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Gas Distribution Price Control Review Final Proposals Document

Document Type: Supplementary Appendices

Ref: 285a/07

Date of Publication: 3 December 2007

Target Audience: Consumers and their representatives, gas distribution networks (GDNs), independent has transporters (IGTs), gas shippers and suppliers and any other interested parties.

Overview:

This document contains the supplementary appendices for the gas distribution price control review's (GDPCR's) final proposals document. The supplementary appendices provide more detailed information regarding the issues raised in the final proposals document. This document also contains a summary of responses to the updated proposals document, together with Ofgem's views.

Contact name and details: Joanna Whittington, Director - Gas Distribution
Tel: 020 7901 7046

Email: GDPCR@ofgem.gov.uk

Team: Gas Distribution

Context

In May 2007 we published our initial proposals on the operating, capital and replacement expenditure required by the GDNs and hence the allowed revenues for the five year period from 1 April 2008. We also set out our proposals on a range of incentives and quality of service outputs. In September 2007 we published our updated proposals on the required operating, capital and replacement expenditure, provided some updates on the proposed incentives. We also consulted on the comparative risk analysis we had carried out and the potential impact that this might have on cost of capital.

Our final proposals document pulls together all the work undertaken to date including the previous six consultation documents. It sets revenue allowances for each of the GDNs for the five year period from 1 April 2008.

There are no further documents planned but there will be further consultation on the form of the modifications to the GDNs' licences and the Gas (Standards of Performance) Regulations to bring effect to the final proposals. Statutory and licence consultations will be undertaken in February 2008.

Associated Documents

- Open letter on Ofgem's proposals to implement revised standards of performance arrangements for Gas Transporters, November 2007 (Ref. 279/07);
- Leakage and Shrinkage Baselines for 2008-13, October 2007 (Ref. 256/07);
- Capacity outputs incentive for GDPCR, October 2007 (Ref. 254/07);
- GDPCR Updated Proposals, September 2007 (Ref. 226/07);
- GDPCR Initial Licence Drafting Consultation (Ref. 221/07);
- GDPCR Cost Reporting Consultation (Ref.. 185/07);
- GDPCR Initial Proposals, May 2007 (Ref. 125/07);
- GDPCR Fourth consultation, March 2007 (Ref. 49/07);
- GDPCR One Year Control Final Proposals, December 2006 (Ref. 205/06);
- GDPCR Third consultation, November 2006 (Ref. 203/06);
- GDPCR One Year Control Initial Proposals, September 2006 (Ref. 169/06);
- GDPCR Second consultation, July 2006 (Ref. 123/06); and
- GDPCR Initial Consultation, December 2005 (Ref. 259/05).

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Appendix 4 – Responses to updated proposals document and consultations on capacity outputs, leakage & shrinkage baselines and cost reporting

1.1. This appendix summarises the responses received from GDNs and other interested parties to questions posed in the updated proposals document[1], capacity outputs incentive consultation[2], leakage & shrinkage baselines consultation[3] and the cost reporting consultation[4], together with our views.

1.2. Responses are available on Ofgem's website (www.ofgem.gov.uk).

1.3. Please note that when summarising respondents' views, we have referred to each GDN company as a single GDN, even if the company owns more than one GDN.

Responses to updated proposals document

1.4. We received 17 non-confidential responses from the following organisations:

- Balfour Beatty;
- Centrica;
- EDF Energy;
- Energywatch;
- Fuel Poverty Action Group (FPAG);
- GMB;
- National Grid Gas Distribution (NGG);
- National Grid Gas Transmission (NGGT);
- Northern Gas Networks (NGN);
- RWE npower;
- SBGI;
- Scotia Gas Networks (SGN);
- Skanska McNicholas plc;
- Statoil UK (STUK);
- United Utilities (UU);
- Wales & West Utilities (WWU); and
- xoserve.

[1] Gas Distribution Price Control Review Updated Proposals Consultation Document, Ref. No. 226/07, 24 September 2007
[2] Capacity outputs incentive for GDPCR - October Update Consultation, Ref. No. 254/07, 23 October 2007
[3] Leakage and Shrinkage Baselines for GDPCR 2008-13 - October Update Consultation, Ref. No. 256/07, 24 October 2007
[4] Gas Distribution Price Control Review Cost Reporting Consultation, Ref. No. 185/07, 23 July, 2007

Responses to Chapter 2 – Form, structure and scope of the price control

1.5. This chapter set out our updated thinking on three of the areas detailed in our initial proposals, which included the form, structure and scope of the price control. There were no specific questions raised in this chapter but some respondents provided comments.

Views of GDNs

1.6. One GDN welcomes the inclusion of the Traffic Management Act (TMA) as a specific re-opener and expects efficient costs to be fully allowed, while another considers a simple re-opener for TMA insufficient unless an ex-ante allowance and pass through of permit costs are allowed. Another GDN also considers that an ex-ante allowance or a re-opener should be allowed for additional costs associated with the TMA.

1.7. One GDN says that the deadband associated with the two-tier recovery mechanism should be 4 per cent, not the 3 per cent proposed.

1.8. A GDN suggests a mechanism should be introduced for services covered by consents that grants an automatic extension to an exclusion for the de-minimis cap, unless otherwise directed by Ofgem within two months of receiving the request. The same GDN supports the provision of emergency services to IGTs remaining excluded but notes that these services are not provided for in the relevant licence condition. Finally, this GDN thinks that the emergency call handling arrangements provided by NGG should be price controlled and treated as cost pass-through for the IDNs, not treated as excluded services.

Views of other respondents

1.9. A non-GDN agrees with Ofgem that a deadband of 3 per cent is appropriate for the two-tier recovery mechanism.

Ofgem's views

1.10. We consider that a specific reopener is appropriate for TMA but that a capex allowance should be made ex ante for the required systems necessary to manage the new arrangements. Further detail on our proposals is set out in the main document.

1.11. We have not changed our position on the deadband for the two tier recovery mechanism and have maintained it at 3 per cent. We acknowledge the greater volatility in gas demand in response to weather as compared to electricity distribution but note that a number of factors impact on the allowed revenue. Further detail is contained in chapter 2 of the main document.

1.12. We do not intend to change our position on excluded services as set out in updated proposals but will increase our monitoring of the emergency call handling costs. Further information is provided in the main document.

Responses to Chapter 3 - Operating expenditure analysis

1.13. Chapter 3 set out our updated views on a range of policy issues associated with our analysis of the GDNs' forecast operating expenditure along with our updated proposals for operating expenditure allowances. Respondents were asked the following questions:

- Do you agree with our revised approach to setting opex allowances and the proposed allowances we have derived using that approach?
- Do you agree with our approach to the additional operating cost items included in these proposals covering the areas where our work was incomplete at initial proposals?

Views of GDNs

1.14. A GDN considers the opex allowances unacceptable and claims that due to errors in our approach there is a shortfall of £100 million in its allowances over the period. This GDN also considers the real pay increase assumptions too low and contradicts market evidence. Another GDN welcomes the recognition of real price effects but does not consider the level proposed to be adequate. One GDN urges Ofgem to review the real price effects assumptions and suggests using an agreed independent index as an alternative.

1.15. A GDN welcomes the move to base the uplift on our disaggregated benchmarks on the upper quartile rather than frontier performance in our top-down opex regression, but it still has several issues with our approach. It is disappointed that it has received an estimated allowance only equal to its base year despite considering itself to be the most efficient. This GDN recommends an alternative approach to applying the uplift factor whereby efficient companies receive a higher uplift than the 6.2 per cent average, while inefficient companies receive an uplift less than the average.

1.16. A GDN welcomes the revised workload assumptions, the revised maintenance analysis and the change to upper quartile for the uplift. It wants additional regional labour adjustments to those we proposed and says that it has made a strong case for this. This GDN welcomes the sparsity allowance but does not think it is adequate.

1.17. Another GDN considers the CAA approach to benchmarking more balanced and transparent and notes that the CC is comfortable with it. This GDN listed various detailed concerns with the direct and indirect opex benchmarking. It said that the indirect opex analysis should be based on external data but if Ofgem continue to use GDN data then it should revert to top-down analysis, excluding SGN data and adjust for standards of service issues and costs.

1.18. Two GDNs note that the adjustment to recognise the distorting effects of the marginal costing of SSE services to SGN has only been made to the bottom up analysis and not to the top down analysis. Another GDN thinks SGN should be omitted from the analysis. One GDN strongly objects to basing indirect opex

allowances for other GDNs on the second best GDN to mitigate SSE marginal cost service, while its allowances remain based on the upper quartile.

1.19. Two GDNs consider that Ofgem has overstated the London effect in adjusting for regional labour costs, while two consider that Ofgem has understated it.

1.20. The GDNs jointly commissioned First Economics to review the basis on which Ofgem has determined the 2.5 per cent per annum productivity assumption. This report concludes that the evidence used by Ofgem and Reckon does not justify such a high level and claims its own methodology is more robust. The GDNs want an allowance for costs to deliver productivity improvements.

1.21. A GDN welcomes Ofgem's approach to carbon monoxide (CO) but is concerned that the proposals could represent a fundamental change in licence obligations. Another GDN notes that the CO industry workshop in October gave no clear guidance on how the issue would be taken forward. A GDN supports the proposal that Emergency Service Personnel (ESP) carry and use CO measuring equipment but notes the additional costs.

1.22. All of the GDNs want a higher allowance than that proposed for training and apprentice costs. One GDN considers that further work is required as the allowances should be based on three year apprenticeship schemes not two years, should reflect additional costs of apprenticeships for contractors and should include recruitment and assessment costs.

1.23. Two GDNs generally agree with the approach taken for environmental decontamination and waste management. Three GDNs consider that waste management should be subject to a re-opener due to the uncertainty involved.

1.24. One GDN is disappointed that it has not received additional regional factors as it thinks it made a robust case for its unique area which suffers from both high and low density. Another GDN wants a higher regional adjustment for its network specific factors.

Views of other respondents

1.25. Energywatch thinks our approach to setting opex allowances fails to fully reflect where efficiency savings have been made and where these could be made in the future. Another non-GDN is concerned that reliance on bottom-up analysis may not properly recognise that differences in companies' operating models can distort analysis. The same respondent thinks that the move to upper quartile from frontier will not fully adjust for this distortion. Two non-GDNs do not agree with the relaxation to upper quartile for the uplift, while another two welcome it.

1.26. A non-GDN considers allowed revenue an inappropriate scale variable for assessing indirect opex efficiency and does not agree with Ofgem's assertion that proximity to London has no impact on local labour market.

1.27. A non-GDN questions the validity of many of Ofgem's assumptions, in particular, the frontier shift assumption, and does not consider that Ofgem has given due consideration to the representations made by GDNs and others.

1.28. A non-GDN supports the 2.5 per cent productivity assumption but considers the real price effects of 2 per cent per annum for contractor rates and the 1 per cent per annum for materials inadequate.

1.29. A non-GDN considers our approach to the additional operating cost items appropriate, and another one welcomes recognition of these items. A non-GDN welcomes the adjustments for non-labour regional factors. Two non-GDNs also welcome the allowances for apprentice & training and waste management. A non-GDN thinks there should also be an allowance for contractor apprentice schemes, and another one questions whether the allowance is adequate to incentivise the contractor side of the market in the required way. A non-GDN does not think the allowances for training and apprentice costs are sufficient.

Ofgem's views

1.30. Our revised analysis of opex, taking into account responses to updated proposals and further work we have carried out, is set out in chapter 3 of the main document. Where we consider that the issues raised justify further changes to our cost assessment, we have adjusted our analysis accordingly. We have given detailed consideration to responses to our consultants' reports and consultations throughout the price control process and have made a range of changes to our analysis as set out in our initial proposals, updated proposals and final proposals documents.

1.31. Our approach to benchmarking captures those efficiency savings already achieved by the GDNs. By applying an ongoing efficiency assumption we are also taking account of the scope for future efficiency savings for gas distribution as a sector.

1.32. In chapter 3, together with appendices 5 and 6 we address the other comments raised above, including:

- why we believe the non-labour regional factors we proposed in updated proposals are appropriate and have therefore not changed these amounts;
- our updated views on real price effects and ongoing efficiencies;
- our views on training and apprentice costs; and
- actions we are taking to address the issue of carbon monoxide discussed in updated proposals.

1.33. We have not adjusted our approach for setting the indirect opex forecasts for SGN for activities where they are the frontier company. The uncertainty as to whether the services from SSE are provided at marginal or fully allocated costs has meant that we have been unable to use SGN as a comparator for these activities. It is already getting an outperformance reward for these activities based on the upper quartile level of costs.

Responses to Chapter 4 - Capital and replacement expenditure analysis

1.34. This chapter set out our updated views on a range of policy issues associated with our analysis of the GDNs' forecast capital and replacement expenditure along with our updated proposals for capital and replacement expenditure allowances. Respondents were asked the following questions:

- Do you agree with our revised approach to setting capex and repex allowances and the proposed allowances we have derived using that approach?

Views of GDNs

1.35. The GDNs have raised a number of concerns with our approach to setting capex and repex allowances and the resulting allowances.

1.36. One GDN thinks that Ofgem has been inconsistent in applying PB Power's findings in a number of areas relating to LTS capex. It also considers that we have failed to: account for interactions between capex and opex and real price effects for construction contractor costs; realise that, even after being scaled back, the downsizing adjustment will still result in network failure without the provision of additional capacity; address the issue of small work volumes in mains reinforcement or consider if our proposed unit costs in this area are realistic; and, realise our proposed unit costs are below current levels and would be insufficient to properly fund the its proactive approach to riser replacement.

1.37. Another GDN is of the view that Ofgem's approach has set unachievable repex cost targets and has penalised it for being the most efficient GDN and driving the frontier for repex. This GDN thinks that the benchmarking should either be based on abandonment costs or a consistent abandonment ratio of 1.05 to calculate allowances for all GDNs. If the present benchmarking continues then a constant abandonment ratio of 1:1.05 should be used to calculate the unit cost allowances for all GDNs. Further, this GDN considers the repex productivity assumption of 2 per cent per annum excessive, and does not agree with the methodology used to set connections capex allowance.

1.38. Another GDN does not think that Ofgem has taken account of the information it has provided in support of its LTS major projects, instead relying on out of date information. The GDN is extremely concerned about the major reduction in allowed reinforcement costs following the assessment of 2006-07 outturns. This GDN said that the gap between Ofgem and them on repex is still substantial, and its main concern is the large difference between the output from the regression methodology and its real costs. This GDN welcomes Ofgem's recognition of the risers issue, and supports an allowance based on the GDN's forecast operating through the capex roller. Finally, it thinks that under the IQI there is too much exposure to potential overspends given the uncertainty over cost pressures, and disagrees with the proposal to apply the standard rolling incentive mechanism to land disposals.

1.39. A GDN thinks Ofgem has failed to provide any rationale for the capex and repex productivity assumptions. It is disappointed with the RPE adjustments for

governors. It considers the application of a flat-rate efficiency factor to all GDNs for connections capex ignores previous efficiency improvements. This GDN considers the repex cost targets unrealistic and is concerned by the approach taken in allocating allowances for risers by taking a mid-point between the views of the GDNs and PB Power. It thinks it is inappropriate to disallow all but £1.8 million of over £11 million costs for GTMS replacement and exit from SOMSA currently provided by NG.

Views of other respondents

1.40. A non-GDN considers that the abandonment ratio of 1.05 will be difficult to sustain with a drive for increased use of no-dig solutions requiring one for one replacement.

1.41. A non-GDN does not think enough attention has been given to the demand forecasting process. It also says that wide ranges of proposed capex per unit of demand growth across the GDNs persist and forecast average investment compared to historical averages is still substantially higher in some GDNs. This respondent also thinks that an incentive on GDNs for LTS and storage is needed, and it is very concerned there could be substantial changes in the capex proposals, which exposes suppliers and customers to additional uncertainty. It is also concerned with the lack of firm views from Ofgem and its consultants on the relationship between capex and opex levels. On repex, this non-GDN says that riser replacement is another area which will only be resolved as part of final proposals, reducing suppliers' ablility to assess the impact of change and increasing risk.

1.42. A non-GDN says the IQI needs further calibration as it is overly harsh. The parameters imply that the Ofgem forecast is near perfect.

1.43. A respondent welcomes the reassessment of repex costs where there has been a shift in replacement mix to generally larger diameter mains. This non-GDN said that regarding abandonment ratios there appears to be a potential conflict between the need to rationalise the network through high abandonment ratios and the need for innovative mains insertion techniques tending to 1:1 replacement.

Ofgem's views

1.44. We have used a number of reports by consultants as an input to our final proposals assessment. Our assessment is based on further discussions with the GDNs, other analysis we have undertaken as well as the consultants' responses. As such our views may differ from those of our consultants. For LTS capex in particular, we took into consideration the latest round of the OCS process which had not been completed prior to the publication of the PB Power capex reports.

1.45. Our consultants were commissioned to carry out further detailed analysis of the GDN's LTS submissions including a review of the demand assumptions and a desktop analysis of large LTS projects. The GDNs provided a number of latest tender price information from early tender talks which we considered and is discussed in chapter 4 of the main consultation document.

1.46. We have made an adjustment to our opex assessment to take into account capex-opex trade offs as discussed in chapter 3 of the main document.

1.47. Our proposals for mains reinforcement have been revised to take into account GDN actual expenditure for 2005-06 and 2006-07 due to the small workload volumes in 2006-07, and the outturn unit costs sense checked against repex unit costs. This is discussed in chapter 4 of the main document.

1.48. We have revised our replacement downsizing adjustment which now only applies to mains with a diameter of less than 355 mm (12 inches equivalent). This adjustment is discussed further in chapter 4 of the main document.

1.49. We have reviewed our repex workload adjustments for the GDNs that were forecasting an abandonment ratio of higher than 1.05. This adjustment is presented in the main document chapter 4. Despite the move to more insertion by the GDNs given the scale of the mains replacement programme and the move to larger projects we consider the abandonment ratio of 1.05 is a minimum. The 2006-07 actuals reflect abandonment ratios higher than 1 and a number of the GDNs are forecasting higher abandonment ratios than we are proposing.

1.50. We consider that a 2 per cent productivity assumption for repex, which was within the range submitted by the GDNs, is achievable. This assumption is detailed further in chapter 4 of the main document.

1.51. SGN recently shared its latest tender information for its repex work with us and argued that this supports its forecasts for repex. We do not consider that this information provides sufficient evidence to support why its unit costs should be significantly different from those derived from our benchmarking analysis of the GDNs' costs. We note that the tender information is from an early stage in the tender process. We also note that the existing EPC contracts for repex for SGN's GDNs were extended at the time of GDN sales and there were opportunities for the repex work to be retendered at an earlier date.

1.52. We have reviewed riser replacement costs taking into account both 2006-07 actuals and the six months of actuals for April to September 2007. Our final proposals for risers are discussed further in chapter 4 of the main document.

1.53. We have considered the SOMSA exit and system replacement costs within non-operational capex. Our proposed allowances for GTMS replacement are presented in chapter 4 of the main document.

1.54. In response to updated proposals, one GDN argued that we should adjust the RAV for the market value of land pre-development, rather than the proceeds of sale. This GDN suggests that to do this is to give customers the benefit of services provided prior to sale, including planning, design and development. In addition, this GDN argues customers have not taken the risks associated with property marketing and development. We do not agree with this proposal. We consider that customers

should share the proceeds, net of attributable costs, with GDNs. Costs of the nature described above would be included in the direct costs attributed to the disposal, before sharing of the benefit between the GDNs and customers. We do not agree that any valuation other than the actual disposal proceeds to a third party can be taken as a reliable measure of value.

Responses to Chapter 5 – Quality of service arrangements

1.55. Chapter 5 set out our updated proposals for the quality of service arrangements in light of responses to initial proposals and additional BPQ data. We proposed the same high-level changes as in initial proposals, but we incorporated a number of revisions to the detail of how these would be implemented, including changes to the quality of service allowances. Respondents were asked the following question:

- Do you agreed with our updated proposals for the quality of service arrangements?

1.56. We also received feedback on our proposals in responses to the licence drafting consultation and in the quality of supply working group. The key points raised, and our response, are summarised in chapter 5 of the main document.

Views of GDNs

1.57. While three of the four GDN owners broadly support our proposals for the quality of service arrangements, the GDNs were concerned about our proposal to transfer the current overall standard of service for responding to emergencies into a licence condition. It was suggested that events which are out of the control of GDNs that can impact on the ability to meet this standard should be excluded from the measure of response to gas emergencies. GDNs put forward a number of suggestions on how the licence condition could be relaxed.

1.58. Another GDN considers that the impact of a number of the detailed aspects of the proposals has not been considered fully enough and the allowances are inadequate.

Views of other respondents

1.59. A non-GDN is disappointed that Ofgem is proposing to migrate a number of Overall Standards of Performance (OSOP) to Guaranteed Standards of Performance (GSOP) as it is concerned with the lack of visibility of performance with GSOPs compared to OSOPs. Another respondent supports the updated proposals for quality of service arrangements but notes that improvements in service should be appropriately funded. Energywatch is strongly supportive of Ofgem's approach in developing a more formal regulatory framework through guaranteed standards and licence conditions for quality of service arrangements, and agrees there should be no further financial provision for the arrangements.

Ofgem's views

1.60. We have not changed our position on the emergency response licence condition for reasons set out in chapter 5 of the main document.

1.61. We will ensure that there is no reduction in visibility of performance as a result of the revocation of the OSOPs. Where the OSOPs have been migrated to licence conditions or GSOPs, we will continue to report on them in the annual quality of service report. In addition, we propose to amend SSC D10 to require GDNs to include the emergency response standard and the telephone service standard in the notice of rights that they provide to suppliers each year. GDNs are already required to include the GSOPs in the notice of rights.

1.62. We have reviewed the proposed allowances for the quality of service arrangements set out in the updated proposals document. We do not propose any further changes.

Responses to Chapter 6 - Incentives

1.63. Chapter 6 set out our updated view on the capex rolling incentive and the mains replacement incentive. This chapter also set out our proposals for the capacity outputs incentive, opex rolling incentive and a revenue driver to deal with the additional costs of the provision of emergency services arising from the loss of metering work. Respondents were asked the following questions:

- Do you agree with our view that an opex rolling incentive is not appropriate?
- Is our approach to capping the expenditure under the mains and services incentive appropriate?
- Is our approach to allocating domestic purge and relight costs to services costs appropriate?
- Do you agree with our approach to the capacity outputs incentive? What are the issues raised by incentivising or not NTS flex capacity?
- Should the volume targets for the flat capacity incentive vary with changes in the calorific value (CV) of gas?
- Is it appropriate to allow a price control re-opener (subject to certain criteria) for any capex spend that may be required following the interruption auctions?
- Is it appropriate to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of metering? If so do you agree with our approach and methodology for the parameters?

Views of GDNs

1.64. Two GDNs disagree with our view on an opex rolling incentive as they consider one is appropriate. One of them says that if one is not introduced then a scaled down version would be acceptable. Two GDNs agree with not including an opex rolling incentive as part of this review.

1.65. Two GDNs generally consider our approach to capping the expenditure under the mains and services incentive appropriate, while the other two do not. All of the

GDNs agree with our approach to allocating domestic purge and relight costs to services costs.

1.66. The GDNs agreed with Ofgem that the uncertainty surrounding the exit capacity arrangements which will apply from 1 October 2011 adds complexity to setting a capacity outputs incentive for this period. Three of the GDNs expressed doubt over whether the level of detail which had been provided in the incentive proposals would be sufficient to allow full development of the incentive ahead of GDPCR final proposals. Two of the GDNs considered that to allow more time for full consideration of the incentive a final decision on setting the incentive parameters should be detached from the GDPCR process and taken early in 2008 ahead of the first interruptible capacity auction.

1.67. The GDNs considered that the proposal to set the interruption incentive at the level of the annuitised value of the cost of reinforcing location network constraints would be an appropriate way of incentivising them to contract efficiently for interruption with customers currently designated Network Sensitive Loads (NSLs), but none of the GDNs agreed with Ofgem that the savings they could achieve through outperformance of the flat capacity incentive would be sufficient to promote efficient interruption decisions on other parts of their networks. Each of the GDNs considered that the costs that they would incur in providing firm capacity to generic interruptible customers would not be limited to the cost of providing additional flat exit capacity. The GDNs considered that in some cases significant capex would be required to support additional generic interruptible customers as firm and that to ensure that such costs were only incurred efficiently it would be necessary for the value of the interruption incentive to be based on the annuitised cost of providing firm capacity to all customers on their networks.

1.68. Three of the four GDNs considered that, new evidence regarding a present or future scarcity of NTS flexibility capacity not withstanding, it would be appropriate not to subject the GDNs bookings of the product to a specific incentive mechanism. One GDN considered that in the absence of an incentive it could be expected that NTS flexibility capacity would become constrained over time and so a modest financial incentive would be appropriate to ensure that GDNs continue to book it efficiently. All of the GDNs except one considered that the volume targets for the flat capacity incentive should vary with changes in the calorific value of gas. One GDN considered that this is not an issue because GDNs' flat capacity targets should continue to be set based on the energy transported rather than the volume of gas.

1.69. The GDNs agreed that it would be appropriate to allow a price control re-opener for additional capex triggered as a consequence of the first interruptible capacity auctions. Each GDN took care to emphasise that the capex eligible for consideration under the reopener should not be restricted to capex associated with locational constraints and should also include any reinforcement costs associated with providing firm capacity to generic interruptible customers and with ensuring sufficient linepack is available on their distribution networks.

1.70. All of the GDNs expressed support to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of meterwork. However,

one GDN listed various refinements to the methodology to ensure that GDNs do not experience windfall losses or gains. Three GDNs think the parameters need to be revisited. One GDN commissioned a report which outlines an alternative approach for calculating the parameters.

Views of other respondents

1.71. One non-GDN says it agrees overall with not including an opex rolling incentive as part of this review. This respondent agrees with our approach to capping the expenditure under the mains and services incentive as well as our approach to allocating domestic purge and relight costs to services costs.

1.72. Each of the shippers agreed that in the period 1 October 2011 – 31 March 2013 it is appropriate that the GDNs should continue to be incentivised to make efficient use of the capacity management options available to them. The shippers did not express disagreement with Ofgem's proposals for setting the flat capacity target, but one shipper considered that, in their view, it was likely that NSLs would go firm and that GDNs would need to adjust their flat capacity bookings to accommodate this volume as well. Two shippers considered that in advance of further analysis on the scarcity of flex, it would not be appropriate to set a flex incentive as part of final proposals on GDPCR. Another shipper considered that a flex incentive should not be necessary and that a possible Ofgem decision to implement a future market allocation of flex would be flawed. This shipper also commented that it is important that the different components of the incentive are subject to equal sharing factors and caps and collars.

1.73. One shipper considered that volume targets for the flat capacity incentive could vary with changes in the CV (calorific value) of gas, but noted that adjusting the targets for changes in CV could be complex and difficult to administer. Another shipper noted that the variation in the CV of gas is low and that to justify an incentive, evidence should be collected and published for consultation and debate. Another shipper considered that on the basis that the current GSMR gas specification will remain in place at least until 2020 there was not the need for flat capacity targets to reflect potential changes in CV.

1.74. One shipper considered that if a capex reopener is required by a GDN, it is important that the evaluation of the application includes a public consultation. Another shipper noted that if significant additional capex is triggered following interruption reform it would be appropriate for Ofgem to review the decision to implement the interruption reform proposal.

1.75. One of the respondents says it understands the justification for having a loss of meterwork revenue driver but says it will be necessary to test the parameters and trigger points to ensure that unnecessary or automatic allowances are not provided to any GDN. Another respondent welcomes the revenue driver but notes the overly pessimistic assumptions used by GDNs about how much meterwork they are likely to retain. This respondent considers it appropriate to apply ongoing efficiency savings to the loss of meterwork unit cost revenue driver.

Ofgem's views

1.76. Ofgem considers that it is inappropriate to implement an opex rolling incentive for the reasons set out in chapter 6 of the main document.

1.77. We also consider that our proposals to cap expenditure under the mains and services incentive are appropriate.

1.78. Ofgem considers that setting a capacity outputs incentive is an important part of the final proposals on GDPCR and that a decision to detach the incentive from the GDPCR process would create an unnecessary delay. Since updated proposals we have published an October consultation on the incentive and engaged in significant dialogue with each of the GDNs. We do not consider that the proposal lacks sufficient detail to be progressed at this stage.

1.79. Following further analysis we agree that it would be appropriate to set the interruption incentive based on the annuitised estimated cost of the investment necessary to support all existing interruptible customers as firm. We also consider that it would be appropriate for storage projects to be considered for inclusion under a capex reopener application. These views are reflected in our October capacity outputs consultation and in final proposals on GDPCR.

1.80. On the basis of the clear view expressed by industry during the consultation on the offtake proposals and in the subsequent appeal that there is no shortage of flex capacity and that demand for the product is not anticipated to increase significantly, we do not consider that it would be appropriate to set a flex incentive at this stage. In the light of any new evidence of a flex constraint, or in the light of a decision to implement an enduring offtake reform proposal which provides for the market allocation of flex, we would be prepared to review this decision. We would be concerned if the GDNs booked flex unnecessarily and so to guard against this we consider that the GDNs should be required to submit a report to Ofgem in the event that their flex bookings increase by more than 10 per cent per annum.

1.81. Regarding the issue of how changes in the CV of gas affects the flat capacity incentive, Ofgem notes that the capacity targets which form the basis of the incentive are in fact energy targets and are expressed in Gwh. If the GDNs were incentivised using volumes of gas in mcm changes in CV would affect performance against the incentive, but since the incentive is based on energy booked this should not be the case. If the CV at a particular exit point falls, more capacity may require being booked, but the effect that this has on the total energy transported should in theory be neutralised by the fall in the CV. Providing the GDNs performance against target is evaluated using an accurate volume to energy conversion there is no reason to suppose that the GDNs will be adversely affected by changes in CV.

1.82. We agree that a loss of meterwork revenue driver is appropriate, subject to the comments that monitoring and efficiency targets should be in place, and subject to the allowance being sufficient to meet the GDNs' efficiently incurred costs. We have accepted some of the GDNs' arguments on how to calculate the costs resulting from

loss of meterwork. However, we have not accepted the arguments that we should provide allowances for allocation of overheads. Further detail is given in chapter 6.

Responses to Chapter 7 – Sustainable development

1.83. In chapter 7 of updated proposals we set out our updated views on the shrinkage incentive, which we consider should be complemented with an environmental emissions incentive. Respondents were asked the following questions:

- Is it appropriate to roll forward the existing shrinkage incentive and if so do you consider the leakage volumes appropriate?
- Is the gas reference price formula appropriate?
- Should Ofgem establish a new incentive to target harmful environmental emissions?
- Do you support the design of the environmental incentive and its parameters?
- Are the strength and baselines for the incentive appropriate?
- Are the cap and collar arrangements appropriate?
- Is it appropriate to introduce a mechanism to address periodicity of investment?
- Are the leakage model and governance arrangements appropriate?

Views of GDNs

1.84. One GDN does not consider that the proposed shrinkage mechanism is a roll forward of the existing arrangements as it represents a significant change that will require change to the UNC. Another GDN considers the proposal to maintain own use gas and theft of gas as functions of throughput and the requirement to calculate and apply factors to these elements adds unnecessary complexity. Another GDN prefers pass-through of shrinkage costs but is broadly supportive of the proposal. Two GDNs expressed concern over the leakage volumes.

1.85. Three GDNs support moving to a day ahead price for the gas reference price formula but with an uplift factor. The fourth welcomes the move away from the three month ahead price and suggests using the within day price as the reference price.

1.86. One GDN agrees with establishing a new incentive to target harmful environmental emissions. Another GDN thinks it is a significant improvement over the current shrinkage based arrangements but is not clear why emissions from gas leakage are subject to separate incentives, one based on the social/environmental cost and another on gas price. One GDN does not consider that the scheme achieves its required objectives and urges Ofgem to reconsider the parameters as well as a mechanism to flex those parameters in response to changes in variables outside GDNs' control. The fourth GDN sees no need for additional incentives in this area as it considers that the GDNs have sufficient incentive to minimise harmful environmental emissions.

1.87. Two GDNs are generally supportive of the design of the environmental incentive and its parameters, and a third GDN has no objections to the adoption of the suggested shadow price provided that its concerns over the parameters are addressed.

1.88. One GDN does not agree with the baseline levels for the incentive but agrees with the strength. Two GDNs also consider the strength to be appropriate.

1.89. One GDN does not think that the environmental emissions incentive requires caps and collars but if they are implemented then they should be set at a company wide level rather than on a GDN specific basis. Three GDNs think caps and collars should be applied. One of these GDNs thinks they should also be applied to the cost of shrinkage gas.

1.90. Three GDNs consider it appropriate to introduce a mechanism to address periodicity of investment. The fourth GDN thinks it is too early to introduce one due to the lack of historical information. As an alternative, it suggests that any capex spend to reduce leakage could be allowed without the application of the IQI.

1.91. The GDNs consider that the leakage model is appropriate. One GDN recommends various changes to the governance arrangements including ensuring there is one common model for assessing leakage and shrinkage and putting in place a model change control process as part of the Shrinkage Forum or within a specific sub-group workstream. One of the GDNs thinks the governance arrangements are well established and transparent to the industry, and says that under the new emissions incentive Ofgem will require further reporting and governance of the model.

Views of other respondents

1.92. Three other respondents are broadly supportive of the shrinkage proposals.

1.93. Two non-GDNs agree that using the day ahead price without an uplift is more appropriate. One respondent is not convinced that using a day ahead price will reflect the most efficient basis by which GDNs acquire shrinkage gas, and suggests using a mixture of day ahead pricing for the throughput dependent on own use gas element of shrinkage and forward pricing for the fixed leakage and theft elements of shrinkage.

1.94. One non-GDN is generally supportive of the proposed incentive to target environmental emissions as well as its design and parameters. Two non-GDNs are also supportive of the incentive.

1.95. One respondent considers the strength and baselines for the incentive appropriate. This respondent says the strength should be reviewed annually in light of carbon price changes.

1.96. One non-GDN thinks the cap and collar arrangements are appropriate. Another respondent does not think they should be symmetrical and the GDNs should face greater financial exposure in the event their environmental emissions exceed the projected fixed element of shrinkage represented by leakage.

1.97. A non-GDN considers that it is appropriate to introduce a mechanism to address periodicity of investment but needs clarity on the precise nature of the proposal.

1.98. One respondent says that the leakage model and governance arrangements are sufficient but Ofgem should actively take part in the Shrinkage Forum and ensure the Forum meets regularly and takes time to discuss topics sufficiently. Another non-GDN supports effective governance through the licence of future changes and thinks Ofgem should have the ability to veto changes proposed by GDNs to their shrinkage models. One non-GDN welcomes the proposals to specify the model/methodology used to calculate leakage in a document governed by the licence and would expect shippers to be consulted on such a document before it is implemented or amended. This respondent also welcomes the proposal on auditing the model.

Ofgem's views

1.99. On 24th October 2007, prior to closure of the updated proposals consultation period, we published an open letter revising our proposed shrinkage volumes and leakage baselines and requested further views on this topic. A summary of respondents' views on this separate consultation is given below in paragraphs 1.152 to 1.162. Ofgem's views on the responses to both the updated proposals on shrinkage and the open letter consultation on shrinkage volumes and leakage baselines are given in paragraphs 1.163 to 1.173.

Responses to Chapter 8 – Other issues

1.100. Chapter 8 included other issues that make up the price control arrangements such as our current thinking on the funding of xoserve and an update on independent systems. No specific questions were asked in this chapter.

Views of GDNs

1.101. One GDN says that it has no reason to change from the current arrangements for independent systems except for a possible move to an LDZ basis for the subsidy arrangements for the conveyance of gas.

Views of other respondents

1.102. One non-GDN has major concerns with UK-Link and its associated funding requirements. This respondent is encouraged by the introduction of user pays arrangements for the funding of xoserve however is concerned that there is potential for user pays to be reduced to the point that their value and inherent flexibility is lost. Another respondent considers that there is insufficient detail as to how user pays model will be developed. In particular, it notes that the initial review group only found five service lines that could potentially be classified as user pays with their appropriateness questionable.

1.103. A non-GDN respondent is disappointed that Ofgem is still so committed to user pays and another respondent is unconvinced that the model will benefit industry

and consumers. This respondent says the industry group to establish the required governance arrangements has made little progress to address some key issues.

1.104. A non-GDN considers, under user pays, the potential for key developments being delayed or opportunities missed through lack of clarity of funding and governance arrangements will be significant. This respondent welcomes Ofgem's view that quantifying any additional value obtained from UK-Link should be undertaken ex-post, however it does not understand how efficiently funding UK-Link replacement could be interpreted as windfall.

1.105. A non-GDN says that consumers connected to independent systems should continue to enjoy the same benefits of competition that all consumers connected to the main networks do.

Ofgem's views

1.106. We note the concerns raised by shippers in relation to the core services plus user pays funding arrangement. A number of concerns relate to a lack of clarity over the governance and detail of the arrangements. In particular, there was concern at the limited progress of the industry group. We consider that the core services plus user pays approach provides incentives on the industry to encourage dialogue and development of new services but also give incentives to users to manage the costs they impose. Given the necessary investment in UK Link replacement towards the end of the price control period it is also timely to introduce these arrangements now.

1.107. The governance arrangements are important to give effect to the proposals. We expect the governance arrangements to be discussed further by the industry over the next couple of months and put in place by the 1 April 2008. In addition, it is expected that xoserve will be consulting with industry during 2008 on the potential scope and design for the new systems. This will provide opportunities to consider future user driven developments. Further detail on our final proposals is set out in chapter 8.

1.108. Following the Secretary of State's decision on the cross subsidy arrangements for independent systems, and proposed amendments to the current arrangements, we are proposing to put in place the necessary licence conditions. Our proposals are detailed in chapter 8 of the main document.

Responses to Chapter 9 – Financial issues

1.109. Chapter 9 set out Ofgem's updated position on cost of capital, including the conclusions of our risk analysis. A more detailed discussion of the cost of capital was set out in the appendix including reviews of several papers prepared by economic consultants on behalf of respondents. It also provided some clarity on specific aspects of the way we calculate the tax allowance, and outlined the consequences for the financeability of the GDNs of the proposed allowances, based on our financial

model, which is based on the GDNs' individual revenue allowances applied to a notional financial structure. Respondents were asked the following questions:

- Does our risk analysis support a range for the cost of equity of 7.0-7.5 per cent
- Is it appropriate to continue to maintain a consistent approach to cost of debt to that taken in TPCR?
- In the light of both the results of our risk analysis and the levels of actual gearing observed in the sector, is there a compelling reason to change our notional gearing assumption from 62.5 per cent?
- Is our approach to determining the GDNS' tax allowances appropriate?
- Should we make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions, such as penalties incurred under incentive schemes?

Views of GDNs

1.110. All of the GDNs consider that the cost of equity should be at least 7.5 per cent due to the effect of the risk differential between gas distribution and transmission and the effect of the higher notional gearing than what was assumed in TPCR.

1.111. One GDN submitted some figures that purported to be an analysis of relative risk between Gas distribution and transmission, from which it derived a cost of equity figure of 9.7 per cent.

1.112. All of the GDNs consider it appropriate to maintain a consistent approach with TPCR for the cost of debt. The GDNs think that the cost of debt should be at least 3.75 per cent.

1.113. One GDN says it thinks that gearing should be at 60 per cent as there is no reason for it to be higher than what was assumed in TPCR. Two GDNs say that either gearing should be set at 60 per cent or cost of debt and cost of equity should be increased to reflect higher notional gearing. Another GDN says that the gearing assumption of 62.5 per cent should not change but the higher gearing than what was assumed in TPCR should be reflected in estimates of the cost of equity.

1.114. Three GDNs broadly agree with our approach to determining their tax allowances. One GDN is concerned that it will be exposed to increased risk by the uncertainty regarding a "best endeavours" retrospective adjustment to allowances for tax payments.

1.115. Three GDNs think that we should make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions.

Views of other respondents

1.116. One non-GDN considers that the evidence supports a range for the cost of equity to be between 6.5 and 7 per cent. It says that a cost of debt of 3.55 per cent would give excessive headroom to GDNs and is not justified by a combination of

trailing averages, current rates and reasonable expectations of the cost of debt for 2008-13. This respondent also considers the gearing assumption conservative but not unreasonable in light of GDNs increasing gearing levels while maintaining comfortable investment-grade credit ratings. It continues to support the approach adopted by Ofgem in TPCR for determining GDNs' tax allowances. Finally, the respondent does not think we should make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions.

1.117. One non-GDN says that the cost of debt and the cost of equity assumptions being proposed are generous and should be kept low as the GDNs are exceptionally low risk businesses. This respondent noted the large premium to RAV for which several regulated utilities had been sold, and reiterated its endorsement of an academic article arguing for changes to the cost of capital methodology including a split cost of capital, use of actual rather than nominal gearing (to capture the benefits of the interest tax shield) and indexing the cost of debt to market levels.

1.118. Two other respondents consider that changes such as the change to the capacity/commodity split will reduce risks for GDNs, which should be reflected in their allowed cost of capital.

1.119. One non-GDN considers the assumed cost of debt to be low and is concerned with the high level of gearing. It also questions the use of a dividend yield assumption of 3.5 per cent, which it argues is inconsistent with the assumed cost of equity.

Ofgem's views

1.120. We consider that an appropriate cost of equity for GDPCR is 7.25 per cent. This figure is in line with long-run average total equity market returns and reflects our assessment of the risks, both systematic and non-systematic that the GDNs face under the terms of the price control. We note that certain market evidence points to a cost of equity of 6.5-7.0 per cent, but we do not accept that the data presented imposes a strict cap on the allowed return on regulatory equity.

1.121. We have examined the analysis underlying the suggested cost of equity of 9.7 per cent. Although it purports to be a relative risk analysis, it is a list of risk factors that this GDN believes it faces, with no corresponding list of risk factors that transmission owners might face. Additionally, the resulting figure relies on an apparently arbitrary selection of probabilities for certain risks transpiring.

1.122. We consider that gearing of 62.5 per cent is appropriate and not overly aggressive, bearing in mind that some GDNs have gearing well in excess of this figure, and the views of credit rating agencies, which indicate that such a gearing level can be compatible with a comfortable investment grade rating. We have a policy of clawing back additional tax shield benefits ex post, so there is no benefit to consumers from a tax perspective from using GDNs' actual gearing instead.

1.123. We have reviewed the various arguments for a lower cost of debt. In general, they appear to be arguing for greater weight to be placed on trends in short-term rates. We note that the CC has recently concluded that an appropriate cost of debt for Heathrow and Gatwick airports is 3.55 per cent based on current rates, and we consider that the GDNs would face very similar costs of debt. On the other hand the GDNs have argued for a marginally higher cost of debt, also with reference to recent market conditions. We consider that 3.55 per cent is adequate in current conditions, and that an efficiently financed utility could expect to maintain an average cost of debt of around this figure even if rates rose substantially for the whole of the price control period.

1.124. The methodology changes to the cost of capital that one respondent highlighted have both been considered in the context of the Financing Networks debate led jointly by Ofgem and Ofwat over 2005-06. There has been little appetite for a split cost of capital, which would be a sufficient change to regulatory practice to potentially undermine the benefits of regulatory certainty, without it being clear that it would result in a materially lower average cost of capital overall. The objections to the WACC failing to represent a marginal cost of capital are arguably of limited relevance when the cost of capital is simply a component of our calculation of allowances, and when we have set fixed capex incentive rates, so that the reward /penalty for under/overspend is not determined by our view on the GDNs' cost of capital .

1.125. The indexation of the cost of debt to market rates has also been widely discussed and has raised a number of concerns as to how it would be applied in practice. It potentially reduces transparency of allowances, and would be likely to lead to substantial over or under recoveries that would have to be collected in future years, possibly increasing the volatility of companies' returns. Thus it is not clear that it would materially reduce companies' risk profile as perceived by the markets. Nor is it clear that customers are better placed to carry interest rate risk than companies.

1.126. Other than some small changes to the tax calculation, primarily in respect of capitalised pension contributions, we have retained the current approach which appears to be supported by the majority of respondents. We can confirm that the tax losses to be rolled forward are those based on the financial model, not actual tax losses.

1.127. We consider that our "best endeavours" approach to the tax reopener places an appropriate level of responsibility on each GDN to behave as an unregulated company would in taking steps to mitigate any increase in its tax liabilities.

1.128. We note the comments on financeability. Two GDNs focus on the use of PMICR. We have previously published some detailed thoughts on PMICR within the fourth consultation document. GDPCR is the first Ofgem review where PMICR has been presented as an important ratio by the rating agencies. We have as a result been in regular discussion with the rating agencies and included their views in our deliberations. We conclude that our approach is consistent with current market conditions. Future reviews will continue to monitor market conditions and rating agency guidance as part of the approach to assessing financeability.

1.129. Our dividend assumption is consistent with current average UK utility yields. The GDNs' actual dividend policies are a matter for their shareholders.

1.130. More detail on our proposals for the cost of capital and financial issues are given in chapter 9.

Responses to the October capacity outputs incentive consultation

1.131. On 23 October 2007, we published an open letter titled "Capacity outputs incentive for GDPCR – October Update Consultation". We used this consultation to: publish proposed values for the flat capacity incentive; publish proposed values for the interruption incentive; restate our intention to consider not implementing a flex incentive; and, provide more detail on the capex reopener criteria. We also used the consultation to consult on changes to the sharing factors proposed for the flat capacity and interruption incentive, and to consult on changes to the way in which we proposed to calculate the value of the interruption incentive. These changes reflected a further development in our thinking regarding the capacity outputs incentive relative to the proposals consulted on in updated proposals.

1.132. We received eight non-confidential responses from the following organisations:

- Centrica;
- EDF Energy;
- National Grid Gas Distribution (NGG);
- National Grid Gas Transmission (NGGT);
- Northern Gas Networks (NGN);
- RWE npower;
- Scotia Gas Networks (SGN); and
- Wales and West Utilities (WWU).

Views of GDNs

1.133. The GDNs broadly welcomed the approach to setting the interruption incentive target proposed by Ofgem. Several GDNs queried the level of estimated investment costs that Ofgem had used as the basis for determining the interruption target, and several considered that the estimates of investment costs should be adjusted for RPE inflation, and final capex proposals on GDPCR, but each agreed that setting the target based on the annuitised investment cost of reinforcing the network to make all customers firm was an efficient methodology to use. One GDN disagreed with the methodology Ofgem had used in calculating the annuitised value of the estimated investment costs. This GDN considered that the annualised interruption target should be based on depreciation of the investment and the regulatory return the GDN would recover from the full value of the investment in the first year.

1.134. In view of the fact that the methodology proposed for setting the interruption target would in some cases result in a more generous interruption incentive than the

one described in updated proposals, each of the GDNs agreed that applying 50 per cent sharing factors on performance against target would be appropriate in this context. One GDN considered that in addition to the sharing factors it would be appropriate for 7.5 per cent incentive caps and collars to apply.

1.135. Three of the four GDNs considered that setting the NTS flat capacity target based on the energy required to support all non-NSL customers as firm was insufficient. The three GDNs who took this view considered that in the event that the GDNs are unable to secure any interruptible capacity under the reformed interruption arrangements, they would have to book NTS flat capacity to meet the needs of NSLs as well. One of the three GDNs who raised this issue acknowledged that it was an issue of second order importance which could be resolved in the event that a capex reopener was required. Each of the GDNs understood the basis on which Ofgem had set the proposed flat capacity targets, but two queried the basis on which Ofgem had translated the volume forecasts in mcm into energy targets in Gwh.

1.136. In the context of the proposal to set 50 per cent sharing factors for the interruption incentive, a majority of GDNs agreed that 50 per cent sharing factors on performance against target would be an appropriate level of risk for the flat capacity incentive. A majority of GDNs considered that a similar overall level of risk should apply to the flat capacity incentive under this proposal as applies to flat capacity in the transitional exit capacity incentive.

1.137. A majority of GDNs considered that in converting the flat capacity targets into a financial incentive the exit capacity price which the incentive should reference was an important issue to consider. A majority of GDNs considered that the efficiency of their decisions in respect of flat capacity should be based on the price information available to them at the time that they book it. On this basis each considered that the price of capacity prevailing at the time it was booked would be the appropriate reference price to use.

1.138. GDN respondents were broadly in favour of the proposal to subject the GDNs bookings of flex to regulatory scrutiny rather than setting an explicit flex capacity incentive. One GDN noted that it was important that the NTS is required to confirm how much flex is likely to be available, as the current position of committing to no more than is currently allocated is of limited planning benefit.

1.139. The GDNs agreed that given the uncertainty associated with the first interruptible capacity auctions, it would be appropriate to define capex reopener criteria as part of final proposals. The GDNs supported Ofgem's view that investment required as a result of the interruption auctions could be driven by the need to remove locational constraints or to provide additional storage on their networks. A number of GDNs queried the precise way the reopener mechanism would work, including the eligibility criteria for a reopener application. Two GDNs considered that it would be appropriate to include a mechanism which allowed investment of less than £1 million to be logged up and added as a one off adjustment to RAV at the end of the 2008-2013 price control period. One GDN considered that the most appropriate way to operate the reopener would be for all eligible investment to be logged up and for retrospective funding to be applied at the

end of the price control. This GDN considered that it would not be appropriate for any capex, which is not eligible for consideration under the capex reopener, to be subject to the capex roller. This GDN explained that capex subject to the reopener is unfunded for five years, whereas any benefits in respect of outperformance of the interruption incentive will be limited by the eighteen months to which this incentive will apply.

1.140. A majority of respondents who commented on Ofgem's proposal to set the IAE threshold at an annual value equivalent to 0.5 per cent of allowed revenue for each GDN supported this proposal. One GDN considered that basing the IAE threshold on a percentage of allowed revenue could unfairly penalise some GDNs in the event that an offtake reform proposal is implemented which requires GDNs to pay the NTS directly for exit capacity. One GDN opposed the 0.5 per cent of allowed revenue threshold on the basis that it could result in some larger GDNs having an IAE of more than £2 million.

Views of other respondents

1.141. NGGT disagreed with Ofgem's proposal to implement 50 per cent sharing factors on performance against target under the flat capacity incentive and questioned the rational behind Ofgem's proposals to widen the caps and collars on this incentive. It considered that 100 per cent sharing factors should be retained in order to provide an appropriate incentive to GDNs to efficiently trade off booking flat capacity on the NTS against investment on their own systems. NGGT also disagreed with Ofgem's proposals to consider not applying a flex incentive. In its response it considered that 'unless GDN flex bookings are controlled via an incentives mechanism, there is a risk that GDNs preferentially book NTS exit flex capacity rather than invest in its own networks'. It further noted that this 'could lead to constraints on the NTS which could disadvantage other NTS users or other GDNs'. NGGT disagreed with Ofgem's view that protection against this tendency could be provided by subjecting GDNs booking of flex to explicit scrutiny in the event that they increased by more than 10 per cent. It argued that this number was arbitrary and considered that it wrongly implied that any increase below the threshold would be acceptable and available from the NTS.

1.142. Other non-GDN respondents did not express strong views on whether Ofgem's proposed methodology for setting the capacity outputs incentive was appropriate, but each expressed views on the appropriate level at which the caps, collars and sharing factors should be set. One non-GDN considered that the interruption incentive should have some cap and collar, and that setting the flat capacity incentive with a cap and collar in the region of 7.5 to 15 per cent would be appropriate. One non-GDN considered that the proposed methodology for setting the interruption incentive was appropriate and welcomed the proposal to use 50 per cent sharing factors to ensure that the benefits of outperformance of the incentive were shared equally between GDNs and customers. Another non-GDN considered that applying a lower sharing factor to any underspend against the interruption incentive, or including a collar but not a cap, might address concerns about GDN windfall gains more effectively than 50 per cent upside and downside sharing factors with no caps and collars. This non-GDN also considered that 100 per cent sharing factors should be preserved for the flat capacity incentive. Each of the other non-

GDN respondents agreed that in the absence of new evidence of a scarcity of flex, it would be appropriate not to implement a flex incentive.

1.143. Each of the other non-GDN respondents agreed that it may be necessary to make provision for a capex reopener, but one non-GDN emphasised that any capex reopener decision should be open to the fullest industry scrutiny.

Ofgem's views

1.144. Ofgem continues to consider that the annuitised value of the estimated investment required to support all existing interruptible customers as firm would be the appropriate level at which to set the GDNs interruption incentive target. We have based our estimates of these costs on information provided in PB Power's October Capex/Repex report[5]. In some cases we have adjusted the estimates for final capex proposals on GDCPR. In every case we have adjusted the 2005-06 estimated costs for four years of real price effects. In the licence condition formula associated with this incentive the actual incentive target will be adjusted annually for inflation.

1.145. We consider that the methodology we have used for calculating the annuitised value of the estimated investment costs is appropriate. The methodology provides an annuitised value based on an average of the regulatory return on the depreciating asset over a forty five year period. If the target was set annually based on the full return received in the first year and GDNs contracted for interruption at this price for the next forty five years, this would lead to inefficient contracting for interruption when investment would have been the longer term efficient option.

1.146. We consider that the flat capacity required to support all existing interruptible customers excluding NSLs as firm is an appropriate level at which to set the flat capacity incentive target. We recognise that in the event that GDNs are unable to contract for any interruption they will require to book more capacity than this, but in setting this incentive we have sought to strike a balance between covering the likely risk to GDNs and protecting customers. In the unlikely event that the GDNs are unable to contract for any interruption they may approach Ofgem with a capex reopener application. If the available evidence suggests that the flat capacity incentive was not set appropriately it will be possible to resolve the materiality of this issue through the capex reopener decision.

1.147. Given the balance between risk and reward of the interruption incentive for the GDNs, we consider that it is an essential part of the capacity outputs incentive that any outperformance gains on the interruption incentive are shared equally between GDNs and customers, and so we continue to consider that 50 per cent sharing factors are appropriate here. We note that in an incentive such as this incentive collars serve to protect the GDNs against unlimited losses, while incentive caps serve to protect customers against unlimited GDN gains. Given that customers will benefit from all savings the GDNs make against the incentive, and given that spending more than the interruption target is likely to be inefficient for the GDNs

[5] PB Power: Gas Distribution Price Control Five Year Control: Capex/repex update, Ref. no: 238/07

relative to investment, we do not consider that caps and collars would serve any purpose in this context.

1.148. We consider that potential efficiency tradeoffs between contracting for interruption and booking incremental flat capacity are aided by equal sharing factors between incentives. On this basis we consider that 50 per cent sharing factors would be appropriate on the flat capacity incentive as well as on the interruption incentive. It has been observed that 50 per cent sharing factors on flat capacity bookings may obscure the efficiency of the GDNs bookings of flat capacity relative to investment on their own networks. At an aggregate level Ofgem understands that flat exit capacity and GDN transportation capacity are complementary rather than substitutable products. We consider that interruptible capacity and NTS flat capacity are more closely substitutable products and so it is most important that efficiency tradeoffs are not obscured by differing sharing factors on these incentives. At an aggregate level we consider that it is appropriate for the GDNs to face a similar level of exposure on the flat capacity incentive for the period 1 October 2011 – 31 March 2013 as they do under the transitional exit capacity incentive.

1.149. Promoting efficiency is the primary objective of the capacity outputs incentive. In view of the fact that under any capex reopener application, the efficiency of the GDNs investment decisions will be, among other things, evaluated with reference to flat capacity charges prevailing at the time of investment, we consider that it would be consistent and appropriate that performance against targets on the flat capacity incentive should reference the exit capacity charge at the time of booking as well. We intend to reflect this change relative to the transitional exit incentive in the licence drafting associated with the flat capacity incentive.

1.150. On the basis of the clear view expressed by industry during the consultation on the offtake proposals and in the subsequent appeal that there is no shortage of flex capacity and that demand for the product is not anticipated to increase significantly, we do not consider that it would be appropriate to set a flex incentive at this stage. In the light of any new evidence of a flex constraint, or in the light of a decision to implement an enduring offtake reform proposal which provides for the market allocation of flex, we would be prepared to review this decision. We would be concerned if the GDNs booked flex unnecessarily and so to guard against this we consider that the GDNs should be required to submit a report to Ofgem in the event that their flex bookings increase by more than 10 per cent per annum.

1.151. We continue to consider that storage investment triggered as a direct consequence of the outcome of the first interruption auctions, as well as reinforcement projects necessary to support new firm capacity, will be eligible for consideration under the capex reopener criteria. For the avoidance of doubt we do not consider that it would be appropriate for the capex reopener to apply on a rolling annual basis. We accept that slight movements in the contracted annual volumes of interruptible capacity are likely to be witnessed, but we consider that significant decisions over long term interruption intentions are likely to be made in the first year of interruption reform and note that the GDNs will have the opportunity to contract for up to five years of interruption at this stage.

Responses to the October leakage and shrinkage baselines consultation

1.152. On 24th October 2007, prior to closure of the updated proposals consultation period, we published an open letter revising our proposed shrinkage volumes and leakage baselines and requesting further views on this topic.

1.153. We received 6 non-confidential responses to the open letter from the following organisations:

- Centrica;
- EDF Energy;
- National Grid Gas Distribution (NGG);
- Northern Gas Networks (NGN);
- Scotia Gas Networks (SGN); and
- Wales & West Utilities (WWU).

1.154. The consultation set out revised baselines for:

- leakage, which would form the target for the environmental emissions incentive and the major part of shrinkage; and
- theft of gas and own use gas, which form the remainder of shrinkage. These were expressed as a fixed volume rather than a proportion of throughput as in updated proposals.

1.155. Respondents were invited to express their views on shrinkage and leakage.

Views of GDNs

1.156. One GDN considered that its allowance should exactly reflect its submission based on data provided prior to correcting for an error in the leakage model related to leakage from pit cast mains. One GDN supported the proposal to allow a fixed volume for own use gas and theft, independent of demand.

1.157. One GDN supported the removal of the link between shrinkage and demand. One GDN proposed an uplift over the gas price of between 1.2 and 1.8 per cent to take into account gas purchase transaction costs.

1.158. One GDN considered that the rate of reduction proposed for its networks was too aggressive and that it should be changed to the average rate proposed for other networks. One GDN considered that its recent shrinkage levels were unusually low due to higher temperatures in 2006-07 compared to the seasonal normal levels.

1.159. One GDN proposed increasing the volume allowances set out in the open letter to take into account changes to reported leakage caused by data cleansing and

removal of pressure control systems from some of its networks. One GDN supported the use of a fixed volume allowance for own use gas and theft.

Views of other respondents

1.160. Most respondents supported a fixed volume allowance, not related to demand, with a gas reference price linked to day ahead or on the day prices. One respondent did not support a fixed volume allowance stating that insufficient supporting evidence had been provided and suggested that non daily metered customers would bear an increased level of risk.

1.161. One respondent considered that only the leakage element of the shrinkage allowance should be a fixed volume and that the own use gas and theft allowances should be linked to demand.

1.162. One respondent considered that GDNs should meter their own use gas and one suggested that GDNs should report and account for gas escapes caused by third party damage.

Ofgem's views on updated proposals document and open letter on shrinkage

1.163. We consider that the proposed shrinkage mechanism is a refinement of the existing arrangements as it provides an ex-ante volume allowance and a gas reference price linked to prevailing market price, as did the arrangements for the one year control. We recognise that the proposed allowances differ from the UNC arrangements but we consider they better reflect underlying network leakage.

1.164. We agree that the additional complexity of retaining a demand driver for own use gas and theft components is not justified given the lack of materiality of the difference to a fixed volume. We propose a fixed allowance for own use gas and theft.

1.165. We do not consider that allowing a pass-through of shrinkage costs would provide an adequate incentive on the GDNs to efficiently manage shrinkage.

1.166. We do not consider that there is a material difference between using within day or day-ahead prices to determine the gas reference price and propose day-ahead prices. This was supported by the majority of respondents.

1.167. We considered the merits of combining the shrinkage allowances and environmental emissions incentive into a single incentive on the grounds of simplicity. We consider that it is appropriate for the environmental emissions incentive to internalise the shadow price of carbon. The proposed shrinkage allowance, while also providing an incentive to reduce leakage, is intended to provide the GDNs with a revenue allowance commensurate with the efficient cost of shrinkage, which is related to the market price of gas. For this reason it would be difficult to combine the two incentives and we propose to introduce two separate incentives.

1.168. We consider the proposed shrinkage arrangements and environmental emissions incentive provide adequate revenue allowances for the GDNs and provide appropriate incentives to reduce emissions and shrinkage. We have taken steps to reduce the GDNs exposure to the effects of externalities over which they have little influence, such as gas prices and CV. We consider the cost of gas purchase alone does not provide adequate incentive to reduce gas leakage and propose to strengthen the incentive by introducing an environmental emissions incentive.

1.169. We continue to believe that it is appropriate to include symmetrical caps and collars at the LDZ level for the environmental emissions incentive, given the uncertainty caused by the introduction of a new incentive regime and the associated possibility of unintended consequences. We do not consider it is appropriate to apply caps and collars to the shrinkage incentive.

1.170. We agree that there are potentially merits in introducing a rolling incentive to address periodicity of investment but this is a new incentive with the attendant greater uncertainty as to the GDNs' abilities to outperform the targets. We do not wish at this stage to magnify the benefits of outperformance or the penalties for underperformance further. We do not intend to introduce a rolling incentive in this price control.

1.171. We agree that a common leakage model would be beneficial and will pursue this during licence drafting, whether this is practical will depend on detailed drafting considerations. We continue to believe that governance of the leakage model by Ofgem is appropriate.

1.172. We intend to set the shadow price of carbon for the environmental emissions incentive in advance for the whole price control period.

1.173. We propose setting the gas reference price as the day ahead price, as published by a reputable market index information provider. This effectively removes all material price risk from the GDNs eliminating the need for an uplift factor and reducing prices paid by customers. We accept that there may be some small additional cost incurred in procuring gas at the index price but given the level of materiality we do not consider it is appropriate to provide an explicit allowance for this.

Responses to the cost reporting consultation

1.174. We received 9 non-confidential responses from the following organisations:

- Centrica;
- Energywatch;
- National Grid Gas Distribution (NGG);
- Northern Gas Networks (NGN);
- RWE npower;
- Scotia Gas Networks (SGN);

- United Utilities (UU);
- Wales & West Utilities (WWU); and
- xoserve.

Responses to Chapter 2 – Cost reporting outputs and timetable

1.175. Chapter 2 set out our expectations of the outputs from the cost reporting process and a draft timetable. Respondents were asked the following questions:

- Are the proposed contents of the annual report appropriate?
- Are there any reasons why, consistent with our desire to promote transparency, we would not publish RRP data?
- Do you have views on the annual timetable including deadlines for submission of information to Ofgem?

Views of GDNs

1.176. All the GDNs provided detailed responses in respect to each of the schedules contained within the proposed annual report. All of the individual points raised will be addressed individually as the report is developed.

1.177. Two GDNs stated that the content of the report is appropriate, while encouraging Ofgem to include only requests for data that are necessary. One GDN expressed concern that the proposed format of the annual report is not aligned to that used by Electricity and Gas Transmission.

1.178. All GDNs support the publication of RRP data, but not the publication of any information which may be commercially sensitive / confidential.

1.179. All GDNs raised issues in respect to the timescale for the first year of reporting under the new format. The GDNs believe that flexibility should be provided for in respect to timings as they believe there will be additional work involved embedding the new process in the businesses. One GDN stated that process should be developed for potential resubmissions of the annual report, accounting for materiality in respect to potential resubmission.

Views of other respondents

1.180. One non-GDN stated that the proposed annual report is a good starting point but provided suggested additions to improve the content.

1.181. Two non-GDNs support the publication of full RRP data. One non-GDN notes practical limitations of doing this (such as the consideration of commercially sensitive information). One non-GDN stated that where a GDN believes that certain data items should not be disclosed in publication, the GDN should prove in every instance the case for redaction.

1.182. One non-GDN believes that the timetable for data submission and publication should be shortened significantly. They state an appropriate timescale would be to publish the RRP by the end of July.

Ofgem's views

1.183. We will address each of the GDNs specific points in respect to the reporting schedules contained within the annual report in the development of the pack. This is an on-going consultative process.

1.184. Where possible, we will seek to ensure that duplication of reporting requirements is removed and that there is consistency between the different RRPs. We will seek to ensure that all information requests within the RRP have a purpose. However we do not wish to unduly constrain the opportunities for analysis in the next price control review.

1.185. Information to be published will be decided as part of the consultative process. We acknowledge concerns raised in respect to the publication of confidential and commercially sensitive information.

1.186. The timetable is to be finalised as part of the consultative process. We acknowledge concerns in respect to the timing of the publication of definitions to be used within the RRP and the flexibility sought by the GDNs in the first year of submission. We consider that in the first year in particular it is more important to obtain good quality data than to maintain a rigid timetable. As we approach the next timetable, maintaining deadlines will be important to allow time to carry out analysis on the data.

Responses to Chapter 3 – Issues

1.187. Chapter 3 discussed a number of policy issues related to the cost reporting process. Respondents were asked the following questions:

- Is it realistic to seek to create benchmarking opportunities across sectors for generic cost types, such as indirect costs?
- How should we determine the criteria for requiring details of cost information from GDNs' service providers whether they are classified as related parties or not? What practical issues are there in requiring detailed third party cost information?
- Should we seek to collect detailed xoserve data directly from xoserve, or via each GDN's RRP?
- Should we look to commission external audit work on any aspect of the RRP or should we rely on our own review process? If so, should we engage auditors directly or rely on the GDNs' statutory auditors?
- Do the regulatory accounts as they stand provide value to stakeholders?
- Under what circumstances, if any, should we consider relaxing the requirement to publish audited regulatory accounts?

- Under what circumstances, if any, should we consider relaxing the requirements to submit a statement of allocation of costs and revenues and to have the application of that methodology audited?

Views of GDNs

1.188. All GDNs expressed concern about the ability to benchmark across sectors for generic cost types. The reasons for this concern include differing interpretations of activity definitions, normalisation issues for different sized firms, different operating policies, different operating environments, the appropriateness of benchmarks used and differing regulatory requirements across different sectors. All GDNs questioned the usefulness of indirect cost benchmarking across sectors given their reservations about the inter-GDN benchmarking work undertaken as part of the current price control review.

1.189. All GDNs expressed concern in respect to any requirement to provide detailed third party cost information. This concern was due to issues in respect to practicality, accuracy and usefulness. All GDNs noted the commercially sensitive nature of third party information.

1.190. One GDN stated that the information requirement for a related party should be no more that that for a third party. Two GDNs believe that data should be collected from related parties and one stressed the importance of GDNs providing information in respect to related parties / third parties on a consistent basis.

1.191. One GDN believes Ofgem should deal directly with xoserve to collect the data but the obligation rests with the GDN to provide it. One believes that the data should be collected through each of the GDNs RRPs. Two GDNs believe its own RRP with the GDN reviewing the information in advance and including the charges within that GDNs RRP.

1.192. One GDN believes external audit work to be unnecessary given the overall cost submission is already reconciled to an audited data source. One GDN believes that the reconciliation to an audited data source in conjunction with and internal (Ofgem) review should provide sufficient assurance. One GDN supports the audit of RRP cost data utilising Agreed Upon Procedures over a limited number of the schedules while advocating the abolition of the Regulatory Accounts and their associated audit. One GDN believes that AUP should be targeted to ensure that results are useful and minimise duplication with the regulatory accounts audit.

1.193. One GDN stated they did not know if the regulatory accounts provided value to stakeholders as they had not received feedback from the stakeholders. One GDN stated that the regulatory accounts are useful for stakeholders that require top line data on the financial performance in the regulatory year. One GDN believes that the regulatory accounts do not add significant value over and above the statutory accounts and one GDN stated that stakeholders do not place much value on the regulatory accounts.

1.194. It is a common view that, given the regulatory accounts provide limited information over and above that contained within the statutory accounts, the publication requirement for the regulatory accounts could be relaxed.

1.195. The GDNs believe that there is a case for redefining the content or superseding the regulatory accounts, when Ofgem feels comfortable with the accuracy of the cost reporting data and there is established reconciliation procedure with an audited source.

1.196. One GDN stated that it is appropriate for Ofgem to request a statement of allocation of costs and revenues and for it to be audited. One GDN believes that going forward the cost reporting schedules could provide the transparency required which could remove Ofgem's requirements to submit a statement of allocation of costs and revenues. One GDN advocates a statement within the RRP to state that the GDN has applied the methodology as set out within the RRP as input by each GDN. On GDN in response stated that there is little, if any, added value provided by condition E3 and that it should be deleted.

Views of other respondents

1.197. One non-GDN stated that while auditing will impose costs, it is necessary to ensure that sufficient objective control in the information gathering process exists and to minimise risks of error which could impact on the price control settlement. One non-GDN stated it is reasonable to place reliance on other audit work where possible.

1.198. One non-GDN stated that it is realistic to create benchmarking opportunities across sectors, but care needs be taken to ensure like for like comparisons. One non-GDN stated that for a benchmarking exercise to be successful, the comparators used must be appropriate and based on a strong body of evidence.

1.199. One non-GDN stated that where third party service provider is a related party, it is essential that detailed information is required from both the third party and the GDN for completeness, where the third party service provider is not a related party, it may be sufficient for Ofgem to have the ability to ask for this information.

1.200. One non-GDN support Ofgems recognition for the need for consistency of activity costs regardless of their source, noting the issues about materiality that will need to be reflected in DNOs contracts with its service providers.

1.201. One non-GDN stated that it would be most effective for xoserve to provide data and information directly to Ofgem. One non-GDN stated that it is appropriate to require relevant information from both xoserve and the GDNs. One non-GDN believes that the obligation to provide xoserve data should rest with the GDNs but that the GDNs could collectively choose to delegate responsibility to xoserve.

1.202. One non-GDN considers the regulatory accounts add value to stakeholders and that it is helpful to have a set of audited accounts reflecting only the regulated business given the GDNs are part of larger corporate groups.

1.203. One non-GDN stated that once the new RRP and annual report is implemented and established as being robust, it would then be appropriate to consider removal or amendment of the requirement to publish the regulatory accounts. One non-GDN stated that once a robust RRP has been established, there is a danger of duplication and reproduction in respect to continuing requirements of Regulatory Accounts.

Ofgem's views

1.204. We consider that benchmarking can be created for generic cost types across sectors, however the level to which the output of such benchmarking can be relied upon is dependent on a number of factors. We acknowledge it is important to establish clear and concise activity definitions, and to be able to account for the normalisation issues associated with comparing different sized firms using different operating policies within different operating environments.

1.205. We consider that where substantive elements of the GDNs operations are subcontracted to a related party, costs should be able to be captured at the same level as if they were carried out by the licensee. We will continue to consider the criteria for requiring details of cost information from GDNs service providers as part of the consultative process.

1.206. We will continue to consider the best way to collect the xoserve data on an annual basis.

1.207. We will continue to consider the level and type of audit appropriate, while weighing up the benefits to be gained from any audit exercise against the costs. We are mindful that devolving part of the review process to a third party may limit the depth of understanding gained by Ofgem staff and that consideration must be given to role of the audited regulatory accounts going forward.

1.208. We consider that once the cost reporting process has been robustly established, it will be an appropriate time to consider in more depth the continuing relevance of the regulatory accounts. We note that, absent any specific independent audit requirements embedded in the cost reporting process, the regulatory accounts will continue to be the only audited separation of NGG into the NTS, the four GDNs and other businesses. It will also be the only audited set of figures for the formula year for NGN, which draws up its statutory accounts to 31 December each year.

Appendix 5 – Opex benchmarking

Introduction

1.1. This appendix provides further detail behind the operating cost analysis in chapter 3. It includes details of the bottom-up analysis carried out for each of the direct and indirect cost activities, how we have applied the uplift so that the overall strength of bottom-up analysis equates to that of top-down analysis and details of the capex-opex trade-off adjustment that we have made.

1.2. More detail of our ongoing opex efficiency assumptions and assumptions about real price effects are provided in appendix 6. Tables setting out our forecasts for operating costs of each individual GDN are set out in appendix 7.

Explanation of our benchmarking analysis

Direct opex

1.3. In both initial proposals and updated proposals we assessed the efficiency of the GDNs by benchmarking their performance for individual activities using regression analysis wherever practicable and carrying out more specific analysis for those areas where it was inappropriate or did not provide sufficiently robust results.

1.4. We continue to believe that this is appropriate and have maintained that approach for these final proposals. Specific areas where we have modified our analysis at a more detailed level are discussed below.

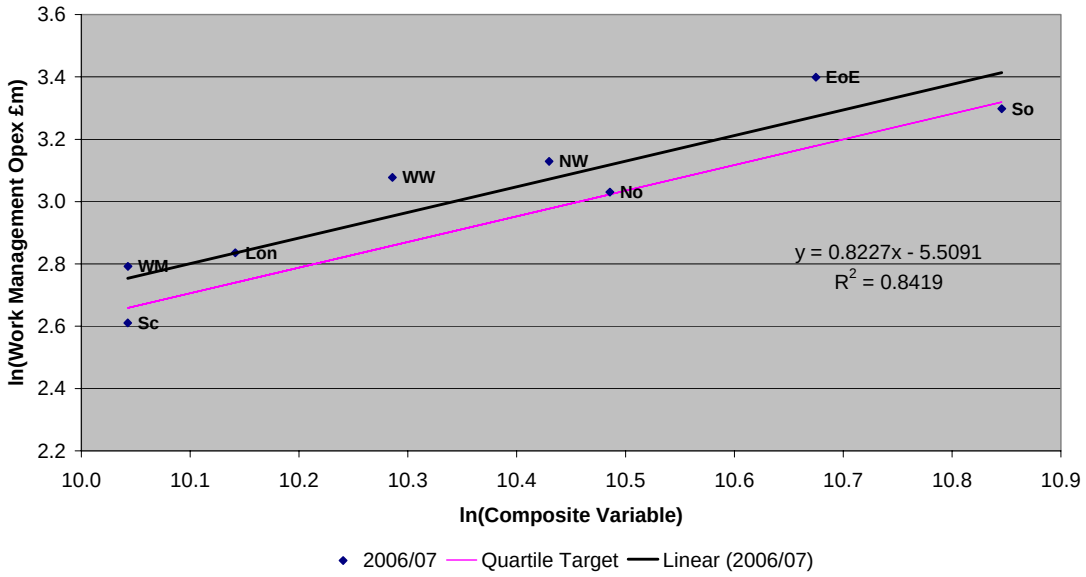
Work Management

1.5. For the work management activity PB Power based their analysis on a regression using a composite scale variable (CSV) combining the number of publicly reported escapes (PREs), the number of repairs and the length of below 7 bar main – the three biggest drivers of cost for this activity in their view.

1.6. We used PB Power's analysis (adjusted for such factors such as our own view of regional labour cost adjustments, gap closure and real price effects) in both initial proposals and updated proposals. We consider that this is an appropriate methodology for determining efficient work management costs. The results of this regression are set out below.

1.7. From DN sales up to 2006-07 NGG provided a discount to the IDNs in its charges for the emergency call handling service. This meant that emergency call handling costs for the IDNs were understated by approximately £1.2 million. We have added these additional costs to the IDN's work management costs and then updated the benchmarking analysis. This increases the GDNs' opex by approximately £1 million per annum.

Figure A5.1 – Work Management regression 2006-07 actuals



Emergency

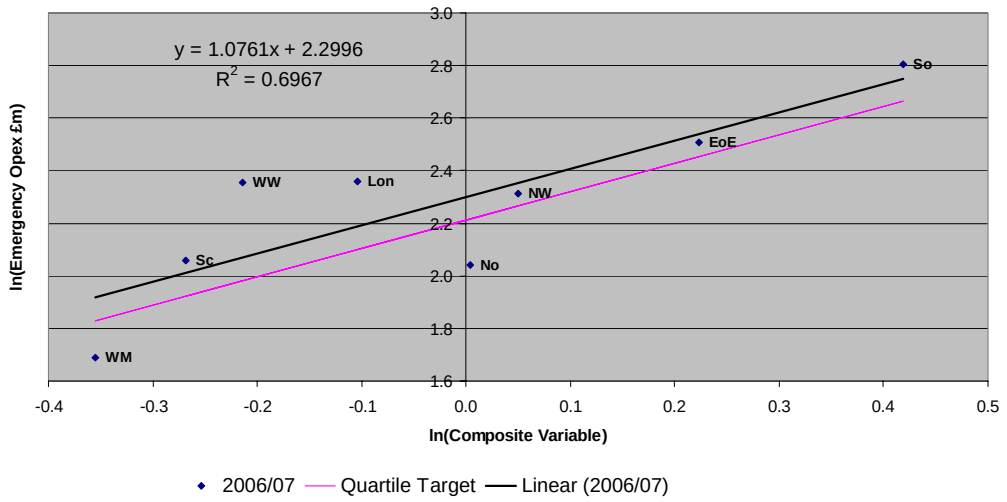
1.8. PB Power's analysis for emergency service costs was also based on regression using a CSV. The most appropriate CSV was considered to be a combination of number of PREs and number of repair jobs. We have adjusted PB Power's analysis to take account of our own view on regional labour adjustments, gap closure, real price effects and ongoing efficiencies.

1.9. At updated proposals the emergency service costs were also adjusted to remove the impact of differing levels of loss of meterwork in the 2006-07 actual data. Emergency service costs are being determined on the basis of no loss of metering and a separate revenue driver is proposed to deal with the increased costs that will be caused by any such loss.

1.10. We do not consider it is appropriate to adjust our approach to determining emergency service opex because of NGN's failure to meet the emergency service standard. Our forecast is based on the upper quartile level of costs rather than just being based on NGN's performance. Other GDNs receive a cost forecast that is higher than NGN's 2006-07 costs and to the extent that NGN needs to increase its costs to perform better it would simply receive a lower outperformance benefit for this activity.

1.11. The results of our emergency service regression are shown below.

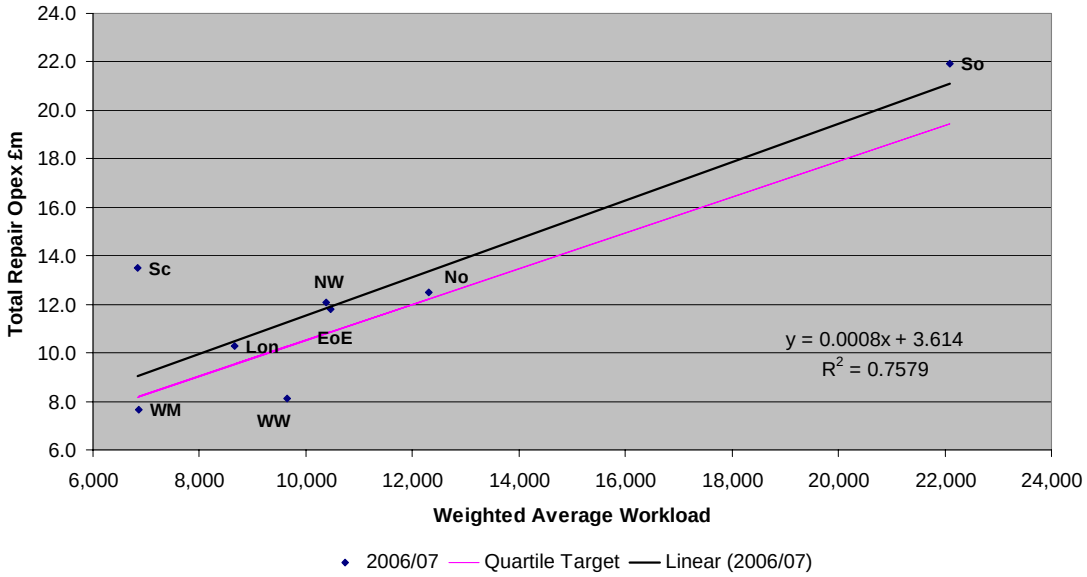
Figure A5.2 – Emergency service regression 2006-07 actuals



Repair

1.12. PB Power's analysis for repair costs was based on regression using a weighted average of the number of repairs as a driver. It was supported by bottom up analysis by PB Power based on their knowledge of the time taken to complete work of this nature, appropriate hourly rates and an allowance for materials and other costs. We have adjusted PB Power's analysis to take account of our own view on regional labour cost adjustments, gap closure, real price effects and ongoing efficiencies.

Figure A5.3 – Repair regression 2006-07 actuals



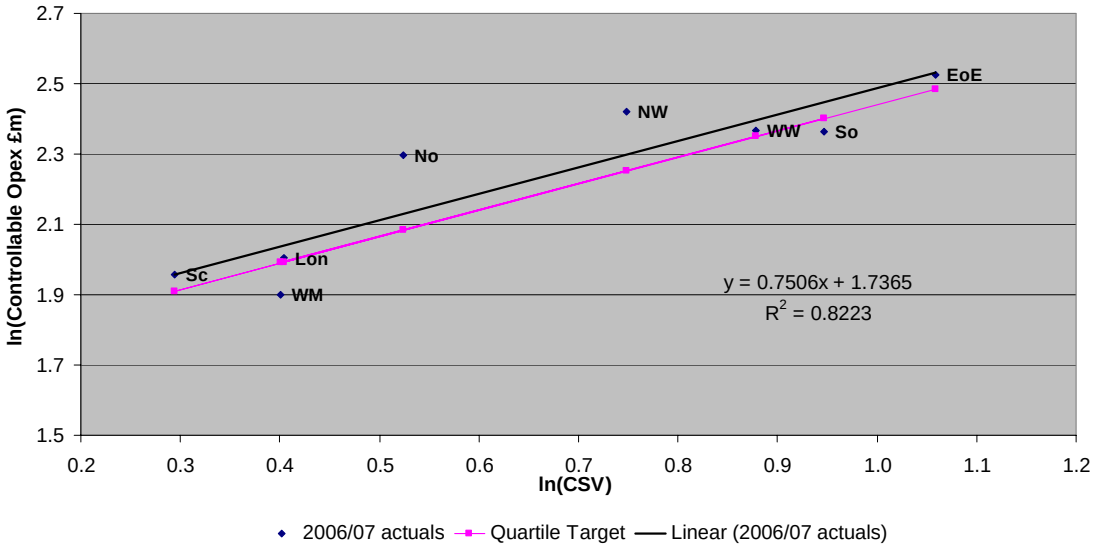
Maintenance

1.13. We have corrected an error in the number of governors for NGN in PB Power's maintenance workbooks. This increase total GDN opex by £0.8 million per annum. There is a £1 million per annum increase for NGN and a £0.2 million per annum decrease for the other GDNs combined.

1.14. We have carried out a further review of our maintenance analysis in light of comments from the GDNs. This has resulted in a re-allocation of some costs from routine to non-routine maintenance which has a consequential impact on allowances. We have also included additional costs associated with cathodic protection work which is a new requirement and was not fully reflected in the base year's costs. However, we do not accept that 2006-07 was an atypically low year for maintenance activities in general. The GDNs have highlighted those areas of activity where costs were atypically low but it is reasonable to expect that some areas of costs would also have been atypically high in that year.

1.15. The overall impact of these changes to our maintenance analysis is to increase our forecasts by approximately £5 million per annum. The revised regression chart is set out below.

Figure A5.4 - Maintenance regression 2006-07 actuals



Other direct activities

1.16. In initial proposals we benchmarked other direct activities based on regression analysis provided by PB Power using network length as the cost driver. When we repeated this analysis for updated proposals using 2006-07 actual costs we were unable to get satisfactory regression results despite significant effort to cleanse the data and consideration of alternative cost drivers. We therefore based our view for ongoing costs of this activity on the GDNs' own forecasts, adjusted for our own view of real price effects and ongoing efficiencies. We have maintained this approach for final proposals.

Indirect opex

IS

1.17. We have benchmarked IS support costs using the average IS spend over 2005-06 to 2012-13 as a percentage of revenue as summarised in the table below. The benchmark is set at the second lowest cost GDN group. The results are summarised below. The overall annual efficiency savings for IS support service costs are now 4 per cent per annum consistent with the NGG's own forecasts.

Table A5.1 - Summary of information systems benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Information Systems (% of revenue)	1.85%	1.85%	2.19%	1.50%	2.38%

Finance, audit and regulation

1.18. We have benchmarked finance, audit and regulation costs as a percentage of revenue. The results are unchanged from updated proposals.

1.19. The benchmark for finance and audits is based on the second lowest cost GDN. The benchmark for regulation is based on the upper quartile level of performance.

Table A5.2 - Summary of finance. audit and regulation benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Finance & Audit (% of revenue)	0.85%	1.17%	0.85%	0.42%	1.19%
Regulation (% of total opex)	0.25%	0.20%	0.33%	0.27%	0.27%

Insurance

1.20. Following updated proposals two GDNs argued that the costs of uninsured claims e.g. personal injury were less correlated than insurance premia to insurance market cycles. We accept that there is some merit in this argument and therefore we have excluded uninsured claims costs from the GDN's efficient base year costs before projecting them forwards using the cycle extrapolated from the Lloyds' non marine insurance index. We have assumed that uninsured claims costs stay constant over 2008-09 to 2012-13. We do not consider the GDNs have provided sufficient evidence to support increasing uninsured claims. We have also made a correction so that the benchmark is based on the second lowest cost GDN group instead of the upper quartile.

Table A5.3 - Summary of insurance benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Base Year Insurance (% of revenue)	1.04%	1.54%	1.12%	0.95%	1.04%
Insurance forecast years	Base year costs exc uninsured claims are forecast to follow the market cycle trend as identified in TPCR				

Property Management

1.21. The GDNs have been benchmarked against each other on the basis of property square foot per network kilometre and facilities management costs per square foot of property using the upper quartile as the benchmark. Rental costs for individual properties have also been benchmarked against local market data and leading to further adjustments for some of the GDNs.

Table A5.4 - Summary of property management benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Property (Sqft floorspace/km pipeline)	2.6	3.8	2.1	3.0	2.7
Property (FM costs/Sqft floorspace)	15.4	29.9	11.0	16.9	36.9

Corporate Centre and Communications

1.22. Corporate and communication costs have been compared as a percentage of total operating costs as shown below. The benchmark is set at the second lowest GDN group.

Table A5.5 - Summary of corporate centre and communications benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Corporate Centre & Comms (% of total opex)	0.96%	1.50%	0.96%	0.34%	1.12%

Human Resources

1.23. In updated proposals we benchmarked the GDNs on their ratio of HR FTEs to total FTEs calculated from data previously provided by the GDNs to LECG. The benchmark is set at the upper quartile level of performance. NGG argued that using HR FTEs would be biased towards those GDNs that had outsourced parts of their HR functions and suggested HR cost per FTE would be a better measure. We consider there is some merit in NGG's argument and have revised our benchmarking accordingly Training and apprentice costs have been assessed separately and therefore they have been excluded from HR costs before applying the benchmark results which are summarised below.

Table A5.6 - Summary HR benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Human Resources (HR cost (£) per FTE)	661	791	664	979	651

Legal

1.24. We have benchmarked legal costs as a percentage of revenue as summarised in the table below. The benchmark is set at the second lowest GDN group. The results are summarised below.

Table A5.7 - Summary legal benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Legal (% revenue)	0.18%	0.18%	0.27%	0.17%	0.22%

Procurement and Logistics

1.25. Procurement and Logistics costs have been compared as a percentage of total opex. The benchmark is based on the second lowest GDN group. The results are summarised below.

Table A5.8 - Summary procurement and logistics benchmarking

	Benchmark value	National Grid Gas	Northern Gas	Scotia Gas	Wales & West
Procurement & Logistics (% of total opex)	0.57%	0.87%	0.57%	0.42%	1.09%

Adjustment between bottom-up and top-down analysis

1.26. In initial proposals we noted that benchmarking individual activities on a bottom up basis produced a total operating cost benchmark that was not being achieved by any GDN and therefore represented a "frontier shift" for all GDNs. We addressed this by applying an uplift to operating costs determined on a bottom-up basis so that they were consistent on an aggregate basis with a top down approach set at the frontier. For the top down analysis we used a CSV with an equal weighting between network length and number of customers.

1.27. The GDNs responded to this by noting that we had used an upper quartile approach on the bottom-up analysis to avoid reliance on the results of just one GDN that might have experienced atypical costs or was unusual in other aspects of its performance. They considered that it would be more consistent to provide an uplift to top down costs determined on an upper quartile basis.

1.28. In updated proposals we modified our approach so that costs were uplifted to a level consistent with top down benchmarking at the upper quartile, noting that this was more consistent with the approach adopted at DPCR4.

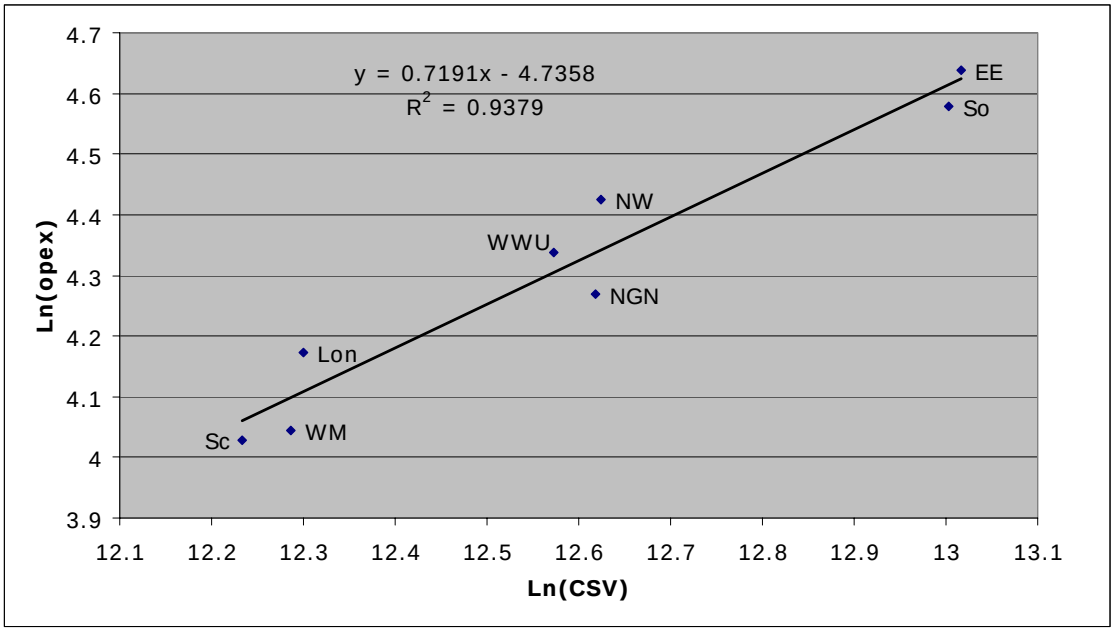
1.29. In response to updated proposals some GDNs argued that since we had adjusted our bottom up analysis to take account of distortions that would be caused

by SGN's possible marginal costing of services received from SSE and Southern was one of the GDNs setting the quartile for the top down analysis, then we should also make an adjustment to the top down analysis to allow for the impact (or even remove SGN from the top down analysis). Accordingly we have added £1.5m, based on 25 per cent of the value of the MSA contract between SSE and SGN, to SGN's costs in the top down analysis.

1.30. The GDNs have highlighted inconsistencies in the customer numbers used in our overall opex regression. The numbers for SGN and NGN included customer numbers on IGT networks whereas NGG and WWU excluded these customers. We have updated our analysis so that the numbers are on a consistent basis.

1.31. The results of the top down regression after correcting for these items and updating for the revised results of the bottom up analysis are shown below. This gives an uplift to be applied to the bottom up results of 6.87 per cent.

Figure A5.5 - Top down opex regression 2006-07 actuals



Capex-opex trade-off

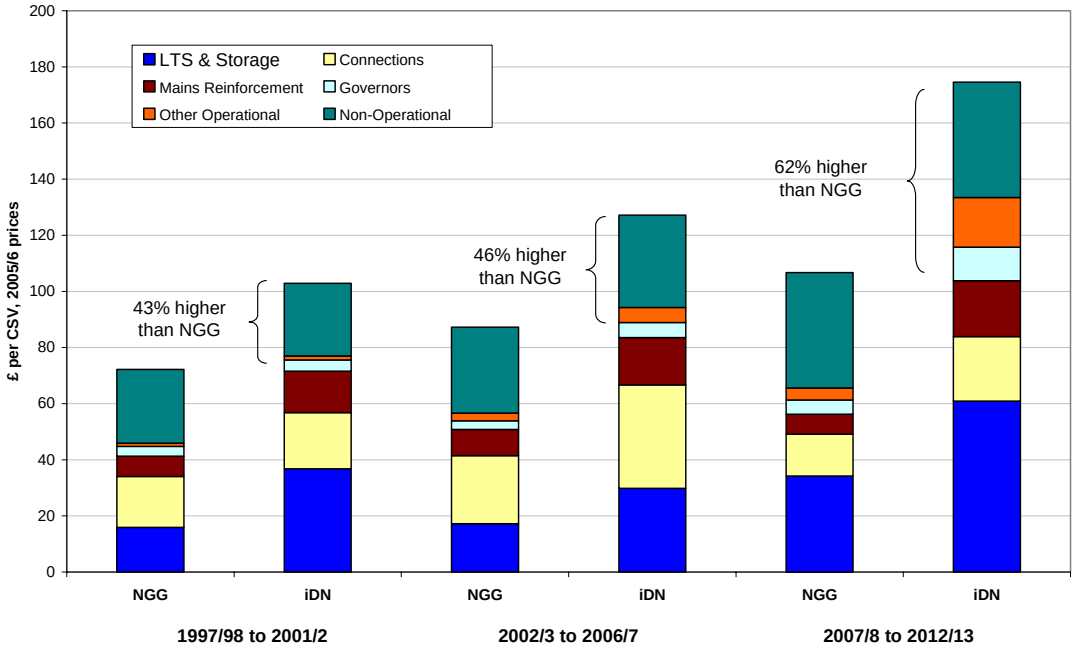
NGG response

1.32. NGG has argued that our approach to cost assessment has failed to recognise the interaction between operating costs and capital investment. It argues that its planning processes consider whole life cycle costs and it makes decisions on investment based on medium-term benefits which may result in higher opex in the short-term. It considers that Ofgem's approach has resulted in insufficient

allowances for NGG based on benchmarks from businesses that have invested significantly higher levels of capex which enable additional opex savings.

1.33. Figure A5.6 below illustrates differences in levels of investment per CSV over the last 16 years.

Figure A5.6 – Investment per CSV 1997-08 to 2012-13



1.34. NGG acknowledges that some of the differences in GDNs' capex per customer may be explained by relative levels of demand growth or the IDNs being located at the extremities of the NTS.

1.35. NGG has highlighted a number of potential mechanisms for interactions between investment and opex such as:

- replacing old plant leading to fewer faults and alarms and less standby time, call-outs and non-routine repairs;
- LP pressure mains reinforcement leading to fewer reported gas escapes and repairs and lower emergency and repair costs; and
- new back-office systems leading to reduced maintenance costs and IS staffing.

1.36. NGG has used a number of approaches to quantify the impact of the opex-capex trade-off including estimates based on the capital substitution effect applied by Europe and First Economics, a bottom-up assessment of the trade-offs and an assessment of the additional opex that would be required to achieve equivalent levels of prices for consumers on NGG's networks given higher levels of capex for the

IDNs. It has also highlighted that we addressed the opex-capex trade-off as part of DPCR4 by using a total expenditure regression to supplement the opex analysis.

1.37. The results of NGG's alternative approaches are summarised in table A5.9 below.

Table A5.9 – Summary of alternative approaches

Quantification Method	**%**	**£m pa**
Bottom-up assessment	5.8	£19m
Europe Economics capital substitution	2.1-4.2	£7-14m
Total expenditure regression	2.8	£9m
Economic appraisal (RAV)	6.5	£21m
Average	**4.3-4.8 %**	**£14-16m pa**

1.38. NGG considers that our opex forecasts should be increased by 4 per cent for its GDNs to account for this interaction.

Our assessment

1.39. We acknowledged that there was some merit in NGG's capex-opex trade-off arguments in updated proposals but noted that there was difficulty in quantifying the interactions and challenged NGG to provide further evidence to support their case.

1.40. NGG provided further information in response to updated proposals but there were still a number of weaknesses in their arguments. In particular the higher levels of capex for the IDNs dates back to 1997-98 while the GDNs were all under common ownership and investment policies and this seemed to suggest that there were a number of inherent or inherited differences between the networks which had not been adequately taken into account in NGG's analysis. We challenged NGG to provide better information to explain this.

1.41. There were also weaknesses in NGG's quantification of the impact. For example, NGG's bottom-up analysis notes that we have disallowed £8 million of their non-routine maintenance costs. It assumes all of this must be related to the opex-capex trade-off without any analysis to quantify this.

1.42. NGG overstates the potential trade-offs between LTS capex and maintenance opex. In reviewing IDN storage capex against their holder maintenance opex they assume that all LTS pipeline capex put forward by the IDNs relates to the provision of additional storage. The main driver of a number of the LTS capex projects is the provision of increased transmission capacity rather than storage.

1.43. At the recent bilateral meetings and in follow-up correspondence NGG presented a more convincing case to support the application of an adjustment for the opex trade-off. It showed that the lower levels of capex for its GDNs between 1997-8 and 2006-07 compared to the sold GDNs are largely explained by lower levels of demand growth (4.5 per cent for NGG compared to 13.2 per cent for the retained GDNs). By contrast levels of forecast demand growth are similar going forwards.

1.44. The difference in governor, other-operational and non-operational capex between the retained and sold GDNs, which is not driven by demand growth, was only 7 per cent for 1997-98 to 2001-02 but is expected to rise to 46 per cent for 2007-08 to 2012-13 based on our updated proposals.

1.45. NGG has also provided a number of papers presented to its internal investment committees which highlight interactions between capex and opex.

1.46. Taking this information into consideration we consider it is appropriate to make a small adjustment to our opex forecasts for NGG to reflect interactions between capex and opex. We consider that the most appropriate way of calculating an adjustment is to adopt a similar approach to DPCR4.

1.47. We have carried out a regression of opex plus governor, other operational and non-operational capex. We have excluded LTS, connections and mains reinforcement capex as differences for these activities are largely driven by demand growth and repex because differences between GDNs largely reflect differences in the diameter mix of mains replacement work. We have then compared the level of efficiency and benchmark costs based on an average of this "totex" regression and a pure opex regression with the results of an opex regression on its own. The additional costs are £6.2 million for NGG's GDNs which we have added to our opex forecasts. This analysis is summarised in table A5.10 below.

Table A5.10 – Comparison of average results of totex and opex benchmarks with opex on its own

		Base analysis - Opex		Opex + capex excl capacity and mains reinforcement					
	Adjusted Normalised Costs 06/7	Efficiency %	06/7 efficient costs (UQ)	Efficiency %	06/7 efficient costs (UQ)	Average 06/7 efficient costs	Adjust to higher of average or base	Adjusted 06/7 efficient costs	Variance to Opex
	A	B	C (=A*B)	D	E (=A*D)	F (=Ave(C,E)	G (= F-C)	H (= C+G)	I (=H-C)
East of England	103.3	94.7%	97.8	98.7%	102.0	99.9	2.1	99.9	2.1
London	64.9	90.0%	58.4	93.7%	60.8	59.6	1.2	59.6	1.2
North West	83.5	88.4%	73.8	92.2%	77.0	75.4	1.6	75.4	1.6
West Midlands	57.1	101.3%	57.8	105.8%	60.4	59.1	1.3	59.1	1.3
NGN	71.4	103.0%	73.5	101.9%	72.7	73.1	0.0	73.5	0.0
Scotland	56.1	99.2%	55.7	97.7%	54.8	55.3	0.0	55.7	0.0
Southern	97.3	99.6%	96.9	99.4%	96.7	96.8	0.0	96.9	0.0
Wales and West	76.6	92.8%	71.1	89.4%	68.5	69.8	0.0	71.1	0.0
	610.3		**585.1**		**593.0**	**589.1**		**591.3**	**6.2**

1.48. This compares with an adjustment of £9 million in NGG's version of the analysis where they have included calculated totex including mains reinforcement, governor, other operational and non-operational capex. We have excluded mains reinforcement as we consider that it is significantly affected by levels of demand growth.

Appendix 6 - Real price effects and ongoing efficiency assumptions

Real growth in input prices

1.49. In both initial and updated proposals we assumed real growth of 2 per cent per annum in contractors' rates, 1 per cent per annum in direct labour earnings and 1 per cent per annum for materials costs. Since then additional information has become available both through the Competition Commission's (CC's) report on BAA, the CAA's November consultation, and further arguments and evidence put forward by the GDNs in response to updated proposals.

Competition Commission

1.50. The CC considered real input price growth for construction as a whole rather than considering contractor, direct labour and materials elements separately.

1.51. They looked at historical data on construction tender price indices and indices compiled by the Department of Business Enterprise and Regulatory Reform (DBERR) and the Building Construction Information Service (BCIS). The CC excluded the more inflationary housing sector and focussed on commercial and infrastructure indices (including utilities) as being more relevant to BAA. The CC observed annual real growth in infrastructure prices of 3.4 per cent per annum in the London area over 2002 to 2006 and 0.8 per cent per annum over 1993 to 2007 (excluding the downturn of the late eighties.) The CC noted that although infrastructure and commercial construction prices had been volatile over the last five years the volatility was no greater than in any previous periods.

1.52. The CC also commissioned Experian to forecast construction prices for 2007 to 2012, based on a model they had developed for the Office of Government Commerce (OGC) which forecasts output prices. The output prices were based on wage rates using forecast labour demand and supply, materials prices based on forecast costs and margins based on forecast output volumes. The key assumptions in Experian's model were:

- continued migration from Eastern Europe to mitigate inflation in unskilled labour, greater inflation in some skilled occupations but this could also be partially managed by sourcing in the global professional market;
- materials costs moderating as demand from India and China stabilised and both countries were likely to increase their exports of raw materials; and
- strong output levels over the whole period particularly in infrastructure including the London Olympics.

1.53. Experian's average forecast of real construction price growth for infrastructure over 2007 to 2012 ranged from 0.1 to 0.5 per cent depending on the assumptions for a number of large infrastructure projects. The Experian forecasts suggest higher

levels of real input growth from 2007 to 2009 dropping off sharply from 2010 onwards.

1.54. The CC notes that BAA has applied a 25 per cent risk margin to all construction projects which includes some allowance for construction price inflation. Neither BAA nor CAA's consultants Currie and Brown were able to quantify this.

1.55. Taking these issues into consideration the CC concluded that real growth in construction costs of 0.75 per cent per annum was appropriate for BAA's capital projects. Our equivalent numbers are on average 1.3 per cent per annum for opex, 2.4 per cent per annum for capex and 2.3 per cent for repex. However, it is difficult to make any precise read across between this and our assumptions in updated proposals because BAA's contingency allowances for capex include an element for inflation risk.

1.56. The CC applied no growth in real input prices for BAA's opex other than for staff costs associated with increased security requirements.

1.57. The CAA has recently published its November consultation on the price controls for Heathrow and Gatwick taking into account the CC's recommendations. The CAA consider it more appropriate to base its assumption for real growth in construction prices on short-run evidence on prevailing trends in the construction sector and forecasts of construction price inflation for 2008 to 2013. It has applied an assumption of 2 per cent per annum.

GDN responses

1.58. The GDNs argued that our assumptions for real growth in direct labour earnings are inappropriate in the context of skill shortages and an ageing work force but their main focus has been on assumptions relating to the contractor market and materials prices.

1.59. They highlighted that in initial proposals we supported the use of the historical Baxter Civil Engineering Index and forward-looking National tender price indices (TPIs) to estimate the rate of growth in contractors' prices 2 per cent per annum but in updated proposals we relied more on longer term trends.

1.60. The GDNs noted that more recent Baxter and TPI information suggests real growth of around 3 per cent per annum in contractors' prices. NGG argued that long-term trends in construction prices which suggest lower growth in contractor prices were irrelevant when setting allowances for the next five years. The focus should be on expected market conditions for that period.

1.61. NGG noted the inclusion of inflation in BAA's risk margins, which NGG stated were not present in its programme. NGG also highlighted that, unlike the CC, Ofgem had applied productivity assumptions of 1.5-2 per cent per annum for capex offsetting the RPE allowances.

1.62. NGG included a recent report from an independent expert suggesting contractor prices in gas distribution were set to rise at 6 per cent per annum (3.5 per cent in real terms) with a 1-2 per cent premia for Greater London. NGG cited the Deloitte report for the OGC in 2006 which stated contractors' rates in London would be driven further by increased spend on the Olympics and Crossrail.

1.63. SGN referred to work it had commissioned by Deloitte which suggested that real price growth of 3 per cent per annum would be appropriate nationally plus a 1.5 per cent premium for London. NGN considered that our assumptions for real price growth should be doubled. WWU refer to the report they commissioned by Chandler KBS which suggested real growth in contract labour of 4 per cent per annum and direct labour of 1.8 per cent per annum.

1.64. NGN noted that the cost for steel and plastic pipes had increased by 4-5 per cent in the last four years and said a 2 per cent assumption for growth in material prices would be conservative. WWU explained that they had experienced significant increases in materials prices in the last two years. The price of plastic pipes had increased by 8 per cent and steel by 10 per cent in 2006-07. WWU said that Ofgem should increase its RPE assumptions or introduce indexation for such prices.

Results of our revised analysis

1.65. The GDNs have consistently put forward arguments for increasing the real price effects that we have allowed in setting allowances. We acknowledge that there is evidence in the short-term to support a higher level of real input price inflation for contract labour. In particular applying the methodology we supported at initial proposals using the historical Baxter index and forward looking tender price information and updating this for more recent evidence points to real contract price inflation of around 3 per cent. The recent work by Experian commissioned by the CC as part of the BAA review suggests high input price inflation over the next 3 years followed by a decline towards the end of the period.

1.66. On this basis we are now assuming an increase in real price growth for contract labour to 3 per cent for the first 3 years and 2 per cent for the next 3 years giving an average of 2.5 per cent over the price control period.

1.67. For direct labour (currently 1 per cent per annum), we have looked at a range of evidence including actual pay and earnings data for 2005 to 2006 for both the whole economy and utilities sector and forecast information including the Treasury and Inbucon (TPCR) work. This produced a range of earnings growth between zero and 3.5 per cent per annum, the majority of evidence being towards the lower end of the range. Data on earnings showed the rate of growth had declined to just above or below inflation in the last few months.

1.68. We recognise that some of the pressures driving up contractor prices will also affect direct labour. We also do not believe it appropriate to increase the differential between contract and direct labour as they are both primarily driven by the same resource namely labour. On this basis we are increasing the assumption for real

growth in earnings to 2 per cent for the first 3 years and 1 per cent for the next three years giving an average of 1.5 per cent over the price control period. We do not consider it appropriate to allow higher real input price growth in London. This would be unsustainable as it would attract additional labour from the regions into London.

1.69. GDNs have made a strong case that the assumption for real growth in materials is significantly understated. PE pipe is a significant element of GDNs' material costs and the cost of PE pipe has increased significantly as its manufacture involves the use of oil as a raw material and is energy intensive. The production of steel pipes is also energy intensive. We consider with the revised evidence that a real price effect of 3 per cent (previously 1 per cent) is more appropriate for materials.

Assumption for ongoing productivity savings

1.70. As part of updated proposals we reviewed our assumptions for ongoing efficiency improvements of 2.5 per cent per annum. We noted that while the additional work we had commissioned from Reckon LLP pointed to a wide range of possible conclusions on productivity savings from 0 to 4.8 per cent per annum it did not suggest our initial proposals assumptions were unreasonable. If we adopted a figure of 1.4 per cent per annum efficiency savings from Reckon LLP's work (towards the lower end of their range) and added 1.1 per cent per annum for comparative competition (in line with DN sales), this would support ongoing productivity of 2.5 per cent per annum.

1.71. We noted a number of weaknesses with the alternative First Economics work that had been commissioned by the GDNs including that consumer prices capture changes in profits, capital employed, rates and pension as well as productivity.

GDN responses

1.72. The GDNs have raised a number of criticisms with our 2.5 per cent assumption directed at the robustness of Reckon LLP's work, our application of the results and the practicality of achieving such ongoing improvements.

1.73. They suggest that there is a key error in our consultants' analysis of "capital-adjusted" labour productivity growth as its calculations effectively assume that all historical growth in total factor productivity is attributable to reductions in labour force alone. They argue that this is unrealistic and a novel proposition. Their consultants, First Economics, question the choice of comparators by Reckon LLP and Ofgem. They suggest that the chemical industry is an inappropriate comparator as it is capital intensive. They note that the other comparators are subsets of larger sector indices.

1.74. The GDNs consider that we should take more account of the First Economics work which looks at relevant industry segments within the RPI to consider the scope for ongoing productivity savings net of real input price growth. This analysis suggests that costs will increase by between 0 per cent and 0.5 per cent per annum.

1.75. The GDNs consider that in basing our 2.5 per cent productivity assumption on a 1.1 per cent comparative competition effect and a 1.4 per cent from Reckon LLP's labour productivity work we had double counted the benefits of comparative competition. We had already derived a 1.2 per cent per annum benefit from our benchmarking analysis.

1.76. They suggest that the 2.5 per cent per annum productivity improvements are based on labour productivity and that we should only apply this to labour costs within GDNs' opex which amounts to approximately 70 per cent of their total opex.

Final proposals

1.77. We have commissioned further work from Reckon LLP which suggests that its analysis is still appropriate. Its methodology is designed to overcome issues of high or low capital growth in comparators overstating or understating the scope for labour productivity improvements in gas distribution.

Table A6.1 Capital-adjusted labour productivity and standard labour productivity

Sector	Capital-adjusted labour productivity, %	Labour productivity, %
Construction	1.5	1.3
Financial intermediation	0.1	1.6
Manufacture of chemicals	4.8	4.3
Sales, maintenance and repair of motor vehicles	2.4	2.8
Transport and storage	2.0	2.1

1.78. Reckon LLP's estimates of capital adjusted labour productivity are not systematically more demanding than standard labour productivity estimates looking at the ratio of labour inputs to capital outputs.

1.79. We still consider that 2.5 per cent is appropriate based on the middle of the range. We note the arguments about the appropriateness of particular comparators including that the comparator for manufacture of chemicals may be inappropriately high because of the degree of capital intensity. Equally there are arguments that financial intermediation could be excluded because the other industries will all include an element of financial or support services.

1.80. In deciding the proportion of opex to which the labour productivity assumption should be applied, we need to consider the whole value chain. For example in addition to direct and contract labour many other elements of opex will also have a labour component and labour productivities associated with it. For example, costs for transporting materials or plant will have a significant labour element and scope for improvements in efficiencies. Professional and consultancy fees are largely labour related. Information System costs will have large labour components.

1.81. Further it is reasonable to expect there to be efficiencies even for capital elements of costs. For example, in TPCR final proposals there was a capex procurement efficiency of 5 per cent across the 5 years for NGG Electricity and Gas Transmission.

1.82. We consider that an efficiency assumption of 2.5 per cent per annum is appropriate for our assessment of GDN opex.

Appendix 7 – Opex tables

National Grid Gas - East of England, Ofgem opex assessment

Table A7.1 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	22.9	22.7	22.4	22.2	22.0	112.3	108.8
Emergency	11.2	11.1	11.0	10.9	10.8	55.0	54.1
Repair	9.4	9.3	9.1	8.9	8.8	45.5	44.5
Maintenance	15.4	14.1	13.4	13.1	13.3	69.4	65.8
Other Direct Activities	2.4	2.3	2.3	2.3	2.3	11.7	11.2
Xoserve	4.5	4.2	4.8	4.6	4.1	22.1	20.7
LNG to SIUs						0.0	0.0
Total Direct Opex	**65.9**	**63.7**	**63.0**	**62.0**	**61.3**	**316.0**	**305.2**

Table A7.2 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	9.9	9.8	9.7	9.5	9.4	48.3	38.9
Finance, Audit and Regulation	3.8	3.7	3.7	3.6	3.5	18.3	18.0
Insurance	3.7	4.1	4.5	4.9	4.8	22.0	22.1
Property Management	4.4	4.3	4.2	4.1	4.0	20.9	20.9
Corporate Centre and Comms	1.8	1.8	1.8	1.7	1.7	8.9	8.8
HR	1.4	1.4	1.3	1.3	1.3	6.7	2.2
Legal	0.5	0.4	0.4	0.4	0.4	2.2	2.1
Procurement and Logistics	1.2	1.2	1.1	1.1	1.1	5.7	5.6
Total Indirect Opex	**26.6**	**26.6**	**26.7**	**26.7**	**26.3**	**132.9**	**118.7**

Table A7.3 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	65.9	63.7	63.0	62.0	61.3	316.0	305.2
Indirect Costs	26.6	26.6	26.7	26.7	26.3	132.9	118.7
Adjustment to top down	5.7	5.6	5.6	5.5	5.5	27.9	26.4
Quality of Service	0.4	0.4	0.4	0.4	0.4	1.9	1.9
SIU costs						0.0	0.0
Training and apprentice allowance	2.2	2.2	2.2	2.2	2.2	11.2	10.7
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	4.7
Waste management costs	0.2	0.3	0.4	0.5	0.6	1.9	1.9
Capex/opex trade-off	2.1	2.1	2.1	2.1	2.1	10.4	0.0
Sub-deduct network surveys	0.1	0.1				0.2	0.0
Non-labour regional factors						0.0	0.0
Total Opex	**104.1**	**102.2**	**101.7**	**100.0**	**98.9**	**506.9**	**469.4**

National Grid Gas - London, Ofgem opex assessment

Table A7.4 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	17.1	16.9	16.8	16.6	16.5	83.8	82.3
Emergency	9.2	9.1	9.0	8.9	8.8	45.0	44.9
Repair	10.2	10.0	9.9	9.7	9.6	49.4	48.9
Maintenance	13.0	10.5	10.2	10.4	10.3	54.4	49.7
Other Direct Activities	1.4	1.4	1.4	1.4	1.4	6.8	6.6
Xoserve	3.1	2.8	3.2	3.1	2.8	14.9	12.1
LNG to SIUs						0.0	
Total Direct Opex	**53.9**	**50.6**	**50.4**	**50.1**	**49.3**	**254.4**	**244.6**

Table A7.5 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	4.6	4.5	4.5	4.4	4.4	22.4	18.0
Finance, Audit and Regulation	1.6	1.6	1.6	1.5	1.5	7.8	7.7
Insurance	1.9	2.1	2.3	2.4	2.4	11.1	11.1
Property Management	3.9	3.8	3.7	3.6	3.5	18.4	18.4
Corporate Centre and Comms	1.2	1.2	1.2	1.2	1.2	6.0	5.9
HR	0.7	0.7	0.7	0.6	0.6	3.3	1.1
Legal	0.4	0.4	0.3	0.3	0.3	1.7	1.7
Procurement and Logistics	0.6	0.6	0.6	0.6	0.6	2.9	2.9
Total Indirect Opex	**14.8**	**14.8**	**14.8**	**14.7**	**14.5**	**73.6**	**66.9**

Table A7.6 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	53.9	50.6	50.4	50.1	49.3	254.4	244.6
Indirect Costs	14.8	14.8	14.8	14.7	14.5	73.6	66.9
Adjustment to top down	4.2	4.1	4.1	4.1	4.0	20.5	19.4
Quality of Service	0.7	0.6	0.6	0.6	0.6	3.2	3.2
SIU costs						0.0	0.0
Training and apprentice allowance	1.3	1.3	1.3	1.3	1.3	6.7	6.2
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	4.7
Waste management costs	0.1	0.2	0.3	0.4	0.5	1.5	1.5
Capex/opex trade-off	1.2	1.2	1.2	1.2	1.2	6.0	0.0
Sub-deduct network surveys	0.1	0.1				0.2	0.0
Non-labour regional factors	1.9	1.9	1.9	1.9	1.9	9.6	9.6
Total Opex	**79.3**	**76.1**	**76.1**	**75.0**	**74.0**	**380.4**	**356.0**

National Grid Gas - North West, Ofgem opex assessment

Table A7.7 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	18.7	18.5	18.3	18.1	18.0	91.6	88.8
Emergency	9.2	9.1	9.0	8.9	8.8	45.2	44.4
Repair	9.6	9.4	9.3	9.1	9.0	46.4	45.5
Maintenance	11.5	11.7	11.2	11.9	11.2	57.4	54.1
Other Direct Activities	1.3	1.3	1.2	1.2	1.2	6.2	5.9
Xoserve	3.3	3.0	3.5	3.3	3.0	16.3	14.6
LNG to SIUs						0.0	0.0
Total Direct Opex	**53.6**	**53.0**	**52.6**	**52.6**	**51.2**	**263.0**	**253.3**

Table A7.8 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	6.9	6.8	6.8	6.7	6.6	33.8	27.3
Finance, Audit and Regulation	2.4	2.4	2.3	2.3	2.3	11.7	11.5
Insurance	2.6	2.9	3.1	3.4	3.3	15.2	15.3
Property Management	5.1	5.0	4.9	4.8	4.6	24.4	24.4
Corporate Centre and Comms	1.4	1.4	1.4	1.4	1.4	7.0	6.9
HR	1.0	1.0	1.0	1.0	0.9	4.9	1.6
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.1
Procurement and Logistics	0.9	0.9	0.8	0.8	0.8	4.2	4.1
Total Indirect Opex	**20.8**	**20.8**	**20.7**	**20.7**	**20.4**	**103.3**	**93.2**

Table A7.9 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	53.6	53.0	52.6	52.6	51.2	263.0	253.3
Indirect Costs	20.8	20.8	20.7	20.7	20.4	103.3	93.2
Adjustment to top down	4.7	4.7	4.6	4.6	4.4	23.1	21.6
Quality of Service	0.2	0.2	0.2	0.2	0.2	1.2	1.2
SIU costs						0.0	0.0
Training and apprentice allowance	1.7	1.7	1.7	1.7	1.7	8.4	7.9
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	4.7
Waste management costs	0.2	0.2	0.3	0.4	0.5	1.6	1.6
Capex/opex trade-off	1.6	1.6	1.6	1.6	1.6	8.0	0.0
Sub-deduct network surveys	0.1	0.1				0.1	0.0
Non-labour regional factors						0.0	0.0
Total Opex	**83.9**	**83.4**	**83.2**	**82.5**	**80.6**	**413.5**	**383.5**

National Grid Gas - West Midlands, Ofgem opex assessment

Table A7.10 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	13.5	13.4	13.3	13.1	13.0	66.4	64.5
Emergency	6.0	5.9	5.9	5.8	5.7	29.3	28.8
Repair	7.2	7.0	6.9	6.8	6.7	34.7	34.0
Maintenance	8.5	17.4	8.0	7.8	7.7	49.4	46.6
Other Direct Activities	1.1	1.0	1.0	1.0	1.1	5.3	5.1
Xoserve	2.7	2.5	2.9	2.8	2.5	13.5	12.2
LNG to SIUs						0.0	0.0
Total Direct Opex	**39.0**	**47.4**	**38.0**	**37.4**	**36.7**	**198.6**	**191.2**

Table A7.11 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	5.2	5.1	5.1	5.0	5.0	25.3	20.4
Finance, Audit and Regulation	1.9	1.9	1.9	1.8	1.8	9.3	9.2
Insurance	1.8	2.0	2.2	2.4	2.3	10.8	10.8
Property Management	4.2	4.1	4.0	3.9	3.8	19.8	19.8
Corporate Centre and Comms	1.0	0.9	0.9	0.9	0.9	4.6	4.6
HR	0.7	0.7	0.7	0.7	0.6	3.3	1.1
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.1
Procurement and Logistics	0.6	0.6	0.6	0.6	0.6	3.0	3.0
Total Indirect Opex	**15.8**	**15.8**	**15.7**	**15.7**	**15.4**	**78.3**	**71.0**

Table A7.12 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	39.0	47.4	38.0	37.4	36.7	198.6	191.2
Indirect Costs	15.8	15.8	15.7	15.7	15.4	78.3	71.0
Adjustment to top down	3.5	3.4	3.4	3.4	3.3	17.0	16.3
Quality of Service	0.2	0.2	0.1	0.1	0.1	0.8	0.8
SIU costs						0.0	0.0
Training and apprentice allowance	1.2	1.2	1.2	1.2	1.2	5.8	5.3
Environmental remediation	1.0	1.1	1.4	0.6	0.6	4.7	4.7
Waste management costs	0.1	0.2	0.2	0.3	0.3	1.1	1.1
Capex/opex trade-off	1.3	1.3	1.3	1.3	1.3	6.5	0.0
Sub-deduct network surveys	0.2	0.2				0.5	0.0
Non-labour regional factors						0.0	0.0
Total Opex	**62.2**	**70.6**	**61.4**	**59.9**	**59.0**	**313.1**	**290.3**

Northern Gas Networks - Northern, Ofgem opex assessment

Table A7.13 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	19.5	19.3	19.1	18.9	18.7	95.4	92.6
Emergency	8.8	8.7	8.6	8.5	8.4	42.9	42.2
Repair	10.7	10.5	10.3	10.1	9.9	51.5	50.4
Maintenance	11.5	10.4	10.3	10.8	10.8	53.8	46.8
Other Direct Activities	1.9	2.0	1.9	1.9	1.9	9.6	9.0
Xoserve	3.3	3.0	3.4	3.3	3.0	15.8	13.6
LNG to SIUs						0.0	0.0
Total Direct Opex	**55.5**	**53.8**	**53.6**	**53.4**	**52.7**	**269.0**	**254.7**

Table A7.14 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	5.5	7.0	7.0	6.9	6.9	33.3	31.4
Finance, Audit and Regulation	2.5	2.4	2.4	2.4	2.3	12.0	11.9
Insurance	2.1	2.5	2.9	3.3	3.2	13.9	13.8
Property Management	2.5	2.4	2.4	2.3	2.3	11.9	12.7
Corporate Centre and Comms	1.4	1.4	1.4	1.3	1.3	6.8	6.7
HR	0.7	0.7	0.7	0.7	0.7	3.5	1.6
Legal	0.4	0.4	0.4	0.4	0.4	2.1	2.1
Procurement and Logistics	0.8	0.8	0.8	0.8	0.8	4.0	3.9
Total Indirect Opex	**15.9**	**17.7**	**17.9**	**18.1**	**17.9**	**87.5**	**84.1**

Table A7.15 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	55.5	53.8	53.6	53.4	52.7	269.0	254.7
Indirect Costs	15.9	17.7	17.9	18.1	17.9	87.5	84.1
Adjustment to top down	4.4	4.5	4.5	4.4	4.4	22.1	21.1
Quality of Service	0.3	0.3	0.3	0.3	0.3	1.6	1.6
SIU costs	0.0	0.0	0.0	0.0	0.0	0.2	0.0
Training and apprentice allowance	1.7	1.7	1.7	1.7	1.7	8.4	7.9
Environmental remediation	1.0	1.0	1.0	1.0	1.0	5.0	5.0
Waste management costs	0.1	0.2	0.2	0.3	0.4	1.2	1.2
Capex/opex trade-off						0.0	0.0
Sub-deduct network surveys	0.1	0.1				0.2	0.0
Non-labour regional factors						0.0	0.0
Total Opex	**79.1**	**79.2**	**79.2**	**79.3**	**78.3**	**395.1**	**375.6**

Scotia Gas Networks - Scotland, Ofgem opex assessment

Table A7.16 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	13.9	13.8	13.6	13.5	13.3	68.1	66.2
Emergency	6.8	6.7	6.6	6.6	6.5	33.1	32.6
Repair	7.4	7.3	7.1	7.0	6.9	35.7	35.0
Maintenance	8.7	8.1	8.6	8.2	7.9	41.4	38.3
Other Direct Activities	1.1	1.1	1.0	1.0	1.0	5.2	4.8
Xoserve	2.1	1.9	2.2	2.1	1.9	10.3	9.1
LNG to SIUs	4.8	4.8	4.8	4.8	4.8	24.0	24.0
Total Direct Opex	**44.7**	**43.6**	**44.1**	**43.1**	**42.3**	**217.8**	**210.0**

Table A7.17 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	5.5	5.4	5.3	5.3	5.2	26.7	25.3
Finance, Audit and Regulation	2.0	1.9	1.9	1.9	1.8	9.5	9.5
Insurance	1.8	2.2	2.6	2.9	2.9	12.4	11.7
Property Management	1.7	1.6	1.6	1.5	1.5	7.9	8.8
Corporate Centre and Comms	1.1	1.1	1.1	1.0	1.0	5.3	5.2
HR	0.6	0.6	0.6	0.5	0.5	2.8	2.9
Legal	0.4	0.4	0.4	0.4	0.4	1.9	1.9
Procurement and Logistics	0.7	0.7	0.7	0.7	0.6	3.4	3.4
Total Indirect Opex	**13.6**	**13.9**	**14.0**	**14.2**	**14.0**	**69.7**	**68.6**

Table A7.18 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	44.7	43.6	44.1	43.1	42.3	217.8	210.0
Indirect Costs	13.6	13.9	14.0	14.2	14.0	69.7	68.6
Adjustment to top down	3.4	3.3	3.3	3.3	3.3	16.6	17.3
Quality of Service	0.2	0.2	0.2	0.2	0.2	1.0	1.0
SIU costs	1.2	0.6	0.6	0.6	0.6	3.6	3.6
Training and apprentice allowance	1.8	1.8	1.8	1.8	1.8	9.2	8.7
Environmental remediation	0.5	0.5	0.5	0.5	0.5	2.5	2.5
Waste management costs	0.1	0.2	0.2	0.3	0.4	1.1	1.1
Capex/opex trade-off						0.0	0.0
Sub-deduct network surveys	0.0	0.0				0.1	0.0
Non-labour regional factors	1.0	1.0	1.0	1.0	1.0	5.0	5.0
Total Opex	**66.6**	**65.1**	**65.8**	**65.1**	**64.0**	**326.6**	**317.9**

Scotia Gas Networks - Southern, Ofgem opex assessment

Table A7.19 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	29.4	29.1	28.8	28.6	28.3	144.2	140.0
Emergency	15.5	15.3	15.1	14.9	14.8	75.6	74.5
Repair	20.0	19.6	19.2	18.9	18.5	96.3	94.5
Maintenance	15.1	14.0	13.2	12.7	12.8	67.7	64.4
Other Direct Activities	2.9	2.9	2.8	2.7	2.7	14.0	13.1
Xoserve	5.4	5.0	5.6	5.4	4.9	26.2	20.6
LNG to SIUs						0.0	
Total Direct Opex	**88.3**	**85.8**	**84.8**	**83.2**	**81.9**	**423.9**	**407.1**

Table A7.20 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	8.2	8.1	8.0	7.9	7.8	40.1	37.9
Finance, Audit and Regulation	3.0	2.9	2.9	2.8	2.7	14.3	14.3
Insurance	2.7	3.3	3.9	4.4	4.3	18.6	17.5
Property Management	2.5	2.4	2.4	2.3	2.2	11.8	13.2
Corporate Centre and Comms	1.6	1.6	1.6	1.6	1.5	7.9	7.8
HR	0.9	0.8	0.8	0.8	0.8	4.1	4.3
Legal	0.6	0.6	0.6	0.6	0.5	2.8	2.8
Procurement and Logistics	1.1	1.0	1.0	1.0	1.0	5.1	5.1
Total Indirect Opex	**20.5**	**20.8**	**21.1**	**21.4**	**21.0**	**104.8**	**103.0**

Table A7.21 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	88.3	85.8	84.8	83.2	81.9	423.9	407.1
Indirect Costs	20.5	20.8	21.1	21.4	21.0	104.8	103.0
Adjustment to top down	6.7	6.7	6.6	6.6	6.5	33.1	31.7
Quality of Service	0.4	0.4	0.4	0.4	0.4	1.9	1.9
Revenue correction	0.7					0.7	0.7
Training and apprentice allowance	2.6	2.6	2.6	2.6	2.6	13.1	12.6
Environmental remediation	0.5	0.5	0.5	0.5	0.5	2.5	2.5
Waste management costs	0.2	0.4	0.5	0.6	0.8	2.5	2.5
Capex/opex trade-off						0.0	0.0
Sub-deduct network surveys	0.2	0.2				0.3	0.0
Non-labour regional factors	1.2	1.2	1.2	1.2	1.2	6.0	6.0
Total Opex	**121.3**	**118.5**	**117.7**	**116.4**	**114.8**	**588.7**	**567.9**

Wales & West Utilities - Wales & West, Ofgem opex assessment

Table A7.22 - Direct opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Work Management	17.0	16.9	16.7	16.5	16.4	83.5	81.1
Emergency	7.2	7.1	7.0	6.9	6.9	35.1	34.6
Repair	9.3	9.1	9.0	8.8	8.7	44.9	44.0
Maintenance	13.5	13.8	12.1	11.3	11.2	61.8	57.4
Other Direct Activities	2.3	2.3	2.3	2.2	2.3	11.3	10.8
Xoserve	3.1	2.8	3.2	3.1	2.8	14.9	13.1
LNG to SIUs						0.0	0.0
Total Direct Opex	**52.4**	**52.0**	**50.2**	**48.8**	**48.2**	**251.5**	**240.9**

Table A7.23 - Indirect opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
IS	6.6	6.8	6.8	6.3	5.4	32.0	30.3
Finance, Audit and Regulation	2.7	2.7	2.6	2.6	2.5	13.1	13.0
Insurance	2.4	2.7	3.1	3.4	3.4	15.0	15.0
Property Management	1.9	1.9	1.8	1.8	1.8	9.2	9.7
Corporate Centre and Comms	1.5	1.5	1.5	1.5	1.4	7.4	7.3
HR	1.1	1.0	1.0	1.0	1.0	5.1	3.9
Legal	0.5	0.5	0.5	0.5	0.4	2.3	2.3
Procurement and Logistics	0.9	0.9	0.9	0.9	0.9	4.4	4.4
Total Indirect Opex	**17.6**	**18.0**	**18.2**	**17.9**	**16.8**	**88.6**	**86.0**

Table A7.24 - Total opex (£m, 2005-06 prices)

Ofgem Final Proposals	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Direct Cost	52.4	52.0	50.2	48.8	48.2	251.5	240.9
Indirect Costs	17.6	18.0	18.2	17.9	16.8	88.6	86.0
Adjustment to top down	4.3	4.3	4.3	4.2	4.1	21.2	20.3
Quality of Service	0.2	0.2	0.2	0.2	0.2	0.9	0.9
SIU costs	0.1	0.1	0.1	0.1	0.1	0.5	0.0
Training and apprentice allowance	1.8	1.8	1.8	1.8	1.8	9.2	8.7
Environmental remediation	2.3	2.3	2.3	2.3	2.3	11.5	11.5
Waste management costs	0.1	0.2	0.2	0.3	0.3	1.0	1.0
Capex/opex trade-off						0.0	0.0
Sub-deduct network surveys	0.1	0.1				0.2	0.0
Non-labour regional factors	2.0	2.0	2.0	2.0	2.0	10.0	10.0
Total Opex	**80.9**	**80.9**	**79.3**	**77.6**	**75.9**	**394.6**	**379.4**

Appendix 8 – Capex and repex tables

1.1. The following tables present the GDNs' normalised BPQ submissions and Ofgem's proposed net capex and repex assessment prior to the application of the IQI incentive. Tables 4.2 and 4.4 in the main document present our proposals with the IQI incentive applied.

National Grid Gas - East of England, Ofgem capex and repex assessment

Table A8.1 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	7.0	7.3	7.8	16.0	10.6	48.7	51.7
Connections	9.2	9.7	10.1	10.3	10.7	50.0	50.0
Mains Reinforcement	4.4	2.5	3.1	2.8	2.9	15.7	15.7
Governors	0.5	0.7	0.5	0.5	0.8	3.1	3.1
Other Operational	1.5	1.4	1.4	1.4	1.4	7.2	7.2
Non Operational	14.6	11.4	17.2	24.8	19.2	87.2	87.2
Total Net Capex	**37.3**	**33.0**	**40.2**	**55.8**	**45.6**	**211.9**	**214.9**
Ofgem Proposed Allowances							
LTS & Storage	7.1	7.4	7.6	4.1	14.6	40.8	39.2
Connections	6.8	6.9	7.0	7.0	7.1	34.8	34.1
Mains Reinforcement	3.7	2.3	2.6	2.3	2.3	13.3	12.1
Governors	0.5	0.7	0.5	0.6	0.8	3.2	3.0
Other Operational	1.6	1.5	1.5	1.5	1.5	7.5	7.1
Non Operational	16.3	11.4	16.8	24.4	19.2	88.2	86.8
Total Net Capex	**36.0**	**30.2**	**36.1**	**39.9**	**45.6**	**187.8**	**182.3**

Table A8.2 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	58.6	67.5	69.7	75.0	77.5	348.3	348.3
Services (excl. Riser costs)	32.7	36.6	37.2	36.6	38.0	181.1	181.1
LTS	0.2	0.2	0.2	0.2	0.2	0.8	0.8
Total Net Repex	**91.5**	**104.3**	**107.0**	**111.7**	**115.7**	**530.2**	**530.2**
Ofgem Proposed Allowances							
Mains	63.3	70.0	71.1	76.5	77.6	358.5	347.5
Services (excl. Riser costs)	28.1	30.3	30.2	29.1	29.4	147.0	143.5
LTS	0.2	0.2	0.2	0.2	0.2	0.8	0.7
Total Net Repex	**91.6**	**100.4**	**101.5**	**105.7**	**107.1**	**506.3**	**491.7**

Table A8.3 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised riser costs	2.1	2.4	2.6	2.7	2.9	**12.7**	**12.7**
Ofgem proposed allowances							
FP proposed allowances	1.5	1.7	1.8	1.9	2.1	**9.0**	**9.0**

National Grid Gas – London, Ofgem capex and repex assessment

Table A8.5 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	42.4	40.1	9.3	23.6	18.8	134.1	136.9
Connections	4.9	4.8	5.7	5.8	6.0	27.2	27.2
Mains Reinforcement	2.4	2.3	1.5	3.3	3.5	13.0	13.0
Governors	2.2	2.2	2.4	2.4	0.6	10.0	10.0
Other Operational	1.2	1.0	1.3	1.1	1.2	5.7	5.7
Non Operational	8.4	6.9	9.3	13.1	9.9	47.7	47.7
Total Net Capex	**61.5**	**57.3**	**29.5**	**49.4**	**40.0**	**237.7**	**240.5**
Ofgem Proposed Allowances							
LTS & Storage	41.9	37.7	7.9	8.6	22.0	118.0	115.4
Connections	4.4	4.4	4.5	4.5	4.6	22.5	22.0
Mains Reinforcement	1.3	1.3	1.0	1.9	1.9	7.5	6.9
Governors	2.1	2.2	2.4	2.5	0.6	9.9	9.5
Other Operational	1.2	1.0	1.3	1.1	1.2	5.7	5.4
Non Operational	10.0	6.9	9.3	13.1	9.9	49.2	47.8
Total Net Capex	**60.9**	**53.6**	**26.3**	**31.8**	**40.2**	**212.8**	**207.0**

Table A8.6 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	71.5	63.7	68.3	70.5	68.1	342.2	342.2
Services (excl. Riser costs)	27.2	24.6	26.3	28.6	28.7	135.4	135.4
LTS	0.1	0.1	0.1	0.2	0.2	0.6	0.6
Total Net Repex	**98.9**	**88.4**	**94.6**	**99.3**	**97.0**	**478.2**	**478.2**
Ofgem Proposed Allowances							
Mains	73.1	64.2	66.4	66.2	62.5	332.4	323.5
Services (excl. Riser costs)	21.6	19.3	20.1	21.7	21.1	103.7	101.2
LTS	0.1	0.1	0.1	0.2	0.2	0.6	0.6
Total Net Repex	**94.8**	**83.5**	**86.6**	**88.1**	**83.8**	**436.7**	**425.2**

Table A8.7 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	7.0	7.6	8.5	9.5	9.6	**42.2**	**42.2**
Ofgem proposed allowances							
FP proposed allowances	5.0	5.4	6.0	6.7	6.8	**29.9**	**29.9**

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Table A8.8 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	6.2	12.3	17.4	26.7	9.9	72.5	75.3
Connections	3.8	4.2	4.4	4.8	4.8	22.0	22.0
Mains Reinforcement	0.8	2.8	2.9	2.2	4.4	13.2	13.2
Governors	2.8	2.7	3.7	3.1	3.9	16.3	16.3
Other Operational	1.2	1.1	1.2	1.2	1.2	5.9	5.9
Non Operational	9.7	8.2	12.5	16.5	13.2	60.0	60.0
Total Net Capex	**24.5**	**31.4**	**42.1**	**54.5**	**37.4**	**189.9**	**192.7**
Ofgem Proposed Allowances							
LTS & Storage	6.3	7.1	6.6	4.5	4.3	28.8	27.8
Connections	3.8	3.8	3.8	3.9	3.9	19.2	18.9
Mains Reinforcement	0.8	2.2	2.2	1.6	1.9	8.7	8.0
Governors	2.9	2.8	3.8	3.2	4.1	16.8	16.0
Other Operational	1.2	1.1	1.3	1.3	1.3	6.1	5.8
Non Operational	11.4	8.2	12.3	16.2	13.2	61.3	59.9
Total Net Capex	**26.2**	**25.2**	**30.0**	**30.7**	**28.7**	**140.9**	**136.3**

Table A8.9 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
Mains	71.5	72.2	71.6	73.8	70.8	359.8	359.8
Services (excl. Riser costs)	31.0	31.2	30.7	31.0	30.1	154.0	154.0
LTS	0.1	0.1	0.1	0.1	0.1	0.3	0.3
Total Net Repex	**102.6**	**103.5**	**102.4**	**104.8**	**100.9**	**514.1**	**514.1**
Ofgem Proposed Allowances							0
Mains	68.8	68.3	67.3	68.0	64.3	336.8	326.2
Services (excl. Riser costs)	24.7	24.5	24.3	24.3	23.5	121.4	118.5
LTS	0.1	0.1	0.1	0.1	0.1	0.3	0.3
Total Net Repex	**93.6**	**92.9**	**91.7**	**92.5**	**87.8**	**458.5**	**445.0**

Table A8.10 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Initial Proposals
GDN normalised UP Riser costs	1.9	2.0	2.2	2.4	2.5	**11.0**	**11.0**
Ofgem proposed allowances							
FP proposed allowances	1.3	1.4	1.6	1.7	1.8	**7.8**	**7.8**

National Grid Gas – West Midlands, Ofgem capex and repex assessment

Table A8.11 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	2.0	2.2	2.1	1.7	1.7	9.7	10.3
Connections	3.3	3.5	3.6	3.7	3.7	17.8	17.8
Mains Reinforcement	2.0	2.1	2.6	2.8	2.3	11.8	11.8
Governors	1.1	0.2	0.2	0.6	1.2	3.3	3.3
Other Operational	1.0	1.2	1.2	1.2	1.2	5.8	5.8
Non Operational	8.2	5.7	8.6	11.6	9.1	43.0	43.0
Total Net Capex	**17.5**	**14.9**	**18.3**	**21.5**	**19.2**	**91.4**	**92.0**
Ofgem Proposed Allowances							
LTS & Storage	2.0	2.2	2.1	1.7	1.7	9.9	9.5
Connections	3.1	3.2	3.2	3.2	3.3	16.0	15.7
Mains Reinforcement	1.8	2.0	1.7	2.3	1.7	9.5	8.6
Governors	1.1	0.2	0.2	0.6	1.2	3.4	3.3
Other Operational	1.0	1.2	1.2	1.3	1.3	6.0	5.7
Non Operational	9.8	5.7	8.4	11.4	9.1	44.3	42.9
Total Net Capex	**18.9**	**14.5**	**16.9**	**20.5**	**18.3**	**89.1**	**85.7**

Table A8.12 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	50.6	49.3	48.5	49.7	48.3	246.4	246.4
Services (excl. Riser costs)	22.7	23.3	23.5	23.0	23.7	116.1	116.1
LTS	0.0	0.0	0.0	0.0	0.0	0.2	0.2
Total Net Repex	**73.4**	**72.6**	**72.0**	**72.8**	**72.0**	**362.7**	**362.7**
Ofgem Proposed Allowances							
Mains	54.9	51.9	49.4	50.1	47.2	253.5	244.8
Services (excl. Riser costs)	18.5	18.7	18.6	17.9	18.3	91.9	89.7
LTS	0.0	0.0	0.0	0.0	0.0	0.2	0.2
Total Net Repex	**73.4**	**70.7**	**68.0**	**68.0**	**65.6**	**345.6**	**334.7**

Table A8.13 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	1.3	1.4	1.6	1.7	1.8	**7.8**	**7.8**
Ofgem proposed allowances							
FP proposed allowances	0.9	1.0	1.1	1.2	1.3	**5.5**	**5.5**

Northern Gas Networks - Northern, Ofgem capex and repex assessment

Table A8.14 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	4.2	9.0	3.1	29.7	30.5	76.5	76.5
Connections	8.9	8.9	9.3	9.2	9.6	45.9	45.9
Mains Reinforcement	4.8	4.9	5.0	5.0	5.1	24.9	24.9
Governors	1.5	1.7	1.8	1.9	1.8	8.8	8.8
Other Operational	7.6	5.4	4.9	4.9	4.4	27.3	27.3
Non Operational	26.6	17.7	10.3	14.2	9.2	77.9	77.9
Total Net Capex	**53.6**	**47.6**	**34.5**	**65.0**	**60.5**	**261.3**	**261.3**
Ofgem Proposed Allowances							
LTS & Storage	4.1	8.8	3.1	29.0	20.8	65.9	62.9
Connections	6.1	6.3	6.4	6.7	6.8	32.3	32.0
Mains Reinforcement	3.2	3.2	3.3	3.3	3.3	16.3	14.9
Governors	1.5	1.7	1.8	1.9	1.8	8.8	8.3
Other Operational	6.9	4.6	4.0	4.0	3.4	23.1	21.6
Non Operational	22.6	14.9	10.6	14.9	9.1	72.2	70.7
Total Net Capex	**44.5**	**39.5**	**29.2**	**59.9**	**45.4**	**218.5**	**210.4**

Table A8.15 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	48.0	51.4	54.3	55.8	57.4	267.0	255.2
Services (excl. Riser costs)	23.6	24.1	24.4	25.0	25.3	122.4	122.4
LTS	6.3	27.7	1.4	0.9	0.9	37.2	37.2
Total Net Repex	**78.0**	**103.2**	**80.2**	**81.7**	**83.6**	**426.7**	**414.9**
Ofgem Proposed Allowances							
Mains	45.3	48.2	49.6	49.8	50.6	243.4	225.2
Services (excl. Riser costs)	24.4	24.3	24.3	24.3	24.3	121.8	119.2
LTS	6.2	27.1	1.4	0.9	0.9	36.5	35.5
Total Net Repex	**76.0**	**99.6**	**75.2**	**75.0**	**75.8**	**401.7**	**379.9**

Table A8.16 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	0.7	0.7	0.7	2.4	2.4	**6.7**	**6.7**
Ofgem proposed allowances							
FP proposed allowances	0.7	0.7	0.7	1.7	1.7	**5.3**	**5.3**

Scotia Gas Networks - Scotland, Ofgem capex and repex assessment

Table A8.17 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	20.9	10.3	18.4	7.7	18.5	75.7	75.7
Connections	5.6	5.5	5.4	5.3	5.3	27.1	27.1
Mains Reinforcement	7.7	7.2	6.4	5.9	7.2	34.4	34.4
Governors	3.8	3.6	3.3	3.2	3.2	17.0	17.0
Other Operational	5.4	5.5	4.3	3.9	3.6	22.7	22.7
Non Operational	16.0	7.9	7.8	3.6	9.1	44.5	44.5
Total Net Capex	**59.3**	**40.0**	**45.7**	**29.6**	**46.8**	**221.4**	**221.4**
Ofgem Proposed Allowances							
LTS & Storage	18.1	7.8	17.3	6.2	7.5	57.0	54.7
Connections	4.9	4.9	4.9	4.9	4.9	24.4	23.7
Mains Reinforcement	5.6	5.5	4.9	4.8	5.3	26.1	23.9
Governors	3.7	3.5	3.2	3.0	3.0	16.3	15.8
Other Operational	5.2	5.2	4.1	3.7	3.3	21.6	20.7
Non Operational	16.9	7.9	3.9	4.2	9.1	42.1	40.7
Total Net Capex	**54.5**	**34.9**	**38.3**	**26.7**	**33.1**	**187.5**	**179.5**

Table A8.18 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	36.0	37.8	37.3	38.0	39.7	188.7	188.7
Services (excl. Riser costs)	18.9	19.0	19.1	19.2	19.3	95.5	95.5
LTS	0.3	0.0	0.0	0.0	0.0	0.3	0.3
Total Net Repex	**55.2**	**56.7**	**56.4**	**57.2**	**59.0**	**284.5**	**284.5**
Ofgem Proposed Allowances							
Mains	32.2	33.5	32.7	32.9	33.0	164.3	161.5
Services (excl. Riser costs)	15.9	16.2	16.3	16.5	16.4	81.5	80.9
LTS	0.3	0.0	0.0	0.0	0.0	0.3	0.3
Total Net Repex	**48.5**	**49.8**	**49.0**	**49.4**	**49.5**	**246.1**	**242.7**

Table A8.19 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	0.8	1.0	1.3	1.6	1.9	**6.6**	**6.6**
Ofgem proposed allowances							
FP proposed allowances	0.5	0.7	0.9	1.1	1.3	**4.7**	**4.7**

Scotia Gas Networks - Southern, Ofgem capex and repex assessment

Table A8.20 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	64.9	75.4	9.7	5.2	6.5	161.8	161.8
Connections	8.2	8.1	8.0	7.9	7.7	39.9	39.9
Mains Reinforcement	13.8	15.6	14.7	13.9	14.5	72.6	72.6
Governors	9.2	9.9	9.8	9.9	10.1	48.9	48.9
Other Operational	6.4	5.2	5.6	3.5	4.1	24.8	24.8
Non Operational	25.5	12.8	10.4	6.1	16.7	71.6	71.6
Total Net Capex	**128.1**	**127.1**	**58.1**	**46.6**	**59.8**	**419.6**	**419.6**
Ofgem Proposed Allowances							
LTS & Storage	31.0	38.8	39.8	38.5	7.1	155.2	139.0
Connections	7.4	7.3	7.3	7.3	7.3	36.7	35.6
Mains Reinforcement	9.7	10.4	10.1	9.6	9.9	49.7	44.1
Governors	9.0	9.3	9.4	9.4	9.5	46.6	45.0
Other Operational	6.2	5.0	5.3	3.3	3.8	23.6	22.7
Non Operational	26.3	12.8	6.8	7.0	16.7	69.7	68.3
Total Net Capex	**89.5**	**83.7**	**78.7**	**75.2**	**54.4**	**381.5**	**354.6**

Table A8.21 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	91.8	97.4	106.2	109.9	115.4	520.7	520.7
Services (excl. Riser costs)	52.3	55.8	56.8	57.0	57.6	279.5	279.5
LTS	2.1	16.1	0.3	0.0	0.0	18.5	18.5
Total Net Repex	**146.2**	**169.2**	**163.3**	**166.9**	**173.0**	**818.6**	**818.6**
Ofgem Proposed Allowances							
Mains	83.4	85.6	88.0	87.7	90.0	434.7	403.5
Services (excl. Riser costs)	46.2	47.9	47.7	46.9	47.4	236.0	227.1
LTS	2.1	15.5	0.3	0.0	0.0	17.9	17.5
Total Net Repex	**131.6**	**149.0**	**136.0**	**134.6**	**137.4**	**688.6**	**648.1**

Table A8.22 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	3.9	4.8	5.7	6.6	7.6	**28.6**	**28.6**
Ofgem proposed allowances							
FP proposed allowances	2.8	3.4	4.0	4.7	5.4	**20.2**	**20.2**

Wales and West Utilities – Wales and West, Ofgem capex and repex assessment

Table A8.23 - Net capex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Capex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
LTS & Storage	18.2	59.6	33.8	16.8	16.6	145.0	138.0
Connections	8.2	8.5	8.8	9.2	9.6	44.3	44.3
Mains Reinforcement	6.8	12.0	7.4	7.7	8.0	41.8	41.8
Governors	1.4	1.4	1.4	1.4	1.5	7.2	7.2
Other Operational	7.5	7.7	6.2	5.9	4.9	32.3	32.3
Non Operational	20.9	13.1	12.5	14.1	16.3	76.9	78.0
Total Net Capex	**63.0**	**102.3**	**70.1**	**55.3**	**57.0**	**347.6**	**341.7**
Ofgem Proposed Allowances							
LTS & Storage	18.5	50.0	14.3	12.4	8.6	103.9	73.3
Connections	6.9	7.0	7.1	7.3	7.4	35.7	34.8
Mains Reinforcement	4.2	7.1	4.4	4.5	4.7	25.0	23.1
Governors	1.4	1.4	1.4	1.4	1.5	7.2	6.7
Other Operational	7.5	7.7	6.2	5.9	4.9	32.2	30.0
Non Operational	18.9	11.0	12.5	14.7	16.3	73.4	72.0
Total Net Capex	**57.4**	**84.3**	**46.0**	**46.3**	**43.4**	**277.4**	**240.0**

Table A8.24 - Net repex, (£m, 2005-06 prices) – pre IQI

GDN Normalised Net Repex	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
Mains	38.9	41.6	45.4	48.9	50.2	225.1	225.1
Services (excl. Riser costs)	24.9	25.8	26.7	27.5	28.5	133.5	133.5
LTS	3.7	14.8	9.4	8.2	7.4	43.5	40.0
Total Net Repex	**67.5**	**82.3**	**81.5**	**84.6**	**86.2**	**402.1**	**398.6**
Ofgem Proposed Allowances							
Mains	36.5	37.5	39.3	40.7	41.2	195.2	190.3
Services (excl. Riser costs)	23.3	23.2	23.2	23.0	23.0	115.7	112.8
LTS	3.6	14.4	9.0	7.8	7.0	41.7	36.6
Total Net Repex	**63.3**	**75.1**	**71.5**	**71.5**	**71.2**	**352.6**	**339.7**

Table A8.25 - Net repex riser costs, (£m, 2005-06 prices)

GDN Normalised Net Repex Riser Costs 2008-09 to 2012-13	2008-09	2009-10	2010-11	2011-12	2012-13	Total	Updated Proposals
GDN normalised UP Riser costs	0.9	1.0	1.0	1.0	1.1	**5.0**	**5.0**
Ofgem proposed allowances							
FP proposed allowances	0.7	0.7	0.7	0.7	0.8	**3.6**	**3.6**

Appendix 9 – Treatment of historical expenditure

National Grid Gas - East of England, treatment of historical expenditure

Table A9.1 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
NGG EoE	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	197.4	197.4
Total Actual	353.4	337.6
Overspend	156.0	140.2
% overspend against allowances	79%	71%
Allocation of overspend		
Related party margins	4.3	2.7
DN sales costs	0.0	0.0
Under recovery of connections income	7.5	3.3
Inefficient above allowance (Pot 1)	4.1	3.7
Efficient overspend (Pot 2b)	114.5	104.8
Reopener (Pot 3b)	25.7	25.7
Total overspend	156.0	140.2
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.9	1.8
Efficient allowed spend (Pot 3a)	195.5	195.6
Total allowance	**197.4**	**197.4**

Table A9.2 - RAV roll forward, (£m, 2005-06 prices)[6]

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	2,115.8					
Additions to pre-2002 assets	18.3					
Revised opening value bf	2,134.1	2,139.9	2,135.6	2,130.8	2,152.0	2,167.0
Depreciation	-74.9	-75.3	-75.6	-75.8	-76.6	-77.3
Net capex additions	83.5	71.4	71.1	97.3	92.7	92.7
Disposals	-2.7	-0.4	-0.2	-0.3	-1.0	0.0
Closing value	2,139.9	2,135.6	2,130.8	2,152.0	2,167.0	2,182.4

[6] 2007-08 capex additions in this and subsequent RAV roll forward tables are based on the forecast allowances as set out in our one year control final proposals. If GDNs' actual capex is different from this forecast, the 2007-08 closing RAV (and thus the 2008-09 opening RAV) will be affected.

National Grid Gas - London, treatment of historical expenditure

Table A9.3 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
NGG London	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	105.2	105.2
Total Actual	185.3	195.8
Overspend	80.1	90.6
% overspend against allowances	76%	86%
Allocation of overspend		
Related party margins	1.6	1.2
DN sales costs	0.0	0.0
Under recovery of connections income	1.9	1.0
Inefficient above allowance (Pot 1)	2.6	2.4
Efficient overspend (Pot 2b)	72.6	84.7
Reopener (Pot 3b)	1.4	1.2
Total overspend	80.1	90.6
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.8	0.8
Efficient allowed spend (Pot 3a)	104.4	104.4
Total allowance	**105.2**	**105.2**

Table A9.4 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,161.5					
Additions to pre-2002 assets	10.0					
Revised opening value bf	1,171.5	1,179.2	1,181.2	1,184.6	1,193.9	1,217.6
Depreciation	-41.1	-41.5	-41.7	-42.0	-42.3	-43.1
Net capex additions	50.3	46.5	45.6	54.7	65.8	66.5
Disposals	-1.4	-3.1	-0.5	-3.5	0.3	0.0
Closing value	1,179.2	1,181.2	1,184.6	1,193.9	1,217.6	1,241.1

National Grid Gas - North West, treatment of historical expenditure

Table A9.5 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
NGG North West	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	129.4	129.4
Total Actual	236.0	240.5
Overspend	106.6	111.1
% overspend against allowances	82%	86%
Allocation of overspend		
Related party margins	2.3	1.4
DN sales costs	0.0	0.0
Under recovery of connections income	4.1	1.6
Inefficient above allowance (Pot 1)	6.8	6.6
Efficient overspend (Pot 2b)	92.3	100.3
Reopener (Pot 3b)	1.2	1.3
Total overspend	106.6	111.1
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.0	0.0
Efficient allowed spend (Pot 3a)	129.3	129.4
Total allowance	**129.4**	**129.4**

Table A9.6 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,290.1					
Additions to pre-2002 assets	11.1					
Revised opening value bf	1,301.3	1,332.2	1,330.1	1,331.1	1,355.1	1,390.7
Depreciation	-45.7	-46.5	-46.7	-47.0	-47.7	-48.7
Net capex additions	78.2	44.2	47.9	71.3	84.5	68.3
Disposals	-1.6	0.2	-0.1	-0.3	-1.3	0.0
Closing value	1,332.2	1,330.1	1,331.1	1,355.1	1,390.7	1,410.2

National Grid Gas - West Midlands, treatment of historical expenditure

Table A9.7 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
NGG West Midlands	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	120.7	120.7
Total Actual	170.7	174.0
Overspend	50.0	53.3
% overspend against allowances	41%	44%
Allocation of overspend		
Related party margins	1.7	1.1
DN sales costs	0.0	0.0
Under recovery of connections income	3.3	1.5
Inefficient above allowance (Pot 1)	1.8	1.7
Efficient overspend (Pot 2b)	32.9	38.6
Reopener (Pot 3b)	10.4	10.4
Total overspend	50.0	53.3
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.9	0.9
Efficient allowed spend (Pot 3a)	119.8	119.8
Total allowance	**120.7**	**120.7**

Table A9.8 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,024.6					
Additions to pre-2002 assets	8.8					
Revised opening value bf	1,033.5	1,047.7	1,058.9	1,058.4	1,068.8	1,082.3
Depreciation	-36.3	-36.7	-37.2	-37.3	-37.7	-38.2
Net capex additions	54.5	46.2	36.3	48.0	52.7	45.6
Disposals	-4.0	1.7	0.4	-0.3	-1.4	0.0
Closing value	1,047.7	1,058.9	1,058.4	1,068.8	1,082.3	1,089.7

Northern Gas Networks - Northern, treatment of historical expenditure

Table A9.9 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
Northern	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	182.0	182.0
Total Actual	245.2	242.0
Overspend	63.3	60.1
% overspend against allowances	35%	33%
Allocation of overspend		
Related party margins	1.8	1.8
DN sales costs	3.6	3.6
Under recovery of connections income	3.2	1.2
Inefficient above allowance (Pot 1)	3.3	2.1
Efficient overspend (Pot 2b)	44.5	45.7
Reopener (Pot 3b)	6.8	5.7
Total overspend	63.3	60.1
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.4	1.4
Efficient allowed spend (Pot 3a)	180.5	180.5
Total allowance	**182.0**	**182.0**

Table A9.10 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,216.2					
Additions to pre-2002 assets	10.5					
Revised opening value bf	1,226.7	1,255.4	1,269.7	1,276.7	1,290.5	1,313.9
Depreciation	-43.0	-43.9	-44.4	-44.8	-45.3	-46.1
Net capex additions	72.4	58.3	51.6	58.5	68.7	72.3
Disposals	-0.5	-0.2	-0.2	0.0	0.0	0.0
Closing value	1,255.4	1,269.7	1,276.7	1,290.5	1,313.9	1,340.1

Scotia Gas Networks - Scotland, treatment of historical expenditure

Table A9.11 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
Scotland	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	145.7	145.7
Total Actual	263.5	255.1
Overspend	117.8	109.4
% overspend against allowances	81%	75%
Allocation of overspend		
Related party margins	3.7	2.7
DN sales costs	0.0	0.0
Under recovery of connections income	4.7	2.1
Inefficient above allowance (Pot 1)	4.1	2.2
Efficient overspend (Pot 2b)	101.2	97.9
Reopener (Pot 3b)	4.1	4.6
Total overspend	117.8	109.4
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	0.9	0.8
Efficient allowed spend (Pot 3a)	144.8	144.8
Total allowance	145.7	145.7

Table A9.12 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	759.4					
Additions to pre-2002 assets	6.6					
Revised opening value bf	766.0	789.9	802.7	835.2	884.2	915.1
Depreciation	-26.9	-27.5	-27.9	-28.8	-30.1	-30.9
Net capex additions	50.3	39.0	60.0	77.9	60.9	89.0
Disposals	0.5	1.3	0.4	0.0	0.0	0.0
Closing value	789.9	802.7	835.2	884.2	915.1	973.2

Scotia Gas Networks - Southern, treatment of historical expenditure

Table A9.13 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
Southern	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	260.8	260.8
Total Actual	392.1	405.8
Overspend	131.3	145.0
% overspend against allowances	50%	56%
Allocation of overspend		
Related party margins	3.4	2.4
DN sales costs	0.0	0.0
Under recovery of connections income	2.8	1.4
Inefficient above allowance (Pot 1)	8.5	4.3
Efficient overspend (Pot 2b)	108.5	129.7
Reopener (Pot 3b)	8.1	7.2
Total overspend	131.3	145.0
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	1.6	1.7
Efficient allowed spend (Pot 3a)	259.2	259.1
Total allowance	**260.8**	**260.8**

Table A9.14 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	2,029.1					
Additions to pre-2002 assets	17.5					
Revised opening value bf	2,046.6	2,068.3	2,087.3	2,097.3	2,110.0	2,169.3
Depreciation	-71.8	-72.6	-73.4	-73.9	-74.6	-76.3
Net capex additions	95.6	91.2	82.6	86.6	133.9	151.5
Disposals	-2.2	0.4	0.8	0.0	0.0	0.0
Closing value	2,068.3	2,087.3	2,097.3	2,110.0	2,169.3	2,244.5

Wales and West Utilities - Wales and West, treatment of historical expenditure

Table A9.15 - Treatment of historical overspend, (£m, 2005-06 prices)

£m 2005-06 prices	Final proposals 1 yr control	Final proposals main control
WWU	**2002-03 to 2006-07**	**2002-03 to 2006-07**
Comparison of actual and allowed spend		
Total Allowed Capex and Non-Mains Repex	170.6	170.6
Total Actual	329.7	326.6
Overspend	159.1	156.0
% overspend against allowances	93%	91%
Allocation of overspend		
Related party margins	3.0	3.0
DN sales costs	14.1	14.1
Under recovery of connections income	3.7	1.7
Inefficient above allowance (Pot 1)	4.9	2.8
Efficient overspend (Pot 2b)	104.9	105.4
Reopener (Pot 3b)	28.6	29.1
Total overspend	159.1	156.0
Allocation of allowed spend		
Inefficient spend within the allowance (Pot 2a)	3.8	3.8
Efficient allowed spend (Pot 3a)	166.8	166.8
Total allowance	**170.6**	**170.6**

Table A9.16 - RAV roll forward, (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Regulatory Asset Value (RAV)						
Opening value bf	1,038.0					
Additions to pre-2002 assets	9.0					
Revised opening value bf	1,047.0	1,096.4	1,130.2	1,144.1	1,178.1	1,209.8
Depreciation	-36.7	-38.0	-38.9	-39.5	-40.4	-41.4
Net capex additions	85.6	70.5	52.6	73.5	72.1	66.5
Disposals	0.5	1.3	0.2	0.0	0.0	0.0
Closing value	1,096.4	1,130.2	1,144.1	1,178.1	1,209.8	1,235.0

Appendix 10 – Final impact assessment on the loss of meterwork revenue adjustment

Objectives

1.1. The aim of this impact assessment is to consider the merits of introducing a revenue driver to offset the increased costs of running the emergency service, which is a consequence of the potential loss of metering work currently being carried out by emergency staff between emergency calls.

1.2. The primary aim of the impact assessment is to further Ofgem's principal objective to protect the interests of consumers. In addition, the impact assessment considers Ofgems's statutory general duty to secure that the licence holders can finance their activities.

Background

Current position

1.3. In chapter 6 of the main document we set out the rationale for the loss of meter work revenue adjustment. GDNs are obliged to provide emergency services to customers. As a consequence of having sufficient staff to respond to an emergency within 1 hour staff may be unused at any point in time. GDNs minimise the costs of providing emergency service staff by finding additional work (supplementary work activity), predominately metering related work, for them to carry out in their unused time which they can leave at short notice in order to attend an emergency.

1.4. GDNs have argued that there is little other supplementary work activity available and have forecast that they will lose approximately 90 per cent of their meter work by 2012-13 as metering competition develops, and higher service levels are demanded, which require a dedicated workforce. They estimate that this will add £35 million per annum or 39 per cent to emergency costs by 2012-13. Some GDNs also argue that there will be an increase in indirect costs attributed to the regulated business.

1.5. Some GDNs have already lost significant amounts of meter work between 2005-06 and 2006-07 but without an impact on costs. All GDNs have forecast that they can sustain an initial loss of metering workload without an impact on costs for example by releasing contract labour used for metering work only. One GDN has indicated that it has already reached the stage where it will start to incur additional costs if it loses any more meterwork.

1.6. There are a number of options available to address the costs to emergency services from the loss of metering. This final impact assessment sets out a cost

benefit analysis of the options, and a qualitative analysis of the advantages and disadvantages of each of the options.

Options

1.7. The options we have considered are:

- option 1 - do nothing. We would set a baseline allowance for the provision of emergency services assuming that insufficient metering work is lost to significantly impact the costs of providing the emergency service.
- option 2 - an ex ante adjustment to baseline allowances. We would set baseline allowances taking account of the GDNs' forecast loss of metering.
- option 3 - an ex ante adjustment to baseline allowances with ex post revenue adjustment. We would set baseline allowances taking account of the GDNs' forecast loss of metering. If the amount of metering work lost is actually greater or less than forecast customers are exposed to 75 per cent of the savings/ costs associated with the difference in workload and GDNs are exposed to 25 per cent of the savings/costs based on an ex ante assessment of the incremental costs of loss of metering. This option was proposed by NGG. We consider that if this option were to be used, then it would be appropriate to use a tipping point as in option 4 below, otherwise the GDNs would make a windfall gain from small losses of meterwork.
- option 4 - an ex post adjustment to the baseline allowance through a revenue driver. We would set the baseline allowance assuming that there are no meter work losses with a revenue driver adjustment based on an ex ante determined unit cost associated with meter work losses. The revenue driver would only apply when the GDN incurs significant incremental costs, at the tipping point. This is our preferred option and table 6.4 in the main document sets out our proposed parameters for this option.

1.8. This impact assessment considers the potential impact of each option.

Competition Assessment

1.9. Currently, the GDNs' position with respect to other metering companies is that, within each price control period, they are strongly incentivised to win meterwork. For the portion of metering which is delivered as supplementary work activity by the GDNs' emergency service staff, the marginal labour cost of the metering work is effectively zero. This has also been beneficial to consumers, as the allocation of the GDN emergency staff to the metering business has reduced the cost attributable to the regulated business, and therefore reduced gas distribution charges.

1.10. Once the price control is in place, the current arrangements place GDNs in a different competitive position over other bidders for meterwork contracts, as they

will be required to meet the emergency staff's costs regardless of whether they win the meterwork contracts. Nevertheless, as can be seen by recent evidence, the GDNs are unlikely to bid to win meterwork contracts at a loss. Instead they would seek to recoup the costs of the emergency service through the price control, in accordance with Ofgem's duty to ensure that they can finance their activities.

1.11. In the case of either Option 3 or Option 4, there will be a change to the allowance to reflect a loss of metering jobs. Within Option 3 or Option 4, the unit cost is intended to approximately reflect the marginal cost of the metering job, as measured by the amount of the emergency service costs recharged to metering, allocated over the metering jobs.

1.12. Option 4 may slightly increase competition from other metering companies, as the GDNs will be incentivised to win meterwork only where the revenue exceeds the allocated direct cost of the staff performing the meterwork. Option 1 or Option 2 retain the current situation, where the GDNs may have, in the short-term (between price control settlements) little incremental cost from performing meterwork, since the staff performing the meterwork are also required to meet the emergency service standards of performance. However, the medium-term incentive is still to price based on the average cost, as demonstrated by the loss of meterwork. Therefore, based on the market evidence, there is likely to be little or no impact on metering competition.

1.13. Under option 3, if the GDNs retain meterwork, they retain 25 per cent of the benefit, but 75 per cent of the benefit is offset by a reduction in the allowance for the increased costs of providing the emergency service. Therefore, the competition impact will be similar to option 4, as 75 per cent of the estimated marginal cost is offset by the higher revenue allowance, but slightly closer to options 1 and 2, as 25 per cent is retained by the GDN.

Impacts, costs and benefits

Environment

1.14. None of the options are likely to have an impact on the environment.

Security of supply

1.15. None of the options are likely to have an impact on security of supply.

Health and safety issues

1.16. None of the options are likely to have health and safety issues.

Distributional effects

1.17. Incentive revenues are recovered from GDN charges. The distribution effect of any of the options would have the same effect as any increase or reduction in GDN charges.

Small businesses

1.18. None of the GDNs are small businesses, and small businesses will not be affected disproportionately as proposals would impact all customers' bills equally.

Risks and unintended consequences

1.19. The main risk of the incentive is that the GDNs are either encouraged to lose meterwork, with a potential increase in costs to consumers, or that GDNs make windfall gains, by reducing the costs of providing the emergency service through other supplementary work activity.

1.20. The GDNs have forecast that they will suffer higher increases in costs than we have allowed. This is due to higher costs than indicated by our benchmarking analysis, or through rises in indirect costs, which we have not allowed within the unit cost. If the actual costs are closer to the GDNs' forecasts, they would make windfall losses.

1.21. If any GDNs make either windfall gains or windfall losses, these would be only for the period of the next price control, as the allowance would be corrected in the following control under RPI-X. Within the 2008-13 period, these would result in an increase or a decrease in the return on capital.

Costs and benefits

1.22. Under options 1 and 2 there would be a set cost to consumers, related to the forecast cost of providing the emergency service. The cost under option 2 would be higher than under option 1.

1.23. Under option 1, the GDNs may argue that the allowance would simply not reflect their likely costs of providing the emergency service, which is critical to the safety case, the GDNs may choose to refer a price control based on option 1 to the Competition Commission.

1.24. Under option 2, any GDN which is able to retain meterwork or find substantial alternative supplementary work activity is likely to make substantial windfall gains, as all consumers will suffer an increase in costs as if the GDNs had lost the meterwork contracts.

1.25. Under options 3 and 4 we would set a unit cost per metering jobs lost related to the increase in stranded costs of providing the emergency service. There would be a "tipping point" prior to which the loss of meterwork would not result in an increase

in costs to consumers (because our analysis suggests that there will not be a material increase in GDNs' stranded costs).

1.26. In both option 3 and option 4, the costs to consumers reflect our current best view of providing an emergency service, if the GDNs lose the meterwork performed by the emergency service personnel. We have no evidence as to whether our forecasts will be correct. If our forecasts are wrong, then, under both options 3 and 4, 100 per cent of the gain or loss will be retained by the GDN, as in either case the ex post allowance is based on a current estimate of the incremental cost per job lost.

1.27. In option 3, there is an additional benefit to the GDNs of 25 per cent of any gains if they retain meterwork above their forecasts. This will increase their allowance by comparison with option 4. However, the cost to consumers will still be lower than if the GDNs lose meterwork as forecast, as the higher meterwork activity will result in a lower cost of providing the emergency service.

Example

1.28. The following example is based on a simplified analysis of the numbers used in table 6.5 in the main document.

Current meterwork jobs – 2,000,000
Forecast loss of meterwork – 90 per cent
Loss of meterwork without incremental cost of providing emergency service – 40 per cent of current jobs
Tipping point – 60 per cent of current jobs
Forecast increased cost of providing emergency service per job post tipping point - £25.

1.29. Table A10.1 shows the impact on the GDNs of various sensitivities.

Table A10.1 - Impact on GDNs of sensitivity analysis

	Option 1	Option 2	Option 3	Option 4
Ex ante allowance (£m)	0.0	25.0	25.0	0.0
Forecast ex post adjustment (£m)	0.0	0.0	0.0	25.0
Forecast allowance (£m)	**0.0**	**25.0**	**25.0**	**25.0**
Forecast GDN gain/(loss) (£m)	*(25.0)*	*0.0*	*0.0*	*0.0*
Sensitivity 1: actual loss 30% (below tipping point				
Actual ex post adjustment	0.0	0.0	(22.5)	0.0
Actual allowance	**0.0**	**25.0**	**2.5**	**0.0**
GDN gain/(loss)	*0.0*	*25.0*	*2.5*	*0.0*
Sensitivity 2: actual loss 60%				
Actual ex post adjustment	0.0	0.0	(11.3)	10.0
Actual allowance	**0.0**	**25.0**	**13.8**	**10.0**
Forecast GDN gain/(loss)	*(10.0)*	*15.0*	*3.8*	*0.0*
Sensitivity 3: actual loss 100%				
Actual ex post adjustment	0.0	0.0	3.8	30.0
Actual allowance	**0.0**	**25.0**	**28.8**	**30.0**
Forecast GDN gain/(loss)	*(30.0)*	*(5.0)*	*(1.3)*	*0.0*
Sensitivity 4: actual loss 90%, actual unit cost 12.				
Actual ex post adjustment	0.0	0.0	0.0	25.0
Actual allowance	**0.0**	**25.0**	**25.0**	**25.0**
Actual GDN gain/(loss)	*(12.5)*	*12.5*	*12.5*	*12.5*
Sensitivity 5: actual loss 90%, actual unit cost 37.				
Actual ex post adjustment	0.0	0.0	0.0	25.0
Actual allowance	**0.0**	**25.0**	**25.0**	**25.0**
Actual GDN gain/(loss)	*(37.5)*	*(12.5)*	*(12.5)*	*(12.5)*

1.30. Table A10.1 indicates that Option 1 is only appropriate if we consider that it is unlikely that GDNs will lose a large proportion of meterwork. In all other cases, the GDNs make windfall losses. We consider that the evidence is that there is a material risk that the GDNs may lose a large proportion of meterwork.

1.31. Option 2 is appropriate if we think that the forecast is a likely case. However, the incentives to retain meterwork are very strong, whereas the risks if more than forecast meterwork is lost than forecast are relatively low. We do not consider that we are in a position to forecast the loss of meterwork to this level of accuracy.

1.32. Option 3 and 4 reduce the risk of a windfall gain or loss due to inaccurate forecasting of the extent of the loss of meterwork. Option 3 has the benefit of higher costs for the GDN if they lose more meterwork than forecast and therefore incentivising them to retain meterwork. Option 4 has the benefit that there is no windfall gain for the GDNs if it transpires that they have over-forecast the extent of the loss of meterwork and that the loss of meterwork is relatively small.

1.33. All of options 2, 3 and 4 expose customers to the risk that the stranded cost of running the emergency service subsequent to a substantial loss of meterwork is

lower than Ofgem and the GDNs have forecast, and expose the GDNs to the risk that it is higher than Ofgem have forecast.

Simplicity

1.34. Options 1 and 2 are the simplest options to implement. Options 3 and 4 are more complex as we would need to calculate the incremental cost per infill job lost for each GDN. In addition we will need to monitor the performance against the revenue driver, to ensure that the GDNs are able to report the level of metering jobs in a form consistent with the allowance per job. This is more complex for option 3, where we need to be able to ringfence the net costs of providing the emergency service separately, including monitoring the allocation of costs to metering or any other supplementary work activity.

1.35. Table A10.2 summarises the costs and benefits of each option as discussed above.

Table A10.2 - Loss of meter work revenue adjustment

	Minimises risk of windfall gains and losses	Provides incentive to retain meterwork	Provides incentive to find supplementary work activity	Minimises need to monitor GDNs' performance
Option 1: no change	××	✓✓	n/a	✓✓
Option 2 – ex ante allowance	××	✓✓	✓	✓✓
Option 3 – ex ante allowance with sharing factor	×	✓	✓	××
Option 4 – ex post allowance with no sharing factor	✓	-	✓	×

1.36. Both options 3 and 4 have similar benefits. However, given the difficulty of forecasting the impact of the loss of meterwork, we conclude that the risk of windfall gains in option 3 is a greater risk to consumers than the risk that there is no incentive to retain meterwork in option 4.

1.37. While under option 4 there is no direct incentive to retain meterwork, if the GDNs lose all the meterwork then they are exposed to the risk that their costs are

higher than our assumption. In addition they are incentivised to find supplementary work activity to reduce unit costs over time.

Conclusion

1.38. Our view is that Option 4, i.e. a loss of meter work revenue driver, is appropriate and chapter 6 of the consultation document provides details of our conclusion and the proposed parameters for the revenue driver.

Appendix 11 – Final impact assessment on environmental emissions

Objectives

1.1. The objective of this impact assessment is to consider the merits of introducing an environmental emissions incentive to further incentivise the reduction in environmentally harmful emissions from the gas distribution networks.

Background

1.2. Section 4AB of the Gas Act 1986 places a duty on the Authority to have regard to guidance[7] published by the Secretary of State relating to social and environmental matters. This guidance includes the aim of reducing greenhouse gas emissions and suggests that the Authority considers environmental impact beyond climate change, citing air quality as an example.

1.3. Natural gas emissions contribute to global warming and have an adverse impact on air quality.

1.4. Shrinkage gas is gas lost from the distribution system due to leakage, theft and gas used for operational purposes. It is currently around 0.65 per cent of annual distribution network throughput, of which some 95 per cent relates to leakage.

1.5. Shrinkage gas costs constitute a portion of the revenue allowance under the one year price control. The shrinkage portion of the allowance is based on an ex ante target shrinkage volume with the reference cost of gas based on the prevailing market price. This protects GDNs from price risk due to changes in the wholesale price of gas but, at the same time, provides an incentive for GDNs to reduce costs by decreasing shrinkage volumes (including leakage) and purchasing gas efficiently. We propose to retain the current shrinkage incentive for the future price control but recognise that its strength is related to the economic cost of shrinkage and does not explicitly take account of the environmental impact of gas leakage. We propose introducing a further incentive to reduce gas leakage from the GDNs by exposing them to the social costs of the emissions to better take into account the environmental impact.

1.6. The proposed leakage incentive will set an ex ante baseline for gas leakage for each LDZ within a GDN for the five year price control period. The baseline will reflect the amount of greenhouse gas leakage that would be expected if this incentive was not introduced.

[7] Social and Environmental Guidance to the Gas and Electricity Markets Authority 24th February 2004

1.7. If the GDNs are able to reduce shrinkage below the baseline they will earn additional revenue that is broadly equivalent to the shadow price of the reduction in environmental emissions. Conversely, if an LDZ's emissions are above the baseline, the revenue allowance for that GDN will be reduced by the shadow price of the environmental emissions above the baseline. This will provide an additional economic incentive for the GDNs to reduce greenhouse gas emissions and will provide additional revenue to facilitate additional investment in reducing environmental emissions.

1.8. We propose to introduce cap and collar arrangements to prevent the unintended consequences of excess revenue adjustments should the outcome of the new incentive differ substantially from our expectations.

1.9. This impact assessment evaluates the costs and benefits associated with introducing the incentive, including ancillary impacts, where possible in a quantitative manner.

Key issues

1.10. Leakage of natural gas from distribution networks contributes to global warming and to air pollution. We need to consider whether it is appropriate for Ofgem to introduce a new incentive exposing the companies to the environmental costs of emissions.

1.11. The gas distribution companies are currently exposed to procurement costs of gas emitted from their networks but not to the full environmental costs of emissions. A key issue for this incentive is determining the appropriate level of environmental costs used in setting the strength of the incentive.

1.12. Different baselines will have a significant influence on the financial outcome for the companies and a key issue will be setting baselines at an appropriate level to avoid the companies being exposed to windfall gains or losses.

1.13. Gas emissions cannot be measured directly and we estimate leakage from an engineering computer model. The robustness of the leakage model and input data to the model are important issues to be considered.

1.14. The proposed incentive raises the issue of periodicity, particularly where capex is considered. Assuming that baselines are reset at the next price control then capex spent at the start of this price control period to reduce emissions will provide the GDNs with significantly higher allowed revenue than if spent at the end of the period. We do not propose to introduce a rolling incentive allowing the companies to benefit from five years of revenue allowances from the environmental incentive irrespective of when the investment is made because of the complexity, interaction with other incentives and the difficultly in establishing an appropriate mechanism.

1.15. Reducing environmental emissions will not be achieved without incurring costs. We anticipate that increased revenue allowances will result in price increases which will affect all customers proportionately. We anticipate that introducing this incentive will increase average distribution charges by between 0.04 per cent and 0.08 per cent in the current price control. However, the resulting improvement in leakage rates will enable us to include lower allowances for shrinkage in subsequent price controls, thus ultimately saving consumers money.

Options

Strength of incentive

1.16. Defra recently published interim guidance on valuing greenhouse gas emissions[8]. This guidance introduces a Shadow Price of Carbon (SPC), which is stated in equivalent tonnes of CO2 emissions as £25.40 in 2007 terms, increasing in real terms by 2 per cent per annum.

1.17. In 2005-06 prices, this equates to an average of £93 per tonne of carbon over the price control period, which is approximately £416 per tonne of natural gas leakage, 87 pence per therm or £29,653 per GWh. According to data published by the Joint Office, leakage from the distribution networks during the gas year 2006 totalled 3978 GWh. Applying the SPC to total leakage results in a social cost for greenhouse gas emissions from the GDNs in 2006-07 of £118 million.

1.18. On 17 July 2007, Defra published the Government's air quality strategy[9], which includes references to the social cost of certain pollutants, including ozone, which is formed from methane in the atmosphere. When compared to the shadow price of greenhouse gas emissions, the cost of air pollution from gas leakage is relatively small.

1.19. We recognise that natural gas emissions also affect air quality. Air pollution is estimated to reduce the life expectancy of every person in the UK by an average of 7-8 months; with estimated annual health costs of up to £20 billion. Air pollution also seriously damages our ecosystems. Such factors reinforce the introduction of a leakage incentive but do not justify a stronger incentive than that based on global warming potential.

Baseline volume & financial exposure

1.20. The GDNs will be exposed to an increase or decrease in allowed revenue based on the difference between reported actual leakage and the incentive baselines.

1.21. Varying the level of the incentive's baseline will not change the incentive on the company to reduce emissions. The level of reduction will be determined by the companies' response to the strength of the incentive and the actual costs of reducing

[8]http://www.defra.gov.uk/environment/climatechange/research/carboncost/index.htm
9 http://www.defra.gov.uk/environment/airquality/strategy/index.htm

emissions. Different baselines will have a significant influence on the financial outcome for the companies and a key issue will be setting baselines at an appropriate level to avoid the companies being exposed to windfall gains or losses.

1.22. The GDNs' submissions suggest that leakage will be further reduced by around 1.5 per cent due to the introduction of this incentive with capital expenditure of around £30 million. We would anticipate some out-performance in the GDNs' estimates and consider that reductions in the range of 2 per cent to 4 per cent achievable.

1.23. Assuming the companies are able to reduce emissions by 2 per cent to 4 per cent below the target baseline, the increase in allowed revenue will be £2.4 million to £4.8 million per annum, which is equal to the social cost of the emissions eliminated measured using the SPC.

1.24. We propose to set baselines for each network consistent with our forecast level of leakage in the absence of this incentive. Some GDNs forecast increasing leakage over the price control period even though old metallic pipes are being replaced with PE and average system pressures were not forecast to rise. Following discussion, the GDNs submitted supplementary information on forecast leakage. We have based our forecasts a combination of historic leakage trends and the GDNs' forecasts of future trensds.

Gas Composition

1.25. The composition of natural gas varies considerably depending on its source, for example, gas from LNG terminals tends to have lower levels of methane than gas from some UKCS gas fields. A different mix of gas will result in a different level of CO2 emissions. The GDNs have no effective influence on the composition of natural gas in their networks. If we set the incentive based on actual tonnes of each gas component emitted this would expose the GDNs to significant windfall gains or losses as the composition of the gas supplied from the NTS varies.

1.26. Ignoring the effect of variations in composition would not change the behaviour of the GDNs in reducing leakage although they would be responding to an incentive based on reducing natural gas leakage rather than the amounts of individual gases contained in natural gas. This would in theory introduce inaccuracies in the link between the reduction in shadow price of emissions and the incentive. However, it should be noted that the calculation of the shadow price is subject to significant uncertainty.

1.27. Assuming a constant gas composition considerably simplifies reporting and monitoring, while providing virtually identical incentive properties.

1.28. We propose assuming a constant gas composition and setting the incentive on natural gas leakage as a proxy for greenhouse gas leakage.

Competition assessment

1.29. None of the options we are considering are likely to have any impact on competition in the wholesale or retail supply markets.

Impacts, costs and benefits

Environment

1.30. We anticipate that introducing the incentive will lead to a reduction in gas emissions with commensurate environmental improvements. Reduced natural gas leakage will reduce greenhouse gas emissions and lead to air quality improvements.

1.31. We anticipate that environmental benefits will be greater as the strength of the incentive is increased. While the level of baselines selected will have a significant impact on allowed revenue, we do not believe that different baselines will materially change the response of the companies to the incentive as the efficient marginal response remains unchanged.

Security of supply

1.32. We anticipate no material impact on security of supply.

Health and safety issues

1.33. The existing mains replacement incentive policy contributed to reducing shrinkage volumes as it results in the replacement of older metallic pipes with new polyethylene pipes which have lower rates of leakage.

1.34. The introduction of an environmental emissions incentive will increase the focus of the GDNs' management on leakage reduction and is expected to increase the amount of money that will be spent on reducing leakage. This in turn should lead to an increased rate of leakage reduction. The new incentive will provide additional focus on pipes that are not subject to the mains replacement incentive and we expect some of these to be replaced earlier than would have been the case in the absence of this incentive.

1.35. We anticipate that the average pressure of gas in the networks will be lower as a result of this incentive than the average pressure without the incentive, particularly in areas of predominantly metallic pipe, which will in turn reduce leakage quantities. Lower pressures could, arguably, appear to result in reduced asset utilisation and capital efficiency. We anticipate that pressure reduction will largely stem from improved pressure control in existing networks, where there is no efficiency loss, but we are aware that there may be some marginal changes to network design leading to replacement pipes being larger than would otherwise be the case. The overall incentive package faced by the companies will align their rewards with the most efficient means of reducing leakage.

1.36. Further reducing the quantity of gas leakage is expected to improve safety by reducing the risk of explosions and alleviate health concerns that indirectly result from leakage through the pollutants emitted.

Distributional effects

1.37. Distributional effects between different consumer groups should not arise as a result of implementing the proposed incentive.

Small businesses

1.38. Small businesses are not expected to be affected differently from customers in general.

Risks and unintended consequences

1.39. The most significant risk relates to setting appropriate leakage baselines. Should baselines be set too high the companies will receive windfall gains and conversely if set too low the companies will be subject to windfall losses.

1.40. In initial proposals, we raised concerns about the operation of the leakage model and the robustness of input data into the model. We have since discussed the operation of the leakage model with the GDNs and are satisfied, although the model's uncertainty range is around +/-20 per cent, that the model is satisfactory for the purposes of setting a leakage incentive. We propose to introduce governance arrangements to mitigate unintended consequences due to operation of the leakage model and are considering process audits to help to ensure the robustness of the input data.

Costs and benefits

1.41. The total shadow cost of greenhouse gas emissions from the gas distribution networks is currently estimated to be £118 million per annum. The emissions also contribute to air pollution.

1.42. As discussed above, we expect allowed revenue and hence distribution charges to increase by between £2.4 to 4.8 million as the GDNs are expected to increase expenditure on leakage reduction and thus outperform the leakage baseline. This revenue allowance, used to fund the costs of leakage reduction, will ultimately be paid for by consumers.

1.43. The suggested range of increased revenue allowances would result in an average increase in distribution transportation maximum allowed revenue of 0.04 per cent to 0.08 per cent.

1.44. We anticipate that the incentive will incrementally reduce natural gas emissions by between 2 per cent to 4 per cent, which is equivalent to a reduction in the shadow price of emissions of between £2.4 to £4.8 million, reducing both greenhouse gas emissions and air pollution.

1.45. The reduction of gas leaking from the networks is also expected to reduce the amount of gas the companies need to purchase under the existing shrinkage arrangements, partially offsetting the cost of the environmental incentive. Assuming a gas cost of 50 pence per therm results in a reduction in shrinkage costs of between £1.4 million and £2.7 million per annum. Under the proposed arrangements these savings accrue to the GDNs until the next price control review. We consider this to be appropriate and do not propose to modify the strength of the environmental incentive to take into account the savings in shrinkage gas purchase costs.

1.46. If the GDNs efficiently invest incremental capex to reduce leakage during the 2008 to 2013 period, this would be subject to the proposed capex incentives and is expected to marginally increase allowed revenue during the price control period commencing in 2013. However, this would be offset by further reductions in environmentally harmful emissions and reduced procurement costs for shrinkage gas. We have analysed the benefits of reduced emissions together with savings in procurement costs of shrinkage gas and the analysis indicates that any investment that provides a positive NPV to the GDNs under the proposed environmental and IQI incentive schemes also provides positive benefits to consumers.

Conclusion

1.47. Quantitative analysis shows that customers may pay additional costs during the next price control that would reflect the social benefits of reduction in carbon emissions during the next price control. We propose to introduce cap and collar arrangements to prevent unintended risks due to unforeseen circumstances. There may be some increase in allowed revenue for the following period, due to incremental capex expenditure, but this will be offset by continuing reductions in environmental emissions and anticipated savings in the allowed revenue for procurement of shrinkage gas in subsequent price controls. Analysis of prices in the future period is highly sensitive to assumptions but based on our projections all efficient investment made by the GDNs will provide positive benefits to consumers.

1.48. Qualitatively, we consider that the introduction of this incentive will bring proportionate environmental benefits and that these benefits outweigh the relatively minor potential increase in transportation charges.

1.49. The design of the incentive internalises the shadow cost of carbon to the GDNs. This is expected to influence management decisions and provide a more appropriate framework for the companies to judge investment decisions that have environmental impacts.

1.50. In the longer term, customers are expected to benefit from reductions in the quantity of shrinkage gas procured as leakage is reduced prior to setting shrinkage allowance for the price control starting in 2013.

1.51. We anticipate that transportation bills will increase as the GDNs are expected to increase expenditure on leakage reduction and thus outperform the leakage

baseline. This incremental revenue allowance, used to fund the costs of leakage reduction, will ultimately be paid for by consumers.

1.52. We propose that the strength of the incentive should be set in line with the governments published shadow price of carbon and that it should be set ex ante for the duration of the price control.

1.53. We propose introducing revised governance arrangements to ensure robust operation of the leakage model.

Appendix 12 – Final impact assessment on the innovation funding incentive

Objectives

1.1. The objective of this impact assessment (IA) is to consider the merits associated with a number of options for encouraging GDNs to carry out research, development and demonstration (RD&D). The primary objective of introducing an incentive is to secure benefits for consumers.

Background

1.2. In updated proposals[10], we consulted on our proposal to introduce an Innovation Funding Incentive (IFI) similar to the one introduced as part of the electricity distribution price control review (DPCR) in October 2004 to address concerns that Distribution Network Operator (DNO) expenditure on research, development and demonstration (RD&D) had declined to the extent that opportunities for opex and capex efficiency gains were being lost. We proposed to link the focus of the IFI to sustainable development objectives, and thus termed it IFI/SD.

1.3. The updated proposals included a thorough, detailed initial impact assessment[11] on the following two options:

- option 1 - Continuation of the status quo (do nothing approach) resulting in a traditional R&D component forming part of the GDNs' opex allowances; and
- option 2 - Implementation of an IFI incentive mechanism on a similar basis to electricity distribution but more focused towards sustainable development issues.

1.4. The impact assessment concluded that option 2 (IFI/SD) has the potential to deliver benefits to consumers over the price control period and into the longer term, and that the cost to consumers of the IFI is modest in the overall context of the price control.

1.5. As set out in chapter 7 of these final proposals, the responses to our IFI/SD proposal were positive and did not introduce any new considerations that were not already accounted for in the proposal. There was no significant challenge to the substance or policy direction of our initial assessment. We have decided to continue with IFI/SD as proposed, and given the thoroughness of the initial impact assessment, we conclude that there is no need for further analysis or policy development in this regard and that it can also stand as the final impact assessment.

[10] GDPCR updated proposals, 226/07, September 2007
[11] GDPCR updated proposals, 226/07a, September 2007, Appendix 12

Appendix 13 – Mains and services cost matrices

National Grid Gas - East of England

Table A13.1 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	33,046	465.3	15.4	36,566	459.7	16.8
services transferred	33,046	286.4	9.5	36,566	282.1	10.3
non domestic services	36	1,576.3	0.1	38	1,544.7	0.1
Total	**66,128**		**24.9**	**73,169**		**27.2**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	36,422	460.8	16.8	34,848	461.1	16.1
services transferred	36,422	282.9	10.3	34,848	283.4	9.9
non domestic services	36	1,558.9	0.1	39	1,549.7	0.1
Total	**72,881**		**27.1**	**69,735**		**26.0**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	35,283	461.7	16.3			
services transferred	35,283	283.7	10.0			
non domestic services	41	1,563.8	0.1			
Total	**70,607**		**26.4**			

Table A13.2 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	35	62.3	2.2	38	62.0	2.3
4-5"	382	68.1	26.0	407	67.7	27.5
6-7"	98	95.8	9.3	139	95.3	13.2
8-9"	50	177.1	8.9	42	176.2	7.4
10-12"	40	247.5	10.0	43	246.2	10.7
>12-18"	12	358.8	4.2	13	357.1	4.8
>18-24"	7	501.5	3.4	8	499.1	4.2
>24"	1	618.9	0.4	2	615.9	1.0
Total	**625**		**64.4**	**692**		**71.2**
	2010-11			**2011-12**		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	29	62.0	1.8	29	61.4	1.8
4-5"	409	67.6	27.7	369	67.1	24.7
6-7"	130	95.2	12.3	119	94.4	11.3
8-9"	53	176.1	9.3	59	174.6	10.3
10-12"	49	246.0	12.0	54	243.9	13.1
>12-18"	11	356.7	4.1	23	353.7	8.1
>18-24"	8	498.5	3.8	13	494.4	6.3
>24"	2	615.2	1.4	4	610.1	2.1
Total	**691**		**72.3**	**669**		**77.8**

	2012-13		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	28	61.5	1.7
4-5"	391	67.2	26.3
6-7"	116	94.5	10.9
8-9"	50	174.8	8.7
10-12"	52	244.2	12.6
>12-18"	28	354.1	10.0
>18-24"	14	494.9	7.2
>24"	3	610.8	1.6
Total	**681**		**78.9**

National Grid Gas - London

Table A13.3 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	21,474	566.5	12.2	18,372	577.9	10.6
services transferred	15,745	338.6	5.3	13,511	345.7	4.7
non domestic services	165	1,990.3	0.3	69	2,030.5	0.1
Total	**37,384**		**17.8**	**31,952**		**15.4**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	19,265	577.3	11.1	21,002	578.1	12.1
services transferred	14,185	345.3	4.9	15,494	345.7	5.4
non domestic services	144	2,028.0	0.3	231	2,027.3	0.5
Total	**33,593**		**16.3**	**36,727**		**18.0**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	20,311	583.8	11.9			
services transferred	14,971	349.1	5.2			
non domestic services	156	2,050.9	0.3			
Total	**35,438**		**17.4**			

Table A13.4 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	22	76.5	1.7	20	77.6	1.6
4-5"	159	83.5	13.2	150	84.7	12.7
6-7"	70	117.5	8.2	48	119.1	5.7
8-9"	33	217.3	7.2	25	220.4	5.5
10-12"	39	303.6	11.7	37	307.9	11.3
>12-18"	29	440.2	12.8	25	446.5	11.1
>18-24"	12	615.3	7.5	10	624.1	6.5
>24"	17	759.3	12.9	15	770.1	11.5
Total	**380**		**75.2**	**330**		**65.9**
	2010-11			**2011-12**		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	21	78.6	1.6	20	76.3	1.5
4-5"	146	85.8	12.5	155	83.3	12.9
6-7"	67	120.7	8.1	87	117.2	10.2
8-9"	29	223.3	6.5	30	216.7	6.5
10-12"	30	311.9	9.3	30	302.8	9.0
>12-18"	25	452.3	11.5	25	439.1	10.9
>18-24"	12	632.2	7.3	15	613.7	9.4
>24"	15	780.2	11.4	10	757.3	7.4
Total	**344**		**68.2**	**373**		**68.0**
	2012-13					
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)			
</=3"	21	76.9	1.6			
4-5"	148	84.0	12.4			
6-7"	75	118.2	8.8			
8-9"	34	218.6	7.4			
10-12"	33	305.4	10.1			
>12-18"	22	442.9	9.9			
>18-24"	12	619.0	7.5			
>24"	8	763.9	6.4			
Total	**354**		**64.1**			

National Grid Gas - North West

Table A13.5 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	33,034	449.3	14.8	32,602	451.3	14.7
services transferred	21,904	271.0	5.9	21,614	272.2	5.9
non domestic services	59	1,571.6	0.1	59	1,571.6	0.1
Total	**54,997**		**20.9**	**54,276**		**20.7**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	32,064	453.8	14.5	32,154	454.9	14.6
services transferred	21,256	273.8	5.8	21,315	274.5	5.9
non domestic services	59	1,571.6	0.1	59	1,588.9	0.1
Total	**53,379**		**20.5**	**53,528**		**20.6**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	30,445	460.0	14.0			
services transferred	20,100	277.9	5.6			
non domestic services	59	1,606.1	0.1			
Total	**50,603**		**19.7**			

Table A13.6 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	99	62.1	6.1	98	62.4	6.1
4-5"	248	67.8	16.8	243	68.1	16.6
6-7"	110	95.4	10.5	109	95.8	10.5
8-9"	41	176.5	7.2	40	177.3	7.0
10-12"	35	246.6	8.7	35	247.7	8.7
>12-18"	31	357.6	10.9	32	359.2	11.4
>18-24"	15	499.9	7.3	14	502.0	7.1
>24"	5	616.9	2.8	4	619.5	2.5
Total	**582**		**70.4**	**575**		**69.9**
	2010-11			**2011-12**		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	90	62.0	5.6	84	62.0	5.2
4-5"	236	67.7	15.9	234	67.7	15.8
6-7"	109	95.2	10.4	108	95.2	10.3
8-9"	54	176.1	9.5	49	176.2	8.6
10-12"	30	246.0	7.3	47	246.1	11.6
>12-18"	28	356.7	9.9	27	356.9	9.7
>18-24"	14	498.6	6.8	11	498.9	5.6
>24"	6	615.3	3.5	5	615.6	2.8
Total	**565**		**68.9**	**564**		**69.6**
	2012-13					
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)			
</=3"	73	62.2	4.5			
4-5"	239	67.9	16.2			
6-7"	91	95.5	8.7			
8-9"	46	176.7	8.1			
10-12"	42	246.9	10.3			
>12-18"	33	358.0	11.7			
>18-24"	9	500.4	4.4			
>24"	3	617.5	1.7			
Total	**535**		**65.7**			

National Grid Gas - West Midlands

Table A13.7 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

Services Replacement	Number of services replaced	unit cost (£/service)	Matrix costs (£m)	Number of services replaced	unit cost (£/service)	Matrix costs (£m)
Services relaid	21,056	473.6	10.0	21,250	477.2	10.1
services transferred	20,745	290.1	6.0	20,945	292.3	6.1
non domestic services	115	1,603.7	0.2	115	1,612.6	0.2
Total	**41,916**		**16.2**	**42,310**		**16.4**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	20,857	481.5	10.0	19,832	484.2	9.6
services transferred	20,569	295.0	6.1	19,544	297.1	5.8
non domestic services	115	1,630.3	0.2	115	1,630.3	0.2
Total	**41,540**		**16.3**	**39,491**		**15.6**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	20,255	487.8	9.9			
services transferred	19,967	299.2	6.0			
non domestic services	115	1,648.0	0.2			
Total	**40,336**		**16.0**			

Table A13.8 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	42	62.8	2.6	26	63.5	1.7
4-5"	170	68.5	11.6	180	69.3	12.5
6-7"	76	96.4	7.4	80	97.6	7.8
8-9"	45	178.4	8.1	44	180.5	7.9
10-12"	35	249.2	8.7	44	252.1	11.1
>12-18"	26	361.4	9.3	23	365.6	8.3
>18-24"	14	505.1	7.2	5	511.0	2.6
>24"	2	623.4	1.2	2	630.6	1.1
Total	**410**		**56.1**	**404**		**53.1**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	18	64.0	1.1	19	64.2	1.2
4-5"	195	69.8	13.6	163	70.1	11.4
6-7"	71	98.3	7.0	88	98.7	8.7
8-9"	47	181.8	8.5	38	182.5	6.9
10-12"	35	253.9	8.8	38	255.0	9.6
>12-18"	19	368.3	7.1	22	369.7	8.0
>18-24"	6	514.7	3.2	7	516.8	3.6
>24"	2	635.2	1.0	3	637.7	1.7
Total	**392**		**50.4**	**377**		**51.1**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	25	65.1	1.7
4-5"	177	71.1	12.6
6-7"	77	100.0	7.7
8-9"	46	185.0	8.6
10-12"	29	258.5	7.4
>12-18"	19	374.8	7.2
>18-24"	4	523.9	2.0
>24"	2	646.5	1.1
Total	**379**		**48.2**

Northern Gas Networks - Northern

Table A13.9 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	27,198	474.0	12.9	27,187	473.7	12.9
services transferred	16,565	288.8	4.8	16,558	288.7	4.8
non domestic services	379	1,618.1	0.6	379	1,615.4	0.6
Total	**44,142**		**18.3**	**44,124**		**18.3**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	27,188	474.5	12.9	27,193	475.9	12.9
services transferred	16,559	289.2	4.8	16,562	290.1	4.8
non domestic services	379	1,618.1	0.6	379	1,623.5	0.6
Total	**44,126**		**18.3**	**44,134**		**18.4**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	27,190	477.0	13.0			
services transferred	16,561	290.8	4.8			
non domestic services	379	1,626.2	0.6			
Total	**44,130**		**18.4**			

Table A13.10 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	89	59.8	5.3	77	60.3	4.7
4-5"	390	65.3	25.4	368	65.8	24.2
6-7"	52	91.9	4.8	72	92.6	6.7
8-9"	15	170.0	2.6	24	171.2	4.1
10-12"	12	237.5	2.7	16	239.2	3.9
>12-18"	15	344.4	5.2	15	346.9	5.2
>18-24"	1	481.3	0.4	1	484.8	0.4
>24"	0	594.0	0.0	0	598.3	0.0
Total	**574**		**46.5**	**573**		**49.1**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	73	60.6	4.4	67	60.7	4.1
4-5"	349	66.1	23.1	345	66.3	22.9
6-7"	95	93.1	8.8	105	93.3	9.8
8-9"	20	172.1	3.5	19	172.6	3.3
10-12"	21	240.5	5.0	21	241.2	5.0
>12-18"	15	348.7	5.3	15	349.7	5.3
>18-24"	1	487.4	0.4	1	488.8	0.4
>24"	0	601.5	0.0	0	603.2	0.0
Total	**574**		**50.5**	**574**		**50.8**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	63	60.7	3.8
4-5"	332	66.3	22.0
6-7"	119	93.2	11.1
8-9"	20	172.5	3.5
10-12"	23	241.0	5.6
>12-18"	15	349.5	5.3
>18-24"	1	488.4	0.4
>24"	0	602.8	0.0
Total	**573**		**51.7**

Scotia Gas Networks - Scotland

Table A13.11 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	15,715	493.5	7.8	16,074	496.0	8.0
services transferred	15,715	301.1	4.7	16,074	302.7	4.9
non domestic services	339	1,680.9	0.6	337	1,687.8	0.6
Total	**31,769**		**13.1**	**32,485**		**13.4**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	16,229	496.7	8.1	16,382	501.6	8.2
services transferred	16,229	303.2	4.9	16,382	306.1	5.0
non domestic services	335	1,691.6	0.6	333	1,704.9	0.6
Total	**32,793**		**13.5**	**33,096**		**13.8**

	2012-13		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	16,558	495.7	8.2
services transferred	16,558	302.4	5.0
non domestic services	331	1,687.1	0.6
Total	**33,447**		**13.8**

Table A13.12 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	75	62.5	4.7	55	62.4	3.4
4-5"	136	68.2	9.3	137	68.1	9.3
6-7"	46	96.0	4.4	64	95.8	6.1
8-9"	26	177.6	4.6	28	177.2	5.0
10-12"	19	248.1	4.7	20	247.6	5.1
>12-18"	6	359.8	2.2	6	359.1	2.2
>18-24"	6	502.8	3.0	6	501.8	3.1
>24"	1	620.5	0.6	1	619.3	0.5
Total	**315**		**33.4**	**318**		**34.7**
	2010-11			**2011-12**		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	45	62.5	2.8	44	63.1	2.7
4-5"	156	68.3	10.6	152	68.9	10.4
6-7"	61	96.1	5.9	67	96.9	6.5
8-9"	22	177.7	3.9	23	179.3	4.1
10-12"	19	248.2	4.8	17	250.5	4.3
>12-18"	6	360.0	2.2	6	363.2	2.1
>18-24"	6	503.1	3.1	6	507.6	3.0
>24"	1	620.9	0.5	1	626.4	0.8
Total	**317**		**33.8**	**316**		**34.1**

	2012-13		
Diameter of mains abandoned	Length of mains abandoned (Km)	Unit cost (£/metre)	Matrix costs (£m)
</=3"	36	61.8	2.2
4-5"	146	67.5	9.9
6-7"	74	95.0	7.1
8-9"	26	175.6	4.6
10-12"	20	245.4	4.8
>12-18"	6	355.8	2.2
>18-24"	6	497.3	3.0
>24"	1	613.8	0.4
Total	**315**		**34.2**

Scotia Gas Networks - Southern

Table A13.13 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	45,287	543.0	24.6	48,092	539.8	26.0
services transferred	25,438	331.3	8.4	27,628	329.4	9.1
non domestic services	748	1,849.0	1.4	799	1,838.6	1.5
Total	**71,473**		**34.4**	**76,519**		**36.5**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	47,515	542.7	25.8	46,609	541.2	25.2
services transferred	27,882	331.1	9.2	27,912	330.1	9.2
non domestic services	814	1,848.0	1.5	809	1,844.1	1.5
Total	**76,211**		**36.5**	**75,331**		**35.9**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	46,354	550.2	25.5			
services transferred	28,307	335.6	9.5			
non domestic services	806	1,872.8	1.5			
Total	**75,467**		**36.5**			

Table A13.14 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	44	66.4	2.9	26	66.4	1.7
4-5"	409	72.5	29.7	492	72.5	35.7
6-7"	131	102.0	13.4	135	102.0	13.8
8-9"	56	188.8	10.5	43	188.6	8.1
10-12"	45	263.7	11.9	37	263.5	9.8
>12-18"	16	382.4	6.1	16	382.1	6.2
>18-24"	16	534.5	8.5	16	534.1	8.6
>24"	5	659.6	3.4	7	659.1	4.8
Total	**723**		**86.4**	**773**		**88.6**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	29	66.4	2.0	31	66.0	2.1
4-5"	468	72.5	34.0	454	72.0	32.7
6-7"	145	102.0	14.8	143	101.3	14.5
8-9"	47	188.7	8.8	52	187.5	9.7
10-12"	45	263.7	11.8	47	261.9	12.2
>12-18"	17	382.4	6.5	18	379.8	6.9
>18-24"	17	534.4	9.1	18	530.9	9.6
>24"	6	659.5	4.2	5	655.1	3.2
Total	**775**		**91.1**	**768**		**90.9**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	28	66.0	1.9
4-5"	421	72.0	30.3
6-7"	166	101.4	16.8
8-9"	65	187.5	12.1
10-12"	47	261.9	12.3
>12-18"	18	379.8	6.8
>18-24"	18	530.9	9.5
>24"	5	655.2	3.5
Total	**767**		**93.2**

Wales & West Utilities - Wales & West

Table A13.15 - Services replacement matrix for 2008-09 to 2012-13 (2005-06 prices)

	2008-09			2009-10		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	25,105	490.4	12.3	25,047	491.1	12.3
services transferred	23,243	299.4	7.0	23,187	299.8	7.0
non domestic services	349	1,669.5	0.6	349	1,672.5	0.6
Total	**48,697**		**19.9**	**48,583**		**19.8**
	2010-11			**2011-12**		
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**
Services relaid	25,047	491.2	12.3	24,854	491.7	12.2
services transferred	23,076	299.9	6.9	22,971	300.2	6.9
non domestic services	349	1,672.5	0.6	349	1,672.5	0.6
Total	**48,472**		**19.8**	**48,174**		**19.7**
	2012-13					
Services Replacement	**Number of services replaced**	**unit cost (£/service)**	**Matrix costs (£m)**			
Services relaid	24,794	493.1	12.2			
services transferred	22,921	301.0	6.9			
non domestic services	349	1,678.4	0.6			
Total	**48,064**		**19.7**			

Table A13.16 - Mains replacement matrix for 2008-09 to 2012-13 (excluding rechargeable diversions) (2005-06 prices)

	2008-09			2009-10		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	49	59.3	2.9	45	59.5	2.7
4-5"	237	64.7	15.3	233	65.0	15.1
6-7"	75	91.0	6.8	76	91.4	7.0
8-9"	36	168.4	6.0	41	169.1	6.9
10-12"	13	235.3	3.1	14	236.2	3.4
>12-18"	10	341.2	3.5	11	342.6	3.7
>18-24"	0	476.9	0.0	0	478.8	0.0
>24"	0	588.5	0.0	0	590.8	0.0
Total	**420**		**37.7**	**420**		**38.8**
	2010-11			**2011-12**		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	43	59.3	2.6	43	59.1	2.5
4-5"	217	64.7	14.0	202	64.6	13.0
6-7"	79	91.1	7.2	84	90.9	7.6
8-9"	50	168.4	8.4	56	168.1	9.4
10-12"	19	235.3	4.6	23	234.8	5.5
>12-18"	11	341.2	3.9	12	340.5	4.1
>18-24"	0	476.9	0.0	0	475.9	0.0
>24"	0	588.6	0.0	0	587.3	0.0
Total	**420**		**40.7**	**420**		**42.2**

	2012-13		
Diameter of mains abandoned	**Length of mains abandoned (Km)**	**Unit cost (£/metre)**	**Matrix costs (£m)**
</=3"	41.82	58.4	2.4
4-5"	193.95	63.8	12.4
6-7"	86.17	89.8	7.7
8-9"	60.50	166.1	10.0
10-12"	25.35	232.0	5.9
>12-18"	12.40	336.4	4.2
>18-24"	0.00	470.2	0.0
>24"	0.00	580.3	0.0
Total	**420.19**		**42.7**

Appendix 14 – Calculating allowed revenue

Allowances

1.1. We have calculated our final proposals for the five year control using an Excel spreadsheet (the financial model). The version of the model used to set final proposals is very similar to the version used at initial and updated proposals. We have had the final proposals version audited by an external firm (PKF) to ensure its arithmetic accuracy and that its calculations of allowed revenues are consistent with our financial, regulatory and economic assumptions. The model, along with explanatory documentation and PKF's audit opinion, will be published shortly after this document.

Calculating allowed revenue

1.2. Tables A14.1 to A14.8 demonstrates the calculation of the price control allowances and projected RAV roll forward for 2008-13 for each of the eight GDNs. The calculation of the movement in the RAV is shown on lines 1 to 7. The opening value of the RAV (line 1) is equal to the closing value of the RAV for 2007-08 as set out in appendix 9. If GDNs' actual capex is different from this forecast, the 2007-08 closing RAV (and thus the 2008-09 opening RAV) will be different from the value shown in these tables.

1.3. The different elements of capital expenditure (lines 2-3) are as follows:

- new capital expenditure (line 2); and
- 50 per cent of new replacement expenditure (line 3).

1.4. These elements are added to the opening RAV, and the allowed level of depreciation (line 4) is subtracted from it to give a closing asset value (line 5). The closing value in any year then becomes the next year's opening value.

1.5. The present value of the closing RAV in each year is shown in line 6. The present value movement in the RAV is then derived by subtracting the present value of the closing RAV from the opening RAV (line 7). Present value calculations involve discounting values by the vanilla WACC of 4.94 per cent.

1.6. The allowed levels of costs and associated items are shown in lines 8 to 18. Operating costs include:

- operating expenditure including ongoing pensions costs but excluding shrinkage, which has been considered separately (line 8);

- shrinkage allowances which for our final proposals are based on the modelling assumption for the gas price underlying our one year control shrinkage figures, multiplied by updated volume forecasts (line 9);
- funding of pensions deficits (line 10); and
- 50 per cent of new replacement expenditure (line 11).

1.7. Our proposed allowances for corporation tax are set out on line 12. The cash allowance for capital expenditure in each year is the sum of lines 13 and 14, being the return on the RAV plus the depreciation allowance. This is equal to the sum of lines 2, 3 and 7.

1.8. Line 15 shows the additional income earned or penalty incurred by the company under the information quality incentive. Line 16 represents the portion of the capital expenditure allowance which is disallowed under the rolling incentive from 2002-07, where the companies do not receive allowances for five years. Finally, line 17 is the allowance for under-recoveries from the 2002-07 control (Pot 3 capital expenditure and pensions) and under-recovery of tax from the 2007-08 control. Line 18 is the sum of lines 8-17.

1.9. The total price control revenue is shown in lines 19-22. Line 19 is equal to line 18, and lines 20 and 21 are estimated non-controllable costs, being the NTS pension charge, rates and the licence fee. Line 22 is the sum of lines 19 to 21, and is the total price control revenue allowance. Line 23 is the equivalent for the 2007-08 control, and line 24 shows the percentage change in total allowed costs.

1.10. The total allowed revenue figures shown in line 22 are presented as far as possible on a like-for-like basis: they show the impact of our price control decisions on the amount that GDNs can recover from their customers. For certain GDNs, there will be a further impact on core allowed revenue as a result of proposed changes in the charging arrangements for independent systems, as set out in chapter 8. These changes mean that total revenue recovered by the affected GDNs from their gas distribution customers will be less than the figures in line 22. The additional costs to serve independent systems will now be recovered through gas transmission charges, as excluded service revenue, rather than through gas distribution charges, as core allowed revenue. The overall revenue that each GDN can recover, and the total charges paid by gas customers across the country, are unaffected by the change.

1.11. For the GDNs affected (Northern, Scotland and Wales & West, lines 25 and 26 set out the impact of removing independent systems from their core allowed revenue.

Table A14.1 - National Grid Gas - East of England price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	2,182.4	2,188.3	2,192.4	2,202.5	2,218.2	2,196.7
2	Total capital expenditure	36.6	30.7	36.6	40.6	46.2	38.1
3	Replacement expenditure added to RAV	47.4	52.0	52.6	54.8	55.6	52.5
4	Depreciation	-78.0	-78.6	-79.1	-79.7	-80.5	-79.2
5	Closing asset value	2,188.3	2,192.4	2,202.5	2,218.2	2,239.5	2,208.2
6	Present value of closing RAV (at vanilla WACC of 4.94%)	2,085.3	2,089.2	2,098.9	2,113.8	2,134.1	2,104.3
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	99.4	101.5	95.8	90.9	86.1	94.7
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	104.1	102.2	101.7	100.0	98.9	101.4
9	Shrinkage allowance	12.1	12.0	12.0	11.9	11.9	12.0
10	Pension deficit funding	1.0	1.0	1.0	1.0	0.9	1.0
11	Expensed repex allowance	47.4	52.0	52.6	54.8	55.6	52.5
12	Tax allowance	8.1	8.6	10.0	10.5	12.0	9.8
13	Return on RAV	105.3	105.6	105.9	106.5	107.4	106.2
14	Depreciation	78.0	78.6	79.1	79.7	80.5	79.2
15	IQI incentive allowance	2.0	2.1	2.2	2.4	2.3	2.2
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-6.2	-5.1	-3.7	-1.4	0.0	-3.3
17	Under-recoveries from 2002-07 control	6.1	6.1	6.1	6.1	6.1	6.1
18	Total of allowed costs	357.9	362.9	366.9	371.5	375.6	367.0
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	357.9	362.9	366.9	371.5	375.6	367.0
20	NTS charge for pensions	4.4	4.3	4.2	4.1	4.0	4.2
21	Non-controllable costs	59.3	59.3	59.3	59.3	59.3	59.3
22	Price control revenue	421.7	426.6	430.4	434.9	439.0	430.5
23	Price Control Revenue for 2007-08	427.2					
24	Change as %age	-1.3%	1.2%	0.9%	1.0%	0.9%	0.3%

Table A14.2 - National Grid Gas - London price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,241.1	1,309.3	1,362.9	1,389.7	1,422.1	1,345.0
2	Total capital expenditure	61.2	53.9	26.7	32.2	40.6	42.9
3	Replacement expenditure added to RAV	50.8	45.2	47.1	48.2	46.1	47.5
4	Depreciation	-43.8	-45.6	-47.0	-47.9	-49.0	-46.7
5	Closing asset value	1,309.3	1,362.9	1,389.7	1,422.1	1,459.8	1,388.8
6	Present value of closing RAV (at vanilla WACC of 4.94%)	1,247.7	1,298.8	1,324.3	1,355.2	1,391.1	1,323.4
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	-6.8	10.8	39.5	35.3	31.8	22.1
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	79.3	76.1	76.1	75.0	74.0	76.1
9	Shrinkage allowance	6.9	6.9	6.8	6.8	6.7	6.8
10	Pension deficit funding	0.6	0.6	0.6	0.6	0.5	0.6
11	Expensed repex allowance	50.8	45.2	47.1	48.2	46.1	47.5
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	61.4	64.4	66.3	67.8	69.4	65.9
14	Depreciation	43.8	45.6	47.0	47.9	49.0	46.7
15	IQI incentive allowance	1.9	1.7	1.8	1.9	1.7	1.8
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-5.3	-4.5	-3.3	-1.5	0.0	-2.9
17	Under-recoveries from 2002-07 control	4.1	4.2	4.2	4.2	4.2	4.2
18	Total of allowed costs	243.6	240.1	246.6	250.7	251.6	246.5
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	243.6	240.1	246.6	250.7	251.6	246.5
20	NTS charge for pensions	2.6	2.5	2.5	2.4	2.3	2.5
21	Non-controllable costs	33.1	33.1	33.1	33.1	33.1	33.1
22	Price control revenue	279.2	275.7	282.1	286.2	287.0	282.1
23	Price Control Revenue for 2007-08	245.1					
24	Change as %age	13.9%	-1.3%	2.3%	1.4%	0.3%	4.9%

Table A14.3 - National Grid Gas - North West price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,410.2	1,435.8	1,459.1	1,485.9	1,513.0	1,460.8
2	Total capital expenditure	26.6	25.5	30.5	31.2	29.2	28.6
3	Replacement expenditure added to RAV	48.4	48.1	47.5	47.9	45.6	47.5
4	Depreciation	-49.4	-50.3	-51.1	-52.0	-53.0	-51.2
5	Closing asset value	1,435.8	1,459.1	1,485.9	1,513.0	1,534.9	1,485.7
6	Present value of closing RAV (at vanilla WACC of 4.94%)	1,368.2	1,390.4	1,416.0	1,441.8	1,462.7	1,415.8
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	43.1	46.5	44.1	45.2	51.6	46.1
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	83.9	83.4	83.2	82.5	80.6	82.7
9	Shrinkage allowance	9.0	8.7	8.5	8.4	8.3	8.6
10	Pension deficit funding	0.7	0.7	0.7	0.7	0.6	0.7
11	Expensed repex allowance	48.4	48.1	47.5	47.9	45.6	47.5
12	Tax allowance	0.0	0.0	0.0	0.0	2.9	0.6
13	Return on RAV	68.6	69.8	71.0	72.3	73.4	71.0
14	Depreciation	49.4	50.3	51.1	52.0	53.0	51.2
15	IQI incentive allowance	1.9	1.9	1.9	2.0	1.9	1.9
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-4.8	-4.5	-3.6	-1.6	0.0	-2.9
17	Under-recoveries from 2002-07 control	3.2	3.2	3.2	3.2	3.2	3.2
18	Total of allowed costs	260.3	261.5	263.4	267.3	269.6	264.4
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	260.3	261.5	263.4	267.3	269.6	264.4
20	NTS charge for pensions	3.0	3.0	2.9	2.8	2.8	2.9
21	Non-controllable costs	31.7	31.7	31.7	31.7	31.7	31.7
22	Price control revenue	295.0	296.1	298.0	301.8	304.0	299.0
23	Price Control Revenue for 2007-08	285.5					
24	Change as %age	3.3%	0.4%	0.6%	1.3%	0.7%	1.6%

Table A14.4 - National Grid Gas - West Midlands price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,089.7	1,108.1	1,120.2	1,132.9	1,148.8	1,119.9
2	Total capital expenditure	19.2	14.7	17.2	20.9	18.6	18.1
3	Replacement expenditure added to RAV	37.8	36.5	35.2	35.3	34.0	35.8
4	Depreciation	-38.6	-39.2	-39.7	-40.2	-40.8	-39.7
5	Closing asset value	1,108.1	1,120.2	1,132.9	1,148.8	1,160.7	1,134.1
6	Present value of closing RAV (at vanilla WACC of 4.94%)	1,056.0	1,067.5	1,079.6	1,094.7	1,106.1	1,080.8
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	34.5	41.6	41.6	39.1	43.8	40.1
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	62.2	70.6	61.4	59.9	59.0	62.6
9	Shrinkage allowance	7.3	7.1	6.9	6.8	6.8	7.0
10	Pension deficit funding	0.5	0.5	0.5	0.5	0.5	0.5
11	Expensed repex allowance	37.8	36.5	35.2	35.3	34.0	35.8
12	Tax allowance	0.0	0.0	1.8	2.7	4.1	1.7
13	Return on RAV	53.0	53.7	54.3	55.0	55.7	54.3
14	Depreciation	38.6	39.2	39.7	40.2	40.8	39.7
15	IQI incentive allowance	1.5	1.4	1.4	1.4	1.4	1.4
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-3.2	-2.4	-1.7	-0.7	0.0	-1.6
17	Under-recoveries from 2002-07 control	3.4	3.4	3.4	3.4	3.4	3.4
18	Total of allowed costs	201.2	210.0	202.7	204.6	205.7	204.8
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	201.2	210.0	202.7	204.6	205.7	204.8
20	NTS charge for pensions	2.2	2.1	2.1	2.0	2.0	2.1
21	Non-controllable costs	24.7	24.7	24.7	24.7	24.7	24.7
22	Price control revenue	228.1	236.9	229.6	231.4	232.4	231.7
23	Price Control Revenue for 2007-08	217.8					
24	Change as %age	4.7%	3.9%	-3.1%	0.8%	0.4%	2.1%

Table A14.5 - Northern Gas Networks - Northern price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,340.1	1,377.8	1,421.2	1,440.5	1,490.2	1,413.9
2	Total capital expenditure	45.4	40.2	29.8	60.6	45.9	44.4
3	Replacement expenditure added to RAV	39.2	51.2	38.8	39.2	39.6	41.6
4	Depreciation	-46.9	-48.0	-49.3	-50.0	-51.5	-49.1
5	Closing asset value	1,377.8	1,421.2	1,440.5	1,490.2	1,524.2	1,450.8
6	Present value of closing RAV (at vanilla WACC of 4.94%)	1,312.9	1,354.3	1,372.7	1,420.1	1,452.5	1,382.5
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	27.9	24.0	49.6	20.9	38.6	32.2
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	79.1	79.2	79.2	79.3	78.3	79.0
9	Shrinkage allowance	9.3	9.2	9.1	8.9	8.8	9.1
10	Pension deficit funding	3.4	3.4	3.4	3.4	3.4	3.4
11	Expensed repex allowance	39.2	51.2	38.8	39.2	39.6	41.6
12	Tax allowance	1.3	0.0	0.5	3.5	4.1	1.9
13	Return on RAV	65.5	67.4	69.0	70.6	72.6	69.0
14	Depreciation	46.9	48.0	49.3	50.0	51.5	49.1
15	IQI incentive allowance	1.8	2.0	1.5	1.6	1.5	1.7
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-2.9	-2.3	-1.8	-0.8	0.0	-1.6
17	Under-recoveries from 2002-07 control	3.4	3.5	3.5	3.5	3.5	3.5
18	Total of allowed costs	246.9	261.6	252.4	259.1	263.3	256.7
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	246.9	261.6	252.4	259.1	263.3	256.7
20	NTS charge for pensions	2.8	2.8	2.7	2.6	2.6	2.7
21	Non-controllable costs	30.9	30.9	30.9	30.9	30.9	30.9
22	Price control revenue	280.6	295.3	286.0	292.6	296.7	290.3
23	Price Control Revenue for 2007-08	273.5					
24	Change as %age	2.6%	5.2%	-3.2%	2.3%	1.4%	2.0%
25	Impact of alternative charging arrangements for independent systems	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0
26	Price control revenue after adjusting for independent systems	280.6	295.3	286.0	292.6	296.7	290.2

Table A14.6 - Scotia Gas Networks - Scotland price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	973.2	1,022.0	1,050.2	1,080.5	1,098.5	1,044.9
2	Total capital expenditure	55.8	35.9	39.0	27.4	34.0	38.4
3	Replacement expenditure added to RAV	25.4	26.2	25.8	26.2	26.3	26.0
4	Depreciation	-32.4	-33.8	-34.6	-35.6	-36.3	-34.6
5	Closing asset value	1,022.0	1,050.2	1,080.5	1,098.5	1,122.4	1,074.7
6	Present value of closing RAV (at vanilla WACC of 4.94%)	973.9	1,000.8	1,029.6	1,046.8	1,069.6	1,024.1
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	-0.7	21.6	21.1	34.5	29.5	21.2
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	66.6	65.1	65.8	65.1	64.0	65.3
9	Shrinkage allowance	5.0	4.9	4.7	4.6	4.5	4.7
10	Pension deficit funding	3.8	3.7	3.6	3.5	3.4	3.6
11	Expensed repex allowance	25.4	26.2	25.8	26.2	26.3	26.0
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	48.1	49.9	51.3	52.5	53.5	51.1
14	Depreciation	32.4	33.8	34.6	35.6	36.3	34.6
15	IQI incentive allowance	0.7	0.6	0.6	0.6	0.6	0.6
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-6.7	-6.2	-3.9	-1.4	0.0	-3.6
17	Under-recoveries from 2002-07 control	1.9	1.8	1.8	1.8	1.8	1.8
18	Total of allowed costs	177.1	179.7	184.4	188.4	190.5	184.0
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	177.1	179.7	184.4	188.4	190.5	184.0
20	NTS charge for pensions	2.0	1.9	1.9	1.8	1.8	1.9
21	Non-controllable costs	15.6	15.6	15.6	15.6	15.6	15.6
22	Price control revenue	194.6	197.2	201.8	205.8	207.9	201.5
23	Price Control Revenue for 2007-08	194.3					
24	Change as %age	0.2%	1.3%	2.4%	2.0%	1.0%	1.2%
25	Impact of alternative charging arrangements for independent systems	-6.0	-5.4	-5.4	-5.4	-5.4	-5.5
26	Price control revenue after adjusting for independent systems	188.6	191.8	196.4	200.4	202.5	195.9

Table A14.7 - Scotia Gas Networks - Southern price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	2,244.5	2,327.4	2,410.9	2,480.4	2,543.9	2,401.4
2	Total capital expenditure	91.6	85.3	80.1	76.5	56.1	77.9
3	Replacement expenditure added to RAV	69.6	78.9	72.4	72.1	73.8	73.4
4	Depreciation	-78.3	-80.6	-83.0	-85.1	-87.1	-82.9
5	Closing asset value	2,327.4	2,410.9	2,480.4	2,543.9	2,586.7	2,469.9
6	Present value of closing RAV (at vanilla WACC of 4.94%)	2,217.9	2,297.5	2,363.7	2,424.2	2,465.0	2,353.7
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	27.3	30.6	48.3	57.6	80.8	48.9
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	121.3	118.5	117.7	116.4	114.8	117.7
9	Shrinkage allowance	13.4	13.1	12.7	12.4	12.0	12.7
10	Pension deficit funding	8.8	8.5	8.3	8.1	7.9	8.3
11	Expensed repex allowance	69.6	78.9	72.4	72.1	73.8	73.4
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	110.2	114.2	117.9	121.1	123.6	117.4
14	Depreciation	78.3	80.6	83.0	85.1	87.1	82.9
15	IQI incentive allowance	1.5	1.6	1.4	1.4	1.5	1.5
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-6.8	-5.6	-4.8	-2.6	0.0	-4.0
17	Under-recoveries from 2002-07 control	2.4	2.5	2.5	2.5	2.5	2.5
18	Total of allowed costs	398.7	412.2	411.2	416.5	423.4	412.4
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	398.7	412.2	411.2	416.5	423.4	412.4
20	NTS charge for pensions	4.5	4.4	4.3	4.2	4.1	4.3
21	Non-controllable costs	51.4	51.4	51.4	51.4	51.4	51.4
22	Price control revenue	454.7	468.0	466.9	472.1	478.9	468.1
23	Price Control Revenue for 2007-08	432.4					
24	Change as %age	5.1%	2.9%	-0.2%	1.1%	1.4%	2.7%

Table A14.8 - Wales & West Utilities - Wales & West price control allowances, 2008-13, (£m, 2005-06 prices)

		2008-09	2009-10	2010-11	2011-12	2012-13	5 yr avg
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value	1,235.0	1,284.6	1,365.8	1,404.5	1,442.4	1,346.5
2	Total capital expenditure	58.8	85.5	47.1	47.4	44.6	56.7
3	Replacement expenditure added to RAV	33.1	39.2	37.3	37.4	37.2	36.9
4	Depreciation	-42.2	-43.6	-45.7	-46.9	-48.1	-45.3
5	Closing asset value	1,284.6	1,365.8	1,404.5	1,442.4	1,476.1	1,394.7
6	Present value of closing RAV (at vanilla WACC of 4.94%)	1,224.2	1,301.5	1,338.5	1,374.6	1,406.7	1,329.1
7	Allowance for change in RAV (=1 - 6, forward valued 6 months)	11.0	-17.3	28.0	30.7	36.6	17.8
	Allowed costs						
8	Controllable operating costs (incl. pensions, excl. shrinkage)	80.9	80.9	79.3	77.6	75.9	78.9
9	Shrinkage allowance	9.6	9.3	9.0	8.8	8.5	9.1
10	Pension deficit funding	5.1	4.9	4.8	4.7	4.6	4.8
11	Expensed repex allowance	33.1	39.2	37.3	37.4	37.2	36.9
12	Tax allowance	0.0	0.0	0.0	0.0	0.0	0.0
13	Return on RAV	60.7	63.9	66.8	68.6	70.3	66.0
14	Depreciation	42.2	43.6	45.7	46.9	48.1	45.3
15	IQI incentive allowance	0.9	0.9	0.9	0.9	0.9	0.9
16	Incentive allowance / (disallowance) under capex roller from 2002-07 control	-5.2	-3.9	-2.8	-1.1	0.0	-2.6
17	Under-recoveries from 2002-07 control	3.3	3.2	3.2	3.2	3.2	3.2
18	Total of allowed costs	230.6	242.0	244.2	246.9	248.8	242.5
	Price Control Revenue						
19	Total of allowed costs (non-pass through)	230.6	242.0	244.2	246.9	248.8	242.5
20	NTS charge for pensions	2.7	2.6	2.6	2.5	2.5	2.6
21	Non-controllable costs	22.3	22.3	22.3	22.3	22.3	22.3
22	Price control revenue	255.6	266.9	269.0	271.7	273.5	267.3
23	Price Control Revenue for 2007-08	252.0					
24	Change as %age	1.4%	4.5%	0.8%	1.0%	0.7%	2.0%

25	Impact of alternative charging arrangements for independent systems	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
26	Price control revenue after adjusting for independent systems	255.5	266.8	268.9	271.6	273.4	267.2

Appendix 15 – Impact of proposals

1.1. The price control allowances represent the maximum revenue that the GDNs can collect via gas transportation charges (primarily use of system charges and customer charges) under our baseline assumptions. Other revenue streams such as connections contributions, metering and meter reading are not affected.

1.2. The precise impact of these proposals on charges to different types of customers will depend on a number of additional factors, including:

- the rate of inflation;
- changes in the level of business rates, due to be re-evaluated in 2010;
- the application of a k factor as a result of under or over-recoveries;
- potential changes to the structure of charges;
- the gains or losses that may be made by GDNs due to specific incentive schemes or revenue drivers.

1.3. For many of these factors, including changes to the levels of business rates and potential changes to the structure of charges, our best estimate of their impact on charges over the period of the price control is zero. This also applies to any incentives or revenue drivers that are symmetric around the levels assumed in our baseline assumptions, since we cannot predict companies' outturn performance.

1.4. For other factors, including inflation and certain incentives, it is reasonable to expect that their impact on allowed revenue will be different from zero. They are, however, contingent on factors that prevent us from accurately predicting the outturn. Due to the difficulty in predicting the outturn effect of such factors, we have not included them in our forecasts of core allowed revenue.

1.5. We appreciate that shippers and consumer groups are keen to understand the overall change in charges, which is the cumulative effect of all factors. Below, we set out our best estimate of the impact of all factors that we consider are likely to have a non-zero impact on the amount of revenue that GDNs are allowed to recover.

Factors affecting allowed revenue

1.6. Table 14.1 below sets out forecast values for each of the major terms in GDNs' allowed revenue licence conditions, for the years 2007-08 and 2012-13. For comparison, we also present the 2007-08 values estimated at the time of our one year control final proposals.

1.7. The forecast values are based on allowed revenues from our one year and five year controls, updated for the factors below:

1.8. Inflation. The allowed revenue figures presented elsewhere in this document are shown in 2005-06 prices. For the baseline allowance we calculate 2006-07, 2007-08

and estimated 2008-09 inflation according to the formula in the base revenue licence term, while adjustments to factors other than the base revenue reflect actual inflation between 2005-06 and 2006-07. For all allowed revenue components we assume 2.5 per cent annual inflation thereafter.

1.9. Changes to shrinkage prices. The actual amount that GDNs can recover under the shrinkage incentive depends on the wholesale price of gas. The assumed shrinkage figure underlying both our one year and five year proposals is based on the wholesale price prevailing during 2006. This is so that changes in the gas price over the last year do not obscure the impact of our proposals. However, gas prices have fallen in the last year, implying that GDNs will recover less than our original estimate under the shrinkage incentive[12].

1.10. Impact of other factors affecting the level of revenue recovered by GDNs in each year. This figure is calculated by comparing the amount that we would have expected GDNs to recover in 2007-08, taking the above factors into account, with the amount actually recovered in this year. Factors contributing to the difference include performance against the mains replacement incentive, and the impact of the mild winter of 2006-07. During 2006-07 GDNs recovered significantly less than their allowed revenue due to the relatively mild weather and consequent low volume of gas throughput. This under recovery contributed to the large charge increases by the GDNs during 2007-08 in recovery of this deficit.

1.11. In 2008-09 and subsequent years, we assume that in each year GDNs recover their allowed revenue, adjusted for incentives and revenue drivers as set out below, and do not make over or under recoveries.

1.12. In 2008-09 and subsequent years, we also present estimated impacts for the following incentives and revenue drivers:

- the loss of meter work revenue driver. We present the cost of the revenue driver if the GDNs lose meter work at the rate they have forecast; and
- the Innovation Funding Incentive (IFI). We present the cost of the IFI if taken up in full by the GDNs. In reality, experience in the electricity distribution sector suggests that the initial impact of this incentive is likely to be less than this, as it may take a few years for GDNs to identify suitable projects and bring expenditure up to the maximum allowed level.

[12] Table 14.1 adjusts the assumed shrinkage element of our 2007-08 allowed revenue by the difference between our original assumed price and an estimated average gas price for 2007. This estimated price is based on actual day ahead prices from 1 January to 15 November and forward prices for the rest of the calendar year.

The difference between the shrinkage numbers underlying our base case allowances and our updated shrinkage forecasts has a negligible impact on the forecast change in revenues as we have assumed the gas price remains constant in real terms between 2007-08 and 2012-13. However, our revised estimate of the cost of shrinkage means that 2007-08 charges should be around 2 per cent lower than they would otherwise have been.

1.13. We assume that GDNs do not make gains or losses under other incentives. In particular, we expect that the introduction of the capacity outputs incentive (explained in chapter 6) on 1 October 2011 will have very little impact on total charges to the generality of customers over the forthcoming price control period. The new incentive will allow the GDNs to recover additional revenue to fund efficient expenditure on interruptions. We expect however that the impact of this change on the level of charges will be offset by the fact that under the reformed interruption arrangements, which come into effect on the same date, all customers will pay full transportation charges. This means that the discount that the GDNs provide to existing interruptible customers will no longer have to be recovered from other customers. The capacity outputs incentive also introduces small changes to the way in which the GDNs' NTS flat capacity bookings are incentivised.

1.14. Our forecasts indicate that the net effect of these changes on 1 October 2011 is not likely to be significant in the context of other potential impacts on charges to customers between 2008 and 2013. The impact of the transitional interruption incentive to apply between April 2008 and September 2011 is not yet known as these arrangements are still subject to consultation.

Impact on domestic customers' bills

1.15. We have also included a figure to show the impact on a typical domestic consumer (this cannot be simply derived by dividing total allowed revenue by number of customers, since each GDN has a number of large industrial users that use much more gas than a domestic customer). This is calculated as follows:

- calculate current charges for an average domestic consumer, using data on the total number of domestic consumers and on the total amount of revenue that GDNs expect to recover from such customers during 2007-08;
- calculate what these charges would have been had GDNs recovered exactly their allowed revenue during this year; and
- apply our per cent increase figure, calculated from adjusted allowed revenues, to the 2007-08 charges to give a forecast customer charge for 2012-13. This represents the amount that a typical domestic customer might expect to pay to cover gas distribution charges in this year.

1.16. This calculation is not dependent on the proportion of the total bill that relates to gas distribution charges, which varies with gas prices.

Table A15.1 - Changes in allowed revenue from 2007-08 to 2012-13 (nominal prices, unless stated)[13]

£m	2007-08 per one year control final proposals	2007-08 latest view	2012-13 latest view	Change from 2007-08 to 2012-13 latest views
Baseline allowance (2005-06 prices) less shrinkage	1,945.8	N/A	2,159.9	214.1
Shrinkage assumed within baseline allowance (2005-06 prices)	88.1	N/A	67.5	-20.7
Non controllables assumed in total allowances (2005-06 prices)	293.8	N/A	292.0	-1.8
Total allowances (2005-06 prices)	2,327.7	N/A	2,519.4	191.7
Baseline allowance less shrinkage, adjusted for inflation (Z_t * RPI_t)	2,045.9	2,070.1	2,637.7	567.6
Shrinkage, after adjustment for gas prices and inflation (Sh_t)	92.7	51.3	44.4	-6.9
Total non controllables, adjusted for inflation (F_t)	308.9	312.7	350.3	37.6
Additional revenue under loss of meter work revenue driver, adjusted for inflation (LM_t)	0.0	0.0	31.1	31.1
Additional revenue under IFI, adjusted for inflation (IFISDt)	0.0	0.0	12.1	12.1
Total allowances, adjusted for inflation and incentives	2,447.4	2,434.1	3,075.7	641.6
Impact of other factors contributing to 2007-08 revenue recovered by GDNs, including 2006-07 under recoveries	0.0	318.6	0.0	-318.6
Total revenue recovered by GDNs	2,447.4	2,752.6	3,075.7	323.0
Average revenue per domestic customer	£94.26	£101.89	£113.84	£11.96

1.17. The £641.6 million change in forecast total allowances between 2007-08 and 2012-13, adjusted for inflation and incentives, is equivalent to a 5.7 per cent average annual rise. This is equal to the 2.0 per cent average annual increase presented in previous chapters + 3.3 per cent average annual inflation – 0.1 per cent shrinkage adjustment + 0.5 per cent impact of loss of meter work and IFI.

1.18. Including the impact of other factors that result in 2007-08 charges exceeding those implied by our allowed revenue figures, charges to a typical domestic customer are expected, under our modelling assumptions, to rise by an average of 1.4 per cent per year over the next five years.

[13] Figures in the first column may differ slightly from those published in our one year control final proposals due to rounding.