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Transmission Price Control Review: Final 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 Final Proposals for the transmission price control review. Ofgem is introducing a regulatory regime that facilitates efficient investment in the transmission networks to support new sources of gas and electricity and maintains high levels of reliability. These Final Proposals provide for some £4.6 billion of infrastructure investment with mechanisms to fund further investment triggered by users. This is in addition to some £500 million of investment already provided to support transmission investment for renewable generation.

We propose a real post-tax rate of return of 4.4 per cent, which we believe is sufficient to attract investment in the companies. The proposed allowances and incentive schemes also provide scope for the companies to earn enhanced returns by improving efficiency and reliability.

Each company will form a view on whether to accept the package of proposals in this document. Should they reject these proposals we would expect to refer the matter to the Competition Commission.

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Context

This document outlines our Final Proposals for the electricity and gas transmission licensees' price controls for the five years beginning 1st April 2007.

Our revised views on the allowances for capital and operating expenditure published in September have been further updated in this document. We believe that these proposals adequately address the issues outlined in previous consultation documents, such as the changes in the efficient operation of transmission networks, broader energy policy and the environment; acknowledging the principal objective to protect the interests of consumers.

Associated Documents

- TPCR 2007-2012 Final Proposals, Appendices, December 2006 (Ref No. 206/06b)
- TPCR 2007-2012 Updated Proposals, September 2006 (Ref No. 170/06)
- TPCR 2007-2012 Updated Proposals - Appendices, September 2006 (Ref No. 170/06a)
- TPCR 2007-2012 Initial Proposals, June 2006 (Ref No. 104/06)
- TPCR 2007-2012 Initial Proposals, Main Appendices, June 2006 (Ref No. 104b/06)
- TPCR 2007-2012 Initial Proposals, Appendix: Offtake Revenue Drivers and Baselines for NGG NTS , June 2006 (Ref No. 104c/06)
- TPCR 2007-2012 Initial Proposals, Draft Enduring Offtake Impact Assessment, June 2006 (Ref No. 104d/06)
- Access Reform in Electricity Transmission: Working group report and next steps, May 2006 (Ref No. 83/06a)
- A framework for considering reforms to how generators gain access to the GB electricity transmission system: A report by the Access Reform Options Development Group April 2006, May 2006 (Ref No. 83/06b)
- TPCR 2007-2012: Third Consultation, March 2006 (Ref No. 51/06)
- TPCR 2007-2012: Third Consultation, Supplementary Appendices, March 2006 (Ref No. 51/06b)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)

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

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Summary

This document sets out our Final Proposals for the Transmission Price Control Review (TPCR). These proposals represent our decisions on the maximum revenue that the four transmission licensees will be allowed to recover from consumers and other network users over the five years from 1st April 2007 and on the incentives that will apply during that period. We believe that this package of measures will protect the interests of consumers whilst providing sufficient revenues to enable transmission businesses to finance their activities and comply with their obligations.

This review takes place at a time of high and volatile energy prices, with companies seeking huge increases in investment to replace ageing assets and to strengthen and extend the networks to connect new sources of imported gas and low carbon electricity generation. But it is uncertain where and when these connections are needed, so we have provided incentives for flexibility, as well as for efficient investment, so that investment can be adjusted to meet higher or lower demands for network capacity than the companies have forecast. The main themes of our Final Proposals are:

A major increase in electricity and gas investment: We propose allowances for capital investment of £4.6 billion (in 2004/05 prices) over the next five years. Including investment already approved to connect renewable generation in Scotland under the Transmission Investment for Renewable Generation (TIRG) mechanism, total allowances for investment amount to £5.1 billion.

- While we have scaled back the companies' forecasts, our Final Proposals, when added to the TIRG funding, represent a total increase of 100 per cent relative to the allowances set during the last major price controls. For the electricity transmission companies the increase is 160 per cent.

Flexibility to respond to new developments: Much of the new investment will be driven by the needs of the generation and gas supply companies that use the network. The outcome of the Government's Energy Review is also likely to have an impact. It is important that the regulatory regime can respond effectively to events.

- We have introduced mechanisms which automatically adjust the revenue allowances of the companies, either up or down, in response to the demand for capacity by companies and customers that use the networks. These will provide a closer alignment between revenue allowances and the requirements for investment to meet changing needs for capacity. This process will work best if demands for capacity, from both new and existing users, are backed by long term financial commitment. Such commitments from users will help the companies to identify where to invest and will reduce the risk either that investment is disallowed at future reviews, or that business and domestic customers have to pay for unnecessary investment.

A continuing focus on efficiency and performance: In delivering investment and operating their networks, we expect well managed companies to operate in an efficient and effective manner, thereby ensuring that consumers continue to benefit from a high standard of performance at the lowest possible cost.

- We propose allowances for operating costs of £2.2 billion over the next five years. These allowances pass through the benefits of cost reductions achieved since the last review to consumers and they assume further improvements in efficiency at around 3 per cent per year in the next price control period.

- We have introduced new incentives to encourage efficient and timely investment that is based on a clear need. In addition, we have introduced a 'safety net', which would allow us to reset revenue allowances if a company should significantly underspend its allowance without good cause. We will incentivise the companies to introduce suitable output measures such that we may assess their efficiency and performance more closely in future reviews.

Encouraging sustainable development: As well as providing investment in networks to connect sustainable energy sources, we propose to introduce a new incentive to target reduced leakage of sulphur hexafluoride - a major greenhouse gas. Our innovation funding incentives will also encourage new research and development initiatives that can bring benefits to the environment.

Our Final Proposals provide for a real post tax return of 4.4 per cent on the regulated asset value of the companies. Our analysis suggests that this is at a level sufficient to continue to attract investment and that there is scope within the incentive arrangements for the companies to earn enhanced returns by improving efficiency and delivering the outputs that network users need.

Our Final Proposals provide total revenue allowances of £1,667 million in 2007/08, rising to £1,764 million by 2011/12 in real terms. This will represent an initial increase of 7.8 per cent against the latest revenue allowances for 2006/07. Electricity transmission revenues will then increase by a further 2 per cent above the rate of inflation each year thereafter, reflecting the rising pattern of investment, while gas transmission revenues will increase in line with inflation. The eventual change in revenues over the five-year period will also depend on the impact of the revenue drivers which will fund any necessary additional investment.

Transmission charges currently only represent around 3 per cent of a domestic consumer's bill, so the initial impact on domestic gas and electricity prices will be very small. However, the impact on prices of increasing levels of investment will become more significant over time and we expect the trend of rising transmission charges to continue well beyond 2012. The impact of these proposals upon charges to larger network users will be somewhat greater than upon domestic consumers.

Next steps

We have asked the licensees to state, by 8th January 2007, whether they accept these proposals in principle. If any company rejects the proposals Ofgem would expect to make a reference to the Competition Commission. We have started our consultation process on the licence modifications to give effect to our proposals. A further informal consultation will be published in early January 2007, with the aim of publishing the final statutory consultation in February 2007. The new licence conditions, if accepted by the licensees, will take effect from 1st April 2007.

1. Introduction

Chapter Summary

This chapter sets out the background to our Final Proposals and summarises the main developments since publication of our Updated Proposals in September 2006. It also explains how this document is structured.

Challenges for the TPCR

1.1. This is the first time that we have reviewed all of the gas and electricity transmission price controls at the same time and these Final Proposals represent the culmination of 18 months of extensive consultation and analysis. The Final Proposals build upon comments received in response to the five consultation documents published between July 2005 and September 2006. They also reflect the extensive analysis we have undertaken, supported by consultants from a number of disciplines.

1.2. The key feature of this price control review has been the significant investment requirements of the transmission businesses over the next five years and, within this context, concerns regarding the effectiveness of the access regime that applies to electricity transmission in signalling new investment requirements.

Flexibility of the price control regime

1.3. A key feature of the investment plans submitted by the companies has been the uncertainty regarding the level and timing of investment driven by new users. We believe it is important that the price controls should be sufficiently flexible to enable the companies to respond to the changing needs of network users and should provide appropriate finance to the companies as and when they need it.

Access arrangements

1.4. A number of issues have arisen in recent years regarding the way that access is provided by the electricity transmission businesses and the efficiency of network investment. The arrangements whereby access was provided on a first come first served basis and the requirement for users to guarantee the full cost of network reinforcement were seen, particularly by renewable generators, as providing significant barriers to entry. We considered that it was appropriate to consider the effectiveness of the access regimes in parallel with reviewing the price controls for the transmission licensees and, where appropriate, set out possible refinements which might facilitate more effective network access by participants in the electricity and gas markets.

Ofgem's approach to the TPCR

1.5. The TPCR sets out proposals for the price controls to apply from April 2007 onwards for each of the transmission licensees in their role as transmission owners (TOs). These 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.

1.6. During the review, we have recognised the need for a significant increase in investment to support the replacement of ageing assets and the connection of new sources of energy. We have interrogated the companies' cost projections that were provided at the beginning of the year. We have also examined the efficiency of historic expenditure in determining the starting Regulated Asset Value (RAV).

1.7. In performing the review, due to the significant differences in scale of the transmission companies, and the limited range of measures to assess output performance, our analysis has primarily relied on interrogation of information provided by the companies, rather than on comparative analysis.

Developments since September

1.8. In September, we published our Updated Proposals for these allowances. We are now setting out our Final Proposals in the light of further analysis and responses to the September consultation.

1.9. 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. It also takes into account the capitalised element of the pension cost allowances and minor adjustments for asset disposals and transfers.

Access reforms

1.10. We consider that there is significant benefit to be gained both for users of the transmission system and consumers from access reforms in electricity and gas transmission, especially with respect to the connection of new generation. This would result from developing access regimes in a way which:

- defines what access rights users will receive;
- provides better signals and commitment from all users regarding their use of access rights to encourage efficient use of existing capacity;
- reduces the burden on new users to guarantee the full costs of new infrastructure, but provides sufficient guarantees to provide some protection to licensees and existing users against the risk of asset stranding; and

- facilitates the timely connection of users.

1.11. The current access regimes are set out within a range of industry codes and, as such, are subject to detailed governance processes which require changes to be approved by the Authority. We are therefore unable to mandate access reforms. The industry is now developing proposals for access reforms, which we hope will be put to the Authority for approval.

Structure of this document

1.12. 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 the final package for each of the four transmission companies in turn;
- chapter 7 discusses a number of policy issues considered in establishing our proposed allowances for capital expenditure and operating costs, as well as the general framework of price control incentives. These are largely common to all companies;
- chapter 8 discusses financial issues, including the important issue of the cost of capital;
- chapters 9 and 10 set out our proposed package of incentives and adjustment mechanisms for electricity and gas respectively. This includes 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 11 sets out how we have considered the issue of sustainable development in the context of the TPCR, and explains how these considerations are reflected in developing our Final Proposals;
- chapter 12 sets out our proposed approach to implementation of the Final Proposals, the development of regulatory reporting for the five year period and further work to examine issues such as the development of output measures.

1.13. There are a number of supplementary appendices which provide more technical detail on our Final Proposals. In particular, appendix 5 provides a glossary of terms relevant to this document and appendix 11 sets out how we have responded to the many individual points made by respondents to the Updated Proposals.

1.14. 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. All figures in this document are given in 2004/05 prices unless otherwise stated.

2. Overview of the Final 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.

Introduction

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

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

Summary of the proposed revenue allowances

2.3. Table 2.1[1] summarises our revenue projections presented on the same basis as in our Updated Proposals.

Table 2.1: Revenue calculations 2007/08 to 2011/12 assuming X=0 (2004/05 prices)

	NGG	NGET	SPTL	SHETL	Total
2006/07 Revenues	442	1005	160	51	1657
September Updated Proposals	472	1076	149	49	1747
December Revenue Allowance	489	1093	156	50	1788
Change from Updated Proposals	16	17	7	1	41

Revenues are given inclusive of excluded service incomes and net of IFI and other adjustments.

2.4. This shows that annual revenue allowances have increased by £41 million as a result of adjustments to the cost allowances and the allowed rate of return. Two

[1] All figures are given in 2004/05 prices, unless otherwise stated, and in the interest of clarity figures have been rounded to the nearest million pounds, where appropriate.

further adjustments are then required in order to arrive at final proposals for the base price control revenue allowances:

- each of the companies has now provided its latest estimate of allowed revenues for 2006/07, reflecting the latest view of over and under-recoveries ("K factors") and other price control adjustments; and
- the companies have provided current forecasts of income in respect of excluded services, for the final year of the current price control and for each year of the next price control period 2007-12.

2.5. The first of these adjustments updates the 2006/07 allowance which is used as the basis for the year-on-year comparison. The second allows us to present the base price control revenue allowance (excluding revenue from excluded services) for both 2006/07 and the next price control period.

2.6. Since publication of our Updated Proposals we have also analysed the impact of holding revenues constant in real terms relative to the anticipated profile of costs over the period ("RPI-0"), having particular regard to the impact of the proposed revenue profile on the companies' financial ratios. We have concluded that, for the electricity transmission licensees, it is appropriate to establish a rising revenue profile ("RPI+2") to ensure that revenues, and associated cash flows, are aligned more closely to the rising trend of costs resulting from the substantial increase in investment envisaged over the 5 year period. However, we propose to hold the allowed revenues constant in real terms for NGG, recognising that there is no equivalent step up in baseline investment for NGG and that the profile of increasing costs will be captured by the revenue driver mechanisms.

2.7. Taking these factors together, our Final Proposals for base price control revenue allowances are set out in table 2.2 below. The table shows the proposed allowances for 2007/08, which for electricity transmission companies will be followed by annual increases at 2 per cent above the rate of inflation. Our proposals represent a "P0" increase of around 8 per cent on average across the four transmission companies.

Table 2.2: Final proposals for base price control revenue allowances 2007/08 (2004/05 prices)

	NGG	NGET	SPTL	SHETL	Total
2006/07 Allowances	416	925	155	50	1546
Base Price Control Revenue	487	985	147	47	1667
Proposed revenue change	71	61	-8	-2	121
P0 change	17%	7%	-5%	-5%	8%

2.8. Appendix 1 sets out the detailed calculations of the base price control revenue allowances and provides a reconciliation to the revenue allowances given in table 2.1 above.

2.9. It should be noted that these revenue allowances will vary to a degree depending on actual demand for capacity relative to the demand for capacity assumed in setting the allowances, through the operation of the adjustment mechanisms.

Capital expenditure

2.10. 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 programmes and associated asset management practices. Our analysis has included an efficiency review of historical capital expenditure up to 2005/06 and an assessment of forecast capital expenditure for 2006/07 to 2011/12.

Historical expenditure

2.11. The outcome of our review of historical capital expenditure is that we have allowed some £3.4 billion of expenditure to enter the RAV in respect of the period up to and including 2005/06. This amount includes £321 million of overspend incurred by NGET and some £126 million of capital expenditure for NGG in respect of a new gas pipeline and major network reinforecement to connect a Liquified Natural Gas (LNG) terminal at Milford Haven.

2.12. Our Final Proposals for NGG exclude £19 million of some £75 million expenditure relating to the delivery of baseline capacity at St Fergus where we believe that NGG has not provided adequate justification for this investment in the light of indications of demand for capacity arising from the long term entry auctions. We considered whether this expenditure should be excluded in its entirety but have concluded that, since this project was initiated in the early days of the new entry regime when the potential implications of operating under an auction regime may have been uncertain, it would be inappropriate to do so.

Forecast expenditure

2.13. The outcome of our assessment of capital expenditure requirements over the course of the review is summarised in table 2.3 below. This table sets out the following capex movements:

- **Original licensee forecast** - this is the initial forecast submitted in December 2005;
- **Adjusted licensee forecast** - this is an alternative representation of the December 2005 forecasts after adjustments were made by Ofgem to reallocate certain costs between capex and opex and to remove load related expenditure which it was intended should be covered by automatic revenue drivers rather than a baseline allowance; and

- **Updated Proposals (UP) and Final Proposals (FP)** - these reflect Ofgem's view on the appropriate allowances. It is important to note that our proposed allowances take into account new capital expenditure information provided by the companies during the review process and are therefore not directly comparable with the original and adjusted forecasts.

Table 2.3 Capex allowances 2007/08 to 2011/12 (5 year totals, 2004/05 prices)

£m	NGG	NGET	SPT	SHETL	Total	% from licensee forecast
Capex allowance (last 5 year price control)	889	1453	152	71	2565	
Original Licensee Forecast	1346	3816	717	834	6713	
Adjusted Licensee Forecast	941	3740	730	188	5599	
Updated Proposals (UP)	797	2953	576	178	4504	-20%
Final Proposals	824	2997	608	181	4609	-18%
Change from UP	27	43	32	3	106	
Change from last price control	-65 -7%	1544 106%	456 300%	110 155%	2044 80%	

2.14. 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 "baseline" revenue allowances for each licensee, we have therefore excluded those uncertain user-driven investments. The remaining investment proposals, other than the projects already provided with funding under the Transmission Investment for Renewable Generation (TIRG) project, have been considered as part of our cost assessment work.

2.15. Our analysis of the companies' investment proposals has identified scope for significant cost reductions, particularly in the area of non-load related expenditure. Our view is that the baseline revenue allowances should provide funding for some £4.6 billion of capital expenditure over the next five years.

2.16. In addition to the baseline revenue allowances, our Final Proposals introduce mechanisms for logging-up specified items of uncertain costs. Subject to these costs passing our efficiency assessment, we propose that they should be included within the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up.

Operating expenditure

2.17. 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. We have:

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

2.18. Our analysis of the companies' forecasts of controllable operating costs has identified scope for savings in a number of areas. Our Final Proposals allow for £2.17 billion of total operating expenditure (excluding pension costs) over the next five years. This represents an increase of around £33 million relative to our Updated Proposals but a reduction of £162 million relative to the companies' forecasts.

Table 2.4 Total opex allowances 2007/08 to 2011/12 (5 year totals, 2004/05 prices)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)	Change from Company Forecast
Past allowances	748	1453	160	57	2417	-
Company forecast	717	1402	157	52	2327	-
Updated Proposals	686	1260	141	46	2133	-8%
Final Proposals	688	1289	143	46	2166	-7%
Change from Updated Proposals	**2**	**29**	**2**	**0**	**33**	

2.19. We have given further consideration to the treatment of specific items of uncertain costs. Our Final Proposals introduce mechanisms for logging-up these costs during the period. We propose that these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up. We estimate that around £10 million of operating expenditure may be subject to these mechanisms.

Financial issues

Cost of capital

2.20. Our Initial Proposals indicated that the available data on the component parts of the cost of capital could potentially support a real post-tax rate of return in the range of 2.8 to 4.8 per cent, although market evidence provided little guidance on an appropriate value within this range. In our Initial Proposals and Updated Proposals we used a modelling assumption of 4.2 per cent post tax real, (equivalent to a "vanilla WACC"[2] of 4.84 per cent). We indicated that our decision would be made as part of these Final Proposals.

2.21. The companies and investors have generally argued that Ofgem should adopt a value towards the top end of the range set out in Initial Proposals (i.e. 4.8 per cent post tax). Their main argument has been by comparison with the decision for electricity distribution (4.8 per cent post tax real) and the large scale of the difference between this and the 4.2 per cent assumed in Initial Proposals over a relatively short period in which market evidence has not changed substantially. The companies and investors have also argued that they have competing uses for capital which offer more attractive risk-adjusted returns. Some other parties, including network users, have argued that the allowed return should be lower than 4.2 per cent.

2.22. Our decision on the cost of capital has taken into account a range of factors including the investment focus of the review, the risk profiles of the companies, our assessment of financeability, the advice of our consultants, respondents' views, consistency with past regulatory decisions, and the importance of providing stability in the allowed return. In the light of these factors, we have concluded that where the transmission companies perform in line with our assumptions they should receive an allowed rate of return of 4.4 per cent post-tax real (equivalent to a vanilla WACC of 5.05 per cent). When actual tax allowances are taken into account, then our proposal represents an effective pre-tax rate of return of around 6.65 per cent.

Pensions

2.23. Allowances for pension costs have been assessed on the basis of the principles developed in the Developing Network Monopoly Price Controls consultation in 2003 and applied in the context of the recent electricity distribution price control review (DPCR4). In our Final Proposals we have maintained the position set out in September, although we have made minor adjustments to reflect new information and the impact of the higher allowed rate of return on the annualised allowance for deficit recovery.

[2] The 'vanilla' WACC is the average of the pre-tax cost of debt and the post-tax cost of equity weighted by the assumed gearing.

Table 2.5 Pension costs 2007/08 to 2011/12 (5 year totals, 2004/05 prices)

	NGG (£m)	NGET (£m)	SPTL (£m)	SHETL (£m)	Total (£m)
September Update	187	247	6	8	448
Final Proposals	202	249	6	8	466
Change from Updated Proposal	**16**	**2**	**0**	**0**	**18**

Financeability

2.24. We have analysed the impact of our Final Proposals, incorporating a range of capital expenditure scenarios, in order to assess whether these can be expected to allow the licensees to be able to maintain an appropriate credit rating. In previous TPCR consultations we have indicated that, were this not to be the case, the appropriate approach would be to assume that companies would be able to raise additional equity and to make allowance for the costs of raising such equity.

2.25. Our analysis suggests that the proposed revenue allowances will allow the baseline positions for the licensees (i.e. reflecting the baseline capex allowance but not any additional expenditure funded by revenue drivers or relating to TIRG) to be funded without any requirement for equity or any other "financeability adjustment" beyond the depreciation ‘tilting’ adopted for final proposals (see chapter 8 for further detail). However, our modelling suggests that additional equity will be required in the case of SHETL to cover TIRG expenditure and in the case of both Scottish licensees if additional investment requirements arise during the price control period and are funded by revenue drivers.

2.26. Our proposals include an ex ante allowance to fund the cost of issuing the new equity necessary to support baseline capital expenditure, TIRG expenditure, and half of the additional investment that a company might potentially incur in the high case estimate submitted to us. The allowance has been set at 5 per cent of the value of equity required, as estimated by our financial model. This results in a value of some £5 million for SHETL and around £1 million for SPTL. We then propose to “true up” the allowance at the next review to reflect actual investment and the equity required to finance it.

Incentives

2.27. We have developed a suite of incentives for the electricity and gas licensees. This includes a fixed strength capital expenditure incentive which defines the exposure licensees will face if actual capital expenditure differs from our allowances. The capital expenditure incentive works in conjunction with our proposals for baseline expenditure, to remunerate investment that is considered highly likely to go ahead, as well as the more uncertain investment projects that will be remunerated by revenue drivers.

2.28. The Final Proposals introduce an Innovation Funding Incentive (IFI) for electricity and gas transmission. This is modelled on the scheme already in place for electricity distribution and which will include research intended to deliver environmental benefits. In electricity, we have also proposed an environmentally focused incentive scheme to reduce leakage rates (and enhance reporting and monitoring of leakage) of a damaging greenhouse gas, sulphur hexafluoride (SF6).

2.29. Our proposals also require the development of output measures, which we anticipate will enable greater visibility as to the performance of the transmission systems in response to the capital expenditure and operating expenditure that we allow the licensees. As such we are proposing to postpone the introduction of a 'penalty only' reliability incentive scheme and roll over the existing symmetrical scheme for a period of two years. If, after two years, these output measures are developed to our satisfaction by the licensees, then a symmetrical scheme will remain in place for the remainder of the price control period.

Impact on consumers

2.30. Transmission charges vary geographically reflecting the fact that transmission costs rise the further energy has to be transported from where it is produced to where it is used. The effect of these proposals on business and domestic consumers will therefore vary. On average transmission charges make up about 3 per cent of a domestic consumer's bill, so the initial impact on prices will be very small. However, the impact on prices will become more significant over time to finance the investments that are proposed. We also expect that the trend of rising transmission charges will continue beyond 2012.

2.31. The impact of these proposals upon transmission charges to many business users will be greater. We have strived to keep these price rises as low as possible through our thorough review of the efficiency of the companies' investment plans and the incentives we have placed on the companies. Consumers will benefit from continuing to have reliable and secure networks, and from the pressure on wholesale prices that access to new sources of supply will bring and from more sustainable networks and sources of energy supply.

2.32. It is important to recognise that, in setting allowances for capital expenditure and operating expenditure for the transmission licensees, we need to fulfil our duty to ensure that the companies can finance their licensed activities against the background of uncertain demands for capacity over the next five years. We consider that our proposals represent an appropriate balance of risk and reward for the licensees and consumers.

Next steps

2.33. We propose to implement revised regulatory reporting and compliance regimes to support the new price controls. In the New Year, we will also begin work to consider the following:

- the development of output measures;
- the analysis of comparative network risk;
- the review of the gas transmission planning methodology; and
- a transmission regime suitable for potential connections to the Scottish Islands.

3. National Grid Electricity Transmission (NGET)

Chapter summary

This chapter sets out our Final Proposals for revenue allowances for NGET for the period 2007 to 2012. It quantifies the changes we have made to our Updated Proposals and sets out the reasons for those changes in the light of consultation responses, further analysis and discussions with stakeholders.

Summary

3.1. NGET owns and maintains the network of electricity transmission assets in England & Wales and is also the System Operator of the GB electricity transmission system (GBSO). This chapter sets out our Final Proposals for NGET in relation to its role as transmission owner (TO). It does not set out any SO costs or allowances, which will be set under the umbrella of the SO external incentive scheme, the proposals for which will be published in December 2006. Further information on NGET and its performance against the previous price controls can be found in appendix 10.

3.2. Our Final Proposals for base price controlled revenues are set out in table 3.1 below. These proposals provide an initial revenue increase of 7 per cent in real terms followed by ongoing real increases of 2 per cent per year (i.e. RPI+2).

Table 3.1 - NGET: Summary of Final Proposals (2004/05 prices)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		333	350	362	386	416
- load (base case)		259	166	210	261	253
Operating costs						
- Controllable		164	158	153	153	154
- Non-controllable		102	101	101	101	101
Depreciation		383	398	411	400	416
Pensions						
- allocated to opex		39	38	37	37	37
Current Tax		101	106	110	110	108
Base Price Control Revenue Allowance	925	985	1,005	1,025	1,046	1,067
Excluded services		58	64	72	76	76
Other revenue adjustments		5	4	4	4	4
Total Revenue		1,049	1,073	1,101	1,126	1,147

3.3. In addition to our decision on the allowed rate of return, there are four main areas where we have made changes to our Updated Proposals. They are summarised below (expressed as a total change, relative to our Updated Proposals, for the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of £43 million resulting from changes to assumed unit costs for overhead lines, the estimated impact of future input cost increases, and our treatment of underground cable replacement. We are also providing a logging-up mechanism for any necessary upgrading of NGET's operational telecom systems resulting from the introduction of BT21CN and for the construction of tunnels to replace underground cables along certain routes. These potential costs are estimated at around £94 million;

- **Operating costs:** an increase of around £28 million reflecting the results of our operational telecoms efficiency study and changes in the treatment of share-based payments to employees, property costs, and cost allocations;

- **Tax:** a reduction in tax allowances of £12 million that arises due to a change in the tax treatment applied to the capitalised element of pensions deficits; and

- **Pensions:** an increase of £3 million arising from the increased annuity element of the annual deficit recovery payment.

Capital expenditure (Capex)

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

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

3.5. Since publishing our Updated Proposals, we have included an additional £12.9 million in the RAV in 2000/01. The most significant adjustment relates to £9.2 million of costs that had been previously excluded from the TO RAV as potentially SO expenditure, but has now been included following clarification provided by the company. We have also made an adjustment in relation to non-operational capital expenditure.

3.6. These adjustments increase the opening value of the RAV for 2007/08 to £5,416 million (see paragraphs 3.17 to 3.18 and table 3.4).

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

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

2005/06 to 2006/07

3.8. Our Updated Proposals provided for some £974 million to enter the RAV[3] in relation to the period 2005/06 - 2006/07. We have scaled back this allowance by £28 million for Final Proposals as a result of more accurate profiling of the seven year total capex and small increases relating to overhead line unit costs, impact of input cost increases and cable replacement. A summary of our treatment of capex for the period to 2006/07 is set out in table 3.2 below:

Table 3.2 – NGET updated forecast capital expenditure for the period 2005/06 to 2006/07 (2004/05 prices)

NGET Forecasts & Allowances (2005/06 - 2006/07)	**Original Licensee Forecast**	**Adjusted Licensee Forecast**	**Ofgem Updated Proposals (UP)**	**Ofgem Final Proposals (FP)**	**Change from UP to FP**
Load Related Expenditure	450	419	426	425	-2
Non Load Related Expenditure	601	567	547	521	-26
Total	**1052**	**986**	**974**	**946**	**-28**

2007/08 to 2011/12

3.9. Our Updated Proposals provided for capital expenditure of £2,953 million over the five year price control period commencing on 1 April 2007. Our Final Proposals increase this allowance to £2,997 million, some £744 million below the licensee's latest adjusted forecast, as set out in table 3.3 below:

[3] Capitalised pensions costs, BETTA additions and other RAV adjustments have also been applied.

Table 3.3 – NGET updated forecast capital expenditure for the period 2007/08 to 2011/12 (2004/05 prices)

NGET Forecasts & Allowances (2007/08 - 2011/12)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure					
Sole-use & infrastructure	1332	1267	1204	1187	-17
Input cost increase	25	25	38	37	-1
Procurement efficiency	0	0	-57	-59	-1
Adjustment for 05/06 actual	0	0	-36	-17	18
Sub total	**1356**	**1291**	**1149**	**1149**	**0**
Non Load Related Expenditure					
Transformers & reactors	226	226	161	161	0
Switchgear	556	556	441	441	0
Overhead Lines	615	615	459	476	17
Underground Cables	515	515	437	443	7
Other non-load related	433	422	409	388	-21
Input cost increase	115	115	64	77	13
Procurement efficiency	0	0	-91	-93	-3
Adjustment for 05/06 actual	0	0	-75	-44	30
Sub total	**2460**	**2449**	**1805**	**1848**	**43**
Total	**3816**	**3740**	**2953**	**2997**	**43**

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

- **Non load-related - underground cables:** we have updated our view of costs for underground cabling installed in tunnels (+£7 million); and
- **Non load-related - overhead lines:** we have updated our view of overhead line unit costs (+£17 million).

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

- **Input price increases:** We have increased our allowance for future input cost increases by £12 million in the light of advice provided by our consultants; and
- **Re-profiling of expenditure:** We have revised the profiling of the seven year capex figures for certain cost categories. This includes aligning some of the non-load related costs more closely with NGET's forecast profile, and refining the allocation of the load-related cost adjustments.

3.12. In addition to the changes set out in the table above, we propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs where we have concluded that it is not appropriate to set ex ante allowances. Subject to these costs passing our efficiency assessment, we propose that they should be included within the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up. These costs are:

- **Underground cable tunnels -** for additional projects potentially required towards the end of the five year period (up to £60 million); and

- **BT21CN -** for potential expenditure on telecoms infrastructure arising as a result of the potential withdrawal of certain tele-protection services (around £34 million) - see chapter 7.

3.13. The remaining gap between our proposed allowances and the adjusted forecast by the licensee is now £744 million, of which £152 million relates to procurement efficiency savings and £391 million relates to asset replacement expenditure including the £60 million of underground cable tunnels expenditure covered by logging-up. The remaining £201 million of other smaller individual items of difference include £79 million of efficiency savings in load related capex, £62 million of capex profiling, £26 million of difference in estimated impact of input cost increase, and £34 million of expenditure relating to BT 21CN covered by logging-up. The logging-up mechanism proposed in the previous paragraph effectively reduces the gap by around £94 million.

3.14. The difference between our allowance and NGET's proposed asset replacement expenditure (the £391 million mentioned in the paragraph above) arises from different views of the required volume of replacement and the efficient unit cost of carrying out such work. The difference in respect of replacement volume, which accounts for the majority of the total difference in asset replacement expenditure forecasts, primarily reflects differences in modelling approaches used in assessing the volume of asset replacement required, but also includes other adjustments by NGET and ourselves.

3.15. NGET's modelling approach has the effect of advancing asset replacement by about two years relative to the timescale which our consultant judges to be appropriate. In addition, our consultant has examined NGET's historical asset replacement and, where the actual rate of replacement diverges from modelled output, has made some adjustments to the assumed asset lives to reflect this. These differences are partly offset by areas in which we have made additional allowances in response to asset condition data submitted by NGET.

3.16. NGET takes the view that its modelling approach is appropriate and that the higher volume of replacement it believes is required was partly due to constraints on resources (including those resulting from the previous price control) during the previous 5 years. We have considered these arguments but continue to believe that our allowances, subject to the various adjustments described above, are appropriate.

Regulatory Asset Value

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

Table 3.4 NGET Regulatory Asset Value 2000/01 to 2006/07 (2004/05 prices)

NGET	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Opening value bf	**5,113**	**5,031**	**5,066**	**5,066**	**5,042**	**5,064**	**5,305**
Depreciation	-317	-321	-330	-338	-346	-358	-371
Net capex additions	355	356	330	313	369	598	482
Adjustments	-119	0	0	0	0	0	0
Closing value cf	**5,031**	**5,066**	**5,066**	**5,042**	**5,064**	**5,305**	**5,416**
Average RAV	**5,072**	**5,049**	**5,066**	**5,054**	**5,053**	**5,185**	**5,360**

3.18. Our Final Proposals therefore establish an opening RAV in 2007/08 of £5,416 million, compared to our Updated Proposals of £5,424 million. The main factors influencing the movement since our Updated Proposals are:

- the inclusion of £12.9 million in relation to 2000/01 expenditure; and
- an adjustment to the expenditure profile for 2005/06 to 2006/07 (-£28 million)

Controllable operating expenditure (Opex)

3.19. In the Updated Proposals document we proposed a controllable operating cost allowance of £754 million for NGET for the five year period from 2007/08 to 2011/12, compared with NGET's forecast of £896 million. As set out in table 3.5 below, our Final Proposals increase this by £28.4 million, including the following reasons:

- **Normalisation:** £5.4 million of pension costs have been removed from NGET's normalised operating cost to avoid double counting the separate pensions allowance;
- **Efficiency savings:** we have reduced the allowance for operational telecoms costs by £4.6 million to reflect further potential efficiency savings;
- **Upwards/Downwards cost drivers:** the allowance has been increased by £46 million to reflect an increased allocation of property costs, increased operational telecom costs associated with new sites, employee share option costs and the correction of an allocation between the TO and SO internal controls.

Table 3.5 – NGET updated controllable opex forecast (5 year totals, £m 2004/05 prices)

NGET Forecast & Allowances (2007/08 - 2011/12)	Licensee Company Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
NGET Forecast (excl. Pensions)	**896**			
NGET RCCC 2004/05 (excl. Pensions)		**778.2**	**785.1**	**6.8**
Upward cost drivers		-3.9	29.7	33.6
Profiled cash costs		**774.4**	**814.8**	**40.4**
Total efficiency adjustments		-89.1	-92.4	-3.4
Efficient cash costs		**685.3**	**722.4**	**37.1**
Total new upward cost drivers		6.0	6.0	0.0
Ongoing opex allowance		**691.3**	**728.4**	**37.1**
Total additional Opex allowance		62.7	54.1	-8.6
Ofgem total controllable allowance		**754.0**	**782.4**	**28.4**

3.20. After these adjustments the difference between our allowance and NGET's forecast is some £114 million. This relates primarily to adjustments where our consultants have identified scope for efficiency improvements and the removal of costs that we believe should not have been included. Overall, our efficiency assessment shows an average year on year reduction in controllable costs of around 3 per cent per annum over the price control period.

3.21. In addition to the proposed changes set out in the table above, we also propose, as set out in 2.19, to introduce logging-up mechanisms for dealing with specified items of uncertain costs, where we have concluded that it is not appropriate to set ex ante allowances. We propose that these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up. In NGET's case we propose to allow logging-up treatment for operating expenditure relating to infrastructure arising due to the effects of BT21CN on tele-protection.

4. Scottish Hydro-Electric Transmission Limited (SHETL)

Chapter summary

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

Summary

4.1. SHETL owns and maintains the network of electricity transmission assets in the north of Scotland. This chapter sets out our Final Proposals for SHETL in relation to its role as transmission owner (TO). Further information on SHETL and its performance against the previous price controls can be found in appendix 10.

4.2. Our Final Proposals for base price controlled revenues are set out in table 4.1 below. These proposals provide an initial revenue decrease of 5 per cent in real terms followed by ongoing real increases of 2 per cent per year (i.e. RPI+2).

Table 4.1 - SHETL: Summary of Final Proposals (2004/05 prices)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		11.6	13.9	15.4	10.7	10.5
- load (base case)		37.0	21.5	16.1	24.7	19.7
Operating costs						
- Controllable		5.6	5.7	5.8	5.9	6.0
- Non-controllable		3.5	3.5	3.5	3.5	3.5
Depreciation		16.7	17.7	18.4	19.1	19.8
Pensions						
- allocated to opex		0.7	0.8	0.8	0.8	0.8
Current Tax		5.4	5.0	4.8	4.5	4.4
Base Price Control Revenue Allowance	49.5	47.0	48.0	48.9	49.9	50.9
Excluded services		0.5	1.0	1.2	1.3	1.3
Other revenue adjustments		0.9	0.7	0.4	0.5	0.5
Total Revenue		48.4	49.7	50.5	51.7	52.7

4.3. The main area where we have made changes to our Updated Proposals is in respect of capital expenditure. This is explained in more detail in the following section.

Capital expenditure (Capex)

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

4.4. We made no further adjustment to the position set out in our Updated Proposals.

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

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

2005/06 to 2006/07

4.6. Our Updated Proposals provided for some £47 million to enter the RAV in relation to the period 2005/06 - 2006/07. Our Final Proposals increase this by £1 million as a result of the increased allowance for input cost increases. A summary of our treatment of capex for the period to 2006/07 is set out in table 4.2 below:

Table 4.2 – SHETL updated forecast capital expenditure 2005/06 to 2006/07 (2004/05 prices)

SHETL Forecasts & Allowances (2005/06 - 2006/07)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure	25	21	21	21	0
Non Load Related Expenditure	25	27	25	27	1
Total	**50**	**48**	**47**	**48**	**1**

2007/08 to 2011/12

4.7. Our Updated Proposals provided for capital expenditure of £178 million over the five year price control period commencing on 1 April 2007. Our Final Proposals increase this allowance to £181 million, around £7 million below the licensee's latest adjusted forecast, as set out in table 4.3 below:

Table 4.3 – SHETL updated forecast capital expenditure 2007/08 to 2011/12 (2004/05 prices)

SHETL Forecasts & Allowances (2007/08 - 2011/12)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure					
Sole-use & infrastructure	778	128	116	114	-2
Input cost increase	0	0	5	5	0
Adjustment for 05/06 actual	0	0	-2	0	2
Sub total	**778**	**128**	**119**	**119**	**0**
Non Load Related Expenditure					
Transformers	14	14	14	14	0
Other non-load related	42	42	42	42	0
Input cost increase	0	4	3	6	4
Adjustment for 05/06 actual	0	0	0	0	0
Sub total	**56**	**60**	**58**	**62**	**4**
Total	**834**	**188**	**178**	**181**	**3**

4.8. The major change set out in table 4.3 above is a £4 million increase in our allowance for future input cost increases in the light of further analysis by our consultants.

4.9. In addition to the changes set out in the table above, we also propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs across all electricity transmission licensees. Subject to these costs passing our efficiency assessment, we propose that they should be included within the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up. These costs are:

- **Generation connections -** to cover 50 per cent of the potential expenditure relating to the provision of more secure (N-1) connections to wind generators up to 100MW in size; and
- **BT21CN -** for potential expenditure on telecoms infrastructure arising as a result of the effects of BT21CN on tele-protection (See chapter 7). SHETL has not forecast any expenditure in respect of BT21CN during the period.

4.10. The remaining gap between our proposed allowances and the adjusted forecast by the licensee is now £7 million. The main factor driving this difference is the adjustment for connection design efficiency which will be subject to logging-up as described above.

Regulatory Asset Value

4.11. Table 4.4 below sets out how we have derived the opening RAV for SHETL on 1 April 2007. This reflects the depreciated value of actual expenditure incurred by

SHETL in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07.

Table 4.4 - SHETL Regulatory Asset Value 2000/01 to 2006/07 (2004/05 prices)

SHETL	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**	**276.2**
Depreciation	-12.9	-13.3	-13.5	-13.7	-13.9	-14.1	-15.7	-16.1
Net capex additions	19.0	9.9	7.2	8.3	8.9	14.4	58.1	28.2
Adjustments	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**	**276.2**	**288.3**
Average RAV	**250.4**	**251.7**	**246.8**	**241.0**	**235.8**	**233.5**	**254.9**	**282.2**

4.12. Our Final Proposals therefore establish an opening RAV in 2007/08 of £288 million, compared to our Updated Proposals of £287 million. The main factor influencing the movement since our Updated Proposals is the additional allowance for input cost increases.

Controllable operating expenditure (Opex)

4.13. In our Updated Proposals document we proposed a controllable operating expenditure allowance of £28.9 million for SHETL for the five year period from 2007/08 to 2011/12, compared with SHETL's forecast of £33.8 million. As set out in table 4.5, our Final Proposals retain this allowance.

Table 4.5 – SHETL updated controllable opex forecast (5 year totals, £m 2004/05 prices)

SHETL Forecast and Allowances (2007/08 and 2011/12)	Licensee Company Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Forecast	**33.8**			
SHETL RCCC 2004/05		**25.0**	**25.0**	**-**
Total Efficiency Adjustment		-1.1	-1.1	**-**
Efficient Cash Costs		**23.9**	**23.9**	**-**
Total Upward Cost drivers		5.0	5.0	**-**
Ongoing Opex Allowance		**28.9**	**28.9**	**-**
Total Additional opex allowance		-	-	**-**
Ofgem total controllable allowance		**28.9**	**28.9**	**-**

4.14. The principal reasons behind the gap between the licensee's forecast and our Final Proposals are lower operating costs in line with the reduction in capex allowance and slightly higher efficiency assumptions.

4.15. We also propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs, where we have concluded that it is not appropriate to set ex ante allowances. We propose that these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up. We propose to allow logging-up treatment for operating expenditure relating to infrastructure arising due to the effects of BT21CN on tele-protection although SHETL has not forecast any expenditure in respect of BT21CN during the period as yet.

5. ScottishPower Transmission Limited (SPTL)

Chapter summary

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

Summary

5.1. SPTL owns and maintains the network of electricity transmission assets in the south of Scotland. This chapter sets out our Final Proposals for SPTL in relation to its role as transmission owner (TO). Further information on SPTL and its performance against the previous price controls can be found in appendix 10.

5.2. Our Final Proposals for base price controlled revenues are set out in table 5.1 below. These proposals provide an initial revenue decrease of 5 per cent in real terms followed by ongoing real increases of 2 per cent per year (i.e. RPI+2).

Table 5.1 - SPTL: Summary of Final Proposals (2004/05 prices)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		52.5	60.5	62.9	63.2	65.0
- load (base case)		71.8	45.3	42.1	85.5	58.9
Operating costs						
- Controllable		16.1	15.7	16.3	16.4	16.4
- Non-controllable		12.5	12.5	12.5	12.5	12.5
Depreciation		63.3	66.4	69.1	63.8	70.5
Pensions						
- allocated to opex		0.5	0.5	0.5	0.5	0.5
Current Tax		17.5	16.9	16.8	15.7	15.1
Base Price Control Revenue Allowance	155.0	147.3	150.3	153.3	156.4	159.5
Excluded services		0.9	1.7	3.4	3.4	5.5
Other revenue adjustments		0.6	0.6	0.6	0.6	0.6
Total Revenue		148.8	152.6	157.3	160.4	165.6

5.3. There are three areas where we have made changes to our Updated Proposals. They are summarised below (expressed as total change, relative to our Updated Proposals, over the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of £32 million resulting from an updated assessment of costs associated with connecting baseline generation capacity and of the engineering design for some asset replacement projects;

- **Operating costs:** an increase of £2 million relating to corporate costs reallocated from the capital expenditure allowance in line with our policy that corporate costs should not be capitalised (see appendix 2); and

- **Tax:** an increase of £5.5 million arising from the increased cost allowances.

Capital expenditure (Capex)

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

5.4. We have made a small adjustment increasing allowed historical capital expenditure by around £1.7 million following discussions with SPTL regarding the reallocation of corporate costs.

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

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

2005/06 to 2006/07

5.6. Our Updated Proposals provided for some £146 million to enter the RAV in relation to the period 2005/06 - 2006/07. We have increased this allowance by £9 million for Final Proposals mainly as a result of our updated view of the engineering design of some asset replacement projects.

Table 5.2 – SPTL updated forecast capital expenditure 2005/06 to 2006/07 (2004/05 prices)

SPTL Forecasts & Allowances (2005/06 - 2006/07)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure	61	43	52	55	3
Non Load Related Expenditure	112	102	94	100	6
Total	**173**	**145**	**146**	**154**	**9**

2007/08 to 2011/12

5.7. Our Updated Proposals provided for capital expenditure of £576 million over the five year price control period commencing on 1 April 2007. Our Final Proposals increase this allowance to £608 million, around £122 million below the licensee's latest adjusted forecast, as set out in table 5.3 below:

Table 5.3 – SPTL updated forecast capital expenditure 2007/08 to 2011/12 (2004/05 prices)

SPTL Forecasts & Allowances (2007/08 - 2011/12)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure					
Sole-use & infrastructure	350	366	288	307	19
Input cost increase	0	0	14	14	0
Procurement efficiency	0	0	-14	-15	-1
Adjustment for 05/06 actual	0	0	1	-2	-3
Sub total	**350**	**366**	**289**	**304**	**15**
Non Load Related Expenditure					
Switchgear	53	53	44	51	7
Overhead Lines	126	126	112	112	0
Other non-load related	187	184	130	141	11
Input cost increase	0	0	14	14	0
Procurement efficiency	0	0	-14	-15	-1
Adjustment for 05/06 actual	0	0	1	2	1
Sub total	**367**	**364**	**287**	**304**	**17**
Total	**717**	**730**	**576**	**608**	**32**

5.8. The major changes set out in table 5.3 above are:

- **load related - baseline generation**: we have increased the allowance by £19 million in the light of new information that there are a number of more expensive generation connections likely to proceed than previously anticipated; and

- **non load related - project specific expenditure**: we have increased the allowance by £18 million having re-assessed the engineering design of some asset replacement projects.

5.9. We have also revised the profiling of the seven year capex figures to refine the allocation of load related cost adjustments.

5.10. In addition to the changes set out in the table above, we propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs, where we have concluded that it is not appropriate to set ex ante allowances. Subject to these costs passing our efficiency assessment, we propose that they should be included within the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up. These costs include:

- **Generation connections -** to cover 50 per cent of the potential expenditure relating to the provision of more secure (N-1) connections to wind generators up to 100MW in size; and

- **BT21CN -** for potential expenditure on telecoms infrastructure arising as a result of the effects of BT21CN on tele-protection (around £29 million) - see chapter 7.

5.11. The remaining gap between our proposed allowances and the adjusted forecast by the licensee is now £122 million, of which £30 million relates to a procurement efficiency saving, £32 million relates to asset replacement costs, and £30 million efficiency gains in the cost of connecting baseline generation. The gap also includes the £29 million costs relating to BT 21CN and the £28 million relating to assumption of efficient connection design, both covered by logging-up as described above. These differences are partly offset by an additional allowance of £28 million, reflecting the estimated impact of future input cost increase. This issue has been raised by the licensee, but no specific amount was included in their adjusted forecast.

Regulatory Asset Value

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

Table 5.4 - SPTL Regulatory Asset Value 2000/01 to 2006/07 (2004/05 prices)

SPTL	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07
Opening value bf	**681**	**654**	**629**	**594**	**580**	**575**	**555**	**716**
Depreciation	-49	-50	-50	-51	-52	-53	-59	-61
Net capex additions	22	25	15	36	47	33	220	109
Adjustments	0	0	0	0	0	0	0	0
Closing value cf	**654**	**629**	**594**	**580**	**575**	**555**	**716**	**764**
Average RAV	**668**	**642**	**612**	**587**	**578**	**565**	**635**	**740**

5.13. Our Final Proposals establish an opening RAV for 2007/08 of £764 million compared to our Updated Proposals of £754 million. The main factors influencing the movement between our Final and Updated Proposals are:

- The inclusion of £1.7 million of corporate costs in 2000/01; and
- Our revised view of expenditure for the period 2005/06 to 2006/07 (£9 million).

Controllable operating expenditure (Opex)

5.14. In the Updated Proposals document we proposed a controllable opex allowance of £79.0 million for SPTL for the five year period from 2007/08 to 2011/12, compared with the SPTL's forecast of £93.5 million. As set out in table 5.5, our Final Proposals increase this allowance to £80.9 million, the main change being an increase of £2 million relating to corporate costs which have been removed from SPTL's forecast capex.

Table 5.5 SPTL updated opex forecast (5 year totals, £m 2004/05 prices)

SPTL Forecast and Allowances (2007/08 and 2011/12)	Licensee Company Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Forecast	**93.5**			
SPTL RCCC 2004/05		**72.5**	**74.5**	**2.0**
Total Efficiency Adjustment		-8.5	-8.5	-0.1
Efficient Cash Costs		**64.0**	**66.0**	**1.9**
Total Upward Cost drivers		12.2	12.2	-
Ongoing Opex Allowance		**76.2**	**78.2**	**1.9**
Total Additional opex allowance		2.7	2.7	-
Ofgem total controllable allowance		**79.0**	**80.9**	**1.9**

5.15. The principal reasons behind the gap between licensee forecast and our Final Proposals are:

- 1.5 per cent per annum efficiency assumption;
- Increases in maintenance and tower painting costs allowed but at a lower level of unit cost than forecast by SPTL; and
- No allowance for an increase in overhead costs.

5.16. We also propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs where we have concluded that it is not appropriate to set ex ante allowances. We propose that these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up. We propose to allow logging-up treatment for operating expenditure relating to infrastructure arising due to the effects of BT21CN on tele-protection.

6. National Grid Gas NTS (NGG NTS)

Chapter summary

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

Summary

6.1. NGG NTS is Transmission Owner (TO) and System Operator (SO) for the GB gas transmission system. This chapter sets out our Final Proposals for NGG in relation to its role as transmission owner (TO). It does not set out any SO costs or allowances, which will be covered in a separate consultation document to be published shortly. Further information on NGG and its performance against the previous price controls can be found in appendix 10.

6.2. Our Final Proposals for base price controlled revenues are set out in table 6.1 below. We have not re-profiled the revenue allowances as we have done for the electricity licensees as NGG does not face the same substantial increase in costs relating to baseline capital investment. We expect that the increase in capital expenditure requirements will be triggered by user commitments under the gas access regimes, which will provide funding through the revenue driver mechanisms.

Table 6.1 - NGG NTS Summary of Final Proposals (2004/05 prices)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Capital Expenditure						
- non-load		105	69	51	39	40
- load (base case)		365	144	5	5	1
Operating costs						
- Controllable		60	58	59	58	60
- Non-controllable		79	79	79	78	78
Depreciation		98	107	111	110	110
Pensions						
- allocated to opex		41	41	40	40	40
Current Tax		39	34	36	42	46
Base price control revenue	416	487	487	487	487	487
Excluded services		1	1	1	1	1
Other revenue adjustments		2	2	2	2	2
Total Revenue		490.5	490.4	490.4	490.5	490.5

6.3. There are four main areas where we have made changes to our Updated Proposals. They are summarised below (expressed as a total change, relative to our Updated Proposals, for the period 2007/08 to 2011/12) and explained in more detail in the sections to follow:

- **Capital expenditure:** an increase of £27 million resulting from an updated view of costs associated with asset replacement for emission reduction and condition requirement;
- **Operating costs:** an increase of around £1.6 million reflecting movements due to the removal of pensions costs and an adjustment for cost allocation;
- **Tax:** an increase of £7 million arising from the increased cost allowances; and
- **Pensions:** an increase of £16 million arising from the increased annuity element of the annual deficit recovery payment.

Capital expenditure (Capex)

Historic capital expenditure

6.4. In our Updated Proposals, £75m of NGG's historical capex was excluded from the RAV pending a final decision on its treatment. This included investment related to increasing the entry capacity at St Fergus (£73m), and other costs that could have been avoided by a more efficient contracting strategy (£2m).

6.5. We do not believe that NGG has provided adequate justification for the £73m of expenditure incurred to increase the entry capacity at St Fergus in the light of indications of demand for capacity arising from the long term entry capacity auctions. Specifically, NGG NTS did not review its initial investment decision in light of important new information at the time on the location of large new sources of gas supply. Our view is that NGG NTS ignored key information at the time and made questionable decisions in the context of the entry capacity regime which had recently been introduced. In our Updated Proposals, we considered whether this investment should be excluded from the RAV in its entirety or should be included at a discounted value.

6.6. We have concluded that, since this project was initiated in the early days of the new entry regime when the treatment of such expenditure may not have been fully clear, it would be inappropriate to exclude it from the RAV altogether. Instead, we are treating this expenditure as if it represented expenditure in excess of allowance within the current price control period. The effect of this is to allow £56 million to enter the RAV at the time at which the expenditure was incurred.

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

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

2005/06 to 2006/07

6.8. Our Updated Proposals provided for some £731 million to enter the RAV in relation to the period 2005/06 - 2006/07. We have increased this allowance by £1 million for Final Proposals as a result of the inclusion of the expenditure discussed in paragraph 6.5 above.

6.9. A summary of our treatment of capex for the period to 2006/07 is set out in table 6.2 below:

Table 6.2 – NGG updated forecast capital expenditure 2005/06 to 2006/07 (2004/05 prices)

NGG Forecasts & Allowances (2005/06 - 2006/07)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure	571	615	614	615	1
Non Load Related Expenditure	133	123	117	117	0
Total	**704**	**738**	**731**	**732**	**1**

2007/08 to 2011/12

6.10. Our Updated Proposals provided for capital expenditure of £797 million over the five year price control period commencing on 1 April 2007. Our Final Proposals increase this allowance to £824 million, around £117 million below the licensee's latest adjusted forecast, as set out in table 6.3 below:

Table 6.3 – NGG updated forecast capital expenditure 2007/08 to 2011/12 (2004/05 prices)

NGG Forecasts & Allowances (2007/08 - 2011/12)	Original Licensee Forecast	Adjusted Licensee Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
Load Related Expenditure					
Baseline load related	632	251	251	251	0
Milford Haven Project	224	280	280	280	0
Input cost increase	41	0	0	0	0
Procurement efficiency	0	0	-13	-13	0
Adjustment for 05/06 actual	0	0	3	3	0
Sub total	**898**	**530**	**520**	**520**	**0**
Non Load Related Expenditure					
Compressor - emissioin reduction	180	180	115	148	33
Other non-load related	268	231	172	166	-6
Input cost increase	0	0	0	0	0
Procurement saving	0	0	-15	-15	0
05/06 actual adjustment	0	0	3	3	0
Sub total	**448**	**411**	**277**	**304**	**27**
Total	**1346**	**941**	**797**	**824**	**27**

6.11. The major changes set out in table 6.3 above are:

- **Costs for emission reduction at compressor sites**: we have taken into account the outcome of the September 2006 entry capacity auction, in terms of increased forecast running hours at a number of compressor sites and scope for relocating existing assets. This results in an increase in estimated capex required to comply with the emission regulations; and
- **Other non load related**: we have increased the allowance for asset replacement and refurbishment in the light of higher forecast utilisation of certain assets. We have also revised the allocation of some of the allowance from general non-load related to specifically related to emission reduction.

6.12. The remaining gap between our proposed allowances and the licensee's adjusted forecast is now £117 million, of which £27 million relates to assumed procurement efficiency savings, £32 million to costs for reducing emission at sites with zero forecast utilisation, and £65 million to asset refurbishment or replacement avoidable by relocating existing assets or due to reduced need to keep assets. The gap is reduced by £6 million due to capex profiling.

6.13. NGG has recently submitted a revised cost forecast for the Milford Haven pipeline project. This forecast represents an increase of £75 million against the previous projection in our Updated Proposals, and an overall increase of £202 million since the company's FBPQ submission at the start of 2006. Due to the late provision of this information, it has not been possible to interrogate these revised cost estimates in an appropriate manner. As a consequence, we have not included the updated forecast within the allowances that we have provided. However, we propose that this additional Milford Haven forecast expenditure of up to £75 million will not be subject to the capital expenditure incentive. Subject to these costs passing our efficiency assessment, we propose that they should be included in the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up.

Regulatory Asset Value

6.14. Table 6.4 below sets out how we have derived the opening RAV for NGG on 1 April 2007. This reflects the depreciated value of actual expenditure incurred by NGG in the period 2001/02 to 2005/06 and our adjusted view of capital expenditure in 2006/07.

Table 6.4 - NGG Regulatory Asset Value 2000/01 to 2006/07 (2004/05 prices)

NGGT	02/03	03/04	04/05	05/06	06/07
Opening value bf	**2,328**	**2,380**	**2,424**	**2,424**	**2,591**
Depreciation	-82	-83	-85	-85	-89
Net capex additions	134	127	84	252	480
Disposals	0	0	0	0	0
Closing value cf	**2,380**	**2,424**	**2,424**	**2,591**	**2,981**
Average RAV	**2,351**	**2,385**	**2,424**	**2,507**	**2,786**

6.15. Our Final Proposals establish an opening RAV for 2007/08 of £2,981 million compared to our Updated Proposals of £2,929 million. The main factor influencing the movement since our Updated Proposals are:

- the inclusion of £56 million to enter the RAV in respect of expenditure to increase entry capacity at St Fergus (see 6.5 above).

Controllable operating expenditure (Opex)

6.16. In the Updated Proposals document we proposed a controllable opex allowance of £293 million for NGG for the five year period from 2007/08 to 2011/12, compared with NGG's forecast of £324 million. As set out in table 6.5 below, our Final Proposals increase this by £1.6 million, for the following reasons:

- **Cost drivers:** we have increased the allowance by £4.5m to correct a previous misallocation between the TO and SO internal controls; and
- **Normalisation:** £2.9m of pension costs have been removed from NGG's normalised opex to avoid double counting the separate pensions allowance.

Table 6.5 NGG updated controllable opex forecast (5 year totals, £m 2004/05 prices)

NGG Forecast & Allowances (2007/08 - 2011/12)	Licensee Company Forecast	Ofgem Updated Proposals (UP)	Ofgem Final Proposals (FP)	Change from UP to FP
NGG Forecast (excl. Pensions)	**324**			
NGG RCCC 2004/05 (excl. Pensions)		**294.4**	**296.3**	**1.9**
Upward cost drivers		14.7	14.6	-0.2
Profiled cash costs		**309.2**	**310.9**	**1.7**
Total efficiency adjustments		-37.8	-37.9	-0.1
Efficient cash costs		**271.4**	**273.0**	**1.6**
Total new upward cost drivers		2.1	2.1	0.0
Ongoing opex allowance		**273.5**	**275.1**	**1.6**
Total additional Opex allowance		19.6	19.6	0.0
Ofgem total controllable allowance		**293.1**	**294.7**	**1.6**

6.17. The differences identified above primarily relate to adjustments where our consultants have identified scope for efficiency improvements and the removal of costs that we believe should not have been included. Overall, our efficiency assessment shows an average year on year reduction in controllable costs of around 3 per cent per annum over the price control period.

6.18. In addition to the changes set out in the table above, we propose to introduce logging-up mechanisms for dealing with specified items of uncertain costs, where we have concluded that it is not appropriate to set ex ante allowances. We propose that these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up. We propose to allow logging-up treatment of any claims for loss of site development value settled during the 2007-12 period, provided they have been sufficiently contested by NGG (further detail is provided in chapter 7.) This expenditure has been forecast by NGG at £10 million over the period 2007-12.

7. Price Control Policy Framework

Chapter summary

This chapter sets out our Final Proposals on incentives for capital expenditure efficiency and on a number of cost assessment policy issues.

Capital expenditure incentive

7.1. We are proposing that the licensees' investment plans are funded by baseline allowances for works that we expect to proceed within the next price control period. These allowances are substantial and are set on an ex ante basis using the best available information. However, there is the potential for our allowances and the companies' actual spend to differ.

7.2. We are also proposing that for more uncertain investment plans, it is appropriate to generate revenue streams using revenue drivers - that is mechanisms which flex revenues in response to flexing demands for connection to the system (these are described in chapters 9 and 10). In the face of these uncertain demands for connection, we consider revenue drivers are the most appropriate mechanism of providing appropriate revenue allowances. These revenue drivers provide funding for additional works over and above that assumed in deriving the baseline. However, there is the potential for the revenue provided by the revenue drivers and the actual spend that occurs to differ.

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

7.4. Our Updated Proposals set out a proposal that transmission companies should bear 25 per cent of the cost, or receive 25 per cent of the benefit, arising from differences between allowed capex and actual capex relative to the baseline allowance. This is broadly consistent with the average incentive rate that is faced by the transmission companies over the duration of the current price controls (17 per cent to 27 per cent).

7.5. There were mixed responses to this proposal. National Grid considered that there is greater uncertainty regarding investment requirements towards the end of the price control period and suggested that the incentive rate should be consistent with the average incentive faced by transmission companies in the final two years of the current regime rather than the average incentive rate over the entire period. This suggested an appropriate incentive rate in the region of 10 per cent. SHETL commented that at a time when investment is expected to increase significantly it is important to provide stronger incentives for efficiency, and suggested that an incentive rate of around 40 per cent would be appropriate.

7.6. We consider that it is desirable to establish a balanced package of incentives that provide, where possible, strong incentives for investment efficiency. These Final Proposals go some way to strengthening the effectiveness of the efficiency incentive by ensuring that incentives have a consistent strength over the price control period. However, the proposed 25 per cent incentive strength is lower than the range of incentive strength set for the electricity distribution companies in DPCR4.

7.7. One factor which influences our view on the appropriate incentive strength is the availability of output measures which can provide a framework for assessing over time whether a company has undertaken the level of investment required to deliver the desired level of network performance. Such measures would be a starting point for allowing us to assess whether genuine efficiency savings have been made or whether investment has been inappropriately or inefficiently deferred, at a cost of a deteriorating service to network users.

7.8. In the case of electricity distribution, statistics for network reliability do, to some extent, provide such output measures. However, in the case of transmission the networks are designed to provide a very high level of reliability and, as a result, year-on-year changes in reliability do not normally provide an indication of investment requirements.

7.9. In the course of the TPCR we have sought to identify alternative output measures which could be used for transmission, but have not succeeded in doing so. In the absence of reliable output measures, we are concerned that a stronger efficiency incentive will encourage inefficient deferral rather than genuine efficiency savings. We therefore do not propose to increase the incentive rate above the 25 per cent proposed for baseline investment in our Updated Proposals.

7.10. We have also considered the appropriate strength of incentive to apply to incremental load related investments in electricity and gas transmission. In electricity, we have taken a view on the amount of load related investment that might be required to connect new generation. The revenue driver mechanism then enables revenues to be flexed up or down depending on the actual demand for entry capacity. Given this interrelationship, it is important to apply a consistent strength of incentive across baseline and incremental investment. We therefore propose to adopt a 25 per cent incentive rate for incremental expenditure.

7.11. The gas entry and exit regimes place greater reliance upon transparent auction signals, user commitments, and defined delivery timescales. These differences are reflected in our approach to setting the baseline capital expenditure allowance for gas transmission, which is limited to committed expenditure only. All other expenditure is funded through revenue drivers. We consider that these differences justify a higher incentive rate for gas load driven investment. The current price control for gas transmission includes a 5 year rolling incentive for such capital expenditure (equivalent to a fixed incentive strength of about 35 per cent) and we propose to continue with this arrangement in the next price control period.

7.12. We discuss below our proposed approach to resetting the RAV for 1 April 2012. Efficiently incurred expenditure against the baseline will enter the RAV in the year that it is incurred. It is proposed that all such expenditure will be subject to our proposed 25 per cent capex incentive, unless an alternative treatment has been agreed for specific items. For instance, the incentive will not apply to specified items of uncertain costs which we have agreed should be logged up, as described in appendix 2. The 25 per cent incentive will be applied through a one-off revenue adjustment on 1 April 2012, if applicable, as outlined in appendix 2.

Capital expenditure safety net

7.13. The lack of useful output measures discussed above also raises the question of how incentives should be structured if, in practice, a company is spending substantially below its allowance for capital expenditure. Given the delay between the point at which asset replacement is required and actual asset failure, and given the high level of system security designed into the transmission networks, the impact of an inappropriate reduction in investment would not necessarily be reflected in deteriorating network performance in the short or medium term.

7.14. Our Updated Proposals consulted upon a mechanism that would trigger a review of capital expenditure allowances in the event of a major shortfall of investment relative to allowance. We proposed that any such review would be limited to capital expenditure and would consider whether the reduction in expenditure against the company's forecasts and allowances reflected genuine efficiency savings or was potentially damaging to the short or long term integrity of the network, and whether it might be appropriate to adjust future capital expenditure allowances. We indicated that such adjustments could be made if, for instance, the cumulative under-spend at any stage in the five-year control period is more than 20 per cent of the cumulative capex allowance.

7.15. This proposed "safety net" mechanism is acceptable to the transmission companies in principle. They have nevertheless sought clarification on how the mechanism might operate in practice, and have identified three issues:

- **inadvertent triggering** – the Scottish transmission companies are concerned that the timing of capital projects is volatile, such that a timing shift of one or two large projects could trigger the mechanism. They would prefer an approach that does not automatically adjust allowances;

- **regulatory risk** – the companies are concerned that the mechanism may result in retrospective claw back of additional returns that have been earned from underspend achieved before the mechanism is triggered. The companies see this as a significant risk; and

- **symmetry** – the companies argue that the proposals do not strike an appropriate balance between risk and reward. National Grid and SHETL suggest that any such mechanism should be applied symmetrically to provide protection for major cost shocks.

7.16. We propose that the mechanism would be triggered if at any stage in the five-year control period annual expenditure is more than 20 per cent below the capital expenditure allowance for that year. Under the mechanism, we propose that a company will retain the benefit of its actions during the period up to the time when the mechanism was triggered.

7.17. Once the mechanism was triggered, we would assess the level of expenditure relative to the information provided to us during the price control review, and we would expect to reset capex allowances for the remainder of the price control period. However, if we are satisfied that the shortfall is purely due to a timing shift of large projects and that the level of investment is expected to revert back towards the allowances we would not expect to make any change to allowances.

7.18. If in the light of this assessment we consider that the company then requires an allowance substantially below the levels reflected in setting the price controls, we would look to consult on appropriate adjustments to the capital expenditure allowance (but not to any other allowances) which would be reflected in a proposal to modify the company's licence. Should a company reject the proposed adjustments then we would consider referring the matter to the Competition Commission.

7.19. We note the companies' comments on asymmetry. However, an overspend safety net has the potential to result in perverse incentives for companies to increase overspend, and to also dilute the incentive properties of the price control regime. Therefore, we do not consider it appropriate to introduce a plan for an overspend reopener, given the flexibility inherent in the regime we are already proposing for capital expenditure allowances.

Rolling forward the RAV

7.20. The regulatory asset value (RAV) is a key building block of the price controls. It can be seen as a measure of the capital employed of the regulated business, based upon past investment, on which the companies earn a rate of return and an allowance for depreciation.

7.21. In rolling forward the RAV from April 2007 to March 2012, expenditure incurred by the companies should be treated in the same way as it has been in developing our proposals. As a consequence, we will take into account changes in accounting treatment, such as changes in capitalisation rates, and make adjustments where appropriate. It will also be necessary to make appropriate adjustments in respect of pensions funding to ensure that any subsequent revenue adjustment in relation to the over and under funding mechanism will not be double counted. We reserve the option to disallow costs from entering the RAV if they are demonstrably inefficient or unnecessary.

7.22. The effectiveness of the proposed package of incentives will depend on transmission companies and their investors having confidence in how costs will be treated in the future. We therefore need to provide clarity as to how we will calculate the RAV and implement the incentive schemes at the next review. Our default starting point is that all capital expenditure will be included in the RAV, with the exception of expenditure which is judged to be demonstrably inefficient or unnecessary.

7.23. However, in the case of the transmission licensees, due to the lumpy and multi-year nature of transmission investments, in the absence of the evidence provided by user commitments in respect of load related expenditure, as well as the lack of comparative tools and output measures, we will place a significant emphasis on our ex-post efficiency review of costs and volumes to determine efficient and economic spend. Where expenditure has been incurred to provide assets that are not required for the duration of the next price control period or where unit costs are considered excessive, we are likely to view such investment as inefficient or unnecessary.

7.24. A key consideration for us in forming a view at future price control reviews on the efficiency of load related capex will be the extent to which the investment decisions were based on strong evidence of long term demand for capacity from network users (backed by financial commitment). The absence of such user commitment evidence at St Fergus in the current price control period was the main factor in our decision only to include part of the investment undertaken by NGG NTS in the RAV (see chapter 6). In contrast, investment based on strong evidence of long term user commitment has a clear, unambiguous case for inclusion in the RAV subject only to a test that the cost of the required volume of investment is reasonable.

7.25. The information (or lack of it) on the long term demand for capacity from network users is generated through the arrangements by which network users buy capacity. To the extent that these arrangements do not generate clear, unambiguous signals, then licensees will be relying on more subjective justification for investment and will face a greater risk of future disallowance. In this light, we believe that the licensees have a clear interest in taking steps to ensure that the access arrangements do generate high quality, robust information based on long term user commitments. In electricity, we believe that significant improvements can be made in this regard which would reduce the risk of disallowance of investment at future price control reviews. While we are aware of current developments in this area, we are yet to form a view on the merits of the proposals under development.

Cost Uncertainties

Specific cost uncertainties ('Known unknowns')

7.26. We have highlighted a small number of identifiable, discrete cost items which are dependent on external factors. We propose that expenditure incurred against these 'known unknowns' should be agreed in advance with Ofgem and logged up.

7.27. The items subject to logging-up are outlined below. Moreover, the general mechanics for logging-up costs is set out in appendix 2.

BT's 21st Century Networks (BT21CN).

7.28. BT is expected to consolidate its telecoms networks to a single platform based primarily on "packet" technology. This is referred to as BT 21 Century Networks (BT21CN). As part of the transition to BT21CN, BT is expected to withdraw its older leased line platform which is presently used by the transmission companies for tele-protection. Tele-protection is not compatible with the new BT21CN format.

7.29. There remain a number of uncertainties regarding the overall timetable for the implementation of BT21CN, the potential withdrawal of older platforms and whether BT would offer the equivalent services going forwards. In light of these considerations, we have not made an ex-ante allowance for the costs of mitigating BT21CN. Instead we propose that licensees can "log up" the efficient costs of mitigating the impact of telecom circuits or services that would demonstrably compromise the transmission licensee's tele-protection systems given the potential withdrawal of BT's Leased Line platform. For the avoidance of doubt this means:

- costs of replacing these telecom circuits or services, or where it is more economic the costs of using an alternative telecoms service for these circuits and services; and
- any appropriate set up costs attributable to the these telecom circuits or services

Quarry and loss of development claims

7.30. NGG NTS has received a small number of claims from businesses citing that the location of particular NTS pipelines prevents the further development of their business. While NGG NTS expects to challenge the basis and quantum of such claims, they are likely to be exposed to some uncertain costs. We therefore propose that NGG NTS can "log up" any settled claims over the period 2007-12 which have been demonstrably challenged by NGG NTS, as far as is reasonable, regarding both the basis of the claim and the quantum of compensation sought. For the avoidance of doubt the following claims under the terms of the Deed of Easement may be logged up:

- loss of crop and drainage;

- loss of land development e.g. housing, quarrying etc;
- sterilised minerals;
- landfill and tipping; and
- power generation.

Capex allowances for connecting windfarms

7.31. In the Updated Proposals, we highlighted the issue of how much capital expenditure should be allowed to connect small, renewable generators in Scotland. We noted that the progress in the reform of the transmission charging would potentially improve the cost signal to generators and enable them to choose economically efficient connection designs. The Scottish Transmission companies have commented that they are contractually committed to provide secure connections and that until such reforms are in place and accepted by users they will be required them to invest on that basis.

7.32. In the light of the uncertainty surrounding the development and implementation of charging reforms, we propose to allow the Scottish Transmission Companies to "log-up" 50 per cent of the incremental costs of providing a more secure (N-1) connection design in relation to small wind farms (less than 100MW).

Cable tunnel expenditure by NGET

7.33. We have identified £60 million of expenditure in relation to underground cable tunnels, which NGET forecast will be incurred towards the end of the price control period. We consider that the expenditure is sufficiently uncertain that it would be inappropriate to set an ex-ante allowance. Instead, we propose that NGET be allowed to "log-up" the costs incurred in relation to the identified cable tunnel projects, subject to an efficiency test. However, any expenditure above £60 million that has been identified will be subject to the capital expenditure incentive scheme.

Milford Haven pipeline project

7.34. We have recently been advised by NGG that the projected cost of the Milford Haven pipeline project is expected to increase from £717 million to £792 million (in 2004/05 prices). Due to the late submission of this information it has not been possible to assess this cost increase as part of TPCR. In setting the price control allowances we have not reflected this increased cost. Given the special circumstances of this project, we propose to ring-fence the additional £75 million and, subject to an efficiency assessment, ignore the implied over spend from the operation of the capital expenditure incentive. However, any expenditure above the £792 million that has been identified will be subject to the capital expenditure incentive regime.

Non-controllable operating costs

7.35. Transmission companies will incur operating costs over which we accept they have little or no influence over (non-controllable). Several items of non-controllable costs are presently subject to pass-through arrangements, such that the companies are able to recover the costs that they actually incur. We propose that this approach will continue for the period 2007/08 to 2011/12. For the purposes of setting the price control Ofgem's licence fees and business rates will be treated as non-controllable opex.

Business rates

7.36. As discussed in our Initial Proposals, the Valuation Office Agency (VOA) in England and Wales and the Scottish Assessors Association (SAA) in Scotland are expected to re-value the assets of transmission networks in 2010 for the purposes of determining future rates charges. Each transmission company is able to influence the valuation that is given and hence the business rates that it will incur in the future.

7.37. We recognise that the timetable for the ratings valuation will occur before the end of the price control period and therefore there is uncertainty regarding the future level of business rates that the transmission companies will incur. Nevertheless, it is important for companies to have appropriate incentives to minimise their business rates. For the purposes of setting the base price control revenue allowances, we have assumed that business rates will be incurred at current levels. For the period up to and including 2009/10, we will put in place a mechanism that will enable companies to recover the difference between the actual and assumed costs. After that time, we will switch-off this mechanism pending the outcome of the revaluation exercise. Where the transmission companies can demonstrate that they have taken reasonable actions to minimise the rating valuations, we will then reactivate the cost adjustment mechanism for the remainder of the period.

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

Wider regulatory developments

Independent Systems cost recovery mechanism

7.39. Independent systems are being considered as part of GDPCR. It is possible that, as part of GDPCR, we will form the view that it is appropriate to amend the NTS licence to introduce a non controllable operating cost relating to independent systems. Any such amendment will not come into effect until 1 April 2008. This matter is discussed further in the GDPCR third consultation document[4]

EU Inter TSO compensation scheme

7.40. There is currently a voluntary scheme operating at an EU level to provide for transmission system operators (TSOs) to contribute towards the costs of other TSOs in recognition of transit flows and the associated need for investment to accommodate such flows. The UK does not participate in the existing voluntary scheme. As discussed in our September Updated Proposals, NGET may participate in the scheme on a voluntary or mandatory basis. In either situation, NGET has no influence over the charges it would be liable for, therefore provision has been made to allow the costs of negative or positive charges to be treated as pass through.

Excluded and de minimis services

7.41. In September, we set out our approach to assessing excluded and de minimis services and the treatment of associated costs and revenues. We have applied our proposed approach in identifying the following items as excluded services.

7.42. For NGET we have identified the following items that we propose to treat as excluded services:

- post-vesting connections;
- rental paid by Cable & Wireless to use NGET's optical fibre telecoms network; and
- non-rechargeable diversions.

7.43. National Grid has not been able to separately identify the costs to NGET of providing all the above services therefore we have performed our calculations based upon total costs and excluded the associated revenue to derive the appropriate allowance. For the purposes of setting NGET's base price control revenue for 2007/08 we have deducted £58 million in relation to excluded services.

7.44. This amount reflects the mechanism that we have put in place relating to the treatment of rental incomes earned by NGET for providing space on its towers and buildings for the placement of telecoms equipment (currently forecast at £1.5 million p.a.) as excluded services. For each year of the next price control period, 50 per cent of this income has been deducted for the purposes of setting the base price control revenue. This approach is consistent with our November 2001 consultation[5] on the provision of telecommunication services.

7.45. NGG NTS provides certain excluded services in common with NGG Distribution, primarily services provided to Fulcrum, Post Emergency Meter Work and Emergency

[4] 203/06 - Gas Distribution Price Control Review Third Consultation Document, Ref No 203/06
[5] November 2001, (Open letter) Energy Networks providing telecommunication services - a consultation document

Services for third parties. We have verified that £1.2 million p.a. of this income is attributable to NGG NTS and this will be deducted from NGG NTS allowed revenue.

7.46. We have confirmed that the costs of services provided by NGG to the independent GDNs, following DN sales, will be treated outside the gas transmission price control. Previously, the Authority has given consents for these services to be exempt from the de minimis threshold during the current period. We have considered the future treatment of these services and propose that when the present consents expire these services will be treated as excluded services. This is consistent with the approach being taken as part of GDPCR.

7.47. The only excluded service provided by SHETL and SPTL relate to incomes from post-vesting connections.

7.48. We have confirmed that all other non transmission owner activities will be treated outside the price controls and will be subject to the cap of 2.5 per cent of allowed revenue, unless the Authority consents otherwise.

Real Wage Growth

7.49. We confirm that in setting the base price control revenue allowances in this document we have adopted the companies' own assumptions and numbers for real wage growth in establishing the operating cost allowances.

Quasi capex

7.50. During the review, NGET and NGG identified some types of operating costs e.g. tower painting, that could be treated as capital expenditure for regulatory purposes. As discussed in our Initial Proposals, we have reviewed these items and accepted the arguments for adopting a different regulatory treatment for some of these costs. However, we have concluded that items such as tower painting should remain within operating costs. This treatment has been reflected in our cost allowances since Initial Proposals.

Non operational capital expenditure

7.51. In our third TPCR consultation document, we consulted on the issue of treatment of historic and forecast non-operational capital expenditure (e.g. vehicles and IT). Our Initial Proposals set out that in setting the previous price controls for NGET, SPTL and SHETL we had included non-operational capital expenditure as part of controllable opex. It is important that the RAV is rolled forward on a consistent basis to that on which it was estimated. In the light of this, we have removed all non operational capital expenditure that has been recorded within historical capex.

7.52. We propose that non-operational capex will be treated on the same basis for the period 2007/08 to 2011/12.

Treatment of NG's offshore insurance captives

7.53. As part of our normalisation exercise, we have 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 competitive in the base year of assessment 2005/06. In light of these considerations we did not 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.

On-going efficiency improvements

7.54. Our proposed controllable opex allowance for all licensees include an ongoing efficiency assumption of 1.5 per cent p.a. starting in 2007/08. The proposed annual efficiency improvement of the transmission companies is broadly at the level set for an average DNO in DPCR4. For National Grid, our consultants have identified scope for significant out performance even at their recommended levels of expenditure.

Capitalisation policy

7.55. During the review we have concluded that it would be difficult to establish a common ground upon which to align across the TOs or within Scottish TOs with respect to the proportion of costs that are capitalised. We have adopted company specific levels of capitalisation across the TOs in determining our allowances. The assessment of the total efficient capital expenditure therefore reflects for each licensee a combination of its efficient direct costs and a relevant proportion of efficient indirect costs.

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

7.56. NGG NTS has responsibility for the day-to-day operation of the gas transportation system. In this role it buys Operating Margins and System Support services from National Grid LNG Storage Limited. The price at which NGG NTS is permitted to buy these services is regulated. Any spare capacity once the necessary services have been provided is auctioned and sold to shippers as a commercial service[6].

7.57. NGG NTS had raised concerns about these arrangements. Investment is required in the facilities to enable the services to continue to be provided. NGG NTS does not think that the current arrangements provide sufficient revenue to fund the

[6] Review of the supply of gas storage and related services, February 1999, available at www.ofgem.gov.uk.

necessary investment. It has also indicated that these services are essential for system operation, and that (in the short term at least) there are no other service providers. NGG NTS has suggested that the necessary investment might be funded through an allowance in the main price control. Historically, these assets formed part of NGG NTS's RAV. The five sites (including Isle of Grain – which was subsequently sold) were moved out of the RAV and a separate price control was put in place with effect from 1 April 1997, as a means of promoting effective competition in storage services.

7.58. The question of direct relevance to the TPCR is whether we wish to reincorporate the LNG assets back into the NGG NTS RAV. This would provide NGG NTS with a long term revenue stream irrespective of whether the facilities were needed in the long term. We have decided to take this approach in respect of one element of historic capital expenditure at Glenmavis reflecting specific circumstances prevailing at the time of the investment[7]. As a general rule, however, we do not think that this is the correct approach having regard to the interests of consumers and our statutory duty to facilitate effective competition. The RAV-based approach would have the effect of funding, in the long term, a service provider (National Grid LNG Storage) that might not be needed - which in turn could be compounded by significant decommissioning costs.

7.59. Our preferred approach is to ensure that the costs borne by consumers reflect the efficient costs of provision as revealed through transparent and robust competitive processes. We are therefore proposing to put in place a new licence obligation on NGG NTS to establish such transparent and robust competitive processes. We will publish the detail of this proposed licence condition in our January 2007 TPCR licence modification consultation document. The purpose of this condition will be to provide a framework for NGG NTS to contract on a longer-term basis for the services it needs, and for potential service providers to have a clear understanding of this process such that NGG NTS maximises the number and variety of potential offers generated through its long term tenders.

7.60. If the terms of this new proposed licence condition are met, then National Grid LNG Storage should be permitted to tender on the same basis as other potential service providers. This would imply the dis-application of the current regulated prices for Operating Margins specified in condition C3 of NGG NTS's licence for contracts awarded under such a process.

7.61. However, we recognise that it will take some time to establish such a framework, and that there is need for NGG NTS to be able to access the services it needs in order to operate a safe and efficient framework. Currently, these services are provided by National Grid LNG. We have analysed the evidence that National Grid has submitted on the costs of continuing to provide these services, and have related this cost data to the current framework within which National Grid LNG

[7] The Glenmavis facility supplies gas for transportation by road tanker for Scottish Gas Networks (SGN) in respect of the Scottish Independent Undertakings (SIUs). The investment undertaken at Glenmavis was considered to be the least cost way of meeting the relevant obligations in respect of the provision of gas to the SIUs.

generates revenue. In the light of this analysis we consider that amendments to the form of price regulation might well be justified.

7.62. We are seeking views on these possible amendments to the price regulation framework through our Initial Proposals Consultation for NGG NTS's System Operator (SO) incentives which will be published in early December[8]. This sets out a proposal to amend the current price caps for LNG storage that are set out in condition C3 to ensure that the price caps continue to reflect the ongoing efficient cost of provision, and are linked to an appropriate reference market price for commercial storage service sold at the National Grid LNG Storage facilities if these market prices are higher than the default levels of the price caps. We will develop our proposals further in the light of responses to this consultation and publish further proposals in February 2007.

[8] National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007: Initial Proposals Consultation

8. Financial Issues

Chapter Summary

This chapter sets out our Final Proposals on a number of financial issues associated with setting the revenue allowances for each of the licensees. This includes our decision on the allowed rate of return.

Cost of capital

Introduction

8.1. In setting a price control allowance, we must form a view on the appropriate return on the Regulatory Asset Value that an efficient company should be able to earn. 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.

8.2. In our Initial and Updated Proposals we assumed, for modelling purposes, a real vanilla return of 4.84 per cent (4.2 per cent on a post tax basis), consistent with a real pre-tax cost of debt of 3.4 per cent, a real post-tax cost of equity of 7 per cent, and gearing of 60 per cent. These assumptions were consistent with the approach adopted in DPCR4 of taking a longer term view on appropriate returns rather than relying upon the snapshot provided by the latest market information.

8.3. The transmission companies and the majority of the investment community have argued that this figure is too low given (a) the comparison with the decisions for electricity distribution and water made in late 2004, and the large scale of the move over a relatively short period in which market evidence has not changed substantially; (b) the greater scale of investment in the coming price control period, (c) the perceived move towards 'penalty only incentives', (d) the greater uncertainty around future costs (especially user driven investment) compared to past reviews; and (e) higher returns available on alternative investments in the UK and elsewhere (both for the groups of which the companies form part, and for holders of their quoted equity).

8.4. Gas shippers have argued that our modelling assumption is too high and challenged our conclusions in relation to several components, presenting alternative evidence to support lower costs of debt and equity than we have assumed, which they believe supports a real post-tax return in the range 3.2 to 3.7 per cent.

8.5. In September, we published the advice prepared by Smithers & Co. on behalf of Ofgem ("the Smithers report") with respect to the constituent parts of the cost of capital. The Smithers report:

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

8.6. In forming a view on the appropriate allowed return to use in the Final Proposals, we have also considered a range of arguments and factors including:

- the overall balance of risk which transmission companies will face given the price control treatment of each of the significant elements of cost (opex, tax, depreciation) and the likely volatility of these functions compared to Ofgem's central estimates;
- the extent to which transmission companies can control their costs through management action;
- the mechanisms for dealing with unanticipated costs arising in the future;
- the expected amount of capital investment in relation to the scale of the business;
- the capital structure of the industry (as measured by the average or 'typical' company);
- the extent to which funds will be generated internally and the amount of new external finance required (including refinancing of existing obligations);
- the competition for capital within the businesses;
- the likely market conditions (supply, price and risk appetite) in which external financial requirements must be met and the potential risks around these;
- the competing demands that will be placed on financial markets from other sources;
- the expectations of capital providers (which are shaped, in part, by relevant regulatory precedent); and

- importantly, the desirability of enabling companies to earn predictable returns over the life of their assets (i.e. assuming constant macro-economic conditions, real returns should be broadly stable over time)

Differential Risk

8.7. We have carried out an initial assessment of the relative levels of risk faced by investors in our regulated transmission and distribution network companies, and have received views from respondents on this issue. While there is some evidence to suggest that transmission is a lower risk activity than distribution, a view that is also supported by credit rating agencies, we do not believe this analysis is sufficiently robust to quantify this difference accurately. As such, we propose to undertake an exercise to assess differential risk between transmission and distribution next year.

8.8. In Initial Proposals, we set out our view 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. Although the Scottish TOs have argued that they face a higher risk, we do not consider that there is sufficient justification for different treatment.

Cost of debt

8.9. One of the main objectives in setting the cost of capital for this review is to facilitate the necessary capital formation (debt and/or equity) to enable the expected investment in the networks to take place.

8.10. The Smithers report concluded that the best long term estimate of the risk-free rate is 2.5 per cent, which is broadly consistent with the range of previous decisions taken by ourselves, other regulators, and the Competition Commission. The Smithers report also highlighted that we may need to apply a term premium to estimate the risk free yield accurately, although the evidence to support this is less clear.

8.11. The observable premium on utility debt is at historically low levels (within the range 98 to 130 basis points for A and BBB rated debt respectively). It is not clear whether these levels may be expected to persist over the entire period of the price controls or revert to the long term average. In setting the cost of capital modelling assumption, we therefore used a cost of debt figure above that implied by current market levels. Our analysis of long term average spreads supports a debt premium within the range 1.0 to 1.5 per cent.

8.12. In the light of these considerations, we conclude that an appropriate range for the pre-tax real cost of debt in these Final Proposals is 3.5 to 4.0 per cent.

Cost of equity

8.13. The transmission companies and investment community have argued that the cost of capital figure should be sufficient to enable companies to attract and retain equity funding. In determining the cost of equity assumption for our Final Proposals, we have had regard to traditional methods such as capital asset pricing model (CAPM) as well as wider market evidence, including the aggregate return on equity over time.

8.14. The Smithers study has considered the long term aggregate market return on equity and concludes that there is little evidence to justify a movement from the range 6.5 to 7.5 per cent considered during DPCR4. However, the report concludes that there is evidence that beta estimates are significantly lower than 1, which would support a lower equity return. As noted above, Smithers' central estimate, using a beta of 0.5, is in the range 4.5 to 6.25 per cent.

8.15. While beta estimates are presently lower than 1, they have varied significantly around this level since privatisation. It is therefore difficult to assess whether the estimates suggested by the Smithers report are representative of long term trends. In view of the scale of the capital expenditure requirement, it is important that the assumed cost of equity is sufficient to enable companies to withstand unanticipated risks and to attract and retain equity funding. Given these considerations, we propose to place greater weight on the range of total market returns than the components of CAPM. Nevertheless, in the light of Smithers' findings we consider it appropriate to adopt a somewhat lower assumption than was used at DPCR4.

Gearing

8.16. Having considered the available evidence and the anticipated financing requirements of the companies, we have concluded that an assumed gearing level of 60 per cent is appropriate. This is broadly consistent with the current gearing levels and the approach adopted at the last price control review.

8.17. This gearing assumption should not be interpreted as an endorsement of any particular capital structure. We believe that the companies and their financiers are best placed to decide on the most appropriate capital structure.

Conclusion

8.18. Drawing on the above evidence we consider that the allowed return for the four transmission licensees should be 4.4 per cent post tax real, equivalent to a vanilla WACC of 5.05 per cent. The table below sets out the assumptions we have used in our financial model, compared with those modelled in previous consultations.

Table 8.1: Cost of capital assumption

	Updated Proposals	Final Proposals
Risk Free Rate	2.30%	2.50%
Debt Premium	1.10%	1.25%
Cost of Debt	3.40%	3.75%
Cost of Equity	7.00%	7.00%
Gearing	60%	60%
Tax	30%	30%
WACC (real pre-tax)	6.00%	6.25%
WACC (vanilla)	4.84%	5.05%
WACC (after tax at 30%)	4.20%	4.40%

8.19. The pre-tax return outlined above is calculated on the basis of a traditional tax wedge assumption. If we take in to account the actual tax allowances we have provided then our proposal represents an effective pre-tax rate of return of around 6.65 per cent. This compares to an allowed pre-tax rate of return of 6.25 per cent for both NGG and NGET, and similarly an allowed pre-tax rate of return 6.5 per cent for both SHETL and SPTL, set at the last main price control review.

Tax

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

8.21. Since Updated Proposals we have reviewed our modelling of capital allowances and made some minor adjustments to the tax allowances to reflect our revised view.

Pensions

Introduction

8.22. In calculating the appropriate allowances for pension costs, we have sought to apply the principles established through the Developing Network Monopoly Price Controls project and applied in DPCR4. Further detail on our pension calculations are set out in appendix 2. Our proposed allowances for pension costs are made up of two components:

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

Ongoing contributions

8.23. Our proposed allowances for ongoing contributions are based on the current actuarially recommended funding rates. These allowances have been subject to minor changes from our Updated Proposals to reflect revised funding contribution rates. The overall allowance for SPTL is currently based on company estimates, as we are awaiting the 2006 actuarial valuation and statement as accepted by their trustees. Any subsequent adjustment will be dealt with in accordance with our pension principles.

Deficit funding

8.24. The Updated Proposals set out our revised conclusions regarding the level of deficit funding in relation to National Grid (NGET and NGG). The most up-to-date actuarial valuations for the schemes of the two Scottish companies indicate that they are in surplus.

8.25. In September, we proposed that:

- it was appropriate to provide an allowance for 70 per cent of unfunded Early Retirement Deficiency Costs (ERDCs) arising in respect of relevant retirement dates between privatisation and 1 April 2004;
- it would be inappropriate for the regulated business to fund any pension costs that relate to unregulated activities, including the cost of repairing the relevant proportion of any deficit; and
- we should make adjustments for the amount by which the 2002 - 07 allowance for pension costs could be argued to have been too low as a result of incorrect attribution of the Centrica surplus and for interest on that amount.

8.26. The transmission companies and the investment community are broadly content with our proposed approach in September. In the light of these responses, we do not propose to modify our policy position further.

8.27. Since September, there have been a small number of minor changes to the pension cost allowance for NGG and NGET. These reflect the impact of the higher allowed rate of return on the annualised allowance for deficit recovery and for NGG a revised assessment of non attributable employees. The table below summarises our proposals for pension cost allowances and further detail is provided in appendix 6.

Table 8.2 - Transmission pensions allowances for TO and SO (nominal terms, 2004/05 prices)

TO and SO	Final (Nominal)			
	Ongoing			
	NGET	NGG NTS	SPT	SHETL
Annual ongoing allowance Opex	£14.6 m	£22.7 m	£0.5 m	£0.8 m
Annual ongoing allowance Capex	£4.8 m	£0.0 m	£0.9 m	£0.9 m
Annual ongoing allowance	£19.4 m	£22.7 m	£1.4 m	£1.7 m
(Cost of Capital used = 5.05%)	**Deficit**			
Total expected deficit	£406.0 m	£371.0 m	£0.0 m	£0.0 m
Non attributable element Centrica		£(91.9)m		
Non attributable element	£(5.3)m	£(31.9)m	£0.0 m	£0.0 m
Unfunded ERDC's	£(42.8)m	£(49.7)m	£0.0 m	£0.0 m
Deficit for allowance	£358.0 m	£197.5 m	£0.0 m	£0.0 m
Annual Deficit Allowance Opex	£39.7 m	£29.1 m	£0.0 m	£0.0 m
Annual Deficit Allowance Capex	£13.1 m	£0.0 m	£0.0 m	
Total Annual Deficit Allowance	£52.8 m	£29.1 m	£0.0 m	£0.0 m
	Total Allowances			
Total Allowance Opex	£54.3 m	£51.9 m	£0.5 m	£0.8 m
Total Allowance Capex	£17.9 m	£0.0 m	£0.9 m	£0.9 m
Total Allowance	£72.3 m	£51.9 m	£1.4 m	£1.7 m
	Movement from Updated Proposals			
Opex	£0.8 m	£4.1 m	£0.0 m	£0.0 m
Capex	£0.3 m	£0.0 m	£0.0 m	£0.0 m
Total	£1.0 m	£4.1 m	£0.0 m	£0.0 m

Accelerated Depreciation

8.28. Our Updated Proposals set out that, once pre-Vesting assets become fully depreciated, we intended to reduce post-Vesting regulatory asset lives to 20 years for all electricity transmission companies, with company specific smoothing adjustments in relation to post-Vesting assets already installed. We proposed that we would adopt a 15 year smoothing period for SPTL, 30 years for SHETL, and 50 years for NGET. We also proposed to adopt a 20 year depreciation period in respect of the approved TIRG schemes. In the light of response to the Updated Proposals, we have retained this approach for Final Proposals.

8.29. One licensee argued that the assets transferred into the RAV as a result of BETTA should have their asset lives reduced to 20 years, as otherwise these assets would have a longer regulatory life than subsequent additions to these assets. We have accepted this argument and have now reduced these assets lives to 20 years. Additionally, given the comparatively large capex commitment involved in TIRG, we propose starting the depreciation of this capex in the year following its expenditure, rather than waiting for the asset to be in use before depreciation begins.

Financeability

8.30. We have analysed the impact of our Final Proposals, incorporating a range of capital expenditure scenarios, in order to assess whether these can be expected to allow the licensees to be able to maintain appropriate credit ratings. In previous documents we have indicated that if this was not the case, we would assume companies would require additional equity and would provide an appropriate allowance for the associated direct costs of equity issuance.

8.31. Our assessment considers that where the key financial ratios (Debt to RAV, Funds from Operations to RAV, and Funds from Operations plus Interest to Interest) for a licensee show a deteriorating trend such that in the final year of the forthcoming price control this would result in a credit rating of BBB / Baa2 or lower, we will assume that new equity is raised earlier in the period to stabilise the ratios at a level consistent with a rating comfortably within investment grade. The hurdle level necessary to trigger this has been determined after consultation with the rating agencies. If the financial ratios in the earlier years were problematic but became acceptable by the final year, then we would address this by a different approach because new equity would not be appropriate (e.g. by re-profiling "X")

8.32. Our analysis indicates that financeability issues are only likely to arise under the higher capital expenditure scenarios for the Scottish TOs. We anticipate that SPTL would require £43 million of new equity if it is required to invest to the maximum level that it has forecast, including all expenditure already allowed for under the Transmission Investment for Renewable Generation (TIRG) scheme. In relation to SHETL, we expect that financeability issues are likely to arise at much lower levels of capital expenditure. Our analysis indicates that SHETL will require £39 million of new equity to finance the baseline capital expenditure allowances and expenditure under the TIRG scheme. This would rise to £165 million if SHETL is required to fund an additional £250 million of capital expenditure to connect new generation.

8.33. The next section will describe how this process works and the level of allowance for issuance costs.

Cost of provision of new equity

8.34. 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, at times, require substantial investment and consequently experience deteriorating credit ratios or apparent financial strain. As discussed above, we expect that companies should be able to raise additional equity, when necessary, to meet funding requirements and maintain credit quality.

8.35. In making an allowance for the cost of equity issuance, it is important to consider three factors:

- the appropriate cost to allow per unit of equity raised;
- the mechanism for determining the appropriate amount of new equity required to achieve financial stability; and
- whether the allowance should be provided ex ante or ex post.

Equity issuance costs

8.36. The cost of equity issuance has two possible components: the direct costs of issuing new equity and the indirect impact on the share price. The Smithers report sets out that the direct cost of equity issuance is typically within the range of 5 to 12 per cent of the value of equity raised, although there are instances where the costs of raising new equity can be significantly higher. We also note that academic research suggests that large companies and utilities typically experience costs towards the lower end of the indicated range and have therefore selected 5 per cent as a representative cost.

8.37. Academic studies on indirect costs of equity issuance have indicated that the main accepted reason for the indirect effect is the information asymmetry that exists between the market and the company raising funds. In the case of network utilities, both the nature of the investment for which equity is required and the prospective return on that investment are clear to market participants. In the light of this, we do not consider it necessary to provide any additional allowance for the indirect costs of equity issuance.

Mechanism for providing for equity issuance costs

8.38. In our Updated Proposals, we consulted upon a number of options for providing equity issuance cost allowances. A key consideration was the uncertainty in the level of investment required and it was suggested that an appropriate way forward might be to provide for the costs of equity issuance on an ex post basis. The Scottish TOs have argued that an ex post approach to equity issuance costs is likely to increase regulatory uncertainty and might therefore discourage investors from providing new equity. In light of these comments, we propose to provide an ex ante allowance for equity issuance costs.

8.39. The difficulty in setting an ex ante allowance is the uncertainty over the level of investment which may be funded through revenue drivers. To allow for this uncertainty, the ex ante allowance will fund the cost of the new equity necessary to fund baseline capital expenditure, TIRG expenditure, and half of the additional investment that a company might incur (as estimated in its FBPQ submission). The allowance will be set at 5 per cent of the value of equity estimated by our financial model by the method described in paragraph 8.31 above. This results in a value of some £5 million for SHETL and around £1 million for SPTL.

8.40. We then propose to "true up" the allowance at the next review to reflect actual investment and the equity required to finance it using the same method. This approach is, for example, similar to the adjustment process that we have already adopted in relation to the over or under funding of pensions. Our approach is set out in greater detail in appendix 2.

Financial ring-fence

8.41. 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. This will 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 propose to bring forward this modification to a timescale consistent with application from 1st April 2007.

9. Adjustment Mechanisms and Incentives: Electricity

Chapter Summary

This chapter sets out how we will set the rules for automatic adjustments to revenue ('revenue drivers') for each of the three electricity transmission licensees in the light of changing patterns of demand for capacity on the network. The chapter also sets out our decisions on the design of incentive schemes for system performance and to support innovation.

Introduction

9.1. Throughout this price control review we have advocated the need for funding to be able to respond flexibly to the changing demands for capacity on the transmission system from new and existing generators. This is to ensure that funding for investment is targeted where it is needed, and to ensure that consumers do not fund anticipated investment which turns out not to be needed. We have also examined how incentives might be used to encourage behaviour which benefits consumers in terms of standards of network reliability and innovation to improve how our networks operate in the future. We believe that our final proposals for revenue drivers, reliability incentives and innovation incentives address these issues effectively and proportionately.

9.2. As noted in chapter 7, the arrangements under which users of the network book transmission capacity can provide important information in driving efficient investment decisions. The licensees have an interest in making sure the access arrangements support efficient investment. In this regard we note the proposals that have been raised by NGET to modify the access arrangements and will consider the merits of NGET's proposal (and the merits of any other change proposals that might be raised) in due course.

Revenue Drivers

9.3. The allowances for capital expenditure in chapters 3 to 5 provide funding for a 'baseline' view of how generation and demand will develop over the period to April 2012. Almost inevitably, what happens in practice will be different from this baseline view.

9.4. Revenue drivers are rules that we set in advance to define how allowances adjust for differences between what we have assumed in setting the baseline allowances and what actually happens. If generation capacity grows more quickly than we have assumed, then allowances will automatically increase. Conversely, if generation capacity grows more slowly than we have assumed, then allowances will be scaled back. The size of the potential adjustments is calculated using cost data for planned investments provided by the companies. These data have been analysed and, in some cases, adjusted.

9.5. There are two different ways in which the revenue driver adjustments could be implemented. First, in a dynamic way for each year within the period. Second, by making one reconciling adjustment at the end of the period, which will then affect revenue allowances from April 2012. For all three companies we are proposing a capex incentive revenue adjustment at the end of the period, as set out in chapter 7. For SPTL and SHETL we are also proposing, if generation growth is more rapid than we have assumed in setting the baseline, to adjust revenues dynamically during the next five years. This is to ensure that the cash flow position of SPTL and SHETL does not deteriorate unduly if the volume of generation connections (and therefore the need for investment) is higher than we have assumed in the baseline.

SPTL and SHETL

9.6. The revenue drivers for SPTL and SHETL are linked to the amount of generation that connects over the period 1 April 2005 to 31 March 2012. The key parameters of the scheme are:

- the volume of generation (MW) we assume will be connected in our baseline;
- the capex (£m) and unit cost (£ per kW) we consider to be consistent with this baseline volume[9]; and
- the unit cost we consider to be appropriate for connected volumes of generation over and above the baseline amount

9.7. Once the baseline volume of generation has been connected, additional allowances will depend on the volume of extra generation connected, as well as a proportion (75 per cent) of the actual costs of work-in-progress for the more advanced new connection projects.

9.8. The revenue drivers have been set using cost data for the range of generation projects that have applied for a connection in the respective areas. The differences between SPTL and SHETL reflect the different characteristics of the projects in the two areas rather than material differences in underlying unit costs. Table 9.1 sets out our Final Proposals:

Table 9.1: Revenue drivers for SPTL and SHETL

	BASELINE			**REVENUE DRIVER**
	Volume (MW)	Allowance (£m)	Unit cost (£m/MW)	Unit cost (£m/MW)
SPTL	1,734	94.4	0.054	0.052
SHETL	1,489	35.4	0.024	0.032

9.9. The adjustments to revenues within this framework will be made in two ways (explained in detail in appendix 7). First, by adjusting the allowance assumed in applying the proposed capex incentive (see chapter 7) for the generality of capex at

[9] Assuming that all connections of less than 100MW in size are built to a 'non-firm' single-circuit design.

the end of the period. Second, once the baseline volume of generation has been connected, by increasing allowances within the period to allow depreciation and a rate of return on:

- 75 per cent of actual additional costs incurred; and
- a further capital sum based on 25 per cent of the estimated unit cost (i.e. the revenue driver) once generation is connected.

9.10. SPTL and SHETL will be handling a large number of potential connection projects, most of which are relatively small, over the period. However, within the current pool of possible projects, there are a small number of projects which have much higher than average unit costs. We consider that the most appropriate way to deal with these exceptional cost schemes (should they proceed) is to exclude them from the revenue driver mechanisms. Otherwise, they could unduly influence the profit or loss for the companies under the scheme by distorting the unit cost allowances. We propose to exclude from the scope of the revenue driver scheme projects which cost more than £0.130 million per MW for SHETL and projects which cost more than £0.163 million per MW for SPTL. The companies will be prohibited through their licences from earning more than a reasonable rate of return on the efficient costs incurred on these excluded projects.

9.11. If the volume of generation is higher than assumed in our baseline capex allowances there might also be a need for deeper reinforcement on the network. While we anticipate this to be a relatively unlikely event, we propose to allow for such developments through the revenue driver mechanisms. We specify a set of conditions (in terms of total MWs of generation in specified areas of the respective networks) which, if met, will trigger further revenue allowances. If there are enough well developed, financially committed projects to meet the specified conditions, then we will allow revenue recovery to commence on 75 per cent of the costs incurred. When the condition is met with actual connected generation, then an additional capital sum would be created. This will be a defined £ million amount rather than a £ per MW unit cost.

9.12. Our starting position is to establish two sets of such conditions for SHETL, reflecting works that might need to be undertaken between Beauly and Dounreay and between Beauly and Blackhillock to accommodate increased flows across the north west boundary of SHETL's network. At this stage, we are proposing no such conditions for SPTL.

9.13. These £m revenue driver estimates for SHETL relate to investment projects for which there is no need case in the short to medium term based on contracted generation. The cost estimates are therefore based on indicative, rather than detailed technical designs. They also relate to projects for which the companies have not yet applied for planning consent. In these circumstances we think it is appropriate for SHETL to re-submit cost estimates as the need for actual investment schemes crystallises and planning consent for specific schemes is granted. Appendix 7 sets out how this process will operate. This process will also enable us to extend the scope of the price control to new sets of circumstances e.g. for connecting the Scottish Islands if this is undertaken by SHETL through a price-controlled route.

NGET

9.14. The revenue drivers for NGET are, like those for SPTL and SHETL, linked to the amount of generation that connects over the period 1 April 2005 to 31 March 2012. Because of the size of the NGET network, and the material differences in costs across it, we will adjust NGET's revenues on a zonal basis rather than by using a single £ per MW revenue driver.

9.15. For each zone we have characterised a profile of generation and demand consistent with our baseline capex allowances (see appendix 7). We then use the revenue drivers to calculate adjustments, in effect, to our capex allowances to the extent that the actual profile of generation and demand by zone is different to the profile assumed in setting the baseline allowances.

9.16. We can only calculate the full scale of the adjustments at the end of the price control period when we can observe how much generation has connected or closed, and where these new connections or closures have been. At this point we will make a one-off adjustment to future revenues to provide NGET with the revenues it would have received had we set the adjusted capex allowance at the start of the period. As with the incentives across the generality of capex, this will expose NGET to 25 per cent of the difference (either way) between what it spends and the (adjusted) level of the allowances. The detail of how we will calculate this adjustment is set out in appendices 2 and 7.

9.17. The revenue driver adjustments to NGET's capex allowances will be calculated at two levels. First, reflecting the local infrastructure costs incurred (or avoided) in connecting more (or less) MW of new connections than assumed in the baseline. This will be a function of the volume of new connections and closures. Second, reflecting the wider network infrastructure impacts of changes in flows between each zone and the wider network. This will be a function of changes in the extent to which there is surplus generation or surplus demand in each zone. The parameters for the scheme are set out in Table 9.2 below.

Table 9.2: NGET revenue driver parameters (£000 per MW)

	Local	Surplus	Deficit
South & South West	15	0	20
Thames Estuary	15	60	0
London	60	0	250
South Wales	15	25	20
East of England & Home counties	10	65	15
West Midlands	5	0	40
East Midlands	5	55	10
North West & North Wales	30	45	0
Yorkshire & Lincolnshire	15	60	0
North East	15	50	0

9.18. We are proposing a separate form of revenue driver for changes in the transfer capability across the network boundary between Scotland and England. If the Authority determine that a change has been made, then a revenue driver shall be activated for the consequent reinforcement works on NGET's network. This revenue driver shall take a value of £275,000 per MW.

9.19. We have amended the scope of the proposed revenue driver for NGET since our Updated Proposals to exclude a revenue driver for local demand variations. We formed this view having analysed the more limited cost variation across zones, and having regard to the greater certainty with which NGET might be expected to forecast changes in demand.

9.20. To illustrate how the revenue driver mechanism works for NGET we can consider an example. The baseline assumes that there is 13,499MW of generation capacity in Yorkshire and Lincolnshire in 2009/10 and peak demand of 5,841MW. If an extra 500MW of actual generation capacity connects in 2009/10 relative to the amount assumed in the baseline, the revenue driver will therefore provide revenue as if the capex allowance on which revenues are calculated had been set £42.5m higher (i.e. 500MW*£15k/MW + 500MW* £70k/MW) from 2009/10.

9.21. The levels of the revenue drivers have been set to recognise that there will be a lag between when the costs are actually incurred and when the additional costs are recognised for the purposes of adjusting revenues.

System performance

9.22. In our Updated Proposals we set out an intention to revise the current reliability incentive schemes to be 'penalty only' schemes. We have decided not to make this change in the form of the incentive at this point in time, pending the outcome of work to develop a wider set of output measures for transmission (discussed further in chapter 12). This work will include reviewing how we measure, and set incentives, in respect of, network performance.

9.23. We are therefore proposing to postpone the introduction of a 'penalty only' reliability incentive scheme and roll over the existing symmetrical scheme for a period of two years, with adjustments for the most recent information. If, after two years, these output measures are developed to our satisfaction by the licensees, then a symmetrical scheme will remain in place for the remainder of the price control period. This symmetrical scheme will expose the companies to financial penalties if their performance is below the target level, and provide rewards if performance is better than the target. The parameters we set out below will be in place for each year for the five year period between 2007/08 and 2011/12, subject to development of wider output measures.

9.24. As with the existing scheme we are proposing to retain a deadband, which is framed by an upper and lower target. Should the licensees' actual performance fall within this range, they will not be penalised or receive a reward. We are also proposing to retain a collar on the licensees' exposure for under-performance; again we are proposing to set this using the most recent information.

9.25. NGET will face a maximum penalty for under-performance of 1.5 per cent of its regulated revenue and a maximum reward for out-performance of 1 per cent of regulated revenue, as with the existing scheme. For SPTL and SHETL we are proposing to retain the existing maximum penalty of 0.75 per cent of regulated revenue for under-performance and a maximum reward of 0.5 per cent of regulated revenue for out-performance. Table 9.3 summarises our proposals. The target will be specified as a volume of unsupplied energy for NGET and as the number of events which result in unsupplied energy for SPTL and SHETL, as under the current schemes. Similarly, the existing set of exclusions, definitions and methodology for calculating unsupplied energy will apply.

Table 9.3: Reliability incentives

	NGET	SPTL	SHETL
Upper target	263MWh	10 events	12 events
Lower target	237MWh	8 event	10 events
Upper collar	619MWh	22 events	27 events
Maximum reward (% of total revenue)	1%	0.5%	0.5%
Maximum penalty (% of total revenue)	1.5%	0.75%	0.75%

9.26. If the companies fail to make adequate progress on the wider development and implementation of output measures, we propose to revisit the provisions of the reliability incentives. Depending on the progress made, and our view as to whether or not the existing scheme parameters represent an appropriate balance of risk and reward going forward, we would propose overhauling the arrangements and moving to a penalties only regime.

Innovation incentives

9.27. In view of the positive results arising from the Innovation Funding Incentive (IFI) in electricity distribution, we have decided to implement IFI schemes for both electricity and gas transmission. This will make available ring-fenced funding for research and development (R&D) projects that conform with industry guidelines for good practice. The scheme will also facilitate engineering R&D projects that support sustainable development priorities such as environmental impact and visual amenity.

9.28. The schemes for transmission will ring-fence an amount equal to the greater of 0.5 per cent of allowed revenue (including revenue entitlements under the TIRG mechanism) or £500,000 each year. The £500,000 floor has been introduced because, for a relatively small company such as SHETL, 0.5 per cent of regulated revenue may not be sufficient to support the company responding to the incentive in a meaningful way.

9.29. In the case of electricity and gas transmission the pass through factor, which in electricity distribution starts at 90 per cent in year one, falling by 5 per cent each year until it reaches 70 per cent, will be set at 80 per cent throughout the period.

9.30. With regard to the amount of eligible IFI expenditure that can be used for internal purposes, we are proposing to adopt the existing rate of 15 per cent for the time being, but are mindful that this is one of the issues recently consulted on through an open letter addressing DNO practical experiences of IFI. We are aware that some parties believe that 15 per cent might be too low. When we have considered the open letter responses we will firm up our views on this aspect and, should a revision be considered appropriate for the DNO IFI scheme, it is likely that this will be extended to electricity and gas transmission IFI arrangements.

9.31. We are retaining the concept of a partial carry over of up to 50 per cent of unspent eligible IFI expenditure from one year to the next. As with the current electricity distribution scheme, we are not proposing cumulative carry over.

9.32. The transmission licensees will be required to report on IFI projects in the same manner as is required under in the electricity distribution scheme i.e. in accordance with regulatory instructions and guidance (RIGs) and a Good Practice Guide managed by the Energy Networks Association (ENA).

10. Adjustment Mechanisms and Incentives: Gas

This chapter sets out our final proposals for the incentive regime for gas entry and offtake. It sets out the obligations we are placing on NGG NTS in respect of the release of capacity, how it will be remunerated for the release of additional capacity over and above these obligated amounts, and how its costs and revenues will be treated if it has to buy back capacity it has sold or sells more capacity than it is obliged to sell.

Introduction

10.1. NGG NTS plays a key role in energy markets in GB through its role in making available transmission capacity to shippers. This can have significant impacts on consumers e.g. by facilitating market entry and thereby influencing prices to consumers. It is important for consumers that NGG NTS's price control provides it with the right incentives to release capacity and to respond efficiently to changing demands for capacity. All figures in this chapter are given in 2004/05 prices unless otherwise stated.

Entry Capacity

10.2. Entry capacity is used by gas shippers who have bought gas from offshore producers or suppliers, or who are holding gas in storage, and wish to bring that gas on to NGG NTS's transmission network. Our proposals for gas entry incentives have three elements relating to NGG NTS's:

- obligations to release entry capacity ("capacity release");
- remuneration for the release of additional obligated capacity ("revenue drivers"); and
- costs incurred in buying back capacity it has sold and revenues generated by selling capacity over and above the amounts it is obliged to sell ("buy back").

Capacity release

10.3. We are proposing to set a baseline amount of capacity at each entry point that NGG NTS will be obliged to release for sale from 1 April 2007 onwards[10]. Capacity that NGG NTS has already sold will be considered to have already been released for the purposes of these obligations. The baseline capacity release obligations are set out in Table 10.1. In addition, NGG NTS will be continue to be obliged to release increments to baseline capacity in respect of past and future incremental capacity sales.

[10] Subject to an obligation to hold back 10% of baseline capacity for release in the shorter term.

Table 10.1: Gas entry capacity baselines as at 1 April 2007

	GWh/day		GWh/day
Easington	1062.0	Aldborough	420.0
Bacton	1783.4	Cheshire	285.9
Isle of Grain	175.0	Hornsea	164.1
Milford Haven	0	Fleetwood	0
St Fergus	1670.7	Caythorpe	0
Teesside	361.3	Wytch Farm	3.3
Barrow	309.1	Blyborough (Welton)	0
Theddlethorpe	610.7	Albury / Winkfield	0
Point of Ayr	73.5	Palmers Wood / Tatsfield	0
Hole House Farm	131.6	Glenmavis	28.5
Humbly Grove	172.6	Partington	174.6
Hatfield Moor (storage)	14.9	Avonmouth	179.3
Hatfield Moor (onshore)	0.3	Dynevor Arms	8.0

10.4. We have sought to set baselines that reflect the physical capability of the network. We have used network modelling to estimate these capabilities. We have sought to characterise the maximum capacity that can be released at each entry point at system peak given the current intact network and assuming flows at nearby entry points are also relatively high. This, in our view, gives a conservative but realistic view of the physical capability of the network. It also gives baselines which are, in our view, consistent with the allowances we have made for NGG NTS in respect of the costs of buying back capacity. An explanation of our modelling approach is provided in appendix 8.

10.5. The current regulatory and commercial regime includes arrangements that enable shippers to bid for additional capacity over and above these baseline amounts. If bidding is sufficiently strong, then NGG NTS can apply to Ofgem to increase the amount of capacity it is obliged to release at the relevant entry point(s) by specified amounts from specified dates. If we approve the release of extra ("incremental") capacity, NGG NTS will be obliged to release for sale these amounts of capacity also at the relevant dates and funding will be provided through the use of revenue drivers (described below).

10.6. This process of shippers bidding for further incremental capacity in the long term (QSEC) auctions will continue to operate as it does today, subject to any changes to these arrangements made in accordance with the relevant governance procedures.

10.7. We are also proposing to introduce a new obligation on NGG NTS to facilitate the transfer of unsold capacity to meet demands for capacity elsewhere. This will oblige NGG NTS, upon request and ahead of an auction (including the long term, QSEC, auctions), to provide a shipper with a rate of transfer that would enable it to buy entry capacity at one point but use it at another. The transfer rates would be specific to each individual request. To give effect to this obligation in a transparent manner we are requiring NGG NTS to establish a methodology (which would need to be consulted on with interested parties, and approved by Ofgem) for calculating such transfer rates. We would expect NGG NTS to submit its proposed methodology to Ofgem by the end of February 2007, such that transfer rates can be issued from 1 April 2007 onwards. In November 2006 we consulted on draft legal text for this capacity transfer obligation. We will update the legal drafting for our second licence consultation in January 2007 in the light of respondents' views.

10.8. An important element of the new licence obligation will be the objectives for the capacity transfer methodology, and how these objectives might reasonably be interpreted by NGG NTS. The purpose of the new obligation is to guard against the risk that capacity is 'sterilised' at an entry point where it is not needed, and where by reducing the obligation at that entry point additional capacity can be made available elsewhere. In calculating the transfer rates it would be reasonable for NGG NTS to factor in any changes in buy back risk as a result of the transfer. It is also reasonable for NGG NTS's methodology to result in a zero capacity transfer rate where this reflects genuine physical constraints on the network.

Revenue drivers

10.9. We are proposing to adjust funding if NGG NTS takes on obligations to release entry capacity over and above the baseline levels, in the light of bidding in the long term entry capacity auctions that occur after 1 April 2007. The revenue drivers will only provide funding for extra capacity that cannot be provided through the substitution of unsold baseline capacity from elsewhere on the network. In assessing the appropriate levels of such substitution, we would have regard to the approved methodology for capacity transfer. For incremental capacity released following auctions held before 1 April 2007, the then prevailing rules for remuneration would apply.

10.10. We have defined a revenue driver function for each entry point as shown in Table 10.3. This sets out for any particular volume of incremental capacity being released, what the associated revenue allowance should be. The revenue allowance starts on the date of contractual delivery of the capacity and is for a fixed five year period. After this period of time, NGG NTS's revenue will depend on the actual costs it incurs (subject to a review of efficiency). The figures in Table 10.3 are the marginal revenues per GWh/d of incremental capacity for each entry point. These values will increase in real terms each year in line with the index set out in Table 10.2.

Table 10.2: Revenue driver index

Formula Year	2007/08	2008/09	2009/10	2010/11	2011/12
Index	100	102.5	104.4	106.3	108.5

10.11. Table 10.3 sets out the revenue driver functions.

Table 10.3: Revenue drivers by entry point and capacity increment

		£M/GW per year - marginal cost			
	Capacity Range	**0-25GW**	**25-100GW**	**100-500GW**	**>500GW**
Entry Point	Easington	0.0155	0.0233	0.0710	0.0533
	Bacton	0.0310	0.0688	0.0758	0.0863
	Isle of Grain	0.0349	0.0310	0.0559	0.1259
	Milford Haven	0.1061	0.1640	0.1395	0.2210
	St Fergus	0.0029	0.0645	0.1955	0.1517
	Teesside	0.0157	0.0159	0.0241	0.0866
	Barrow	0.0443	0.0165	0.0249	0.0974
	Theddlethorpe	0.0194	0.0000	0.0258	0.0816
	Point of Ayr	0.0161	0.0256	0.0162	0.0320
	Hole House Farm	0.0778	0.0015	0.0252	0.0498
	Humbly Grove	0.0621	0.0194	0.0193	0.1574
	Hatfield Moor (storage)	0.0233	0.0052	0.0423	0.0182
	Hatfield Moor (onshore)	0.0233	0.0052	0.0423	0.0182
	Aldborough	0.0251	0.0247	0.0593	0.0174
	Cheshire	0.0095	0.0000	0.0076	0.0122
	Hornsea	0.0098	0.0141	0.0361	0.0359
	Fleetwood	0.0867	0.0000	0.0137	0.0632
	Caythorpe	0.0371	0.0340	0.0694	0.0638
	Wytch Farm	0.0246	0.0082	0.0936	0.0383
	Blyborough (Welton)	0.0361	0.0155	0.0662	0.0449
	Winkfield	0.0247	0.0180	0.0647	0.0422
	Tastsfield	0.0464	0.0577	0.0896	0.1756
	Glenmavis	0.0126	0.0000	0.0066	0.1317
	Partington	0.0104	0.0024	0.0100	0.0142
	Avonmouth	0.0800	0.0284	0.0721	0.1061
	Dynevor Arms	0.0439	0.0967	0.0854	0.2461
	Albury	0.2161	0.0155	0.0674	0.0519
	Palmers Wood	0.0882	0.0438	0.0896	0.1756

10.12. The revenue drivers in Table 10.3 above have been calculated using the same modelling approach adopted for setting the baseline capacity release obligations. They are based on pre-tax rate of return of 6.25 per cent and include an adjustment for financing costs in the period before the capacity is scheduled to be delivered and an allowance for operating and maintenance costs of 1% of the revenue driver capex allowance.

10.13. To illustrate how the revenue drivers will work in practice, consider a hypothetical example where there is a signal for incremental capacity of 150 GWh/day of capacity at Theddlethorpe. NGG would earn an extra £1.77m each year.

£1.77m is calculated as 25 GWh at £0.019m per GWh (=£0.485m) + 75 GWh (i.e. 100GWh – 25GWh) at £0 per GWh (=£0) + 50Gwh (i.e. 150GWh – 100 GWh) at £0.025m per Gwh (=£1.288m).

Buy back

10.14. NGG NTS sells entry capacity which is 'financially firm'. This means that NGG NTS is unable to deliver the capacity it has sold, e.g. if there are physical constraints on the network at a particular point in time, it must buy back capacity until it is able to meet its obligations. It also has the option to sell capacity over and above the amount it is obligated to sell (and thereby choose to take on more risk of having to buy back capacity). This section sets out our final proposals on how NGG NTS's revenue will be adjusted in the light of the buy back costs it incurs and the revenues it earns from the sales on 'non-obligated' capacity.

10.15. We are proposing to restructure these incentives relative to how they operate today. The main change is have separate incentive schemes for:

- new obligated capacity (the “incremental buy back incentive”); and
- all other capacity (the “operational buy back incentive”).

10.16. The rationale for this approach is that the risks NGG NTS faces in investing to release incremental capacity are fundamentally different to the risks NGG NTS faces in managing the risks of buy back on the prevailing network. By setting two incentive schemes we believe that we can provide more effective and focused incentives on NGG NTS to operate efficiently.

Incremental buy back incentive

10.17. The incremental buy back scheme will apply to costs incurred in buying back permanent obligated incremental capacity released for sale as a result of bidding in long term capacity auctions that occur after 1 April 2007. The scheme will have the following parameters:

- A target cost of zero;
- A 100% exposure to these buy back costs, subject to a cap on NGG NTS's exposure of £4m a month and £36m a year under the scheme; and
- A prohibition on NGG NTS paying any more than £0.52 per KWh per quarter for any capacity within the scope of the scheme it buys back.

10.18. Whether NGG NTS has to buy back capacity or not will depend in part on the date by which it is obliged to make the additional capacity available. Currently the lead time is 36 months, unless NGG NTS apply to have this extended and we agree to this request. In some instances NGG NTS has requested, and we have consented to, lead times of 48 months.

10.19. We are proposing to replace this process with a default lead time of 42 months and a system of permits for NGG NTS which allow the lead time to be extended further. We are proposing to grant NGG NTS 12 permits, with each permit allowing NGG NTS to extend the lead time of up to 100GW of capacity by up to 6 months. Additional permits can be earned by agreeing to deliver capacity earlier than the default lead time. It is up to NGG NTS how it chooses to use these permits – although they will need to be committed in advance of each long term auction (and will only be deemed to have been earned or used to the extent that incremental capacity is subsequently released at the relevant entry point).

10.20. In introducing the permits approach we are formalising a process that already exists, whereby NGG NTS can apply to the Authority on a case by case basis to extend lead times. There is no added complexity for shippers through the introduction of these arrangements.

10.21. We are proposing to confer each of the initial allocation of permits with a residual value of £3 million. The value of unused permits will be reflected in NGG NTS's allowed revenue from the start of the next price control (April 2012). We believe that this process provides the appropriate degree of flexibility over the delivery of additional capacity, while also retaining the appropriate incentives on NGG NTS to set challenging delivery targets for itself.

10.22. NGG NTS has contended that despite its past performance indicating otherwise, all future releases of incremental capacity will (with one possible exception) take at least 48 months to deliver. We have not been persuaded by the evidence presented by NGG NTS to support this view. We do intend, however, to review our position in two years' time as part of the proposed review of the parameters of the operational buy back incentive scheme.

Operational buy back incentive scheme

10.23. The operational buy back incentive scheme determines how certain specified costs net of revenues are shared between NGG NTS and shippers (through higher NGG NTS charges). The relevant costs and revenues are:

- costs incurred in buying back capacity other than permanent obligated incremental capacity released for sale as a result of bidding in long term capacity auctions that occur after 1 April 2007;
- revenues received through the sale to shippers of capacity ahead of the gas day over and above the amount that NGG NTS is obligated to release; and
- revenues received through the sale to shippers of interruptible entry capacity and entry capacity on the gas day.

10.24. The scheme will have the following parameters:

- A target cost of £18m, and

- 50 per cent sharing between NGG NTS and shippers of costs net of revenues up to limits on total net costs of £18m (if costs exceed revenues) and -£18m (if revenues exceed costs) in any given year.

10.25. This represents an incremental reform of the existing incentive scheme to make the upside and downside parameters more balanced. We have not proposed to introduce more extensive changes to the scheme caps and collars, as proposed in our September Update. This decision reflects genuine uncertainty - and to some extent, conflicting information from NGG NTS - on future buy back prices and volumes, and the scope for NGG NTS to sell capacity over and above the baseline levels. We therefore concluded that the most prudent approach from the perspective of consumers was to observe behaviour in the light of our proposed baselines and in the light of the proposed capacity transfer methodology, and to review and potentially re-set the parameters of the scheme in two years' time.

10.26. We are, however, proposing an amendment to the treatment of revenues from capacity sales where NGG NTS makes available capacity earlier than planned at entry points where it is providing new incremental entry capacity. In these circumstances, NGG NTS will be permitted to retain 100 per cent of the revenue. This will be limited to the six months prior to the incremental capacity being released and will not apply if NGG has chosen to extend the original delivery date beyond the 42 month default delivery date, and where NGG NTS has sold the non-obligated capacity more than 18 months in advance. If NGG NTS is correct in its strongly held view that no further incremental capacity can be provided in less than 48 months, then there will be no revenues associated with this element of the incentive regime.

Buy back incentives in aggregate

10.27. The two incentive schemes described above (together with the offtake scheme discussed further below) concern the delivery of capacity by NGG NTS to shippers. Collectively, the incentive schemes imply a maximum upside or downside risk in any given year. The probability of NGG NTS incurring maximum losses under all three schemes in the same year is, in our view, very low.

10.28. However, despite its low probability we do not consider that this is a risk that we can reasonably impose on NGG NTS given the scale of the impact such an event would have in the year it occurred. We therefore propose to cap NGG NTS's total aggregate downside risk across all three incentive schemes at £48m in any given year. The separate incentive scheme for the delivery of capacity at Milford Haven[11] will be outside the scope of this aggregate cap.

[11] 'Incentive Arrangements for the Provision of NTS Entry Capacity at Milford Haven - Decision Document', Ofgem, July 2006

Offtake

Context

10.29. A key theme throughout the transmission price control review process has been the introduction of a user commitment framework for offtake capacity from the NTS. Under this framework all classes of users should have adequate and equal opportunities to gain access to NTS offtake capacity through booking arrangements that provide accurate and financially backed investment signals. We continue to believe that the introduction of such a model is appropriate for gas offtake as it would, amongst other things, reduce the risk of stranded assets on the network. These arrangements are known as the enduring offtake arrangements. If implemented, the arrangements would take effect from October 2010 and replace the transitional offtake arrangements.

10.30. As outlined in the September Update, NGG NTS has raised a Uniform Network Code (UNC) modification proposal to implement enduring offtake reform. This modification proposal is known as 0116V, 'Reform of the NTS Offtake Arrangements'.[12] In addition, a number of alternative proposals have been raised by industry participants, including a proposal to extend the transitional offtake arrangements beyond October 2010.[13] These proposals are currently being consulted upon under UNC modification processes. It is anticipated that the modifications will be submitted to the Authority shortly, following which it will be required to decide whether to accept or reject the proposals.

10.31. As outlined in previous documents, Ofgem intends to publish an Impact Assessment on the proposals. This Impact Assessment will be published in early 2007. We have decided that it would be beneficial to seek comments from industry participants on the results of this Impact Assessment prior to releasing decisions on the modification proposals. It is noted that nothing in this document can fetter the discretion of the Authority in considering the modification proposals that have been raised.

10.32. Given this background, our final proposals focus on the incentives associated with the delivery of incremental gas offtake capacity and the efficient operation of NGG NTS at an offtake level both prior to and in the enduring offtake period. Our final proposals cover six principal areas:

- the determination of NGG NTS offtake baselines;
- revenue drivers;
- buy back incentives; and
- non-obligated capacity incentives.

[12] It is noted that NGG NTS originally raised modification proposal 0116. However, following a request that the modification proposal be varied, it was subsequently withdrawn and re-raised as modification proposal 0116V.
[13] These include modification proposal 0116A, raised by E.on UK, modification proposal 0116BV, raised by RWE Trading, modification proposal 0116CV, raised by British Gas Trading and modification proposal 0116VD raised by Scotia Gas Networks.

- constrained LNG incentive
- transitional offtake incentives

Baselines

10.33. We are setting baselines for the transitional offtake period from 1 October 2008 to 30 September 2010 and for the enduring period from 1 October 2010. Baseline numbers for the enduring offtake period will be consistent with those for the transitional offtake period. The baselines for flat capacity at each offtake point are based on a 'practical maximum physical capacity' approach.

10.34. In terms of flexibility capacity we share the concerns raised by industry participants regarding the level of flexibility to be made available under the proposed enduring arrangements, including whether the baselines truly reflect system capability. However, in view of the uncertainties associated with the management of flexibility following NGG's sale of four of its gas distribution businesses, we are continuing to propose a national baseline flexibility level of 22 mcm/day for each year of the enduring period in the next price control period.

10.35. In order to address the concerns regarding availability of flexibility we remain of the view that NGG NTS should have financial incentives to release more flexibility where it is available. These incentives are discussed further below. This should assist in ensuring that the availability of flexibility is maximised. In addition, we intend to monitor the release of flexibility carefully in the light of the NGG NTS licence obligation to operate an efficient, economic and coordinated pipeline system.[14]

10.36. We have made some minor adjustments to the numbers for baseline flat capacity set out in the September Update. We remain of the view that nodal baselines for five sites in the constrained south west area of the NTS should be adjusted upwards for the enduring offtake period and we are setting an allowance for NGG NTS to enter into interruption contracts in the south west to manage the delivery of capacity to these sites. Baselines for both flat and flexibility capacity and the south west contracting allowance are set out in more detail in appendix 9.

Revenue drivers

10.37. As outlined in previous documents, we continue to believe that, in view of the uncertainty regarding future demands for capacity, it is not appropriate to provide NGG NTS with a fixed allowance in advance for load related investment. Instead, we have proposed setting revenue drivers for investment in incremental capacity where this is triggered by user commitments. This ensures that NGG NTS is not provided with funding in advance for investments that ultimately are not necessary. As with the entry regime, the revenue drivers will only provide funding for extra capacity that cannot be provided through the substitution of unsold baseline capacity from elsewhere on the network in accordance with an approved methodology that NGG NTS would be required to develop under its licence.

[14] Special Condition C5, paragraph 1, of the NGG NTS Gas Transporter Licence.

10.38. We remain of the view that revenue drivers are appropriate for gas offtake and we have adopted an approach consistent with the gas entry regime. Under this approach the revenue drivers will provide NGG NTS with a steady income stream for a period of five years and would be activated from the date at which NGG NTS is contractually required to deliver incremental capacity.

10.39. Since the release of our updated proposals we have received further submissions on costs from NGG NTS. Following receipt of this data and further assessment of the efficient level of costs, the allowed capex numbers have been revised upwards. These changes reflect unit cost increases identified by NGG NTS, in particular in relation to projects which are already underway and have been subject to competitive tendering processes, such as the Langage Power Station Phase 1 project. We also consider that allowance should be made for potential increases in certain costs and the revenue drivers have therefore been adjusted in line with our capex consultants' views on the outlook for steel prices and contractor costs. A detailed summary of our revenue driver proposals appears in appendix 9.

Buy back incentive

10.40. As with the entry capacity regime, for the enduring offtake period, we have proposed incentives on NGG NTS to ensure that incremental capacity is delivered in a timely manner. These are known as incremental capacity buy back incentives. This incentive is likely to be particularly important going forward should significant transmission investment be needed to support future gas fired power station projects.

10.41. Our final proposals for the offtake buy back incentive are largely unchanged from the September Update. We remain of the view that the incremental buy-back scheme should have an annual cap on costs of £36m. However, in order to ensure that NGG NTS remains incentivised on the delivery of capacity throughout the year we are proposing a monthly cap of £4m. This is consistent with our entry capacity proposals. Once this cap is reached, all costs are passed on to consumers. NGG NTS will also be prohibited from paying any more than £0.52/kWh/quarter in the event that it has to buy back incremental obligated capacity.

10.42. As noted above NGG NTS's total aggregate downside risk across all of its three buy back incentive schemes (across entry and offtake) will be capped at £48m in any given year.

10.43. We consider that it is appropriate to retain a default lead time of 38 months for the delivery of offtake related investments. This is shorter than corresponding period for the entry capacity regime, largely due to the fact that offtake projects are not as large as entry investment projects. We will provide NGG NTS with 365 days of permits in total for 30 GWh/day to extend lead times in the enduring offtake period. NGG NTS will not be permitted to apply a permit to capacity which it is already committed to deliver. As such, permits can only be used in advance of long term allocations. As in the case of the entry regime, the permits will have a residual value if they are not used during the price control period. This will be set at £3m and pro-rated according to the number of unused days.

Non-obligated capacity incentives

10.44. NGG NTS will be provided with an incentive to release additional capacity over and above baselines. This is known as the non-obligated capacity incentive. The introduction of such an incentive has been supported by a number of respondents particularly with respect to the release of flexibility capacity.

10.45. Our proposals on this incentive remain unchanged from the updated proposals and allow NGG NTS to receive a 50 per cent share of all of the revenues associated with the release of non-obligated incremental capacity including flexibility capacity. We are also proposing to cap the gains NGG NTS can make under the incentive at £20m p.a. We consider that an incentive based around sharing the revenues from sales of non-obligated capacity is consistent with our approach for incentivising the release of non-obligated entry capacity. As outlined above, we intend to monitor NGG NTS's conduct carefully to ensure it releases available capacity in accordance with its licence obligations.

Constrained LNG incentive

10.46. As part of its system operation functions, NGG NTS needs to procure transmission support services to enable offtake capacity to be delivered to customers under certain peak day scenarios. NGG NTS currently has financial incentives under its licence to ensure that it uses LNG and other storage facilities efficiently in providing these transmission support services. These incentives are target based incentives with 100 per cent sharing factors. As part of the price control review incentives need to be set for 2009/10, 2010/11 and 2011/12. This incentive is known as the constrained LNG (CLNG) incentive.

10.47. In order to set targets for this incentive certain assumptions are required regarding future volume and prices for CLNG. In our updated proposals we consulted on high, medium and low cases for CLNG targets based on different price and volume assumptions. Following consideration of respondent's views and further information provided by NGG NTS we have decided that a variation of the medium case scenario is appropriate. As such, for our final proposals we have accepted NGG NTS's forecast volume requirements for CLNG in the south east and south west of England. We have however made some adjustments to NGG NTS's price forecasts under this scenario. Our final proposals are for targets set at £4.3m for 2009/10, £3.6m for 2010/11 and £2.9m for 2011/12. Further details regarding the setting of these targets are set out in appendix 9.

10.48. We also remain of the view that it is appropriate to set 100 per cent sharing factors around these targets given NGG NTS's continued ownership of LNG facilities.

Transitional offtake incentives

10.49. As outlined in previous documents, whilst the offtake arrangements for the transitional offtake period are in place, incentives governing NGG NTS's behaviour in this period have not been set. These incentives will be as set out in our Initial and Updated Proposals. In summary, NGG NTS will continue to have an incentive governing the use of interruption in the transitional offtake period from 1 October 2008 to 30 September 2010. Under the existing interruption arrangements, NTS sites that are interrupted for greater than 15 days are provided with additional rebates. NGG NTS will continue to be incentivised in relation to these interruption rebates. Further details regarding this incentive are set out in appendix 9.

Innovation incentives

10.50. As mentioned in chapter 9, we have decided to implement an Innovation Funding Incentive (IFI) for both electricity and gas transmission. This will make available ring-fenced funding for R&D projects that conform with industry guidelines for good practice. The arrangements for NGG will be as described in chapter 9.

11. Sustainable Development and the Environment

Chapter Summary

This chapter sets out how the TPCR takes account of our sustainable development and wider environmental duties. It discusses the role our proposals play in facilitating the shift towards lower carbon forms of generation, and sets out how we have had regard to other environmental impacts that flow from the operation of the transmission networks. It also sets out our proposed new incentive to reward the electricity transmission companies for reducing leakage rates of SF6, an extremely potent greenhouse gas used as an insulating agent in high voltage switchgear, as SF6 emissions are not currently incentivised through the EU Emissions Trading Scheme (ETS).

Introduction

11.1. In developing our Final Proposals we have had regard to the different ways in which our proposals might influence progress towards sustainable development goals. We have considered the direct and indirect impacts of our proposals, including how we might use financial incentives to ensure that companies take environmental costs into account when they make decisions.

11.2. Our proposals can be considered under the following headings:

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

11.3. As discussed in chapter 9 we are introducing an Innovation Funding Incentive in electricity and gas transmission. This will facilitate R&D in engineering projects that support sustainable development priorities such as environmental impact and visual amenity, and may help deliver environmental benefits in the future.

Emissions

11.4. Our Final Proposals for capital expenditure and operating costs are set at levels consistent with the companies meeting their obligations under relevant environmental legislation. This can be expected to have a beneficial impact on emissions. For example, we have provided allowances for operating costs consistent with planned changes to maintenance processes to support reduced leakages of SF6.

11.5. The transmission networks play an important role in enabling new generators to enter the market. This is important from an environmental perspective in circumstances where the new generation being connected is lower carbon than the generation that it is replacing. Our Final Proposals provide large and flexible revenue allowances to fund the investment needed to connect new generation, much of which is anticipated to be renewable generation.

11.6. Further, we are proposing to introduce a new incentive for the electricity transmission companies focused on reducing leakage rates of SF6 - an extremely potent greenhouse gas used as an insulating agent in high voltage switchgear. This will ensure that the companies focus attention on this issue, and are rewarded for finding ways of reducing leakage rates over time.

11.7. We are proposing this new incentive because SF6 emissions are outside the scope of the European Union Emissions Trading Scheme (EU ETS). Therefore, the companies have weaker financial incentives to reduce emissions of SF6 relative to emissions of greenhouse gases covered by EU ETS (only carbon dioxide at present). As a first step we are proposing a relatively simple scheme such that the licensees are eligible to receive a payment should they beat specified leakage rate targets in each year of the five year price control period. We are proposing to implement this for NGET with effect from 1 April 2007, once we establish the detailed regime for this incentive. We will implement the scheme for SPTL and SHETL when we have resolved some outstanding issues on measurement and reporting.

11.8. We are proposing that the incentive scheme should recognise the increasing role of SF6 filled switchgear in the licensees' capital expenditure plan over the next five years. As such we are proposing that the measure we will be incentivising is the leakage of gas as a percentage of the inventory of the gas in use. We are not proposing that gas leakage as a result of decommissioning of SF6 switchgear in high voltage transmission equipment should be incentivised. We consider that if we were to do so it would be double-counting efforts to reduce SF6 leakage, given the EC Regulation on Certain Fluorinated Gases. This regulation provides an appropriate framework by which SF6 is treated and salvaged during the decommissioning process. It does not, however, deal with SF6 leakage in high voltage switchgear in its operational life. We also recognise that there are certain exclusions that may need to feature as part of the scheme. These issues are yet to be resolved with the licensees, but we envisage exclusions relating to force majeure, and where the security of a site should override considerations of SF6 leakage.

11.9. We are proposing that the schemes should be comprised of the following parameters in table 11.1. The target leakage profile will be refined and confirmed as part of the implementation process.

Table 11.1 - Ofgem's proposed parameters for NGET's SF6 Incentive

NGET SF6 Parameters	2007/08	2008/09	2009/10	2010/11	2011/12
Target leakage (as % of inventory)	3.00	2.75	2.50	2.25	2.00
Payment for beating target (as % of regulated revenue)	0.2	0.2	0.2	0.2	0.2

11.10. We consider that the target profile set out above represents an appropriate strength incentive, given the information we have at our disposal on historic levels of SF6 leakage. Given the limitations of the information at our disposal, our proposals therefore aim to provide not only an incentive to directly manage and reduce leakage rates, but also to develop appropriate auditing and reporting processes.

11.11. We recognise that the introduction of this incentive requires us to establish consistent methods of measurement and reporting (e.g. to ensure that the correct amounts of usage and leakage are attributed to the transmission businesses, where these data are currently reported at a more aggregated level). We will take forward work with the companies to establish the technical detail underpinning this incentive. The scheme will not be 'switched on' until this work is complete and, if necessary, the target leakage rates have been adjusted. These considerations mean that we are not in a position to implement the scheme for SPTL and SHETL on 1 April 2007.

11.12. This is an initial step in providing focused environmental incentives through the price control. We envisage further development in this area over time in the light of experience of the proposed SF6 scheme, which we will keep under review and proposed refinements where appropriate.

Revenue from EU ETS allowances

11.13. The operation of the gas transmission system in its current form results in National Grid receiving an allocation of allowances under the EU ETS. The extent to which National Grid operates the transmission systems in an efficient manner determines the amount of efficiency savings that are created. As proposed in our Initial Proposals, the companies will be allowed to retain any efficiency savings associated with the value of allowances. This provides a strong financial incentive to reduce carbon dioxide emissions.

Losses

11.14. Total losses across the electricity transmission network represent, on average, some 1.7 per cent of the electricity generated, or 6 TWh. If losses were lower, then less electricity would need to be generated to meet any given level of demand. In turn this would reduce emissions associated with electricity generation.

11.15. NGET has separate incentives in its capacity as System Operator that relate to transmission losses. We recently published our Initial Proposals on the form of these incentives from 1 April 2007[15]. The incentive we are proposing to continue for NGET is based around the price of wholesale electricity, which in turn reflects the value of carbon as revealed through EU ETS. NGET's incentive in managing losses on the network is therefore influenced by the price of carbon.

11.16. Leakage from the gas transport network leads to emissions of methane, a greenhouse gas. However, the gas transmission system has very low levels of leakage, since it is a high pressure network. We are considering the issue of methane emissions from the gas transmission network as part of the System Operator incentives.

Visual amenity

11.17. It is generally accepted that transmission assets reduce visual amenity, and that visual amenity has a value to consumers. The existing electricity transmission network has 26,550 kilometres of overhead line in GB, comprising 5,250 kilometres of 132kV, and 21,300 kilometres of 275/400kV.

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

11.19. We are keen to ensure that the value to consumers of visual amenity is recognised and considered objectively in determining how the networks are developed over time. In the most recent electricity distribution price control (DPCR) we allowed a small amount of additional funding for the companies to fund the replacement of overhead lines with underground cables in environmentally sensitive areas. However, the cost of undergrounding transmission lines is significantly higher than the costs of undergrounding lower voltage distribution lines, and therefore we propose not to adopt this approach in the context of transmission.

11.20. However, for transmission we need a different approach. There is much less transmission in sensitive areas, but the visual impact is much greater per km because of the size of transmission pylons. But the costs of replacing a km of transmission line with underground cable are also significantly higher. To illustrate, based on illustrative cost estimates provided by the transmission companies, a single project to replace a relatively small stretch of overhead transmission lines with underground cable could quite feasibly cost more than the entire five-year budget for the DPCR scheme across all fourteen distribution companies.

11.21. We also need to be aware of the other processes, most notably the planning consent process, through which visual amenity and other impacts of new transmission investment are considered. These considerations are on a case-by-case

[15] National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007: Initial Proposals Consultation

basis, and we think that our approach to visual amenity in respect of transmission should also be on a case-by-case basis. We will give effect to this approach by monitoring and, where appropriate, participating in the planning consent process - and through our own analysis and consultation with key stakeholders where we think a case for funding adjustments might be justified.

12. Price Control Development and Compliance

Chapter Summary

This chapter sets out our Final Proposals for routine regulatory reporting and compliance arrangements, together with an outline of the regulatory initiatives we propose to develop further.

Regulatory Reporting

12.1. In previous consultations we have indicated that we intended to adopt the approach initiated in DPCR4 and introduce an annual regulatory reporting pack. The licensees and credit agencies have generally welcomed this approach. This will improve the quality of our information on cost, revenue, incentive, and output reporting and will help us to monitor performance and set future price controls and incentives. We expect the licensees to provide accurate, complete and timely information and we will routinely publish this information.

12.2. This should lead to improved transparency by providing a comparison of actual outturn data against allowance and an indication of the cumulative RAV under the generally applicable assumption that no capital expenditure has been inefficiently incurred. The accompanying appendix 2 contains details of the proposed methodology for assessing RAV.

12.3. The timetable for the introduction of regulatory reporting is as follows:

- December 2006 – Illustrative examples discussed with the licensees
- February 2007 – Formal public consultation
- April 2007 – Introduction date for the Regulatory Reporting Pack (RRP)
- July 2007 – Revenue Reporting of the previous year outturn by the Licensees
- July-Sept 2007 – Cost Reporting of the previous year outturn by the Licensees
- January 2008 – Publication of the 2006/07 Regulatory Reporting Pack.

12.4. In addition to regulatory reporting, we will maintain our focus on ensuring licence compliance is maintained by the licensees. To this effect, we propose to strengthen our arrangements for collecting and reviewing routine information that is reported by the licensees, and for monitoring compliance against licence requirements. We will undertake investigations into specific issues as and when necessary.

Developing Output Measures

12.5. This price control review is characterised by a substantial increase in forecast capex in comparison to historical levels. Whilst changes in load related capital expenditure are dealt with by revenue drivers, changes in non-load related capital expenditure are not so readily captured by high level measures. We have developed our proposals by using the conventional top-down approach and assessing any specific asset condition information provided by the licensees.

12.6. However, faced with the challenge of the significant upturn in costs to replace and refurbish assets, we believe it is important for the industry and ourselves to improve the measurement of overall network condition, underlying network risks and the impact on system performance. Better output measures, that also allow comparative analysis (including international comparisons), should help the licensees to demonstrate any efficiency achieved in, or potential increased need for, such investment. Having confidence in such measures would allow us to better set and sharpen the incentives for the licensees, aligning their reward and penalty more closely with required network performance, so as to realise better value overall for consumers.

12.7. We plan to initiate work to develop output measures for electricity and gas transmission soon after the implementation of these Final Proposals. An initial step will be to establish a reporting mechanism for existing information relating to the condition, risks and performance of assets and the overall network. This will be included as part of the Regulatory Reporting work. However, it is anticipated that other output and performance measures will be developed as appropriate.

12.8. We will work with the licensees and other relevant stakeholders to devise and populate suitable output measures for transmission. As discussed in chapter 9 we propose to postpone the introduction of a 'penalty only' reliability incentive scheme and roll over the existing symmetrical scheme for a period of two years. If, after two years, these output measures are developed to our satisfaction by the licensees, then the symmetrical scheme will remain in place for the remainder of the price control period.

Comparative risk analysis

12.9. During this review, we have carried out an assessment of the relative levels of risk faced by investors in network companies to inform our cost of capital discussions in future price controls. As set out in chapter 8, while there is some evidence to suggest that a transmission regulatory regime may be lower risk than distribution, we have found this difficult to quantify accurately and have treated this evidence with caution. Over the course of the next year, we will be examining this issue in more detail in conjunction with a wider assessment of comparative risk across our regulated energy networks.

NGG Review of Gas Transmission Planning Methodology

12.10. The Initial Proposals document raised the need to review the application of the 5 per cent margin on the 1 in 20 scenario peak day flow when planning future network capacity. Having considered advice from our consultants and responses to the Initial Proposals, we set out our belief in the Updated Proposals document that reforming the flow margins alone might not yield the best solution for consumers and network users. This should be considered as a major component of a wider ranging review of NGG's forecasting and network planning which will deliver greater transparency and clarity for system users and help to ensure better consistency, especially when faced with changing patterns of flow across the NTS network in future. We plan to initiate work with NGG in this area soon after the implementation of the next price control.

12.11. NGG will be required to facilitate this process and support Ofgem throughout the review. This will require considerable input from NGG in undertaking the necessary detailed analysis and network modelling work which will underpin the review, and in developing the material for workshops and consultation documents, as well as in exploring the options for reform of the present methodology. In addition to providing greater transparency on NGG NTS's investment decisions for network users, this work will hopefully improve the quality of information available - and the framework for analysis - for future price control reviews.

Transmission connections to the Scottish Islands

12.12. In our September Update, we noted that that revenue drivers would not be designed to handle very large extensions to the transmission network (such as to connect Shetland, Orkney, or the Western Isles) because of considerable uncertainties over the technology used and the design specifications.

12.13. We identified two potential approaches to this issue. First, we could re-open the price control of SHETL when further information is available, using existing regulatory arrangements to finance this investment by a monopoly transmission provider. Second, we could open up the provision of such transmission links to alternative providers. A competitive approach could potentially bring quicker delivery, drive down costs, encourage innovation, give more certainty to ex ante costs, and reveal cost information.

12.14. We propose to undertake further development work on the potential for facilitating competition in large transmission links. We will consider the extent to which we consider there would be benefits to consumers. We expect to initiate a consultation on this issue during 2007.

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The Supplementary Appendices are included in a separate appendices document.

Appendix 1 – Price Control Calculations

Introduction

1.1. This appendix sets out the way that the revenue allowances for each of the transmission licensees has been calculated for the period 2007/08 to 2011/12, including the key assumptions that have been adopted in order to derive price control revenue allowances. It also sets out a reconciliation of the base price control revenues from the revenues calculated in table 2.1.

Background

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

1.3. The text below sets out a description of how the base price control revenue calculations are constructed. This description is accompanied by the price control calculation tables generated by our financial model, expressed in 2004/05 prices. We also provide a brief description of the revenue reconciliation and the accompanying tables.

Price control calculations

The balance between 'P0' and 'X'

1.4. In setting the price control a decision needs to be made about the balance between the immediate change in revenues in the first year of the price control ('P0') and the path of revenues over the remaining years (or 'X'). There is no "right" answer on the appropriate balance between 'P0' and 'X', but there are two main considerations in coming to a decision, namely the financial profile of companies and the longer-term trend in revenues.

Approach to the revenue calculations

Calculating the movement in the RAV

1.5. The calculation of the movement in the RAV is shown in lines 1 to 6. In each year total capital expenditure[16] (line 2) is added to the opening RAV (line 1) and the allowed level of depreciation (line 3) is subtracted from it to give a closing asset value (line 4). The closing value in any year (line 4) then becomes the next year's opening value (line 1).

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

Calculating allowed items

1.7. The allowed levels of costs and associated items are shown in lines 7 to 14. Line 7 shows the allowed level of operating expenditure (excluding pensions costs which have been considered separately) in each year. This is the sum of controllable and non-controllable operating cost allowances. The annual allowances for capital expenditure are given in line 8. Ofgem's proposed allowance for expensed pensions costs are then set out in line 9.

1.8. Ofgem's proposed allowances for corporation tax are set out in line 10 is based on the methodology set out in our initial proposals. The total annual cash costs that will be incurred by each licensee are calculated by adding together lines 7 to 10 in each year (line 11). The annual cost is then discounted to determine the present value equivalent cost (line 12). This is calculated by discounting the total allowed items figure by the vanilla WACC[17] of 5.05 per cent, using a mid-point value.

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

Calculating annual revenue

1.10. In order to profile revenue, a revenue index is calculated to reflect our revenue profiling assumption as shown in line 15. This is then discounted as for the total allowed items line, as shown in line 16.

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[16] Total capital expenditure includes an allowance for capitalised pension, BETTA additions and other adjustments.
[17] Calculated as the average of the pre-tax cost of debt and post-tax cost of equity weighted by the assumed gearing level. This is consistent with a post-tax cost of capital of 4.4 per cent.

1.11. Price control revenue in line 17 is then derived by taking the total present value of allowed items and the five year movement in closing RAV in line 14, deducting the present value of excluded services revenue for the period 2007/08 to 2011/12 (calculated from line 18), dividing the result by the sum of the discounted revenue index in line 16 and then multiplying by the revenue index in line 15. The relevant items of excluded services revenue (those for which costs remain in the operating cost excluding pensions allowance in line 7) are included in line 18.

1.12. Total revenue is shown in line 19 and is the sum of price control revenue (line 17) and excluded services revenue (line 18). The present value of line 19 is shown in line 20 and the total present value over five years is shown in line 21.

Revenue reconciliation

1.13. As set out in chapter 2, we have made two revenue adjustments to arrive at final proposals for the base price control revenue allowances:

- each of the companies has now provided its latest estimate of allowed revenues for 2006/07, reflecting the latest view of over and under-recoveries ("K factors") and other price control adjustments; and
-
- the companies have provided current forecasts of income in respect of excluded services, for the final year of the current price control and for each year of the next price control period 2007-12.
-

1.14. The first of these adjustments updates the 2006/07 allowance which is used as the basis for the year-on-year comparison. The second adjustment is necessary to allows us to present the base price control revenue allowance (excluding revenue from excluded services) for both 2006/07 and the next price control period.

1.15. Our calculations to derive the base price control allowances for 2006/07 are set out in lines 1 to 4. The second stage of our adjustments involve deducting the present value total of projected excluded service revenues (line11) from the present value total of allowed costs (line 8) to derive the total present value of net allowed items (line 12). Revenues are then calculated, under the assumption of RPI+2, such that the present value total of profiled base price control revenues (line 15) equates the present value of the net allowed items.

NGET

All prices are £m in 2004/05 terms

	Licensee = NGET TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		5,415.6	5,634.2	5,761.3	5,931.6	6,187.4
2	Total capital expenditure		601.3	524.9	581.1	655.6	677.9
3	Depreciation		-382.7	-397.8	-410.9	-399.8	-416.1
4	Closing asset value		5,634.2	5,761.3	5,931.6	6,187.4	6,449.2
5	Present value of opening/closing RAV		5,415.6				5,041.1
6	5 year movement in PV of RAV						374.5
	Allowed items						
7	Operating costs (excluding pensions)		266.0	259.7	254.3	254.0	254.9
8	Capital expenditure		601.3	524.9	581.1	655.6	677.9
9	Pensions allowance		38.5	37.8	37.4	37.3	36.9
10	Tax allowance		101.1	105.6	110.4	110.2	108.1
11	Total of allowed items		1,006.9	928.1	983.2	1,057.1	1,077.7
12	Present value of allowed items		982.4	861.9	869.3	889.7	863.4
13	5 year movement in PV of RAV						374.5
14	Total present value over 5 years						4,841.3
	Revenue						
15	Revenue index		1.000	1.020	1.040	1.061	1.082
16	Discounted revenue index		0.976	0.947	0.920	0.893	0.867
17	**Base price control revenue**	**924.9**	**985.5**	**1,005.2**	**1,025.3**	**1,045.8**	**1,066.7**
18	Excluded service revenue	58.2	58.4	64.3	71.9	75.8	76.1
19	Total TO revenues	983.1	1,043.9	1,069.5	1,097.2	1,121.6	1,142.8
20	Present value of total revenue		1,018.5	993.3	970.0	943.9	915.6
21	Total present value over 5 years						4,841.3
22	IFI revenue forecast		3.9	4.0	4.1	4.2	4.3
23	Price control extension reconciliation		0.7	0.0	0.0	0.0	0.0
24	Total price control revenue		1,048.5	1,073.5	1,101.3	1,125.8	1,147.1

Supplementary tables: Revenue reconciliation

	Licensee = NGET TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	2006/07 Revenue reconciliation						
1	Revenue published in Updated Proposals	1004.6					
2	Revised company forecast	983.1					
3	Excluded services	58.2					
4	Base Price control revenue (2006/07)	924.9					
	Adjustments to Base Price Control Revenue						
5	Total of allowed items		1,006.9	928.1	983.2	1,057.1	1,077.7
6	Present value of allowed items		982.4	861.9	869.3	889.7	863.4
7	5 year movement in PV of RAV						374.5
8	Total present value over 5 years						4,841.3
9	Excluded Service revenues		58.4	64.3	71.9	75.8	76.1
10	Present value of exclude service revenue		57.0	59.7	63.6	63.8	61.0
11	Total Present value over 5 years						305.0
12	Total Present value of net allowed items						4,536.3
13	**Base price control revenue**		**985.5**	**1,005.2**	**1,025.3**	**1,045.8**	**1,066.7**
14	Present value of Base PC revenue		961.5	933.6	906.5	880.2	854.6
15	Total present value of base PC revenue						4,536.3

SHETL

All prices are £m in 2004/05 terms

	Licensee = SHETL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		288.3	320.2	337.9	351.0	367.3
2	Total capital expenditure		48.5	35.3	31.5	35.4	30.1
3	Depreciation		-16.7	-17.7	-18.4	-19.1	-19.8
4	Closing asset value		320.2	337.9	351.0	367.3	377.6
5	Present value of opening/closing RAV		288.3				295.2
6	5 year movement in PV of RAV						-6.9
	Allowed items						
7	Operating costs (excluding pensions)		9.1	9.2	9.3	9.4	9.5
8	Capital expenditure		48.5	35.3	31.5	35.4	30.1
9	Pensions allowance		0.7	0.8	0.8	0.8	0.8
10	Tax allowance		5.4	5.0	4.8	4.5	4.4
11	Total of allowed items		63.8	50.3	46.4	50.0	44.8
12	Present value of allowed items		62.2	46.7	41.1	42.1	35.9
13	5 year movement in PV of RAV						-6.9
14	Total present value over 5 years						221.1
	Revenue						
15	Revenue index		1.000	1.020	1.040	1.061	1.082
16	Discounted revenue index		0.976	0.947	0.920	0.893	0.867
17	Price control revenue	49.5	47.0	48.0	48.9	49.9	50.9
18	Excluded service revenue		0.5	1.0	1.2	1.3	1.3
19	Total revenue		47.5	49.0	50.1	51.2	52.2
20	Present value of total revenue		46.4	45.5	44.3	43.1	41.8
21	Total present value over 5 years						221.1
21	IFI revenue forecast		0.5	0.5	0.5	0.5	0.5
22	Capex roller incentive		0.4	0.2	-0.1	0.0	0.0
23	Total price control revenue		48.4	49.7	50.5	51.7	52.7

Supplementary tables: Revenue reconciliation

	Licensee = SHETL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	2006/07 Revenue reconciliation						
1	Revenue published in Updated Proposals	50.8					
2	Revised company forecast	49.7					
3	Excluded services	0.2					
4	Base Price control revenue (2006/07)	49.5					
	Adjustments to Base Price Control Revenue						
5	Total of allowed items		63.8	50.3	46.4	50.0	44.8
6	Present value of allowed items		62.2	46.7	41.1	42.1	35.9
7	5 year movement in PV of RAV						-6.9
8	Total present value over 5 years						221.1
9	Excluded Service revenues		0.5	1.0	1.2	1.3	1.3
10	Present value of exclude service revenue		0.5	1.0	1.1	1.1	1.0
11	Total Present value over 5 years						4.6
12	Total Present value of net allowed items						216.5
13	**Base price control revenue**		**47.0**	**48.0**	**48.9**	**49.9**	**50.9**
14	Present value of Base PC revenue		45.9	44.5	43.3	42.0	40.8
15	Total present value of base PC revenue						216.5

SPTL

All prices are £m in 2004/05 terms

	Licensee = SPTL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		764.2	825.2	864.5	900.5	985.4
2	Total capital expenditure		124.3	105.7	105.0	148.7	123.9
3	Depreciation		-63.3	-66.4	-69.1	-63.8	-70.5
4	Closing asset value		825.2	864.5	900.5	985.4	1,038.8
5	Present value of opening/closing RAV		764.2				812.0
6	5 year movement in PV of RAV						-47.7
	Allowed items						
7	Operating costs (excluding pensions)		28.6	28.2	28.8	28.9	28.9
8	Capital expenditure		124.3	105.7	105.0	148.7	123.9
9	Pensions allowance		0.5	0.5	0.5	0.5	0.5
10	Tax allowance		17.5	16.9	16.8	15.7	15.1
11	Total of allowed items		170.9	151.3	151.2	193.7	168.2
12	Present value of allowed items		166.7	140.5	133.7	163.0	134.8
13	5 year movement in PV of RAV						-47.7
14	Total present value over 5 years						691.0
	Revenue						
15	Revenue index		1.000	1.020	1.040	1.061	1.082
16	Discounted revenue index		0.976	0.947	0.920	0.893	0.867
17	Price control revenue	155.0	147.3	150.3	153.3	156.4	159.5
18	Excluded service revenue		0.9	1.7	3.4	3.4	5.5
19	Total revenue		148.2	152.0	156.7	159.8	165.0
20	Present value of total revenue		144.6	141.2	138.5	134.5	132.2
21	Total present value over 5 years						691.0
21	IFI revenue forecast		0.6	0.6	0.6	0.6	0.6
22	Capex roller incentive		0.0	0.0	0.0	0.0	0.0
23	Total price control revenue		148.8	152.6	157.3	160.4	165.6

Supplementary tables: Revenue reconciliation

	Licensee = SPTL	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	2006/07 Revenue reconciliation						
1	Revenue published in Updated Proposals	159.6					
2	Revised company forecast	156.3					
3	Excluded services	1.3					
4	Base Price control revenue (2006/07)	155.0					
	Adjustments to Base Price Control Revenue						
5	Total of allowed items		170.9	151.3	151.2	193.7	168.2
6	Present value of allowed items		166.7	140.5	133.7	163.0	134.8
7	5 year movement in PV of RAV						-47.7
8	Total present value over 5 years						691.0
9	Excluded Service revenues		0.9	1.7	3.4	3.4	5.5
10	Present value of exclude service revenue		0.9	1.6	3.0	2.9	4.4
11	Total Present value over 5 years						12.7
12	Total Present value of net allowed items						678.2
13	**Base price control revenue**		**147.3**	**150.3**	**153.3**	**156.4**	**159.5**
14	Present value of Base PC revenue		143.8	139.6	135.5	131.6	127.8
15	Total present value of base PC revenue						678.2

NGG

All prices are £m in 2004/05 terms

	Licensee = NGGT TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		2,981.5	3,353.4	3,458.9	3,404.4	3,338.2
2	Total capital expenditure		470.3	212.8	56.0	44.2	41.0
3	Depreciation		-98.3	-107.3	-110.6	-110.4	-109.9
4	Closing asset value		3,353.4	3,458.9	3,404.4	3,338.2	3,269.3
5	Present value of opening/closing RAV		2,981.5				2,555.5
6	5 year movement in PV of RAV						426.0
	Allowed items						
7	Operating costs (excluding pensions)		138.4	136.9	137.5	136.6	138.3
8	Capital expenditure		470.3	212.8	56.0	44.2	41.0
9	Pensions allowance		41.4	41.1	40.3	40.2	39.9
10	Tax allowance		38.9	33.8	36.3	41.6	45.8
11	Total of allowed items		688.9	424.6	270.2	262.6	265.1
12	Present value of allowed items		672.1	394.3	238.9	221.0	212.4
13	5 year movement in PV of RAV						426.0
14	Total present value over 5 years						2,164.7
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.976	0.929	0.884	0.842	0.801
17	Price control revenue	416.4	487.2	487.2	487.2	487.2	487.2
18	Excluded services revenue		1.3	1.2	1.2	1.3	1.3
19	Total revenue		488.5	488.4	488.4	488.5	488.5
20	Present value of PC revenue		476.7	453.6	431.8	411.2	391.4
21	Total present value over 5 years						2,164.7
22	IFI revenue (0.4% of line 18)		1.9	1.9	1.9	1.9	1.9
23	Total price control revenue		490.5	490.4	490.4	490.5	490.5

Supplementary tables: Revenue reconciliation

	Licensee = NGGT TO	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	2006/07 Revenue reconciliation						
1	Revenue published in Updated Proposals	442					
2	Revised company forecast	419					
3	Excluded services	2.9					
4	Base Price control revenue (2006/07)	416.1					
	Adjustments to Base Price Control Revenue						
5	Total of allowed items		672.1	394.3	238.9	221.0	212.4
6	Present value of allowed items		0.0	0.0	0.0	0.0	426.0
7	5 year movement in PV of RAV						2,164.7
8	Total present value over 5 years						0.0
9	Excluded Service revenues		488.5	488.4	488.4	488.5	488.5
10	Present value of exclude service revenue		476.7	453.6	431.8	411.2	391.4
11	Total Present value over 5 years						2,164.7
12	Total Present value of net allowed items						-2,164.7
13	**Base price control revenue**		**487.2**	**487.2**	**487.2**	**487.2**	**487.2**
14	Present value of Base PC revenue		475.4	452.5	430.8	410.1	390.4
15	Total present value of base PC revenue						2,159.1

Appendix 2 - RAV Roll Forward and Capital Expenditure Incentive Mechanisms

Introduction

1.1. We recognise the importance of predictability in regulation and that the success of the incentive framework depends, to a significant extent, on network companies and their investors having confidence in how these arrangements will be applied. This appendix sets out key assumptions and principles underlying this review and explains how we expect to use these assumptions and principles as the basis for assessing 2007-12 costs and performance at the next price control review and beyond.

1.2. In conducting price reviews, we have discretion over the way in which price limits are set and we look to develop the regulatory framework in the light of all relevant developments. There can be no assurance that future reviews will be conducted in the same manner as this one. In particular, nothing in this appendix is intended to provide any guidance about how costs arising after 1 April 2012 will be treated in future reviews.

1.3. We do not intend to alter the treatment of costs and incentives in relation to the period 2007-12 from that set out here unless the proposed formulation is shown to contain errors or be inconsistent with the Authority's statutory duties. We will however take due account of the disadvantages of changing approach mid period. It is also possible that unforeseen new issues will arise during the price control period that are not provided for in the methods set out in this appendix, in which case we will consult on the appropriate way forward.

1.4. Should any licensee reject these Final Proposals, the approach set out here may no longer apply, depending on the outcome of the Competition Commission reference.

RAV calculation 2007-12

Introduction

1.5. The regulatory asset value (RAV) is a key building block of the price control review. It can be seen as a measure of the capital employed in the regulated business, based on past investment, on which the companies earn a return and receive depreciation.

1.6. In developing these proposals, we have needed to form a view on the categories and proportions of costs that should be included in the RAV of each licensee (treated as capital expenditure). Such decisions are important as they determine what costs are remunerated over a period of time that exceeds the expected duration of these price controls.

1.7. In order to roll forward the RAV from April 2007 to March 2012, expenditure that the transmission companies incur in this period should be treated in the same way as in developing the proposals – that is, the same categories of costs added to the RAV. This should simply be a matter of adding actual capital investment and adjusting for depreciation and inflation. However, companies have different ways of accounting for past capital expenditure (investment) and in many cases these will vary over time – for example changing the amount or proportion of overheads allocated to capital expenditure.

1.8. We propose to make appropriate adjustments to the costs incurred by the transmission companies to ensure that, in rolling forward the RAV, costs are included on the same basis as when the price controls were set. For example, if companies increase the proportion of operating costs that are capitalised, we will adjust costs to reflect the proportion of such costs capitalised in setting the price controls.

Key definitions

1.9. To perform the RAV roll forward calculations for the TO function, it is necessary to define four categories of costs:

- TO net operational capital expenditure;
- TO operating costs;
- TO pensions costs; and
- Other costs.

1.10. These categories are intended to be mutually exclusive. They do not include interest or tax costs (except for business rates). The categories refer to costs directly incurred by the licensee or a related party of the licensee on their behalf and not to the level of any recharges between the licensee and a related party. We reserve the option to disallow costs from any of these categories if they do not relate to the transmission business or are demonstrably inefficient or wasteful.

TO net operational capex

1.11. TO net operational capex is defined as the sum of:

- operational capital expenditure (including, without limitation, such expenditure in relation to health and safety, environmental issues or a diversion of an existing line) incurred by the Licensee in performing its functions as TO;
- costs treated as quasi-capital expenditure - that is certain items of expenditure (e.g. removal costs, major replacement or refurbishment of line fitting or circuit breakers) not capitalised for accounting purposes which, because they improve the operating capacity of the system, are treated as capital expenditure for regulatory purposes with explicit agreement from Ofgem; and

- a company specific proportion of “indirect” costs applied on a consistent basis;

less

- customer contributions;
- cash proceeds (or market value for intra-group transfers) from the disposal of operational assets; and
- costs logged up by agreement.

1.12. TO net operational capex should be reported excluding all pension costs, all depreciation, related party margins unless specified below, costs in relation to pass-through items (including business rates and Ofgem licence fees), fines and penalties incurred by the transmission company, costs falling within IFI, the SF6 incentive, de minimis costs, and other excluded services costs.

1.13. TO net operational capex should also be reported on a cash basis. We will therefore make adjustments for any provisions and accruals to ensure costs are on this basis (subject to not creating boundary problems between different price control periods).

TO operating costs

1.14. TO operating costs is defined as:

- direct operating expenditure incurred by the licensee in performing its TO function, including without limitation insurance costs and the deduction of insurance claim receipts;
- non-operational capital expenditure that is treated as operating expenditure; and
- a company specific proportion of “indirect” costs applied on a consistent basis;

less

- cash proceeds (or market value for intra-group transfers) from the disposal of non-operational assets (e.g. the sale of personal vehicles);
- costs treated as quasi-capital expenditure; and
- costs logged up by agreement.

1.15. TO operating costs should be reported excluding all pension costs, all depreciation, profits from related party margins, costs in relation to pass-through items (including business rates and Ofgem licence fees), fines and penalties incurred by the transmission company, costs falling within IFI, de minimis costs, and other excluded services costs.

1.16. TO operating costs should also be reported on a cash basis. We will therefore make adjustments for any provisions and accruals to ensure costs are on this basis (subject to not creating boundary problems between different price control periods).

1.17. For the purposes of rolling forward the RAV, non operational capital expenditure comprises expenditure on assets that do not form part of the live transmission system, including:

- non system operation IT;
- vehicles;
- plant and machinery;
- small tools and equipment; and
- land and buildings.

1.18. Non operational capex is treated as operating costs for regulatory purposes.

1.19. For regulatory purposes, quasi capital expenditure (quasi-capex) comprises items of operating costs that Ofgem has agreed with National Grid that may treat as capital expenditure for regulatory purposes. At present these include:

- circuit breaker refurbishment;
- tower foundation and steelwork;
- decommissioning of cables, overhead lines, substations and gas compressors; and
- asbestos removal from substations.

1.20. Ofgem may agree further items of quasi capex subject to consideration of the following factors:

- broad consistency with relevant accounting standards and conventions;
- substitutability with other opex or capex items; and
- the incentives for efficiency on such expenditure.

1.21. No other items may be treated as quasi capex without Ofgem's explicit agreement.

TO Pension costs

1.22. In considering actual pension contributions, the relevant amounts will be actual cash contributions attributable to the distribution business and paid into the relevant pension scheme. Where relevant, this will include statutory contributions to the Pension Protection Fund.

1.23. We anticipate that the companies' actual pension contributions will differ from those projected as part of the price control in response to changing circumstances. Since the projected RAV includes a proportion of actual pension contributions in the period 2007-12, it will be important to ensure that where future revenues are affected by any over- or under-funding relative to the allowance our adjustments do not double-count this impact.

1.24. It is important that pension allowances and contributions will be removed from capital expenditure prior to any consideration of rolling incentive arrangements.

Other costs

1.25. Other costs include all other items excluded from the above definitions.

Other Definitions

1.26. Costs can only be included to the extent they represent the cost of services required by the TO function of the transmission business – i.e. if not provided by the group, including any related party, the licensee would need to procure these services separately.

1.27. For both opex and capex, any costs restated will be applied in the year in which the cost was incurred rather than the year of the restatement.

1.28. It is important that in rolling forward the RAV, costs have been capitalised on a consistent basis, including the efficient level of direct and indirect costs. For this purpose, indirect costs are defined as all costs that are not defined as direct labour, direct materials and direct contractors (external) below:

- Direct labour is defined as that part of the transmission company's own workforce and that of a material related party service provider that can clearly identify which system assets and/or operational premises their effort is being expended upon, evidenced by time sheets / time writing that records the amount of time spent;

- Direct materials are defined as materials drawn from supplies for specific system assets or operational premises that are supported by stores issue notes and all materials are delivered directly to site; and

- Direct contractors (external) are defined as the charges invoiced by contractors (external) for work on specific system assets and/or operational premises and can include elements of labour, materials etc.

1.29. Related party profit margins will be excluded from the definitions above unless the related party concerned earns at least 75 per cent of its turnover from sources other than related parties and charges to the licensed entity are consistent with charges to external customers. For this purpose, an entity will be considered to be a related party if it is in the same group as the transmission company (be it a holding company, affiliate, subsidiary, associate, joint venture) or if that entity and the transmission company have any other form of common ownership.

RAV roll forward calculations

1.30. The categories of costs which will be included within the RAV are:

- 100 per cent of baseline net operational capital expenditure;
- incremental net operational capital expenditure triggered by the automatic revenue drivers;
- a consistent proportion of capitalised operating costs and pensions to those reflected in setting the price controls, excluding non-operational capex that we assume is fully expensed; and
- no part of other costs or taxes (including VAT).

1.31. The value of these costs will typically enter the RAV in the year that they are incurred, subject to meeting our efficiency tests. As such, when resetting the price controls to apply from 1 April 2012 the opening RAV at that date will reflect the depreciated value of the costs incurred during the period and previous periods.

1.32. Costs will also be subject to the fixed capital expenditure incentive mechanism unless otherwise agreed. This will include incremental expenditure triggered under the electricity revenue drivers. We propose that the incentive mechanism is applied as an adjustment to revenues sufficient to ensure that the company receives the relevant proportion of costs or benefits of its actions (see paragraph 1.40 below).

1.33. The present exceptions to the capital expenditure incentive include those specified cost items that are subject to logging-up and an additional £75 million of expenditure identified by NGG in relation to Milford Haven that has not been reflected in the allowances, and capital expenditure under the Transmission Investment for Renewable Generation (TIRG) scheme.

1.34. To provide greater confidence, we intend to publish updated RAV information on an annual basis. This will set out our provisional view of the RAV based upon the information obtained under the new regulatory reporting regime. Nevertheless, we intend to continue to undertake a detailed efficiency review of expenditure at the end of the review period which may highlight the need for further adjustments.

Future efficiency assessment

1.35. In rolling forward the RAV from April 2007 to March 2012, expenditure incurred by the companies should be treated in the same way as it has been in developing our proposals. As a consequence, we will take into account changes in accounting treatment, such as changes in capitalisation rates, and make adjustments where appropriate. It will also be necessary to make appropriate adjustments in respect of pensions funding to ensure that any subsequent revenue adjustment in relation to the over and under funding mechanism will not be double counted. We reserve the option to disallow costs from entering the RAV if they are demonstrably inefficient or unnecessary.

1.36. The effectiveness of the proposed package of incentives will depend on transmission companies and their investors having confidence in how costs will be treated in the future. We therefore need to provide clarity as to how we will calculate the RAV and implement the incentive schemes at the next review. Our default starting point is that all capital expenditure will be included in the RAV, with the exception of expenditure which is judged to be demonstrably inefficient or unnecessary.

1.37. However, in the case of the transmission licensees, due to the lumpy and multi-year nature of transmission investments, in the absence of the evidence provided by user commitments in respect of load related expenditure, as well as the lack of comparative tools and output measures, we will place a significant emphasis on our ex-post efficiency review of costs and volumes to determine efficient and economic spend. Where expenditure has been incurred to provide assets that are not required for the duration of the next price control period or where unit costs are considered excessive, we are likely to view such investment as inefficient or unnecessary.

1.38. A key consideration for us in forming a view at future price control reviews on the efficiency of load related capex will be the extent to which the investment decisions were based on strong evidence of long term demand for capacity from network users (backed by financial commitment). The absence of such user commitment evidence at St Fergus in the current price control period was the main factor in our decision only to include part of the investment undertaken by NGG NTS in the RAV (see chapter 6). In contrast, investment based on strong evidence of long term user commitment has a clear, unambiguous case for inclusion in the RAV subject only to a test that the cost of the required volume of investment is reasonable.

1.39. The information (or lack of it) on the long term demand for capacity from network users is generated through the arrangements by which network users buy capacity. To the extent that these arrangements do not generate clear, unambiguous signals, then licensees will be relying on more subjective justification for investment and will face a greater risk of future disallowance. In this light, we believe that the licensees have a clear interest in taking steps to ensure that the access arrangements do generate high quality, robust information based on long term user commitments. In electricity, we believe that significant improvements can be made in this regard which would reduce the risk of disallowance of investment at future price control reviews. While we are aware of current developments in this area, we are yet to form a view on the merits of the proposals under development.

Capital expenditure incentive

1.40. These Final Proposals provide for a fixed strength incentive mechanism to apply to capital expenditure (RAV additions excluding pension costs). This provides a consistent incentive for efficiency in relation to capital expenditure throughout the price control period.

1.41. The incentive mechanism applies to RAV additions whether above or below the level of the allowance. It should be noted that for all three electricity transmission licensees, we are proposing that the allowance to which the capex incentive applies is the allowance as adjusted for capex differences implied by the load related revenue drivers (discussed in chapter 9 and set out in more detail in appendix 7). In the case of incremental gas transmission expenditure, we propose that actual expenditure incurred will enter the RAV five years after the UCA has been triggered in relation to the delivery of that incremental capacity.

1.42. As with other incentive mechanisms in these Final Proposals, the resultant revenues for the period after 2012 are intended to be on a pre-tax basis (i.e. it is not intended that they give rise to further revenues in respect of the tax charge on the revenues). The starting point for the calculation of this incentive scheme is the traditional incentive regime, which has been modified in the manner discussed in chapter 7.

1.43. Using a pre-tax cost of capital of 6.25 per cent and an asset life of 40 years, an unmodified five year retention would imply that in relation to baseline capital expenditure the transmission company would keep (bear) 36 per cent of the present value of any capex under/over spend. Since the incentive mechanism requires that the incentive rate is 25 per cent, then it is necessary to adjust revenues downwards (upwards) by the equivalent of 11 per cent of the present value of the under/over spend, to bring the net retention share back to 25 per cent. We intend to codify these adjustments within the transmission licences.

1.44. The capex incentive adjustment calculation will be undertaken at the end of the price control period. The first step will be to calculate, for each year of the price control, the difference between our allowances for capital expenditure, and what the licensee actually spent. We then express these differences in present value terms (with the present being the year in which we do the calculation) and add them up. This gives a total net under-spend or over-spend for the period in present value terms. We then apply the incentive rate (25 per cent in our final proposals). This determines the amount of penalty or benefit that the licensee will face. We determine this amount usually in the first formula year after the price control period ends.

1.45. However, in rolling forward the RAV we need to take account of the fact that during the period we have been providing the licensees with a fixed revenue allowance based on depreciation and return of the assumed baseline capex allowance, rather than their actual capex. If the licensee has spent less than its allowance, then it will in effect have received depreciation and return on expenditure it has not undertaken. Conversely, if the licensee has spent more than its allowance, then it will have received insufficient funding to cover depreciation and return on the capex it has incurred. The adjustment to revenues at the end of the period will be net of the effect of rolling forward the RAV in line with actual capex.

1.46. At the end of this process there will remain a capital sum equal to the licensee's actual capex over the period less the cumulative depreciation on that actual capex. This capital sum, subject to any further adjustments (e.g. following a review of the efficiency of the investment undertaken) can then roll forward as part of the RAV.

1.47. For electricity transmission companies, the RAV additions for the purpose of this comparison will include adjustments to allowances for differences between the generation and demand background assumed in setting the baseline capex allowances and the generation and demand background that occurs in practice. More detail on how this will impact on the calculation of the capex incentive revenue adjustment is provided in appendix 7.

Mechanism for logging-up costs

1.48. In chapters 3 to 6 we have specified certain costs that some or all the licensees may "log up" for remuneration at the next price control, subject to an ex-post efficiency review. In all cases only costs incurred after 1 April 2007 are eligible for logging-up. The costs that may be logged up are:

- Costs of mitigating the effects of BT's 21st Century Networks (see paragraphs 7.24-7.27);
- Costs of claims for loss of development of land against NGG NTS (see paragraphs 7.28-7.30);
- The costs of wind generation connections (see chapters 4 and 5); and
- The costs of underground cable tunnels (see chapter 3).

1.49. The basic process for logging-up costs will begin with the licensees recording eligible costs in their annual Regulatory Reporting Pack submissions over 2007-12. Efficient logged up expenditure will be considered up to the value of the current cost projections and remunerated as a revenue adjustment at the beginning of the next price control.

1.50. In respect of the capitalised elements of these costs, and subject to these costs passing our efficiency assessment, we propose that they should be included within the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of logging-up. Similarly, we propose that the expensed element of these costs should be recovered during the next price control period, including an adjustment for financing costs incurred during the period of logging-up.

Tax

1.51. We propose to claw back the tax benefits of gearing in excess of that assumed in the cost of capital calculation. This will only apply where both of the following conditions apply in a given year:

- actual interest payable exceeds interest charges in the price control financial model, for the year ending 31 March; and
- regulatory gearing (net debt to RAV) on 31 March exceeds 60 per cent

1.52. Where these conditions apply, we would expect to claw back at the next price control review the tax benefits gained from the difference in interest charges. If only one or none of these conditions applied over the price control period, no adjustment would be made in respect of that year.

Equity Issuance

1.53. To assess if there is a need for equity we analyse the impact of our proposals, incorporating a range of capital expenditure scenarios, in order to assess whether these can be expected to allow the licensees to be able to maintain appropriate credit ratings. For these purposes, our approach to financial modelling has been to model costs in nominal terms, consistent with the approach adopted by the rating agencies.

1.54. Where our assessment indicates that the financial ratios for a licensee show a deteriorating trend such that in the final year of the forthcoming price control this would result in a credit rating of BBB / Baa2 or lower, we will assume that new equity is raised earlier in the period to stabilise the ratios at a level consistent with a rating comfortably within investment grade. The hurdle level necessary to trigger this has been determined after consultation with the rating agencies.

1.55. The difficulty in setting an ex ante allowance is the uncertainty over the level of investment which may be funded through revenue drivers. To allow for this uncertainty, the ex ante allowance will fund the cost of the new equity necessary to fund baseline capital expenditure, TIRG expenditure, and half of the additional investment that a company might incur (as estimated in its FBPQ submission). We will then “true up” the allowance at the next review to reflect actual investment (whether higher or lower) and the equity required to finance it.

1.56. In cases where equity is required, our assessment of the amount will follow the steps set out below:

- Step 1 – Model is run with debt providing any necessary finance.
- Step 2 – The financial ratios are examined to see if, in our opinion, they would not support an appropriate level of rating. This would occur if the ratios indicated a deteriorating trend such that in the final year of the price control at least two of the three main financial ratios (i.e. Debt/RAV, FFO/Debt, FFO+Interest/Interest) are materially below the level indicated by the agencies as needed to support a BBB+/Baa1 or higher rating (i.e. they are below the hurdle level) or whenever the Debt/RAV exceeds the hurdle rate.
- Step 3 – If the ratios will not support the desired rating then initially the equity needed to return the licensee to the minimum level (i.e. the hurdle) is assumed to be input in the final year of the price control.
- Step 4 – This equity is then re-profiled over the price control to minimise any deterioration in the financial ratios and an allowance of 5 per cent of this figure to cover the expected direct issuance costs is provided.

- Step 5 –At the following price control review the forecast levels and timing for capital expenditure driven by TIRG and Revenue Drivers are replaced by the outturn levels and the model rerun through steps 1 to 4 above. This will give a "corrected" level of equity issuance and the extent of adjustment (if any) needed to the ex ante allowance made in the previous price control. Any required adjustment will be made by varying revenue allowances under the new control.

- Step 6 – Any ex post assessment of tax arising from "excess gearing" is mitigated to the extent this was needed to avoid an equity injection.

1.57. The following tables are provided purely to illustrates the approach set out in nominal terms:

Ratios before Equity	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Net debt / closing RAV	60%	63%	65%	75%	84%	88%
FFO/Net Debt	15%	11%	10%	8%	6%	5%
(FFO+interest)/Net Interest payable	3.77	3.16	2.86	2.84	2.39	1.93
New Equity (£m Nominal)				**£110m**	**£80m**	
Ratios after Equity	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Net debt / Closing RAV	60%	63%	65%	53%	58%	67%
FFO/Net Debt	15%	12%	11%	11%	10%	8%
(FFO+interest)/Net Interest payable	3.77	3.25	2.94	2.92	3.35	2.72

1.58. The "Ratios before Equity", which are before any new equity, indicate a deteriorating trend such that in our view from 2009/10 the licensee would breach the hurdle levels for a sustainable investment credit rating. Consequently equity is introduced under the test outlined in the preceding paragraph; equity would be required to be introduced before the end of the price control period.

1.59. The result is an expectation in the financial model that some £190m of equity would be needed (equivalent to £165m in 2004/05 prices) and as such an allowance for equity issuance costs of some £8.3 million (in 2004/05 prices) would be made.

Appendix 3 – 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.[18]

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[19].

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[20]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[21]

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:

[18] entitled "Gas Supply" and "Electricity Supply" respectively.
[19] 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.
[20] 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.
[21] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[22] 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[23] 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.

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

Appendix 4 - Glossary

B

Baseline

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

Baseline Capital Expenditure

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

British Electricity Trading and Transmission Arrangements (BETTA)

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

Buy Back

The process of compensating users if NGG NTS are unable to deliver entry capacity, which is sold on a financially firm basis.

C

Capital Expenditure (Capex)

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

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 Deficiency 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.

European Union Emissions Trading Scheme (EU ETS)

The EU ETS is a market based mechanism for the reduction of carbon emissions. It is a cap and trade scheme designed to reduce the level of emissions at an EU wide level through the trading of emissions permits.

F

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.

Great Britain System Operator (GBSO)

See SO.

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.

Innovation Funding Initiative (IFI)

A mechanism to remunerate research & development expenditure by DNOs.

K

K-factors

Correction factors to account for the under or over-recovery of revenues between years of the price control.

L

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.

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

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

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.

Q

Quarterly System Entry Capacity (QSEC)

A period of time for which NGG NTS entry capacity can be purchased. Entry capacity is sold forward via Quarterly System Entry Capacity Auctions which offer capacity at each aggregate system entry point.

R

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.

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.

S

Safety net

A mechanism that would trigger a review of allowances in the event of a major shortfall of investment relative to allowances.

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.

Sulphur Hexafluoride (SF6)

A potent greenhouse gas frequently used in electrical equipment.

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

Total Cost Allowance (TCA)

Is the Unit Cost Allowance multiplied by the number of units.

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

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.

Vanilla Weighted Average Cost of Capital (Vanilla WACC)

The weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity.

W

Weighted Average Cost of Capital (WACC)

The weighted average of the expected cost of equity and the expected cost of debt.

Appendix 5 - Feedback Questionnaire

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

1. Does the report adequately reflect your views? If not, why not?
2. Does the report offer a clear explanation as to why not all the views offered had been taken forward?
3. Did the report offer a clear explanation and justification for the decision? If not, how could this information have been better presented?
4. Do you have any comments about the overall tone and content of the report?
5. Was the report easy to read and understand, could it have been better written?
6. Please add any further comments?

1.2. Please send your comments to:

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