associated with the transmission networks relate to electricity substations and compressor stations in gas. The noise levels associated with overhead lines varies with weather conditions (it is greater when it is raining) but is generally imperceptible, unless within close proximity.

12.15. Noise from substations can be substantial. However, on the whole, substations are sited away from major populations. The sound emitted from a typical electricity substation is detected as a low frequency hum. Allowing for distance, these pieces of equipment represent noise consistent with levels of general background noise.

Our proposals

Allowances for capital expenditure and operating costs

12.16. The allowances for replacement capital expenditure underpinning our initial proposals embody a significant amount of environmental betterment. In many instances the assets being replaced (if the replacement programme is based on robust data of asset condition) will be the assets with most detrimental environmental impacts.

12.17. Another driver for this type of environmental improvement relates to the increasingly stringent requirements of environmental legislation. Our initial proposals are set on a basis consistent with our current view on the companies meeting their obligations under law in respect of the environment in an efficient way. What this means in practice involves a dialogue with the companies and the relevant environmental authorities. For example, the replacement of gas-fired with electricity-powered compressors on the NTS.

12.18. The TPCR allowances will also reflect the changing demands for transmission capacity as revealed by the locational decisions of generators. To the extent that there are other commercial drivers pushing generation towards more remote parts of the network (such as the Renewables Obligation - and additional proposals for Government to subsidise transmission charges for wind generation in remote areas) then our allowances for load-related expenditure will accommodate the building of more transmission.

12.19. This will, inevitably, magnify any environmental detriments associated with the building of transmission. The connection of generation to more remote parts of the network will also increase losses (because the energy will need to be transmitted further – and losses increase with distance). Conversely, the connection of additional renewable generation will bring environmental benefits as an increasing proportion of electricity demand is met by means other than the burning of fossil fuels. These effects are not, however, direct consequences of our initial proposals – rather they reflect the wider commercial context within which the TPCR is being undertaken.

Possible additional policy initiatives

12.20. One option in developing our proposals is to assess the environmental impacts our proposals will have, and in particular the significant allowances for replacement expenditure and the funding for network investment to connect large scale renewable generation to the network, and conclude that no further measures are required.

12.21. However, while we think that such an approach would be consistent with a reasonable interpretation of our statutory duties, we think that additional measures can be introduced to improve further the environmental impacts at the margin.

Innovation Incentives

12.22. As noted in chapter 8 above, we are proposing to introduce an IFI-type engineering R&D incentive for the electricity transmission companies. One option is to extend this type of mechanisms to encompass innovation with environmental considerations as a primary driver. However, there might be benefits is maintaining a separation between engineering innovation and environmental initiatives.

Revenue from EU ETS allowances

12.23. The operation of the transmission systems in their current form results in National Grid receiving an allocation of allowances under the EU Emissions Trading Scheme (ETS). The extent to which National Grid operates the transmission systems in an efficient manner determines the amount of efficiency savings that are created. We are proposing to permit the companies to retain any efficiency savings associated with the value of allowances in part or in full. This provides a strong financial incentive to reduce carbon emissions.

12.24. However, currently SF6 emissions are outside the scope of EU-ETS, and therefore this mechanism would not provide a financial incentive to reduce emissions. We are currently considering whether separate measures are appropriate to address this issue and will consult with relevant other regulatory authorities and Defra in forming a view.

Under-grounding

12.25. As part of the DPCR we allocated additional funds for the DNOs to underground a proportion of their network in environmentally sensitive areas. This allowance was based on an assessment of costs and benefits.

12.26. The similar issue in transmission involves a different assessment of costs and benefits. The cost of undergrounding a 400kV transmission line is in the order of 15 to 20 times more expensive than installing an overhead line. In contrast, the cost difference for distribution lines is in the order of 5 -10 times. In general, the cost premium increases with voltage.

12.27. The benefits might also be different in transmission as compared to distribution. There are factors that work both ways. Transmission towers are much bigger – therefore, other things being equal the visual amenity detriment will be higher. However, transmission towers are also, in general, installed in more remote locations – and hence fewer people live in close proximity to them.

12.28. The academic literature of valuing visual amenity indicates that valuation techniques are highly uncertain and give a very wide range of estimates. It also indicates that the benefits are much greater when they relate to the installation of a new line as compared to the upgrading of an existing line.

12.29. We will continue work to explore the costs and benefits of under-grounding of transmission lines in developing our proposals. However, our current view is that the case for additional allowances is less compelling for transmission as compared to distribution - and that the interests of consumers might be better protected by focusing on other environmental impacts such as emissions. In finalising our views we will also have regard to the distributional consequences of any additional allowances on charges to end consumers, including in the context of fuel poverty.

Appendices

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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 July 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. We will be holding a workshop to present our initial proposals on 5 July at The London Underwriting Centre in London. This will provide an opportunity for interested parties to raise issues and ask questions. If you wish to attend the workshop the please send an email to Colin Green.

1.7. Having considered the responses to this consultation, Ofgem intends to publish updated proposals for the price controls in September 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. The Updated Proposals will be followed by Final Proposals in December.

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 initial 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 initial 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 initial proposals are set out in later chapters.

CHAPTER: 6

Question 6.1: Do you think our proposed approach to the costs incurred in the current price control period in respect of increasing capacity at St Fergus is appropriate?

CHAPTER: 7

Question 7.1: Do you agree with our proposed treatment of non-operational capex and 'quasi capex'?

Question 7.2: Do you agree with our proposed approach to future input price changes and indexation? Is our assumption of a 1.5% annual efficiency saving for opex realistic and appropriate?

Question 7.3: Is our assumption on efficient connection design for wind generation, and the associated reduction to some of the company cost forecasts, appropriate?

Question 7.4: Do you think that we need to allow explicitly for the possibility of re-opening the price controls for specified single events where the timing and level of costs is uncertain and driven by third party decisions? If so, what might such events be and why?

Question 7.5: What do you think of our proposed options for setting incentives for efficient capital expenditure?

CHAPTER: 8

➔

➔ **Question 8.1:** Should the licensees' revenue allowances for tax payments be set to avoid any need for ex post adjustments?

➔

➔ **Question 8.2**: Are there any other measures which could be taken to reduce perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plc's?

Questions

There are no questions in this chapter.

CHAPTER: 10

Question 10.1: Is our proposed two-part revenue driver design appropriate and proportionate to the issue it is seeking to address?

Question 10.2: What are the costs and benefits of seeking to facilitate greater competition between providers of transmission services, in respect of the prospective transmission links to the Scottish Islands?

Question 10.3: Is our proposed approach to funding for innovation appropriate and necessary?

Questions 10.4: Is our proposal to extend the existing performance incentive scheme appropriate?

CHAPTER: 11

Question 11.1: What do you think of our revised proposals for setting entry capacity release obligation baselines, and for the proposed mechanisms for enable such baselines to be re-allocated in some circumstances?

Question 11.2: Are our proposals for revenue drivers for entry and offtake appropriate and proportionate, given the issues they are seeking to address?

Question 11.3: Are our proposals for revenue drivers for entry and offtake appropriate and proportionate, given the issues they are seeking to address?

Questions 11.4: Is there a case for an innovation incentive for NGG NTS?

CHAPTER: 12

Question 12.1: Do you agree with our assessment of the main impacts of the transmission system? What are the most important impacts from the perspective of consumers?

Question 12.2: Should emissions of SF6 be subject to a separate incentive scheme, given that they are currently outside the scope of the European Emission Trading Scheme (EU-ETS)

Question12.3: Should there be additional measures to promote innovation in support of environmental benefits, either as part of the proposed incentive scheme for innovation for NGET, SPT and SHET or as a separate measure?

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.[2]

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[3].

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[4]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[5]

[2] entitled "Gas Supply" and "Electricity Supply" respectively.
[3] 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.
[4] 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.
[5] 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[6] 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[7] 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.

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

Appendix 3 - 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 amount of capacity that the transmission licensee is obliged to release. Baselines also determine the levels above which incremental capacity is defined.

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

Merger and Monopolies 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 4 - 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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