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Transmission Annual Report for 2009 -10

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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 fourth report on transmission licensees' operating and capital expenditure based on the regulatory reporting process introduced as part of the Transmission Price Control Review for 2007-12 (TPCR4).

This report sets out revenue, operating costs, 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 2010. This is the third 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 2010 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 2010.

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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 (RIIO-T1).

This report is the fourth annual report and covers the third 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
- Transmission Annual Report for 2008/09 (ref 48/10) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/RegReporting
- TPCR4 Rollover Policy Update and Initial Analysis of Business Plans http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/TPCR4roll.pdf

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Summary

Purpose of the Report

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 (RIIO-T1). 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 4.0) April 2010. 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 2009/10

Total revenue across all electricity and gas TOs was £2330m just 2 per cent lower than the allowance. The electricity and gas SO revenues were £1182m just 3 per cent lower than the allowance.

Total controllable operating costs across the TO licensees was £284m, 12 per cent above allowances. As in previous years this is due to overspends by NGET due to continuing upward cost pressures. Total controllable operating costs across the SO licensees was £87m, 7 per cent above allowances again due to overspends by NGET.

Total electricity and gas capital expenditure by all TOs was £993m, 13 per cent above allowances (before calculation of incentivised capex and revenue drivers). This was due to NGET, SHETL, and NGG exceeding their load related capital expenditure allowances. Overall non load related capital expenditure was lower than allowances. Total SO capital expenditure was £22m, 27 per cent above allowances.

This report does not cover pension costs which are covered in the TPCR4 Rollover Policy Update and Initial Analysis of Business Plans document (ref 54/11) and Decision on strategy for the next transmission price control - RIIO-T1(ref 41/11).

1. Review of Transmission Owners (TO) Performance

Chapter Summary

This chapter summarises the key data and issues relating to the Transmission Owners' performance in 2009-10

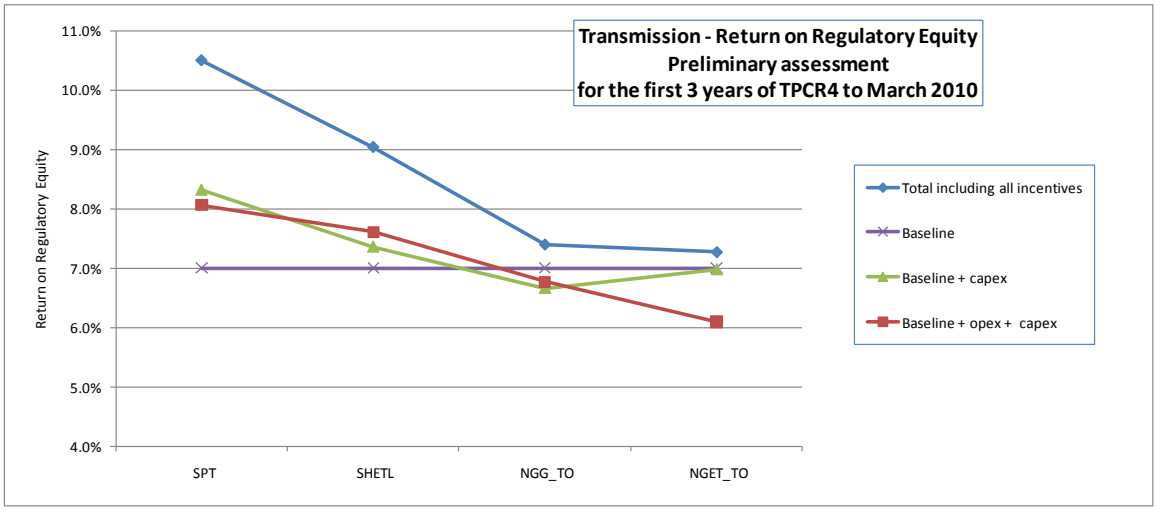
Background

1.1. In this section we provide an overview of the main components of TO performance in 2009/10 compared with the price control allowances in a 2009-10 price base. The only exception to this is that the revenue comparison is included in nominal prices.

Returns on Regulatory Equity

1.2. In previous 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 consider that it helps us (and all interested parties) understand better how companies have performed.

Figure 1: 2009/10 Returns on Regulatory Equity



1.3. Figure 1 shows the provisional RoRE assessment for the first 3 years of the current transmission price control (TPCR4). This data relates only to the transmission operator part of the business, i.e. it excludes any performance relating to the system operator. The chart differs from that included in our December strategy consultation as we have now incorporated the estimated impact of outperformance on TIRG. The results represent our initial estimate of this outperformance and we will

work together with the Transmission Operators to develop our approach to the assessment.

Summary of Price Control Revenue (in nominal prices)

1.4. The revenue figures shown below exclude income from excluded services such as post-BETTA connection charges, services for third parties, and miscellaneous and de minimis income.

National Grid Electricity Transmission

Table 1: NGET TO Revenue Summary

(figures in £m)	2009-10 £m	2008-09 £m	Variance £m	Variance %
Total Allowance*	1,511.5	1,407.1	-104.4	-7.4%
Total Actual Revenue	1,465.1	1,421.6	-43.4	-3.1%
Over / Under Recovery	-46.4	14.6		

NB. The figures also include income collected on behalf of the Scottish TOs.

1.5. NGET under-recovered revenue by £46.4m. This was due to allowances for Strategic Investment, Inter-TSO Compensation (between Scottish TOs and SO), and timing differences carried forward from 2008/09. The table below shows the main areas of movement in NGET TO revenues, year on year.

Table 2: NGET TO Year on Year Movement in Allowed Revenue

(figures in £m)	2009-10	2008-09	Movement £m
Retail Price Index (RPI)			53.4
Base Revenue (PRt)	1,223.8	1,147.4	76.4
Transmission Investment in Renewable Generation (TIRGt)	12.1	7.4	4.8
Pass Through (PTt)	266.1	237.4	28.7
Incentive Payments (IPt)	26.3	19.0	7.3
Other revenue terms	-2.2	-3.1	0.9
Correction Factor (Kt)	-14.6	-1.0	-13.6
Total Allowed Revenue (TO)	1,511.5	1,407.1	104.5

1.6. NGET's base line allowed revenues rose by £104.5m, a 7 per cent year on year increase between 2008-09 and 2009-10. The largest single element of this increase £53.4m is due to inflation. Other increases include an additional £28.7m of pass-through costs and an increase of £4.7m under the Transmission Investment for Renewable Generation (TIRG) programme.

1.7. NGET was able to recover incentive revenues of £26.3m in 2009/10. The incentive revenues include £9.0m under the reliability incentive and £2.4m under the Sulphur Hexafluoride (SF6) leakage arrangement, which provides NGET with an incentive to minimise the volume of SF6 gas that leaks from transmission equipment. NGET was also able to recover £4.9m via the IFI scheme, which allows it to pass through 80% of spend on eligible research and development projects. IFI spend was

£6.1m in 2009-10. In 2009-10, NGET also received £10m as allowed pre-construction revenues.

Scottish Hydro-Electric Transmission

1.8. Table 3 shows SHETL allowed and actual TO revenues for 2009/10 together with data for the previous year and the year on year change.

Table 3: SHETL Revenue Summary

(figures in £m)	2009-10	2008-09	Variance £m	Variance %
Total Allowance	61.7	57.8	3.9	7%
Total Actual Revenue	61.4	59.3	2.1	4%
Over / Under Recovery	-0.3	1.5		

Table 3: SHETL Year on Year Movement in Allowed Revenue

(figures in £m)	2009-10	2008-09	Movement £m
Retail Price Index (RPI)			0.6
Transmission Base Revenue (PRt)	57.9	54.8	3.2
Transmission Investment in Renewable Generation (TIRGt)	1.6	0.4	1.1
Pass Through items (PTt)	-0.2	-0.3	0.1
Incentive Payments (IPt)	0.4	0.7	-0.3
Other revenue terms	3.6	0.0	3.6
Correction Factor (Kt)	-1.6	2.2	-3.8
Total Allowed Revenue (TO)	61.7	57.8	3.9

1.9. SHETL's transmission base revenue (PRt) increased by about £4m, of which £0.6m was due to inflation. Overall, incentive payments in 2009/10 were £0.3m lower than the previous year. The incentive for 5 year rolling Capex and Opex was £0.4m less than the previous year. SHETL recovered slightly more revenue under the Innovation Funding Incentive in 2009/10, £0.44m, compared with £0.31m in 2008/09.

Scottish Power Transmission Limited

Table 4: SPTL Revenue Summary

(figures in £m)	2009-10	2008-09	Variance £m	Variance %
Total Allowance	197.9	180.1	17.8	10%
Total Actual Revenue	193.6	180.4	13.1	7%
Over / Under Recovery	-4.3	0.3		

1.10. Table 6 shows SPTL allowed and actual TO revenues for 2009/10 together with data for the previous year and the year-on-year change. SPTL allowed revenue increased from £180m in 2008/09 to £198m in 2009/10. Of this, £6.6m was due to inflation.

Table 5: STPL Year on Year Movement in Revenue

(figures in £m)	2009-10	2008-09	Movement £m
Retail Price Index (RPI)			6.6
Transmission Base Revenue (PRt)	181.7	171.7	10.0
Transmission Investment in Renewable Generation (TIRGt)	13.6	8.2	5.4
Pass Through items (PTt)	-0.3	-0.4	0.1
Incentive Payments (IPt)	3.2	0.4	2.8
Other revenue terms	0.0	0.0	0.0
Correction Factor (Kt)	-0.3	0.20	-0.5
Total Allowed Revenue (TO)	197.9	180.1	17.8

1.11. SPTL Transmission Investment in Renewable Generation (TIRGt) revenue increased from £8.3m in the previous year to £13.6m. This was mainly due to a £3.4m increase in the England Scotland interconnector project and a £1.3m increase in the Sloy project. SPTL Incentive Payments (IPt) were higher than the previous year. The main reason for this was that SPTL received £2.5m for approved pre-construction costs.

1.12. SPTL 's revenue in respect of IFI eligible projects in 2009/10 was £0.10m compared to £0.14m in the previous year. There was a small movement of £0.5m in the correction "K" factor due to an over-recovery of revenue of £0.3m compared to an under-recovery of £0.2m in the prior year.

National Grid Gas – NTS

Table 6: NGG NTS Movement in Revenue

(figures in £m)	2009-10	2008-09	Variance £m	Variance %
Total Allowance	604.5	563.1	41.4	7%
Total Actual Revenue	610.5	538.1	72.4	13%
Over / Under Recovery	6.0	-25.0		

1.13. NGG TO over-recovered against the allowed revenue by £6m. NGG explained that the over-recovery was due to additional revenues from the cold winter weather

Table 7: NGG NTS Year on Year Movement in Allowed Revenue

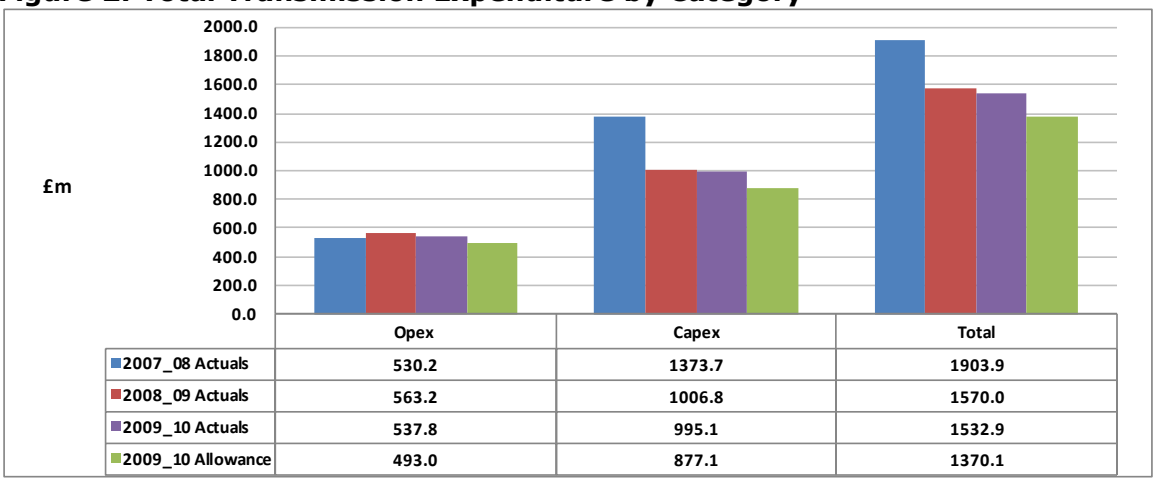
(figures in £m)	2009-10	2008-09	Movement £m
Retail Price Index (RPI)			20.1
Transportation Owner Base Revenue (TOZt)	546.5	526.3	20.2
Less Milford Haven (TOZAt)	-11.3	-10.9	-0.4
TO Cost Pass Through (TOFt)	41.5	44.6	-3.1
TO Incentive Adjustments (TOGt)	2.7	1.6	1.1
TO Correction Factor (TOKt)	25.1	1.5	23.6
Allowed Transportation Owner Revenue (TOMRt)	604.5	563.1	41.4

1.14. NGG TO revenue stood at £604m for the year this represents an increase of 7 per cent, or £41m, on the previous year. Of this, £20m was the effect of inflation on the base revenue allowance. Pass-through costs decreased by £3.1m, mainly due to a decrease of £3.3m in licence fees paid. Licence fees were higher in 2008/09 due to costs associated with the abolition of energywatch and the creation of Consumer Focus/Consumer Direct

1.15. The increase of £1.16m in incentive adjustments relates to an increase in spending on Innovation Funding Initiative (IFI) eligible projects.

Total Expenditure

Figure 2: Total Transmission Expenditure by Category



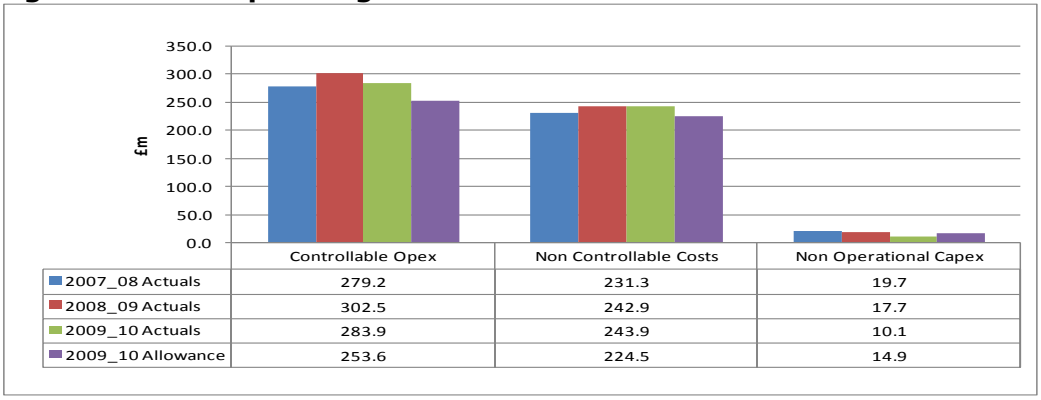
	Opex	Capex	Total
2007_08 Actuals	530.2	1373.7	1903.9
2008_09 Actuals	563.2	1006.8	1570.0
2009_10 Actuals	537.8	995.1	1532.9
2009_10 Allowance	493.0	877.1	1370.1

1.16. Total Transmission operating costs and capital expenditure across all TOs was £1.5bn in 2009-10, 2.4 per cent lower than the previous year; although NGET capital expenditure was higher all other spend was lower. Despite lower expenditure than in 2008/09 the figure was higher than price control allowances by 11.9 per cent. This was due to higher operating costs than allowances within NGET and higher capital expenditure within NGET and NGG, although there was lower expenditure by SPTL particularly in the area of non load related capex.

Total Operating Costs

1.17. The total operating cost allowance can be separated into 3 elements: controllable costs, non controllable costs and an allowance for non operational capex, each of which is defined in the glossary at appendix 4. Figure 3 below shows the performance in 2009/10.

Figure 3: Total Operating Costs



	Controllable Opex	Non Controllable Costs	Non Operational Capex
2007_08 Actuals	279.2	231.3	19.7
2008_09 Actuals	302.5	242.9	17.7
2009_10 Actuals	283.9	243.9	10.1
2009_10 Allowance	253.6	224.5	14.9

1.18. In 2009/10 both controllable and non controllable costs were in excess of allowances, but non operational capex was lower.

Controllable Operating Costs (including non operational capex)

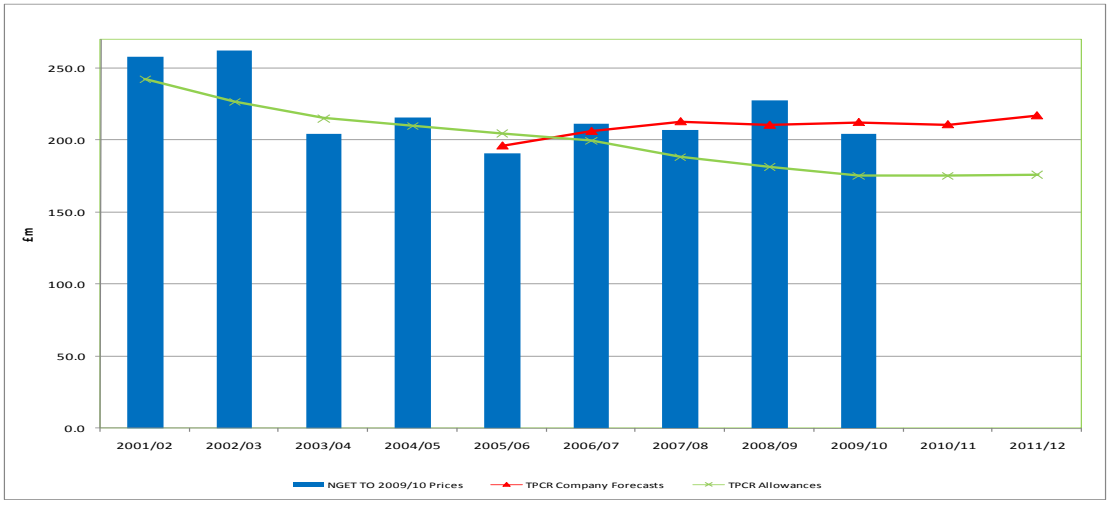
NGET

1.19. Controllable operating costs were £204.5m, 9.8 per cent below 2008/09 expenditure of £226.7m. The main reasons for the decrease are:

- Reduction in own use electricity costs due to price reductions and efficiencies (£2.5m)
- One-off insurance proceeds (£4.1m)
- Reduction in charges from the Corporate Centre (£2.0m)
- Reduction in excluded services costs (£8.8m)
- Reduction of non operational capex (£6.8m) due to reductions in IS and vehicle investment
- There have been other reductions in shared services costs due to efficiencies but these have been largely offset by increases in maintenance and site care costs

1.20. The chart below shows NGET's performance against operating costs allowances.

Figure 4: NGET Opex Performance against Allowances

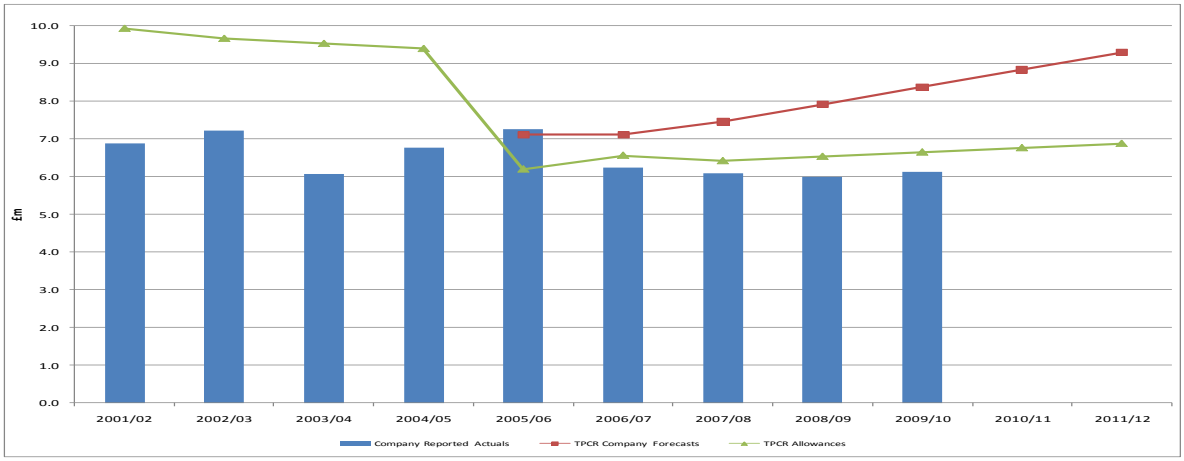


1.21. NGET operating costs remain above the price control allowances, although the overspend has reduced. Non operational capex was lower than the allowance - this reflects the high spend in 2008/09.

SHETL

1.22. Figure 18 below shows the operating cost trend for SHETL since the last price control. Operating costs for 2009/10 were £6.1m, 7.6 per cent below the allowance.

Figure 5: SHETL Opex Performance against Allowances

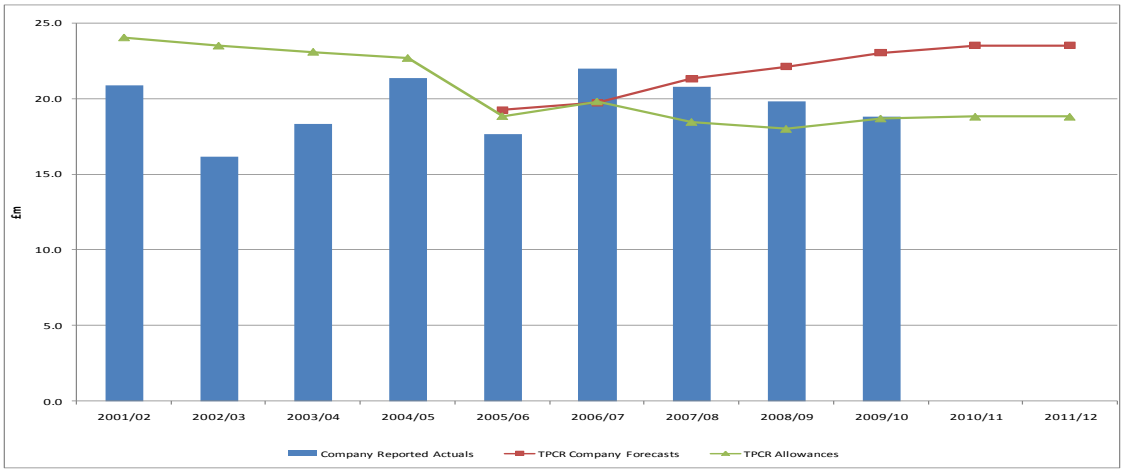


SPTL

1.23. Figure 19 shows the operating cost trend for SPTL since the last price control. Opex in 2009/10 was £18.8m, £0.1m above the allowance; this includes an adjustment of £4.4m for capitalisation. Operating costs before the capitalisation

adjustment increased in 2009/10 due to the start of a tower painting programme (£1.7m).

Figure 6: STPL Opex Performance against Allowances

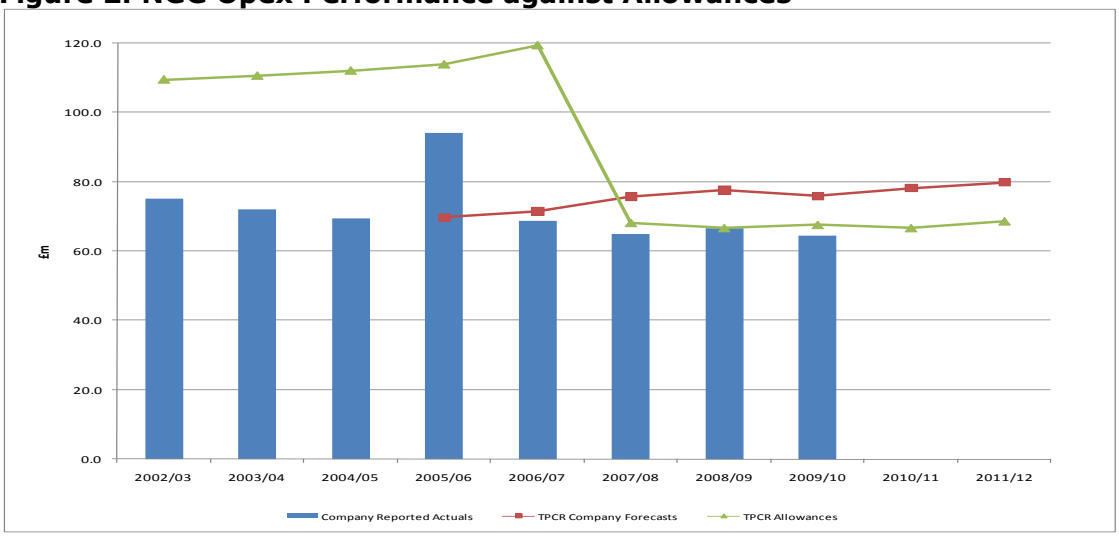


NGG

1.24. Controllable operating costs were £64.5m, 2.9 per cent lower than expenditure of £66.4m in 2008/09. This was largely due to lower electricity prices and the completion of the marker post replacement scheme.

1.25. The chart below shows NGG's performance against operating costs allowances. Overall NGG are slightly lower than price control allowances.

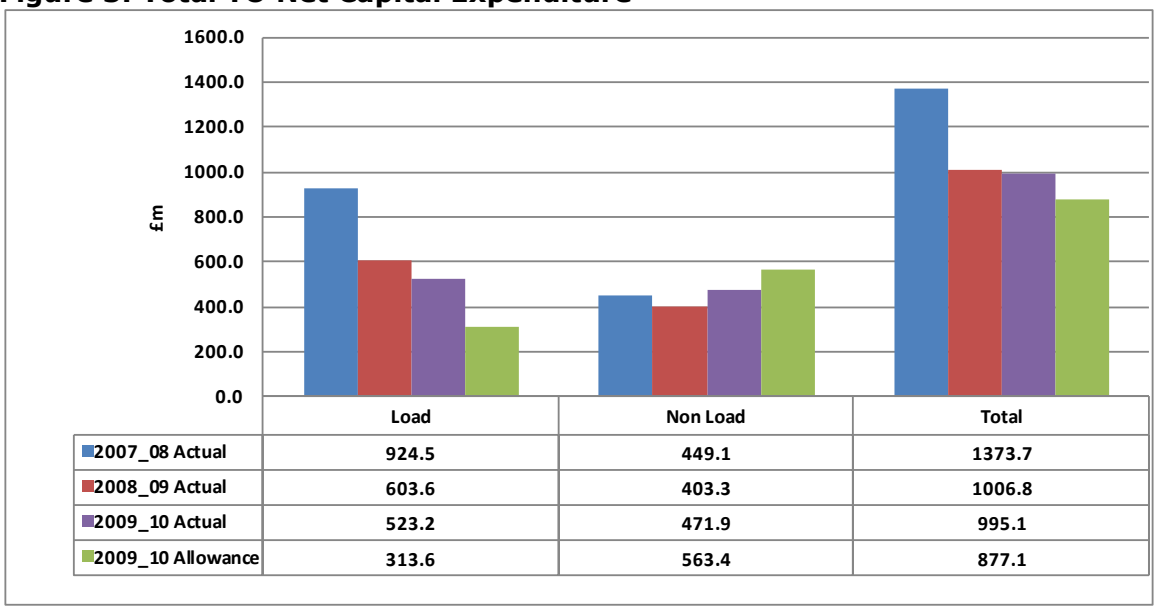
Figure 2: NGG Opex Performance against Allowances



Total Capital Expenditure (Base Line)

1.26. The capital expenditure figures shown here are after all adjustments made by Ofgem. These adjustment include: where the percentage of capitalised overheads exceeds that in the base year that was used in setting the original allowances at TPCR4 and monies received from the disposal of operational assets

Figure 3: Total TO Net Capital Expenditure



	Load	Non Load	Total
2007_08 Actual	924.5	449.1	1373.7
2008_09 Actual	603.6	403.3	1006.8
2009_10 Actual	523.2	471.9	995.1
2009_10 Allowance	313.6	563.4	877.1

1.27. Across all transmission operators total capital expenditure was in excess of allowances by 13.2%. Load related was overspent by 66.3% but non load related expenditure was underspent by 16.3%.

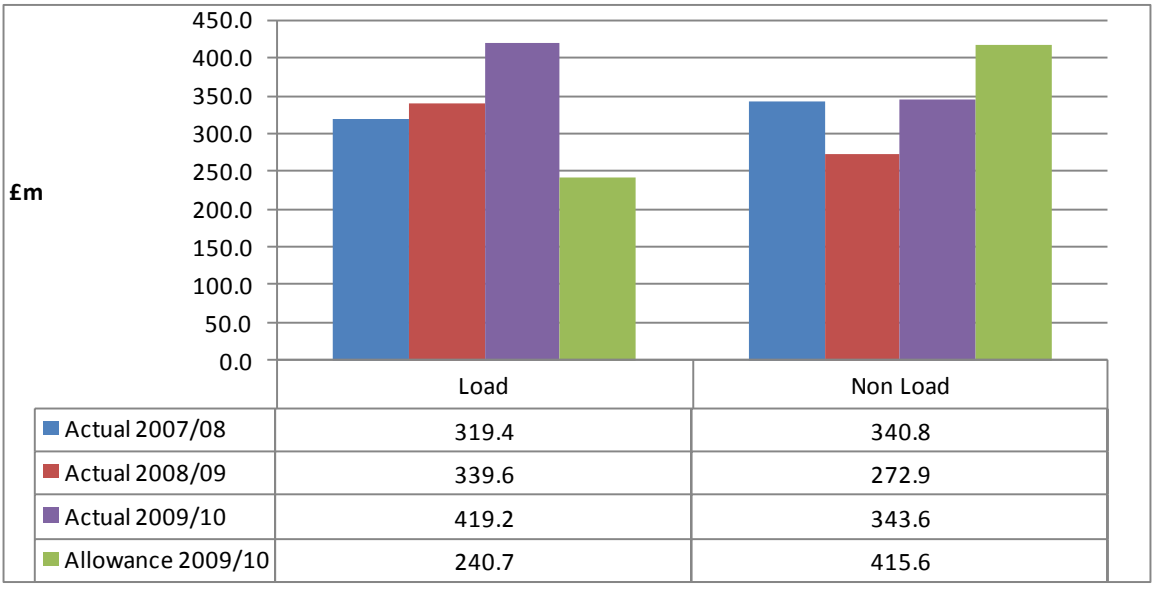
1.28. All the capex allowance figures, baseline and incentivised, are shown before any impact of revenue drivers. All NGET's revenue drivers and the downward element of Scottish TOs' revenue drivers (if connecting lower volume of generation than baseline level) will take effect as a one-off amount at 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. 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

1.29. NGET's load related capital expenditure was £419.2m, after deducting £93.3m of Regulatory Work in Progress relating to projects that will not trigger a revenue driver until a future price control period. The spend in the year is 74.2 per cent above the allowance and 26.1 per cent above expenditure in 2008/09. The increase was due to generator-related infrastructure and wider infrastructure investment to connect new generation and increase capacity.

1.30. Non load related capital expenditure was £343.6m, 17.3 per cent below the allowance but 25.9 per cent above expenditure in 2008/09. There were increases in transformer and switchgear replacement and renewal of the operational telecommunications infrastructure, but there were reductions in overhead and underground cables replacement.

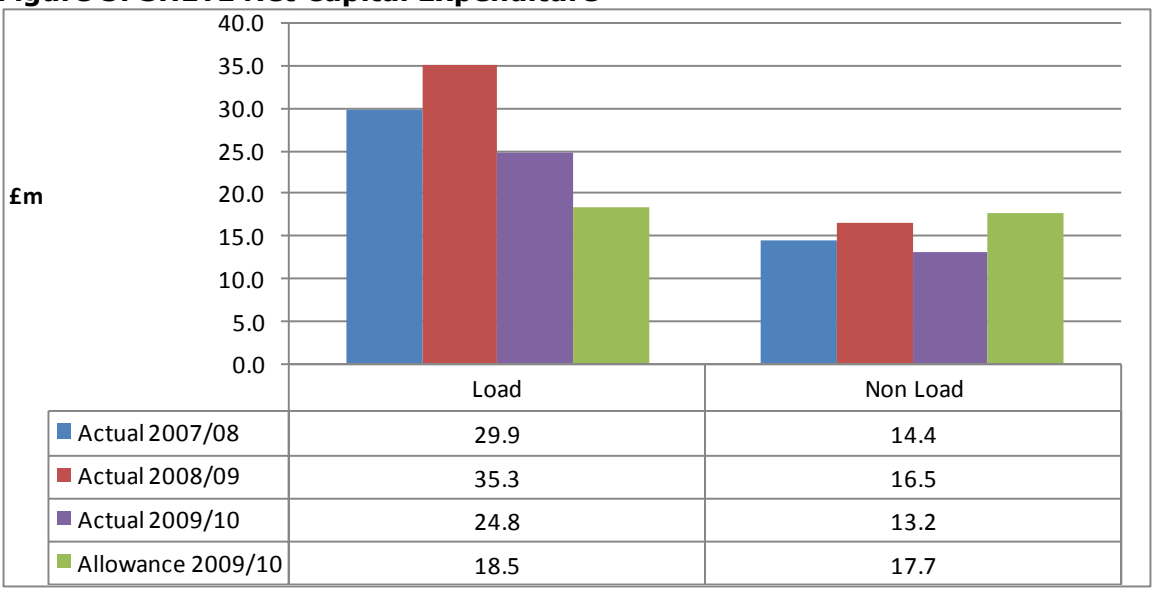
Figure 4: NGET Net Capital Expenditure



	Load	Non Load
Actual 2007/08	319.4	340.8
Actual 2008/09	339.6	272.9
Actual 2009/10	419.2	343.6
Allowance 2009/10	240.7	415.6

Capital Expenditure SHETL

Figure 5: SHETL Net Capital Expenditure



	Load	Non Load
Actual 2007/08	29.9	14.4
Actual 2008/09	35.3	16.5
Actual 2009/10	24.8	13.2
Allowance 2009/10	18.5	17.7

1.31. SHETL's load related capital expenditure was £24.8m, 34.1 per cent above the allowance but 29.7 per cent lower than expenditure in 2008/09. There was an increase in sole use connections and a reduction in infrastructure expenditure due to the delays in commencing work on schemes.

1.32. Non load related capital expenditure was £13.2m, 25.4 per cent below the allowance and 20 per cent lower than expenditure in 2008/09. Expenditure on transformer and overhead lines increase, but expenditure on switchgear and underground cables decreased.

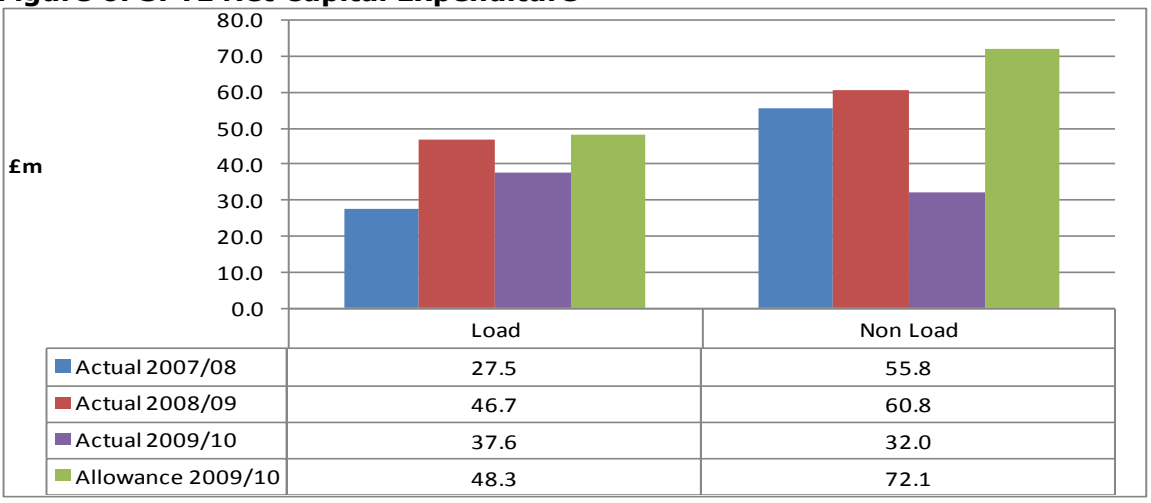
Capital Expenditure SPTL

1.33. SPTL's load related capital expenditure was £37.6m, 22.2 per cent below the allowance and 19.5 per cent below expenditure in 2008/09. This was due to continuing delays in the planning and consenting process

1.34. Non load related capital expenditure was £32.0m, 55.6 per cent below the allowance and 47.4 per cent below expenditure in 2008/09. Expenditure on transformers, overhead lines and underground cables showed the most significant decreases. This was mainly due to deferring a number of projects into future years

1.35. Both load and non load related expenditure was below the forecast for 2009/10 made in 2008/09. Total expenditure was £69.6m, 38.1% lower than the forecast of £112.4m.

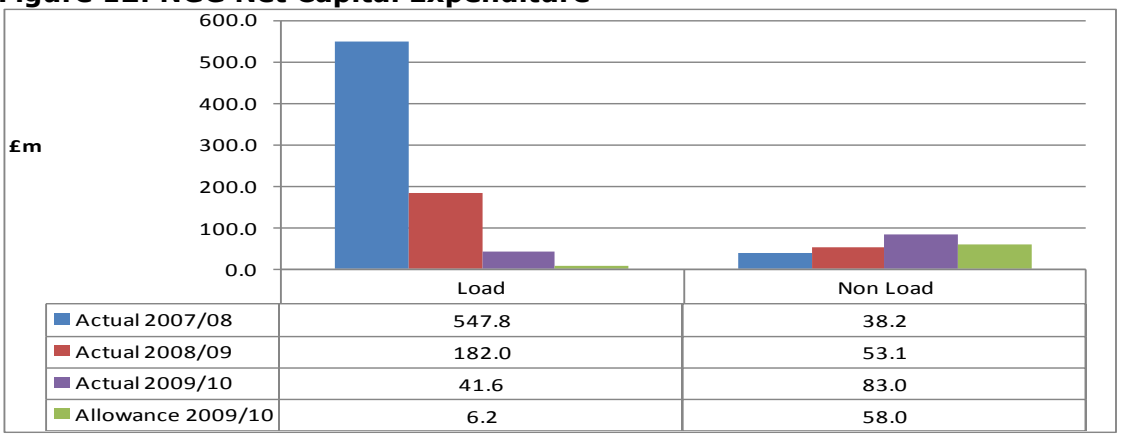
Figure 6: SPTL Net Capital Expenditure



	Load	Non Load
Actual 2007/08	27.5	55.8
Actual 2008/09	46.7	60.8
Actual 2009/10	37.6	32.0
Allowance 2009/10	48.3	72.1

Capital Expenditure NGG

Figure 12: NGG Net Capital Expenditure



	Load	Non Load
Actual 2007/08	547.8	38.2
Actual 2008/09	182.0	53.1
Actual 2009/10	41.6	83.0
Allowance 2009/10	6.2	58.0

1.36. NGG's load related expenditure was £41.6m, significantly above the allowance, but 77.1 per cent lower than 2008/09. The allowance assumed that the Milford Haven pipeline project to have been completed by now, however the project is still to be completed.

1.37. Non Load related expenditure was £83.0m, 43.1 per cent above the allowance and 56.3 per cent above expenditure in 2008/09. This was due to increased expenditure on changing compressor stations over to electric drive engines to reduce emissions and on asset health.

Incentivised Capex

1.38. 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.

1.39. The following table shows calculations required to derive the incentivised capex figures, showing the actual for 2009/10 and a cumulative position. NGET are above the allowance in 2009/10, but SHETL and SPTL are both below. Both SHETL and SPTL are also below the incentivised allowances on a cumulative basis, SPTL by 34 per cent.

Table 9: Incentivised Capex

Capex Values (£m)	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Load Related	419.2	24.8	37.6	481.6	41.6
Non Load Related	343.6	13.2	32.0	388.9	83.0
Pension Deficit	10.1			10.1	
Subtotal for Provisional RAV	772.9	38.0	69.6	880.5	124.6
Logged up capex	29.3	0.1	3.2	32.6	
Incremental capex				0.0	65.7
TIRG	42.6	3.6	28.6	74.8	12.6
TO Incentives	12.3	8.7	0.0		
Regulatory WIP	93.3			93.3	
Total Actual Expenditure	950.4	50.4	101.4	1081.2	203.0
Load Allowance (before revenue driver adjustment)	240.7	18.5	48.3	307.4	6.2
Non Load Allowance	415.6	17.7	72.1	505.4	58.0
Pension Deficit	10.1			10.1	
Total 2009/10 Final Proposals	666.4	36.1	120.4	822.9	64.2

Incentivised Capex Values (£m)	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Total Capex	772.9	38.0	69.6	880.5	124.6
Less capitalised pensions	(3.7)	(0.6)	(0.7)	(5.0)	
Less net load related sole use	(39.6)	(8.5)	(8.9)	(57.0)	
Less Pension Deficit	(10.1)			(10.1)	
Total Actual Incentivised Capex	719.5	28.9	60.0	808.4	124.6
Total capex allowance	666.4	36.1	120.4	822.9	64.2
Revenue driver adjustment	60.0	1.7		61.7	
Less capitalised pensions	(3.9)	(1.0)	(0.9)	(5.9)	
Less net load related sole use	(26.8)	(1.9)	(5.9)	(34.7)	
Less Pension Deficit	(10.3)			(10.3)	
Total Final Proposal Incentivised Capex	685.4	34.9	113.6	833.8	64.2
Incentivised Capex Over / (Under Spend)	34.1	(6.0)	(53.5)	(25.4)	60.4
As a Percentage	5.0%	(17.1%)	(47.1%)	(3.0%)	94.1%

Cumulative	NGET TO	SHETL TO	SPT TO	Elec Total	NGG TO
Actual Incentivised Capex	1,801.3	108.4	234.0	2,143.7	945.7
Final Proposal Incentivised Capex	1,779.6	117.8	354.4	2,251.8	847.6
Incentivised Capex Over / (Under Spend)	21.7	(9.4)	(120.3)	(108.0)	98.1
As a Percentage	1.2%	(8.0%)	(34.0%)	(4.8%)	11.6%

Logged Up Capex

1.40. 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, with the impact of this being 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 RIIO-T1 after a review for efficiency.

1.41. The table below summarises the current cumulative logged costs as at the end of 2009/10. The main increase in costs from last year is by NGET on cable tunnels, part of their London cable replacement project.

Table 10: Cumulative logged Up Capex 2006/07 to 2009/10

	NGET	SHETL	SPTL	NGG	Total
BT21CN			7.7		7.7
Cable Tunnels	38.5				38.5
Plugs (only for Scottish companies)			0.3		0.3
Quarry & Loss Development Claims				2.3	2.3
Milford Haven Pipeline Project				86.0	86.0
Other	24.5	0.3	6.3	18.7	49.8
Total Logging Up Capex	63.0	0.3	14.3	106.9	184.6

Provisional RAV

1.42. 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."*

1.43. 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 RIIO T1. Our assessment of RAV is therefore provisional. Table 11 below summarises our provisional view of the current RAV and how it has grown over the TPCR4 period.

1.44. 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 licence but this does not, as yet, include all network investment. Certain expenditure incurred (for example under TIRG or logged up costs) will, after review, be included in RAV at future dates (dependent on the type of spend).

Table 11: Provisional RAV

2004-05 prices £m	Opening RAV 1st April 2004	Net Additions	Depreciation	Closing RAV 31st March 2010	Uplifted to 2009-10 prices
NGET	5,042	3,273	(2,269)	6,046	6,934
SHTL	233	209	(98)	345	396
SPTL	575	547	(366)	757	868
NGG	2,424	1,648	(577)	3,496	4,009
Total	8,274	5,678	(3,309)	10,643	12,206

1.45. Table 12 below summarises the spend which TOs have undertaken but which sits outside of the RAV.

Table 12: Costs Not Yet in RAV

2009-10 prices £m	TIRG	TOI	Items treated as logged up	Revenue driver	Total
NGET	82	13	63	211	368
SPTL	98	0	14	0	113
SHTL	17	9	0	0	25
NGG	0	0	107	316	423
Total	196	22	184	526	928

Innovation Funding Initiative (IFI)

1.46. The transmission companies have spent £11.1m on IFI projects in 2009/10, 80% such expenditure is offset by allowed revenue up to a cap of 0.5 per cent of turnover or £0.5m 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 details the expenditure by licensee. Cumulative expenditure within this price control is £25.4m, 80 per cent of which (£20.3m) of which is allowed

Table 13: IFI Costs

£m	NGET TO	SHETL TO	SPTL TO	Elect. Total	NGG TO
IFI Expenditure	6.1	0.5	0.1	6.7	3.4
80% allowed	4.9	0.4	0.1	5.4	2.7

2. Review of System Operators (SO) Performance (in 2009/10 Prices)

Chapter Summary

This chapter summarises the financial data from licensees as System Operators. The main areas of concern are: both NGET and NGG are continuing to exceed their capital expenditure allowances.

Background

1.47. In this section we provide an overview of the main components of SO performance in 2009/10 compared with the price control allowances converted to 2009/10 price level.

Summary of Price Control Revenue

National Grid Electricity

1.48. 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.

Table 14: NGET SO Revenue Summary

(figures in £m)	2009-10	2008-09	Variance £m	Variance %
Licensee Bids (CSOBM)	230.6	330.8	-100.2	-30%
Contracts of availability (BSCC)	446.3	589.7	-143.4	-24%
Balancing service adjustments	-0.7	2.2	-2.9	
Incentive Payments	15.0	-15.0	30.0	
Balancing External	691.1	907.7	-216.6	-24%
Balancing Internal	99.6	99.3	0.31	0%

NB. The balancing external cost is the total cost of external balancing services, as opposed to the incentivised balancing costs discussed below.

1.49. Ofgem sets NGET a cost target for the year, the Incentivised Balancing Cost (IBC). If NGET incurred costs below the IBC, it receives an incentive payment of up to £15m. Conversely, if NGET incurred costs above the IBC, it is penalised by up to £15m. For 2009-10, NGET's incentivised balancing costs were £415.5m, so less than the lower limit of the target dead-band of £526.43m and NGET earned an incentive of £15m.

National Grid Gas

1.50. NGG SO under-recovered against the maximum allowed revenue by nearly £36m. NGG has explained that the under-recovery was caused shrinkage gas costs out turning £40m higher than anticipated

Table 8: NGG SO Revenue Summary

(figures in £m)	2009-10	2008-09	Variance £m	Variance %
Total Allowance	426.8	367.5	59.3	16%
Total Actual Revenue	391.1	342.8	48.3	14%
Over / Under Recovery	-35.7	-24.7		

Table 9: NGG SO Movement in Allowed Revenue

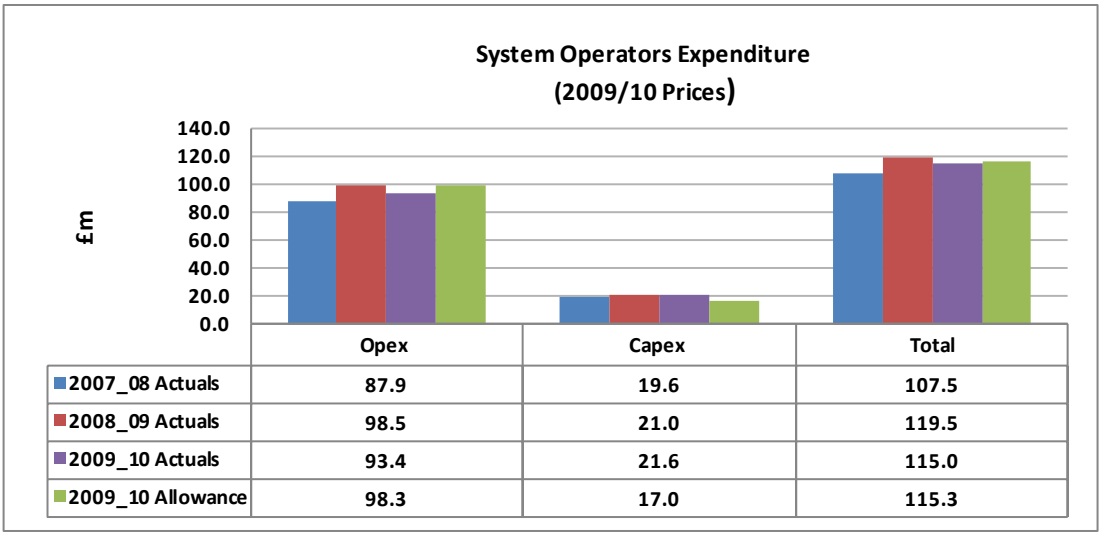
(figures in £m)	2009-10	2008-09	Movement £m
SO Entry Incentive Revenue (SOEIRCt)	53.4	45.7	7.7
SO Exit Incentive Revenue (SOExIRCt)	103.5	82.8	20.7
NTS External Cost SO Revenue (SOOIRCt)	175.6	176.3	-0.7
NTS Internal Cost SO Revenue (SOIntIRCt)	68.9	66.9	2.0
Other revenue terms	0.5	0.0	0.5
Correction Factor (SOKt)	24.9	-4.2	29.1
Allowed System Operator Revenue (SOMRt)	426.8	367.5	59.3

1.51. NGG SO allowed revenues increased from £367.5m in 2008/09 to £426.8m in 2009/10, an increase of 16%. The system operator correction factor (SOKt) moved by £29m. The exit incentive revenue increased by £21m, mainly because of an increase in charges forgone due to NTS exit capacity curtailment rights.

Total Internal Expenditure

1.52. Total electricity and gas system operator expenditure (operating costs and capital expenditure) was £115m in line with the total allowances. Operating costs were underspent but capital expenditure was overspent.

Figure 13: Total SO Expenditure



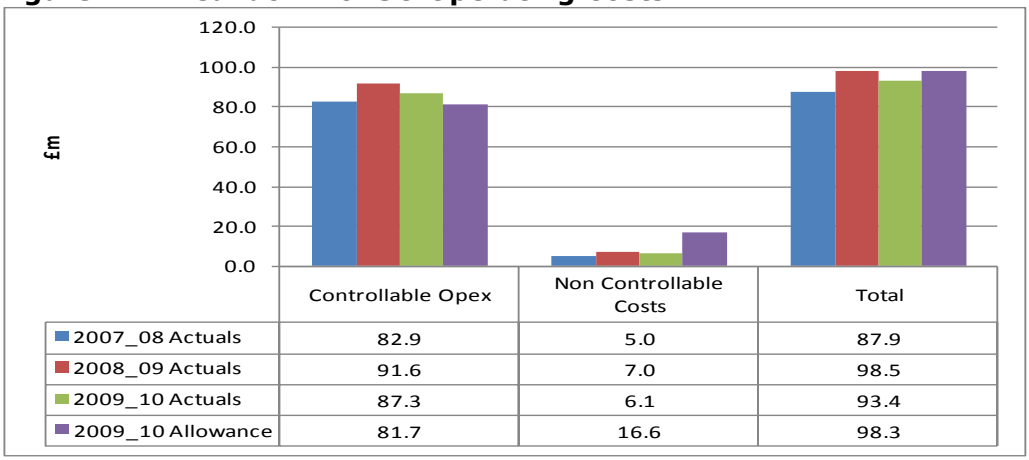
	Opex	Capex	Total
2007_08 Actuals	87.9	19.6	107.5
2008_09 Actuals	98.5	21.0	119.5
2009_10 Actuals	93.4	21.6	115.0
2009_10 Allowance	98.3	17.0	115.3

Total Internal Operating Costs

1.53. The table below shows a breakdown operating expenditure between controllable and non controllable costs. Controllable costs are £87.3m, 4.7 per cent lower than 2008/09 but 6.9 per cent above allowances.

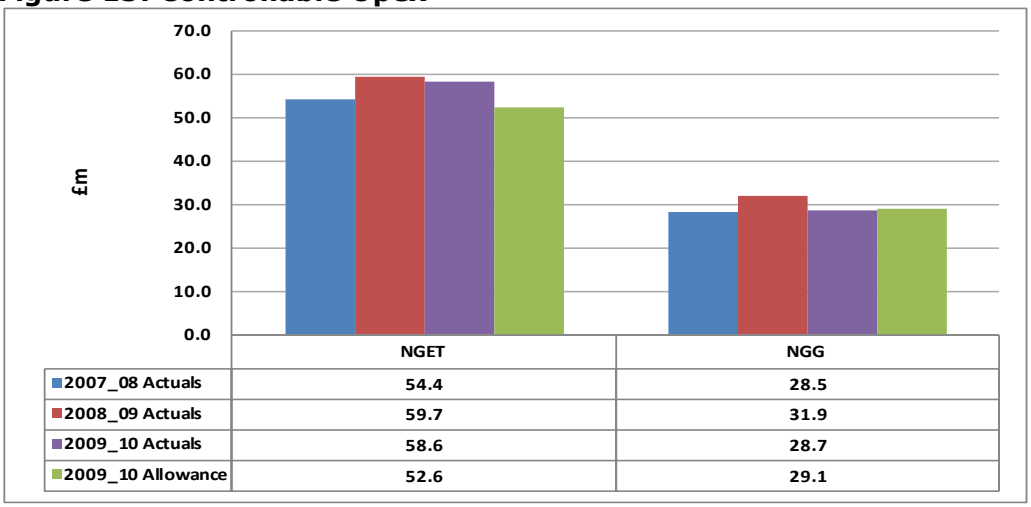
1.54. Controllable expenditure is higher than allowances in NGET due to increased levels of critical IS support, incremental market facilitation costs and changing workloads that are offsetting efficiencies. Within NGG controllable expenditure is lower than 2008/09 and slightly lower than the allowance. Staff cost increases were offset by efficiencies.

Figure 14: Breakdown of SO Operating Costs



	Controllable Opex	Non Controllable Costs	Total
2007_08 Actuals	82.9	5.0	87.9
2008_09 Actuals	91.6	7.0	98.5
2009_10 Actuals	87.3	6.1	93.4
2009_10 Allowance	81.7	16.6	98.3

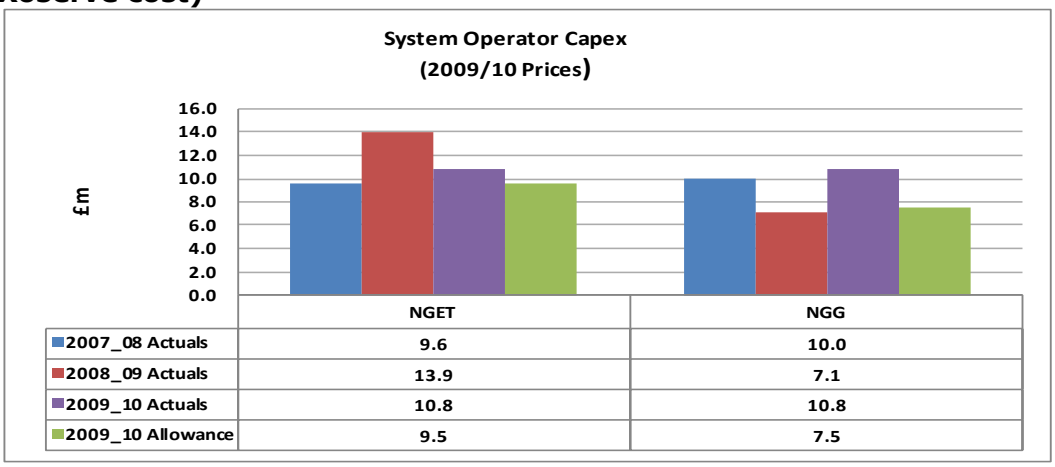
Figure 15: Controllable Opex



	NGET	NGG
2007_08 Actuals	54.4	28.5
2008_09 Actuals	59.7	31.9
2009_10 Actuals	58.6	28.7
2009_10 Allowance	52.6	29.1

Total Internal Capital Expenditure

Figure 16: SO Capex (after adjustment for prior year expenditure and Xoserve cost)



	NGET	NGG
2007_08 Actuals	9.6	10.0
2008_09 Actuals	13.9	7.1
2009_10 Actuals	10.8	10.8
2009_10 Allowance	9.5	7.5

1.55. The capex both for NGET and NGG were higher than allowances, but expenditure by NGET was lower than 2008/09 and NGG was higher. Spend by NGET was driven by critical systems and infrastructure investment. The increase in expenditure by NGG was in critical IS systems and follows on from a system strategy review.

Provisional RAV

1.56. Table 12 shows how the provisional RAV has developed from the opening values assumed for TPCR4. There is no logged up expenditure reflected in these RAV numbers.

Table 10: SO RAV

2004-05 prices £m	Opening RAV 1st April 2006	Net Additions	Depreciation	Closing RAV 31st March 2010	Uplifted to 2009-10 prices
NGET	43	52	(34)	61	70
NGG	40	32	(39)	33	37
Total	84	84	(74)	94	107

Appendices

Index

Appendix 1 – Data on Individual Transmission Licensees

1.1. This appendix 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)

NGET Transmission - TO

Regulated Income	Allowance £m	Actual £m	Timing Difference £m
Final Proposals	1,175.1		
Adjustments from final proposals to license	2.1		
Difference for income specific inflation	46.5		
Core Allowance	1,223.7	1,177.2	(46.4)
Excluded Services		99.9	
Allowed Adjustments		37.1	
Timing Differences		(0.1)	
per NGET Regulatory Accounting Statement		**1,314.1**	

Controllable Opex	Actual £m
Accounting Controllable Opex	199.4
Non operational capex	6.1
Total	205.4
Net movement in provisions / other adjustments	(0.9)

	Allowance £m	Actual £m	Variance £m
Cash Controllable Opex	**175.5**	**204.5**	**29.0**

Non Controllable Costs	Actual £m
Total	**118.9**

Innovation Funding Incentive (IFI)	Actual £m
Opex (80% of which is allowed)	**6.1**

Logged Up Operating Costs	Actual £m
Opex	-

Capex (including pensions)	Allowance £m	Actual £m	Pension costs in actual £m
Load Related	240.7	419.2	2.0
Non Load Related	415.6	345.1	1.7
Pension Deficit	10.1	10.1	-
Subtotal	666.4	774.4	3.7
Capex not yet included in the RAV			
Logged up capex		29.3	
Anticipatory (strategic) investment		12.3	
TIRG		42.6	
Regulatory WIP		93.3	
Total		951.9	

Incentivised Capex	Allowance £m	Actual £m	Variance £m
Total capex	666.4	774.4	
Pension deficit	(10.1)	(10.1)	
less revenue driver adjustment	60.0		
less capitalised pensions	(3.9)	(3.7)	
less net Load related sole use	(26.8)	(39.6)	
Total	**685.5**	**721.0**	**35.4**

Capex Additions	774.4
Ofgem Adjustments	(1.5)
Provisional RAV Additions	**772.9**

Gearing / Interest	Actual
Interest Costs (£m)	175.2
Net Debt	4,090.0
Provisional RAV (at year end price level)	7,092.5
Capex not yet included in the RAV (at year end price level)	376.4
Gearing as % of provisional RAV and capex not yet in RAV	54.8%

System Activities and Performances	Actual
Overhead Circuit km	14,127
Underground Circuit km	686
Measured system maximum demand (GW)	53.2
Total directly connected generation (GW)	62.7
Total directly connected wind generation (GW)	0.2
Total embedded generation (GW)	4.9
Incentivised loss of supply volume - NGET only (MWh)	61
System availability	94.8%
SF6 leakage rate (tonnes)	10.8

NGET Transmission - SO

Regulated Income	**Target**	**Actual**	**Variance**
	£m	**£m**	**£m**
External	691.8	691.1	(0.7)
Internal	100.5	99.6	(0.8)
Balancing Services Use of System Charges	792.3	790.7	(1.6)
Scottish & Hydro Charges		308.8	
Other Income		23.3	
per NGET Regulatory Accounting Statement		**1,122.8**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	59.1
Net movement in provisions / other adjustments	(0.5)

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
Cash Controllable Opex	**52.6**	**58.6**	**6.0**

Logged Up Costs	**Actual**
	£m
Operating Costs	1.5
Capital Expenditure	(0.3)
Total	1.1

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
SO Capex	**9.5**	**10.8**	**1.3**

	Actual
Total	
Gearing / Interest	
Interest Costs (£m)	1.4
Net Debt	31.3
Provisional RAV (at year end price level)	71.6
Gearing as % of provisional RAV	43.7%

Licensee's Comments

NGET Transmission Owner (ETO)

1.4. The turbulence witnessed in the global financial markets and the corresponding recession in the UK began to abate in 2009/10. However, these macro economic factors continued to offer challenges during the year. In response a continued flexible approach was undertaken to manage these economic uncertainties and financial impacts at a time when the need to invest in a low carbon economy is growing.

1.5. In 2009/10, TO capital investment was £952m, which marked the highest annual capex delivered to date, and £210m higher than 2008/09. At a level of £721m, incentivised capex was close to the level of adjusted capital allowances.

1.6. Capital investment increased for both load and non-load related investments when compared with 2008/09. Whilst investment in demand-led, load related schemes reduced, this was more than offset by an increase in generation-related investment. This continuing increase in connection activity saw a dozen generation projects (~3GW, largely gas and wind) being provided an operational connection in 2009/10.

1.7. During 2009/10, the headline ETO opex overspend was £29m over an allowance of £176m. This, however, was £17m less than the £46m overspend in 2008/09. This decrease primarily related to lower excluded services costs compared to 2008/09, a fall in energy prices and volumes and the impact of management initiatives, including corporate centre savings. These downward cost movements were partially offset by disruptive failures of several FMJL type current transformers, increased maintenance costs, flood clean-up costs and expenditure to achieve longer-term efficiency initiatives in shared services.

NGET System Operator (ESO)

1.8. ESO controllable costs decreased by £1m to £59m. The movement in costs was primarily driven by a reduction in corporate costs, which was offset by an increase in incremental UK and EU market facilitation costs. Further improvements in opex efficiency in 2009/10 were used to offset unforeseen upward cost pressures, including an increased focus on understanding industry impacts of future demand and generation scenarios, whilst proactively responding to increasing customer requirements. ESO controllable costs were £6m higher than the allowance.

1.9. Like-for-like ESO capital investment in 2009/10 decreased by £3m to £11m, following a reduction in the levels of critical IT system and control room related investments on asset health projects, such as integrated Electricity Management System and Balancing Mechanism asset upgrades. £1m was spent in 2009/10 on the continuing upgrade of critical property infrastructure, such as uninterruptible power supplies at the Electricity National Control Centre. Overall, ESO capital investments were £1m higher than the £10m allowance.

Scottish Hydro Electric Transmission (SHETL)

SHETL

Regulated Income	**Allowance**	**Actual**	**Timing Difference**
	£m	**£m**	**£m**
Base Price Control	56.1	57.95	
Difference for income specific inflation			
Under / Over Recovery (Current Year)		(0.30)	
	56.1	57.7	1.6
Excluded Services		2.26	
Allowed Adjustments		5.35	
Timing Differences		(1.6)	
Total Regulatory Turnover		**63.70**	

Controllable Opex	**Actual**
	£m
Accounting Controllable Opex	6.1
Non operational capex	0.0
Total	6.1
Net movement in provisions / other adjustments (to be recalculated)	0.0

	Allowance	**Actual**	**Variance**
	£m	**£m**	**£m**
Cash Controllable Opex	**6.6**	**6.1**	**0.5**

Non Controllable Costs	**Actual**
Network Rates	3.9

Innovation Funding Incentive (IFI)	**Actual**
	£m
Opex (80% of which is allowed)	0.5

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

Capex (including pensions)	**Allowance**	**Actual**	**Pensions included in actual**
	£m	**£m**	**£m**
Load Related	18.5	24.8	0.4
Non Load Related	17.7	13.2	0.2
Subtotal	36.1	38.0	0.6
Capex Not yet Included in RAV			
Logged up capex		0.1	
TIRG		3.6	
TO Incentive Capex		8.7	
Total		**50.4**	

Incentivised Capex	**Allowance**	**Actual**	**Variance**
	£m	**£m**	**£m**
Total capex	36.1	38.0	
less capitalised pensions	(1.0)	(0.6)	
Less net Load related sole use	(1.9)	(8.5)	
Total	**33.2**	**28.9**	**4.3**

Additions	38.0
Ofgem Adjustments	1.7
Provisional RAV Additions	**39.7**

Gearing / Interest (From Debt table)	**Actual**
Interest Costs (£m)	9.2
Net Debt	166.1
Provisional RAV (at year end price level)	405.1
Capex not yet included in RAV (at year end price level)	25.6
Gearing as % of provisional RAV and capex not yet included in RAV	38.6%

System Activities and Performances	**Actual**
Overhead Circuit km	5,219
Underground Circuit km	74
Measured system maximum demand (GW)	1.7
Total directly connected generation (GW)	2.8
Total directly connected wind generation (GW)	0.2
Total embedded generation (GW)	1.3
Number of incentivised loss of sypply events (#)	7
System availability (%)	97.38
SF6 leakage mass (Kg)	91.0

Licensee's comments

Operational Expenditure

1.10. SHETL has continued to tightly & rigorously control the level of operating costs within the business. As the volume, value and complexity of the capital projects undertaken increases there has been a small increase in the level of net operating costs. This has resulted in an underspend of £0.5M in cash controllable Opex costs against the OFGEM allowance after adjusting for the pension deficit payment of £1.9M.

Capital Expenditure

1.11. In 2009/10 SHETL decreased capital expenditure, following relatively high expenditure in 2008/09 to recover developer related scheme delays. Overall, price control capital expenditure has decreased by £6.7M in the year (excluding consideration of expenditure on Revenue Driver qualifying schemes and Customer Contributions).

1.12. Load related expenditure was higher than allowance, driven by delivery of developer related schemes. Load related expenditure has decreased by £3.0M in the year. Notable schemes in the year included;

- Connection and infrastructure works to facilitate the NGG demand connection at St Fergus
- Connection works to deliver the connection of Edinbane wind farm
- Carradale GSP reinforcement
-

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 decreased by £3.7M. Notable schemes in the year included;

- Persley GSP transformers replacement
- Cassley GSP transformer replacement
- Mossford GSP transformer replacement

Scottish Power Transmission (SPTL)

SPTL

Regulated Income	Allowance £m	Actual £m	Timing Difference £m
Base Price Control	181.7	181.7	
Difference for income specific inflation	0.0		
Under / Over Recovery (Current Year)		(4.3)	
	181.7	177.3	(4.4)
Excluded Services		2.6	
Allowed Adjustment		16.5	
Timing Differences		(0.3)	
Total Regulatory Turnover		**196.1**	

Controllable Opex	Actual £m
Accounting Controllable Opex	13.9
Non operational capex	0.5
Total	14.4
Adjustment to capitalisation (to be recalculated)	4.4

	Allowance £m	Actual £m	Variance £m
Cash Controllable Opex	**18.7**	**18.8**	**(0.1)**

Non Controllable Costs	Actual £m
Network Rates	**14.6**

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

Logged Up Operating Costs	Actual £m
Opex	0.0

Capex (including pensions)	Allowance £m	Actual £m	Pension costs in Actual £m
Load Related	48.3	37.6	0.3
Non Load Related	72.1	41.2	0.4
Subtotal	**120.4**	**78.8**	**0.7**
Capex Not Yet Included in RAV			
Logged up capex		3.2	
TIRG		28.6	
TO Incentive Capex		0.0	
Total		110.6	

Incentivised Capex	Allowance £m	Actual £m	Variance £m
Total capex	120.4	78.8	
less capitalised pensions	(0.9)	(0.7)	
Less net Load related sole use	(5.9)	(8.9)	
Total	**113.6**	**69.2**	**44.3**

Additions	78.8
Ofgem Adjustments	(9.2)
Provisional RAV Additions	**69.6**

Gearing / Interest (From Debt table)	Actual
Interest Costs (£m)	18.4
Net Debt	406.5
Provisional RAV (at year end price level)	887.8
Capex not Yet included in RAV (at year end price level)	115.6
Gearing as % of provisional RAV and Capex net yet included in RAV	40.5%

System Activities and Performances	Actual
Overhead Circuit km	3,753
Underground Circuit km	297
Measured system maximum demand (GW)	4.2
Total directly connected generation (GW)	7.8
Total directly connected wind generation (GW)	0.7
Total embedded generation (GW)	0.9
Number of incentivised loss of sypply events (#)	6
System availability	96.1%
SF6 Leakage Mass (Kg)	731.0

Licensee's Comments

Revenue

1.14. Revenue of £196.1m received by SP Transmission in 2009/10 is broadly in line with allowed revenue as prescribed in our licence.

Controllable Opex

1.15. Cash controllable opex costs of £19.4m are in line with the opex allowance.

Capital Investment

1.16. During 2009/10 a further 266MW of renewable generation was connected to the Grid at Crystal Rigg, Dunlaw and Toddleburn windfarms. A total of 718MW of renewable generation has now been connected to the transmission network during TPCR4 (and 852MW in total).

1.17. The connection of renewable generation to the transmission network continues to be heavily dependent on obtaining planning consents in acceptable timescales.

1.18. In terms of network modernisation a number of replacement projects were temporarily deferred in 2009 to manage liquidity and avoid borrowing at excessive rates in the capital markets.

1.19. Despite this, expenditure is within 8% of Ofgem allowances for non-load expenditure three years into the price control. Investment plans have been reprofiled for 2010/11 and 2011/12 to accommodate the deferred projects.

Interest

1.20. Interest expensed for the year was £5.9m lower than the prior year. This was due to a reduction in group loan borrowings.

System Activities and Performance

1.21. System availability rose from 92.7% in 2008/09 to 96.1% in 2009/10 primarily as a result of reduced access requirements for construction projects. The majority of access continues to be required to facilitate planned outages, necessary to deliver customer connections, strategic reinforcements and asset modernisation.

1.22. During 2009/10 there were two 'incentivised loss-of-supply incidents' on the transmission network. The level of performance continues to be better than the long-term average for this type of incident.

National Grid Gas (NGG)

NGG - NTS TO

Regulated Income	Allowance £m	Actual £m	Timing Difference £m
Final Proposals	558.7		
Adjustments from final proposals to license	26.2		
Difference for income specific inflation	19.5		
Maximum allowed revenue	604.5	610.5	6.0
NTS Exit Charges foregone		(69.9)	
Elimination of DN Pensions Deficit & Other Adjustments		(25.6)	
Other Income			
per NGG Regulatory Accounting Statement		**515.0**	

Controllable Opex	Actual £m
Accounting Controllable Opex	61.9
Non operational capex	3.5
Total	65.4
Net movement in provisions / Other adjustments	(0.9)

	Allowance £m	Actual £m	Variance £m
Cash Controllable Costs	**67.6**	**64.5**	**(3.1)**

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

Inovation Funding Initiative (IFI)	Actual £m
Opex (80% of which is allowed)	**3.4**

Logged Up Operating Costs	Actual £m
Opex	2.4

Capex (including pensions)	Allowance £m	Actual £m	Pension Costs in actual £m
Load Related	6.2	41.6	0.5
Non Load Related	58.0	83.0	1.0
Subtotal	**64.2**	**124.6**	**1.4**
Capex Not Yet Included in RAV			
Incremental Capex		65.7	
Logged Up Costs		12.6	
Strategic Stock		-	
Total		203.0	

Incentivised Capex	Allowance £m	Actual £m	Variance £m
Total Capex	64.2	124.6	
Ofgem Adjustment		-	
Total Capex	64.2	124.6	60.4

Additions	124.6
Ofgem Adjustments (deferred for consideration)	-
Provisional RAV additions	**124.6**

Gearing / Interest	Actual
Interest Costs	91.7
Net Debt	2,360.4
Provisional RAV (at year end price level)	4,100.7
Capex not yet in the RAV (at year end price level)	432.7
Gearing as % of provisional RAV and capex not yet in the RAV	52%

System Activities and Performances	Actual
NTS Length Km	7,610
Installed Compressor Power (MW)	1,164

NGG - NTS SO

Regulated Income

	Target	Actual	Variance
	£m	£m	£m
Core Allowance	426.8	391.1	(35.7)
Balancing neutrality charges		(9.2)	
Capacity Management costs		(1.0)	
Correction of legacy database system design issue		10.7	
per NGG Regulatory Accounting Statement		**391.6**	

Controllable Opex

	Actual
	£m
Accounting Controllable Opex	28.8
Net movement in provisions	(0.1)

	Allowance	Actual	Variance
	£m	£m	£m
Cash Controllable Costs	**29.1**	**28.7**	(0.4)

Non Controllable Costs

	Actual
	£m
Agency Costs (xoserve)	6.1

Logged Up Costs

	Actual
	£m
Total	-

SO Capex

	Allowance	Actual	Variance
Total	**7.5**	**10.8**	3.3

Gearing / Interest

	Actual
Interest Costs	0.8
Net Debt	18.4
Provisional RAV (at year end price level)	37.8
Gearing as % of provisional RAV	49%

Licensee's Comments

NGG Transportation Owner (GTO)

1.23. The turbulence witnessed in the global financial markets and the corresponding recession in the UK began to abate in 2009/10. However, these macro economic factors continued to offer challenges during the year. Throughout this period NGG has continued to invest economically and efficiently to renew, build and invest in future capabilities.

1.24. In 2009/10, TO total capital investment was £203m which was £137m lower than in 2008/9. This was largely due to the completion of a number of major projects which decreased load related investment by £136m, whilst incremental entry/exit spend also fell by £22m. These reductions were partially offset by an increase in non load related capital expenditure which was driven by the continued programme to equip key compressor stations with electric drive units to reduce, NOx, SOx and CO2 emissions combined with the continuing targeted replacement of assets using a risk based approach.

1.25. Incentivised capex was £60m over the 2009/10 incentive allowance, predominantly due to the increased non-load related spend and continued spend on the Milford Haven pipeline project.

1.26. GTO cash controllable opex costs decreased by £2m to £64m in 2009/10 largely due to completion of the pipeline marker post replacement scheme in 2008 and a lower number of operational incidents. Energy management initiatives combined with a reduction in energy prices helped to further reduce costs. These opex efficiency savings were however partially offset by investment in longer-term workforce renewal and increased investment in longer-term costs reduction initiatives. Combined, these movements meant that GTO controllable opex costs were £3m below the allowance.

NGG System Operator (GSO)

1.27. GSO controllable costs decreased by £3m to £29m primarily as a result of lower consultancy costs associated with meter assurance works and corporate centre savings. The reductions and efficiencies were partially offset by an increase in staff costs to principally deliver IS programs, and the costs associated with achieving longer term efficiencies in shared services and business services. GSO controllable costs were marginally below the allowance of £29m.

1.28. GSO capital investments in 2009/10 increased by £4m to £11m. This was £3m higher than the allowance of £8m, due primarily to the profile of critical IS system investments. The continued focus on IS security from government bodies has continued to drive an increased level of investment in these areas to accommodate the additional requirements.

Appendix 2 - Responses and Questions

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

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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 existing and future consumers, 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];
- the need to contribute to the achievement of sustainable development; 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; 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

2.1. 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 its 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 - 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:

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