ofgem Promoting choice and value
for all gas and electricity customers

Transmission Annual Report for 2008-09

Document Type: Annual Report

Ref: 48/10

Date of Publication: 1 April 2010

Target Audience: This document may be of particular interest to users of the transmission networks, licensees, providers of finance, consumer groups and other interested parties.

Overview:

This is the third report on transmission licensee's costs and forecast capital expenditure based on the regulatory reporting process introduced as part of Transmission Price Control Review for 2007-12 (TPCR4).

This report sets out revenue, operating cost, capital expenditure, and returns on regulatory equity for the four licensees in respect of their transmission owner (TO) responsibilities for the year ended 31st March 2009. This is the second year of the current price control. The report sets out Ofgem's provisional assessment of the Regulatory Asset Value (RAV) for each licensee as at 31 March 2009 although the RAV will not be finalised until the next price review following an efficiency assessment. It also provides information on system operator (SO) responsibilities for the year ended 31 March 2009.

Contact name and details: Martin Rodgers, Head of Network Business Support

Tel: 020 7901 7273

Email: martin.rodgers@ofgem.gov.uk

Team: Network Cost and Outputs Team, Local Grids and RPI-X@20

Context

All transmission licensees are required to report annually to Ofgem on the income received and costs they incur in operating, maintaining and improving their transmission systems. Over time, this information will show the trend of expenditure on each transmission system and will inform decisions in future price control reviews, the one year roll-over of TPCR4 as well as the next full review (TPCR5).

This report is the third annual report and covers the second year of the 2007 - 2012 price control period.

The aim of the report is to present the key information on the licensees operating and capital costs in a meaningful and user friendly format.

Associated Documents

- TPCR 2007 - 2012 Final Proposals, December 2006 (ref 206/06) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=191&refer=Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses
- Transmission Annual Report for 2006/07 (ref 60/08) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=9&refer=Networks/Trans/RegReporting
- Transmission Annual Report for 2007/08 (ref 31/09) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=27&refer=Networks/Trans/RegReporting
- Electricity Distribution Cost Review 2007-2008 (ref 165/08) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=28&refer=Networks/ElecDist/PriceCntrls/CostRep
- Gas Distribution Annual Report 2007/08 (ref 27/09) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=484&refer=Networks/GasDistr/GDPCR7-13

- Copies of these documents can be found on our website (www.ofgem.gov.uk)

Table of Contents

Summary 1
The purpose of the review 1
Results for 2008/09 1
1. Background and Introduction 3
Electricity and Gas Transmission in Great Britain 3
Regulatory Reporting 4
Objectives 4
Process for 2008/09 5
Compliance 5
2. Review of Transmission Owners (TO) Performance (in 2008/09 prices) 6
Background 6
Returns on Regulatory Equity (RORE) 6
Price Control Revenue 8
National Grid Electricity Transmission 8
Scottish Hydro-Electric Transmission 9
Scottish Power Transmission 10
National Grid Gas 11
Total Expenditure 12
Total Operating Costs 13
Controllable Operating Costs (including non operational capex) 13
Controllable Opex NGET 14
Controllable Opex SHETL 15
Controllable Opex SPTL 16
Controllable Opex NGG 17
Interest Cost 18
Pension Costs 19
Tax Clawback Calculation 19
Total Capital Expenditure (Base Line) 20
Capital Expenditure NGET 21
Capital Expenditure SHETL 21
Capital Expenditure SPTL 22
Capital Expenditure NGG 22
Incentivised Capex 23
Logged Up Capex 24
Forecast Capex (Base Line) to 2011/12 25
NGET 25
SHETL 27
SPTL 28
NGG 29
Provisional RAV 30
Capitalisation Items 31
Innovation Funding Initiative (IFI) 32
3. Review of System Operator (SO) Performance (in 2008/09 prices) 33
Background 33

Price Control Revenue 33
National Grid Gas 33
National Grid Electricity Transmission 34
Total Internal Expenditure 36
Total Internal Operating Costs 36
Pension Costs 37
Total Internal Capital Expenditure 38
Forecast Internal Capital Expenditure 39
Provisional RAV 40
Appendices 41
Appendix 1 - Data on individual transmission licensees 42
National Grid Electricity Transmission (NGET) 43
LICENSEE'S COMMENTS 45
NGET Transportation Owner (TO) 45
NGET System Operator (SO) 45
Scottish Hydro Electricity Transmission (SHETL) 46
LICENSEE'S COMMENTS 47
Scottish Power Transmission (SPT) 48
LICENSEE'S COMMENTS 49
National Grid Gas (NGG) 50
LICENSEE'S COMMENTS 52
NGG Transmission Owner (TO) 52
NGG System Operator (SO) 53
Appendix 2 - Responses and Questions 54
Appendix 3 – The Authority's Powers and Duties 55
Appendix 4 - Glossary 57
Appendix 5 - A guide to Return on Regulatory Equity 60
Appendix 6 - Amendments to Regulatory Reporting Pack (RRP) Tables 61
Appendix 7 - Feedback Questionnaire 62

Summary

The purpose of the review

Historical data is a critical input to our price control work. At the time of the last transmission price control review (TPCR4) we made a commitment to capturing and publishing annual cost reports. The contents of this report will improve the quality of our information on costs, revenues, incentives and outputs and will help us to monitor and set future price controls and incentives. This enables comparison of actual expenditure with the price control allowances set at TPCR4 and will inform both the price control roll-over (which will apply for the 2012/13 regulatory year) and the next price control (TPCR5). We also report on external and internal System Operator (SO) costs.

The report also provides greater transparency of the financial performance of the companies, particularly in relation to the regulatory allowances.

The basis for the reporting of TO and SO costs is set out in the Transmission Price Control Review Reporting Rules; Instructions and Guidance (version 3.0) April 2009. These rules were developed following the last price control to provide a robust and coherent framework for cost reporting in the format of a Regulatory Reporting Pack (RRP). The pack comprises formatted Excel workbooks and a commentary on annual expenditure.

In reading the report it is important to take account of differences in the time at which costs and investments were incurred and when consequential adjustments are made to regulatory allowances (e.g. for logged up costs and incremental investment revenue drivers). Due to these timing differences returns and RAV are understated and debt to RAV is overstated.

Results for 2008/09

Average return on regulatory equity for all TOs was 7.2%, slightly above the 7.0% allowed return, although there was a spread from 6.8% to 8.2%.

Total revenue across electricity and gas TOs was £2200m which is within 1.0% of the allowance. The electricity and gas SO revenues were £1250m, the electricity SO balancing costs significantly above the target, £826m against £545m (the upper limit of the "deadband"). This was due to higher margin costs, power prices and constraint costs.

Total controllable operating costs across the TO licensees of £319m were 15.5% above allowances. As in 2007/08 this is primarily due to NGET costs exceeding allowances. Internal electricity and gas SO costs of £91m were 13.7% above allowances, split equally between gas and electricity. The key causes of this were, bringing in house critical IT systems from an outsourced supplier, general and specific energy price inflation.

Total electricity and gas capital expenditure by TOs was £1034m, 4.1% above allowances (before calculation of incentivised capex and revenue drivers). This was mainly due to NGET and SHETL exceeding their load related capital expenditure allowances. In aggregate NGG exceeded its load related allowance due to continuing spend on Milford Haven, but was lower on non load related expenditure. Internal SO capital expenditure was £20.8m, 14.9% above allowances.

National Grid is now projecting volumes of non load related capex which are significantly lower than were forecast at the time of the last price control. Given the scale of the change, we will be seeking to understand the reasons for the forecasting differences. We will do this either during the TPCR4 price control roll-over, or during TPCR5.

National Grid forecast SO internal capex to significantly exceed (32.9%) the price control allowance over the 5 year period due to upgrading of critical systems.

As in 2007/08 all licensees incurred lower interest costs than envisaged at the time of the last price control.

Overall total contributions to pension schemes were £297.2m, £261.1m (87.9%) of which were deficit payments made by National Grid.

1. Background and Introduction

Chapter Summary

This is the third year of the Regulatory Reporting process introduced as part of the last transmission price control settlement.

Electricity and Gas Transmission in Great Britain

1.1. Electricity Transmission: The transmission system is a network of power lines that transport electricity at high voltages across Great Britain. Electricity is generated at power plants and the transmission system conveys this into the local distribution networks for onward distribution to customers. There are three electricity transmission owners in the UK; one in England & Wales and two in Scotland. The systems are fully interconnected, but exist under separate ownership.

1.2. The electricity transmission system in England & Wales is owned and operated by National Grid Electricity Transmission (NGET) plc. It is the largest of the three transmission companies, covering around 150,499km2 and delivers around 305 TWh of electricity to over 28.4 million electricity customers on an annual basis.

1.3. Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electricity Transmission Ltd (SHETL) own, plan and develop (but do not operate) the Electricity transmission system in Scotland. Together, they cover an area of more than 78,117km2 and deliver about 32.6 TWh of electricity annually to about 2.7 million customers. SPTL covers the south of Scotland, while the north is covered by SHETL.

1.4. Gas Transmission: The Gas National Transmission System (NTS) comprises a network of high pressure pipes and compressor stations connected to the distribution network and independent systems. Gas is brought into Great Britain from gas fields in the North Sea and Norway, via pipelines linking us to continental Europe and from liquefied natural gas (LNG) terminals. The NTS is owned by National Grid Gas.

1.5. Regulation of the Transmission system is separated into two; Transmission Owners (TOs) who own and maintain the network of transmission assets and Systems Operators (SOs) who operated the network.

1.6. The system operators covering the whole of GB are NGET for electricity and NGG for Gas.

Regulatory Reporting

1.7. In the Transmission Price Control Review Final Proposals (Ref 206/06) published in December 2006 paragraph 12.1 we made a commitment to publish an annual regulatory reporting pack:

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

1.8. Following TPCR4 new licence conditions (B16 and A40 for gas and electricity respectively) were introduced to provide for an annual reporting process.

1.9. This is the third RRP for the Transmission Operators (TOs). It relates to the 2008/09 financial year, the second year of the current price control period 2007 to 2012. The information for the following licensees is included in the report:

- National Grid Electricity Transmission plc (NGET) both TO and SO,
- Scottish Hydro Electric Transmission Limited (SHETL),
- Scottish Power Transmission Limited (SPTL), and
- National Grid Gas plc (NGG) both TO and SO

Objectives

1.10. The Transmission Price Control Review Reporting Rules: Instructions and Guidance set out the objectives of the RRP. These are:

- To ensure the RAV is rolled forward according to the TPCR4 Final Proposals;
- To improve the robustness and consistency of data reported to us;
- To reduce the burden on TOs to provide such information at a price control; and
- To improve the transparency of reporting requirements.

1.11. Thus, the key elements of the annual reporting process are to provide an overview of:

- revenue,
- operating costs,
- capital expenditure,
- financeability, and
- a provisional regulatory asset value (RAV).

1.12. The provisional RAV is calculated in accordance with the methodology set out in the TPCR4 Final Proposals. This RAV is provisional until finalised at the next price

control. We will shortly consult on the scope of the TPCR4 roll-over for one year. Depending on the outcome of this consultation and subsequent decisions we will undertake a review of historical capex either under the roll-over or under TPCR5.

1.13. We have also developed a measure of "return on regulatory equity" which we first utilised in the 2007/08 Transmission Regulatory Report. We plan to use this as a means of comparing the overall financial performance of businesses with the assumptions built into price control allowances. This also provides some context for the more detailed assessments of components of expenditure performance arising from the annual cost reporting process

Process for 2008/09

1.14. The regulatory reporting process for 2008/09 was similar to the one followed in previous years. Companies submitted revenue, cost, and financial data at the end of July 2009. We then undertook a review of the information and raised a number of supplementary questions. The review involved one visit to each licensee to assess performance and clarify the data submitted. All licensees were given the opportunity to meet with Ofgem's Senior Partner Transmission and Governance to review key findings from the reporting process.

1.15. Overall, the response from licensees to the process undertaken was constructive.

1.16. It is proposed to make some minor changes to the reporting process for future years to address points that have arisen with the licensees during the course of RRP review.

Compliance

1.17. We take compliance with licence conditions very seriously. We expect licensees to augment their processes and systems where necessary, to collect, reconcile and supervise data so as to complete reporting to us in accordance with the RRP guidance. There is a requirement for licensees to come forward with information on any errors that have occurred in previous submissions and, where errors are inadvertent, we have not penalised the licensees.

1.18. During this year we have validated, to our satisfaction, substantive samples of the financial data submitted by each of the licensees in their various reports to us. This includes data contained in the regulatory reporting pack.

2. Review of Transmission Owners (TO) Performance (in 2008/09 prices)

Chapter Summary

This chapter summarises the key data from the licensees as Transmission Owners. The main areas of concern are: NGET's operating costs being above the allowance for the second year, NGET's further changes in the quantity of some asset replacement volumes for the price control period similar to 2007/08 although on a reduced scale, and SPTL's reduction in expenditure on asset maintenance.

Background

2.1. In this section we have provided an overview of the main components of TO performance in 2008/09 compared to the price control allowances converted to this years' price level, specifically:

- Return on Regulatory Equity (RoRE)
- Turnover in 2008/09
- Interest costs in 2008/09
- Pension costs in 2008/09
- Operating Costs in 2008/09,
- Capital Expenditure in 2008/09,
- Forecast Capex to 2011/12, and
- Provisional RAV for 2008/09.

Returns on Regulatory Equity (RORE)

2.2. In the 2007/08 Transmission Regulatory report we developed the RORE calculation. This measure will not necessarily be consistent with standard accounting metrics for the return on equity, but we think it helps us (and all interested parties) understand better how companies have performed. A guide to RORE can be found in Appendix 5.

2.3. The figures for NGET and NGG include internal SO as RORE for SO alone is not meaningful. Excluding SO data has the effect of increasing NGET RORE from 6.82% to 7.01% and NGG from 7.55% to 7.77%.

Figure 1 - 2008/09 Returns on Regulatory Equity

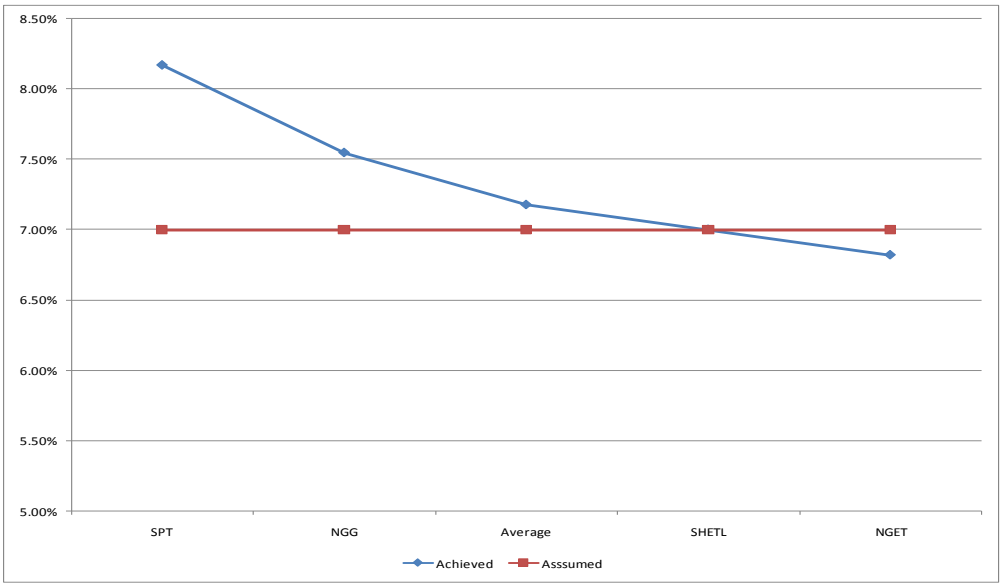
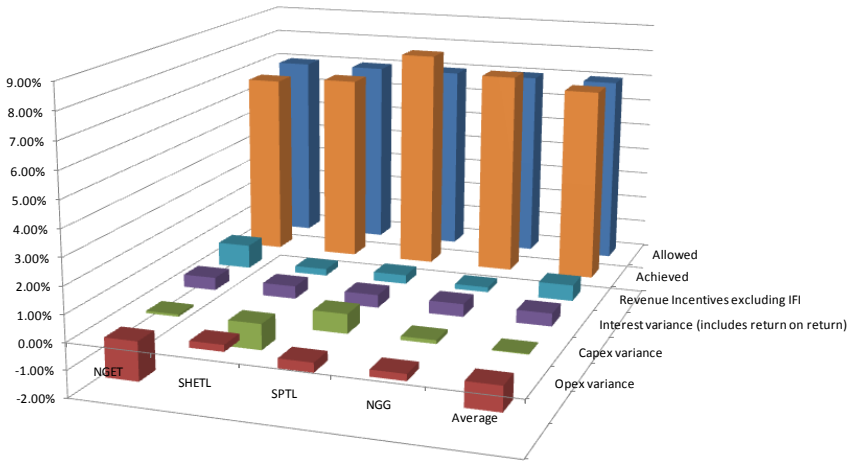


Figure 2 - Components of Variance in Returns on Regulatory Equity



	NGET	SHETL	SPTL	NGG	Average
Opex variance	-1.46%	0.25%	-0.34%	-0.24%	-0.91%
Capex variance	-0.08%	-0.97%	0.71%	0.14%	0.03%
Interest variance (includes return on return)	0.47%	0.47%	0.47%	0.47%	0.47%
Revenue Incentives excluding IFI	0.89%	0.25%	0.33%	0.19%	0.59%
Achieved	6.82%	7.00%	8.17%	7.55%	7.18%
Allowed	7.00%	7.00%	7.00%	7.00%	7.00%

2.4. Figure 1 above compares the returns on regulatory equity assumption which underpinned the last price control with the actual returns earned by each TO. NGET's return was below the allowed return, this was due overspending on opex offset to some extent from revenue incentives. SPTL is higher than allowed due to capex under spends and revenue incentives offset by overspend on opex. NGG have

benefited mainly from under spending their capex allowance. The cumulative RoRE performance after 2 years is as follows.

2.5. Figure 2 shows the way in which different components contributed to the overall variance. As in 2007/08 all TOs have benefited from lower interest rates.

2.6. The cumulative RoRE performance after 2 years is as follows.

Cumulative RoRE Performance					
NGET	SHETL	SPTL	NGG	Average	Allowed
6.88%	8.07%	8.51%	7.33%	7.20%	7.00%

Price Control Revenue

2.7. The revenue figures shown below exclude income from excluded services such as; post BETTA connection charges, services for 3rd parties, miscellaneous and de minimis income

National Grid Electricity Transmission

Table 1 - NGET TO Revenue Summary

(figures in £m)	2007/08	2008/09	Year on year variance	Variance%
Total Allowance	1297.71	1407.08	109.36	8%
Total Actual Revenue	1298.72	1421.63	122.91	9%
Over / Under Recovery	1.00	14.55	13.55	

NB. Figures include income collected on behalf of the Scottish TOs.

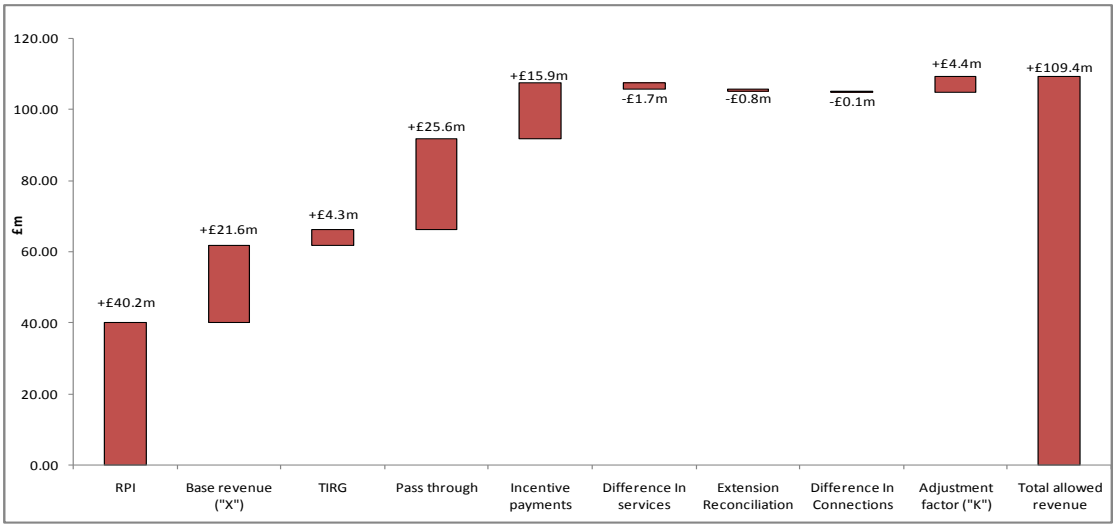
2.8. NGET's base line allowed revenues rose by £109.4m (8%) year on year. The largest single element of this increase (£40.2m) is due to inflation. Other significant increases include an additional £25.6m of pass- through costs and an increase of £4.3m in construction revenues associated with the England – Scotland interconnection project under the Transmission Investment for Renewable Generation (TIRG) programme. Table 1 shows NGET allowed and actual TO revenues for 2008/09 and the previous year as well as the year on year change.

2.9. NGET was able to recover incentive revenues of just under £19m in 2008/09, which represents an increase of nearly £16m on the previous year. This includes £10.5m under the reliability incentive (an increase of £12m) and £2.2m under the Sulphur Hexafluoride (SF6) leakage arrangements, which provides NGET with an incentive to minimise the volume of SF6 gas that leaks from transmission equipment. NGET was also able to recover £6.2m via the IFI scheme, which allows it to pass through 80% of spend on eligible research and development projects. At £7.7m, IFI spend in 2008/09 was more than double the £3m spent in the previous year.

2.10. NGET recovered £14.6m of revenues in excess of the allowed maximum for the year. The explanation given for the over recovery is the early connection of

generation plant in Scotland and delays to the connection of generation plant in negative charging zones. The chart below shows the areas of movement in NGET TO revenues, year on year.

Figure 3 - NGET TO Year on Year Movement in Revenue



Scottish Hydro-Electric Transmission

2.11. Table 2 shows SHETL allowed and actual TO revenues for 2008/09 together with data for the previous year and the year on year change.

Table 2 - SHETL Revenue Summary

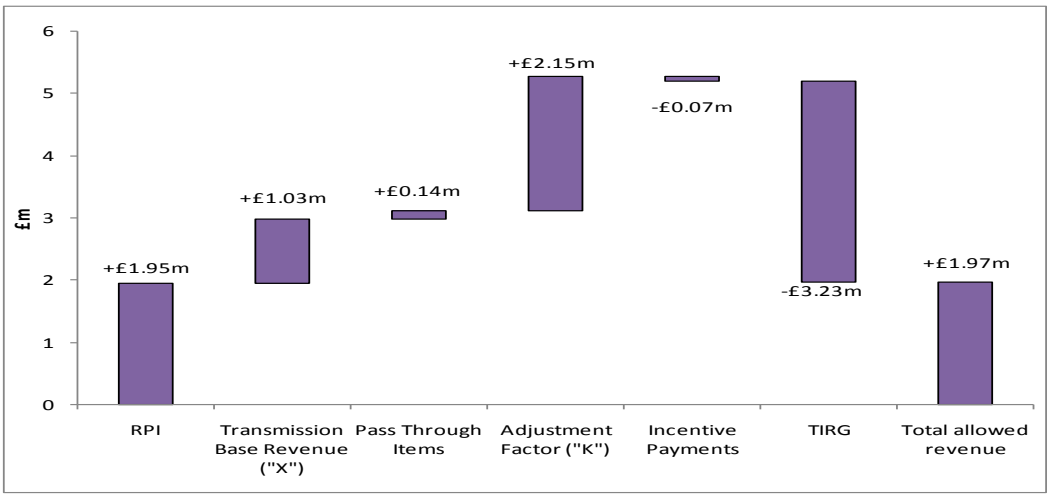
(figures in £m)	2007-08	2008-09	variance	variance%
Total Allowance	55.49	57.46	1.97	4%
Total Actual Revenue	53.54	59.32	5.78	11%
Over / Under Recovery	-1.95	1.86	3.81	

2.12. SHETL's base line revenues increased by around £2m in 2008/09 compared with 2007/08. There was an increase of around £3m in base revenues, £2m of which was due to inflation. This was offset by a decrease of a similar amount relating to pre-construction revenues for the Beauly-Denny project that were recoverable in 2007/08. The remaining £2m relates to differences in the SHETL revenue recovery positions for the two preceding years when SHETL over-recovered £1.9m against its allowed revenue. The licensee has explained that this relates to the timing of costs associated with the public inquiry into the Beauly-Denny project.

2.13. SHETL was entitled to recover marginally less revenue under the Innovation Funding Incentive in 2008/09, £0.31m, compared with £0.35m in 2007/08.

2.14. The chart below shows the areas of movement in SHETL revenues, year on year.

Figure 4 - SHETL Year on Year Movement in Revenue



Scottish Power Transmission

Table 3 - SPTL Revenue Summary

(figures in £m)	2007-08	2008-09	Year on year variance	Variance%
Total Allowance	169.69	180.10	10.41	6%
Total Actual Revenue	169.50	180.44	10.94	6%
Over / Under Recovery	-0.19	0.34	0.53	

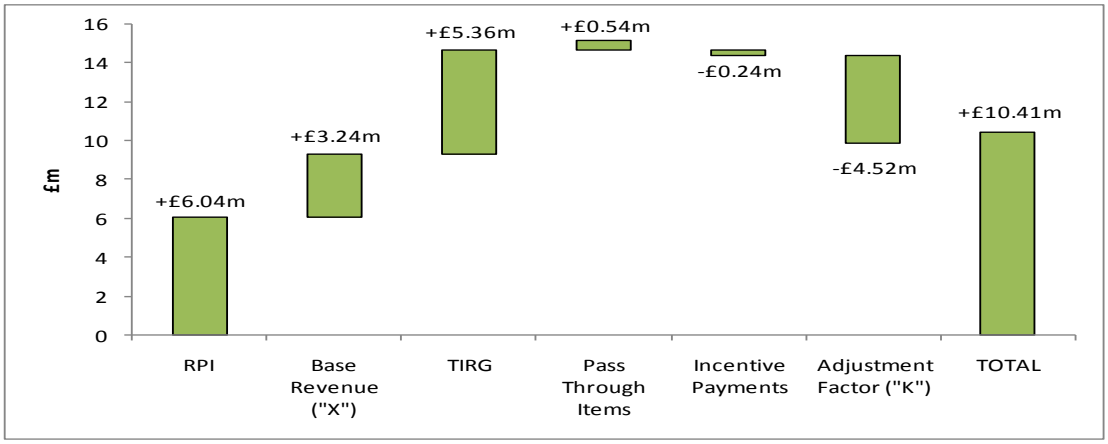
2.15. SPTL base line allowed revenues increased from £170m in 2007/08 to £180m in 2008/09. Of this £6m was due to inflation. Table 3 shows SPT allowed and actual TO revenues for 2008/09 together with data for the previous year and the year-on-year change.

2.16. Compared to 2007/08, there was a positive variance against TIRG revenue of £5.4m due to increased allowances in respect of the England – Scotland interconnector project, Project B5 and Sloy. There was a large negative movement in the correction "K" factor due to the fact that there was a small positive correction adjustment in 2008/09 compared with a significantly larger one in the previous year. Figure 5 shows SPTL allowed and actual TO revenues for 2008/09 and the previous year as well as the year on year change.

2.17. SPT performed slightly worse under its incentive mechanisms, which meant that it was entitled to recover around a quarter of a million pounds less than in the previous year. The principal reason for this was SPTLs performance under the reliability incentive, where adverse weather conditions caused an increased number of loss of supply incidents. The revenue for the reliability incentive relates to performance in 2007/08.

2.18. SPTL spent less on IFI eligible projects in 2008/09, £0.17m compared to £0.23m in the previous year. This figure represents less than half of the amount that SPTL is entitled to spend under the IFI arrangements.

Figure 5 - STPL Year on Year Movement in Revenue

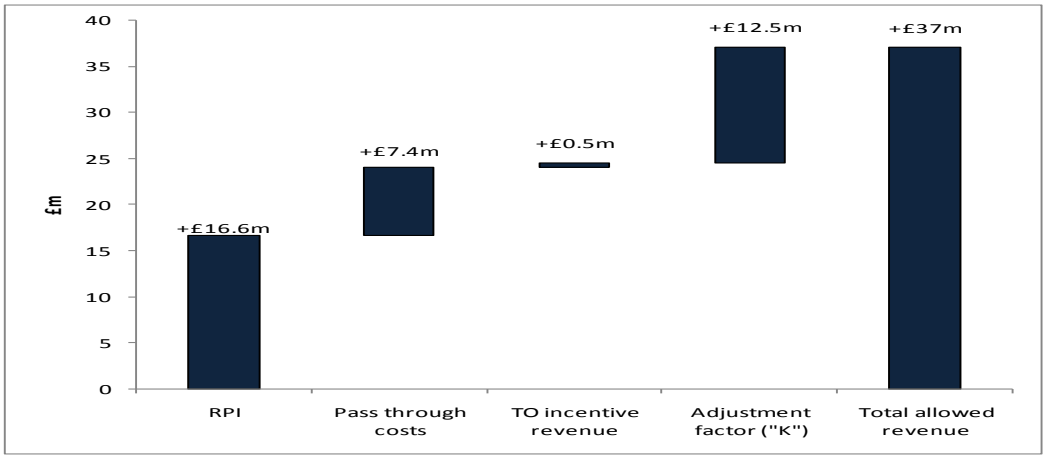


National Grid Gas

Table 4 - NGG TO Movement in Revenue

(figures in £m)	2007-08	2008-09	Year on year variance	Variance%
Total Allowance	526.07	563.09	37.02	7%
Total Actual Revenue	524.04	538.10	14.06	3%
Over / Under Recovery	-2.03	-24.99	-22.96	

Figure 6 - NGG TO Year on Year Movement in Revenue



2.19. NGG TO revenues stood at £563m for the year 2008/09. This represents an increase of 7%, or £37m, on the previous year. Of this, £16m was the effect of inflation on the base revenue allowance. Pass-through costs increased by around

£7.4m, owing primarily to costs associated with the conveyance of liquefied petroleum gas to independent systems, offset by a decrease in the pass through of additional security costs. Figure 6 shows NGG allowed and actual TO revenues for 2008/09 together with data for the previous year and the year-on-year change.

2.20. NGG TO under-recovered against the maximum allowed revenue by £25m, or around 4% of allowed revenue. NGG has explained that the under-recovery was mainly due to revenues from capacity auctions being 16% lower than expected. Booked exit capacities were also lower than anticipated when the charges were set.

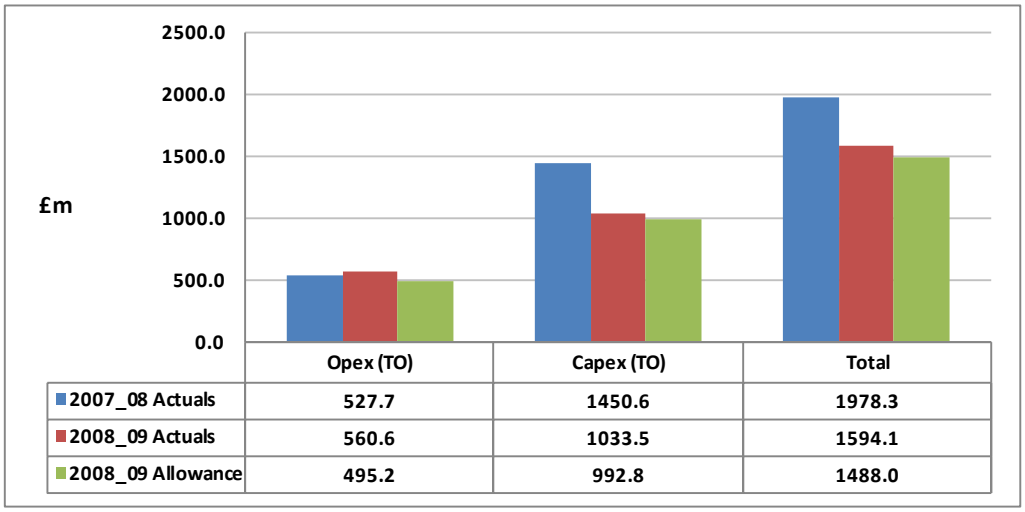
2.21. The increase of £0.5m in incentive payments relates solely to an increase in spending on Innovation Funding Initiative (IFI) eligible projects.

Total Expenditure

2.22. Total transmission expenditure across all TOs (operating costs and capital expenditure) of £1.6bn represents a decrease of 19.5% (£386m) on the prior year; this was due to the substantial completion of the Milford Haven pipeline project in 2008. Despite this total expenditure was 6.9% (£103m) above the price control allowances. Operating expenditure was £61.7m overspent, while capital expenditure was £40.7m overspent against base line allowances.

2.23. The variance in total expenditure against allowance is partially explained by the factors above, increases in cost of own use electricity due to high electricity prices and increases in load related capital expenditure

Figure 7 - Total Transmission Expenditure by Category

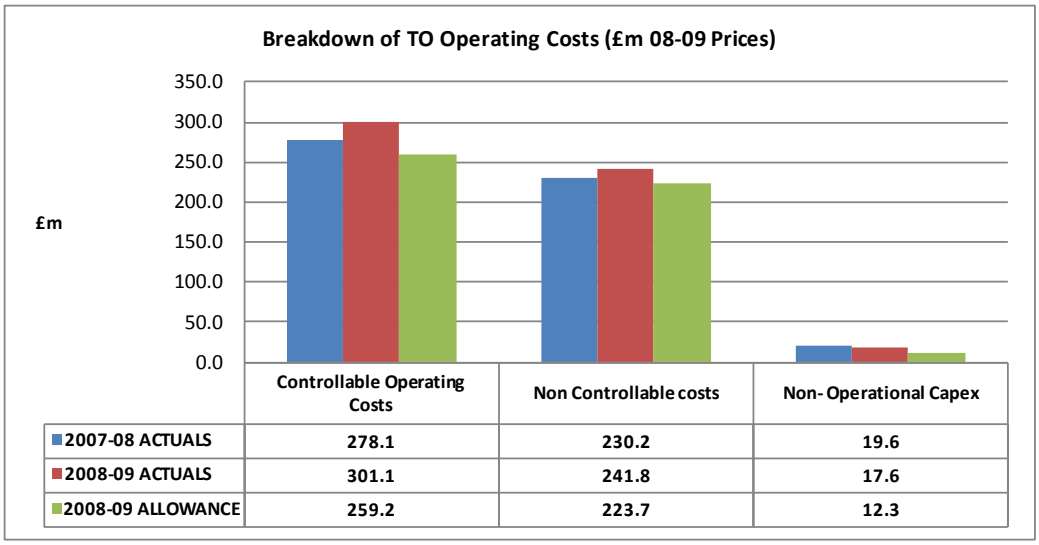


	Opex (TO)	Capex (TO)	Total
2007_08 Actuals	527.7	1450.6	1978.3
2008_09 Actuals	560.6	1033.5	1594.1
2008_09 Allowance	495.2	992.8	1488.0

Total Operating Costs

2.24. The total operating cost allowances for the transmission companies can be divided into 3 main elements: controllable, non controllable and an allowance for non operational capex. Performance for 2008/09 is shown below.

Figure 8 - Breakdown of TO Operating Costs

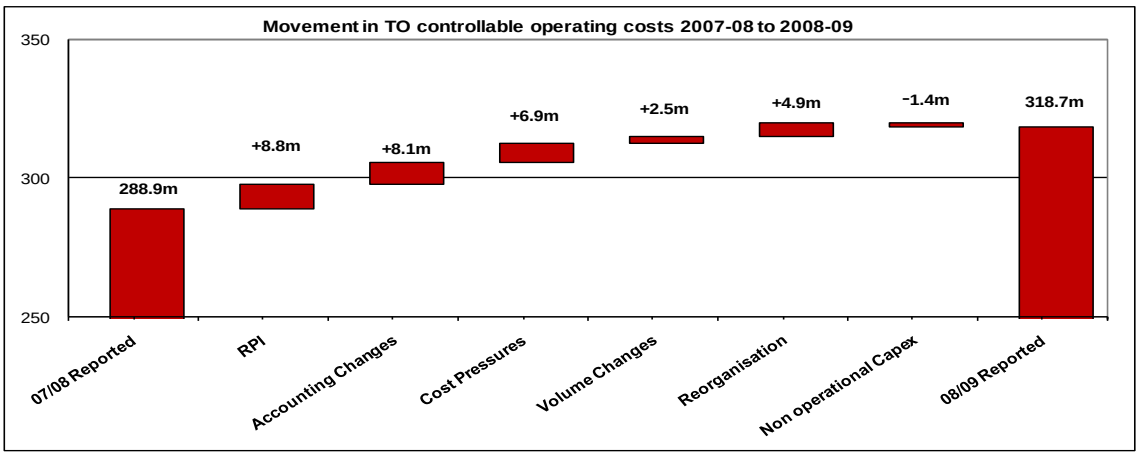


	Controllable Operating Costs	Non Controllable costs	Non- Operational Capex
2007-08 ACTUALS	278.1	230.2	19.6
2008-09 ACTUALS	301.1	241.8	17.6
2008-09 ALLOWANCE	259.2	223.7	12.3

2.25. TOs incurred a total of £301.1m in controllable operating expenditure (excluding non-operational capex) in 2008-09. This represents 16.2% (£41.9m) overspend against the 2008/09 allowance of 259.2m, and an 8.3% (£23m) increase on the 2007/08 expenditure.

Controllable Operating Costs (including non operational capex)

Figure 9 - Movement in Total TO Controllable Operating Costs

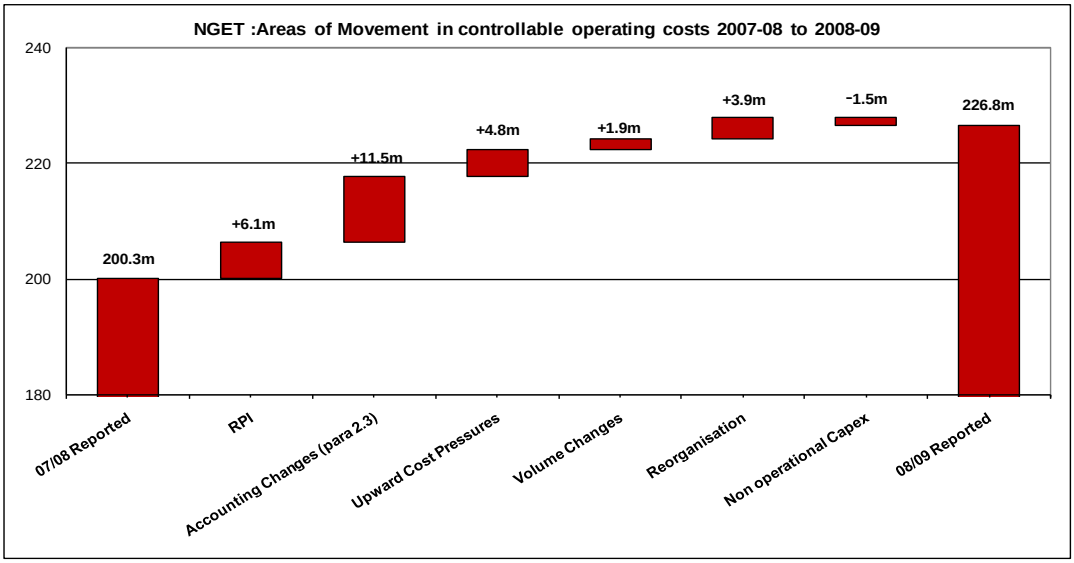


2.26. Figure 9 shows the main components of movements in controllable operating costs from 2007/08 to 2008/09 for all transmission assets owners (TO).

2.27. Overall, total controllable operating costs for the TOs was £21m (7%) higher than last year's expenditure. Across the TOs the costs movements are largely driven by NGET and NGG and relate mainly to accounting adjustments increasing costs pressures and management initiative such as reorganisations,

Controllable Opex NGET

Figure 10 - NGET movement in Controllable Opex



2.28. Figure 10 above shows the main components of movement in controllable operating costs between 2007-08 and 2008-09 for NGET.

2.29. Controllable operating expenditure for 2008/09 was £226.8m; 10% above 2007/08 expenditure of £206.4m. Aside from general inflation, most of the increase in operating costs is attributable to the following four areas of NGET's operations:

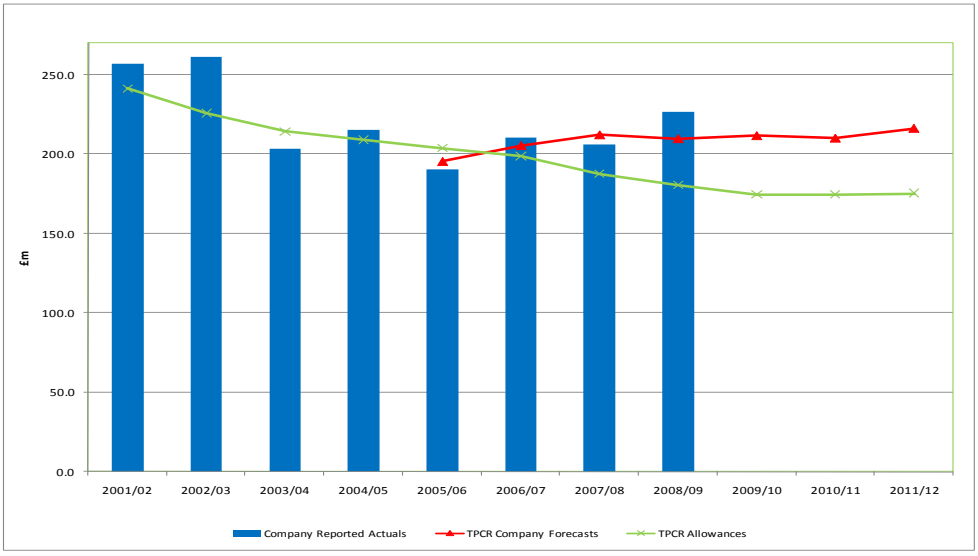
- Accounting change - reclassification of excluded services overhead diversion schemes (£11.5m). These costs are offset by additional revenues
- Increase in own use electricity due to a steep rise in electricity prices (£4.3m).
- The impact of various change and reorganisation programmes, which have been running for the last few years, which have further increased operating costs. The net effect of these changes was £3.9m increase in operating costs in the current year, as shown above. Over the last three years NGET have implemented various change and reorganisation programmes, these initiatives include the

transformation of shared services functions and back office processes and systems.

- Lastly, there has been an increase in planned and unplanned maintenance.

2.30. The chart below shows NGET's performance against operating cost allowances.

Figure 11 - NGET Opex Performance against Allowances



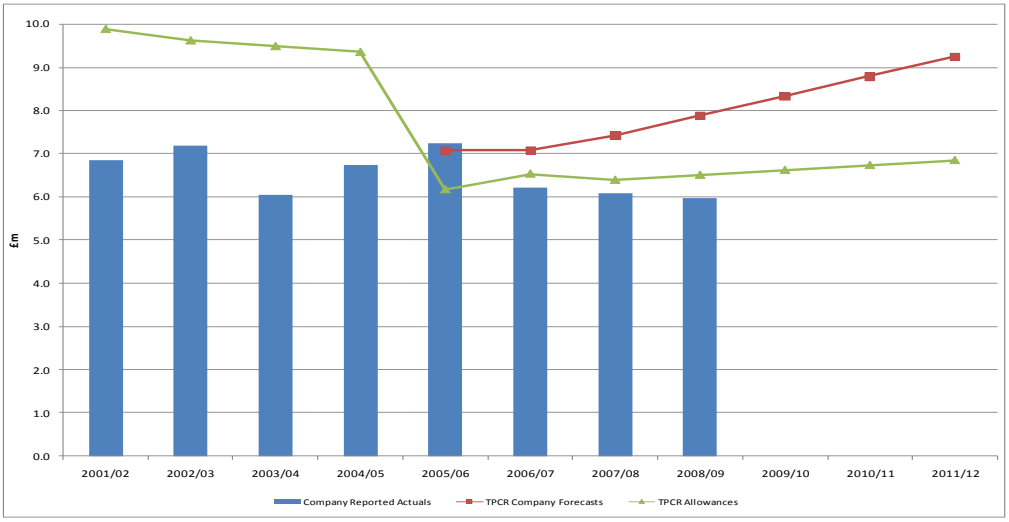
2.31. NGET have overspent against their allowance in the first two years of the price control. In 2008/09 they spent £46.0m (representing 26.7%) more than the allowance, this is due to accounting changes, high energy costs and increased maintenance costs

2.32. In 2008/09, NGET also brought forward the investment in IS systems. This has resulted in non operational capex being £4.5m higher than the allowance of £8.4m.

Controllable Opex SHETL

2.33. Figure 12 below shows the operating costs trend for SHETL since the last price control. Controllable operating expenditure for 2008/09 was £6.0m, representing an 8.1% under spend against allowance. However, SHETL signalled that operating costs are expected to increase in future years as their network expands.

Figure 12 - SHETL Opex Performance against Allowances

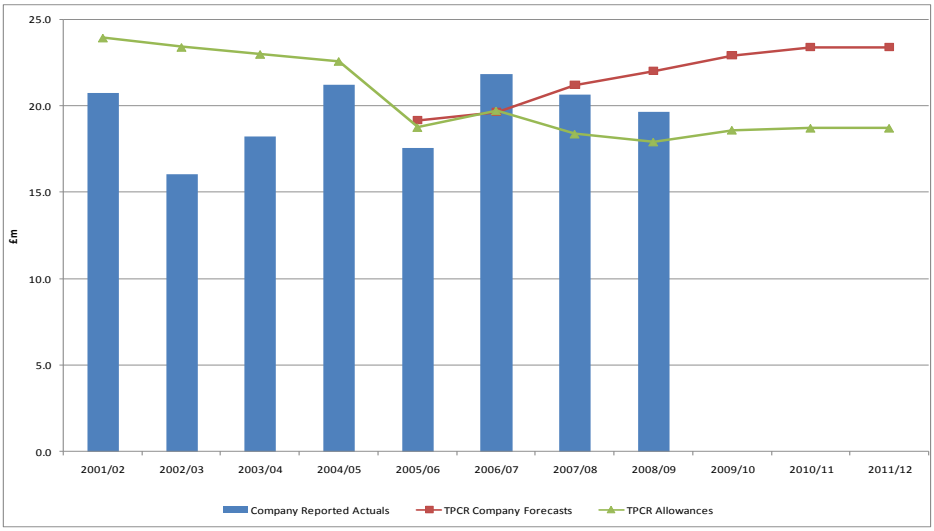


2.34. SHETL stated that they would not need to replace assets to resolve the issues caused by BT's implementation of their 21 century network (BT21CN). SHETL expect to work with BT to ensure continued availability of the current platform post 2014. This is, however, subject to enough existing users committing to the continued use of this facility.

2.35. There has been an ongoing focus on operational efficiency within group companies that provide services to SHETL. This has translated into a £0.9m under spend against price control allowance.

Controllable Opex SPTL

Figure 13 - SPTL Opex Performance against Allowances



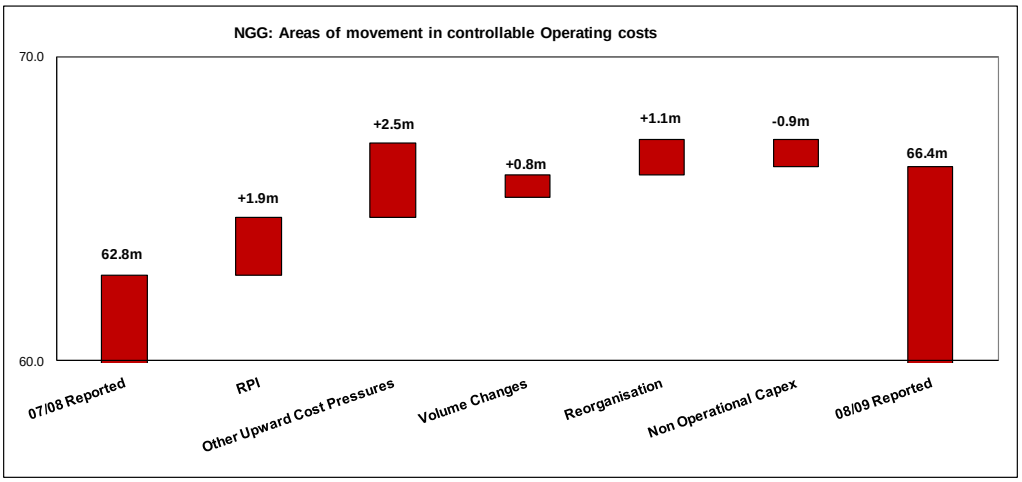
2.36. SPTL experienced a £1.8m (9.9%) over spend in controllable opex in 2008/09. This was after an adjustment a £5.8m for capitalisation. The major reasons given for the under spend were constrained planned maintenance as a result of network construction activity and a management decision to focus on major overhead lines (OHL) refurbishment as against tower painting . According to SPTL, the OHL refurbishment programme consumed the majority of the available outages, restricting the ability to carry out maintenance activities

2.37. Despite the apparent reduction in maintenance activity- especially tower painting, SPTL consider that the full maintenance programme, as proposed in the price control submission will be met. SPTL has stated that they had commenced an accelerated tower painting programme in 2009 to ensure work is completed before the end of the price control and are forecasting to spend about £1m per annum in future years.

2.38. SPTL's overspend against their non-operational capex allowance was due to land and building expenditure relating to work to fit out a new depot.

Controllable Opex NGG

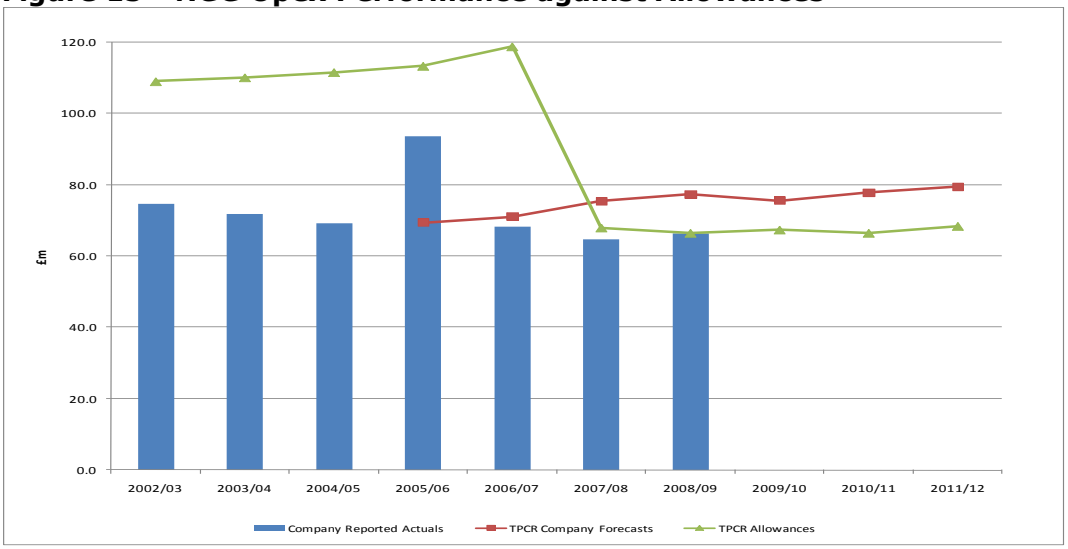
Figure 14 - NGG Movement in Controllable Opex



2.39. Figure 14 above shows the main components of movement in controllable operating costs between 2007-08 and 2008-09 for NGG.

2.40. Controllable operating expenditure for 2008/09 was £66.4m, an increase of 2.6% on 2007/08 expenditure of £64.7m. Operating costs were higher than the price control allowance due mainly to higher electricity costs, but this was offset by lower expenditure on non operational capex.

Figure 15 - NGG Opex Performance against Allowances



Interest Cost

2.41. To provide a comparison of interest costs between operators, Table 5 summarises, for each of the Transmission Operators - the end of year net debt position, achieved interest rate and the composition of the gross debt portfolio –. In the TPCR4 financial model, the allowance for financing costs was calculated by using the pre-tax cost of debt assumption made in the Weighted Average Cost of Capital (WACC), i.e. 3.75% real. As the table shows, all four of the TOs are comfortably outperforming on the cost of debt, particularly SHETL and SPT.

Table 5 - Interest Costs

Table 2.3 Interest costs (£m)	**NGET TO**	**SPT TO**	**SHETL TO**	**NGG TO**
Opening net debt	3,317.8	504.4	158.1	2,181.1
Closing net debt	3,844.6	410.0	158.1	2,513.3
Average net debt	**3,581.2**	**457.2**	**158.1**	**2,347.2**
Aggregation of gross debt (ex. derivatives/leases)*				
-Fixed	48%	30%	100%	52%
-Floating	9%	70%	0%	15%
-Index-linked	43%	0%	0%	32%
P/L net interest (attributable to TO) - £m	**233.3**	**24.3**	**7.9**	**147.8**
Achieved nominal interest rate - %	6.5%	5.3%	5.0%	6.3%
Average March-March RPI inflation	3.0%	3.0%	3.0%	3.0%
Achieved real interest rate - %	**3.4%**	**2.3%**	**2.0%**	**3.2%**
TPCR interest rate assumption	3.75%	3.75%	3.75%	3.75%
Implied (under)/ out-performance	0.3%	1.5%	1.8%	0.5%
*Note: For NGET and NGG the aggregation of gross debt includes debt that may be attributable to non-transmission assets e.g. LNG, metering etc.				

Pension Costs

2.42. Table 6 below compares actual pension costs with the price control pension allowances. The allowances and actual are based on the cash amount paid into the pensions scheme rather than the charge shown in the financial statements. The pension numbers quoted are provisional and may be subject to re-statement on final agreement with Ofgem regarding input data and allocations.

NGG have made a deficit payment that is significantly higher than assumed in TPCR4 (where allowances were set based on a notional 10 year deficit recovery period) since they have agreed to reduce their deficit over a 2.5 year period (resulting from a deferral of payments in earlier years). The difference to allowed funding will be corrected at subsequent full price controls subject to it being determined as efficiently incurred.

Table 6 Pension Cost 2008/09

	Electricity Transmission				Gas
Pension costs (£m) - nominal	**NGET TO**	**SPT TO**	**SHETL TO**	**Total**	**NGG TO**
2008/09 Actual					
Ongoing costs	14.4	1.1	1.2	16.7	9.0
Deficit repair	63.2	0.0	0.0	63.2	178.0
Total	**77.6**	**1.1**	**1.2**	**80.0**	**186.9**
Allowances					
Ongoing costs	15.8	1.5	1.8	19.1	12.2
Deficit repair	41.6	0.0	0.0	41.6	29.8
Total	**57.3**	**1.5**	**1.8**	**60.6**	**42.0**
Variance to allowance					
Ongoing costs	(1.3)	(0.4)	(0.6)	(2.3)	(3.3)
Deficit repair	21.7	0.0	0.0	21.7	148.2
Total	**20.3**	**(0.4)**	**(0.6)**	**19.3**	**144.9**

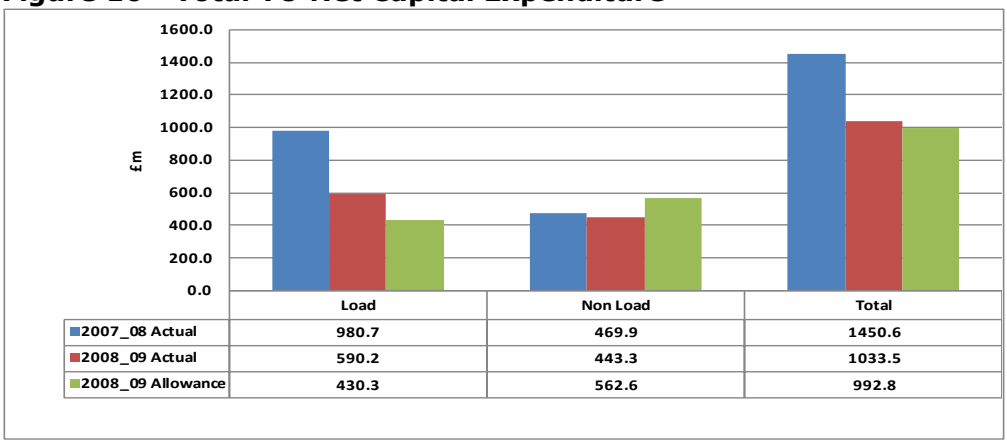
Tax Clawback Calculation

2.43. As outlined in the Transmission Price Control Review: Final Proposals decision document 206/06 section 8.21, we intend to make ex post adjustments to reduce the tax allowance where both actual gearing and actual interest expense exceed the level assumed in the TPCR4 financial model. The methodology for this was published in an open letter of 31 July 2009 "Clawback of tax benefit for excess gearing".

2.44. Calculations (including the "shadow" RAV element) have been made for both 2007-08 and 2008-09. This indicates that there are no adjustments required for either year.

Total Capital Expenditure (Base Line)

Figure 16 - Total TO Net Capital Expenditure



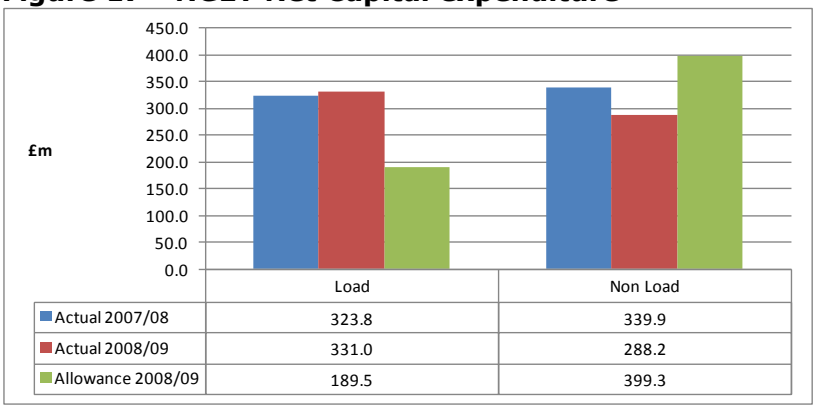
	Load	Non Load	Total
2007_08 Actual	980.7	469.9	1450.6
2008_09 Actual	590.2	443.3	1033.5
2008_09 Allowance	430.3	562.6	992.8

2.45. Across all of the Transmission Operators total Load related capital expenditure was £590.2m, 37.2% above the TPCR4 base line allowance and 39.8% below the expenditure incurred in 2007/08. Non load capital related expenditure in 2008/09 was £443.3m, 21.2% below the TPCR4 allowance and 5.6% below the expenditure incurred in 2007/08. These variances are against base line allowances.

2.46. All the capex allowance figures, base line and incentivised, are shown before any impact of revenue drivers. All NGET's revenue drivers and the downward element of Scottish TOs' revenue drivers (if connecting lower volume of generation than baseline level) will take effect as a one-off amount at the end of the TPCR4. The upward element of Scottish TOs' revenue drivers (if connecting higher volume of generation than baseline level), on the other hand, will take effect in the year that the baseline generation volume is exceeded. Currently none of the TOs are triggering the upward revenue drivers, but SHETL and SPTL are currently connecting lower than baseline volume of generation and could trigger downward revenue driver adjustments at end of TPCR4. The adjustment for revenue drivers, if triggered, will have an impact on licensee's performance against allowances both on an annual basis and at the end of the price control period.

Capital Expenditure NGET

Figure 17 - NGET Net Capital expenditure



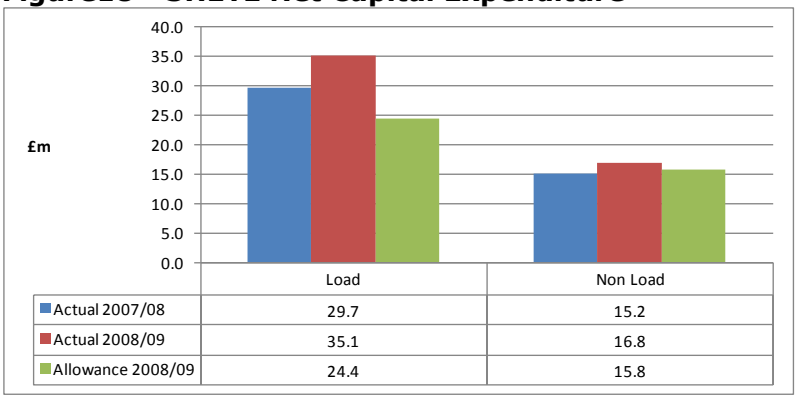
	Load	Non Load
Actual 2007/08	323.8	339.9
Actual 2008/09	331.0	288.2
Allowance 2008/09	189.5	399.3

2.47. NGET load related capital expenditure was £331.0m, 74.7% above the TPCR4 base line allowance of £189.5m and 2.2% above the expenditure incurred in 2007/08 £323.7m. As well as inflationary pressures, increased load expenditure was due to generation projects not envisaged in TPCR4, revised generation timescales, and demand related investment higher than expected in TPCR4. Demand related investment includes Grain LNG and provision of capacity for the 2012 Olympic Games.

2.48. NGET non-load related expenditure in 2008/09 was £288.2m, 27.8% below the allowance and 15.5% below the expenditure incurred in 2007/08. This was due to re-phasing and prioritising capital projects. Transformer replacement increased but overhead line replacement reduced as priority was given to load related schemes.

Capital Expenditure SHETL

Figure18 - SHETL Net Capital Expenditure



	Load	Non Load
Actual 2007/08	29.7	15.2
Actual 2008/09	35.1	16.8
Allowance 2008/09	24.4	15.8

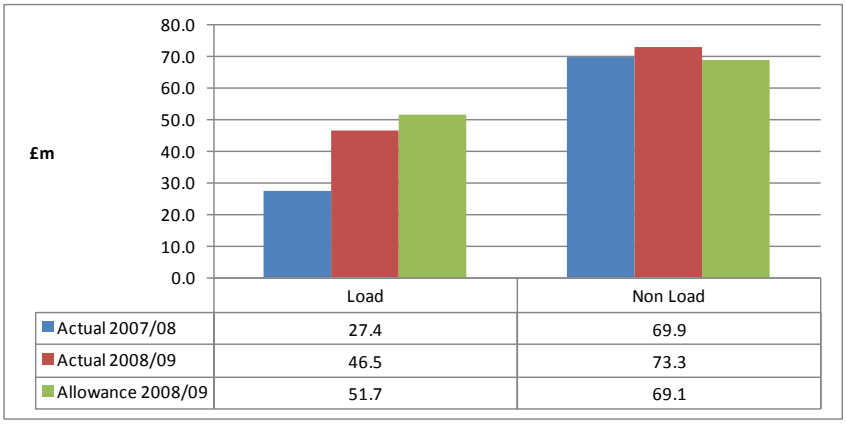
2.49. SHETL significantly increased load related capital expenditure in 2008/09 to £35.1m, 43.7% above the base line allowance of £24.4m and 18.1% above the expenditure incurred in 2007/08. Load related expenditure increased £5.4m. SHETL

also commented that the planning process was now more manageable, although this is not necessarily echoed by SPTL.

2.50. SHETL non load related capital expenditure 2008/09 was £16.8m, 6.4% above the allowance and 10.7% above the expenditure incurred in 2007/08.

Capital Expenditure SPTL

Figure 19 - SPTL Net Capex Expenditure



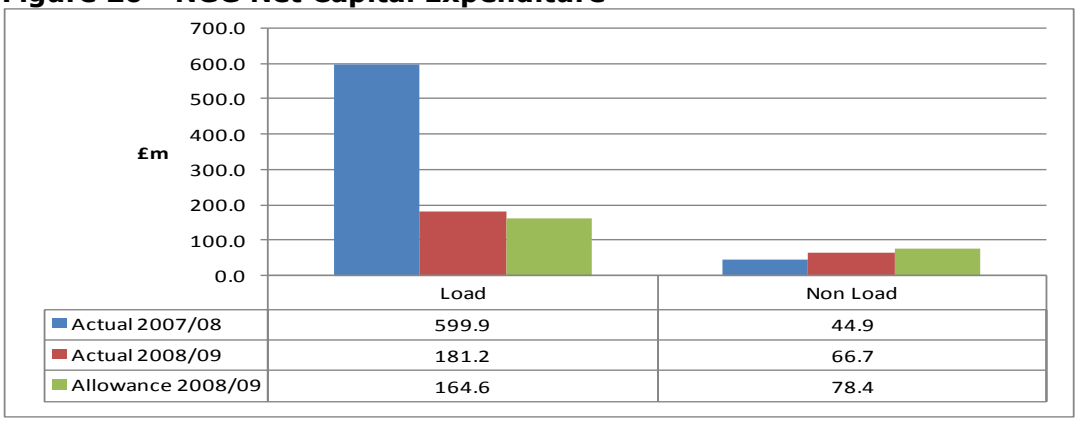
	Load	Non Load
Actual 2007/08	27.4	69.9
Actual 2008/09	46.5	73.3
Allowance 2008/09	51.7	69.1

2.51. SPTL load related capital expenditure was £46.5m, 10.1% below the TPCR4 base line allowance of £51.7m and 69.8% above the expenditure incurred in 2007/08. The actual expenditure was also well below the forecast for 2008/09 made in 2007/08 of £100.4m. Generation connections were significantly below forecast due to protracted consents process.

2.52. SPTL non load related capital expenditure 2008/09 was £73.3m, 6.1% above the allowance and 4.8% above the expenditure incurred in 2007/08.

Capital Expenditure NGG

Figure 20 - NGG Net Capital Expenditure



	Load	Non Load
Actual 2007/08	599.9	44.9
Actual 2008/09	181.2	66.7
Allowance 2008/09	164.6	78.4

2.53. NGG load related capital expenditure was £181.2m, 10.1% above the TPCR4 base line allowance and 69.8% below the expenditure incurred in 2007/08. Load related investment decreased by £422.3m due to the substantial completion of the Milford Haven pipeline being delivered in 2008 which is now operational although there are still planning consent issues outstanding with Tewkesbury Council. Total forecast spend for Milford Haven in TPCR4 is now estimated to be £1.15bn against £818m at the time of TPCR4. A further £85.8m expenditure is forecast to be spent in the next 3 years.

2.54. NGG have strategic stock of £10.3m. This relates to safeguard orders placed for key fittings to ensure delivery of the Milford Haven project on the required date. The majority of this surplus pipe and fittings has now been identified for usage on the Easington to Paull pipeline project.

2.55. NGG non-load related capital expenditure in 2008/09 was £65.1m, 17.0% below the allowance and 44.8% above the expenditure incurred in 2007/08. The increase in non load related expenditure is due to increases in asset health expenditure, although emissions expenditure has fallen. The review of the compressor emissions reduction strategy started in 2008 is still ongoing hence the reduced expenditure.

Incentivised Capex

2.56. At TPCR4 an incentive was introduced to minimise the impact of over or under spend on efficiently incurred capex. Previously if a licensee overspent on capex it would not be remunerated until the following price control, consequently a reduction in the actual return on regulated capex would occur. A capex incentive term was added to the license so that only 25% of the net costs / benefit from under / over spend on capex will result in a charge / gain for licensees.

2.57. The following table shows calculations required to derive the incentivised capex figures, showing the actual for 2008/09 and a cumulative position. All companies are above the allowance in 2008/09. Despite increasing load related expenditure this year both SHETL and SPTL are below the incentivised allowances on a cumulative basis.

Table 7 Incentivised Capex

Capex Values (£m)	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Non Load	288.2	16.4	60.5	365.1	52.9
Load excluding Milford Haven	331.0	35.1	46.5	412.6	115.2
Milford Haven				0.0	66.0
Pension Deficit	10.3			10.3	
Subtotal for Provisional RAV	629.4	51.5	107.0	787.9	234.1
Logged up capex	8.4	0.2	6.0	14.6	7.3
Incremental capex				0.0	88.0
TIRG	25.2	8.6	34.8	68.6	
Regulatory WIP	(78.7)			(78.7)	
Total Actual Expenditure	584.3	60.3	147.8	792.4	329.4
Non Load Allowance	399.3	15.8	69.1	484.1	78.4
Load Allowance (before revenue driver adjustment)	189.5	24.4	51.7	265.6	164.6
Pension Deficit	10.3			10.3	
Total 2008/09 Final Proposals	599.1	40.2	120.8	760.1	243.0

Incentivised Capex Values (£m)	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Total Capex	629.4	51.5	107.0	787.9	234.1
Less capitalised pensions	(3.3)	(0.6)	(1.3)	(5.2)	
Less net load related sole use	(95.3)	(6.7)	(9.4)	(111.4)	
Less Pension Deficit	(10.3)			(10.3)	
Total Actual Incentivised Capex	520.6	44.2	96.3	661.1	234.1
Total capex allowance	599.1	40.2	120.8	760.1	243.0
Less revenue driver adjustment	(58.0)			(58.0)	
Less capitalised pensions	(3.9)	(0.9)	(0.9)	(5.7)	
Less net load related sole use	(13.0)	(2.9)	(8.7)	(24.6)	
Less Pension Deficit	(10.3)			(10.3)	
Total Final Proposal Incentivised Capex	514.0	36.3	111.2	661.5	243.0
Incentivised Capex Over / (Under Spend)	6.7	7.9	(14.9)	(0.4)	(9.0)
As a Percentage	1.3%	21.7%	(13.4%)	(0.1%)	(3.7%)

Cumulative	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Actual Incentivised Capex	1,097.9	79.1	187.6	1,364.6	817.4
Final Proposal Incentivised Capex	1,089.2	82.6	239.7	1,411.5	779.8
Incentivised Capex Over / (Under Spend)	8.6	(3.5)	(52.1)	(46.9)	37.6
As a Percentage	0.8%	(4.2%)	(21.7%)	(3.3%)	4.8%

Logged Up Capex

2.58. In TPCR4, we introduced a mechanism by which licensees could "log up" certain capital costs. Under this procedure the expenditure is separately recorded and at the next price control the Transmission Operators will receive income on all efficiently incurred expenditure as though that expenditure had been included at the previous price control and the impact of this is NPV neutral for the licensee. However in the intervening period the RAV is effectively understated and the ratio Debt to RAV overstated unless due allowance is made for this "capex not yet included in the RAV". These costs will be added to the RAV at the start of TPCR5 after a review for efficiency.

2.59. The implementation of BT21CN has now been delayed by BT until 2018 and therefore it becomes a cost in TPCR5 not TPCR4. TOs have adopted differing solutions to the problems caused by BT21CN.

2.60. The table below summarises the current cumulative TPCR4 logging up costs associated with the respective transmission operators

Table 8 - Cumulative Logged Up Costs 2007/08 to 2008/09

	NGET	SHETL	SPTL	NGG	Total
BT21CN			6.5		6.5
Cable Tunnels	3.9				3.9
Plugs (only for Scottish companies)					
Quarry & Loss Development Claims				1.9	1.9
Milford Haven Pipeline Project				83.1	83.1
Other	8.7	0.2	3.4	6.3	18.7
Total Logging Up Capex	12.6	0.2	9.9	91.3	114.0

Forecast Capex (Base Line) to 2011/12

NGET

2.61. The current 2008/09 forecast for the price control period includes two years actuals spend and three years forecasts. Commodity costs that had risen in 2007/08 fell in 2008/09.

Table 9 - NGET Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	1,577.4
2007/08	323.8
2008/09	331.0
2009/10	313.1
2010/11	226.6
2011/12	184.9
Latest Capex Forecast (Jul. 2009)	1,379.3
Change in Forecast £m	(198.1)
Percentage Change	-12.6%
TPCR4 Final Proposals Allowance	1,311.2
Forecast over/(under) spend against Allowances	68.2
Percentage Change	5.2%

2.62. NGET's current load related forecast for the TPCR4 period of £1379.3m is £68.2m, 5.2% higher than allowance, and 12.6% below the previous forecast. The current forecast anticipates strong generation connection activity, completion of previous deferred connection schemes. NGET has responded to market signals where appropriate and deferred a number of generation connections and infrastructure projects.

Table 10 - NGET Non Load Related Capex Forecast

NGET Capex Non Load Forecast £m [2007/08 - 2011/12]	NGET
Licensee's Previous Capex Forecast (Jul. 2008)	1,979.6
2007/08	339.9
2008/09	288.2
2009/10	389.8
2010/11	422.7
2011/12	626.3
Latest Capex Forecast (Jul. 2009)	2,066.9
Change in Forecast £m	87.3
Percentage Change	4.4%
TPCR4 Final Proposals Allowance	2,109.6
Forecast over/(under) spend against Allowances	(42.7)
Percentage Change	-2.0%

2.63. NGET's current non load related forecast for the TPCR4 period of £2066.9m is 2.0% lower than allowance and 4.4% higher than the previous forecast. Non load volumes were reduced in 2007/08 against expectations at the price control. They have been adjusted again in 2008/09 (see table below).

2.64. NGET states that their non load asset replacement / refurbishment strategy has not significantly changed but the latest asset health assessments have allowed NGET to revise technical asset lives and refurbish rather than replace some assets. In particular some circuit breaker lives have been extended and others refurbished rather than replaced. The asset lives of overhead lines in rural areas have also been extended.

Table 11 - NGET Non Load Related Volumes 2007/08 to 2011/12

Asset Class	FBPQ Forecast	2007/08 RRP Projections	2008/09 RRP Projections
Transformers (units)	86	39	43
Reactors (units)	35	16	7
Circuit Breakers	530	160	
Circuit Breaker (replacement)(units)			191
Circuit Breaker (refurbishment)(units)			159
Overhead Line (full refurbishment)(cct km)	1468	576	543
Overhead Line (fittings only)(cct km)	1198	1003	907
Cables (km)	71.6	50.3	74.5

NB. The information for circuit breakers changed between the 2007/08 RRP and the 2008/09 RRP

2.65. The non load forecast includes £64.1m (2008/09 prices) additional expenditure on cable tunnels in the London area, over and above the £68.4m (2008/09 prices) allowed as logged up. The overall plan has significantly changed with expenditure

extending into TPCR5. Additionally, the forecast includes replacement of operational telecoms equipment at substations.

2.66. Table 11 reveals that National Grid is now projecting volumes of non load related capex which are significantly lower than were forecast at the time of the last price control. Given the scale of the change, we will be seeking to understand the reasons for the forecasting differences. We will do this either during the TPCR4 price control roll-over, or during TPCR5.

SHETL

Table 12 - SHETL Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	126.7
2007/08	29.7
2008/09	35.1
2009/10	22.7
2010/11	33.4
2011/12	35.9
Latest Capex Forecast (Jul. 2009)	156.8
Change in Forecast £m	30.1
Percentage Change	23.8%
TPCR4 Final Proposals Allowance	135.7
Forecast over/(under) spend against Allowances	21.1
Percentage Change	15.5%

2.67. SHETL's current load related forecast for the TPCR4 period of £156.8m is 15.5% higher than the allowance and 23.8% above the previous forecast. SHETL are confident that they will spend the capex allowance and connect greater than 1489MW which was their baseline capex allowance.

Table 13 - SHETL Non Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	96.4
2007/08	15.2
2008/09	16.8
2009/10	14.7
2010/11	16.0
2011/12	18.7
Latest Capex Forecast (Jul. 2009)	81.4
Change in Forecast £m	(15.0)
Percentage Change	-15.5%
TPCR4 Final Proposals Allowance	70.7
Forecast over/(under) spend against Allowances	10.6
Percentage Change	15.0%

2.68. Current SHETL non load related forecast of £81.4m is 15.0% higher than the allowance and 15.5% below 2007/08 forecast. SHETL expect to outturn close to the control period TPCR4 allowance.

SPTL

Table 14 - SPTL Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	483.7
2007/08	27.4
2008/09	46.5
2009/10	53.6
2010/11	137.3
2011/12	175.0
Latest Capex Forecast (Jul. 2009)	439.8
Change in Forecast £m	(43.9)
Percentage Change	-9.1%
TPCR4 Final Proposals Allowance	346.6
Forecast over/(under) spend against Allowances	93.2
Percentage Change	26.9%

2.69. SPTL's current load related forecast for the TPCR4 period of £439.8m is 26.9% higher than the allowance and 9.1% below previous forecast. SPTL are confident that they will spend the capex allowance and connect greater than 2132MW which was their baseline capex allowance. This is despite the fact that delays in planning and consents have reduced expenditure in the first 2 years of the price control. Forecasted contracted generation connection expenditure considerably exceeds the allowances towards the end of the control period.

Table 15 - SPTL Non Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	349.2
2007/08	69.9
2008/09	73.3
2009/10	58.8
2010/11	77.6
2011/12	69.9
Latest Capex Forecast (Jul. 2009)	349.5
Change in Forecast £m	0.3
Percentage Change	0.1%
TPCR4 Final Proposals Allowance	347.0
Forecast over/(under) spend against Allowances	2.5
Percentage Change	0.7%

2.70. SPTL's current non load related forecast for TPCR4 of £349.5m is 0.7% higher than allowance. Previous forecasts for the price control period are similar

2.71. Actual cumulative spend to date is above the allowance but investment will decrease in 2009/10. Overall SPTL expect to outturn close to the total TPCR4 allowance. SPTL non load expenditure asset volumes will be broadly in line with forecasts made at the time of TPCR4. But increase in commodity prices could lead to reduced asset replacement volumes or over spends.

NGG

Table 16 - NGG Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	819.3
2007/08	599.9
2008/09	177.6
2009/10	38.1
2010/11	33.3
2011/12	24.0
Latest Capex Forecast (Jul. 2009)	872.9
Change in Forecast £m	53.5
Percentage Change	6.5%
TPCR4 Final Proposals Allowance	594.1
Forecast over/(under) spend against Allowances	278.8
Percentage Change	46.9%

2.72. NGG's current load related forecast of £872.9m is 46.9% higher than allowance and 6.5% above the previous forecast. This is due to the forecast for the Milford Haven project being nearly twice the TPCR4 allowance, other load related expenditure being lower than the allowances. Expenditure on Milford Haven now extending into 2012/13 although at significantly reduced rates. NGG claim that given the majority of capex is driven by market signals; capex forecasting and planning are volatile.

Table 17 - NGG Non Load Related Capex Forecast

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	256.2
2007/08	44.9
2008/09	65.1
2009/10	82.3
2010/11	50.4
2011/12	39.4
Latest Capex Forecast (Jul. 2009)	282.2
Change in Forecast £m	25.9
Percentage Change	10.1%
TPCR4 Final Proposals Allowance	346.9
Forecast over/(under) spend against Allowances	(64.8)
Percentage Change	-18.7%

2.73. NGG's current NGG non load related forecast of £282.2m was 18.7% lower than allowance and 10.1% above the previous forecast. Emissions capex forecast has been reduced and appears to be moved into TPCR5.

Provisional RAV

2.74. In the Final Proposals of the last Transmission Price Control (Ref 206/06) we made a commitment to publish updated RAV information (Ref 206/06, December 2006, TPCR4-FP), Appendix 2 of the Final Proposals (paragraph 1.34) stated *"To provide greater confidence, we intend to publish updated RAV information on an annual basis. This will set out our provisional view of the RAV based upon the information obtained under the regulatory reporting regime. Nevertheless, we intend to continue to undertake a detailed efficiency review of expenditure at the end of the review period which may highlight the need for further adjustments."*

2.75. In compiling this report we have not completed a review of the efficiency of any capital expenditure schemes. Instead, only the processes and methods have been examined and areas of concern identified for consideration in TPCR5. Our assessment of RAV is therefore provisional. Table 18 below summarises this provisional view.

2.76. In estimating this RAV, we have applied the approach identified in the TPCR4 Final Proposals. The provisional RAV has been rolled forward in accordance with the license but this does not, as yet, include all network investment. Certain expenditure incurred in 2008/09 will, after review, be included in RAV at a future date. This is identified as "capex not yet in the RAV" in for each licensee in Table 19

Table 18 Provisional RAV

£m	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
RAV b/fwd (in 2007/08 prices)	6,220.0	338.2	819.2	7,377.4	3,755.2
RPI Inflation of 4.1%	184.6	10.0	24.3	219.0	111.5
RAV b'fwd (in 2008/09 prices)	6,404.6	348.2	843.5	7,596.4	3,866.7
RAV provisional additions (Table XX)	629.4	51.5	107.0	787.9	234.2
RAV depreciation	(453.4)	(19.8)	(73.3)	(546.5)	(123.4)
RAV c'fwd (at average RPI in 2008/09)	6,580.6	379.9	877.2	7,837.8	3,977.5
RAV c'fwd (at end year RPI in 2008/09)	6,473.9	373.8	863.0	7,710.7	3,913.0

2.77. In practice it proved necessary to make specific adjustments to the licensee's initial estimate of RAV. Further details of these adjustments are provided in Table 19 below. This table summarises the capex adjustment to submissions from the supplied regulatory accounts and segmental analysis. They arise from items excluded from the RAV such as interest during construction, related party margins, general overheads and non operational capex each of which are discussed further in the capitalisation section.

Table 19 RAV Adjustments

£m	NGET TO	SHETL TO	SPT TO	Elect. Total	NGG TO
Regulatory Accounts Capex	848.0	60.7	166.2	1,074.9	373.0
Deduct:					
Capitalised Interest	(71.4)			(71.4)	(26.5)
Non Operational Capex	(12.9)		(2.4)	(15.3)	(2.3)
Capitalised Depreciation of Non Operational Assets			(2.0)	(2.0)	
Capitalisation of Corporate / Group costs		(0.1)	(0.5)	(0.6)	
Customer Contributions	(38.0)		(3.2)	(41.2)	(9.4)
Related party margins			(7.0)	(7.0)	
Excess overheads		(0.3)	(3.3)	(3.6)	
Scrap sales				0.0	
Add:					
Pensions deficit	10.3			10.3	
Quasi capex	4.9			4.9	
West Sole capex (LNG refurbishment)					3.6
Rounding	1.6			1.6	1.4
subtotal	**742.5**	**60.3**	**147.8**	**950.6**	**339.8**
"Capex not yet in Rav":					
Deduct:					
TIRG	(25.2)	(8.6)	(34.8)	(68.6)	
Logging up items	(8.4)	(0.2)	(6.0)	(14.6)	(7.2)
Incremental capex				0.0	(88.1)
Regulatory WIP	(78.7)			(78.7)	
Stategic Stock				0.0	(10.3)
Strategic WIP (ENSG)	(0.8)			(0.8)	
subtotal	**(113.1)**	**(8.8)**	**(40.8)**	**(162.7)**	**(105.6)**
RAV additions after provisional review	**629.4**	**51.5**	**107.0**	**787.9**	**234.2**

Capitalisation Items

2.78. There are a number of differences between the expenditure which companies treat as capital for the purposes of their published accounts and the expenditure which is viewed as appropriate for inclusion in the Regulatory Asset Value. To aid transparency we have identified these in Table 19 and they are described below.

2.79. National Grid statutory accounts capitalise interest incurred during construction whereas the Scottish licensees have not. Because a return is provided on capital expenditure as part of the price control it is not appropriate for the RAV to include these costs and consequently they are removed.

2.80. Non operational capex is expenditure, usually capitalised in statutory accounts, which has not been incurred on the operational system of the licensees. This is usually on items (such as personal computers and vehicles) which can also be supplied as services. The costs of such services are provided for when setting the revenue allowance for controllable costs. Such expenditure is therefore not included in the RAV.

2.81. In some group structures it is possible for charges to the licensee regulated business to include items which would not be treated as part of the RAV if they had been directly incurred by that business. Examples of this are depreciation on non operational expenditure and related party margins.

2.82. The treatment of customer contributions may be in the form of an advance to mitigate against future charges. These advances will not form part of the baseline revenue allowance and consequently such receipts are deducted from the overall expenditure on the RAV.

2.83. At this time we have also made an overhead adjustment where the percentage of capitalised overheads exceeds that in the base year that was used in setting the original allowances at TPCR4. This is a provisional treatment of these costs which we will review at the next price control

2.84. Where a licensee receives monies from the disposal of operational assets, or assets that become surplus to operational requirements or from assets as scrap, these receipts are deducted from the RAV to reflect its reduced value.

2.85. NGG operate certain LNG facilities to provide gas for sites remote from the NTS network (e.g. in Scotland) where it would not be economic to have a pipeline. Consequently at TPCR4 it was agreed the refurbishment of these facilities would be treated as an allowed addition to the RAV.

2.86. There can be capital expenditure on items which are being remunerated via a different form to the baseline revenue allowance. This type of expenditure is therefore also removed from the RAV although it may become part of the RAV at a later date dependent on the form of revenue adjustment. Examples of such "capex not yet included in the RAV" include TIRG, Incremental Capex, and Logged up expenditure, Regulatory Work In Progress (WIP), and overspends on Milford Haven.

Innovation Funding Initiative (IFI)

2.87. The transmission companies have spent a total of £10.2m on IFI projects in 2008/09 and 80% of such expenditure is allowed up to a cap of 0.5% of turnover or £0.5 million whichever is the higher. These are Research and Development projects paid for by the licensee and undertaken by external parties (e.g. Universities). The table below show the expenditure by licensee. The total cumulative expenditure within this price control period is £15.1m, 80% (£12.1m) of which is remunerated under the IFI incentive.

Table 20 - IFI Costs

£m	NGET TO	SPT TO	SHETL TO	Elect. Total	NGG TO
IFI Expenditure	7.7	0.1	0.4	8.2	2.0
80% allowed	6.2	0.1	0.3	6.5	1.6

3. Review of System Operator (SO) Performance (in 2008/09 prices)

Chapter Summary

This chapter summarises the financial data from the licensees as Transmission System Owners. The main areas of concern are: NGET's significant increase in incentivised external balancing costs, and NGET and NGG capex forecasts that exceed price control allowances.

Background

3.1. In this section we have provided an overview of the main components of System Operators financial performance in 2008/09 compared to the price control allowances converted to this years' price level, specifically:

- External and Internal Turnover 2008/09
- Pensions 2008/09
- Internal Operating Costs in 2008/09,
- Internal Capital Expenditure in 2008/09,
- Forecast Internal Capex to 2011/12, and
- Provisional RAV for 2008/09

Price Control Revenue

National Grid Gas

Table 21 - NGG Revenue Summary

(figures in £m)	2007-08	2008-09	Year on year variance	Variance%
Total Allowed Revenue	278.28	367.51	89.23	32%
Total Actual Revenue	274.14	342.75	68.60	25%
Over / Under Recovery	-4.13	-24.76	-20.63	

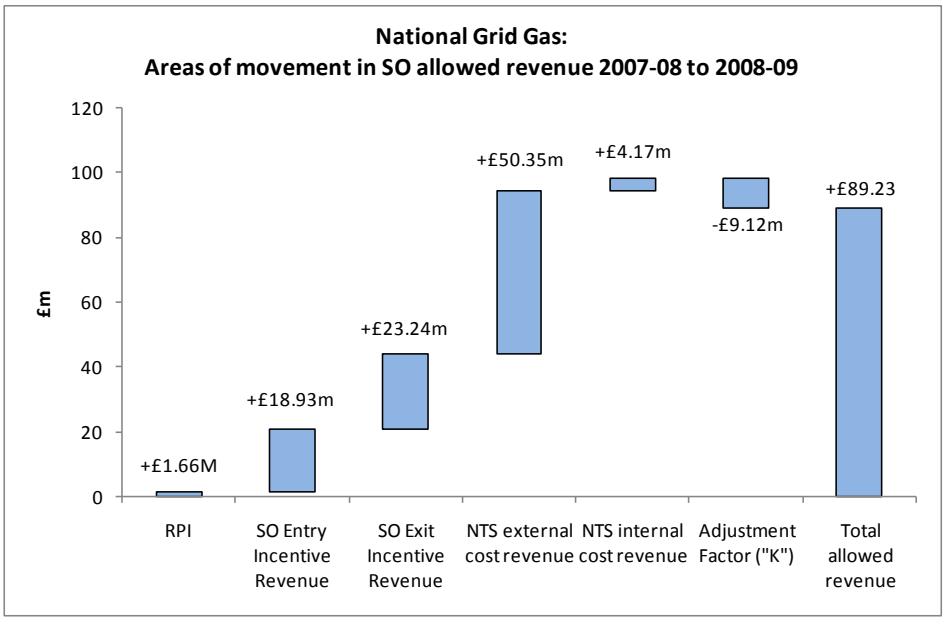
3.2. NGG SO allowed revenues increased from £278m in 2007/08 to £367.5m in 2008/09. This is an increase of 32%. The most significant areas of movement were in NTS external costs revenue. The main driver for this has been the cost of unaccounted-for gas, which increased by £50m in 2008/09 and own-use gas (OUG), which cost an additional £19m year on year, despite a decrease in OUG volumes of 8% .These increased costs were offset to some degree by decreases in the cost of operating margin and residual balancing. NGG SO was entitled to recover additional revenues via the entry capacity incentive, primarily through the release of entry capacity at Milford Haven.

3.3. NGG SO under-recovered against the maximum allowed revenue by nearly £25m. NGG has explained that this under-recovery was caused by shrinkage gas

prices which were significantly higher than anticipated and by better than expected performance against the SO incentive. If shrinkage gas prices are higher than forecast this leads to an under recovery as NGG is allowed to recover the actual cost.

3.4. The chart below shows the areas of movement in NGG SO revenues, year on year.

Figure 21 - NGG Movement in Allowed Revenue



National Grid Electricity Transmission

Table 22 - NGET Revenue Summary

(figures in £m)	2007/08	2008/09	Year on year variance	Variance%
Balancing External	569.85	907.68	337.82	59%
Balancing Internal	112.92	99.32	-13.60	-12%

The balancing external costs in 2008/09 is the total cost of external balancing services, as opposed to the £826m incentivised cost discussed below

3.5. NGET operates the electricity transmission system in Great Britain. As a part of its role as system operator, NGET is required to ensure that generation and demand are in balance. It does this through the balancing mechanism, whereby participating generation and demand units make bids and offers to NGET to decrease or increase generation or demand. For example, if NGET requires more generation at a certain point on the network, it will accept an offer from a generator to supply a specified quantum of additional power to the network at a price agreed between the two parties. NGET also enters into contracts with generation and demand units to provide ancillary services, such as to provide for the use of intertrips – systems which

automatically remove generation from the system in the event of failure of a transmission circuit.

3.6. The costs NGET incurs in performing its system operation duties are recovered from the generators and suppliers through the Balancing Services Use of System charge and hence they are included in the revenue section of this report.

3.7. As in previous years, Ofgem agreed with NGET a scheme designed to provide an incentive on the system operator to manage the costs associated with balancing the system in 2008/09. Through the scheme, Ofgem sets NGET a cost target for the year (the Incentivised Balancing Cost (IBC)). In 2008/09 if NGET incurred costs below the IBC, it could receive an incentive payment of up to £15m. Conversely, if NGET incurred costs above the IBC, it could be penalised by up to £15m.

3.8. In 2008/09, NGET's incentivised balancing costs were £826m against the upper limit of the target "deadband" of £545m. This means that the IBC was exceeded by £281m, and that NGET incurred the maximum penalty of £15m through the incentive scheme. At £330m, the cost of bids and offers was more than double the £164m cost in 2007/08. The ancillary services contracts increased by £182m to £590m.

3.9. The main drivers of NGET's increased balancing costs in 2008/09 are:

- Margin costs. NGET ensures that there is sufficient system generation available to provide for eventualities such as an unexpected demand increase, or the failure of a generator. The combination of short energy market, lower than anticipated availability of nuclear generation, the introduction of the Large Combustion Plant Directive and a reduction in the number of available commercial service providers had the effect of increasing NGET's margin costs. NGET's utilisation of expensive oil plant on the balancing mechanism was higher than anticipated.

- Power prices. Power prices increased markedly shortly after the incentive scheme had been agreed with Ofgem. This had a knock-on effect on the cost of bids and offers in the balancing mechanism and on future contract prices.

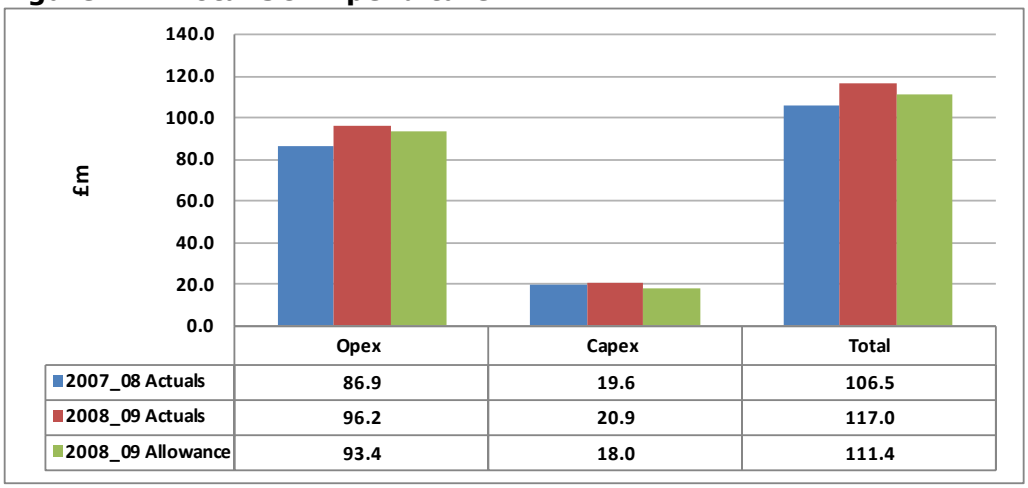
- Constraints. A constraint occurs where there is insufficient capacity on the transmission system to transmit energy from the point of generation to the point of consumption. The most significant of these on the GB transmission is the 'Cheviot' constraint in the circuits linking England and Scotland. NGET can resolve constraints by, for example, accepting a bid in the balancing mechanism from a generator located within the constraint to reduce its output and accepting an offer from a generator on the other side of the constraint to reinstate that energy. In 2008-09, the volume of constraints was greater than that expected at the start of the year, owing to an increase in circuit outages. As explained above, high power prices meant that the cost of reinstating margin was higher than anticipated. Output from the Scottish wind farms was also greater than expected.

Total Internal Expenditure

3.10. In this section we have provided an overview of the main components of SO financial performance in 2008/09.

3.11. Figure 22 below summarises aggregated total industry opex and capex expenditure for both electricity and gas system operators comparing current expenditure to previous year's and TPCR4 allowances. Total SO outturn expenditure was £114.7m, 2.9% above the TPCR4 allowance £111.4m and 5.7% above the expenditure incurred in 2007/08 £108.5m.

Figure 22 - Total SO Expenditure



	Opex	Capex	Total
2007_08 Actuals	86.9	19.6	106.5
2008_09 Actuals	96.2	20.9	117.0
2008_09 Allowance	93.4	18.0	111.4

3.12. Operational expenditure in 2008/09 was £96.2m, 3.0% above allowances and 10.7% above the expenditure incurred in 2007/08. Capital expenditure in 2008/09 was £20.9m, 16.1% above the allowances and 6.6% above the expenditure incurred in 2007/08.

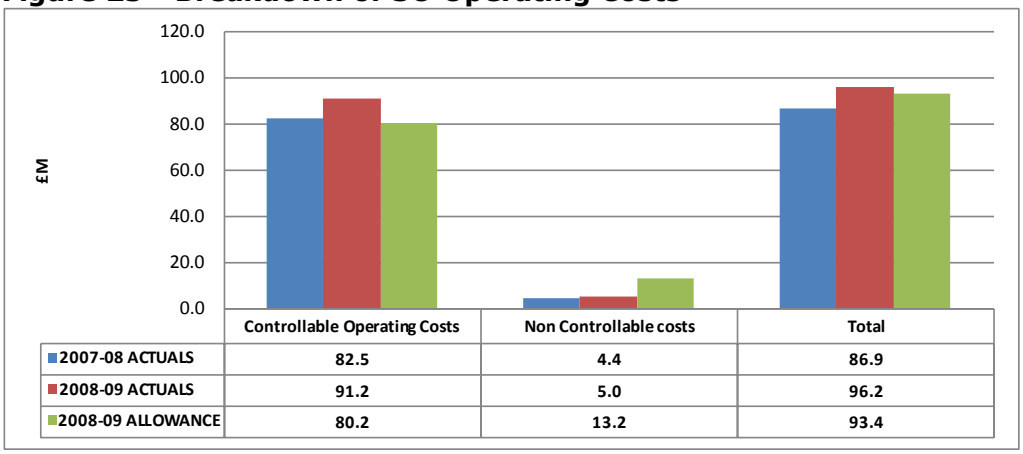
Total Internal Operating Costs

3.13. Figure 23 below shows the breakdown of total operating costs between controllable and non-controllable compared to 2007/08 allowances. Overall, there was a 10.7% increase from last year, and a 3.0% overspend on allowance.

3.14. NGET have cited the decision to bring the operations of critical systems back in-house, the pressing need to enhance capability and resilience of control room staff and skilled labour shortage and retention as the main contributors to the increase in operating costs.

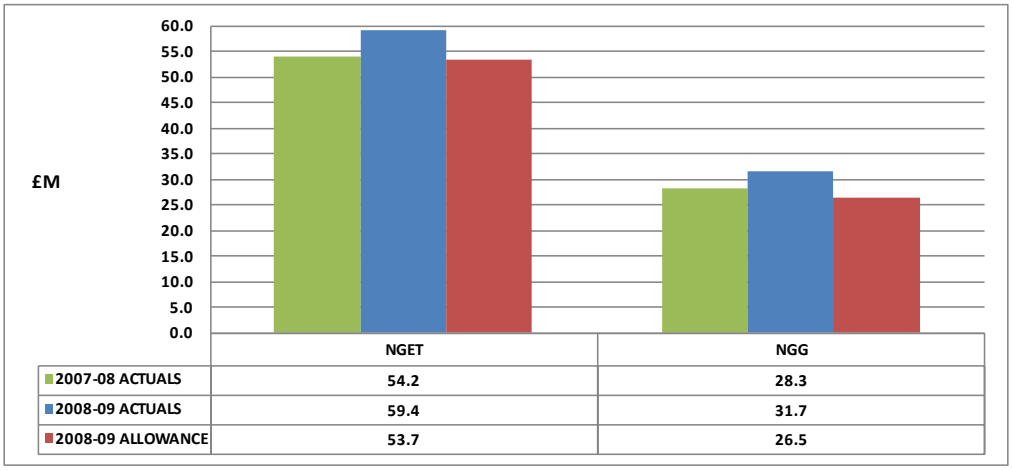
3.15. Critical operations cover control room, data centre infrastructure and IS Systems & Networks operations. These previously outsourced services have now been brought back in house to ensure service and reliability levels are maintained.

Figure 23 - Breakdown of SO Operating Costs



	Controllable Operating Costs	Non Controllable costs	Total
2007-08 ACTUALS	82.5	4.4	86.9
2008-09 ACTUALS	91.2	5.0	96.2
2008-09 ALLOWANCE	80.2	13.2	93.4

Figure 24 - Controllable Opex



	NGET	NGG
2007-08 ACTUALS	54.2	28.3
2008-09 ACTUALS	59.4	31.7
2008-09 ALLOWANCE	53.7	26.5

3.16. NGET stated that they are experiencing a shortage of and strong demand for skilled power system engineers, and authorised control room staff remains below what is considered as to be optimum level required. They have responded to the current staff attrition levels by paying market supplements.

Pension Costs

3.17. Table 23 below compares pension costs with allowed pension spend. The allowances and actual are based on the cash amount paid into the pensions scheme rather than the charge shown in the financial statements. The pension numbers quoted are provisional and may be subject to re-statement on final agreement with Ofgem regarding input data and allocations.

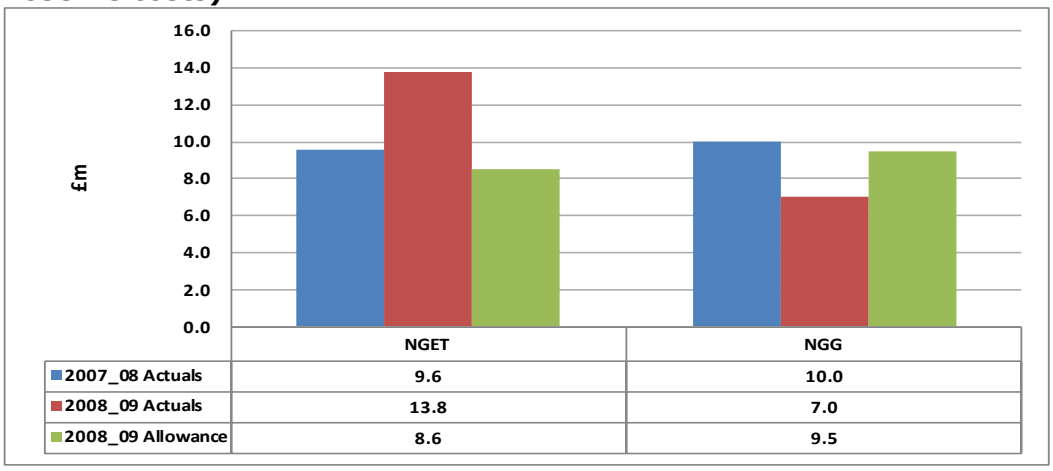
Whilst NGET SO has deficit funding £6.4m higher than assumed this is substantially a timing difference since the 2007/08 payment was £4.4m less than assumed in TPCR4. The difference to allowed funding will be corrected at subsequent full price controls subject to any overspend being determined as efficiently incurred.

Table 23 - Pension Costs

Pension costs (£m) - nominal	NGET SO	NGG SO
2008/09 Actual		
Ongoing costs	5.7	4.7
Deficit repair	19.2	0.7
Total	**24.9**	**5.4**
Allowances		
Ongoing costs	4.8	5.5
Deficit repair	12.8	0.2
Total	**17.6**	**5.7**
Variance to allowance		
Ongoing costs	0.9	(0.8)
Deficit repair	6.4	0.5
Total	**7.4**	**(0.3)**

Total Internal Capital Expenditure

Figure 25 - SO Capex (after adjustment for prior year expenditure and Xoserve costs)



3.18. NGET capital expenditure 2008/09 was £13.8m, 60.5% above the allowance and 43.8% above the expenditure incurred in 2007/08m.

3.19. There has been acceleration in critical asset replacement within the Electricity National Control Centre (ENCC). Despite this the current level of IT systems expenditure is forecast to continue for the rest of TPCR4 and subsequent control period.

3.20. NGG capital expenditure 2008/09 was £7.0m, 26.3% below the allowance and 30.0% below the expenditure incurred in 2007/08m.

Forecast Internal Capital Expenditure

3.21. We also asked the companies to provide us with updated capex forecasts for the price control period. Table 24 below compares this with TPCR4 Final Proposals.

3.22. Both electricity and gas SO forecast to significantly overspend the total capital allowances by 59.5% and 10.5% respectively over the whole price control period. National Grid indicated they need to invest more than previously forecast in updating and replacing critical systems such as the Balancing Mechanism system to ensure reliability and security.

Table 24 - NGET Forecast Capex

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	82.3
2007/08	12.9
2008/09	14.5
2009/10	19.7
2010/11	16.0
2011/12	15.5
Less Prior Year allowance expenditure	(3.9)
Latest Capex Forecast (Jul. 2009)	74.7
Change in Forecast £m	(7.6)
Percentage Change	-9.2%
TPCR4 Final Proposals Allowance	46.8
Forecast over/(under) spend against Allowances	27.9
Percentage Change	59.5%

3.23. Current NGET capex forecast for TPCR4 £74.7m is 59.5% higher than the allowance but 9.2% below last years forecast. Capital expenditure going forward is significantly above allowance due to upgrading of critical systems which are becoming less reliable with dated technological software not being compatible to operational market needs.

3.24. NGET ESO forecast spend has reduced by £5.2m year on year which has been achieved by the re-prioritisation of projects.

Table 25 - NGG Forecast Capex

	£m
Licensee's Previous Capex Forecast (Jul. 2008)	75.8
2007/08	10.6
2008/09	9.1
2009/10	26.0
2010/11	17.0
2011/12	19.6
Less Xoserve Expenditure	(20.9)
Latest Capex Forecast (Jul. 2009)	61.4
Change in Forecast £m	(14.4)
Percentage Change	-19.0%
TPCR4 Final Proposals Allowance	55.6
Forecast over/(under) spend against Allowances	5.8
Percentage Change	10.5%

3.25. Current NGG capex forecast for TPCR4 £61.4m is 10.5% higher than the allowance and 19.0% below last years forecast.

Provisional RAV

3.26. Table 26 shows the provisional RAV; we have applied the approach identified in the SO final proposals.

Table 26 - SO RAV

£m	NGET SO	NGG SO
RAV b/f	49.6	38.7
RPI Inflation of 4.1%	2.0	1.6
RAV provisional additions	12.5	7.6
RAV depreciation	(9.3)	(13.6)
RAV c'fwd	54.8	34.3

Appendices

Index

Appendix	Name of Appendix	Page Number
1	Data on individual transmission licensees	42
2	Responses and Questions	54
3	The Authority's Powers and Duties	55
4	Glossary	57
5	A guide to Return on Regulatory Equity	60
6	Amendments to Regulatory Reporting Pack (RRP) Tables	61
7	Feedback Questionnaire	62

Appendix 1 - Data on individual transmission licensees

1.1. This chapter provides a comparison between allowance and actual expenditure for each licensee in nominal terms. After each table there is a statement by the licensee on their expenditure to provide greater clarity on this aspect.

1.2. All the data presented is derived from the information in the regulatory reporting packs. These packs are reconciled back to the audited published information contained within the Regulatory Accounts and various elements (e.g. Income) have also been subject to audit review under agreed upon procedures determined by the Authority.

1.3. Net debt can include financing for significant network assets that are not as yet included the provisional RAV (e.g. logged up costs and revenue driven expenditure). This expenditure on "Capex not yet in the RAV" may be capital in nature and has been funded by the licensee (potentially with debt) and will, if efficient, attract relevant income allowances in the future and may thus be viewed as "shadow RAV". Consequently without the adjustment shown the gearing indicated will overstate to that extent the percentage relative eventual final RAV.

National Grid Electricity Transmission (NGET)

Table 1 - NGET TO

NGET Transmission - TO

Regulated Income	Allowance	Actual	Timing Difference
	£m	£m	£m
Final Proposals	1,147.5		
Adjustments from final proposals to license	2.1		
Difference for income specific inflation	(2.6)		
Core Allowance	1,147.0	1,162.0	15.0
Excluded Services		92.9	
Allowed Adjustments		23.9	
Timing Differences		(1.6)	
per NGET Regulatory Accounting Statement		**1,277.2**	

Controllable Opex	Actual
	£m
Accounting Controllable Opex	216.2
Non operational capex	12.9
Total	229.1
Net movement in provisions / other adjustments	(2.4)

	Allowance	Actual	Variance
	£m	£m	£m
Cash Controllable Opex	**180.7**	**226.7**	**46.0**

Non Controllable Costs	Actual
	£m
Total	**117.8**

Innovation Funding Incentive (IFI)	Actual
	£m
Opex (80% of which is allowed)	**7.7**

Logged Up Operating Costs	Actual
	£m
Opex	-

Pensions	Allowance	Actual	Under / (Over) Recovery
	£m	£m	£m
Ongoing	15.8	14.4	(1.3)
Deficit	41.6	63.2	21.6
Total	**57.3**	**77.6**	**20.3**

Capex (including pensions)	Allowance	Actual	Pension costs in actual
	£m	£m	£m
Load Related	189.5	331.0	1.7
Non Load Related	399.3	288.2	1.5
Pension Deficit	10.3	10.3	-
Subtotal	599.1	629.4	3.2
Capex not yet included in the RAV			
Logged up capex		8.4	
Anticipatory (strategic) investment		0.8	
TIRG		25.2	
Regulatory WIP		78.7	
Total		742.4	

Incentivised Capex	Allowance	Actual	Variance
	£m	£m	£m
Total capex	599.1	629.4	
Pension deficit	(10.3)	(10.3)	
less revenue driver adjustment	(58.0)		
less capitalised pensions	(3.9)	(3.2)	
less net Load related sole use	(13.0)	(95.3)	
Total	**513.9**	**520.7**	**6.7**

Capex Additions	629.4
Ofgem Adjustments	-
Provisional RAV Additions	**629.4**

Gearing / Interest	Actual
Interest Costs (£m)	233.3
Net Debt	3,731.3
Provisional RAV (at year end price level)	6,473.9
Capex not yet included in the RAV	170.3
Gearing as % of provisional RAV and capex not yet in RAV	56.2%

System Activities and Performances	Actual
Overhead Circuit km	14,145
Underground Circuit km	655
Measured system maximum demand (GW)	53.4
Total directly connected generation (GW)	61.3
Total directly connected wind generation (GW)	-
Total embedded generation (GW)	5.1
Incentivised loss of supply volume - NGET only (MWh)	52
System availability	94.6%
SF6 leakage rate (tonnes)	9.9

Table 2 - NGET SO

NGET Transmission - SO

Regulated Income	**Target**	**Actual**	**Variance**
	£m	**£m**	**£m**
External	905.5	907.7	2.2
Internal	99.8	99.3	(0.5)
Balancing Services Use of System Charges	1,005.3	1,007.0	1.7
Scottish & Hydro Charges		289.7	
Other Income		(17.7)	
per NGET Regulatory Accounting Statement		**1,279.0**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	60.1
Net movement in provisions / other adjustments	(0.7)

Allowance	**Actual**	**Variance**
£m	**£m**	**£m**
53.7	**59.4**	**5.8**

Cash Controllable Opex

Logged Up Costs	**Actual**
	£m
Operating Costs	0.5
Capital Expenditure	0.3
Total	0.8

Pensions	**Allowance**	**Actual**	**Under / (Over) Recovery**
	£m	**£m**	**£m**
Ongoing	4.8	5.8	1.0
Deficit	12.8	18.6	5.8
Total	**17.6**	**24.4**	**6.8**

SO Capex	**Allowance**	**Actual**	**Variance**
	£m	**£m**	**£m**
Total	**8.6**	**13.8**	**5.3**

Gearing / Interest	**Actual**
Interest Costs (£m)	1.9
Net Debt	30.8
Provisional RAV (at year end price level)	54.8
Gearing as % of provisional RAV	56.2%

LICENSEE'S COMMENTS

NGET Transportation Owner (TO)

1.4. The challenges in 2008/09 have been significantly different to those of 2007/08 and were dominated by turbulence in global financial markets and the economic recession in the UK. National Grid has maintained a flexible approach towards investment, asset and system operating strategies in order to respond to changes in demand and the re-sequencing of load-related requirements that have resulted.

1.5. In 2007/08, National Grid highlighted how it was experiencing significant inflationary pressures due to commodity price increases, global economic growth and indicated how it intended to manage the effects of such inflation by delaying certain investments until prices stabilised. Looking forward, National Grid continues to keep the transmission investment plan under review, responding to demand falling back, continuing entry connection activity and the potential need for further works (including anticipatory/ENSG reinforcements) to maintain the viability of achieving the Government's targets for 2020 and facilitating a low carbon future.

1.6. National Grid's overall level of capital investment in 2008/09 was above the level of 2007/08 and incentivised Capex was broadly in line with incentive capital allowances. In addition circa £80 million has been spent on schemes expected to connect after March 2012, bringing the total such investment in the first two years of this price control to £125 million.

1.7. During 2008/09, the headline ETO opex overspend versus allowances increased by £18 million. The 'like-for like' opex overspend increased more modestly after taking into account opex offset by additional revenues; accelerated investment in systems; exceptional costs; and atypical energy costs.

NGET System Operator (SO)

1.8. 2008/09 witnessed a step up in both investment in and operational support for critical operating systems. ESO controllable costs increased by £8m to £60m primarily as a result of the decision to increase and enhance the level of IS support for and resilience of critical operating systems and to increase the capability and resilience of control room staff.

1.9. Like for like, ESO Capex investment during 2008/09 was £5m higher than the £9m allowance as a result of the decision to accelerate critical asset replacement schemes such as the Integrated Electricity Management System (iEMS) and Balancing Mechanism (BM) asset upgrades as well as the associated property power supply upgrades.

Scottish Hydro Electricity Transmission (SHETL)

Table 3 - SHETL TO

SHETL

Regulated Income	**Allowance**	**Actual**	**Timing Difference**
	£m	**£m**	**£m**
Base Price Control	54.8	54.8	
Difference for income specific inflation	0.1		
Under / Over Recovery (Current Year)		1.9	
	54.9	56.6	1.7
Excluded Services		1.7	
Allowed Adjustments		0.7	
Timing Differences		2.0	
Total Regulatory Turnover		**61.0**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	5.6
Non operational capex	0.0
Total	5.6
Net movement in provisions / other adjustments	0.4

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
Cash Controllable Opex	**6.5**	**6.0**	**0.5**

Non Controllable Costs	**Actual**
Network Rates	3.7

Innovation Funding Incentive (IFI)	**Actual**
	£m
Opex (80% of which is allowed)	0.4

Logged Up Operating Costs	**Actual**
	£m
Opex	0.0

Pensions	**Allowance**	**Actual**	**Under / (Over) Recovery**
	£m	**£m**	**£m**
Ongoing Costs	**1.8**	**1.2**	**0.6**

Capex (including pensions)	**Allowance**	**Actual**	**Pensions included in actual**
	£m	**£m**	**£m**
Load Related	24.4	35.1	0.4
Non Load Related	15.8	16.8	0.2
Subtotal	40.2	51.9	0.6
Capex Not yet Included in RAV			
Logged up capex		0.2	
TIRG		8.6	
Total		**60.7**	

Incentivised Capex	**Allowance**	**Actual**	**Variance**
	£m	**£m**	**£m**
Total capex	40.2	51.9	
less capitalised pensions	(0.9)	(0.6)	
Less net Load related sole use	(2.9)	(6.7)	
Total	**36.3**	**44.6**	**(8.3)**
Additions		51.9	
Ofgem Adjustments		(0.4)	
Provisional RAV Additions		**51.5**	

Gearing / Interest (From Debt table)	**Actual**
Interest Costs (£m)	7.9
Net Debt	158.1
Provisional RAV (at year end)	373.7
Capex not yet included in RAV	9.3
Gearing as % of provisional RAV and capex not yet included in RAV	41.3%

System Activities and Performances	**Actual**
Overhead Circuit km	5,225
Underground Circuit km	73
Measured system maximum demand (GW)	1.6
Total directly connected generation (GW)	2.8
Total directly connected wind generation (GW)	0.2
Total embedded generation (GW)	1.2
Number of incentivised loss of sypply events (#)	7
System availability	96.7%
SF6 leakage mass (Kg)	88.0

LICENSEE'S COMMENTS

Operational Expenditure

1.10. SHETL has continued to tightly & rigorously control the level of operating costs within the business and this along with the impact on operating costs of the delays in developer related capex schemes in 2007/08 has resulted in an underspend of £0.9M in cash controllable Opex costs against the OFGEM allowance.

Capital Expenditure

1.11. In 2008/09 SHETL continued to increase capital expenditure in line with the TPCR4 agreed OFGEM allowances. Overall, price control capital expenditure has risen by £8.3M in the year.

1.12. Load related expenditure was higher than allowance recovering delays from the previous year associated with a number of developer related schemes. Load related expenditure has increased by £6.2M in the year. Notable schemes in the year included;

Glendoe hydro electric power station infrastructure works
Tealing 132kV switchgear replacement
Tealing Static Var Compensator (SVC)

1.13. Non-Load related expenditure was lower than annual allowance but is in line with the overall TPCR4 allowance. Non-Load related expenditure has increased by £2.1M. notable schemes in the year included;

Dundee city 132kV cables (MD1/MD2) replacement
275kV GA10 switchgear replacement
Strichen Grid Supply Point transformer replacement

Scottish Power Transmission (SPT)

Table 4 - SPT

SPTL

Regulated Income	Allowance £m	Actual £m	Timing Difference £m
Base Price Control	171.6	171.7	
Difference for income specific inflation	0.2		
Under / Over Recovery (Current Year)		0.3	
	171.8	172.0	0.2
Excluded Services		2.1	
Allowed Adjustment		8.2	
Timing Differences		0.2	
Total Regulatory Turnover		**182.5**	

Controllable Opex	Actual £m
Accounting Controllable Opex	11.5
Non operational capex	2.4
Total	13.9
Adjustment to capitalisation (to be recalculated)	5.8

	Allowance £m	Actual £m	Variance £m
Cash Controllable Opex	**17.9**	**19.7**	**(1.8)**

Non Controllable Costs	Actual £m
Network Rates	**13.9**

Inovation Funding Incentive	Actual £m
Opex (80% of which is allowed)	0.1

Logged Up Operating Costs	Actual £m
Opex	0.0

Pensions	Allowance £m	Actual £m	Under / (Over) Recovery £m
Ongoing Costs	**1.5**	**1.1**	**0.3**

Capex (including pensions)	Allowance £m	Actual £m	Pension costs in Actual £m
Load Related	51.7	46.5	0.5
Non Load Related	69.1	73.3	0.8
Subtotal	**120.8**	**119.8**	**1.3**
Capex Not Yet Included in RAV			
Logged up capex		6.0	
TIRG		34.8	
Total		160.6	

Incentivised Capex	Allowance £m	Actual £m	Variance £m
Total capex	120.8	119.8	
less capitalised pensions	(0.9)	(1.3)	
Less net Load related sole use	(8.7)	(9.4)	
Total	**111.2**	**109.1**	**2.1**

Additions	119.8
Ofgem Adjustments	(12.8)
Provisional RAV Additions	**107.0**

Gearing / Interest (From Debt table)	Actual
Interest Costs (£m)	24.3
Net Debt	410.0
Provisional RAV (at year end)	862.6
Capex not Yet included in RAV	75.2
Gearing as % of provisional RAV and Capex net yet included in RAV	43.7%

System Activities and Performances	Actual
Overhead Circuit km	3,754
Underground Circuit km	288
Measured system maximum demand (GW)	4.1
Total directly connected generation (GW)	7.5
Total directly connected wind generation (GW)	0.6
Total embedded generation (GW)	0.8
Number of incentivised loss of sypply events (#)	6
System availability	92.7%
SF6 Leakage Mass (Kg)	774.0

LICENSEE'S COMMENTS

Revenue

1.14. Revenue of £182.5m received by SP Transmission Ltd in 2008/09 is in line with allowed revenue as prescribed in our Licence.

Controllable Opex

1.15. Cash controllable opex costs were £1.8m above allowance for 2008/09 due to Ofgem adjustments to overheads; our performance against allowance is negatively impacted by Ofgem's capitalisation adjustment of £3.3m.

Capital Investment

1.16. Notwithstanding the impact of the challenging economic climate and the availability of finance, SP Transmission recorded its highest ever level of capital investment during 2008/09.

1.17. Investment to provide new capacity for generation increased by over 75% compared to 2007/08 as a number of large wind farms and associated reinforcement works entered the main construction phase. Dunlaw, Toddleburn and Crystal Rig windfarms were connected during the year and major works were undertaken at Markshill, Dunlaw and on 'P' route 132kV overhead line to facilitate renewable generation. There does, however, continue to be delays to projects caused by planning consent issues and system design changes required to accommodate revised customer requirements.

1.18. Investment to replace ageing and poor condition assets has continued at record levels and is ahead of OFGEM's allowance for the first two years.

Interest

1.19. The interest expense for the year was £5.3m lower than the prior year, primarily due to the reduction in debt, following the issue of £191 million ordinary shares.

System Activities and Performance

1.20. System availability continues to be lower than the historical average. This is mainly attributable to a higher level of planned outages, which predominantly take place outside the winter period. These are planned outages necessary to deliver our commitments to customers for new connections, strategic reinforcement associated with Government renewables targets and the asset modernisation programme.

1.21. During 2008/09 there were six 'incentivised loss-of-supply incidents' on the transmission network, which is slightly better than the long-term average number for this type of incident.

National Grid Gas (NGG)

Table 5 - NGG TO

NGG - NTS TO

Regulated Income	**Allowance**	**Actual**	**Timing Difference**
	£m	**£m**	**£m**
Final Proposals	556.2		
Adjustments from final proposals to license	6.1		
Difference for income specific inflation	0.8		
Maximum allowed revenue	563.1	538.1	(25.0)
NTS Exit Charges foregone		(57.8)	
Elimination of DN Pensions Deficit & Other Adjustments		(28.5)	
Other Income		-	
per NGG Regulatory Accounting Statement		**451.8**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	64.2
Non operational capex	2.3
Total	66.5
Net movement in provisions / Other adjustments	(0.1)

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
Cash Controllable Costs	**66.4**	**66.4**	**(0.0)**

Non Controllable Costs	**Actual**
	£m
Total	**106.4**

Inovation Funding Initiative (IFI)	**Actual**
	£m
Opex (80% of which is allowed)	**2.0**

Logged Up Operating Costs	**Actual**
	£m
Opex	14.0

Pensions	**Allowance**	**Actual**	**Under / (Over) Recovery**
	£m	**£m**	**£m**
Ongoing	12.2	9.0	(3.2)
Deficit	29.8	178.0	148.2
	42.0	187.0	144.9
Ongoing (under recovery in 2002 - 07)	4.8	-	N/A
Total	**46.8**	**187.0**	**144.9**

Capex (including pensions)	**Allowance**	**Actual**	**Pension Costs in actual**
	£m	**£m**	**£m**
Load Related	164.6	181.2	0.9
Non Load Related	78.4	66.7	0.3
Subtotal	**243.0**	**247.9**	**1.2**
Capex Not Yet Included in RAV			
Incremental Capex		88.0	
Logged Up Costs		7.3	
Strategic Stock		10.3	
Total		353.5	

Incentivised Capex	**Allowance**	**Actual**	**Variance**
	£m	**£m**	**£m**
Total Capex	243.0	247.9	
Ofgem Adjustment		(13.8)	
Total Capex	243.0	234.1	(8.9)

Additions	247.9
Ofgem Adjustments (deferred for consideration)	(13.8)
Provisional RAV additions	**234.1**

Gearing / Interest	**Actual**
Interest Costs	147.8
Net Debt	2,488.2
Provisional RAV (at year end price level)	3,913.0
Capex not yet in the RAV	100.6
Gearing as % of provisional RAV and capex not yet in the RAV	62%

System Activities and Performances	**Actual**
NTS Length Km	7,612
Installed Compressor Power (MW)	1,276

Table 6 - NGG SO

NGG - NTS SO

Regulated Income	**Target**	**Actual**	**Variance**
	£m	**£m**	**£m**
Core Allowance	367.5	342.7	(24.8)
Balancing neutrality charges		(1.4)	
Capacity Management costs		(1.2)	
GSO Provision re Deemed Interruptible Charges Foregone error		(10.7)	
per NGG Regulatory Accounting Statement		**329.4**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	32.1
Net movement in provisions	(0.4)

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
Cash Controllable Costs	**26.5**	**31.7**	5.2

Non Controllable Costs	**Actual**
	£m
Agency Costs (xoserve)	6.9

Logged Up Costs	**Actual**
	£m
Total	-

Pensions	**Allowance**	**Actual**	**Under / (Over) Recovery**
	£m	**£m**	**£m**
Ongoing	5.5	4.7	(0.8)
Deficit	0.2	0.7	0.5
	5.7	5.4	(0.3)
Ongoing (under recovery in 2002 - 07)	2.1	-	N/A
Total	**7.9**	**5.4**	**(0.3)**

SO Capex	**Allowance**	**Actual**	**Variance**
Total	**9.5**	**7.0**	(2.4)

Gearing / Interest	**Actual**
Interest Costs	1.4
Net Debt	24.7
Provisional RAV (at year end price level)	34.3
Gearing as % of provisional RAV	72%

LICENSEE'S COMMENTS

NGG Transmission Owner (TO)

1.22. The challenges in 2008/09 were significantly different to those of 2007/08 and were dominated by the impact of changes to the UK security of supply arrangements, turbulence in the global financial markets and economic recession in the UK. The economic instability led to changes in terms of demand-side response (to higher energy prices and recessionary pressures), lower growth in energy demand and reappraisal of supplyside investment decisions by energy sector investors.

1.23. As part of the 2007/08 RRP narrative, National Grid highlighted how it had experienced significant inflationary pressures due to commodity price increases, global economic growth and increased competition for UK construction resources. These global economic drivers impacted the level of construction in 2008/09, which were largely determined in advance and reflect the impact of the aforementioned 2007/08 real inflationary pressures.

1.24. 2008/09 saw significant changes to UK security of supply arrangements. As a result, the gas National Transmission System (NTS) has become increasingly complex and inherently more difficult to operate as new entry points and sources of supply are commissioned. In response to market signals, National Grid continues to fast-track wherever possible the delivery and commissioning of new NTS capacity, connections and associated reinforcements necessary to ensure the continued safe operation of the NTS. National Grid has continued to manage the impact of delays in the completion of new gas importation capacity and storage facilities.

1.25. National Grid endeavours to minimise the consequential impact of delays in obtaining the necessary planning consents upon both customer and consumer costs and benefits. Experience of working with the new planning act has demonstrated that the difficulty and cost in gaining planning consent for pipelines and particularly above ground installations has markedly increased for future schemes. Whilst the Planning Act will increase costs, it should however provide greater certainty on timescales and diligent application of process.

1.26. In summary, National Grid continues to pro-actively manage the impact of rapidly changing economic conditions and the onset of the more fundamental changes taking place within the UK energy sector i.e. undertaking the changes necessary to ensure the continued safe and secure operation and development of energy transmission systems (in response to changing consumer demand patterns, customer and governmental requirements) whilst helping to facilitate the decarbonisation of the UK energy sector and achievement of climate change targets.

NGG System Operator (SO)

1.27. 2008/09 witnessed a step up in investment in and operational support for critical operating systems. The result of this was that GSO controllable costs increased as a result of management's decision to increase the level of IS support and enhance the resilience of critical operating systems. In addition electricity own use costs were high due to prevailing market conditions.

1.28. Operationally Winter 2008/09 was dominated by the Russia-Ukraine dispute which impacted the UK by stimulating significant export flows to the continent as shippers sought to manage their positions across UK and European markets. This coincided with a period of very cold weather in early January which required significant flows from UK storage to meet the high demands. This presented significant operational challenges which were successfully met through the deployment of the available suite of operational and commercial balancing tools, many being used for the only the first or second time. Experiences from this event were captured and reviewed with industry and Government. This resulted in a number of changes, including the introduction of new Safety Monitor / Gas Balancing Alert information, together with a corresponding refinement in the way that Safety Monitors are calculated.

Appendix 2 - Responses and Questions

We welcome views on the information published in this report. Please send your comments to:

Martin Rodgers
Head of Network Business Support, Networks Cost and Outputs Team,
Local Grids and RPI-X@20
Ofgem
9 Millbank
London
SW1P 3GE
Email: martin.rodgers@ofgem.gov.uk

Appendix 3 – The Authority's Powers and Duties

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

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

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[2].

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

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

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[3]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[4]

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

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

- Promote efficiency and economy on the part of those licensed[5] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

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

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

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[6] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

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

Appendix 4 - Glossary

B

Baseline

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

Baseline Capital Expenditure

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

BT21st Century

BT's consolidation of its telecoms network sometime in the future onto one platform; this may mean that some tele-protection services used by TOs will be incompatible with the new platform. Hence TOs may be required to replace tele-protection lines.

C

Cash Controllable Costs

Excludes exceptional provisions (e.g. restructuring costs), and the net movement in provisions but includes the "non operational" capital expenditure which has been excluded from the assessment of RAV.

I

Incentivised loss-of-supply incidents

Incidents on the transmission network which impact 4 or more customers, these incidents typically occur on the main backbone of our interconnected transmission network.

L

Load Related Capex

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

N

Non controllable costs

Costs not within the direct control of the licensee and allowed to be passed on to the customer. These include network rates, license fees, security costs, Scottish Independent Undertakings price differential and xoserve TO costs.

Non-Load Related capex

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

Non operational capex

Capital expenditure on items other than the operational system e.g. personal computers, vehicles.

Q

Quasi Capex

Operating costs that are treated as operating costs in the regulatory and statutory accounts, but are reported as capex for regulatory reporting purpose.

R

Regulatory Asset Value (RAV)

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

Return on Regulatory Equity (RoRE)

The financial return achieved by shareholders in a licensee during a price control period from it's out-turn performance under the price control. The return is measured using income and cost definitions contained in the price control regime (as opposed to accounting conventions) and is expressed as a percentage of (share) equity in the business. Importantly, in the calculation the gearing (proportions of share equity and debt financing in the RAV) and cost of debt figures used are those given as the 'assumed' levels in the relevant price control final proposals. The aim of

the RORE measure is to provide an indication of the return achieved by the owners of a licensee which can be compared to the cost of equity originally allowed in the price control settlement and to the return achieved by other licensees on an equivalent basis.

S

System Operations - External costs

The costs incurred in real time system balancing, matching of electricity and gas demand and supply, ensuring the stability and security the system.

System Operations - Internal costs

The provision of staff and IT systems to enable system operations to take place.

Appendix 5 - A guide to Return on Regulatory Equity

1.1. Historically, the debate during a price control review has focused heavily on the level of the allowed return, even within a relatively narrow range. It is understandable that this number is of interest, particularly among analysts, as it constitutes a significant element of the overall revenue cap for regulated companies. Furthermore, it is a single figure rather than a complex incentive mechanism and its outperformance can be readily demonstrated in the capital markets.

1.2. However, we believe that an excessive focus on the allowed return means that the impact of other elements of the price control can be overlooked even though they are potentially of a greater magnitude. We have therefore developed a tool to holistically measure the performance of the companies under the control – by measuring returns on regulatory equity over the five year period.

1.3. When calculating RoRE, we are not attempting to be consistent with accounting return on equity metrics. We do, however, think it is important that companies, investors, analysts and other interested parties understand the basis of our calculations and also why actual shareholder returns differ from those presented in our analysis. We do not, for example, take account of a company's capital structure nor analyse the cost of its embedded debt, both of which would likely impact actual returns. Furthermore, we have only made adjustments for what we consider to be meaningful variances from an assumed baseline. We recognise that there may be other factors that can affect actual shareholder returns. In our analysis we consider variances in returns from: cost expenditure, pensions, tax, incentives and the cost of debt. For the latter, we measure the difference between our allowance and a benchmark based on actual 10 year trailing average bond yields for a comfortable investment grade issuer. This allows a like for like comparison between Transmission Owners.

1.4. When measuring RoRE, we initially calculate a value for the equity component of the Regulatory Asset Value (RAV) by applying our notional gearing assumption of 60%. Secondly, the starting point is always the allowed return on equity implied within the cost of capital determination for the price control 7%. We then express variances between out-turned expenditure versus our ex ante determinations as a percentage of the equity capital for each relevant driver. These are then added or subtracted from the baseline equity return. In calculating the RoRE we apply any necessary adjustments, for example – corporation tax and for variances in total expenditure.

Appendix 6 - Amendments to Regulatory Reporting Pack (RRP) Tables

Ofgem propose making a few minor amendments to the RRP tables in 2009/10 to address points that have arisen during the course of the RRP review. These will be developed over the next few months. We would welcome views on any additional changes that would be appropriate.

Appendix 7 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk