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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 contains the supplementary appendices for the Transmission Price Control Review Final Proposals. The supplementary appendices provide more detailed information regarding some of the issues raised in the main document.

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Context

This document contains the supplementary appendices for the Transmission Price Control Review Final Proposals which sets new price controls for the electricity and gas transmission licensees' for the five years beginning 1st April 2007.

Associated Documents

- TPCR 2007-2012 Final Proposals, December 2006 (Ref no. 206/06)
- 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 consultant's reports and responses to the Ofgem consultation documents can also be found on the Ofgem website (www.ofgem.gov.uk).

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Appendix 6 – Pension Allowance

Treatment of pension fund costs

1.1. In setting price controls we make an allowance for the efficient level of costs we expect companies to incur over the period of the price control, including costs companies incur to fund their pension schemes.

1.2. Chapter 8 sets out the allowances that have been made for pension costs based on currently available data. We anticipate that actual contributions may differ from those projected. Therefore the ongoing contributions for employees in both defined benefit schemes and defined contribution schemes that are attributable to the transmission business (including related party employees working on transmission) plus the total deficit contribution for defined benefit schemes is likely to differ from the pension allowance.

1.3. The basis on which allowances have been proposed at this review means that the extent to which pension contributions differ from the pension allowances will be offset against actual future pension costs in determining future pension allowances. Any such adjustments would be net of tax, to the extent that the over or under payment has reduced or increased tax payable.

1.4. In considering actual pension contributions, the relevant amounts will be actual cash contributions attributable to the transmission business and paid into the relevant pension scheme. Where relevant this will also include statutory contributions to the Pension Protection Fund that would be incurred by an investment grade rated employer.

1.5. We intend that the treatment of pension costs at future reviews would be in accordance with the principles set out in previous consultation papers. For example any Early Retirement Deficiency Contributions (ERDCs) that are incurred after 1st April 2004 will be wholly for the account of shareholders. This can be achieved by reducing the amount of actual contributions by the amount of any ERDC's before considering over or under funding.

1.6. The following table sets out the year by year opex and capex allowances for Transmission in real prices against which actual contributions (net of any adjustment for ERDCs) will be compared.

Table A6.1 Annual Pension Allowance (Transmission Owner only)

TO	Final (2004/2005) Prices			
Annual ongoing allowance Opex	NGET	NGG NTS	SPT	SHETL
2007/2008	£10.3 m	£14.5 m	£0.5 m	£0.7 m
2008/2009	£10.4 m	£14.9 m	£0.5 m	£0.8 m
2009/2010	£10.6 m	£14.8 m	£0.5 m	£0.8 m
2010/2011	£11.2 m	£15.3 m	£0.5 m	£0.8 m
2011/2012	£11.4 m	£15.6 m	£0.5 m	£0.8 m
Annual ongoing allowance Capex	NGET	NGG NTS	SPT	SHETL
2007/2008	£3.4 m		£0.8 m	£0.8 m
2008/2009	£3.4 m		£0.8 m	£0.8 m
2009/2010	£3.5 m		£0.8 m	£0.9 m
2010/2011	£3.7 m		£0.8 m	£0.8 m
2011/2012	£3.8 m		£0.8 m	£0.8 m
Annual Deficit Allowance Opex	NGET	NGG NTS	SPT	SHETL
2007/2008	£28.1 m	£26.8 m		
2008/2009	£27.4 m	£26.1 m		
2009/2010	£26.7 m	£25.4 m		
2010/2011	£26.0 m	£24.7 m		
2011/2012	£25.3 m	£24.1 m		
Annual Deficit Allowance Capex	NGET	NGG NTS	SPT	SHETL
2007/2008	£9.3 m			
2008/2009	£9.0 m			
2009/2010	£8.8 m			
2010/2011	£8.6 m			
2011/2012	£8.4 m			

Appendix 7 – Electricity Revenue Drivers

Introduction

1.1. This appendix describes in more detail the mechanics of our revenue driver proposals for NGET, SPTL and SHETL.

1.2. As discussed in chapter 9 of the main document we are proposing two different mechanisms for adjusting the revenues of the licensees to the extent that the assumptions on profiles of generation and demand underpinning our baseline capex allowances turn out to be different in practice:

- first, by providing for adjustments in revenue allowances on a dynamic basis within the period from 1 April 2007 to 31 March 2012 for SPTL and SHETL, if the rate at which new generation seeks connection to their transmission networks is more rapid than we have assumed; and
- second, by using a capex allowance adjusted for revenue drivers for the application of the capex incentive (see also appendix 2).

1.3. These two issues are described in turn below. We will also be consulting further on the necessary draft legal text and any other appropriate documentation to give effect to these adjustment mechanisms in January 2007.

SPTL and SHETL Revenue drivers

1.4. The automatic revenue adjustments for SPTL and SHETL will be calculated using the concept of a revenue driver Regulatory Asset Value ("RD-RAV"). The RD-RAV is a deemed capital sum from which we will derive a revenue allowance.

1.5. The opening value of the RD-RAV on 1 April 2007 will be zero for SPTL and for SHETL. It will only be added to after the point at which the baseline volume of new generation has been connected. The baseline volume of generation for SPTL is 1,734 MW and for SHETL is 1,489 MW. The reference point is the amount of generation connected as at 1 April 2005.

1.6. Once the baseline volume of generation has been connected, then additions to the RD-RAV can occur in one of two ways in relation to local connection costs:

- where the licensee has committed for a particular new generation project at least 25 per cent of the total local infrastructure costs they estimate incurring by completion, then 75 per cent of actual costs incurred will be added to the RD-RAV each year (adjusted for financing costs given the lag in time between the costs entering the RD-RAV and the costs being incurred); and

- where the local works for a relevant generation project are completed, then a final addition to the RD-RAV will be made in the following year, equal to 25 per cent of the Unit Cost Allowance (UCA) multiplied by the relevant volume of MW. The UCA for SPTL is £52/kW and for SHETL is £32/kW.

1.7. The revenue allowance for SPTL and SHETL derived from the RD-RAV will be consistent with depreciation over a 20 year period and a pre-tax real rate of return of 6.25 per cent. It will also include an allowance for operating and maintenance costs of 1 per cent of the total gross (i.e. before depreciation) RD-RAV value.

1.8. For the one possible project in each licensee's area that spans the baseline volume of generation, then additions to the revenue driver RAV will be pro-rated on the basis of the proportion of the MW of that particular project that are in excess of the baseline volume.

1.9. The revenue allowance for SPTL and SHETL excludes allowances for very high cost schemes. They are defined as schemes for which the relevant costs are greater than £130/kW for SHETL and greater than £163/kW for SPTL. The licensee will be limited to earning no more than a reasonable rate of return on very high cost schemes.

1.10. At the end of the period, it would be Ofgem's intention to roll the closing value of the RD-RAV into the main RAV. Our approach is set out in appendix 2.

1.11. Chapter 9 also sets out our proposals for revenue drivers for deep reinforcement projects - which will be triggered when a specified cumulative amount of generation is signalled or connected in specified geographical areas. To the extent that these conditions are met, the process for accumulating additions to the RD-RAV will in essence be the same. If the specified conditions are met on the basis of the relevant amount of generation being sufficiently advanced in their development such that the licensee is committed for at least 25 per cent of the total estimate local connection costs, then 75 per cent of actual costs incurred will be added to the RD-RAV each year. And once the specified amount of generation has connected in the specified area, then a final addition will be made equal to 25 per cent of the Total Cost Allowance (TCA) - which is a £m amount rather than a £ per MW amount.

1.12. The table below sets out the four specific deep reinforcement revenue drivers we are putting in place for 1 April 2007 for SHETL. The associated map is provided in Map A7.1 at the end of this appendix.

Table A7.1: SHETL Deep reinforcement revenue drivers:

Total contracted generation of:	Total Cost Allowance
1850MW or more north of North West boundary	£52m
300MW or more north of North of Beauly boundary	£47m
85MW or more south of Port Ann within the South West zone	£89m
105MW north of Inveraray within the South West zone	£52m

1.13. As noted in chapter 9 we recognise the potential need to amend the costs allowed for under these deep reinforcement revenue drivers, and the potential need to add new revenue drivers. We are proposing the following process for cost revisions of the revenue drivers listed in Table A7.1 above:

- The licensee may apply to the Authority to vary the Total Cost Allowance specified in its licensee when planning consent for the relevant works (in the view of the licensee) have been applied for and obtained;
- The Authority may consult on this proposal, and may request additional information to be provided by the licensee to demonstrate the efficiency of its proposed investment; and
- The Authority in the light of this information may consult on a modification to the relevant licence condition to give effect to an amended value for the Total Cost Allowance.

1.14. This process will also be followed for addition revenue drivers that the licensees might wish to propose for inclusion in the licence. This would include, for example, changes to the specified conditions for the revenue drivers listed in Table A7.1 above. In respect of SPTL, while we have not included any such revenue drivers for 1 April 2007 because at this stage we viewed the conditions and associated costs as too uncertain (and therefore subject to change). We do however recognise the potential need to consider revenue drivers to address the following circumstances:

- **Additional generation connecting:**
- south of Penwherry
- north west of Gretna
- east or south west of Glenlee:

- **Boundary transfers:**
- Greater than 132MW on 132kV circuit between Gretna and Harker;
- Greater than 620MW on circuit between Kilmarnock South and Coylton.

Capex incentive: Load related adjustments to allowances

1.15. The capex incentives described in appendix 2 sets out how we propose to adjust allowed revenues at the next price control to ensure that the licensees are exposed to 25 per cent of the difference between actual and allowed capex. The allowed capex for the purpose of this comparison needs to 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. This section explains how the revenue drivers will impact on the capex incentive adjustment.

1.16. If we did not make an allowance for revenue drivers, then any observed difference between actual and allowed capex might simply reflect the baseline generation and demand profile being wrong - which is essentially outside the control of the licensees. By making these adjustments to the capex allowance we are therefore making the capex incentive more focused.

1.17. The introduction of revenue drivers adds a level of complexity to the capex incentive calculation, but the structure of the calculation remains broadly the same. The main difference is that the capex allowance is not known with certainty at the start of the price control period - but rather is a function of things that might happen during the price control. However, at the end of the period when the revenue adjustment is calculated, the capex allowance is known with certainty - because we know what actual data to apply to the revenue driver rules.

1.18. The following example illustrates this. The baseline capex allowance is £100m each year and there is a revenue driver of £1million per MW of connected generation (relative to a baseline volume). We will assume for illustrative purposes that the actual volume of connected generation turns out to be the same as baseline in the every year other than the fourth year, when an extra 10 MW is connected. This is set out in the table below, together with an illustrative line for actual capex.

Table A7.1: Capex incentive (with revenue drivers) example

	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Allowances						
Baseline capex allowance	100	100	100	100	100	
Revenue driver capex allowance	0	0	0	100	0	
Actual expenditure						
Actual capex	120	100	100	190	100	
Difference	-20	0	0	10	0	
Return	6.25%					
PV Difference	-27.1	0.0	0.0	11.3	0.0	
Total PV underspend						-15.8
Incentive Rate	25%					
Gross adjustment	11.8					
Incentive award	-3.9					

1.19. In this example the licensee over-spends relative to allowances in 2007/08 and under-spends relative to (adjusted for revenue drivers) allowances in 2010/11. The present value sum of these two items is £15.8million. The gross adjustment is therefore to increase revenues by £11.8 million - which leaves 25 per cent (£3.9million) of overspend with the licensee.

1.20. From this position we also need to reconcile to ensure that depreciation and return is provided for actual expenditure, as opposed to the baseline capex allowance. In this example, we would have to allow depreciation and return on an extra £20million incurred in 2007/08 and an extra £90million incurred in 2010/11. This is effectively part of rolling forward the RAV.

1.21. At the end of the price control period there will be some work in progress which in the fullness of time would have delivered outputs that, in turn, would have been recognised under the revenue driver. In rolling forward the RAV we will seek to treat these costs in a manner consistent with the application of a 25% incentive rate.

The Calculation of the Revenue Drivers for SPTL, SHETL and NGET

1.22. This section sets out the detail on how the revenue driven adjustment to the capex allowance is to be calculated. The mechanisms will be formalised in the licences. We will publish our next round of consultation on draft legal text in January.

SPTL and SHETL

1.23. For SPTL and SHETL, the adjustment to the capex allowance for differences between baseline and actual generation connections is relatively straightforward.

- If the baseline volume of new generation is not connected by the end of the period, then we will scale back the baseline allowance in line with the unit cost for the baseline. This is £54/kW for SPTL and £24/kW for SHETL. For example, if SPTL connects 100 MW less than the baseline amount (of 1,734 MW) then we will scale back the capex allowance by £5.4m. We will assume that this lower capex allowance is distributed evenly across the five year period. We will also carefully consider the need to scale back allowances for any wider infrastructure investments predicated on the baseline volume of generation being connected. This is likely to be a more material issue if the shortfall in connected generation is significant.

- If more than the baseline volume of generation is connected, then we will add to the baseline capex allowance by an amount equal (a) to the volume of connected generation above the baseline multiplied by the revenue driver unit cost. (This is £32/kW for SHETL and £52/kW for SPTL) and (b) the £m revenue driver for any deeper reinforcement projects that have been triggered and completed. The profile of these additional allowances will be set to reflect the profile of actual costs.

NGET

1.24. The revenue driver parameters are more complicated for NGET, but the process is essentially the same. We calculate an adjustment based on the difference between the actual and assumed volume of the relevant revenue driver variable and multiply it by the relevant revenue driver value. The complication for NGET arises from the larger number of revenue driver variables.

1.25. As discussed in chapter 9, there are 10 zones with a maximum of three revenue driver variables for each zone. The zone boundaries are set out in Map A7.2 at the end of this appendix. There is also a variable for increases in transfer capability across the Scotland to England boundary. We will calculate the difference between the actual values of the variables in each year, and the value assumed in setting the baseline. We will then multiply these differences by the relevant UCA - subject to the obvious constraint that the scaling back of the capex allowance should only affect capex that could have been avoided in the period, and not capex incurred prior to the start of the price control period.

1.26. The baseline values for generation and demand underpinning the zonal entry, surplus and deficit baseline values are set out in Tables A7.2 and A7.3 below.

Table A7.2: Baseline generation profile for NGET

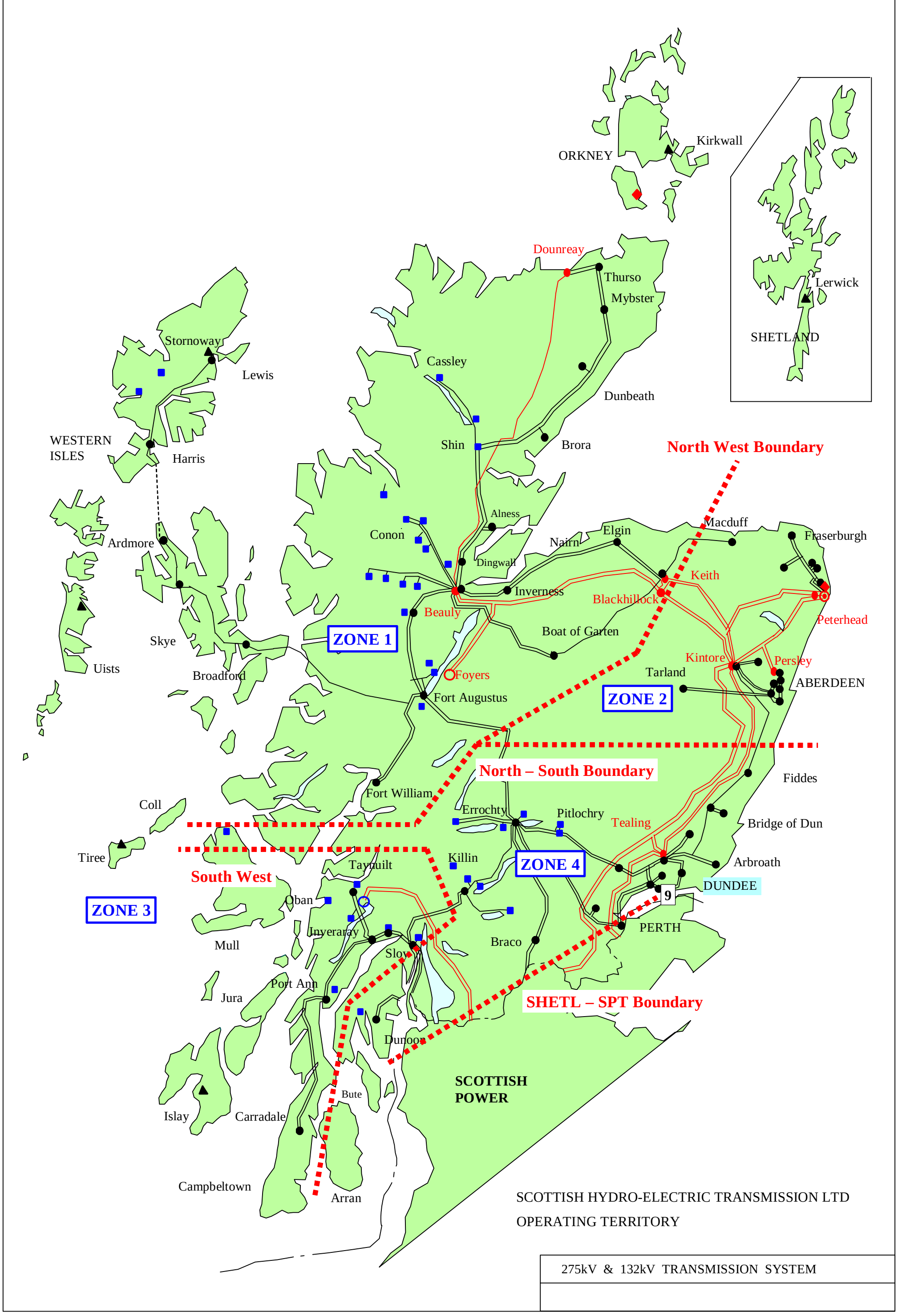
	Formula year starting 1 April								
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
South & SW	2609	2609	3459	3459	3859	3859	3859	3859	3859
Thames Estuary	8991	8341	8314	8514	9954	9078	9078	8397	8397
London	4159	4159	4159	4159	4159	4159	4159	4159	4159
South Wales	4421	4421	3951	3951	3951	3951	3951	3951	5951
East & Home Counties	7805	7805	7309	7309	7309	7309	7309	7309	5721
West Midlands	4231	4231	4231	4231	4231	4231	4481	4747	4747
East Midlands	5252	5252	5252	5252	5252	5252	5252	7032	7032
North West & N Wales	10564	10616	10658	10658	9678	9928	10428	10678	10678
Yorks & Lincs	13499	13499	13499	13499	13799	14039	12058	12058	12058
North East	3475	3475	3475	3475	3475	3475	3475	3475	3475

Table A7.3: Baseline demand profile for NGET

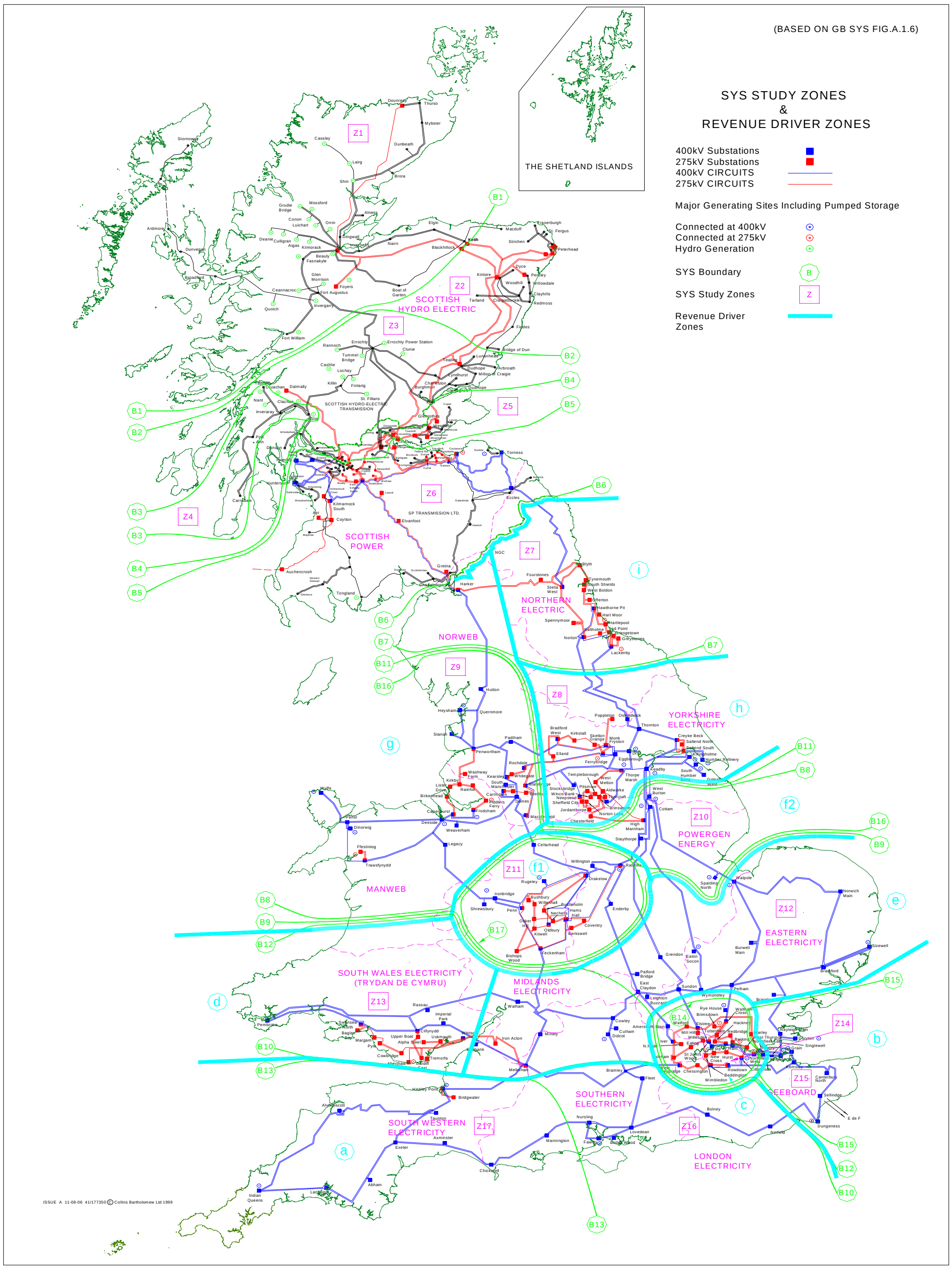
	Formula year starting 1 April								
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
South & SW	7263	7344	7438	7504	7546	7589	7648	7706	7773
Thames Estuary	2753	2813	2876	2930	2972	3016	3065	3114	3167
London	10267	10409	10568	10689	10773	10871	10986	11102	11226
South Wales	2310	2326	2309	2323	2329	2337	2347	2355	2362
East & Home Counties	8508	8514	8623	8698	8717	8771	8839	8908	8967
West Midlands	7639	7697	7767	7811	7827	7855	7897	7936	7982
East Midlands	521	527	538	544	549	549	553	557	550
North West & N Wales	8198	8243	8273	8231	8203	8213	8235	8260	8273
Yorks & Lincs	5820	5827	5844	5841	5819	5803	5795	5787	5786
North East	2993	2996	2970	2970	2960	2950	2944	2939	2933

Map A7.1: SHETL network boundaries

Figure 1 - MAP of Main Network Zones and Boundaries



Map A7.2: NGET Revenue Driver zones



Appendix 8 – Gas Entry Modelling

1.1. This appendix describes in more detail the technical basis on which we have set gas entry capacity for:

- baseline capacity release obligations, and
- revenue drivers

Our modelling request

1.2. A discussion of the modelling request we made to NGG NTS was included in the Updated Proposals; this is briefly summarised below. NGG NTS was asked to model the capability of the network using a 'least helpful supply substitution' approach for the formula year 2008/09 with the demand side set at the 1 in 20 peak day demand level. This analysis was carried out under the three supply scenarios identified in NGG NTS's most recent Ten Year Statement (TYS).[1]

1.3. The same least helpful supply substitution approach was used when NGG NTS was asked to provide estimates of the costs of additional incremental capacity at these (and certain potential new) entry points.

NGG NTS's modelling output

1.4. We received most of the results for the Transit UK scenario in March (except for some potential new entry points) and these were summarised in the 3rd Consultation Document. NGG NTS provided results for remaining potential new entry points under the Transit UK scenario in April, for the Global LNG scenario in May, and for the Auctions+ scenario in June. For a number of entry points (including constrained LNG points) NGG NTS had not yet provided results by June for any of the three supply scenarios. We received final data for these entry points for all three supply scenarios from NGG NTS in November.

1.5. In summary, this modelling work therefore produced three sets of data on network capability and network reinforcement costs (with the latter including four observations on incremental revenues for different increment sizes), for both existing and potential new entry points, namely for:

- 2008/09, 1 in 20 demand, Transit UK supply scenario, supply substitution;
- 2008/09, 1 in 20 demand, Global LNG supply scenario, supply substitution; and
- 2008/09, 1 in 20 demand, Auctions+ supply scenario, supply substitution.

[1] National Grid (December 2005), Gas Transportation Ten Year Statement 2005.

1.6. NGG NTS made somewhat different modelling assumptions than we anticipated. We sought an external view on this particular issue in the context of our quality assurance (QA) work, and have made some adjustments to the numbers derived from our analysis. As a result, we consider that the data we have are sufficiently robust to define our baseline and revenue driver proposals.

Our subsequent adjustments (using NGG NTS's modelling output)

Baselines

1.7. Owing largely to the difference in interpretation of the modelling instructions between NGG NTS and Ofgem, the analysis provided by NGG NTS did not fully account for some of the zonal constraints on the network (i.e. network constraints that are common to several entry points). We have therefore undertaken some additional analysis to take into account zonal constraints.

1.8. In order to do this we have taken the results of the nodal analysis discussed above and for each scenario calculated the maximum 'free increment[2]' in each zone[3]. We identified the maximum 'free increment' in each zone by taking the maximum nodal 'free increment' in that zone, as estimated by NGG NTS, as a proxy for the maximum zonal 'free increment'.

1.9. The maximum 'zonal' free increment was then divided between each node in the zone in such a way that each node received at least the amount of capacity which had already been sold by NGG NTS in respect of that zone. Any remaining 'zonal' free increment was then allocated in proportion to a measure of the 'size' of the entry point in question. The size of the entry point was proxied by the peak terminal supply associated with that entry point in NGG NTS's most recent TYS and using additional data on certain storage points which are included in the TYS only as an aggregated total. Where no such data was available, the current baseline was used as a proxy.

1.10. We then used an arithmetic average of the results from the three supply scenarios to calculate our proposed baselines.

1.11. In subsequent discussions with NGG NTS, issues were identified at a small number of entry points where this analysis still did not take adequate account of the zonal constraints on the network. We analysed these issues relative to the existing baselines, and made a small number of adjustments. In some instances these increased the proposed baselines while in other instances they led to a reduction in the proposed baselines (relative to the position we had adopted prior to the discussions with NGG NTS).

[2] The 'free increment' is the additional capacity that NGG NTS estimated could be released at system peak at each entry point considered in isolation, given various constraints we specified in our modelling request.
[3] The zones we used were the same as those in NGG NTS's (now withdrawn) Network Code modification 118.

Revenue Drivers

1.12. The revenue drivers seek to characterise an estimate of the costs that NGG NTS might need to incur if it has to provide additional capacity at a particular entry point. These costs vary by entry point and by the size of the increment being provided. We have allowed for both of these sources of difference in our proposals.

1.13. We estimated the revenue drivers using the same NGG NTS modelling output as used in setting the baselines. We also had regard to the interaction between our proposals for capacity transfer and the revenue drivers. To illustrate, we concluded that it was reasonable to assume, to an order of approximation, that the circumstances in which NGG NTS needs to build extra capacity (i.e. when the revenue drivers apply) are the circumstances in which capacity would, if possible, have been transferred to that entry point. Hence, the scenario in which the sum of baseflow[4] and allocated zonal free increment is at a maximum for the relevant entry point is more likely to represent the prevailing circumstances when the revenue driver is activated. In practical terms this means that we chose (from the three supply scenarios in the TYS) the network reinforcement cost estimates corresponding to the scenario with the maximum baseflow plus free increment. Where there was no obvious higher maximum baseflow plus 'free increment', we chose the maximum of the three cost functions to determine our revenue drivers.

1.14. On the basis of evidence on the costs of network projects we revised the unit costs for 1,200mm and 900mm pipelines that NGG NTS had assumed[5] in the source data for gas entry revenue drivers they provided to us. For all other types of network reinforcement projects we adopted the same unit cost assumptions as NGG NTS had assumed in the source data (adjusted for arithmetic errors). We adopted unit costs that are lower than the unit costs used by NGG NTS in its cost forecasts. This approach ensured that we applied consistent unit cost assumptions for the baseline gas capex allowance and for the gas entry (and offtake) revenue drivers.

[4] The 'baseflow' is the capacity that NGG NTS estimated could be released within a 'balanced network' where supplies across entry points are equal to 1 in 20 demand, prior to estimating the 'free increment' (ie the additional capacity that could be released at each entry point considered in isolation over and above 'baseflow').
[5] NGG NTS's pipeline unit cost assumptions in the source data for gas entry revenue drivers provided to us were based on the "Transcost" pipeline cost formula contained in its Incremental Entry Capacity Release (IECR) Methodology Statement.

Appendix 9 – Offtake Revenue Drivers and Baselines for NGG NTS

Introduction

Overview

1.1. This appendix outlines our Final Proposals on the incentive framework for NGG NTS as gas transmission licensee over the next TPCR period with respect to the offtake of gas from the National Transmission System (NTS).

1.2. As part of the sale of four of the gas distribution networks (GDNs), we implemented incentives on NGG NTS for the period to 30 September 2008 (the "interim" period). Offtake arrangements are now also in place for the period from 1 October 2008 to 30 September 2010 (the "transitional" period). However incentives on NGG NTS have not yet been determined for this period.

1.3. We continue to propose that enduring offtake reform, underpinned by user commitments, should take effect from 1 October 2007 and apply to the allocation of NTS offtake rights to NTS users from 1 October 2010 onwards given investment lead times of around 3 years (the "enduring" period). User commitment is a key element across the proposed price control framework. We consider that the introduction of user commitment models where capacity requests are backed by financial commitments to capacity for users should increase investment certainty for NGG NTS reduce the risk of stranded assets.

1.4. This appendix therefore outlines our Final Proposals for the incentive framework for NGG NTS for both the transitional and enduring offtake arrangements.

1.5. A summary of respondents' views on our Updated Proposals is provided in appendix 11.

The transitional regime

Introduction

1.6. In this section we consider the incentive arrangements that will apply to NGG NTS in the transitional offtake period.

1.7. As stated in our Initial Proposals Consultation, we believe that, as a general principle, the transitional incentives should represent a continuation of the interim incentives already specified for the period May 2005 to October 2008. However, we have considered:

- whether the existing interim NTS incentives are appropriate for the transitional period; and
- whether there are any elements of the proposed enduring incentives framework that it would be appropriate to bring forward into the transitional period.

1.8. This section of the appendix sets out our Final Proposals on the appropriate price control design in the context of gas transmission offtake during the transitional period, and is structured under the following headings:

- Baselines;
- revenue drivers; and
- transitional incentives.

Baselines

1.9. Our Final Proposals for baselines in the transitional period are consistent with the Proposals that we set out in our Initial Proposals and our Updated Proposals.

1.10. As noted in the our Initial Proposals, in the absence of a full user commitment model, NGG NTS will not have an obligation to offer baseline capacity levels for sale in the transitional period. However, we continue to believe that it is necessary to set baselines for the transitional period to act as delineation between the funding of the existing NTS asset base and the remuneration of incremental investment.

1.11. Proposed baseline numbers were provided in our Updated Proposals. We have made some minor amendments to these numbers for our Final Proposals to correct for rounding errors. These numbers constitute our Final Proposals for transitional baselines, and have been included in Annex 1.

1.12. Our final proposal is that baselines should not be specified for interruptible capacity (so that additional revenues are clearly linked to the provision of additional firm capacity) and should be at the same level (i.e. practical maximum physical capacity) and on a nodal basis as under the enduring regime[6].

1.13. We continue to consider that it would not be appropriate to specify separate baselines for the GDN flexibility product in this period as flexibility requirements are not expected to trigger investment within the transitional period and flexibility is not acknowledged as a separate product within the framework applicable to Transmission Connected Customers (TCCs).

[6] We explain why our proposed model includes nodal baselines that represent practical maximum physical capacity in the context of the enduring regime in the next section.

Revenue drivers

1.14. Consistent with our views outlined in the Initial Proposals, and following consideration of respondents' views, our Final Proposals are that:

- revenue drivers for the transitional period will be specified as part of the TPCR;
- incremental revenue will be contingent upon delivery of capacity; and
- the same basis for remunerating incremental investment should be applied throughout the next price control period.

1.15. We are proposing revenue drivers triggered upon the date that NGG NTS has contracted to deliver that capacity across both the transitional and enduring periods.

1.16. Whilst the transitional arrangements already require user commitments through the ARCA process, they do not represent a full user commitment model for non-specific, load related reinforcement. As such, in the transitional regime, it will be necessary for incremental revenue to be triggered absent of an explicit user commitment / ARCA in some circumstances in order to recognise non-specific, load related reinforcement consistent with NGG NTS's assessment of its 1 in 20 obligation. Given the absence of a full user commitment model, we consider it appropriate for Ofgem to have some oversight of the case for such investments before they are remunerated through the application of revenue drivers. Therefore, our Final proposal is that a licence obligation should be placed on NGG NTS to submit to the Authority, for approval, an annual report (once for each year of the transitional period) outlining:

- all incremental investments proposed or underway absent of an explicit user commitment;
- all incremental investments delivered absent of an explicit user commitment; and
- the rationale for such investments.

1.17. It is noted that following an assessment of capacity requests from DNs submitted earlier in the year, NGG NTS has approached Ofgem requesting that revenue driver funding be triggered for the delivery of load related investments in the south west.

1.18. NGG NTS has indicated that 5.29 GWh/day of incremental capacity has been requested in the south west for the gas year 2008/9 and 5.63 GWh/day has been requested for the gas year 2009/10[7]. As a result, NGG NTS considers that these requests necessitate investment in the south west area, namely the Wormington to Sapperton and Sapperton to Eastern Grey pipelines. Following discussions with NGG NTS, Ofgem has concluded it is minded to grant its consent to the triggering of the south west revenue driver (discussed further below) to recognise the need for load

[7] These represent year on year capacity increases. For example, the increase of 5.29 GWh/day for 2008/9 is calculated against the incremental capacity figures for 2007/8. Further, the incremental capacity figures for 2007/8 are measured against the baseline figures as proposed from 1 April 2007.

related pipeline investment in the south west area from the gas year 2008/9. We therefore propose that a formal consent to the south west revenue driver being triggered is issued following implementation of the proposed TPCR licence provisions scheduled for 1 April 2007.

1.19. It is noted that incremental capacity requests have also been made in the south west and south of England for 2007/8. NGG NTS is proposing to meet these requests through the use of Constrained LNG (CLNG). As such, the provision of incremental capacity for 2007/8 is not funded through the revenue driver for the south west, which is intended to remunerate investment projects only.

1.20. Our Final Proposals for appropriate revenue drivers throughout the forthcoming price control period are outlined later in this appendix.

Transitional incentives

1.21. In the Initial Proposals Consultation, we indicated that it would be appropriate to simplify the incentives that apply to NGG NTS for the transitional period relative to those that currently apply within the interim offtake period which ends on 30 September 2008.

1.22. The following incentive schemes were defined for NGG NTS in relation to transmission offtake for the interim period:

- charges foregone and exit investment incentive;
- constrained LNG incentive; and
- buy back and greater than fifteen day interruptions incentive.

1.23. Each of these incentive schemes is considered in turn below in relation to its proposed applicability during the transitional period.

Charges foregone and exit investment incentive

1.24. In the Initial Proposals Consultation we proposed that the charges foregone and exit investment incentive should not continue for the transitional period. This is a sliding scale incentive scheme, with the target determined as the aggregate of a target for charges foregone (i.e. the deemed cost of procuring interruption from customers through the "interruptible discount") and a target for incremental investment costs. The effect of this incentive is to reward NGG NTS for releasing additional exit capacity in response to demand and to reward it for efficiently managing the costs of interruption at NTS offtake points.

1.25. We note that the revenue driver framework proposed negates the need for an exit investment incentive. Furthermore, we note that the concept of charges foregone will not exist within the enduring period and that the current incentive is currently subject to quite restrictive caps and collars of £1m. As such, following the consideration of respondents' views and consistent with our position in the Initial

Proposals Consultation, our final proposal is that the charges foregone and exit investment incentive should not apply during the next price control period.

Constrained LNG incentive

1.26. In our Initial Proposals Consultation, we proposed that the CLNG incentive that currently applies to NGG NTS should be retained in its current form with the incentive target value updated. This incentive is intended to ensure that NGG NTS uses LNG facilities efficiently when managing network constraints. Due to NGG NTS's ownership of constrained LNG storage facilities (through National Grid LNG), the scheme is separate from the exit investment scheme with no caps and collars and 100 per cent sharing factors. This structure eliminates the scope for distorting behaviour between the regulated gas transmission business and the LNG businesses that are wholly owned by NG.

Table A9.1: NGG's performance to date under the CLNG incentive

	2002/03	2003/04	2004/05	2005/06	2006/07
CLNG incentive target	£5.9m	£6.2m	£6.6m	£6.6m	£6.6m
Actual performance	£6.6m	£2.3m	£1.2m	£1.8m	£3.1m*
Retained benefit	£-0.7m	£3.9m	£5.4m	£4.8m	£3.5m

*Forecast expenditure.

1.27. Table A9.1 shows NGG NTS's performance to date under the CLNG incentive.

1.28. Targets for this incentive have already been specified for the remainder of the interim period, these being £2.6million for 2007/08 and £2.1million for 2008/09[8]. As such, for our Final Proposals targets need to be set for 2009/10, 2010/11 and 2011/12.

1.29. Our Final Proposals are to retain the constrained LNG incentive in its current form with 100 per cent sharing factors and no cap or collar for the remainder of the next price control.

1.30. In our Updated Proposals, we outlined a range of potential CLNG incentive targets, in accordance with a high, medium and low case. In discussions relating to the setting of the targets, NGG NTS has contended that it has CLNG requirements both in the south west and south east of England. In the scenarios we assumed that:

- CLNG in the south west is managed through the Avonmouth LNG facility; and

[8] National Grid Transco - Potential sale of gas distribution businesses. Final Proposals for interim incentives and formal consultation under Section 23 of the Gas Act 1986, Ofgem, April 129/05, page 43.

- CLNG in the south east is managed through a combination of the Transmission Services Agreement (TSA) that National Grid holds with BP and Sonatrach at Isle of Grain and through contracting for services from the Humbly Grove facility.

1.31. The high and medium case scenarios both assumed that there is a south east and south west CLNG requirement. The distinguishing feature between these scenarios was that the high case scenario assumed that NGG NTS requires funding each year to hold space in the Humbly Grove facility which is funded by reference to prevailing gas prices.

1.32. Furthermore, both the high and medium case scenarios also assumed that NGG NTS is given no ex ante allowances for purchasing gas in the south east for the 1 in 20 winter peak day on which constrained LNG services are required. Instead the scenarios assumed that to the extent that NGG NTS purchases gas for use on the peak day, it can keep the proceeds from the revenues of selling any surplus gas.

1.33. Following the consideration of respondents' views and further information provided by NGG NTS regarding services at Humbly Grove, we have determined that a variation of the medium case represents the most appropriate way forward. We remain unconvinced that NGG NTS should receive funding for each year for the cost of holding space in the Humbly Grove facility based on prevailing prices. As such, we have developed a variation to the medium case which assumes that NGG NTS's entire south east CLNG requirement is funded on the basis of the terms of the TSA contract.

1.34. We also remain of the view that it is inappropriate to provide NGG NTS with ex ante funding for the costs of purchasing gas for use on a 1 in 20 peak day. Instead we consider that this funding can be achieved by NGG NTS setting up a CLNG manager account. Under these arrangements, to the extent that NGG NTS uses CLNG on a peak day it would be "cashed out" under this account and therefore receive proceeds for the gas it has used for CLNG. The creation of such an account would be likely to require changes to the Uniform Network Code (UNC). We consider that the creation of such an account would have better regulation benefits to the extent that it avoids the need for Ofgem to set ex ante gas purchase cost allowances for NGG NTS's usage of CLNG.

1.35. The proposed CLNG incentive targets for the period 2009/10-2011/12 are outlined in Table A9.2 below. As noted above, targets for the interim period have already been specified.

Table A9.2: Targets for CLNG incentive

	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Target	£2.6m*	£2.1m*	£4.3m	£3.6m	£2.9m

*Targets for 2007/08 and 2008/09 have already been specified.

Buy back and greater than fifteen day interruptions incentive

1.36. A buy back and greater than 15 day interruptions incentive currently applies to NGG NTS. This is a sliding scale incentive (with a cap and collar) that establishes a target for the costs of interrupting sites greater than 15 days each year and a target for buy back costs. Under current arrangements, additional rebates are given to those sites that are interrupted for greater than 15 days each year. If the costs of these rebates and any capacity buy backs undertaken by NGG NTS exceed the target that is set then NGG NTS bears a share of these costs.

1.37. In our Initial Proposals Consultation we proposed to continue with the greater than fifteen day interruptions incentive, given that the interruptions regime is likely to remain unchanged for the transitional period. We also proposed that no buy back related costs should be allowed as part of the price control settlement for the transitional period. We considered this was appropriate:

- given the degree of discretion NGG NTS has with regard to the delivery of incremental capacity in the transitional period, and
- on the basis that existing UNC arrangements give NGG NTS the right to reduce offtake capacity to NTS users for maintenance purposes without buying back rights

1.38. Our final proposal is that no buy back related costs should be allowed as part of the price control settlement for the transitional period. We would note that in the event of a significant event beyond NGG NTS's control that leads to buy-back liabilities under the UNC, the income adjusting event provisions could be applied.

1.39. It is our final proposal that the greater than 15 day incentive should be retained for the transitional period. Given that costs in recent years have been zero, it is our final proposal that the incentive target should be zero for 2009/10 and the first 6 months of formula year 2010/11 as shown in Table A9.3 below.

1.40. Our final proposal is that the current sharing factors should continue to apply to the fifteen day incentive, that an incentive cap is not necessary (given the imposition of a zero target) and that there should be an incentive collar of -£2million. The proposed parameters are outlined in Table A9.4 below.

1.41. It should be noted that parameters for the combined buy back and greater than 15 day incentive have already been specified up to and including 30 September 2008. In particular, the collar was set at -£7million. However, we consider it appropriate to change the collar for the rest of the price control period with respect to the greater than 15 day incentive. This is because the collars for the interim period were calculated in relation to NGG NTS's potential exposure under the buy back incentive, which would not apply for the rest of the price control period.

Table A9.3: Targets for the greater than 15 day interruption incentive

	2007/08	2008/09 until 30/09/08	2008/09 from 1/10/08	2009/10	2010/11**
Target	£1.73m*	£1.68m*	£0m	£0m	£0m

*Targets for 2007/08 and 2008/09 (until 30 September 2008) have already been specified.
** Applicable for the period 1 April 2010 to 30 September 2010 only.

Table A9.4: Parameters for the greater than 15 day interruption incentive

		Cap and collar		Sharing factors	
		Cap	**Collar**	**Upside**	**Downside**
Buy back and greater than 15 day interruption incentive	Applicable from 1 April 2007 to 30 September 2008	N/A	-£7m	75 per cent	50 per cent
Greater than 15 day interruption incentive	Applicable from 1 October 2008 to 30 September 2010	N/A	-£2m	75 per cent	50 per cent

The enduring regime

The importance of user commitment models

1.42. In our Initial Proposals Consultation we outlined the importance of a long term user commitment model for offtake and identified the key benefits of such a model. In particular, we identified how a user commitment model would work in practice. In principle, we considered this model would involve:

- all NTS users (both existing and new users) being required to indicate their future usage of the NTS to NGG NTS
- signals of future usage provided sufficiently far in advance to allow NGG NTS to make an informed assessment of the appropriate level of NTS investments that are required (consistent with the level of user commitment), and
- signals made by users - both new and existing - backed by an appropriate level of financial commitment

1.43. Among the key benefits identified, we noted that a user commitment model would improve investment signals and consequently reduce the risk of stranded assets emerging on the network, promote security of supply and increase the transparency of offtake arrangements. We continue to think that user commitments should underpin the development of the gas transmission network.

1.44. In our Initial Proposals Consultation, we also identified that a model with nodal baselines, a nodal product and an obligation on NGG NTS to substitute capacity between nodes to meet demand at other nodes would be most appropriate for further development.

Enduring offtake arrangements

1.45. As outlined in the September Update, NGG NTS has raised a UNC Modification Proposal to implement enduring offtake reform. This proposal is known as 0116V 'Reform of the NTS Offtake Arrangements' and is currently being consulted upon.[9] Four alternative UNC Modification Proposals have also been issued for parallel consultation:

- Modification Proposal 0116A, raised by E.on UK, which proposed the retention and extension of the transitional offtake arrangements;
- Modification Proposal 0116BV, raised by RWE Trading, which proposes certain amendments to the NGG NTS Proposals;
- Modification Proposal 0116CV, raised by British Gas Trading, which proposes certain further amendments to the NGG NTS Proposals; and
- Modification Proposal 0116VD, raised by Scotia Gas Networks, which proposes certain amendments to the NGG NTS Proposals.

1.46. NGG NTS has stated that its Modification Proposal was based on the following key assumptions:

- common NTS exit capacity services made available to all users to avoid scope for undue discrimination and to meet EU Gas Regulation requirements;
- "pay as bid" allocation mechanisms should be used where investment cannot be completed in time (or is unlikely to be efficient) to minimise the risk of undue discrimination in the allocation of constrained capacity;
- capacity products embracing the concept of "flexibility" utilisation should be implemented; and
- a user commitment model should be promoted requiring users to provide financially backed signals for capacity requirements to minimise the risk of investment inefficiencies and asset stranding

1.47. The proposal governs the release and allocation of two NTS exit capacity products, namely flat and flexibility capacity and is summarised at a very high level below.

Flat offtake rights

1.48. The main characteristics of NGG NTS's proposed modification in respect of flat capacity are:

[9] It is noted that NGG NTS originally raised modification proposal 0116. However, following a request from NGG NTS that the modification proposal be varied, it was subsequently withdrawn and replaced with modification proposal 0116V.

- a "prevailing rights" approach to capacity allocation where users wishing simply to maintain their existing or "prevailing" capacity holdings are required to provide a financial commitment for a specified number of years;
- where a user wishes to increase their prevailing holding, it would be required to provide a sustained commitment; and
- NGG NTS would have the ability to release unsold baseline capacity in the short term as well as any additional capacity it may elect to offer for sale on a discretionary basis. In addition NGG NTS would release a daily "use it or lose it" interruptible product and would have discretion regarding the release of any additional volumes of interruptible capacity at the day ahead stage.

Flexible offtake rights

1.49. The main characteristics of NGG NTS's proposed modification in respect of flexibility capacity are:

- NGG NTS has indicated that it would offer for sale a fixed amount of flexibility capacity as an annual product in long term pay-as-bid auctions up to 5 years in advance. All parties including GDNs and direct connects would therefore be able to access flex capacity in the long term through this auction process;
- in order to manage diversity of GDN requirements, NGG is proposing a zonal approach whereby bidders would bid for capacity at particular zones and flex would be allocated to those that valued it the most, subject to certain specified constraints in the form of 17 zonal maxima and 4 regional maxima; and
- day ahead and on the day, users may apply for flexibility capacity by submitting Offtake Profile Notifications (OPNs). However, if the availability of flexibility capacity is constrained, such capacity will be allocated through a "pay as bid" auction process

1.50. We note that consideration of Modification Proposal 0116V and its four alternatives is currently the subject of UNC consultation processes.

1.51. Before deciding on the Modification Proposals, it is our intention to conduct a further impact assessment on enduring offtake reform, focussing on the Proposals being consulted upon. It is also our intention to seek comments from industry participants on the results of this Impact Assessment prior to releasing decisions on the Modification Proposals. We have recently issued cost surveys to industry participants to inform the Impact Assessment, and responses are due by 11 December 2006. These cost surveys can be located on www.ofgem.gov.uk in the "transmission price control review" area of work.

1.52. In the sections below we set out the incentives that are proposed to apply to the enduring period. The introduction of these incentives is contingent upon the implementation of Modification Proposal 0116V or a similar alternative proposal based around 0116V. Nothing in this document can fetter the discretion of the Authority with regards to its decision in relation to these or any other modification Proposals. If Modification Proposal 0116A were to be implemented such that the transitional offtake arrangements were extended, we note that the transitional period incentives specified within this document would continue to apply throughout the next price control period.

Enduring incentives

Interaction of user commitment models with 1 in 20 obligation

1.53. In our Initial Proposals Consultation, we considered the interaction between a full user commitment framework and NGG NTS's 1 in 20 obligation.

1.54. It remains our view that, within a full user commitment framework, it would only be appropriate for additional NTS capacity to be provided if NTS users (including GDNs) have signalled that such capacity would be of value to them.

1.55. Our final proposal is therefore that NGG NTS would only be remunerated for incremental investment to the extent that there is an associated user commitment. We are still of the view that compliance with NGG NTS's 1 in 20 obligation could be achieved by investing in line with user commitments which signal peak aggregate daily demand. We consider that this would provide greater clarity of responsibility between NTS users and NGG NTS. In addition, causality for investment would be unambiguous with users being incentivised to provide long term investment signals.

1.56. The mechanisms proposed for remunerating incremental investment are discussed further below.

1.57. Consistent with the position outlined in our Initial Proposals Consultation, we consider it is neither necessary nor appropriate to modify Standard Special Condition A9 as it is not our intention to change the 1 in 20 obligation with which compliance is required.

1.58. As noted in the September Update, NGG NTS has previously raised concerns regarding its remuneration in situations where it was considered to be efficient to 'over-build' relative to the immediate demand for capacity as revealed in the long-term capacity allocation process. This might potentially be a relevant consideration if the cost of 'over-building' is very low as a by-product of the technical design identified by NGG NTS. In considering explicit revenue adjustments to accommodate such a situation we need to be mindful of the fact that NGG NTS can be rewarded for anticipating future demand for capacity through the operation of the proposed revenue drivers - and these incentives should be allowed to operate as intended.

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

Baseline derivation

1.60. Our final proposal is that baselines should be determined on a nodal basis and perform a dual function, in the enduring period, both as a high level separation between TO revenue allowances and remuneration of incremental capacity as well as defining obligations for capacity release upon NGG NTS. Consistent with our Proposals for the transitional regime, we are proposing that baselines should not be specified for interruptible capacity (so that additional revenues are clearly linked to the provision of additional firm capacity).

1.61. In the following section, we consider:

- the scope of the baselines determined, and
- the methodology that should be applied to determine the appropriate level of nodal baselines

Baseline scope and substitution obligations

1.62. As stated above, we still consider that NGG NTS should only be remunerated for incremental investment to the extent that there is an associated user commitment. As such, we propose that investments that do not have an associated user commitment should not be funded as part of the TO price control allowance. In practice this will mean that the baselines determined for the enduring period reflect capacity levels on 1 April 2007 and remain flat throughout the price control period.

1.63. We continue to propose a framework for the reallocation of baselines. We consider that this will ensure that NGG NTS maximises the use of spare capacity in its existing network before undertaking investment in additional capacity. Under such a framework, we envisage that:

- NGG NTS will be obliged, under the terms of its licence, to consult on and develop a transparent methodology for baseline revisions. This methodology would address processes associated with substitution and the upward revision of baselines to reflect developments at offtake and entry. The methodology would need to reflect NGG NTS's statutory and licence obligations with respect to efficient network development.
- In terms of substitution, NGG NTS would be required under the terms of its licence, to use all reasonable endeavours to identify the potential for the substitution of unsold NTS flat capacity baselines such that the level of NTS obligated incremental flat capacity is minimised;
- NGG NTS will be required to submit a report to Ofgem following each long term capacity allocation setting out how it proposed to substitute baseline capacity and seeking Ofgem's approval for any reallocation of baselines. Once approved the baselines will be changed with effect from the delivery date of the capacity bought in the long term allocation.

- NGG NTS will be required to publish a statement setting out revised baseline numbers, reflecting any revisions to the baselines that have been approved by Ofgem; and
- NGG NTS will also be required to submit to the Authority an annual statement explaining the basis upon which the licensee has reached the view that user demands cannot be satisfied in full by the substitution of baselines in order to demonstrate compliance with its obligations in this regard.

1.64. It is necessary to consider the interaction between gas exit and gas entry in determining appropriate revenue drivers and baselines. It is our final proposal that the substitution obligation placed upon NGG NTS should be extended to oblige NGG NTS to increase exit baselines in the event that exit capacity is generated as a result of entry investments undertaken and vice versa.

1.65. We have recently completed an initial consultation on the licence drafting associated with these Proposals. We expect to issue a further licence consultation on the Proposals in January 2007.

Baseline level

1.66. We remain of the view that a practical maximum physical capacity approach is appropriate to determine the level of nodal baselines as this, relative to other methodologies, best reflects the actual physical capability of the system and therefore recognises (at least on an approximate basis) that capacity in excess of baselines is likely to incur incremental investment costs that require funding, and capacity below such levels is not.

1.67. It is our final proposal that enduring period baseline numbers should be consistent with the nodal baselines specified for the transitional period (and provided in Annex 1), with adjustments to:

- reflect the proposed product definitions for the enduring period; and
- adjust upwards the nodal baselines for five sites in the constrained south west quadrant that have historically been interruptible.

1.68. We have therefore specified a baseline for all interruptible sites equivalent to their current allowance, as reflected by their System Offtake Quantities (SOQs), therefore accommodating all interruptible load on the network.

1.69. To reflect the fact that the baselines have been adjusted upwards, above the practical maximum physical level for these nodes, it is our final proposal to include an additional revenue allowance in the SO allowed revenue, which will aim to provide remuneration for efficiently incurred contracting costs at these five sites. We propose that this revenue allowance should be £3.4m p.a. for the enduring period. This allowance is based upon NGG NTS's estimates of the potential costs of providing firm capacity through the use of CLNG. These estimates have been adjusted consistent with the methodology applied to derive our Final Proposals for the CLNG incentive targets. Furthermore, we propose that 50 per cent sharing factors should be applied to the extent that NGG NTS deviates from the target determined.

1.70. We outline our Proposals for flat and flexibility capacity baselines for the enduring period in Annex 1. With respect to the flexibility product, we share the concerns raised by industry participants regarding the level of flexibility to be made available under the proposed enduring arrangements, including whether baselines truly reflect system capability. However, in view of the uncertainties associated with the management of flexibility in a post gas distribution network sales environment, we are continuing to propose a national capacity release obligation at 22 mcm/day (238 GWh/day) for each year of the enduring period in the next price control period.

1.71. In order to address concerns regarding availability of flexibility we remain of the view that NGG NTS should have financial incentives to release more flexibility when it is available. These incentives are discussed below. In addition, we intend to monitor the release of flexibility carefully in the light of the NGG NTS licence obligation to operate an economic, efficient and coordinated system.

Revenue drivers

1.72. We continue to consider that pre-specified revenue drivers are the appropriate basis for remunerating incremental capacity delivered above baseline levels, in order to:

- incentivise capital efficiencies on the part of NGG NTS;
- reduce the need for regulatory intervention during a price control period; and
- provide some remuneration of capital expenditure within the price control period.

1.73. It is our final proposal that revenue drivers should be contingent upon an appropriate user commitment and therefore that revenue drivers should apply to all load related capital expenditure in the next price control period. Furthermore, it is our proposal that revenue should accrue on the date on which NGG NTS has contracted to deliver capacity rather than on the physical date of delivery as:

- this is consistent with the approach adopted at entry; and
- it will incentivise NGG NTS to make efficient trade-offs and consider means of contractual delivery other than investment such as contracting solutions and the use of CLNG.

1.74. Therefore, to the extent that NGG NTS is unable to physically deliver against the rights it has sold; it would need to buy back this capacity from users from the contractual delivery date. Furthermore, it is our final proposal that the early delivery of capacity could be rewarded through the incentive proposed for the release of non-obligated capacity, which is discussed further below.

1.75. In determining revenue drivers, we have aimed to strike an appropriate balance between precision and simplicity. It is our final proposal that it is appropriate to:

- specify zonal revenue drivers for small capacity increments required as a result of general demand growth on the assumption that cost variability across a group of nodes in a similar geographic location is roughly the same;
- specify project specific revenue drivers in relation to those large projects which are currently anticipated, such as Marchwood power station, on the assumption that a single, nodal revenue driver will, because of the non-linearity of investment costs, be unable to reflect the variability in unit costs associated with both very large and very small projects; and
- modify the licence in respect of unanticipated projects above a certain size threshold or with respect to new exit points.

1.76. It therefore remains our final proposal to implement a zonal revenue driver for all capacity increments in the constrained, south west quadrant of the transmission network that are less than 15GWh/day in size and nodal, project specific revenue drivers, for all projects above this threshold regardless of their location.

1.77. We continue to consider that it is not appropriate to specify zonal revenue drivers for areas outside of the constrained, south west quadrant as NGG NTS does not anticipate the need for incremental, load related investments anywhere other than the south west quadrant in the next price control period. In the event that there is exit investment in these areas, we propose to consider the appropriate revenue drivers on a case by case basis and modify the licence accordingly.

1.78. Following the receipt of further information from both NGG NTS and our capex consultants, we are now proposing that an appropriate revenue driver applicable to nodes in the south west quadrant would be £0.82m per GWh/day.

1.79. Table A9.5 below details our revised assessment of the efficient levels of capital expenditure for each of the five anticipated large projects identified by NGG NTS in its FBPQ. These revised estimates have been informed by further assessment of the efficient level of costs by our capex consultants and further submissions on costs by NGG NTS.

1.80. As a result of the new data received, the allowed capex numbers have been subject to upwards revision in order to:

- include capital expenditure costs associated with these projects that have been or will be incurred outside the five year price control period; and
- partially reflect increases in unit costs identified by NGG NTS, in particular in relation to projects which are already underway and which have been subject to competitive tendering processes such as Langage power station Phase 1.

Table A9.5: Allowed capital expenditure (£m, 2005/6 prices)

	Total capex
Langage power station Phase 1 (40 GWh/day)	92
Langage power station Phase 2[10] (18 GWh/day)	54
Marchwood power station (45 GWh/day)	44
Pembroke power station (87 GWh/day)	62
Grain power station (55 GWh/day)	103

1.81. In the case of both Pembroke and Grain power stations, we have continued to apply a factor of 80 per cent to our latest assessment of the efficient cost of pipe-line investment to reflect the potential scope for contracting solutions to delivery of exit capacity at these sites. Furthermore, we note that the capex for Langage power station Phase 1 has been subject to an adjustment to reflect funding received with respect to this project in the current price control period.

1.82. We have applied an annuitisation factor of 0.10272 [11] to our assessment of allowed capital expenditure above to derive the project specific revenue drivers shown in Table A9.6 below.

Table A9.6: Project specific revenue drivers (£m, 2005/6 prices)

	Revenue driver
Langage power station Phase 1 (40 GWh/day)	9.5
Langage power station Phase 2 (18 GWh/day)	5.5
Marchwood power station (45 GWh/day)	4.5
Pembroke power station (87 GWh/day)	6.4
Grain power station (55 GWh/day)	10.6

1.83. Given that investment for flexibility is not anticipated any remuneration of investment for flexibility capacity will be dealt with on a case by case basis rather than through the ex ante determination of revenue drivers.

1.84. In addition, our capex consultants have reached a view that the price of both steel and contractor costs are likely to change in real terms over the forthcoming price control. As such, we propose that these anticipated changes in prices should be included within the relevant licence drafting such that the applicable revenue

[10] Includes reinforcement of the Mappowder to Illchester and Easton Grey to Littleton Drew.
[11] This annuitisation factor has been derived assuming (1) a pre-tax rate of return of 6.25 per cent (2) associated operating costs equivalent to 1 per cent of investment costs (3) asset lives of 45 years, (4) 20 per cent of investment costs incurred in t-2 and 80 per cent in t-1 and (5) revenue drivers applicable for a 5 year period. Relative to our Update Proposals, the derivation of this factor has been adjusted to allow depreciation on capex incurred prior to the delivery of the project.

drivers are adjusted in accordance with these anticipated price changes consistent with the year in which the capital expenditure is incurred[12].

1.85. Table A9.7 below details our assumptions regarding real price changes and the resulting weighted index that we propose to apply to the revenue drivers.

Table A9.7: anticipated changes to input prices (in real terms)

	steel costs	**contractor costs**	**other**	**weighted index**
weighting	**30 per cent**	**53 per cent**	**17 per cent**	**100 per cent**
2005/6	100	100	100	**100.0**
2006/7	99.11	104.90	100	**102.3**
2007/8	96.74	111.34	100	**105.0**
2008/9	94.46	117.53	100	**107.6**
2009/10	92.38	122.53	100	**109.7**
2010/11	90.11	127.52	100	**111.6**
2011/12	89.12	132.57	100	**114.0**

Proposals for buy-back incentive

1.86. Under the existing UNC regime, NGG NTS is subject to minimal buy back exposure. For example planned, maintenance related outages do not require buy back actions if undertaken within an agreed number of "maintenance days". In addition any planned outages that exceed the allowed number of days or any unplanned outages are subject to administered compensation arrangements. Under these arrangements, NGG NTS exposure has historically been at or close to zero. Further, we would note that in the event of a significant event beyond NGG NTS's control, the income adjusting event provisions could be applied.

1.87. Going forward however, we consider that it is important to strengthen the incentives on NGG NTS to meet its investment commitments and ensure that incremental capacity is delivered in a timely manner. This is likely to be particularly important going forward should significant transmission investment be needed to support future gas fired power station projects that are developed in response to a tightening of supply in the electricity generation sector.

1.88. Our Final Proposals for the offtake buy back incentive are relatively unchanged from the Updated Proposals.

1.89. We continue to consider that investment related buyback costs should be treated as excluded revenue with NGG NTS's exposure capped at £36million.

[12] Based on an assumption that 20 per cent of capex costs will be incurred in year t-2 and the remaining 80 per cent will be incurred in year t-1, where t is the year in which the capacity is delivered.

Following further consideration of the potential exposure of NGG NTS to buy back actions associated with incremental investment, we have decided there should be a monthly cap on exposure to retain incentives throughout each year. It is our proposal that this monthly cap should limit NGG NTS's exposure to £4million a month, subject to the overall annual cap of £36million. Furthermore, the exposure of NGG NTS to exit and entry buy back incentives combined is capped at £48million.

1.90. We also continue to propose that buy backs are subject to an administered cap of the buy-back price on a similar basis to our entry capacity Proposals. It also remains our final proposal that the administered price cap should default to zero five years after the contractual delivery date, assuming no capacity has been delivered.

1.91. NGG NTS's modification proposal currently assumes default lead times of 38 months for NTS exit capacity projects, given the capacity application window proposed for July each year. We consider that a lead time of 38 months is appropriate at exit. However, we continue to consider that it may be appropriate to provide NGG NTS some flexibility over investment lead times. Consistent with our September Update we remain of the view that a permit system should be created to allow NGG NTS to vary the lead times of projects on an ex ante basis. It is envisaged that this framework would allow a specified number of projects to run over the "default" lead time and would allow the ex ante specification of shorter lead times to earn credits that could allow the delay of other projects.

1.92. Our Final Proposals are that the default lead time for exit projects be set at 38 months (3.2 years) with NGG NTS being provided extension permits for 365 days for 30 GWh/day for use, on an ex ante basis, during the next price control period. Ofgem's view is that these permits can only be exercised on an ex ante basis prior to the annual long term allocation and would apply for the enduring offtake arrangements only. As such, and subject to Ofgem's assessment of modification proposal 0116 and its alternatives, the first opportunity for NGG NTS to utilise a permit would be July 2007.

1.93. We are also proposing to reward NGG NTS if it manages to deliver capacity without needing to play a permit by the end of the price control period. We are proposing that the residual value of the permits for the full 365 days will be set at £3million and pro-rated according to the number of unused days.

1.94. In terms of operational buy backs, and consistent with our approach to the transitional regime it is our Final proposal that such costs should be borne in full by NGG NTS and that an operational buy back incentive does not need to be set at this time.

Treatment of non-obligated capacity

1.95. It is our view that NGG NTS should be incentivised in relation to the release of non-obligated capacity, including:

- non-obligated incremental flat capacity;
- non-obligated incremental flexibility capacity; and
- interruptible capacity.

1.96. It is our final view that the obligation to release baseline capacity should continue up to and including the gas day, running until the end of the gas day concerned. As such, non-obligated capacity revenues would not, for the purposes of this incentive, include the release of baseline capacity at any stage.

1.97. It is our final proposal that revenue generated from the sale of non-obligated capacity should be subject to a separate sliding scale incentive. We propose a zero target for this incentive, with all revenues from non-obligated capacity subject to a 50 per cent sharing factor and a cap of £20million such that the potential cost to customers is limited. We consider that an incentive that is 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.

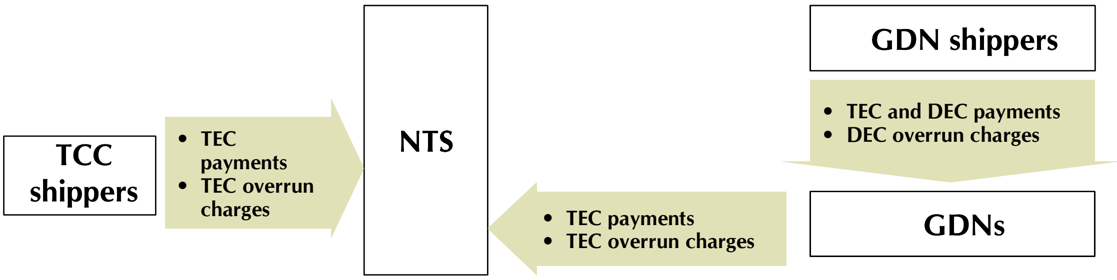
Payment flows

1.98. In our Final Proposals consultation on transitional incentives for GDNs, we noted that the NTS and GDN-GT licences, as currently drafted, envisaged that the mechanism for payment flows would move to an Option 2A approach on 1 October 2008 (or such later date that the Authority otherwise directs in writing).

1.99. It is our final proposal that the implementation of the Option 2A payment flows model should be delayed until 1 October 2010 to coincide with the introduction of the enduring offtake arrangements and, specifically, changes to the charging framework itself as part of these reforms. This would allow any changes to the charging systems required to be coordinated and managed efficiently.

1.100. The "Option 2A" model was described in more detail in the Third TPCR Consultation. Figure A9.1 below illustrates the payment flows under such an approach.

Figure A9.1: Option 2A payment flows



Key: TEC: Transmission Exit Capacity, DEC: Distribution Exit Capacity

Annex 1: Indicative baseline numbers

Overview

1.101. This Annex sets out our Final Proposals for baselines for both GDN and other "transmission connected customer" (TCC) offtake points during the five year price control period commencing on 1 April 2007.

1.102. These baselines have been derived by the application of a practical maximum physical capacity approach.

Data table

1.103. The table presented below contains:

- Transitional period baselines:
- for flat capacity at GDN offtakes; and
- for NTS exit capacity at TCC offtakes;
- Enduring period baselines, with respect to flat capacity.

Transitional period baselines

1.104. At GDN offtakes, the data represents the level of "flat" capacity on 1 April 2007 and shall apply for the period from 1 April 2007 to 30 September 2010.

1.105. At TCC offtakes, the data represents the level of NTS exit capacity (i.e. the combined NTS offtake capacity product provided to TCCs, as currently defined in the UNC) on 1 April 2007 and shall apply for the period from 1 April 2007 to 30 September 2010. These baseline numbers have been subject to minor adjustments relative to our Updated Proposals to ensure that the data is expressed to two decimal places.

Enduring period baselines

1.106. At all offtakes, the data for the enduring period represents the level of "flat" capacity on 1 April 2007 and shall apply for the period from 1 October 2010 onwards. These flat baselines are the same as those presented for the transitional period, with the exception of five interruptible sites in the south west quadrant where baselines have been subject to upwards revision as discussed in chapter 10 and appendix 9.

1.107. The flat baselines for the enduring period are presented in Table A9.1.1 below with the revisions to SW interruptible sites highlighted in bold.

1.108. With respect to the flexibility product, and consistent with the product definition proposed by NGG NTS, a national capacity release obligation for flexibility capacity is proposed at 238 GWh/day for each year of the enduring period in the next price control period.

Table A9.1.1: Indicative baseline data for the transitional period and enduring periods

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	**Enduring flat baseline (GWh/day)**
Bacton	GDN (EA)	3.66	3.66
Brisley	GDN (EA)	3.11	3.11
Cambridge	GDN (EA)	0	0
Great Wilbraham	GDN (EA)	35.59	35.59
Matching Green	GDN (EA)	83.85	83.85
Peterborough Eye/Tee	GDN (EA)	25.45	25.45
Roudham Heath	GDN (EA)	14.7	14.7
Royston	GDN (EA)	2.67	2.67
Whitwell	GDN (EA)	161.87	161.87
West Winch	GDN (EA)	11.69	11.69
Yelverton	GDN (EA)	84.44	84.44
Alrewas	GDN (EM)	92.15	92.15
Blaby	GDN (EM)	11.03	11.03
Blyborough	GDN (EM)	90.89	90.89
Caldecott	GDN (EM)	11.08	11.08
Thornton Curtis (DN)	GDN (EM)	106.64	106.64
Drointon	GDN (EM)	107.51	107.51
Gosberton	GDN (EM)	15.79	15.79
Kirkstead	GDN (EM)	1.21	1.21
Market Harborough	GDN (EM)	9.48	9.48
Silk Willoughby	GDN (EM)	3.53	3.53
Sutton Bridge	GDN (EM)	1.15	1.15
Tur Langton	GDN (EM)	82.52	82.52
Walesby	GDN (EM)	0.93	0.93
Asselby	GDN (NE)	3.64	3.64
Baldersby	GDN (NE)	1.34	1.34
Burley Bank	GDN (NE)	20.31	20.31
Ganstead	GDN (NE)	23.15	23.15
Pannal	GDN (NE)	148.41	148.41
Paull	GDN (NE)	38.14	38.14
Pickering	GDN (NE)	9.38	9.38
Rawcliffe	GDN (NE)	3.42	3.42
Towton	GDN (NE)	81.13	81.13

Offtake Point	Type of Offtake	Transitional baseline (GWh/day)	Enduring flat baseline (GWh/day)
Bishop Auckland	GDN (NO)	69.26	69.26
Coldstream	GDN (NO)	1.93	1.93
Corbridge	GDN (NO)	0.07	0.07
Cowpen Bewley	GDN (NO)	53.71	53.71
Elton	GDN (NO)	33.26	33.26
Guyzance	GDN (NO)	2.19	2.19
Humbleton	GDN (NO)	0.15	0.15
Keld	GDN (NO)	1.7	1.7
Little Burdon	GDN (NO)	17.75	17.75
Melkinthorpe	GDN (NO)	0.34	0.34
Saltwick Pressure Controlled	GDN (NO)	9.22	9.22
Saltwick Volumetric Controlled	GDN (NO)	69.26	69.26
Thrintoft	GDN (NO)	5.16	5.16
Towlaw	GDN (NO)	0.55	0.55
Wetheral	GDN (NO)	26.86	26.86
Horndon	GDN (NT)	46.41	46.41
Luxborough Lane	GDN (NT)	165.3	165.3
Peters Green	GDN (NT)	348.98	348.98
Peters Green South Mimms	GDN (NT)	0	0
Winkfield	GDN (NT)	15.91	15.91
Audley	GDN (NW)	8.2	8.2
Blackrod	GDN (NW)	136.81	136.81
Ecclestone	GDN (NW)	21.14	21.14
Holmes Chapel	GDN (NW)	20.83	20.83
Lupton	GDN (NW)	16.23	16.23
Malpas	GDN (NW)	0.49	0.49
Mickle Trafford	GDN (NW)	29.58	29.58
Partington	GDN (NW)	96.29	96.29
Samlesbury	GDN (NW)	140.68	140.68
Warburton	GDN (NW)	107.25	107.25
Weston Point	GDN (NW)	30.64	30.64
Aberdeen	GDN (SC)	38.44	38.44
Armadale	GDN (SC)	3.01	3.01
Balgray	GDN (SC)	11.4	11.4
Bathgate	GDN (SC)	24.22	24.22
Broxburn	GDN (SC)	64.37	64.37
Careston	GDN (SC)	3.05	3.05
Drum	GDN (SC)	77.53	77.53
St Fergus	GDN (SC)	0.88	0.88

Offtake Point	Type of Offtake	Transitional baseline (GWh/day)	Enduring flat baseline (GWh/day)
Glenmavis	GDN (SC)	145.79	145.79
Hume	GDN (SC)	1.22	1.22
Kinknockie	GDN (SC)	2.35	2.35
Langholm	GDN (SC)	0.15	0.15
Lauderhill	GDN (SC)	0	0
Lockerbie	GDN (SC)	5.7	5.7
Netherhowcleugh	GDN (SC)	0.2	0.2
Pitcairngreen	GDN (SC)	1.59	1.59
Soutra	GDN (SC)	8.94	8.94
Stranraer	GDN (SC)	0.68	0.68
Mosside	GDN (SC)	0	0
Farningham	GDN (SE)	135.12	135.12
Shorne	GDN (SE)	67.06	67.06
Tatsfield	GDN (SE)	276.46	276.46
Winkfield	GDN (SE)	106.26	106.26
Braishfield A	GDN (SO)	99.23	99.23
Braishfield B	GDN (SO)	46.65	46.65
Hardwick	GDN (SO)	118.68	118.68
Ipsden	GDN (SO)	12.39	12.39
Ipsden 2	GDN (SO)	14.25	14.25
Mappowder	GDN (SO)	47.68	47.68
Winkfield	GDN (SO)	79.91	79.91
Aylesbeare	GDN (SW)	22.75	22.75
Cirencester	GDN (SW)	9.18	9.18
Coffinswell	GDN (SW)	0	0
Easton Grey	GDN (SW)	30.89	30.89
Evesham	GDN (SW)	6.58	6.58
Fiddington	GDN (SW)	26.64	26.64
Ilchester	GDN (SW)	33.07	33.07
Kenn	GDN (SW)	70.91	70.91
Littleton Drew	GDN (SW)	2.84	2.84
Lyneham	GDN (SW)	0	0
Pucklechurch	GDN (SW)	28.38	28.38
Ross	GDN (SW)	4.28	4.28
Seabank (DN)	GDN (SW)	57.62	57.62
Alrewas	GDN (WM)	130.79	130.79
Aspley	GDN (WM)	84.65	84.65
Audley	GDN (WM)	21.83	21.83
Austrey	GDN (WM)	86.09	86.09

Offtake Point	Type of Offtake	Transitional baseline (GWh/day)	Enduring flat baseline (GWh/day)
Leamington	GDN (WM)	4.26	4.26
Lower Quinton	GDN (WM)	29.91	29.91
Milwich	GDN (WM)	21.04	21.04
Ross	GDN (WM)	16.52	16.52
Rugby	GDN (WM)	80.08	80.08
Shustoke	GDN (WM)	44.76	44.76
Stratford-upon-Avon	GDN (WM)	4.68	4.68
Maelor	GDN (WN)	57.56	57.56
Dowlais	GDN (WS)	113.11	113.11
Dyffryn Clydach	GDN (WS)	47.92	47.92
Gilwern	GDN (WS)	46.67	46.67
Abson (Seabank Power Station phase I)	DC - FIRM	27.8	**36.59**
Bacton (Great Yarmouth)	DC - FIRM	20.04	20.04
Barking (Horndon)	DC - INTERRUPTIBLE	58.59	58.59
Billingham ICI (Terra Billingham)	DC - FIRM	43.54	43.54
Blackness (BP Grangemouth)	DC - FIRM	27.29	27.29
Blyborough (Brigg)	DC - INTERRUPTIBLE	16.89	16.89
Blyborough (Cottam)	DC - INTERRUPTIBLE	17.54	17.54
Burton Point (Connahs Quay)	DC - INTERRUPTIBLE	73.21	73.21
Caldecott (Corby Power Station)	DC - FIRM	21.12	21.12
Deeside	DC - FIRM	28.48	28.48
Didcot A	DC - INTERRUPTIBLE	0	**87.29**
Didcot B	DC - FIRM	50.47	50.47
Eastoft (Keadby Blackstart)	DC - INTERRUPTIBLE	2.38	2.38
Eastoft (Keadby)	DC - FIRM	36.06	36.06
Enron Billingham	DC - INTERRUPTIBLE	121.51	121.51
Epping Green (Enfield Energy, aka Brimsdown)	DC - FIRM	18.41	18.41
Ferny Knoll (AM Paper)	DC - FIRM	1.08	1.08
Goole (Guardian Glass)	DC - FIRM	1.62	1.62
Gowkhall (Longannet)	DC - FIRM	43.32	43.32
Harwarden (Shotton, aka Shotton Paper)	DC - FIRM	11.59	11.59
Hollingsgreen (Hays Chemicals)	DC - INTERRUPTIBLE	3.25	3.25
Medway (aka Isle of Grain Power Station, NOT Grain Power)	DC - INTERRUPTIBLE	38.12	38.12
Middle Stoke (Damhead Creek, aka Kingsnorth Power Station)	DC - FIRM	40.94	40.94

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	**Enduring flat baseline (GWh/day)**
Moffat (Irish Interconnector)	INTERCONNECTOR FIRM, EXIT ONLY	433.4	433.4
Peterborough (Peterborough Power Station)	DC - INTERRUPTIBLE	23.28	23.28
Pickmere (Winnington Power, aka Brunner Mond)	DC - FIRM	15.38	15.38
Roosecote (Roosecote Power Station)	DC - INTERRUPTIBLE	14.73	14.73
Rosehill (Saltend Power Station)	DC - FIRM	57.83	57.83
Ryehouse	DC - FIRM	38.66	38.66
Saddle Bow (Kings Lynn)	DC - FIRM	17.98	17.98
Saltend BPHP (BP Saltend HP)	DC - FIRM	9.1	9.1
Sandy Lane (Blackburn CHP, aka Sappi Paper Mill)	DC - FIRM	4.55	4.55
Seabank (Seabank Power Station phase II)	DC - FIRM	19.1	19.1
Sellafield Power Station	DC - INTERRUPTIBLE	12.35	12.35
Shellstar (aka Kemira, not Kemira CHP)	DC - FIRM	13.97	13.97
Shellstar (aka Kemira, not Kemira CHP)	DC - INTERRUPTIBLE	2.27	2.27
Shotwick (Bridgewater Paper)	DC - FIRM	5.52	5.52
St. Fergus (Peterhead)	DC - FIRM	108.3	108.3
St. Neots (Little Barford)	DC - FIRM	35.2	35.2
Stallingborough	DC - FIRM	28.16	28.16
Stallingborough	DC - FIRM	38.34	38.34
Stanford Le Hope (Coryton)	DC - FIRM	36.61	36.61
Staythorpe PH1	DC - FIRM	38.12	38.12
Staythorpe PH2	DC - FIRM	38.12	38.12
Sutton Bridge	DC - FIRM	37.47	37.47
Teesside (BASF, aka BASF Teesside)	DC - FIRM	9.75	9.75
Teesside Hydrogen	DC - FIRM	6.61	6.61
Terra Nitrogen (aka ICI/Terra Severnside)	DC - FIRM	0.65	**13.1**
Thornton Curtis (Humber Refinery, aka Immingham)	DC - FIRM	46.89	46.89
Thornton Curtis (Killingholm B)	DC - INTERRUPTIBLE	44.94	44.94
Thornton Curtis (Killingholme A)	DC - FIRM	36.28	36.28
Tonna (Baglan Bay)	DC - FIRM	26.75	26.75
Weston Point (Castner Kelner, aka ICI Runcorn)	DC - FIRM	11.7	11.7
Weston Point (Rocksavage)	DC - FIRM	38.19	38.19
Wragg Marsh (Spalding)	DC - FIRM	42.02	42.02
Zeneca (ICI Avecia, aka 'Zenica')	DC - FIRM	0.11	0.11

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	**Enduring flat baseline (GWh/day)**
Hatfield Moor Max Refill	STORAGE SITE	30.21	30.21
Hole House Max Refill	STORAGE SITE	119.58	119.58
Partington Max Refill	STORAGE SITE	2.41	2.41
Glenmavis Max Refill	STORAGE SITE	1.62	1.62
Barton Stacey Max Refill	STORAGE SITE	0	**100.94**
Avonmouth Max Refill	STORAGE SITE	0	**2.3**
Dynevor Max Refill	STORAGE SITE	2.61	2.61
Garton Max Refill	STORAGE SITE	211.01	211.01
Hornsea Max Refill	STORAGE SITE	22.43	22.43
Rough Max Refill	STORAGE SITE	160	160
Bacton (IUK)	INTERCONNECTOR	623.58	623.58
Bacton (BBL)	INTERCONNECTOR	0	0

Appendix 10 – Company Overviews

Introduction

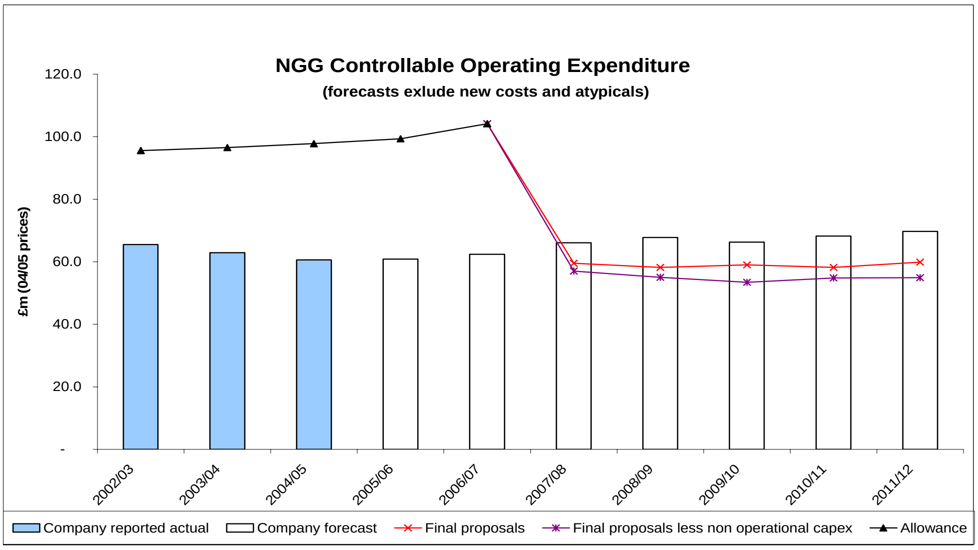
1.1. This appendix presents historic and forecast controllable operating costs, capital expenditure and reliability data (where available) for each of the companies. The charts contain historic data from various sources including reports from our consultants. However, it is important to note that Ofgem or its predecessor may have made adjustments to the consultants' advised numbers in formatting the actual allowances in some historical periods, and that the cost categorisation (e.g. between load and non-load related capex, or between capex and opex) may have changed across different price control periods. Details have not been shared with the companies prior to publication. (All figures in this appendix are shown in 2004/05 prices).

NGG

1.2. Within the current price control period, up to 2005/06, there has been a capex underspend of around 41 per cent. There has also been an opex underspend of around 35 per cent during the period, although much of this out-performance relates to the revised allocation of operating expenditure between transmission and distribution.

1.3. Figure A10.1 below sets out NGG NTS' performance against allowance in terms of controllable operating costs, and NGG NTS' forecast from 2005/06.

Figure A10.1: NGG performance against opex allowance



1.4. Capital expenditure profiles for NGG are shown in figures A10.2 and A10.3. The NGG capex allowance and outturn data before 2002/03 was not available. For the current period, the NTS allowance was split by assigning Compressor related allowances to the non-load related category and the rest to the load related category. The "2006/07 Final Proposals" data from 2007/08 onwards reflects the baseline capex allowances for the next price control period, whereas those for earlier years reflect our view of the level of capex that will be included in the RAV from 2007/08.

Figure A10.2: NGG performance against capex allowance (load related expenditure)

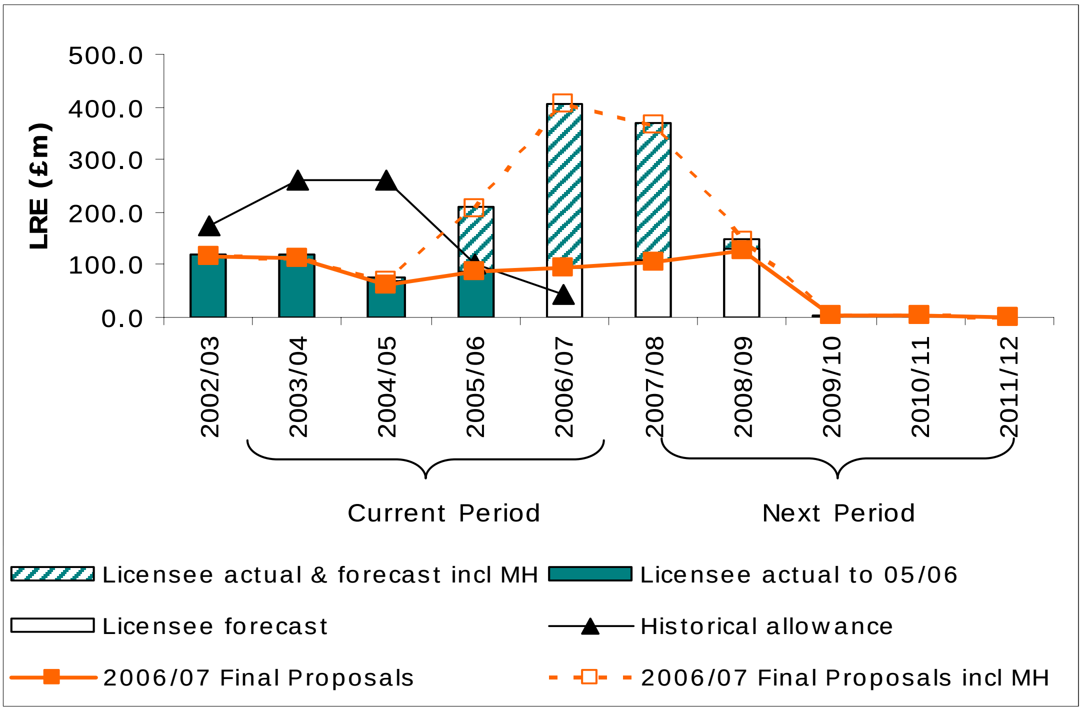
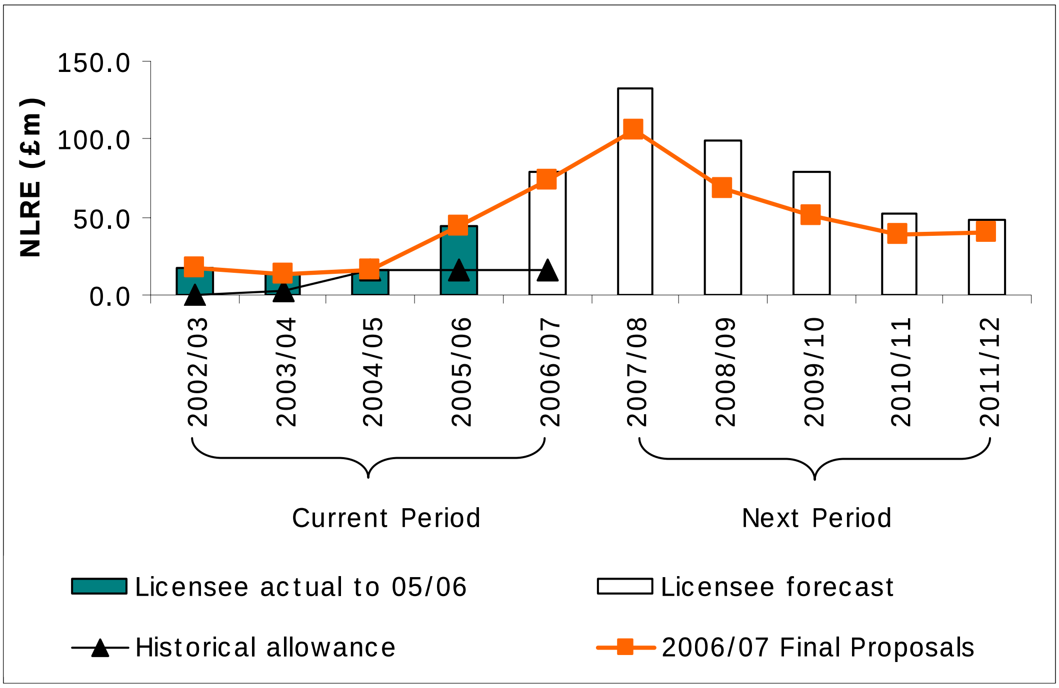


Figure A10.3: NGG performance against capex allowance (non load related expenditure)

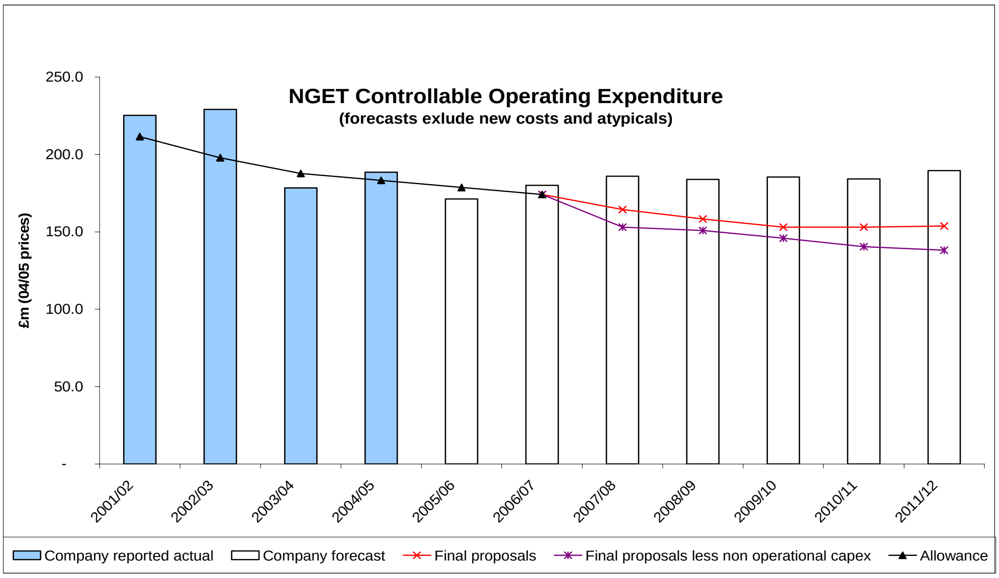


NGET

1.5. Over the last 5 year price control period (2001/2 to 2005/06), there has been a capex overspend of around 22 per cent, mainly attributed to a large increase in the last two years of this period. There was also an opex overrspend of around 5 per cent during the same period. We also extended NGET's price control by one year for 2006/07. NGET has also been allowed revenues arising from the Transmission Investment in Renewable Generation (TIRG) project - amounting to a capex commitment of £104 million. Reliability levels on NGET's system have averaged 99.9998 per cent between 2001/2 and 2005/6.

1.6. Figure A10.4 below sets out NGET's performance against allowance in terms of controllable operating costs, and NGET's forecast from 2005/06.

Figure A10.4: NGET performance against opex allowance



1.7. Capital expenditure profiles for NGET are shown in Figures A10.5 and A10.6. Data relating to the historical period before 2001/02 has been obtained from various sources and may not reflect accurately the costs or allowances in the relevant categories. It is included here for indicative purpose only. The "2006/07 Final Proposals" data from 2007/08 onwards reflects the baseline capex allowances for the next price control period, whereas those for earlier years reflect our view of the level of capex that will be included in the RAV from 2007/08.

Figure A10.5: NGET performance against capex allowance (load related expenditure)

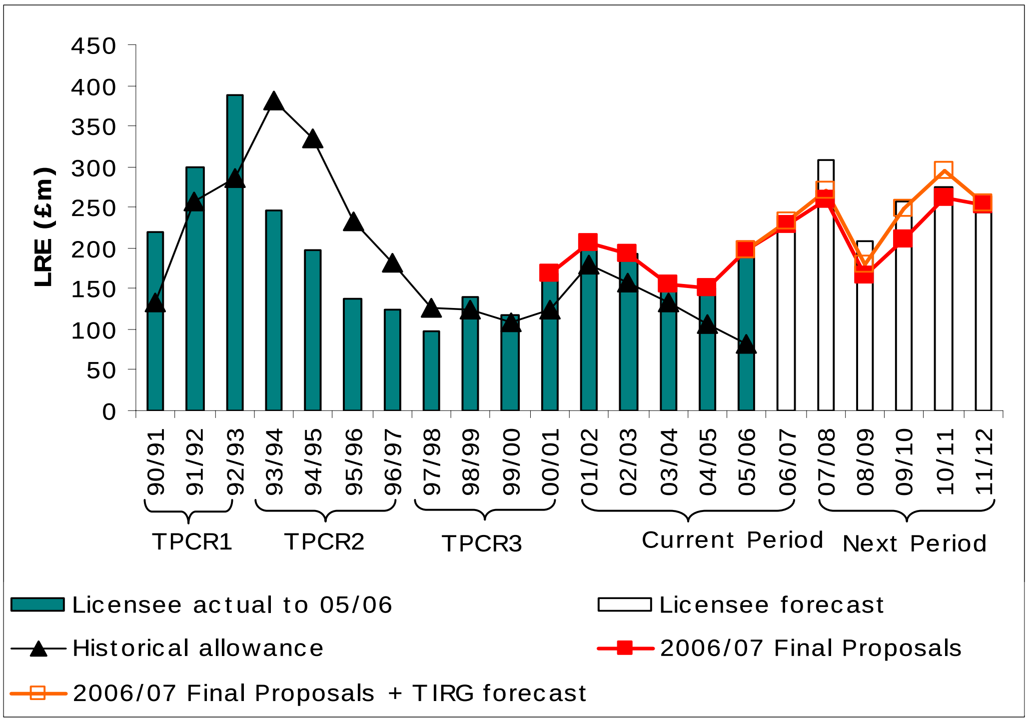
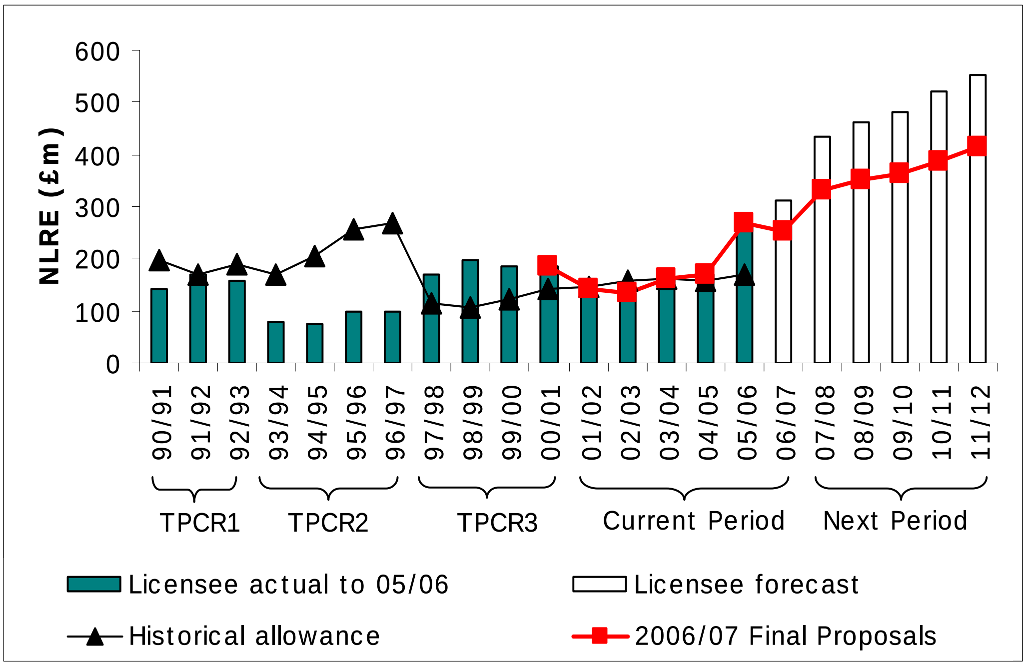


Figure A10.6: NGET performance against capex allowance (non load related expenditure)



1.8. NGET's network reliability performance since 1990/91 is shown in figure A10.7 below.

Figure A10.7: NGET reliability levels

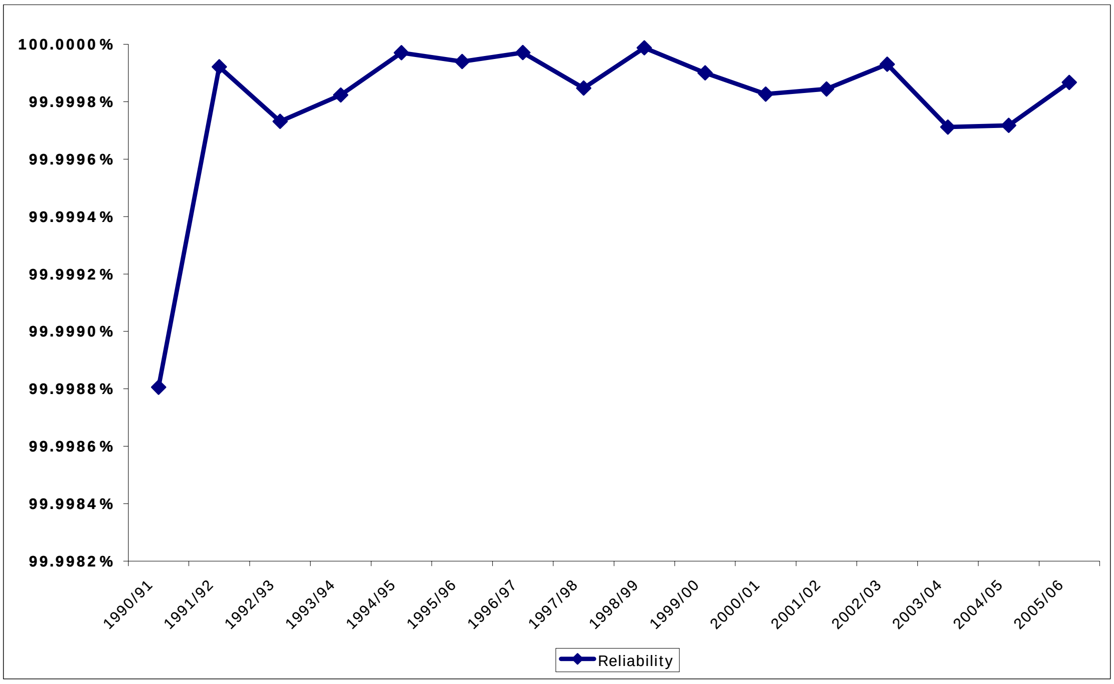


Table A10.1: NGET unsupplied and supplied energy

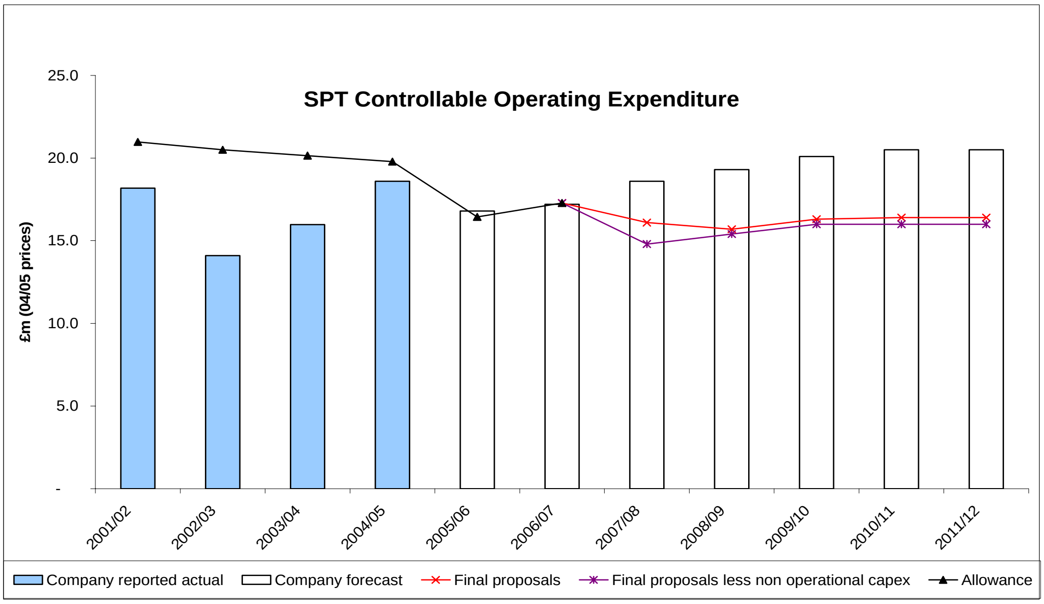
Year	Total Unsupplied Energy (MWh)	Total Supplied Energy (MWh)
1990/91	3200	268,000,000
1991/92	211	269,500,000
1992/93	720	268,500,000
1993/94	480	271,700,000
1994/95	80	274,400,000
1995/96	171	284,800,000
1996/97	83	287,000,000
1997/98	441	289,200,000
1998/99	36	293,700,000
1999/00	293	295,500,000
2000/01	526	304,000,000
2001/02	473	304,400,000
2002/03	215	308,500,000
2003/04	900	312,500,000
2004/05	888	314,850,000
2005/06	417	314,800,000

SPTL

1.9. Over the last price control period (1999/00 to 2004/05) SPTL has overspent its capex allowance by 13 per cent and operating expenditure was below allowance by 18 per cent. As with SHETL, SPTL's price control was extended by two years to expire in March 2007. SPTL has been allowed capex commitments of around £180 million arising from the TIRG project.

1.10. Figure A10.8 below sets out SPTL's performance against allowance in terms of controllable operating costs, and SPTL's forecast from 2005/06. SPTL has under spent its controllable opex allowance.

Figure A10.8: SPTL performance against opex allowance



1.11. Figures A10.9 and A10.10 set out SPTL's capital expenditure profiles. Data relating to the historical period before 2000/01 has been obtained from various sources and may not reflect accurately the costs or allowances in the relevant categories. It is included here for indicative purpose only. The "2006/07 Final Proposals" data from 2007/08 onwards reflects the baseline capex allowances for the next price control period, whereas those for earlier years reflect our view of the level of capex that will be included in the RAV from 2007/08.

Figure A10.9: SPTL performance against capex allowance (load related expenditure)

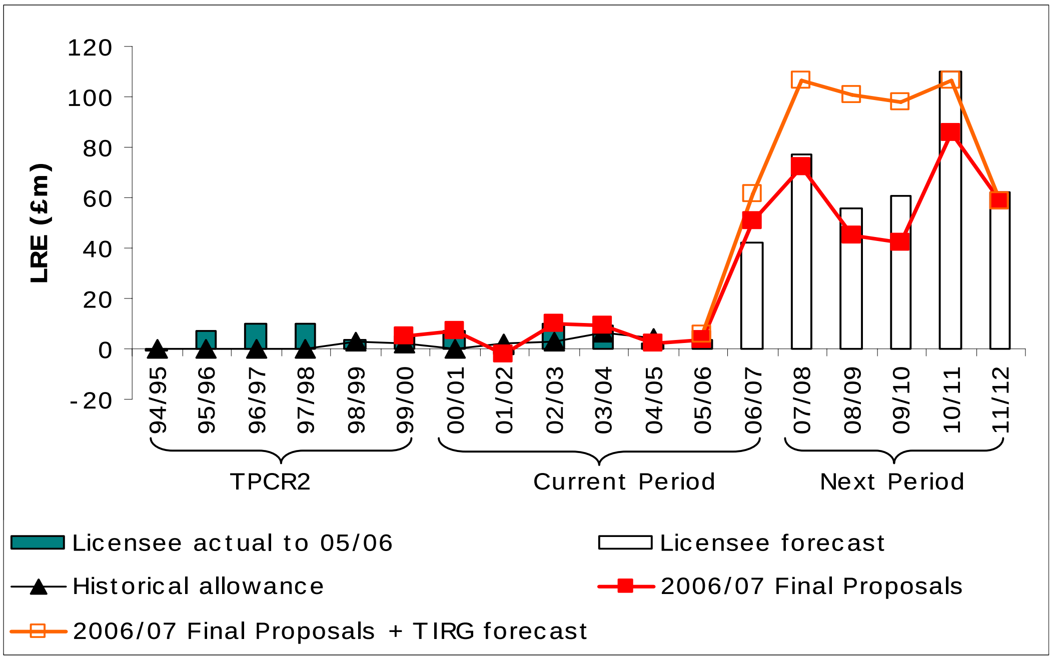
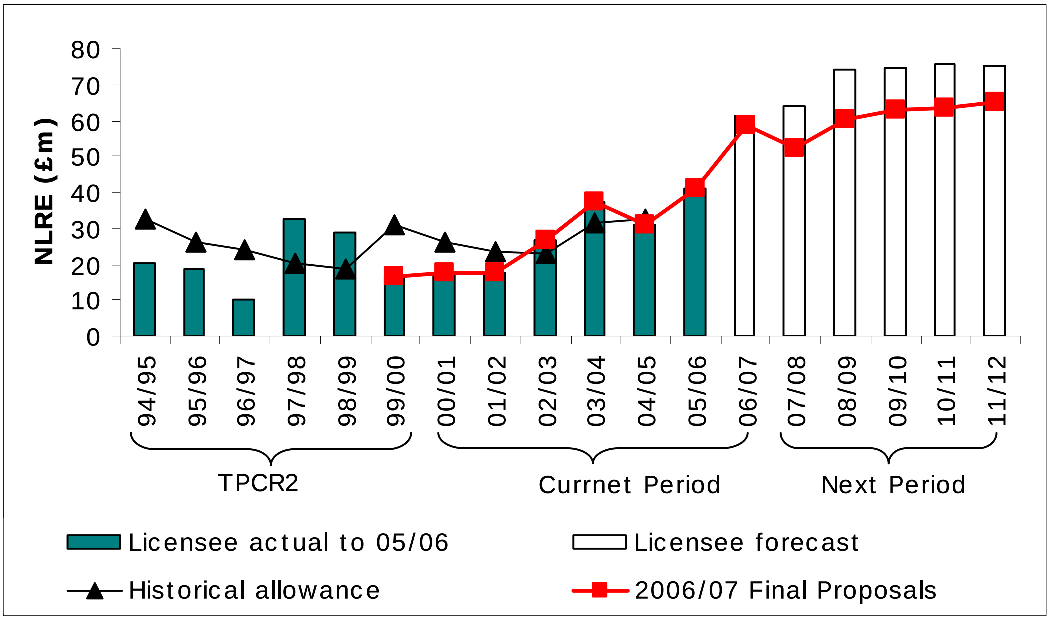


Figure A10.10: SPTL performance against capex allowance (non load related expenditure)

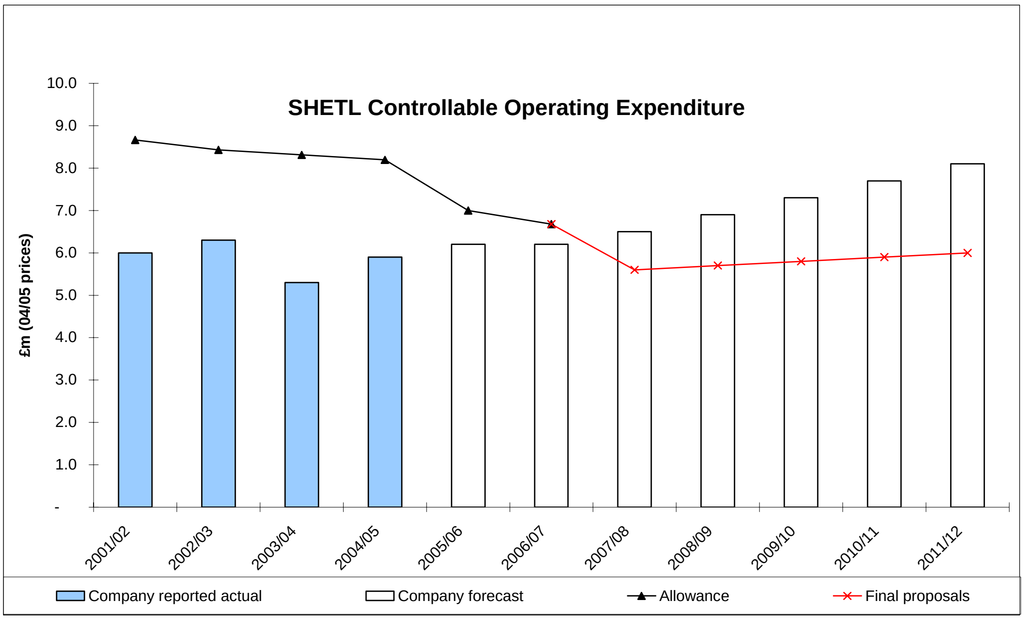


SHETL

1.12. The allowances we are setting for SHETL are against the backdrop of a 32 per cent capex underspend over the last price control period 1999/01 to 2004/5), and opex savings below the allowance of 30 per cent. SHETL's price control was extended for two years to run until March 2007. SHETL has also been allowed revenues arising from the TIRG project, amounting to a capex commitment of £252 million.

1.13. Figure A10.11 below sets out SHETL's performance against allowance in terms of controllable operating costs, and SHETL's forecast from 2005/06.

Figure A10.11: SHETL performance against opex allowance



1.14. Figures A10.12 and A10.13 set out SHETL's capital expenditure profiles. Data relating to the historical period before 2000/01 has been obtained from various sources and may not reflect accurately the costs or allowances in the relevant categories. It is included here for indicative purpose only. The "2006/07 Final Proposals" data from 2007/08 onwards reflects the baseline capex allowances for the next price control period, whereas those for earlier years reflect our view of the level of capex that will be included in the RAV from 2007/08.

Figure A10.12: SHETL performance against capex allowance (load related expenditure)

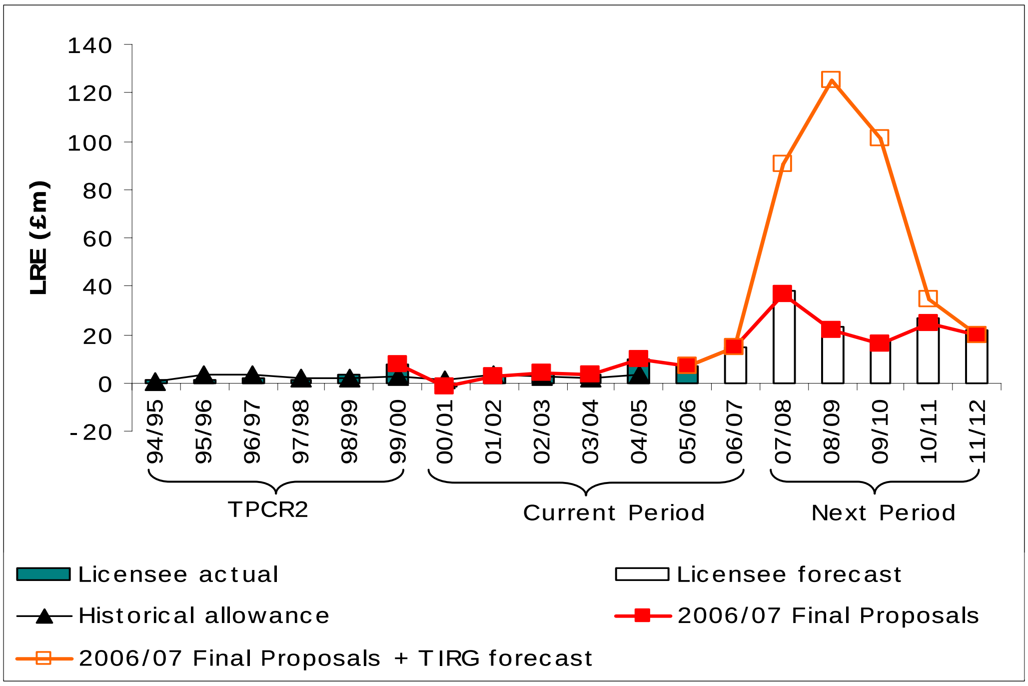
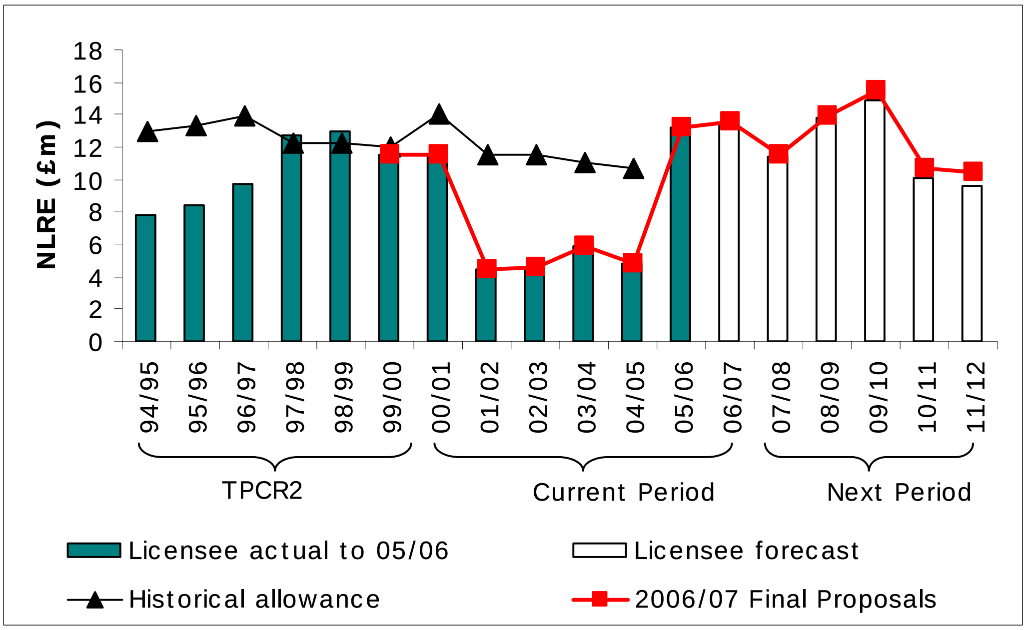


Figure A10.13: SHETL performance against capex allowance (non load related expenditure)



Appendix 11 - Summary of Respondents' Views

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

Chapters 3 to 6 - Company Chapters

Licensees' views

1.2. NGET considers that the gap between its view of capex and Ofgem's is considerable, and that if the gap is not closed it will have problems complying with its licence obligations. It considers that Ofgem's assumption of a low volume of asset replacement and a low assumption of the unit costs of asset replacement are unrealistic and may cause reductions in system reliability. NGET is concerned that the gap of around £670million is exacerbated by our capex incentive proposals such that it will be exposed to 25 per cent of the value of the over spend. Greater concerns exist with regard to overspend as it considers the potential for overspend is greater than for underspend. On opex, NGET considers that we have made unrealistic assumptions on the scope for efficiencies, inappropriate disallowance of employee share scheme costs and costs to achieve efficiency improvements. NGET considers that the proposed allowances we set out in September would not allow it to meet its licence obligations.

1.3. NGG NTS considers that our proposed disallowance of £75 million of St Fergus costs is unreasonable in light of the baselines we set for the last Transco price control. NGG NTS would like to seek more clarity as to how St Fergus will be treated, and in particular, whether or not it would be able to withhold the relevant capacity and treat the revenues as unregulated. NGG NTS also considers that in respect of non-load related capital expenditure we have used unreasonably limited supply scenarios, extreme assumptions relating to potential cost savings, lack of recognition of auction signals and a failure to recognise the costs of complying with legislative requirements in relation to emissions.

1.4. SHETL does not agree with our proposed approach to apply a 25 per cent incentive rate to efficient capital expenditure given our position on the baseline. It considers that such an approach is a dilution of the incentive effect, and a sliding scale mechanism as employed in DPCR4 would be more appropriate.

1.5. SPTL's main comments on capex allowances relates to revenue drivers and baselines, which are dealt with below. Other issues identified by SPTL include the need for appropriate funding for major investment at Dewar Place, as well as Overhead Lines, BT21st Century and Non-Operational Capital Expenditure. SPTL believes our opex proposals are around £14m too low, and as a result its planned tower painting programme can not be undertaken. It also considers there will need to be a 12 per cent reduction in substation maintenance activities.

Other respondents' views

1.6. The majority of other respondents consider that whilst our Updated Proposals allowances represent substantial increases in capital expenditure, they welcomed our approach to provide allowances that enabled the licensees to fund the forecast growth in their business at most efficient cost.

Ofgem's view

1.7. We consider that our Final Proposals represent an appropriate and consistent suite of allowances across the licensees, and build upon the proposals we set out in September. Our response to the points made above manifests itself in chapters 3 to 6 of this document. We consider that our approach on capex incentives and revenue drivers reduces the exposure that both the licensees and consumers face, from setting allowances which turn out to be inappropriate. However, on NGET's perceived unit cost gap, we have reviewed the further information from NGET and have made minor adjustments to align the base unit cost to what is deemed to be efficiently achievable for 2005/06.

1.8. With regards to our disallowance at St Fergus, we continue to believe that at the time of committing to the investment, NGG should have reviewed all information available to it and should have decided not to go ahead with the investment. We therefore still believe that it is inappropriate to include all the inefficient investment in the RAV.

Chapter 7 – General price control and policy and cost assessment issues

Licensees' views

1.9. NGT (combined response) believes we have made unreasonable assumptions about the scope for efficiencies in particular areas, most notably on quasi capex. NGT also believes that we have been over-rigid on disallowing cost items on the basis of policy. As mentioned above, NGT is also concerned about our proposals to limit the extent to which actual spend can vary from allowances, as espoused by our capex incentives.

1.10. SPTL considers that it has seen unprecedented increases in input prices, linked to a number of factors, such as the increase in demand for raw materials, which it suggests has increased project tender prices by 10 per cent to 55 per cent over the last year. SPTL feels that despite our recent increase in allowances to recognise the effect of input prices, these are still inadequate.

1.11. SHETL does not agree with the phasing of the opex allowance associated with the increased asset base. SHETL considers that whilst the total incremental allowance over the review period appears reasonable it would expect the opex costs to be increasing as the assets become established. As mentioned, above, SHETL takes issue with our approach to capex incentives.

Other respondents' views

1.12. The majority of respondents were in support of our proposals for the capex incentive and consider it an appropriate way to manage, in conjunction with our revenue drivers, the uncertainty related to setting ex ante capital expenditure allowances. One such respondent felt it was important to have consistent incentives between opex and capex to prevent substitution from one to the other.

Ofgem's views

1.13. We believe that our proposals on the capex incentive represent an appropriate way to manage the variation between our allowances and actual costs. We consider that it is desirable to establish a balanced package of incentives that provide, where possible, strong incentives for investment efficiency. Our Final Proposals go some way to strengthening the effectiveness of the efficiency incentive by ensuring that the licensees have a consistent strength incentive 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. One factor which has influenced our view on the appropriate incentive strength is the availability of output measures, as these can provide a framework for assessing 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.

1.14. We feel that our allowances appropriately recognise the increase in input prices faced by the licensees. We recognise the concerns expressed by SPTL with regards to input price movements, but following our updated proposals document in September, we have conducted further analysis, and concluded that in general our updated proposals were appropriate. Our Final Proposals in this area are set out in chapter 7 of this document.

Chapter 8 – Financial Issues

Licensees' views

1.15. NGT (combined response) draws from other price controls to illustrate its concerns that our September proposal for the cost of capital is too low. It refers to the higher cost of capital for the water and sewerage companies, as well as in DPCR4. NGT takes issue with the equity beta of 0.5 in the Smithers report and does not think this is viable. Given the range of factors that need to be considered, NGT believes that the base rate of return should be at least 4.7 per cent. NGT welcomes the significant developments in the pensions area of the TPCR, but considers that there are still issues that need resolving with regard to the treatment of the Centrica surplus prior to 2002/03 and double counting of the liabilities associated with existing non-regulated activities.

1.16. SHETL regards the modelling assumption of 4.2 per cent post tax real cost of capital as being wholly inadequate to finance the transmission business. SHETL considers that our proposals are inconsistent with previous regulatory decisions, and are inappropriate in the context of the investment focus of this review and the financeability issues raised.

1.17. SPTL is concerned with our proposals of a cost of capital of 4.2 per cent, and consider that 4.8 per cent is more appropriate. SPTL considers that the cost of capital should be consistent with that set for the DNOs, which was based on extensive consultation less than two years ago. SPTL is particularly concerned with our proposed cost of debt of 3.4 per cent.

Other respondents' views

1.18. Several respondents were supportive of our Updated Proposals position that the post tax real cost of capital should be substantially lower than that adopted in electricity distribution. Some of these respondents agreed that the transmission businesses were lower risk than the distribution companies, and in particular that the cost of debt had fallen substantially.

Ofgem's views

1.19. We have recently reviewed our position on the cost of capital, and consider that the post tax real cost of capital should be 4.4 per cent post tax real. Our judgement has been influenced by our assessment of the overall level of risk associated with the respective businesses, as well as developments in the cost of debt which we consider provide a rationale for a cost of capital below that set for the electricity distribution companies.

1.20. Since the updated proposals document, we have made some minor adjustments to the pension cost allowances for NGG NTS and NGET. However, as set out in chapter 8, we consider the position we set out in September with regards to pension allowances is largely unchanged.

Chapter 9 - Adjustment and Incentive Mechanism Electricity

Licensees' views

1.21. NGET considers that, with some reservations about the UCAs used, our proposals for revenue drivers are broadly sensible. However, NGET remains concerned about the 25 per cent capex incentive rate. NGET believes that a penalty only reliability incentive needs to balance target loss of supply and the base rate of return. NGT (joint response) considers that there is a strong case for IFI, but there needs to be changes to the parameters. NGT considers the pass through rate should be a flat profile, in excess of 80 per cent. It also believes that there should be an increased share allowed for internal R&D, up to 30 per cent.

1.22. SHETL believes that a great deal of progress has been made in developing a revenue driver mechanism to provide a solution to uncertain load related expenditure. However, it considers that in particular there are some issues to resolve on the local works' UCAs. SHETL supports our proposed approach for IFI.

1.23. SPTL considers that our assumptions for the baseline are too low, and should include most recent project costs. SPTL also suggests that the unit costs of connecting generation beyond its baseline are higher than the unit costs assumed in deriving the baseline. SPTL feels that there needs to be an increase in the threshold for IFI funding, either in the form of a higher percentage of regulated revenue, or a de minimis amount.

Other respondents' views

1.24. The majority of respondents agree with our system of revenue drivers. These respondents acknowledge that the uncertainty regarding future demands for connections can be dealt with by our proposed mechanism. Some respondents questioned whether it was appropriate to allow a pass through amount at all, and consider that all funding should be made available upon completion.

1.25. Respondents broadly supported our proposals for IFI, stating that it represented an appropriate approach to ensuring expenditure is made on research and development.

Ofgem's views

1.26. Our proposals for revenue drivers provide an appropriate mechanism for creating revenues for the transmission licensees, which flex with changes in generation connections.

1.27. We believe that extending IFI to electricity and gas transmission is an appropriate mechanism to deal with potential decline in expenditure on research and development. The IFI mechanism we have developed includes a de minimis amount of expenditure, which is intended to enable SPTL and SHETL to make use of the scheme in the same way as NGET and NGG NTS.

Chapter 10 - Adjustment and Incentive Mechanisms Gas

Licensees' views

1.28. NGG NTS states that it has more issues with gas revenue drivers than with electricity revenue drivers. It does not consider that the UCAs represent a reasonable ex ante view of investment costs, and the problem is exacerbated by our proposals to expose the licensee to 38 per cent of the difference between allowance and actual costs. As mentioned above NGT (joint response) supports IFI subject to some changes to the values of the parameters.

1.29. SHETL expresses concern at our proposals primarily for the offtake regime, as it considers that the mechanism is based on a user committing to pay unknown transportation charges. It is also concerned that at certain locations we have proposed an increase in baseline capacity that could undermine a shipper's decision to participate in the September 2006 QSEC auctions. As mentioned above, SHETL supports out plans for IFI.

1.30. SPTL does not make any comments on gas incentives.

Other respondents' views

1.31. The majority of respondents support our proposals for revenue drivers and consider it an appropriate mechanism for generating revenues in response to uncertain demands for connection.

1.32. The majority of respondents consider our proposals for IFI represent a sound approach to addressing declining expenditure in research and development.

Ofgem's views

1.33. We consider that revenue drivers are the most appropriate way of remunerating investment necessary to meet uncertain demands for capacity. Our proposals embody our views of an efficient set of unit costs for NGG NTS. Similarly, we consider that our proposals for the capex incentive provide an appropriate mechanism to limit the extent to which actual capital expenditure differs from our allowances.

1.34. Our proposals on IFI provide an appropriate mechanism by which the licensees can fund expenditure for innovative projects. We consider that the auditing and reporting measures that support the IFI mechanism ensure that expenditure is targeted in the right areas, and is aimed at delivering benefits to consumers.

Chapter 11 - Sustainable Development and the Environment

Licensees' views

1.35. NGT (joint response) is in support of an SF6 scheme in principle. It considers that the incentive needs to be on leakage as a percentage of inventory, and that any incentive payment needs to be sufficient to capture the opex and capex costs of beating the leak rate.

1.36. SHETL agrees that an incentive mechanism should be developed in order to encourage improved management of SF6 and a decrease in leakage as a percentage of inventory. SHETL also agrees that due to the relative costs of undergrounding transmission circuits it is not appropriate to apply an undergrounding allowance.

1.37. SPTL considers that if an incentive on SF6 is introduced, it needs to recognise the increase in the amount of SF6 filled switchgear that will be in operation on the transmission system over the price control period. SPTL suggests that whilst the design of SF6 equipment is by and large in accordance with international standards, there are various areas such as improved handling techniques and maintenance that could be incentivised.

Other respondents' views

1.38. Whilst the majority of licensees agree with our approach on the SF6 incentive and undergrounding, several respondents express disappointment that despite positive developments in this area, we have not proposed an allowance for undergrounding.

Ofgem's views

1.39. Our proposals for an SF6 incentive recognise that there are no measures to incentivise best management practices, monitoring, reporting and a reduction in the leakage rates of SF6 via any other mechanism. We recognise that given the relative dearth of information on SF6 leakage, our proposals should be reviewed following experience of the operation of the scheme during the first year. We also consider that if appropriate monitoring and reporting procedures are not put in place, the incentive scheme will not be switched on.

1.40. We note the views of some respondents that an undergrounding allowance should feature as part of the TPCR. However, we consider that the cost benefit analysis provides a less compelling case than in electricity distribution. The transmission system is considerably less prevalent in National Parks and Areas of Outstanding Natural Beauty than electricity distribution networks, so any money available for undergrounding circuits would be better spent in distribution. Undergrounding at transmission voltages is also substantially more expensive than distribution. We think it is important to point out that the planning consents process represents an appropriate mechanism in which interested parties can express concern over a particular transmission line. Similarly, there is nothing preventing a third party from providing funding to underground transmission lines.

List of Respondents

List	Name
1	Western Power Distribution
2	Schroder Investment Management Ltd
3	Canatxx
4	Scottish Environment Protection Agency
5	Renewable Energy Systems Ltd
6	Energywatch
7	Friends of the Lake District
8	Mulberry Capital
9	Friends of the Peak District
10	Scottish Renewables
11	Highlands and Islands Enterprise
12	BG Gas Services
13	Association of Electricity Producers
14	Chemical Industries Association
15	British Wind Energy Association
16	Scottish Power
17	SBGI (Society of British Gas Industries)
18	Scottish Hydro Electricity Transmission Ltd
19	National Grid
20	EDF Energy Ltd
21	Centrica
22	Macquarie Bank
23	Wales and West Utilities
24	National Association for AONB
25	RWE npower
26	Natural Power Consultants and FORL
27	Energy Networks Association
28	United Utilities
29	Place
30	Renewables Advisory Board
31	Total E & P UK
32	Siemens
33	Fidelity Investment

34	Council for National Parks
35	Newton Investment Management
36	Teachers