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Gas Distribution Price Control Review Fourth Consultation Document

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

Overview:

The total revenue of gas distribution networks (GDNs) is approximately £2.3 billion per annum. The Gas Distribution Price Control Review will set the maximum revenue that each network can recover from its customers in the five years from April 2008.

This document details our consultants' initial analysis of the GDNs' operating, capital and replacement expenditure requirements for the period 2008-13. In the light of this analysis we are consulting on how we should set cost allowances and, in particular, we are seeking views on key policy issues including the proposed adjustments in relation to accounting policies; the way in which the different types of analysis can be brought together; the treatment of regional differences, real price effects and pension costs; and issues raised by the on going mains replacement programme.

The document sets out our updated view on a number of incentives including revenue drivers and capital expenditure rolling incentives. It also provides the methodology that we intend to use for considering financial issues.

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Context

The price control that currently applies to the gas distribution networks (GDNs) expires on 31 March 2008. This document is the fourth consultation held on the gas distribution price control review (GDPCR) and is designed to develop our thinking in setting the price control that will apply from 2008 to 2013.

The primary focus of this consultation is on the GDNs' costs and the document sets out our consultants' initial analysis of the efficient level of operating, capital and replacement expenditure costs that an efficient GDN will incur from 2008.

Our next document on GDPCR will be initial proposals which will be published at the end of May 2007. That document will bring together our thinking on the consultations to date and their associated responses into an initial set of proposals.

Associated Documents

- 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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Summary

We are resetting the price control that applies for the five year period from April 2008 to the eight gas distribution networks, owned by National Grid Gas, Northern Gas Networks, Scotia Gas Networks and Wales and West Utilities. The price control will limit the revenue which the GDNs will be able to recover from their customers. At the same time it will establish a framework that creates incentives for GDNs to invest and operate efficiently to deliver an appropriate level of outputs and to meet their statutory obligations and licence conditions.

In October 2006, in order to assist us in determining the appropriate level of revenue, the GDNs provided us with their historical costs, forecasts of their future costs and a description of the policies and procedures which they adopt in operating, maintaining and renewing their networks. This document sets out the work that, together with our consultants, we have carried out since receiving this information. We have:

- made adjustments to the historical cost data so that it is on a consistent cash cost basis across the companies and reflects the same activities;
- benchmarked the total operating expenditure (opex) of the GDNs as well as undertaking a more detailed analysis of direct and indirect opex, again making extensive use of benchmarking; and
- reviewed the workload assumptions and policies underpinning the capital and replacement expenditure forecasts (capex and repex), where appropriate also making use of benchmarking comparisons between companies.

In some areas the analysis suggests large differences of opinion between us and the GDNs on the appropriate level of future costs. Further work still needs to be carried out in refining and verifying this analysis in order to establish an appropriate basis for our initial proposals in May. However, the work does raise important policy questions and issues on which we are now seeking views. These include:

- the appropriate accounting treatment of non-operational capex and the application of our policy to exclude margins from the cost analysis where they are applied by parties related to the GDNs;
- how we should bring the different strands of the analysis together to set allowances and in particular the extent to which we can rely on benchmarking given the small number of GDNs and the fact that they have been in separate ownership for only a short period of time;
- how we should take account of differences between companies as a result of the different geographical areas they serve and whether there is a case for making adjustments to allowances to take account of increases in costs which are likely to exceed the rate of inflation;

- whether we should adapt our pension principles to address the level of contribution rates and the scale of differences put forward by GDNs; and
- developments in the way GDNs are implementing the Mains Replacement Programme.

Work on the incentives framework has continued since we published our third consultation document in November 2006. This document sets out our latest thinking on the volume driver and in the event that we decide to implement a capex rolling incentive the arrangements for doing this in practice.

The timetable for consideration of financial issues necessarily lags the cost analysis. In this document we set out the work that we intend to carry out on the cost of capital and seek views on our proposed approach to financeability in particular on the use of adjusted interest cover ratios.

We intend to publish our initial proposals on 29 May.

1. Introduction

Chapter Summary

This chapter sets out the purpose of the document, describes the background to and objectives of GDPCR, and explains how the document is organised.

Question box

There are no specific questions in this chapter.

Purpose of this document

1.1. The price control that currently applies to the GDNs expires on 31 March 2008. The Gas Distribution Price Control Review (GDPCR) will reset the revenue allowances for the eight GDNs for the next price control period, 1 April 2008 to 31 March 2013.

1.2. Ofgem sets controls to limit the revenue that monopoly transmission and distribution companies can recover from their customers. It generally sets transmission and distribution price controls every five years. Once the price control is set, prices, in the main, are restricted by RPI-X. The incentives that RPI-X creates are a key mechanism for fulfilling our principal objective to protect the interests of consumers.

1.3. This consultation document focuses on GDNs' costs and details our consultants' analysis on appropriate operating, capital and replacement expenditure allowances that an efficient GDN will incur from 2008. These cost assessments form the basis for setting revenue allowances for the price control period. At this stage these are our consultants' views and we have not made an assessment or formed a view on the approach, adjustments and provisional conclusions that they have reached.

1.4. The purpose of this consultation is to seek views on the work undertaken by our consultants, consulting on how we should set cost allowances and in particular seeking views on a number of key policy issues that have been identified as part of this work. This includes the proposed accounting policies and adjustments; the way in which the different types of analysis should be drawn together; the treatment of regional differences, real price effects and pension costs; and issues raised by the on-going mains replacement programme.

1.5. This document also provides an update on our thinking on incentives, in particular considering revenue drivers, the capex rolling incentive, and the information quality incentive. The remaining framework of incentives will be set out in our initial proposals. The document also sets out the approach we intend to follow in determining the cost of capital and other financial issues.

1.6. It should be noted that unlike other reviews where there have been a number of years of cost data to work from to develop initial proposals, and the equivalent 2006-07 data has been used more as a check, this is not the case for GDPCR due to the timing of DN sales. The first full year of cost data under independent ownership is 2006-07 and therefore we are likely to place more weight on this data. In addition, due to uncertainty over offtake and interruption reform the GDNs' cost submissions have not included any capital investment impact associated with these reforms. The GDNs will have the opportunity to revise their investment forecasts during the summer along with their actual cost data for 2006/07 which will require us to undertake a significant amount of analysis, potentially requiring the updated proposals which are to be published in September to be more substantive.

1.7. In November 2006, we published the third consultation document which sought views on a whole range of related policy issues and in particular considered quality of service, opex and capex incentives, extensions to the gas network to fuel poor communities and possible incentives on Corporate Social Responsibility, innovation funding and accuracy of pipeline records. A summary of responses in these areas is given in Appendix 5. We will set out our proposals in these areas in our initial proposals document which we intend to publish in May. To the extent that our thinking has developed in these areas, in a way in which we would welcome views before putting forward proposals, we have set out our latest thoughts in this document.

Background to GDPCR

1.8. GDPCR is the first gas distribution price control review since National Grid Gas plc's (NGG's) sale of four of its eight GDNs to three new GDN owners on 1 June 2005. As a result, the current industry structure is substantially different from that in place at the time of the previous price control review. These changes will have important implications for the conduct of this review. The creation of separately owned, managed and operated GDNs will allow more effective comparisons to be made between the businesses, building on the sense of rivalry which exists between independent management teams.

1.9. The benefits from this comparative competition will build up over time and be passed back to consumers at future reviews. To do this effectively, an important part of GDPCR is to put in place a cost reporting framework designed to maximise Ofgem's ability to compare GDNs' costs at future reviews, and to pass the benefits of increasing efficiency back to consumers.

Objectives of GDPCR

1.10. The Authority's principal objective under section 4AA of the Gas Act 1986 is to protect the interests of consumers, wherever appropriate by promoting effective competition. In addition (and without limitation), the following general duties[1] are also likely to have particular relevance to GDPCR:

- the need to secure that, so far as it is economical to meet them, all reasonable demands for gas conveyed through pipes are met;
- the need to secure that licence holders are able to finance their authorised activities;
- to promote efficiency and economy on the part of licence holders and the efficient use of gas conveyed through pipes;
- to be transparent, accountable, proportionate, consistent and to target regulatory activities only in cases where action is needed;
- to protect the public from dangers arising from the conveyance of gas through pipes or the use of such gas pipes, and to take into account any advice given by the Health and Safety Commission about any gas safety issue;
- to have regard to the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas; and
- to contribute to the achievement of sustainable development.

1.11. The Authority's powers and duties are set out in more detail in Appendix 2.

Structure of this document

1.12. This consultation document is organised as follows:

- Chapter 2 - details the accounting policy and resulting adjustments made to the GDNs' costs data;
- Chapter 3 - sets out the operating expenditure analysis undertaken;
- Chapter 4 - details consultants' capital and replacement expenditure analysis;
- Chapter 5 - considers some of the incentives for the price control review;
- Chapter 6 - consults on the methodology for considering financial issues; and
- Chapter 7 - highlights next steps and the timetable.

[1] Section 4AA(2), 4AA(3), (4AA(5), 4AA(5A) and section 4A Gas Act 1986

2. Accounting policy and adjustments

Chapter Summary

This chapter discusses the work to review GDNs' costs submissions for the price control to ensure that they are on a consistent cash cost basis and that any inappropriate costs are removed. It also consults on a number of policy issues arising from this work.

Question box

Question 1: Do you agree with our proposed accounting adjustments? Are there any other accounting adjustments that we should be considering?
Question 2: Do you agree with our adjustments for related party margins?
Question 3: Do you think we should change our treatment of non-operational capex?

Accounting policy and adjustments

2.1. In October 2006 we received responses to the Business Plan Questionnaires (BPQs) from each of the GDNs and xoserve setting out historical and forecast cost information and associated explanatory narrative. The first step in analysing historical costs as part of a price control review is to check that they are on a consistent ongoing cash cost basis with any disallowable costs removed.

2.2. Over the last few months we have asked each of the GDNs a series of supplementary questions and discussed key issues with them as part of cost visits in order to highlight whether any adjustments needed to be made to their data. We have focused on a number of key areas including:

- non-cash costs, such as provisions and accruals;
- non-recurring or atypical costs such as restructuring costs or one-off items;
- costs that should be disallowed for regulatory purposes such as related party margins (which are discussed further in paragraphs 2.11 to 2.28 below); and
- accounting policies of the various GDNs, such as their capitalisation policies.

2.3. In practice, as all of the GDNs used NGG's 2004-05 accounting policies and it has been only a short period since the GDNs were under common ownership, the differences in accounting treatment between GDNs were relatively small. Going forward, it will be important to ensure that this remains the case. We intend to develop improved guidelines in this area as part of the work on cost reporting that will be carried out this year.

2.4. Our proposed adjustments to the GDNs' controllable operating costs are set out in Table 2.1 below. Our proposed adjustments to capital expenditure (capex) and replacement expenditure (repex) are set out in Appendix 6.

Table 2.1 - Proposed adjustments to opex (£m, 2005-06 prices)

	NGG				**NGN**	**SGN**		**WWU**
GDN	**East of England**	**London**	**North-West**	**West Midlands**	**North England**	**Scotland**	**South England**	**Wales West**
Controllable operating costs	114.7	84.6	94.6	66.6	85.3	66.7	126.5	98.1
Reconciliation to regulatory accounts	-	-	-	-	-	-	-	0.6
Non-cash costs - provisions	-	-	-	-	(0.6)	-	-	(0.6)
Atypical costs	(5.3)	(4.6)	(4.6)	(3.4)	(0.6)	(0.6)	(0.3)	(2.6)
Disallowed costs - related party margins	(0.2)	(0.1)	(0.1)	(0.1)		-	-	-
Accounting policies - capitalisation	0.4	0.4	0.4	0.4	2.8	-	-	0.3
Total adjustments	(5.1)	(4.3)	(4.3)	(3.1)	1.6	(0.6)	(0.3)	(2.4)
Adjusted controllable operating costs	109.6	80.3	90.3	63.5	86.9	66.1	126.2	95.7

Reconciliation to the regulatory accounts

2.5. Given that the GDNs' BPQ submissions are not audited it is important that they are appropriately reconciled to their audited regulatory accounts. There were difficulties in verifying these reconciliations for some of the GDNs due to a lack of clarity in the information provided. We will be working with the GDNs to ensure that it is easier to achieve clear reconciliations for the 2006-07 data to support our work on updating the cost analysis for that year.

2.6. There was a difference of £0.6 million for 2005-06 repex between the regulatory accounts and WWU's BPQ submission. We have transferred £0.6 million from repex back to direct opex so that the data matches WWU's audited regulatory accounts.

Provisions

2.7. The two negative adjustments for provisions included a provision for an onerous lease for WWU and a provision for public and employer liability costs for NGN. These provisions were adjusted to reflect the cash spent in 2005-06 rather than the accounting charges.

Atypical costs

2.8. Some atypical or non-recurring costs were identified and removed from the cost base of each of the GDNs. These included:

- compensation under the standards of performance arrangements;
- staff costs associated with restructuring;
- adjustments for atypical levels of accruals; and
- costs associated with GDN sales.

2.9. Consistent with our approaches in other price controls such as DPCR4 (the last price control review of electricity distribution) we will make allowances for an efficient level of compensation in determining overall opex allowances.

2.10. In total these adjustments amounted to a £22 million reduction in the GDNs' BPQ submissions.

Related party margins

2.11. We have removed related party margins associated with Fulcrum Connections from NGG's costs on a basis consistent with the treatment of margins in the one-year price control. This results in £0.4 million being removed from opex, £4.9 million from capex and £0.4 million from repex respectively.

2.12. NGN's costs include a margin from United Utilities Operations Limited, who carry out network operations and asset management on NGN's behalf. Our present position is that these costs should be allowed. This is discussed further in paragraphs 2.15 to 2.19.

Capitalisation policies

2.13. Although the GDNs are applying the same accounting policies we have identified some differences in interpretation associated with the capitalisation of support service costs to capex and repex. We have re-allocated £1.5 million associated with logistics from NGG's repex to indirect opex. We have re-allocated £2.8 million associated with support service costs from NGN's repex to indirect opex. We have re-allocated £0.3 million associated with rental costs and finance staff from WWU's capex to indirect opex.

Issues arising from the accounting work

Treatment of related party margins

2.14. In setting a price control we explicitly provide for a return on capital expenditure included in the RAV. It is important that all related party profit margins should be removed to make sure therefore that companies do not earn a return twice. Ofgem's general policy for the treatment of related party margins was developed as part of DPCR4. It was also applied as part of the recent Transmission Price Control Review (TPCR). Margins are removed unless the related party earns 75 per cent of its turnover externally and charges are consistent with those to external customers - effectively a test of whether there is an arms length relationship. In practice for those reviews the policy only needed to be applied to wholly owned subsidiaries of the regulated businesses.

United Utilities Operations Limited (UUOL)

2.15. UUOL is contracted through an eight-year Asset Services Agreement (ASA) to carry out all asset management and operational activities other than those related to system operation on behalf of NGN. NGN has no ownership interest in UUOL. United Utilities holds a 15 per cent shareholding in NGN, it has a seat on the board and UUOL's entire turnover is associated with NGN.

2.16. For the purposes of the one year control we considered whether our general policy for related party margins was appropriate in the particular circumstances of NGN and UUOL where United Utilities only has a 15 per cent shareholding in NGN. We decided on balance the margin should be allowed given the small shareholding and that there was evidence that UUOL's contract with NGN was on normal commercial terms. The contract was awarded following a competitive tender in compliance with the EU directive in which there was one other bidder. Further CKI, Hong Kong Electric and Li Ka Shing together hold a majority shareholding in NGN and so have a strong financial incentive to ensure that the contract is maintained on a normal commercial basis.

2.17. For the reasons set out above we do not consider it appropriate to change the treatment of UUOL's margin for the remaining duration of its existing contract with NGN which coincides with the end of the next price control period in 2012-13.

2.18. It is likely that our policy will evolve as further examples of margins and business structures are put forward by licensed companies responding to regulatory incentives to reduce costs. As such no assumption should be made that this treatment will apply in future price control periods or to other businesses.

2.19. In particular, in future reviews, we will want to consider whether we are treating such businesses consistently in terms of our policies on related party margins and pensions. Under our existing approach to margins UUOL is treated as independent of NGN, but the ultimate pension liabilities of their operational staff remain with NGN and are subject to Ofgem's pension funding principles.

Treatment of xoserve margins

2.20. xoserve provides a single interface between the NTS, GDNs and shippers for a variety of functions such as invoicing shippers for the use of the transportation systems and managing the change of supplier process. It is jointly owned by the GDNs and NGG (NTS)[2]. xoserve currently charges a profit margin in its charges to the GDNs and NGG (NTS) in accordance with the ASA under which it operates.

2.21. If we applied the DPCR4 rules set out in paragraph 2.14 the margin would be disallowed from NGG and SGN but allowed for NGN and WWU as in their case 75 per cent of xoserve's turnover would be external to the group. It is clear that the DPCR4 policy did not envisage circumstances where GDNs and NGG (NTS) jointly own an agency and that agency's costs form part of the regulated cost base. Our current position is to disallow xoserve's margin for all GDNs on the basis that nearly 100 per cent of xoserve's turnover is to the GDNs and NGG NTS in aggregate.

Treatment of connections margins

2.22. In the one-year price control we applied adjustments to the GDNs' costs for margins associated with connections work. We allowed the GDNs to recover losses (equivalent to negative margins) associated with conservative charging for monopoly connections work from the generality of customers. We also disallowed related party margins for the price controlled element of connections work, i.e. net capex

[2] NGG has a 57 percent shareholding (46 percent NGGT and 11 percent NGGD), SGN has a 23 percent shareholding, and both NGN and WWU have 10 percent shareholdings.

associated with the ten metre rule[3], the final connections allowance, employee ordered works and the costs that were associated with undercharging.

2.23. In principle the GDN could have earned profit margins on the competitive elements of their connections work. In practice as they were undercharging they made a loss on these activities. We did not allow them to recover this from customers as a whole.

2.24. In DPCR4 all the costs net of customer contributions for connections work carried out by a related party in its own name or on behalf of the licensee are included in the RAV. Under the electricity distribution licence all connections made by the DNO or by a related party to the DNO's network are part of the distribution business. This has the effect that any related party connections margins are removed. The GDNs will retain a proportion of any margin they charge on connection costs through the capex rolling incentives.

2.25. We consider that a difference in approach is justifiable to the extent that competition has developed in the two markets. In electricity there is still very limited competition. A margin charged by a related party cannot be market tested. In gas connections, the new housing and large non-domestic segments of the connections market have effective competition. We propose to allow the margins in these cases for costs that are rechargeable from the customer requiring the connections but to disallow margins on costs that are recovered from the generality of customers through the RAV such as costs associated with the ten metre rule. All margins should be removed for gas connections to existing housing and smaller non-domestic sites, where there is not effective competition, subject to any capex roller incentives.

2.26. Our approach to segments of the gas connections market is summarised below. This is consistent with the approach in the one-year control and is explained further in Appendix 6.

Table 2.2 – Treatment of connection margins in the RAV roll forward

Type of connection	Competitive?	Revised RAV treatment
Existing one-off domestic housing and small non-domestic connections	No	Margins fully removed subject to capex rolling incentives – actual costs and contributions taken into account
New housing and large non-domestic connections	Yes	Margins only removed for price controlled element of work. i.e. ten metre rule allowance, final connection allowance and employee ordered work

[3] Up to the first ten metres of a connection in the public highway are provided free to the customer requiring the connection where the connection is within 23 metres of a relevant gas main. The costs are recovered from the generality of customers through the RAV.

2.27. Under this approach it would be necessary to determine the boundary between the competitive and non-competitive segments of the market. Our current position, consistent with the one-year control, is that connections to existing housing are a monopoly activity, connections to new housing are competitive and 35 per cent of connections to non-domestic customers are competitive. It is for consideration whether we should update this annually using the Connections Industry Review as the basis for this decision or whether it would be simpler to establish a predetermined percentage of the market which is competitive for these purposes.

2.28. Applying this policy in practice means that we have looked at the business structures for Fulcrum, which still carries out connections to non-domestic customers on behalf of NGG, to identify the actual costs that have been incurred before any margins are added. We also looked at the structures for Scotia Gas Connections and Scotia Gas Contracting to identify their actual costs. As SGN established these businesses between April and June 2006 we will remove any associated margins as part of the work on 2006-07 accounting adjustments.

Treatment of non-operational capex

2.29. Non-operational capex includes system operations, IS, vehicles, telecoms and security. GDNs currently capitalise the cost of IS hardware and associated operating software, but not internal software development or software licenses. The GDNs are forecasting that their non-operational capex over the next price control period will be £484 million, approximately 25 per cent of their total capex.

2.30. There are currently different treatments of these costs across network price controls as set out in Table 2.3 below.

Table 2.3 Treatment of non-operational capex

Price control	**DPCR**	**TPCR**	**GDPCR**
Treatment of non-operational capex	23.5 % capitalised 76.5 % expensed	100 % expensed	100% capitalised

2.31. Treating non-operational capex as opex may provide more appropriate incentives for efficiency as such investment is typically aligned with shorter term management strategy and objectives. It would also increase consistency, in particular between gas distribution and transmission as this would remove any perverse incentives for NGG to reallocate costs between businesses. However, changing the treatment of non-operational capex would reduce consistency over time in GDNs' costs.

2.32. We currently apply 45 year straight line depreciation to GDNs' new assets. This was calculated based on a weighted average asset life across different assets. An additional £484 million (in 2005-06 prices) of non-operational capex with an asset life of approximately 7 years would not significantly impact on this average given a total RAV of approximately £11 billion. The annual impact on allowed revenue of adjusting the depreciation rate would be 0.1 per cent.

2.33. Changing the treatment of non-operational capex to an opex allowance would have a large initial impact on allowed revenue. The additional opex would imply a P0 increase of close to 5 per cent. There may be ways of mitigating this impact, as noted in paragraph 6.15.

2.34. We are giving further consideration as to whether non operational capex should be treated as opex or capex and would welcome views in this area. In any event we consider that both GDNs' own non-operational capex and their share of non-operational capex incurred by xoserve should be treated in the same manner. We also consider that software licence fees and internal software development costs should be included in non-operational capex to avoid boundary issues between different categories of IS cost.

3. Operating expenditure analysis

Chapter Summary

This chapter sets out the range of analysis undertaken by our consultants on operating costs. It considers how to draw this work together by benchmarking the companies to establish efficient allowances. It also considers our approach to pension costs and consults on options to evolve our pension principles.

Question box

Question 1: How should we bring together the various consultants' analysis to establish an efficient cost benchmark and cost allowances? In the light of our approach to setting a benchmark, what approach should we take to glidepaths?
Question 2: Is there a case for making adjustments to allowances for real price effects, specifically direct labour, contract labour or materials?
Question 3: Is there a case for making adjustments to allowances for regional factors and if so what approach should be adopted?
Question 4: Should we adapt our pension principles to address the forecast defined benefit pension contributions, which are both extremely high and vary widely across GDNs (despite funding very similar benefit packages)?
Question 5: Should we change our pension recovery mechanism in order to avoid distorting incentives between making salary and non-salary cost savings?

Introduction

3.1. In October, we received responses to the BPQs for each of the GDNs setting out their historical and forecast costs. Table 3.1 sets out a summary of the forecast net direct and indirect opex for each GDN for 2008-09 to 2012-13 after accounting adjustments (discussed in chapter 2) and further activity level adjustments (discussed later in this chapter) to bring the data onto a consistent basis across companies. In all other respects these are the GDNs' forecasts.

Table 3.1 GDN forecast total opex after accounting adjustments, 2008-09 to 2012-13

£'m (2005-06 prices)		Direct Activities	Indirect Activities
NGG	East England	443.8	188.5
	London	355.8	145.0
	North West	356.2	151.2
	West Midlands	252.2	114.8
NGN	North England	344.1	119.9
SGN	Scotland	302.1	63.9
	South England	562.2	95.8
WWU	Wales & West	340.5	124.6
Total GDN		**2956.9**	**1003.7**
Annual average GDN spend		**591.4**	**200.7**

3.2. We appointed a number of consultants to review GDNs' operating costs including:

- Europe Economics to carry out a top-down benchmarking exercise of total controllable costs and total factor productivity (TFP) analysis;
- PB Power to review direct operating activity costs, and
- LECG to review the indirect opex (support services) activities.

3.3. In addition Ofgem have carried out regression analysis on total controllable direct operating costs to support the review of individual activities performed by PB Power.

3.4. Over the last few months our consultants have reviewed the GDNs' BPQ submissions on historical and forecast controllable opex and raised supplementary questions to get a better understanding of the historical data and forecasts, address issues of inconsistency across GDNs and, where appropriate, gather additional information to support the cost assessment. PB Power and LECG have attended costs visits to each GDN together with Ofgem staff to discuss the BPQ submissions, ask follow-up questions and to challenge and improve their understanding of the GDNs' forecast assumptions. The consultants have then undertaken detailed cost analysis to provide initial recommendations to Ofgem on appropriate levels of allowances.

3.5. This chapter summarises the cost work and the initial recommendations presented by the consultants to Ofgem. As we made clear in chapter 1 this work reflects the latest thinking of Ofgem's consultants. It does not represent Ofgem's views and we will not necessarily follow our consultants' approach in setting future cost allowances. We will publish our views in due course as part of initial proposals.

Top-down benchmarking and total factor productivity (TFP) analysis

3.6. It was recognised at the start of this work that the relatively small number of comparators and limited number of years of data under separate ownership meant that there were significant data issues which would limit the scope of this analysis and place limits on the reliability of the conventional approaches to such a benchmarking exercise. Europe Economics (EE) tested a range of different forms of analysis and models including regression analysis, data envelope analysis (DEA) and multilateral indices of productivity in order to identify the most appropriate top down productivity measures from which conclusions for future performance could be drawn.

3.7. The most robust method for benchmarking costs based on the available data was corrected ordinary least squares (COLS). Under this approach a standard ordinary least squares regression is carried out but the average regression line is then shifted down so that it passes through the point for the lowest cost or frontier company. A number of cost drivers were tested for the regression including composite scale variables (CSV) similar to the methodology used in DPCR4. Testing started with different sets of possible drivers in multi-variate models and eliminating any insignificant drivers until only significant variables were left. This approach gave two preferred COLS models: one with throughput as the sole remaining cost driver, the other with customer numbers as the cost driver. Both models gave a good fit to the data with little to choose between the two models so EE proposed giving equal weight to them both.

3.8. Other methods, although broadly consistent with COLS, were not considered robust enough to use in their own right. DEA for example displayed its weakness with small sample sizes by placing a large proportion of the GDNs on or near to the efficiency frontier. Methods that used pre-determined weights for different drivers, such as using a CSV, were very sensitive to the weights chosen.

3.9. EE also performed TFP analysis to estimate the scope for efficiency gains when compared to similar sectors in the economy as a whole rather than just the relative scope for efficiencies between GDNs. This indicated that we could expect the industry to achieve gains in operating expenditure productivity of between 1.9 and 3.7 per cent per annum over and above the underlying growth in productivity in the economy as a whole. Compounded over the five year price control period this gives productivity improvements for the sector as a whole in the range 9.2 per cent to 17.2 per cent above the economy as a whole.

3.10. Averaging the results of the two preferred COLS models and setting an upper quartile target for efficiency, then combining this with the TFP results for the sector as a whole gives the following GDN specific annual efficiency improvement targets for the five year period of the price control.

Table 3.2 - Results of the Europe Economics analysis

		Lower TFP assumptions			Higher TFP assumptions		
		Frontier Shift	Catching Up	Total	Frontier Shift	Catching Up	Total
NGG	East England	1.18%	0.24%	1.42%	3.00%	0.24%	3.23%
	London	1.18%	1.61%	2.77%	3.00%	1.61%	4.56%
	North West	1.18%	1.58%	2.75%	3.00%	1.58%	4.53%
	West Midlands	1.18%	0.00%	1.18%	3.00%	0.00%	3.00%
NGN	North England	1.18%	0.00%	1.18%	3.00%	0.00%	3.00%
SGN	Scotland	1.18%	0.19%	1.38%	3.00%	0.19%	3.19%
	South England	1.18%	0.68%	1.85%	3.00%	0.68%	3.66%
WWU	Wales & West	1.18%	1.35%	2.52%	3.00%	1.35%	4.31%

3.11. The weighted average of the total reductions (using controllable costs as weights) give the TFP reductions described above. The catch-up factors are derived from the COLS regressions, giving the annual amount each GDN needs to achieve upper quartile performance; this is set at zero for GDNs already at or beyond the upper quartile efficiency level.

Direct opex analysis - PB Power

3.12. PB Power carried out a review of the direct operating activities of each GDN. The activities covered by this review were: work management; emergency; repairs; maintenance; other direct activities; and shrinkage.

3.13. The analysis was mainly based on regression analysis of 2005-06 costs submitted by the GDNs and a bottom up construction of costs to determine an efficient level of costs for each of these activities. To roll these costs forward for the next price control period PB Power removed the varying real price assumptions applied to contractor prices, to labour and to materials by the GDNs and replaced them with its own assumptions of 2.25 per cent per annum real price increases for contractor costs and 1 per cent per annum increases for labour and materials.

3.14. To ensure that data for their regressions was on a consistent basis, PB Power applied adjustments for regional differences based on regional and county information published by the Building Construction Information Service (BCIS) of the Royal Institution of Chartered Surveyors (RICS). These adjustments were then reversed once an appropriate allowance was determined for each GDN.

3.15. PB Power's benchmarking was carried out without making the transfer of costs from London to East England for the Outer-Met adjustment so that the costs remained with the underlying cost drivers. Gas holders in this area are recorded as East England assets so were transferred into London for consistency. The opex analysis carried out by other consultants and by Ofgem was performed after making the outer-met transfer from London to East England.

3.16. PB Power has adopted a glidepath approach to determining allowances, whereby underperforming GDNs are expected to close 70 per cent of the gap to the upper quartile benchmark by 2012-13. In addition PB Power has applied ongoing efficiency improvement based on its experience and judgement.

3.17. A similar approach was used for capex and repex and is explained in greater detail in chapter 4.

Table 3.3 - PB Power's recommended adjustments and projections for direct opex (excluding shrinkage[4])

2008-09 to 2012-13 totals (2005-06 prices)	GDN Adjusted Opex	PB Proposed opex	PB Proposed reduction
	£m	£m	
Work management	963.0	860.4	-10.6%
Emergency	468.9	417.2	-11.0%
Repairs	453.4	388.8	-14.2%
Maintenance	424.3	364.3	-14.1%
Other Direct Activities	77.7	68.0	-12.6%
xoserve	137.7	137.7	0.0%
LNG to SIUs	24.0	24.0	0.0%
Total	**2549.1**	**2260.5**	**-11.3%**

3.18. Overall PB Power is proposing an 11 per cent reduction to the total GDN forecast costs for these activities. These reductions are a combination of efficiency assumptions based on analysis of the 2005-06 costs, workload adjustments, lower levels of assumed real price increases and greater productivity improvements than those assumed by the GDNs.

Work management

3.19. For this activity PB Power performed regression analysis based on a CSV derived from the main factors that influence these costs. Those factors were: the number of publicly reported gas escapes (PREs), the number of repairs and the length of less than 7 bar main. The regression based on this CSV for the GDNs' 2005-06 costs gave a reasonable fit to the data.

Emergency

3.20. For the emergency activity PB power performed regression analysis based on a CSV combining the number of PREs and number of repair jobs for each GDN. This

[4] This data excludes shrinkage costs of £408m otherwise is consistent with Table 3.1

regression analysis was supported by a bottom up analysis of the emergency activity which considered the different elements of the work that is undertaken by emergency teams including waiting time, travelling time, time take to deal with emergency jobs, meter work and other fill-in times and the associated levels of labour and materials costs.

3.21. PB Power also reviewed the forecast trend in numbers of PREs and adjusted these numbers for their own views of what the trend might be when taking account of such factors as the replacement of iron mains with Polyurethane (PE) mains. The efficient unit cost derived from the regression and bottom up analysis was then adjusted for ongoing efficiency savings applied to the revised workload to give their cost projection for this activity.

3.22. The analysis and baseline allowances for this activity have been derived on the basis that there will be no further loss of meter-work which the GDNs are able to use to offset some of the idle time of the staff providing the emergency service. The bottom-up analysis of costs also allowed PB Power to consider the potential impact of any loss of meter-work and to quantify the associated increase in emergency costs. PB Power has applied an additional allowance based on GDNs losing 55 per cent of their existing meter work.

Repairs

3.23. Regression was also used to estimate the efficiency of repair work supported by a review of contract prices. Workloads were adjusted to take account of the impact of the replacement of older iron mains with PE pipes. Specific allowance was also made for the additional landfill tax that will be payable by the GDNs as a consequence of the new Waste Management Regulations[5]. PB Power also considered the impact of Gas Safety (Management) Regulations[6] on reprogramming repair work, but have assumed no change from GDNs' practices in 2005-06.

Maintenance

3.24. Maintenance is divided into three main categories: LTS maintenance; Storage maintenance and other maintenance.

3.25. PB Power examined a number of potential cost drivers for LTS maintenance but concluded that regression analysis was not sufficiently robust in this area. Their analysis was based on a comparison of unit costs between GDNs as well as findings on NTS maintenance costs during the Transmission Price Control Review. The unit cost was assumed to reduce by 1 per cent per annum to reflect ongoing productivity improvements.

[5] The Waste Management (England and Wales) Regulations 2006, SI 2006/937
[6] 1996, SI 1996/551

3.26. Storage maintenance was derived by combining a bottom-up analysis of the inspection and routine maintenance for low pressure storage installations with the results of regression analysis on the costs of gas holder painting. A 13 year repainting cycle was assumed for gas holders.

3.27. Other maintenance comprises a number of activities. For Instrumentation and governor maintenance regression analysis was used to compare the GDNs. As two data points had to be excluded as clear outliers, the benchmark was set by using the best fit regression line on the remaining six GDNs. The allowances for the remaining activities in Other Maintenance were determined using bottom-up analysis.

Shrinkage

3.28. PB Power reviewed the policies and procedures of the GDNs for managing leakage (which accounts for 90-94 per cent of shrinkage). They considered the GDNs' forecasts leakage levels against factors such as changes in average system pressure and increasing proportion of PE pipes on the distribution system. They did not find any reason to reject the GDNs' forecasts for shrinkage levels and proposed that these forecasts should be accepted.

Direct opex analysis - Ofgem

3.29. We have also carried out regression analysis of total controllable direct operating costs excluding shrinkage to supplement the analysis of individual direct activities carried out by PB Power. This analysis used data from 2005-06 and 2006-07 without applying any regional factor adjustments.

3.30. We tested customer numbers, network length and throughput as cost drivers for controllable direct operating costs and found that customer numbers and throughput gave the best fit to the data.

3.31. The impact on direct operating costs of moving each of the GDNs to the upper quartile efficiency line in each of those regressions is shown in table 3.4 below. More detail of each regression is included in Appendix 7.

Table 3.4 - Results of Ofgem regressions on 2006-07 direct opex

2005-06 prices	GDN Direct opex excluding shrinkage	Opex adjustment based on throughput		Opex adjustment based on customer numbers	
	£'m	£'m	%	£'m	%
East England	77.3	0.1	0.2%	1.8	2.3%
London	54.0	-9.9	-18.3%	-3.9	-7.2%
North West	61.2	-6.2	-10.2%	-3.7	-6.0%
West Midlands	40.0	0.0	-0.1%	3.8	9.5%
North England	55.2	1.7	3.0%	-1.0	-1.9%
Scotland	51.4	-9.8	-19.0%	-11.4	-22.2%
South England	98.8	-25.6	-26.0%	-18.3	-18.5%
Wales & West	52.9	0.0	-0.1%	-0.4	-0.8%
Total	**490.8**	**-49.7**	**-10.1%**	**-33.1**	**-6.7%**

3.32. Each of the above regressions provides a reasonable fit of the costs to the underlying data and the overall rankings and cost reductions are broadly similar. A number of points can be drawn from the results:

- Scotland, South England and London appear to be the least efficient GDNs. In the case of both South England and London this may be partly due to regional effects which have not been taken account of in these regressions. For South England and Scotland this may also be partly due to their business model involving lower central support costs but more costs incurred within the direct operating activities;
- East of England, West Midlands and North England appear to be the most efficient GDNs;
- A number of GDNs are particularly susceptible to the choice of cost driver used, generally having a larger adjustment when throughput is used rather than customer numbers.

Indirect opex/support services - LECG

3.33. LECG carried out a review of the indirect operating costs that each GDN needs to carry out in support of its direct activities. Where there is more than one GDN within an ownership group, or where there are activities other than gas distribution, the nature of these indirect activities generally means that they are carried out by one central function and the costs allocated to individual businesses on an appropriate basis. For this reason the review of these activities has not been carried out at an individual GDN level, rather at the level at which the activity is carried out. The savings identified can then be allocated to individual GDNs in line with the original allocation of costs.

3.34. The activities covered by this review were: information services; finance, audit and regulation; insurance; property management; corporate centre and communications; human resources; legal; and procurement and logistics.

3.35. The review involved benchmarking these activities between the GDNs and against relevant external third party benchmarks. This was supported by a qualitative review of the GDNs' policies and procedures for forecasting, together with an assessment of the steps taken to achieve cost savings since DN sales.

3.36. LECG has not made regional adjustments for indirect operating costs. This is because these activities generally do not need to be located in specific areas, so the GDN is free to choose an appropriate cheaper location to avoid any higher regional costs. For example National Grid provides most of these services from the Midlands, even for their London GDN.

3.37. A summary of the range of adjustments proposed by LECG to indirect opex is set out below. Further details of the type of analysis used to set the benchmark, together with the proposed adjustment to each of the indirect operating cost activities is included in Appendix 7.

Table 3.5 - Average annual indirect opex reductions across all GDNs

2005-06 prices	Adjusted BPQ opex	Proposed reduction (Low case)		Proposed reduction (high case)	
	£m	£m	%	£m	%
IS	53.2	1.7	3%	5.6	11%
Finance Audit and Regulation	31.5	5.6	18%	13.7	43%
Insurance	31.6	8.1	26%	9.3	29%
Property management	32.0	3.0	9%	6.0	19%
Corp centre & Comm.	14.3	1.4	10%	3.4	24%
HR	19.9	2.4	12%	4.8	24%
Legal	5.0	0.7	15%	1.0	19%
Procurement & logistics	13.3	2.1	16%	3.3	25%
Total	**200.7**	**25.1**	**13%**	**47.1**	**23%**

3.38. LECG's low savings case would reduce forecast indirect operating costs across all GDNs over the price control period by approximately £125 million compared to the GDN submissions. Their high savings case would reduce costs by about £235 million compared to the GDNs' submissions.

3.39. In most areas SGN appear to be either the most efficient or second most efficient on the benchmarks. This may be due to a number of factors:

- it may reflect a strategy of keeping central costs low at the expense of higher direct costs;
- there may be some remaining differences in cost allocation between SGN and the other GDNs although we believe that we have adjusted for any major differences; or
- it may reflect SGN contracting some of its support service activities out to SSE.

3.40. SGN has a Managed Service Agreement (MSA) in place with SSE which covers a range of support service activities. Under these arrangements SGN receives a number of services at marginal cost. We are considering whether this may create an unsustainable benchmark for the other GDNs as SGN is not required to pay a share of the fixed costs for these services. We are considering whether the benchmarks need to be adjusted to take account of SGN's MSA.

3.41. NGG's indirect operating costs appear relatively high compared to the other GDNs. This may be due to a centralised approach to managing their activities (the converse of SGN's costs appearing low) or it may suggest that NGG has not yet fully reduced its costs to reflect the sale of four GDNs.

xoserve

3.42. LECG also carried out a review of the costs of the services provided by xoserve on behalf of the GDNs. These costs are split among the GDNs in accordance with the Agency Services Agreement (ASA) and included in the GDNs controllable costs. This review was supported by PB Power carrying out a review of the major capex project spend by xoserve. PB Power did not recommend, at this stage, any reductions to xoserve's capex spend.

3.43. LECG's review of xoserve focussed on xoserve's key material support functions, namely the information system and property management support functions.

3.44. In its low case LECG has applied NGG's assumption of a 4 per cent per annum compound reduction in IS costs. In its high case LECG applied a further £0.54 million reduction in base year costs for 2006-07 before rolling forward for the 4 per cent per annum reduction. This additional reduction was based on the high savings scenario for NGG's IS costs.

3.45. On property management costs LECG found that xoserve were paying annual rents £0.35 million higher than indicated by third party rent data. They also found that their property management costs were higher than the median (low case) and upper quartile (high case) cost savings for the GDNs by £0.72 million and £0.97 million respectively. The savings for xoserve's costs based on these savings are set out in Table 3.6 below.

Table 3.6 LECG xoserve opex adjustments, (2005-06 prices)

£'m	2008-09	2009-10	2010-11	2011-12	2012-13
IS costs	0.92	1.22	1.62	2.00	2.36
Property Management	1.07	1.07	1.07	1.07	1.07
Low case total	**1.99**	**2.29**	**2.69**	**3.07**	**3.43**
IS costs	1.42	1.71	2.08	2.44	2.79
Property Management	1.32	1.32	1.32	1.32	1.32
High case total	**2.74**	**3.03**	**3.40**	**3.76**	**4.11**

3.46. Any efficiency savings related to xoserve will be allocated to each GDN and to NGG (NTS) in proportion to their share of xoserve's total costs.

3.47. We note that IGTs currently sit outside of the core industry systems provided by xoserve and there is an opportunity with the proposed replacement of UK Link during this price control period to identify cost effective ways to incorporate all GTs. Further consideration will be given to this as part of initial proposals.

Overall review of opex analysis

3.48. We have compared the total bottom-up efficiency savings recommended by PB Power and LECG (both low and high savings cases) with the efficiency savings recommended by EE from their top down benchmarking exercise. The PB / LECG savings set out below are savings against the GDNs' forecast for the price control period. The EE savings shown below are savings against the GDNs' 2006-07 costs and do not take account of future cost changes in the GDNs' BPQ forecasts. This comparison is set out in Table 3.7 below.

Table 3.7 Comparison of consultants' recommended adjustments

£'m 2005-06 prices	2008-09 to 2012-13 total GDN savings	Average annual savings, all GDNs
PB Power with LECG low efficiency	426.1	85.2
PB Power with LECG high efficiency	539.0	107.8
EE low case savings	248.4	49.7
EE high case savings	474.0	94.8

3.49. This is for illustrative purposes only. We are considering the options for using different elements of the opex analysis to determine price control allowances for each GDN. This is discussed further below.

Policy issues arising from the opex analysis

3.50. The consultants have made a number of assumptions regarding the application of regional factors, approach to setting benchmarks, catch-up and real price effects in order to make recommendations on price control allowances for each GDN to Ofgem.

3.51. We are giving further consideration to whether these types of approach are appropriate and if so whether the assumptions made by our consultants are reasonable. In reaching a view we will take into account among other things issues of consistency over time and across price controls and the impact on incentives. The sections below on benchmarking, glidepaths, regional factors and real price effects are relevant to opex, capex and repex.

Bringing together different elements of the opex analysis

3.52. The main objective of the cost assessment work is to establish the efficient levels of opex, capex and repex required by each of the GDNs to deliver an appropriate level of outputs including meeting the safety requirements established by the Health and Safety Executive (HSE), provision of network capacity and quality of service.

3.53. As discussed earlier in this chapter, we have used a number of different approaches to assess opex including benchmarking of total opex, benchmarking for individual direct and support activities to assess the extent of under or outperformance by each GDN and TFP to assess the scope for ongoing efficiency improvements.

3.54. There are a number of potential options for using the different elements of the analysis. For example:

- we could adopt a mechanistic approach to combining the elements of the analysis. For example, aggregating PB Power's direct opex results with LECG's results from benchmarking support services. A weighted average could then be taken of these results and the outcome of EE's benchmarking to determine allowances;
- we could place more reliance on the benchmarking of total direct opex we have carried out, PB Power's analysis of direct opex activities and LECG's work on support services. In this case EE's benchmarking work on total controllable opex and our work on total controllable direct opex would be used as more of a cross-check as to whether our overall opex allowances were appropriate; or
- alternatively we could form a judgement on the appropriate levels of allowances for each GDN using each of the consultants' conclusions together with submissions from the GDNs as evidence in reaching our decision.

There are a number of advantages and disadvantages to each approach which are discussed below.

Mechanistic approach

3.55. We do not consider that a mechanistic approach would be appropriate at this stage given the limitations on the comparative analysis which can be made for this review. There has been significant industry restructuring over past 2 years, the new management teams have been in place for a limited period and therefore the 2004-05, 2005-06 and 2006-07 cost data are all atypical to some degree. These issues would be difficult to address in a mechanistic approach to setting allowances.

Focus on disaggregated benchmarking

3.56. The disaggregated benchmarking of direct and support services activities allows there to be more focus on the relevant cost drivers for particular activities and in the case of indirect/support service activities to carry out effective benchmarking against appropriate external comparators in regulated or competitive sectors. As such, it may be a more robust approach to assessing the efficient costs for each of the GDNs.

3.57. A key concern with this approach raised by the GDNs is that such a disaggregated approach may lead to "cherry-picking" of the most efficient GDN for each activity leading to the construction of an artificially efficient GDN. This can be mitigated by the approach to benchmarking and is discussed further in paragraphs 3.61 to 3.67 below. Another potential issue is that at the activity level data submitted by the GDNs, for example for work management, emergencies and repairs was less consistent than the total opex data. There were differences in treatment of certain types of costs such as supervisory costs, waste management costs etc. There were also some inconsistencies in allocation between direct and indirect opex. We have sought to mitigate these issues through further normalisation of the data and consider we have captured the main differences in reporting between GDNs.

Judgement based on the evidence

3.58. The third approach is to reach a judgement on the appropriate allowance based on the evidence from all of the benchmarking and cost assessment work. This has the advantage that it allows us to take account of weaknesses in particular areas of the analysis and form a view of the overall issues concerning the efficiencies of each GDN based on a range of evidence. It also allows us to reflect potential limitations of the comparative data

3.59. This approach has the potential weakness that there is less transparency on how Ofgem's proposed allowances have been derived although this can be mitigated through clear explanation of the main factors taking into consideration in reaching our decisions and how any judgements have been applied consistently across all GDNs. This will also help to address any concerns relating to cherry-picking.

3.60. Our current thinking is that this approach is most likely to be appropriate for this review and that we would form a judgement of current levels of efficiency and scope for catch-up based on further consideration of the benchmarking work of direct opex and LECG's assessment of support costs. EE's analysis would be used as a cross-check against this.

3.61. In addition we would seek to identify the scope for further efficiency improvements for all GDNs through consideration of EE's work on TFP, PB Power's assessment of the scope for future efficiency savings in direct activities and submissions from the GDNs.

Application of benchmarking

3.62. The cost assessment work carried out to-date by our consultants and internal team has made extensive use of regression and other benchmarking analysis across the GDNs in order to compare costs and assess efficiency. The benchmarking analysis for direct opex, capex and repex has been undertaken on an individual GDN basis. The regression analysis applies a "line of best fit" to normalised costs (in some cases adjusted for regional factors). This line represents the average cost of all 8 GDNs. Those GDNs furthest below the line have the lowest cost and vice versa.

3.63. LECG has carried out benchmarking of support service costs between GDNs and against external comparators using ratios such as IS costs as a proportion of revenue, legal costs as a proportion of revenue, facilities management costs per square foot etc. Benchmarking analysis for support services has been undertaken on an ownership group basis rather than licensee and again those groups below the line are identified as lowest cost.

3.64. There are various ways of using this analysis to form judgements on future efficient levels of costs. One could base the assessment of efficiency on the lowest cost company (or "frontier GDN"). For example, for regression analysis the average regression line would be shifted so that it passes through the lowest cost GDN. Other companies would be expected to improve efficiency and catch up with this level.

3.65. Given that this is the first price control in gas distribution where we have used comparative analysis between GDNs we are giving consideration to the most appropriate way of using the regression and other benchmarking results. The main concerns raised by the GDNs at this stage regarding the comparative analysis are that:

- it may be too early to start using such analysis across the GDNs given the short period for which the new management teams have been in place;
- there is a risk of cherry-picking and creating an artificially efficient GDN if the analysis is carried out at too disaggregated a level and then built up to form a view of allowances;
- there may be remaining differences in cost allocation that distort the analysis if it is applied at too disaggregated a level; and that
- factors other than efficiency may be driving performance relative to the benchmark.

3.66. Ofgem considers that comparative analysis through benchmarking and other techniques is an important part of the cost assessment at this review. As only a short time has elapsed since DN sales and there are limitations with the data, there needs to be particular care in how the benchmarking is applied in this case.

3.67. One option to deal with these issues is to apply an alternative benchmark between the average regression line and the frontier. For example, in DPCR we applied the upper quartile costs rather than frontier costs to establish the efficiency benchmark for total costs. In effect the average regression line is shifted downwards so that is passes through the upper quartile - between the second and third of the 8 GDNs. This would help to ensure that the benchmark is not defined by a GDN that achieves low cost because of poor quality, residual cost allocation issues or any specific factors. It also addresses concerns that may arise from a frontier approach to benchmarking that a different company may set the frontier for each activity so that an artificially low benchmark is determined for total costs.

3.68. The consultants' benchmarking analysis and recommendations make no additional allowance for singleton companies compared to companies that own several GDNs. This is consistent with our principles as set out in Ofgem's Roles & Responsibilities decision document[7] as part of DN sales that stated:

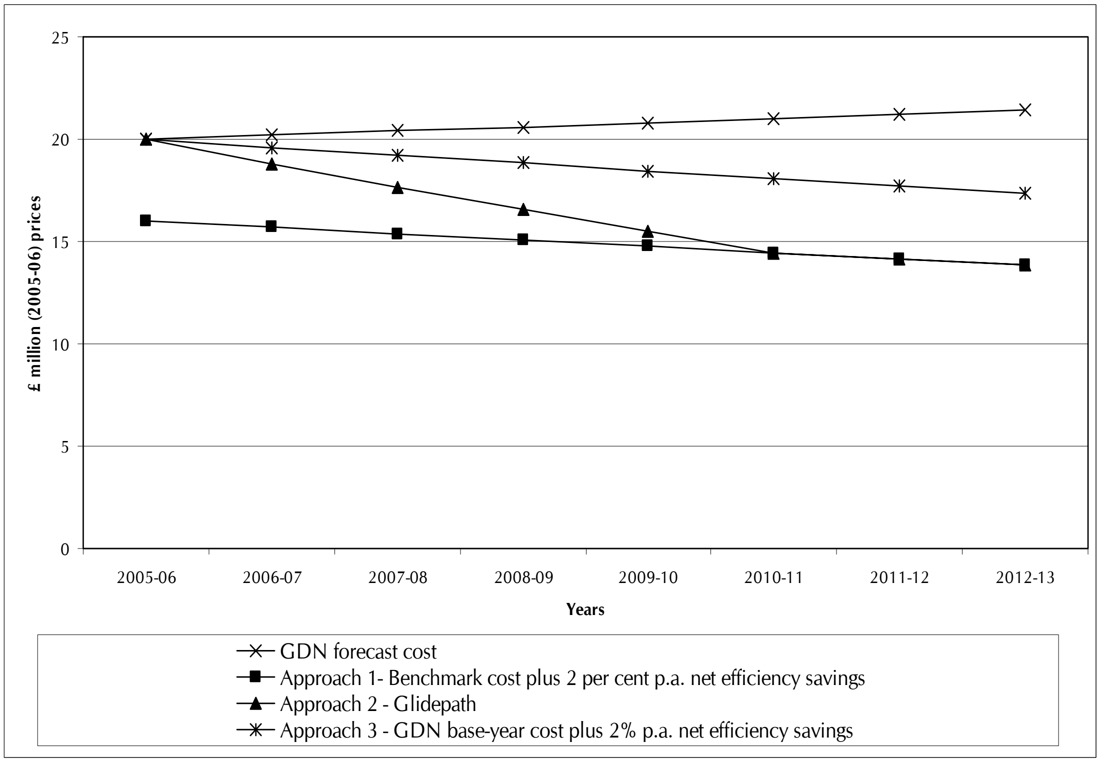
- capex incurred as a result of loss of economies of scale will not be included in Ofgem's assessment of allowed revenue for that GDN; and
- for ongoing operational costs, if economies of scale do exist, then Ofgem will use this information in setting future allowances. In particular, given that NGG owns four GDNs then it follows that it is likely to be relatively efficient for those activities which have the potential to benefit from economies of scale. In turn, these efficiently incurred costs will be taken into consideration when setting the allowed revenues for that activity for all GDNs.

Glidepaths

3.69. Once benchmarking has been carried out there are a number of possible approaches to using the results to set price control allowances. These are shown in Figure 3.1 below.

[7] Ofgem, National Grid Transco – potential sale of gas distribution network businesses, Allocation of roles and responsibilities between transmission and distribution networks, Decision document, May 2004, 119/04

Figure 3.1 - Example of different approaches to applying benchmarks



Approach 1 - Full gap closure

3.70. One approach in line with DPCR4 would be to set allowances for 2008-09 to 2012-13 on the basis of the benchmark level of costs plus some ongoing level of efficiency savings. As two GDNs have already achieved the upper quartile level of costs for 2005-06 or 2006-07 (as appropriate) it may be reasonable to expect all GDNs to achieve this level by 2008-09 and then achieve some ongoing savings. This approach would provide frontier performers with a reward for outperformance but this would be reduced overtime unless they achieved ongoing levels of efficiency improvement.

3.71. Such an approach potentially provides strong incentives for efficiency as it would mean that inefficient GDNs earn less than the average cost of capital until they catch up. Outperforming GDNs would be able to earn an above average cost of capital for a period. However, this approach does not allow GDNs any costs which may be needed to achieve future efficiency savings. If a GDN significantly improves efficiency but still has costs which are higher than the quartile it will be exposed to the additional costs.

Approach 2 - Glidepath

3.72. If there are limitations in the benchmarking data because of atypical years or potential structural differences between GDNs that mean it may be impractical for high cost GDNs to catch up with the benchmark over a short period, then assuming immediate gap closure may be inappropriate. An alternative approach is to assume a glidepath whereby cost reductions are phased over a period of time. For example, in DPCR3 it was assumed that the DNOs would close 75 per cent of the gap to the frontier company over a period of 3 years.

3.73. The slope of the glidepath can take into account an assessment of how quickly a GDN could make managerial or technical changes in order to achieve greater efficiencies. For example, if new asset management tools were needed to more effectively prioritise maintenance expenditure and improve levels of efficiency it might be appropriate to allow GDNs a number of years to develop and implement such systems. If the potential efficiencies are related to improved supervision of operational staff it might be appropriate to expect the changes to be achieved relatively quickly. PB Power's judgement is that GDNs should be able to close 70 per cent of the gap with the upper quartile by 2012-13, the end of the next price control period.

3.74. A potential advantage of this approach is that it would implicitly allow GDNs some costs to achieve future efficiency savings.

3.75. The disadvantage of such an approach is that a glidepath extending beyond the beginning of the price control period would give additional revenue to those GDNs revealed as higher cost, and would require consumers in that GDN's area to fund a cost level higher than the chosen efficient benchmark.

3.76. This risks creating perverse incentives because if such firms cut costs quickly they may end up earning higher returns than more efficient GDNs. For example, suppose a high cost GDN is allowed 75 per cent of the difference between its base year costs and the benchmark in year 1 of the price control, 50 per cent of the difference in year 2, 25 per cent in year 3 and is expected to have closed the gap by year 4. If this GDN in practice closes the gap to the benchmark by year 1 it will earn a return significantly greater than the cost of capital.

3.77. By contrast a more efficient GDN whose costs are already at the benchmark level would only receive a return equal to the cost of capital unless it achieves additional efficiencies.

3.78. We are giving further consideration to the use of glidepaths.

Approach 3 - Allowances based on historical costs

3.79. Another alternative for this price control period taking into account the limited opportunities for new management teams to make an impact on the structure of their businesses could be to base allowances on GDNs historical costs for 2006-07 rolled forwards to take into account ongoing efficiencies that can be achieved by all GDNs. Under this approach we would signal our intention to undertake detailed comparative benchmarking at the next review to ensure that there are strong incentives for GDNs to reduce costs.

3.80. While this approach would lessen the reliance on limited data on costs in years where there has been significant structural change it risks creating perverse incentives as discussed above. Higher cost companies which have taken fewer steps to reduce costs since GDN sales may benefit from higher revenues. It may also mean that customers bear an inappropriate level of costs.

3.81. We do not consider that it is appropriate to set allowances by rolling forwards GDNs' own historical costs for the reasons set out above. We are giving further consideration to the type of benchmark that is appropriate and whether a glidepath should be applied taking into account factors such as the availability of data, the robustness of the analysis that has been carried out and the impact on the strength of incentives. In deciding the appropriate balance of incentives it will also be important to consider whether an opex roller should be applied. No final decision has been made on this issue.

Treatment of regional differences

3.82. Half of the GDNs have put forwards specific factors which they suggest cause them to have higher than average costs. SGN and NGG have argued that London and South-East England have higher costs due to pressures on salaries and contractors' rates due to skilled labour shortages and the impact of the Olympics as well as additional costs associated with excavations and congestion charging. SGN and WWU have argued that they have additional costs because of sparsity in Scotland and Wales.

3.83. The approach to regional factors has differed across previous price controls. Our consultants at the last price review made use of some inter Local Distribution Zone (LDZ) benchmarking carried out by Transco as part of their assessment of potential opex efficiencies. This included some regional factor adjustments. In both DPCR3 and DPCR4 Ofgem applied regional adjustments for Scottish Hydro's and EDF-LPN's opex to take account of the need to operate in remote areas in the Highland and Islands and travelling time, greater competition for labour and costs of excavation in London respectively.

3.84. In the current water price control, Ofwat applied regional factors based on a study of building and construction cost indices (including the effects of labour) published by the Royal Institution of Chartered Surveyors' Building Construction Information Service (BCIS). Adjustments were made to capex for 9 companies where it was shown that they had costs that were significantly higher than the average.

3.85. We are giving consideration to whether it is appropriate to make adjustments for regional differences as part of the gas distribution price control and if so what approach should be used. One option would be to follow a similar approach to electricity distribution and only make adjustments for areas where there is evidence of significantly higher than average costs. For example, in gas distribution it might be appropriate to apply regional adjustments for GDNs operating in London because of market evidence of higher than average costs.

3.86. An alternative approach which has been adopted by PB Power in its analysis is to make regional adjustments for all GDNs based on relative direct and contract labour costs. PB Power has based its regional factors on BCIS data similar to the methodology adopted by Ofwat. This is discussed further in chapter 4.The direct labour factors for South England and London GDNs take into account the fact that while field staff will have higher than average wages, back office operations don't need to be located in a particular region and therefore do not need adjustments.

3.87. PB Power's view is that the following regional adjustments for both contract and direct labour should be applied as set out in Table 3.8 below.

Table 3.8 - PB Power's proposed regional factor adjustments to be applied to GDNs' costs

Regional Factors	NGG				NGN	SGN		WWU
	East of England	London	North West	West Midlands	North England	Scotland	South England	Wales West
Direct Labour	0.98	1.10	0.98	0.98	0.98	0.98	1.03	0.98
Contract Labour	1.00	1.11	0.93	0.94	1.01	0.99	1.06	0.96

3.88. It could be argued that if there are significant regional differences then it is more comprehensive to apply adjustments to all GDNs rather than simply those that have the greatest cost pressures.

3.89. We are also considering what activities could be covered by regional adjustments. For example, there may be cost differences which cannot be avoided by GDNs in carrying out direct activities such as attending emergencies, carrying out connections and mains replacement but regional adjustments should not be necessary for supporting activities such as legal, HR, corporate centre activities etc. GDNs have some flexibility in choosing where to locate their support services in order to benefit from more favourable costs. For example, NGG manages most of its distribution activities, including those carried out in North London, from the Midlands.

3.90. We would welcome views on whether it is appropriate to apply regional adjustments and if so, what activities they should cover and how these should be estimated.

Real price effects

3.91. The approach to real price effects (RPEs) is a significant issue in this review given the scale of real growth in contractors' rates, direct labour salaries and materials costs forecast by the GDNs. The GDNs' assumptions for RPEs are set out in Table 3.9 below.

Table 3.9 - GDN assumptions for real price effects[8]

RPEs	NGG				NGN	SGN		WWU
	East of England	London	North West	West Midlands	North England	Scotland	South England	Wales &West
Direct Labour	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Contract Labour	2.2%	3.8%	2.2%	2.2%	4.0%	4.4%	4.4%	4.5%

3.92. The assumptions for real price effects for materials vary both by GDN and by type of material.

3.93. Approximately 13 per cent of total forecast direct opex, capex and repex for 2008-09 to 2012-13 is a result of companies forecasting increases in costs which exceed the rate of inflation.

3.94. In the third consultation document, we explained that we continue to support the retention of the RPI as the key price index and do not propose to link any cost allowances to alternative cost indices, apart from gas shrinkage. We will consider RPEs in determining levels of ex-ante cost allowances and efficiency target. This will take account of the balance between real cost increases and efficiency savings.

3.95. All GDNs have stated that they face potential skills shortages in some of the key areas of their business which if not addressed now will become an increasing issue over the medium term. In addition, we have been approached by EU Skills (the Sector Skills Council for the industry) who are working with the GDNs on possible collaborative approaches to addressing these potential long and short term skills shortages. We support this approach to the extent that it brings benefits, for example, by being a more effective and lower cost means of securing future skills to the industry. We note similar examples in other sectors such as the power academy in electricity.

[8] In their BPQ submissions a number of GDNs presented real price effects net of efficiency savings. We have presented their real price effects before such efficiency savings are deducted.

Direct Labour

3.96. We have reviewed a range of recent information on real wage growth including:

- worked commissioned by NGG as part of the transmission review (TPCR);
- information from the Income Data Services pay reports;
- recent pay settlements for SSE and NGG; and
- the Inbucon report commissioned by Ofgem for TPCR.

3.97. These indicate that real wage growth is in the range of 0.4 to 1.7 per cent per annum with most pay settlements relevant or comparable to the utility sector being in the range of 0.5 to 1.2 per cent.

3.98. There is real wage growth within the RPI for the economy as a whole. It is only appropriate to allow an element for real wage growth to the extent that there are differences between the proportion of a GDNs' costs represented by labour and the proportion in the economy as a whole. We are giving further consideration to whether it is appropriate to make an allowance for real wage growth and if so the appropriate level of the allowance. We would welcome views in this area.

Contract Labour

3.99. We have reviewed some relevant historical indices for growth in contractors' rates. The Baxter index has been used historically in GDNs' engineering period contracts[9]. It may overestimate real growth in costs in gas distribution as it is focused more on steel construction work which requires a limited workforce with more specialist expertise. The Road Construction Index is a possible alternative indicator of market trends in costs but is arguably less relevant to gas distribution.

3.100. We have calculated historical annual average growth rates for a number of periods for each of these indices as set out in Table 3.10 below.

[9] This index is created using a defined weighting of various components, based on the percentages used by our consultants and the GDNs: 53 per cent labour and supervision, 22 per cent Plant and Road Vehicles, 7 per cent Aggregates, 2 per cent Cements, 7 per cent Coated Macadam & Bituminous Products, 3 per cent DERV Fuel, 1 per cent Gas Oil Fuel and 5 per cent Fixed.

Table 3.10 – Market data on real growth in contractors' rates excluding RPI

Average Annual Road Construction 1990-2006	Average Annual Road Construction 2000-06	Average Annual Baxter 2000-06	Baxter 2005-06	Road Construction 2006
1.95%	3.02%	2.80%	0.24%	4.02%

3.101. These suggest significant variations in growth with real prices depending on the period that is chosen. We are currently considering whether it is appropriate to make an allowance for growth in contractors' rates and possible sources of forecast information.

Materials

3.102. The latest BCIS report highlighted that materials prices would increase slightly during the second half of 2006 and early 2007 due to increases in the price of steel, oil and copper. It indicated that prices would then be in line with the RPI. Penspen's review of pipeline construction unit costs for TPCR indicated a similar trend. We are giving further consideration to real growth in materials costs.

Treatment of pensions costs

3.103. Ofgem's policy on pensions was first set out in 2003[10]. Cash pension contributions relating to service within the price control period are reviewed as part of total operating costs, and then, based on the forecast level of contributions reviewed as a proportion of underlying salaries to identify the explicit pensions allowance within the total opex allowance. The opex analysis within this chapter has been based on a combination of normalised and actual levels of pension contributions for 2005-06 and 2006-07. The total cost allowance will vary to reflect actual pension contribution rates, where the benchmark operating cost level for future years is impacted by changes in those contribution rates.

3.104. Should actual pension costs differ from allowed pension costs due to changes in the ex ante assumptions underlying the pension allowance, then these are allowed through an ex post adjustment within the subsequent price control. Should a GDN choose to fund more or less than the amount required by an actuarial valuation, a similar adjustment is made, subject to ensuring that consumers are not disadvantaged by the additional or reduced level of contributions.

[10] The pension principles were first outlined in Developing Monopoly Price Controls, Initial Conclusions, June 2003, and then applied within DPCR4 and TPCR.

3.105. In addition, an allowance will be given for funding pension deficits attributable to current and former employees of the transportation business, but excluding costs attributable to other members of the pension schemes, including those employed in excluded service and de minimis activities.

3.106. Ofgem's pension principles state that these cash costs of servicing defined benefit schemes will be allowed in full, subject to being reasonable and prepared in line with normal actuarial practice. We have reviewed the assumptions used by the GDNs actuaries, and can find no evidence that they are not reasonable and in line with normal actuarial practice. We have also found no evidence that there has been a failure of stewardship in respect of the scheme management for any of the schemes.

3.107. Nevertheless, the total level of funding required to meet these cash costs has led us to review whether the application of certain of the pension principles need to be reviewed to reflect changing circumstances. All GDNs have provided final or draft proposed actuarial contribution rates. The contribution rates and funding levels for the GDN defined benefit schemes are as follows:

Table 3.11: GDN Proposed Funding Rates for Defined Benefit Schemes

	NGG	NGN	Scotia	WWU
Future accrual contribution rate	31%	31%	37%	39%
Past accrual funding level	97%	85%	77%	82%

3.108. These variances are despite the schemes having the same benefit packages, and being funded at the same level at 31 May 2005. For comparison, average future accrual contribution rates for electricity Transmission Owners (TOs), which were performed at approximately the same date, are approximately 25 per cent, and the government review of UK schemes as a whole indicated a UK average contribution rate in 2005 of 16 per cent, an increase of 1.5 per cent year-on-year on 2004[11].

Choice of funding valuation basis

3.109. Our pension principles conclude that, as long as a funding valuation uses actuarial assumptions which are reasonable and in line with best practice that the costs will be allowed in full. To the extent that there are differences in valuation basis, the impact on customers will normally be small, and will only result in timing differences. In addition, where benchmarking techniques are used at a total opex level, there are incentives on GDNs and other network companies to negotiate efficient levels of contribution rates, since lower contribution rates will reduce the portion of pension contributions within Total Operating Costs, and therefore increase

[11] "Occupational Pension Schemes, 2005", Government Actuary's Dept, p. 94.

the allowed level of pensionable salaries. Most network schemes also have some proportion of members employed in non-regulated activities.

3.110. While this continues to be our preferred approach, we recognise that it poses some risks to consumers which were not observed in previous reviews:

- the very high level of contributions could, in the future, result in a stranded surplus which is unavailable to consumers in the medium-term, since Trustees may be unwilling to accept reduced contribution levels or returns of surplus at future reviews; and
- the increased focus since the Pensions Act 2004 on the strength of the employers' covenant may result in customers paying for the higher contribution levels required by Trustees whose sponsors have adopted higher-risk financing structures.

3.111. To address these concerns we are considering three options for determining ex ante allowances on which we welcome consultation responses. Option 1 in particular would represent a divergence from our established pension principles.

Option 1

3.112. As with the total operating cost review, the ex ante operating cost pension allowance should be based on a benchmark contribution rate derived from analysis of GDN and comparable company contribution rates.

Option 2

3.113. As with tax or the return on capital, our allowances should reflect the contributions that would be made by a notional GDN with comfortably investment-grade financial position. To the extent that the observed contribution rates of those network companies with a more aggressive financial profile are higher, we would set an ex ante allowance which we evaluated as a best estimate of the contributions which would be made by such a notional GDN.

Option 3

3.114. The ex ante approach should be maintained at present, but to the extent that a surplus arises in future, there will be an ex post review of whether that surplus has arisen as a result of high contribution rates. If so, then that surplus will be used for the benefit of consumers to reduce future pension allowances, regardless of whether the Trustees agree to reduce future cash contribution rates.

3.115. In the case of either option 1 or 2 GDNs would still be able to recover actual contributions at future reviews through the over-funding mechanism, as long as they did not result in a stranded surplus. While these approaches may result in lower allowances for ongoing pension contributions and/or deficits, they may not impact total operating cost allowances for GDNs which are not at the efficiency frontier, since the operating cost allowances may be unchanged – with more being allowed as salaries, with lower associated contribution rates.

Equalisation of incentives

3.116. As a result of the high variability of pension contribution rates, our pension principles include a Pension Correction Mechanism ("PCM") which corrects for differences between ex ante assumptions of pension contributions and ex post actual cash contributions made. The PCM allowance is allowed over time on a NPV-neutral basis, and the GDNs will receive allowances in 2007-08 to 2012-13 in respect of over-funding between 2003-04 and 2006-07.

3.117. We have received consultation responses which indicate that isolating the pension contributions from other opex, and applying the PCM to actual cash contributions, is impacting the incentives for GDNs to reduce different categories of operating costs, depending on whether cost reduction has a knock-on effect on total pension contributions. Given that the GDPCR review is expected to have a large focus on achieving efficiencies in operating costs within the GDNs, we consider that it is appropriate to adjust the future application of the PCM for the GDNs, to equalise incentives between employment costs and other opex. Under the current formulation, the PCM allowance is calculated for the GDNs as:

(Actual cash contribution) - (Cash allowance)

in both cases where the cash numbers relate to the pension contributions within the regulated business only. We suggest that, for 2007-08 to 2012-13 the impact of the PCM is limited to changes in actuarial valuations only, i.e.:

(Actual DB cash contribution) – (Actual DB pensionable salary * allowed contribution rate)

This will result in efficiency savings being retained by the GDNs within the GDPCR review period, and inefficiencies being borne by the GDNs.

4. Capital and replacement expenditure analysis

Chapter Summary

This chapter sets out the analysis our consultants have carried out in assessing the GDNs' forecast capital (capex) and replacement (repex) expenditure and their initial recommendations.

Question box

Question 1: What are your views on PB Power's adjustments to the GDNs' forecast capital and replacement expenditure?
Question 2: What are your views on PB Power's general approach to the assessment of costs?
Question 3: What are your views on PB Power's approach to the cost assessment for each activity?
Question 4: Is it appropriate at this time to reconsider the approach to prioritisation within the risk model for the Mains Replacement Programme and should the approach to encroachment and diversions be amended?

Introduction

4.1. In October, we received responses to the BPQs for each of the GDNs setting out their historical and forecast costs. Tables 4.1 and 4.2 below set out a summary of the forecast net capex and repex for each GDN for 2008-09 to 2012-13 after accounting adjustments (discussed in chapter 2) and further activity level adjustments (discussed later in this chapter) to bring the data on to a consistent basis across companies.

4.2. We have appointed PB Power to carry out a detailed assessment of each GDN's expenditure requirements. Over the last few months PB Power has reviewed the GDNs' BPQ submissions on historical and forecast costs and raised supplementary questions to gain a better understanding of the historical data and forecasts, address issues of inconsistency across GDNs and, where appropriate, gather additional information to support the cost assessment.

4.3. PB Power has, together with Ofgem staff, attended costs visits to each GDN to discuss the BPQ submissions, ask follow-up questions and to challenge and improve their understanding of the GDNs' forecast assumptions. PB Power has then carried out detailed cost analysis to assess efficiency and make recommendations on appropriate levels of expenditure. It is important to note that these are preliminary recommendations at this stage presented by consultants to Ofgem. A key part of our work in developing initial proposals will be to consider which parts of the analysis are robust and should be applied and which parts of the analysis are less appropriate or require further work.

4.4. PB Power's analysis has included:

- a high-level assessment of policies, procedures and forecasting processes associated with capex and repex, including criteria for investment and project approval and their approach to asset management;
- reviewing GDNs' forecast costs to understand whether they are based on appropriate assumptions including the justification for their workload forecasts, assumptions for productivity and real price growth;
- assessing GDNs' efficiency for particular capex and repex activities by benchmarking costs across GDNs;
- carrying out bottom-up analysis to consider the appropriate costs for particular activities based on information submitted in the BPQ and their engineering experience; and
- reviewing certain key activities to consider the scope for ongoing efficiency savings through new ways of managing the work, improved systems etc.

4.5. The types of technique that PB Power has applied have varied by activity depending on the nature of the work, availability and consistency of data across the GDNs and scope for comparisons.

4.6. The following sections describe PB Power's approach to the assessment of capex and repex in more detail and discuss their initial findings. We first describe the results of their work on policies and procedures, followed by the general approach to cost assessment and then specific detail relating to each area of expenditure.

Table 4.1 Total GDN forecast net capex 2008-09 to 2012-13 (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU		
GDN Net Capex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**North England**	**Scotland**	**South England**	**Wales & West**	**Total GDN**	**Average annual GDN spend**
LTS & Storage	53.3	84.3	57.7	9.7	75.2	78.4	213.8	111.0	683.4	17.1
Connections	47.5	30.3	21.7	17.5	47.0	52.8	47.1	46.7	310.5	7.8
Mains Reinforcement	14.2	11.1	12.8	11.4	24.7	38.3	71.9	34.5	218.8	5.5
Governors	2.9	9.7	15.7	3.1	8.9	19.0	53.0	9.4	121.5	3.0
Other Operational	9.3	7.9	7.8	7.1	26.3	26.5	27.6	29.5	142.0	3.5
Non Operational	84.8	59.0	63.7	43.1	78.3	35.9	61.8	75.9	502.4	12.6
Total Net Capex	**211.9**	**202.3**	**179.3**	**92.0**	**260.3**	**250.8**	**475.2**	**306.9**	**1978.7**	**49.5**

Table 4.2 - Total GDN forecast net repex 2008-09 to 2012-13 (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU		
GDN Net Repex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**North England**	**Scotland**	**South England**	**Wales West**	**Total GDN**	**Average annual GDN spend**
Mains	338.9	332.1	351.6	234.5	253.4	215.7	521.2	247.7	2495.0	62.4
Services	178.9	157.9	149.4	110.2	128.3	137.0	383.7	146.7	1391.9	34.8
LTS	0.0	0.2	0.0	0.0	37.1	0.3	18.4	36.4	92.4	2.3
Total Net Repex	**517.8**	**490.1**	**500.9**	**344.6**	**418.9**	**353.0**	**923.2**	**430.8**	**3979.3**	**99.5**

Capex and repex analysis

Policies and procedures

4.7. PB Power has reviewed the GDNs' policies and procedures governing capital expenditure, including processes for investment appraisal and found no major issues. They also found their forecasting processes to be reasonable, but have challenged detailed assumptions through benchmarking and other cost assessment work as discussed below.

General approach to the cost assessment

4.8. There are a number of key steps in PB Power's cost analysis.

Workload assessment

4.9. PB Power has reviewed the workload forecasts submitted by each GDN to ensure that they are appropriately justified, consistent with historical trends, their stated forecasts assumptions and external factors including the HSE's requirements. For example, PB Power has reviewed large LTS capex projects to ensure that they are consistent with demand forecasts and the GDNs' 1 in 20 requirements. PB Power has reviewed connections and mains reinforcement workloads examining whether they are consistent with future demand growth and assumptions regarding market share. Where appropriate PB Power has recommended adjustments to the workload forecasts where outliers were found.

Adjustments for inconsistencies between GDNs

4.10. As discussed in chapter 2 it is important to ensure that there is good quality comparable information. PB Power has carried out adjustments to bring activity level information on to a consistent basis. This included applying the accounting adjustments discussed in chapter 2 and carrying out further detailed work to ensure that there is consistency at an activity level. While there were only relatively small differences in accounting treatment for overall opex, capex and repex, there were greater differences in the categorisation of costs between activities, particularly for direct opex. PB Power has recommended transfers of costs between activities (for example, between mains and governor capex) and between areas of expenditure (for example, between capex and direct opex) to address these inconsistencies.

4.11. For NGG the capex associated with the Outer Met area was assessed as part of the London Network and repex associated with this area was assessed as part of the East of England Network. This is consistent with the way in which the disaggregated costs and workload were reported by NGG.

Regional differences

4.12. PB Power considers that there are some significant regional differences in salaries for direct labour and contractors' rates which drive some of the variation in costs between GDNs. As detailed in chapter 3, PB Power has applied estimated regional adjustments for both contract and direct labour for all GDNs as set out in Table 3.8.

4.13. PB Power has then used two main techniques to assess an efficient level of costs in the base year: comparative benchmarking and bottom-up assessments based on engineering experience and GDNs' data to form a judgement on the appropriate levels of costs.

Benchmarking across GDNs

4.14. For each activity PB Power has considered the appropriate level of detail at which to carry out the analysis, the appropriate workload driver(s) and the form of regression[12] or unit cost analysis.

4.15. For example, PB Power has focused its connections analysis on total connections costs. It has used a weighted average of different connections work elements (e.g. specific reinforcement, mains and services work) for existing housing, new housing and non-domestic connections as the workload driver.

4.16. PB Power has determined the efficiency benchmarks based on the upper quartile level of costs. As discussed in chapter 3, this effectively means that the benchmark costs are set between the second and third lowest costs of the 8 GDNs.

4.17. Further detail is set out below on the approach used for each activity.

Bottom-up or activity-specific analysis

4.18. For activities where benchmarking was less appropriate or further analysis was needed to support the results of the benchmarking, PB Power has carried out a bottom-up assessment based on its experience and detailed information gathered from the GDNs to form a judgement on the appropriate levels of expenditure. It has also carried out some analysis that is tailored to specific activities, such as assessing the unit costs for particular pipeline diameters.

[12] PB Power has used log-linear regressions for most activities where regression analysis was found to be appropriate but has made use of linear regressions in some cases.

Gap closure

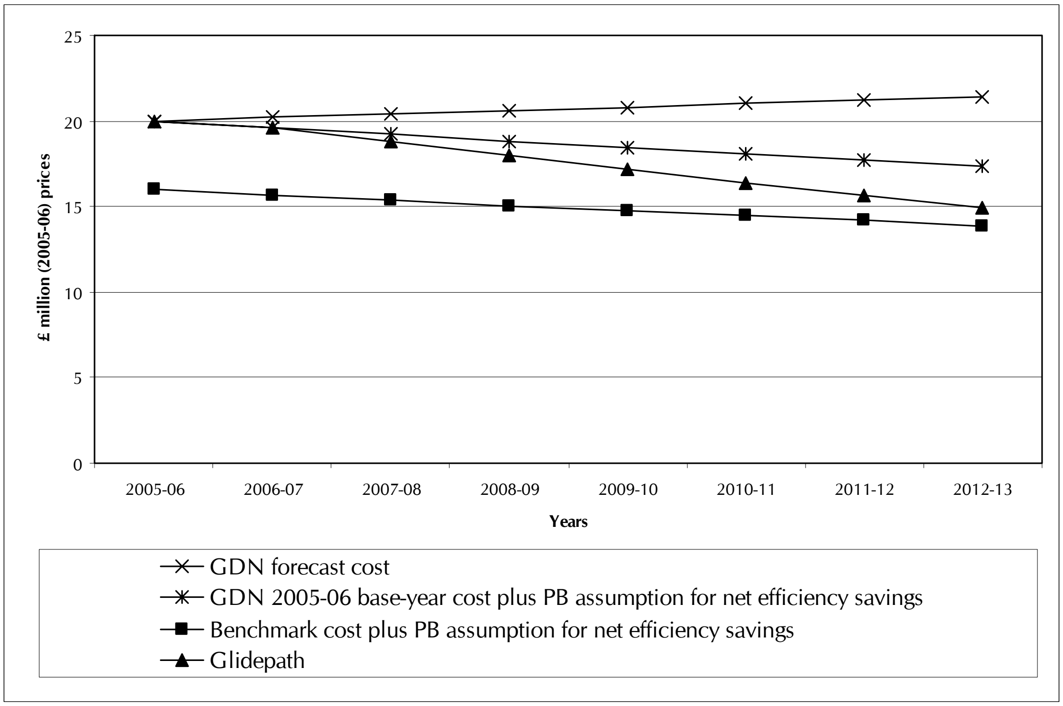
4.19. PB Power has used the GDNs' actual costs and the benchmark costs for the base year to determine projections for 2008-09 to 2012-13. PB Power has used its experience and information provided by the GDNs to form a judgement on the appropriate level of real price effects and the scope for ongoing efficiency savings that can be achieved by even the best performing GDNs.

4.20. PB Power has applied a 2.25 per cent per annum growth in contractors' rates based on evidence from the Baxter and Road Construction Indices. It has applied 1 per cent per annum growth in real wages based on evidence from the DTI Employment Relation Research series and the Annual Survey of Hours and Earnings (ASHE). It has applied 1 per cent per annum real growth in material costs. The ongoing efficiency savings vary by activity.

4.21. PB Power has then rolled forwards the GDNs' costs in the base year and the benchmark costs to reflect these real price effects and its projected ongoing efficiency savings. The resulting profiles are labelled “GDN base year costs plus PB assumptions for net efficiency savings” and “Benchmark costs plus PB assumptions for net efficiency savings”.

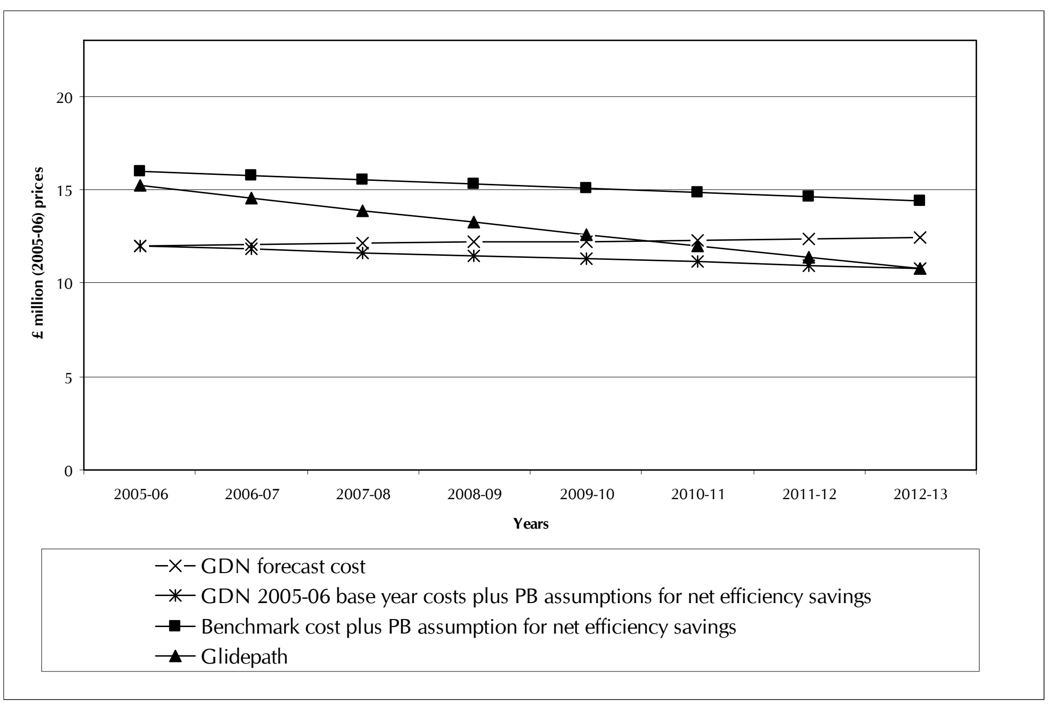
4.22. Where the GDN's base year costs are higher than the benchmark costs PB Power has assumed that they will close 70 per cent of the gap by the end of the price control period, 2012-13. Where GDNs' performance is already better than the benchmark, PB Power has assumed that they will retain some of the benefits of outperformance for part of the price control period. These two cases are illustrated in the Figures below.

Figure 4.1 Glidepath for underperforming GDN



4.23. PB Power's overall efficiency savings are the difference between the GDNs' forecast costs and the glidepath profile.

Figure 4.2 Glidepath for outperforming GDNs



4.24. PB Power’s efficiency adjustments are the difference between the GDN’s forecast costs and the glidepath. Under this approach the GDN receives a reward for outperformance at the beginning of the price control period but has to make efficiency savings or mitigate cost increases to meet the allowance at the end of the period.

Approach to the cost assessment for each activity

4.25. The following sections explain the main elements of PB Power's cost analysis for each capex and repex activity. Further details are set out in Appendices 8 and 9. PB Power's recommended adjustments are set out in Tables 4.3 and 4.4 below.

LTS and storage capex

4.26. Simple benchmarking analysis of total costs is inappropriate for LTS and storage capex as levels of investment will depend on forecast patterns of supply and demand for each GDN, levels of capacity required to meet the 1 in 20 requirements and existing network constraints.

4.27. PB Power's analysis has therefore been tailored to this area of expenditure. PB Power has examined the GDNs' demand and supply forecasts that underpin their capex projections and compared them to the NGG NTS forecasts and forecasts in their ten-year statement. PB Power has noted that a number of the GDNs are forecasting faster demand growth for 2005-06 to 2008-09 than NGG (NTS) but a slower level of demand growth from 2008-09 to 2012-13. This may lead to LTS and storage capex being incurred earlier in the price control period. PB Power has not recommended any adjustments based on this information but further work is needed in this area.

4.28. PB Power has reviewed each of the major LTS and storage projects on a case-by-case basis. It has been noted that a number of planned projects or phases of projects are inconsistent with the base case assumptions stated in the BPQ guidance. The guidance stated that the GDNs should assume they would be able to continue to purchase existing NTS capacity at administered prices and would be able to purchase incremental capacity through user commitment. PB Power has adjusted the GDNs' forecasts to remove this expenditure but this will need to be given further consideration once the form of the enduring NTS capacity arrangements has been decided.

4.29. PB Power has developed benchmark unit costs per kilometre for pipelines of different diameters based on comparisons of historical and forecast costs submitted by the GDNs. All real price effects have been removed to bring the costs onto a consistent basis. PB Power has based the benchmarks on median values of costs for each diameter, with adjustments to remove additional costs which reflected specific circumstances (for example rail and river crossings) and to ensure that costs were increasing in diameter. The lower quartile was taken for the largest diameter (1200 mm) since the data set included projects with particular route difficulties and individual adjustments would be appropriate for such projects. PB Power has reviewed the costs of the pipeline projects against these benchmarks, taking into account specific circumstances which may lead to higher than average costs, and has recommended a number of efficiency adjustments.

4.30. PB Power has also made a high level assessment of whether the total level of expenditure on capacity related projects is consistent with forecast increases in demand and forecast requirements for additional diurnal storage. PB Power has estimated a reference cost of diurnal storage of £50 million per million cubic metres (mcm) based on a pipeline length of 12 km providing 0.1 mcm of storage. Where GDNs' storage costs exceed twice this reference level PB Power has applied adjustments to reduce their expenditure.

4.31. PB Power is proposing significant reductions in LTS capex in particular for SGN. The reduction is principally due to the deferral of a pipeline construction project proposed by SGN for 2012/13 in South England GDN into the next price control period and a reduction in RPEs. Diurnal storage analysis carried out by PB Power indicates sufficient capacity within the South England network without this project.

Mains reinforcement

4.32. PB Power has reviewed each GDNs' mains reinforcement workload taking into account historical trends, forecast demand growth and the impact of the mains replacement programme. It has not made any changes to the proposed workloads.

4.33. PB Power has assessed the efficiency of mains reinforcement work in 2005-06 through regression analysis with a weighted average of workload for different pipe diameters as the cost driver. This has been calculated by multiplying the work volume for different pipe sizes by reference unit cost for those pipe sizes based on historical actual and forecast information provided by the GDNs.

Governors

4.34. PB Power has reviewed the GDNs' forecasts for governor replacement in the context of historical trends and the policies for governor replacement. PB Power has identified that a number of the governors due for replacement should have been replaced under policies instigated in previous price control periods. PB Power has recommended that the costs associated with these installations should be removed as they should have been incurred in previous price control periods.

4.35. PB Power considers it inappropriate to carry out unit cost or regression analysis to assess levels of efficiency for governors as there are wide variations in costs that are driven by design pressure and complexity of site installations. They have reviewed the GDNs' own unit cost forecasts taking into account historical and forecasts trends and the GDNs' forecast assumption. PB Power has made no adjustments for efficiency but has replaced the GDNs' estimate of real price effects with its own as discussed in paragraphs 4.19 and 4.20 above.

Connections

4.36. PB Power has reviewed the GDNs' forecast workloads against historical information and data on connections market shares. PB Power has also compared the forecast length of main per service across GDNs. PB Power has recommended that Scotland's forecast for the number connections to existing housing should be reduced by 12,000 reflecting uncertainty over the ongoing level of Local Authority sponsored housing modernisation schemes. They have recommended that WWU's forecast workload for kilometres of mains associated with connections should be reduced by 20 per cent to bring them down to the national average.

4.37. As discussed in paragraph 4.14, PB Power has assessed the efficiency of GDNs' connections costs in 2006-07 through regression analysis with weighted average workload as the cost driver. The weighted average workload has been calculated by multiplying the volume of each element of work (e.g. governors, specific reinforcement work, mains and service work for existing housing, new housing and non-domestic connections) by average unit costs. PB Power has used the average of the results from the total and disaggregated cost regressions to calculate the benchmarks and levels of efficiency.

Other operational capex

4.38. Other operational capex includes expenditure on land and buildings for operational sites and plant and equipment.

4.39. PB Power has compared total forecast capex for land and building for the 5-year period across GDNs. It considers that the lowest cost GDN is an outlier and has benchmarked costs on the basis of the upper quartile performance of the remaining 7 GDNs. PB Power has recommended adjustments for companies above this level. PB Power has also benchmarked total plant and equipment capex across GDNs.

Non-operational capex

4.40. Non-operational capex includes System Operations, IS, xoserve capex, vehicles and a number of smaller items including telecoms and security. LECG has reviewed IS infrastructure and hardware capex, IS support costs and total IS opex and capex. PB Power has reviewed the remaining areas of non-operational capex including large IS projects. Further work is ongoing in this area.

4.41. In the third consultation document Ofgem set out the following principles regarding the allowable costs for GTMS replacement:

- Ofgem must be satisfied that GTMS is obsolete before any replacement costs are allowed, and
- Only efficient costs of GTMS replacement would be allowed. Any additional costs incurred to bring forward SOMSA exit would not be allowed, nor any additional

costs associated with bringing forward GTMS replacement to facilitate SOMSA exit.

4.42. PB Power considers that GTMS is obsolete, as from 2009 spares will no longer be available and the operating system will no longer be supported. PB Power considers that the proposed timing of replacement is prudent and the collaborative programme that has been put forward is the most efficient means of replacement. PB Power has recommended that the full forecast costs associated with GTMS replacement should be allowed and PB Power has estimated the costs which are associated with SOMSA exit and which should be disallowed in accordance with Ofgem's principles.

Mains and services repex

4.43. PB Power has reviewed the mains and service replacement workload for each GDN including the split of the mains workload by diameter and the relationship between mains and services volumes. This has taken into account each GDNs' remaining iron mains population, the number of remaining years of the mains replacement programme and comparisons of GDNs' assumptions for the ratio of mains abandoned to mains installed.

4.44. PB Power has applied a number of adjustments to GDNs' workload including:

- reducing the number of kilometres of mains abandoned where this exceeded the rate required to remove remaining iron mains by 2031, allowing for a "ramp-down" at the end of the period,
- adjustments to the diameter mix so that there is a reasonable match with the remaining iron mains population taking into account some downsizing due to insertion, and
- adjustments to service workloads to bring them into line with historical trends or based on comparisons across GDNs.

4.45. PB Power has recommended that an allowance be made for replacement of risers in multi-occupancy buildings based on a replace on failure approach. It has recommended that costs above this level should be disallowed pending the completion of further survey work to identify the population of risers needing replacement and further industry discussion. Work is ongoing in this area.

4.46. PB Power has assessed the efficiency of mains replacement work in 2005-06 through regression analysis with a weighted average of workload for different pipe diameters as the cost driver. This has been calculated by multiplying the work volume for different diameters of mains installed and different categories of service replacement by reference unit costs based on contract information provided by the GDNs.

LTS repex

4.47. There are a small number of large LTS replacement projects forecast in the next price control period. PB Power has made adjustments to the GDNs' forecast costs for these projects by replacing the GDNs' forecast real price effects with its own. In addition it has recommended that repex which is not associated with specific projects should be removed. If this expenditure were needed in the timescales indicated named projects should have been included in the forecasts.

PB Power's recommendations

4.48. PB Power's recommended adjustments to the GDNs' forecast capex and repex for 2008-09 to 2012-13 is set out in Tables 4.3 and 4.4 below.

4.49. As discussed in paragraph 4.3 above it is important to note that these are draft recommendations to Ofgem. These recommendations will be updated further by our consultants over the next months. A key part of our work in developing initial proposals will be to consider the PB Power recommendations together with comments and other evidence presented by the GDNs to determine where adjustments are appropriate and how they should be quantified.

Table 4.3 - PB Power adjustments and recommendations for net capex (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU		
GDN Net Capex 2008-09 to 2012-13	**East of England**	**London**	**North West**	**West Midlands**	**North England**	**Scotland**	**South England**	**Wales & West**	**Total GDN**	**Average annual GDN spend**
LTS & Storage	53.3	84.3	57.7	9.7	75.2	78.4	213.8	111.0	683.4	17.1
Connections	47.5	30.3	21.7	17.5	47.0	52.8	47.1	46.7	310.5	7.8
Mains Reinforcement	14.2	11.1	12.8	11.4	24.7	38.3	71.9	34.5	218.8	5.5
Governors	2.9	9.7	15.7	3.1	8.9	19.0	53.0	9.4	121.5	3.0
Other Operational	9.3	7.9	7.8	7.1	26.3	26.5	27.6	29.5	142.0	3.5
Non Operational	84.8	59.0	63.7	43.1	78.3	35.9	61.8	75.9	502.4	12.6
Total Net Capex	**211.9**	**202.3**	**179.3**	**92.0**	**260.3**	**250.8**	**475.2**	**306.9**	**1978.7**	**49.5**
PB recommended adjustments										
LTS & Storage	-6.8	-16.6	-9.8	-0.1	-6.9	-21.8	-65.1	-32.8	-159.8	-4.0
Connections	-12.0	-5.7	-3.0	-3.2	-12.0	-9.8	-9.7	-15.5	-71.0	-1.8
Mains Reinforcement	0.2	-2.2	-2.0	-0.1	-1.0	-8.6	-12.6	-0.9	-27.1	-0.7
Governors	0.0	-6.8	-13.2	-1.9	-0.3	-2.3	-14.0	-6.4	-44.8	-1.1
Other Operational	-1.3	-0.7	-0.5	-0.4	-5.0	-6.4	-6.5	-11.1	-31.8	-0.8
Non Operational	-0.2	-0.1	-0.2	-0.2	-6.8	0.7	1.2	-7.2	-12.6	-0.3
Total Net Capex	**-20.0**	**-32.0**	**-28.7**	**-5.8**	**-31.9**	**-48.2**	**-106.6**	**-73.9**	**-347.2**	**-8.7**
PB recommended projections										
LTS & Storage	46.5	67.7	47.9	9.6	68.4	56.6	148.7	78.2	523.6	13.1
Connections	35.5	24.6	18.6	14.3	35.0	42.9	37.4	31.2	239.5	6.0
Mains Reinforcement	14.4	8.9	10.8	11.4	23.7	29.6	59.3	33.6	191.7	4.8
Governors	2.9	2.9	2.4	1.2	8.6	16.7	39.0	3.0	76.7	1.9
Other Operational	8.0	7.2	7.3	6.7	21.3	20.1	21.1	18.3	110.2	2.8
Non Operational	84.6	58.9	63.5	42.9	71.5	36.6	63.0	68.7	489.8	12.2
Total Net Capex	**191.9**	**170.3**	**150.6**	**86.1**	**228.5**	**202.6**	**368.5**	**233.0**	**1631.5**	**40.8**

Table 4.4
- PB Power adjustments and recommendations for net repex (£m, 2005-06 prices)

	NGG				NGN	SGN		WWU	Total GDN	Average annual GDN
GDN Net Repex over 2008/09 to 2012/13	**East of England**	**London**	**North West**	**West Midlands**	**North England**	**Scotland**	**South England**	**Wales & West**		
Mains	338.9	332.1	351.6	234.5	253.4	215.7	521.2	247.7	2495.0	62.4
Services	178.9	157.9	149.4	110.2	128.3	137.0	383.7	146.7	1391.9	34.8
LTS	0.0	0.2	0.0	0.0	37.1	0.3	18.4	36.4	92.4	2.3
Total Net Repex	**517.8**	**490.1**	**500.9**	**344.6**	**418.9**	**353.0**	**923.2**	**430.8**	**3979.3**	**99.5**
PB recommended adjustments										
Mains	6.5	4.7	-56.7	-29.9	-19.3	-59.0	-129.5	-16.1	-299.4	-7.5
Services	-29.6	-39.2	-30.5	-26.6	-5.0	-48.5	-143.4	-32.8	-355.7	-8.9
LTS	0.0	0.0	0.0	0.0	-1.2	0.0	-1.0	-2.4	-4.7	-0.1
Total Net Repex	**-23.2**	**-34.4**	**-87.2**	**-56.6**	**-25.6**	**-107.5**	**-273.9**	**-51.3**	**-659.7**	**-16.5**
PB recommended projections										
Mains	345.4	336.8	294.9	204.5	234.1	156.7	391.6	231.6	2195.6	54.9
Services	149.3	118.7	118.8	83.5	123.3	88.4	240.3	113.9	1036.2	25.9
LTS	0.0	0.2	0.0	0.0	35.9	0.3	17.4	34.0	87.7	2.2
Total Net Repex	**494.6**	**455.6**	**413.7**	**288.0**	**393.3**	**245.5**	**649.3**	**379.5**	**3319.6**	**83.0**

Repex programme

4.50. The cost of the repex programme is a key driver of GDN costs. The cost of the programme is rising significantly. In light of this and changes in NGG's approach to mains replacement, we have raised with the GDNs and the HSE whether a limited review is required of the risk modelling and the general approach to this programme.

4.51. In particular, the GDNs have until now focussed mainly on the replacement of the pipes forecast to have the highest risk to the public based on the distribution from the risk model. NGG is now moving to larger ‘postcode’ based projects to achieve efficiencies. In order to create these larger projects, more pipes with lower risk scores are included earlier in the replacement programme. To offset this and reduce the same level of risk annually, NGG is proposing to include a larger proportion of large diameter pipes which have higher levels of risk associated with them and increase the volumes of pipes replaced. This increases costs incurred in the 2008-2013 period potentially by more than the savings generated through carrying out larger projects in the first place. In addition, the statistical uncertainties involved in using the model to assess differences in the amount of risk removed between different pipes are increasing as absolute levels of risk of pipes remaining are reducing.

4.52. We are seeking views on whether, now or at some time in the future, the GDNs are sufficiently far down the risk curve that volume adjustments to maintain the total annual level of risk removal are appropriate given the statistical uncertainties with which it is possible to model risk. For instance the prioritisation approach on workload could be amended such that those pipes which still have relatively high risk are removed but the annual workload is then selected more generally from the remaining group. Such an approach would provide the GDNs with greater flexibility to deliver the repex programme more efficiently. We recognise that if there is a case for reconsidering the prioritisation model, the timing of this is likely to vary by GDN.

4.53. We note that there are also two further areas which contribute to the costs of the programme. The required level of repex is increasing each year due to new buildings being constructed within 30 metres of existing pipes (encroachment). However, the GDNs replace some of their pipes each year with PE pipes through general capex work or condition monitoring and the encroachment level is not adjusted to take account of this work. Also, we understand that mains diversions that replace pipes that are within 30 metres do not count towards the GDNs' level of risk removed per annum and yet will reduce the risk taken off the network. We seek views on whether adjustments should be considered to the repex programme to take account of these two relatively minor areas.

System Operator Managed Service Agreement (SOMSA) Exit

4.54. As part of DN sales it was expected that the new independent GDNs would set up their own separate system control centres in the period 18 months after sale. Due, in part, to the impact of this change on the relevant safety cases for the companies this process will take a longer period of time than originally envisaged. In line with our policy on costs arising from the DN sales process, the costs associated with exiting the SOMSA will be disallowed as part of the price control and be borne by the companies.

4.55. A central argument underpinning the benefits that arise from GDN sales came from the sense of rivalry that independent management teams carrying out the same activity would experience. Over time this would lead to differences in performance between GDNs which could be used to set tougher price controls than would otherwise be the case so that GDN customers would experience lower charges more quickly. In this respect the operation of system control would appear no different from any other aspect of the GDN's business. SOMSA exit should facilitate delivery of the full benefits of GDN sales.

5. Incentives

Chapter Summary

This chapter considers the issues associated with revenue drivers, the capex rolling incentive and information quality incentive as part of the gas distribution price control.

Question box

Question 1: Is it appropriate to retain the current volume driver?
Question 2: Is it appropriate to implement any of the revenue drivers discussed in this chapter and are there any other drivers that we should consider that we have not included in this chapter?
Question 3: Is it appropriate to strengthen the capex rolling incentives?
Question 4: Are our proposals for the treatment of offtake reform related costs and mains replacement costs under the IQI appropriate?

Introduction

5.1. The basic price regulation model of fixed allowances for expected costs (also known as RPI-X) provides strong incentives for companies to outperform our cost assumptions as the savings are retained by shareholders for the duration of the price control period. After this time the savings are passed on to consumers. However, RPI-X can give perverse incentives to companies, for example to cut back on the quality of service which they deliver to customers or to delay efficiency savings until the final year of the price control. The RPI-X incentives can also be undermined if there is significant uncertainty about some of the cost assumptions which could lead to companies making windfall profits or losses.

5.2. As part of the price control we have historically included additional incentives to counteract any perverse incentives that may arise from RPI-X regulation. In the context of this GDPCR this includes incentive mechanisms which have been developed in other price control reviews both within Ofgem and by other regulatory bodies. These formed the basis of the third consultation document. A summary of responses to these issues is set out in Appendix 5.

5.3. We will come forward with proposals as part of the May 2007 initial proposals document. In this chapter we have set out further detail on specific incentives, namely; revenue drivers, capex rolling incentives and the information quality incentive, which we consider require further consultation.

Revenue drivers

Rationale for revenue drivers

5.4. Revenue drivers may be appropriate where there is significant uncertainty about certain elements of a company's costs for the period of the price control. The risk is that GDNs could make windfall gains or losses if their costs are much lower or higher than their allowance. GDNs may also be less responsive to their customers' needs if they risk exposure to costs which they may not be able to recover ex post. Additionally, increased risks could impact GDNs' required cost of capital, particularly if the risks are perceived to be asymmetric.

5.5. With a revenue driver we can set, for example, the unit costs as part of the price control review but the allowance would be based on actual volumes. During the price control period the company undertakes the appropriate volume of work and has incentives to minimise unit costs in order to maximise its efficiency gains.

5.6. Revenue drivers do, however, increase the complexity of price controls. They can also place an additional burden in terms of implementing, monitoring and auditing the drivers. The revenue driver needs to be clear and easily measurable to ensure that volumes cannot be manipulated or artificially inflated by the companies.

5.7. In our second consultation document we consulted on the volume driver and sought views on whether other forms of driver may be appropriate. In both the second and third consultation documents we noted that we intended to set out our initial view on the revenue drivers in our initial proposals document. In this document we set out the analysis we have undertaken to date on the revenue drivers and are seeking views, given the analysis, on whether any or all of the revenue drivers discussed are appropriate for the next price control period.

5.8. In order to evaluate whether a variable is an appropriate candidate for a revenue drive we propose to consider it where:

- the costs vary materially;
- the costs are difficult to forecast;
- the variation in cost is out of the GDN's control; and
- the variable can be easily measured and independently audited.

5.9. We will also want to consider how any drivers fit with the GDNs' charging structure so that as a package we make gas distribution charges easier to predict.

The volume driver

5.10. In the current price control, a proportion of the GDNs' allowed revenue is subject to a volume driver which has the effect of varying the GDNs' allowed revenues with gas throughput on their networks. The rationale is that the GDNs' costs of operating the network increase if the volume of gas flowing through the network increases.

5.11. The volume driver protects the GDNs from the costs that arise from increasing throughput on the network, for example increased shrinkage costs. Under the current arrangements the volume driver constitutes 35 per cent of the core allowed revenue while 65 per cent of the revenue is fixed. The volume driver mechanism is designed for a price control covering several years and so is not applicable for the one year price control extension.

5.12. The volume driver is calculated using different weights for different loads on the GDN networks. A 100 per cent weighting is given to loads up to 5,860MWh per year, a 15 per cent weighting is given to loads between 5,860MWh and 1,465GWh and a 5 per cent weighting is given to loads greater than 1,465GWh per year. The weighting was determined on the basis that larger loads tend to be connected to higher pressure tiers of the distribution network and therefore use less of the network than smaller loads.

5.13. The current volume driver was derived from analysis as part of the 2002 price control review. As part of the review it was noted that capacity requirements are driven by peak capacity which could be represented by the level of annual demand. The analysis included a review of the marginal cost of LDZ capacity and peak demand volumes and concluded that the cost of additional capacity was approximately 25 to 50 per cent of total allowed revenues. The 35 per cent volume driver reflected a value within this range.

5.14. The revenue driver takes account of throughput growth by comparing throughput volumes in the previous year to growth in the current year. Steady growth over the price control period, which was forecast at the time of the 2002 price control review, would therefore result in a year on year increase in revenue through the volume driver. This type of revenue driver is likely to be appropriate if additional throughput volumes require the provision of additional capacity in order to meet 1 in 20 peak demand requirements. However, for smaller variations in throughput and in particular throughput related to variations in weather, changes in throughput are unlikely to trigger significant changes in LDZ capacity.

5.15. In Appendix 11 we compare forecast throughput volumes with actual throughput volumes. The analysis indicates that there was around a 12 percent variance between average actual and forecast volumes. Throughput volumes, which were forecast to rise steadily over the price control period actually tended to be lower than forecast and fluctuated over this period. NGG has stated that the variance between forecast and actual throughput volumes has resulted in an adverse variance of approximately £53 million in volume driver revenue across its four GDNs over the last three years of the price control.

5.16. Table 5.1 shows aggregate annual GDN performance against the volume driver. The first row shows GDN revenues if 35 per cent of revenues did not vary with throughput but changed in relation to RPI-X only. The second row shows the revenues with the volume driver adjustment. The third row, the volume driver adjustment, is the difference between the first and second rows. Any variation in revenues from the volume driver would have arisen from variations in throughput. We consider that these variations in throughput are likely to have arisen from factors such as weather and gas price variations. In particular 2005-06 was considered to have a colder than average winter and volume driver revenues were higher in this year. In comparison 2006-07 has had a relatively mild winter and forecast throughput for 2006-07 relative to throughput in 2005-06 is expected to result in an adverse variance of £75.4 million.

Table 5.1 - Impact of volume driver aggregated across all GDNs with forecast data for 2006-07 (£m, 2005-06 prices)

	2002-03	2003-04	2004-05	2005-06	2006-07
Revenue without volume driver adjustment	2,064.8	2,009.6	1,968.0	1,942.6	1,906.1
Revenue with volume driver adjustment	2,064.8	2,020.6	1,962.3	1,953.8	1,830.7
Impact of volume driver on revenue	n/a	11.1	-5.7	11.2	-75.4

5.17. In their responses the GDNs questioned whether the current volume driver is appropriate and have noted the effect that a warmer or colder winter can have on collected revenues. They considered that their throughput related costs are appropriately 5-10 per cent of total transportation revenues[13] and indicated that the costs relate broadly to shrinkage and odorant costs[14]. As set out in table 5.2 ,our analysis shows that shrinkage costs vary between 2 and 7 percent of total transportation revenue. Data on odorant costs for 2005-06 appears to indicate that costs vary by between approximately £250,000 to £500,000 per GDN which relates to between 0.1 and 0.2 per cent of the relevant GDN's total transportation revenue for 2005-06. Given the magnitude of odorant costs these costs tend not to be reported separately in GDNs' BPQ responses.

[13] For the purposes of the analysis in this chapter total transportation revenues is the sum of annual capex, opex (including pensions and shrinkage) and repex costs and excludes other costs such as licence fees, rates, k factor adjustments etc.
[14] Some GDNs have noted that MEG costs (MEG is a chemical which is added as part of gas conditioning to reduce leakage) also vary with throughput but these costs appear to be in the order of tens of thousands of pounds per GDN and are therefore not reported separately by GDNs. Moreover, the mains replacement programme is likely to further lower these costs.

Table 5.2 Shrinkage gas costs as a percentage of total transportation revenue with forecast data for 2006-07

GDN	2002-03	2003-04	2004-05	2005-06	2006-07	Average
North West	3.90%	3.86%	4.32%	5.24%	5.27%	4.52%
East England	4.43%	3.85%	4.23%	5.17%	5.19%	4.57%
West Midlands	3.12%	2.74%	4.17%	6.61%	5.89%	4.50%
London	1.94%	1.62%	3.27%	5.55%	5.05%	3.49%
Northern	3.76%	3.68%	4.39%	6.07%	6.11%	4.80%
Scotland	3.88%	3.67%	3.21%	3.78%	4.33%	3.77%
South England	3.45%	2.70%	4.46%	6.68%	6.10%	4.68%
Wales and West	2.79%	2.60%	4.43%	5.50%	5.96%	4.26%
Total	**3.49%**	**3.11%**	**4.10%**	**5.59%**	**5.53%**	**4.33%**

5.18. Shrinkage gas costs reflect wholesale gas prices which have been particularly high over the latter years of the price control period. As part of the one year price control extension GDNs' allowed revenues for shrinkage costs will be linked to forward wholesale gas prices so GDNs already have incentives to manage shrinkage costs. There is a risk that a volume driver that reflected cost variability from shrinkage could duplicate the incentive. It may therefore be appropriate to remove the volume driver as it appears unlikely to be proportionate to the risks to which GDNs are exposed. Removing the volume driver is likely to have an impact on charging and we will need to be mindful of this before removing the volume driver.

Other revenue drivers

5.19. As part of the price control review we have also consulted on and reviewed other potential revenue drivers including a capacity related driver, a customer number related driver and a connections related driver.

Capacity related revenue driver

5.20. As discussed above in the 2002 price control review we used throughput as a proxy for capacity costs. As part of our review of the form of the revenue drivers we reviewed two types of capacity measures, namely LTS and storage costs and peak demand volumes to assess whether either of these measures could provide a suitable basis for a revenue driver.

5.21. Our analysis, which is set out in detail in Appendix 11, examined whether the forecasts for the two capacity measures broadly matched the actual costs/ volumes and whether variations were material. The analysis indicated that average allowed costs varied from average actual costs by around 46 percent over the price control period. However, due to the large variances between years for both allowed and actual costs, there was no statistical grounds for concluding that actuals and allowances were significantly different. In addition, we consider that it may be difficult to determine the appropriate measure for a capacity driver. It particular we would not want to reward GDNs with an incremental capacity driver if they are not investing in the network by simply utilising spare network capacity.

5.22. Our analysis of peak day demand volumes indicates that actual volumes tended to be lower than forecast and to lie outside the forecast range. However, the variance between forecast and actual volumes was on average only around 3 per cent. Moreover, we note that the 1 in 20 peak day demand volumes are determined by the GDNs and are subjective, so cannot be independently confirmed. The GDNs can meet 1 in 20 peak demand through a number of capacity outputs such as interruption, use of DN storage, use of NTS and DN flat and flexibility capacity etc. Any associated revenue driver could be subject to manipulation as the GDNs would be incentivised to meet 1 in 20 peak demand in a way that maximises their revenue rather than by choosing the optimal capacity outputs. There is also a risk that a capacity related revenue driver could duplicate and potentially undermine the capacity outputs incentive which is intended to provide incentives for GDNs to procure capacity outputs efficiently to meet 1 in 20 demand.

Customer number related revenue driver

5.23. We considered whether a customer number related revenue driver might be appropriate as changes to the number of customers on the network are likely to have an impact on peak capacity demand.

5.24. Analysis of customer numbers was more limited than for capacity costs as there were no explicit assumptions about customer numbers as part of the last price control review therefore a review of forecast and actual numbers was not possible. However, from 2003-04 we started to collect customer numbers as part of the quality of supply report. Table 5.3 below shows the year on year percentage change in customer numbers. This data appears to show a steady and stable growth in customer numbers. A couple of GDNs show a small decline in customer numbers in 2003-04 of between 0.1 and 0.2 percent. Overall customer growth for the GDNs appears to be between 0.1 and 1 per cent growth per annum.

Table 5.3 - Year on year percentage change in customer numbers

GDN	2003-04 to 2004-05	2004-05 to 2005-06	Average
North West	0.11%	0.28%	0.20%
East England	0.56%	0.65%	0.61%
West Midlands	-0.12%	0.37%	0.12%
London	-0.21%	0.24%	0.01%
Northern	0.42%	0.57%	0.49%
Scotland	1.05%	1.02%	1.04%
South England	0.30%	0.79%	0.54%
Wales and West	0.92%	0.88%	0.90%

5.25. Although our data set is relatively small, a customer number related revenue driver may have limited effect given the low and predictable growth. While there was some support for a customer related driver among the GDNs to reflect changes in their underlying costs those who did not support the driver questioned whether a driver was necessary to address small variations to revenue.

Connections related revenue driver

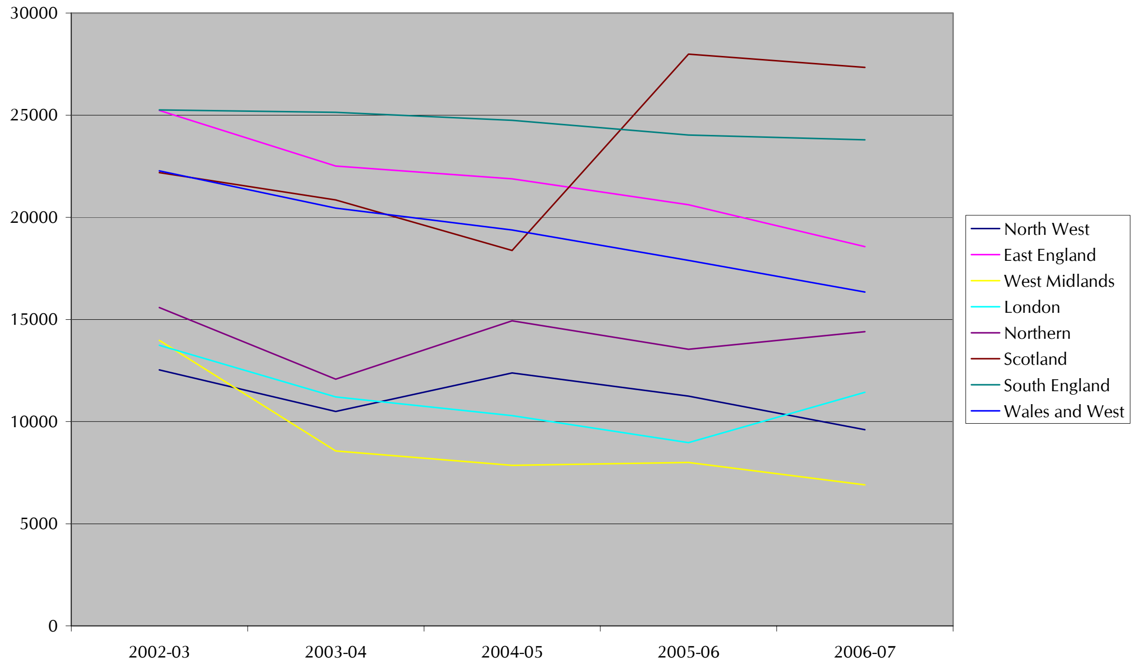
5.26. GDNs are required to provide up to the first 10 metres of a gas connection laid in the public highway free of charge if a domestic customer is within 23 metres of a gas main. As part of the price control we set an allowance for these costs but in the 2002 price control review we considered that competition in connections could result in an erosion in the work provided by GDNs. There has been a lack of competition in this area and as part of the review in connections competition[15] we noted that any proposals to level the playing field for these types of connections was likely to be frustrated by the current streetworks legislation.

5.27. We recognised as part of the one year review that as connections competition has been limited, actual connections costs were much higher than forecast and the GDNs received an ex post adjustment to their allowances. A review of forecast and actual costs would have shown a poor correlation so we did not carry one out.

5.28. Figure 5.1 shows that actual connections volumes between 2002-03 and 2005-06 and forecast connection volumes for 2006-07 have been subject to significant variation in volumes for some of the GDNs over the price control period while the level of connection costs is equivalent to between 2 and 11 percent of total transportation revenues.

[15] Review of competition in gas and electricity connections, proposals document, February 2007 (26/07)

Figure 5.1 - Connection volumes over the last price control with forecast data for 2006-07 (number of connections)



5.29. One GDN supported a connections based revenue driver on the basis that it was difficult predicting volumes in the current review period. One GDN proposed a connections driver for connecting new generation. The other GDNs did not comment specifically on connections based revenue driver. We consider that there may be scope for a connections related revenue driver and we will need to undertake further analysis to determine the scope and form of a revenue driver.

Capex rolling incentives and the information quality incentive

Background and rationale

5.30. In the absence of a specific incentive, GDNs keep any efficiency savings they make (or bear any excess costs they incur) for the duration of the price control. Consequently, the strength of the capex incentive varies depending on whether the saving is made at the start, middle or end of the price control. The capex rolling incentive fixes the incentive rate over the price control period.

5.31. Traditionally, the capex allowance is set based on our views of the GDNs' capex forecasts. There is a significant information asymmetry between the regulator and the company. GDNs also have an incentive to inflate their capex forecasts in order to maximise their scope for outperformance. Therefore, it can be difficult to differentiate between additional investment necessary to maintain network integrity and artificially inflated capex forecasts.

5.32. The Information Quality Incentive (IQI), which was implemented as part of DPCR4, manages this risk by allowing the GDN to choose higher allowances than we forecast but incentivises them not to inflate their bids. The incentive does this in two ways – by giving additional income to companies who forecast capex spend close to our consultant's forecast (which may be subject to adjustment by Ofgem) and by providing these companies with a higher capex rolling incentive rate than those companies with higher capex forecasts.

5.33. In the third consultation document we consulted on a capex rolling incentive and information quality incentive. We intend to make a decision on these incentives in our initial proposals document. The remainder of this chapter details our latest thinking on these incentives and how they could apply in practice if we decided to implement a capex roller.

DPCR sliding scale incentive matrix

Overview of the incentive

5.34. The DPCR sliding scale incentive matrix takes the form of two incentives. Firstly, DNOs are allowed to earn an additional income on their RAV based on how close their forecast is to our consultant's forecast (in DPCR4 this was PB Power). The sliding scale additional income set out in the matrix is indicative. In practice the additional income is applied annually as a pre tax rate of return on the GDN's average RAV.

5.35. The second part of the incentive sets the incentive rate for future efficiency savings based again on how close the GDN's forecast is to our consultant's forecast. Under the incentive a GDN with an inflated capex forecast has a lower incentive rate than a GDN with a more accurate forecast. The DPCR sliding scale incentive is shown below. It shows that taking both the additional income incentive and the efficiency incentive the GDNs will earn the highest income by accurately forecasting their intended capex spend (this is highlighted in blue).

Table 5.4 - Electricity Distribution sliding scale matrix

DNO:PB Power Ratio Efficiency Incentive	100 40%	105 38%	110 35%	115 33%	120 30%	125 28%	130 25%	135 23%	140 20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
as pre-tax rate of return	0.200%	0.168%	0.130%	0.090%	0.046%	-0.004%	-0.062%	-0.124%	-0.192%
Rewards & Penalties									
Allowed expenditure	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual Exp									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	4.5	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	2.6	2.5	2.3	2.1	1.7	1.1	0.4	-0.4
110	0.5	0.7	0.8	0.7	0.6	0.3	-0.1	-0.7	-1.4
115	-1.5	-1.2	-1.0	-0.9	-0.9	-1.1	-1.4	-1.8	-2.4
120	-3.5	-3.1	-2.7	-2.5	-2.4	-2.5	-2.6	-3.0	-3.4
125	-5.5	-4.9	-4.5	-4.2	-3.9	-3.8	-3.9	-4.1	-4.4
130	-7.5	-6.8	-6.2	-5.8	-5.4	-5.2	-5.1	-5.2	-5.4
135	-9.5	-8.7	-8.0	-7.4	-6.9	-6.6	-6.4	-6.3	-6.4
140	-11.5	-10.6	-9.7	-9.0	-8.4	-8.0	-7.6	-7.5	-7.4

5.36. For example, if the GDN expects to spend 100 per cent of the PB Power forecast it will earn an income of 4.5 by not inflating its forecast. This is calculated as (105-100) x 40 per cent + 2.5. In comparison if it inflated its bid to 140 per cent of the PB Power forecast it would only earn an income of 0.6 as it loses out on both the additional income incentive and the efficiency incentive.

Mechanics of the incentive

5.37. The sliding scale incentive is based on the ratio of the company's forecast to PB Power's view determined as:

Ratio = company view/ PB Power view x 100

5.38. The allowance for companies with a ratio of 100 (i.e. the company and PB Power's forecast are the same) is 105 (i.e. a multiple of 1.05 of the PB Power forecast) to reward the company with efficiency savings even if it delivered the original allowance. For companies with a ratio greater than 100 (i.e. the company's forecast is higher than the PB forecast) 25 per cent of the GDN's higher forecast is included in the allowance. This is calculated as

Allowance = 105 + (Ratio – 100) x 0.25

5.39. The highest efficiency incentive in the matrix i.e. 40 per cent is based on the highest capex incentive that applied in electricity distribution in DPCR3. Under the matrix the variation of the efficiency incentive rate for higher deviations between GDN and PB Power forecasts is relatively small and is determined by:

Efficiency incentive percentage rate = 40 – (Ratio – 100) x 0.5

5.40. The value of the additional income is set to ensure that the matrix is incentive compatible (i.e. it balances the incentive to ensure that the GDNs earn the highest income by not inflating their capex forecasts) and does not have a linear relationship with the Ratio.

5.41. In DPCR4, to avoid any perverse incentives for companies within the same ownership group the ratio was calculated on a group basis and therefore the companies had the same efficiency incentive and additional income.

5.42. In practice the sliding scale incentive is corrected for ex post. The GDNs earn depreciation and a rate of return on any efficiency savings for the duration of the price control and we make an addition or reduction to their revenue at the end of the price control to reflect the capex incentive rate determined by the IQI.

Issues for gas distribution

Strengthening the capex incentives

5.43. As part of the GDPCR we have to consider the strength of the capex incentives. It is our view that relatively strong incentives will incentivise the GDNs to make efficiency savings as they keep a higher proportion of the savings. A stronger incentive could also affect the GDN's decision on whether to overspend, or to seek alternative ways of managing unanticipated events, as GDNs would be exposed to a greater proportion of the cost if we determine that the increase in costs should not be allowed. There is, however, a risk with stronger incentives that GDNs may cut necessary capex spend to the detriment of network integrity and we would need to give further consideration to whether the existing outputs including the safety case, guaranteed standards, licence conditions etc were sufficiently robust to prevent this happening.

Interactions between capex and opex incentives

5.44. Under a traditional RPI-X incentive scheme, where the RAV is updated at the end of the period, there is an incentive to present costs as capex rather than opex. This is because a capex "overspend" will be partly remunerated through an increase in RAV, while an opex "saving" is for the benefit of the company until the end of the price control period. However, since opex levels around years 3 and 4 of a 5 year control are likely to form a reference point for setting future allowances, the incentive is somewhat mitigated.

5.45. Additionally, there are genuine trade-off decisions to be made, for example in deciding whether to invest in capex to save future opex. Due to the periodicity of incentives, the trade-off will vary through the price control.

5.46. The introduction of a capex roller would change the trade-offs. If we remove the periodicity of capex, we are likely to end up with a stronger incentive in most situations. This is likely to reduce the incentive to present costs as capex, although this risk will be reduced further by improved cost reporting.

5.47. Where there is a genuine trade off between capex and opex spend GDNs are relatively less likely to invest in capex to save on opex, particularly towards the end of the price control, when opex savings will only be retained for 1 or 2 years. However, even without an opex roller, the opex incentive is relatively strong, with 100 per cent of savings being retained. Moreover, the benchmarking of opex incentives is likely to increase its strength. We are continuing to explore whether we should take any further action to alter the balance of incentives (such as an opex roller) and will present our views in Initial Proposals.

Implications of offtake and interruptions reform

5.48. The IQI is further complicated by issues that have arisen during GDPCR. In particular further reform of offtake arrangements and interruptions are due to be implemented in 2010. Given the uncertainty about these arrangements the GDNs have not provided us with the capex costs associated with these reforms as part of their BPQ responses. A decision to implement the new interruption arrangements was taken on 15 March 2007 and a decision on offtake arrangements is expected in the near future.

5.49. GDNs will have an opportunity to revise their capex forecasts by the time of the next BPQ submission in July. These forecasts may affect forecasts of LTS and storage capex. However, PB Power's forecast would not have taken account of the capex costs associated with these reforms, so including it in the IQI could undermine the workings of the incentive.

5.50. If we were to implement the IQI we consider that the capex costs associated with reform should not be included in the IQI but that the incentive strength for capex costs associated with offtake and interruptions reform should be subject to the IQI incentive strength to avoid distortions between this and other capex.

The mains replacement incentive

5.51. When we set the mains replacement incentive as part of the previous price control, GDNs were exposed to an incentive rate of 33 per cent for efficiency savings in mains replacement unit costs and 50 per cent for additional costs. In comparison GDNs were exposed to a 31.2 per cent incentive rate for efficiency savings for services costs. As a consequence it appears that the GDNs may have reallocated certain mains replacement costs as services costs as the benefits of efficiency savings arising from the former outweighed the exposure to additional costs of the latter.

5.52. In our third consultation document we proposed to include services costs in the mains incentive and also align the mains replacement incentive with the capex incentive.

5.53. However, aligning capex and mains replacement incentive would be complicated by the IQI. We could include repex forecasts in the IQI and ensure that the mains replacement incentive strength is the same as the capex incentive for each of the GDNs. We would do so using conformed assumptions on volumes (i.e. any difference between the company forecast and Ofgem's assessment would be solely due to unit costs). Another option would be to exclude the mains replacement incentive from the IQI, and determine the unit costs with reference to our consultant's analysis, but to apply the IQI incentive strength to each of the GDNs. Alternatively, we could retain the current arrangements and continue to have different incentive strengths for capex and mains replacement. This increases the risk of gaming between capex and repex costs, although the scope for this is limited by the inclusion of the services costs in the mains replacement incentive.

5.54. On balance, determining the unit costs and incentive rate for the mains replacement incentive from the IQI would be our preferred option as other repex allowances will be subject to the IQI and it limits further scope for gaming.

6. Methodology for considering financial issues

Chapter Summary

This chapter sets out our proposed methodology for determining the cost of capital to apply to the GDNs and our approach to assessing financeability.

Question box

Question 1: Do you agree with our proposed plan of work to determine the cost of capital? Are there other key areas of analysis that we should be carrying out?
Question 2: Is the range of key ratios we have identified adequate for carrying out an assessment of financeability?
Question 3: Is our approach to the issues raised by adjusted interest cover ratios appropriate (see Appendix 10 for details)?

6.1. Our assessment of the major financial issues will appear in the Initial Proposals document in May, with further evidence in the September update. However, as we are beginning our analysis, we feel it is appropriate to set out our approach to allow opportunity for interested parties to have input into the way we are assessing such issues as the cost of capital and financeability. Additionally, it is appropriate to comment on some of the responses already received in the context of earlier consultation documents.

Determining the cost of capital to apply to GDNs

6.2. Our approach to determining the cost of capital will be consistent with that used in recent Ofgem price controls, in particular the 2007-12 Transmission Price Control Review[16]. The cost of capital reflects the risks and rewards available to network companies, and as such can only be determined in the context of the overall proposals, including the cost allowances and the incentive mechanisms. It is unlikely that the final cost of capital will be determined before final proposals, but we will publish the results of the analysis described below in Initial and Updated proposals together with our modelling assumption on the cost of capital in order to determine allowances.

Risk-free rate and debt premium

6.3. For both these parameters the TPCR review took into account long-term trailing average data (5-10 years) for gilt yields and spreads for 'A' rated utility bonds. The figure incorporated into final proposals was consistent with this range and the

[16] Transmission Price Control Review: Final Proposals, December 2006 (Ref. 206/06)

conclusions of the Smithers[17] report on the long-term equilibrium rate. We will update the analysis of trailing averages. This approach has the advantage of mitigating the impact of any unusual movements or short term trends in the spot rate.

6.4. Another reason, in normal circumstances, for using long-term trailing averages is that network utilities have tended to build up their debt levels over time, so will have a range of different bonds and loans at different rates and with different maturities. There is likely to be a correspondence between such market averages and the companies' actual embedded debt costs. By contrast the IDNs only acquired their networks in 2005, and so do not have debt from before this date. They also geared up at or shortly after the point of acquisition. Although the companies' financing strategies are generally not a matter for Ofgem's concern (provided they are compliant with licence requirements) it may be appropriate to review whether our approach should take account of these specific circumstances.

Cost of equity

6.5. The cost of equity can either be assessed by determining an equity risk premium for the market and an equity beta (which represents the systematic risk variability of a company relative to the market as a whole), or by an aggregate return on equity, as used in DPCR4[18]. Work carried out for Ofgem in 2003[19] and 2006 (see footnote 16) has demonstrated the difficulty of assessing a stable beta over the long term for utility networks in general. While the Smithers report of 2006 estimated beta at around 0.5, it also noted a wide confidence interval around this estimate and the final proposals for TPCR[20] noted that beta estimates had varied substantially since privatisation. As a result the aggregate return approach of DPCR4 was given greater weight in TPCR.

6.6. Moreover, it is difficult to find evidence of betas for gas distribution companies specifically, due to the lack of publicly listed stand-alone gas distributors. The companies covered by GDPCR, for example, include two privately owned networks (NGN, WWU), 2 networks that are 50 per cent owned by a multi-utility group (SGN/SSE) and 4 that are, again, only part of a larger utility group (National Grid). While there may be some examples internationally, they are few and far between and unlikely to provide enough data to be statistically significant. Our work on the cost of equity will therefore focus on attempts to measure the riskiness of the GDNs in the context of the price control package. Nevertheless, should any respondent choose to submit arguments based on beta values, we will give them due consideration.

[17] Wright, S., Mason, R., Satchell, S., Hori, K., and Baskaya, M., (2006) Report on the cost of capital, Smithers & co Ltd
[18] Electricity Distribution Price Control Review final proposals, Ofgem 265/04, November 2004
[19] Wright, S., Mason, R., and Miles, D. (2003), A study into certain aspects of the cost of capital for regulated utilities in the UK, Smithers & co Ltd
[20] Transmission Price Control Review final proposals, Ofgem 206/06, December 2006

Risk analysis

6.7. As initially proposed within TPCR, we intend to prepare a comparative risk analysis of the proposed GDPCR review. This will provide support to overall conclusions, rather than being an independent estimate of the cost of capital. The focus will be on the relative riskiness of debt and equity investment, as measured by sensitivity or volatility of equity and debt returns. The relative risk of debt and equity may be different, as for example a large capital programme may increase equity returns but also increase funding risk.

6.8. There are a number of areas where regulated businesses face risks which arise from their price control packages and other elements of the regulatory framework and are, or are perceived to be, asymmetric. If this is the case, then the expected returns may be different (higher or lower) from that implied by the cost of capital figure, and will influence the GDNs' decisions as to whether the price control is acceptable. We intend to review the evidence for these risks, whether they are specific to individual price controls or systematic to Ofgem, and whether they are sufficiently material to justify adjustments to the cost of capital. If so, we will then consider whether the existing equity returns reflect those adjustments.

6.9. Our proposed risk analysis will be dependent on being able to obtain reasonable estimates for the ranges of key inputs, in particular cost drivers. If we are able to construct a model in sufficient detail, we may carry out Monte Carlo simulations, in which case the distribution of probabilities within these ranges will also be relevant. Given the GDNs' short history as independent entities, the historical data we have to inform these estimates is limited. We are realistic, therefore about the conclusions we will be able to draw, and will avoid spurious accuracy.

Financial modelling

6.10. We will publish the results of the financial model at initial proposals. This will contain indicative revenue allowances for the GDNs for 2008-13. As such we will need to make an assumption regarding the cost of capital at this stage, even though we will not have completed our analysis. The financial model will be externally audited. We intend to publish it shortly after initial proposals, as we did for the one year control. We will do the same for final proposals, when the model will have been re-audited, but do not intend to do so for updated proposals.

Assessing financeability

6.11. We will also be in a position at initial proposals to make our initial assessment of the financeability of the GDNs, assuming a notional capital structure, based on the assumptions underlying the cost of capital used for the financial model. In the third consultation document, we canvassed opinion on the range of appropriate ratios to use. Respondents made a number of suggestions, as detailed in Appendix 5. The responses indicated broad support for using Funds From Operations (“FFO”)/Interest, Retained Cash Flow/Debt, and Debt/RAV, as per DPCR4.

6.12. Several respondents also mentioned adjusted interest cover ratios, in particular PMICR, as used by Moody's and Fitch. We have reservations about this ratio's usefulness for testing the financeability of an Ofgem financial model, where it reduces to a function of the cost of capital. We also observe that it gives consistently weaker indications of financeability than the other key ratios. As such we are looking at different approaches to using it in our financeability testing. These are outlined in detail in Appendix 10.

6.13. The results of our financeability review will be materially affected by decisions on the timing of allowances for capex and repex. There are principally three areas, which we will need to consider together:

- Repex - currently funded 50 per cent in the year incurred and 50 per cent over 45 years;
- Non-operational capex - currently funded over 45 years; and
- Capex - currently funded over 45 years.

6.14. The current funding treatment for repex was introduced in 2002, in response to the size of the mains replacement programme, which was just beginning. It was assessed in the context of a price control that covered gas transmission and LNG storage as well as gas distribution. Since the costs of the programme have increased, this means that repex is now a larger part of GDN spending than it was for Transco in the 2002-07 review. In the light of this shift we intend to review the 50/50 treatment.

6.15. Our choices for treatment of non-operational capex are outlined in paragraphs 2.29 to 2.34. The scale of non-operational capex is such that there could be potential financeability concerns if it were treated as opex, and a substantial increase in P0. However, the impact on P0 would be mitigated if we capitalised more of the repex programme, for example, and the financeability concerns could be avoided by profiling revenues in line with costs rather than assuming a constant value of X over the price control.

6.16. In their responses, the GDNs argue that we should review depreciation rates for new capex, particularly for IS investment. Accelerating depreciation provides another means to address financeability concerns, and may be an alternative to expensing a large portion of repex. However, there is a danger that if depreciation rates cease to be consistent with the average expected lives of the underlying assets, this may cause deterioration of the RAV over the long-term.

7. Next steps

Chapter Summary

This chapter sets out next steps and timetable for the rest of GDPCR.

Question box

There are no questions relating to this chapter.

Consultants' reports

7.1. The consultants' reports are currently being updated following discussions with the companies and updating for factual accuracy. The reports will be finalised and published after initial proposals in the summer.

GDPCR costs workshop

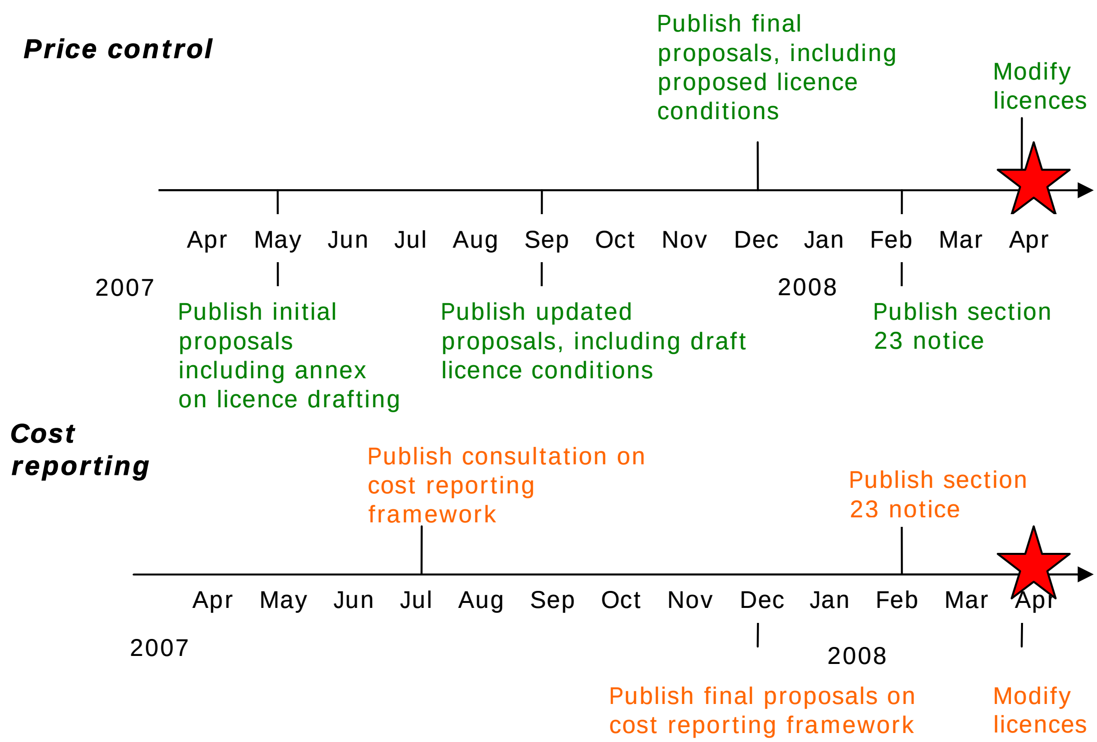
7.2. We are holding a cost workshop on the 19 April 2007 to discuss in detail the companies cost submissions, our consultants' review of them and their recommendations and more generally the issues raised in this consultation.

7.3. This will be a technical and detailed meeting and the numbers will be restricted to ensure that the format works effectively. If you would like to attend, please contact Paul Newman on 020 7901 7026 or email GDPCR@ofgem.gov.uk by no later than 6 April 2007.

Timetable going forward

7.4. Figure 7.1 shows Ofgem's timetable for completing the gas distribution price control review.

Figure 7.1 - Timeline for GDPCR



Appendices

Index

Index - Supplementary Appendices

Appendix 1 - Consultation Response and Questions

1.1. We would like to hear the views of interested parties in relation to any of the issues set out in this document. In particular, we would like to hear from gas consumers and their representatives, gas distribution networks and any other interested parties.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 25 April 2007 and should be sent to:

- GDPCR Responses
- Ofgem
- 9 Millbank
- London SW1P 3GE
- Email: GDPCR@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, we will publish initial proposals for the GDPCR price control in May 2007 which will be followed by updated proposals in September 2007 and final proposals in December 2007. Any questions on this document should, in the first instance, be directed to:

- Mark Cox
- Price Control Policy & Management
- Ofgem, 9 Millbank, London, SW1P 3GE
- Tel: 020 7901 7458
- Email: mark.cox@ofgem.gov.uk

1.7. The remainder of this appendix restates the consultation questions for convenience.

CHAPTER: One

There are no questions in chapter 1

CHAPTER: Two

Question 1: Do you agree with our proposed accounting adjustments? Are there any other accounting adjustments that we should be considering?
Question 2: Do you agree with our adjustments for related party margins?
Question 3: Do you think we should change our treatment of non-operational capex?

CHAPTER: Three

Question 1: How should we bring together the various consultants' analysis to establish an efficient cost benchmark and cost allowances? In light of our approach to setting a benchmark, what approach should we take to glidepaths?
Question 2: Is there a case for making adjustments to allowances for real price effects, specifically direct labour, contract labour or materials?
Question 3: Is there a case for making adjustments to allowances for regional factors and if so what approach should be adopted?
Question 4: Should we adapt our pension principles to address the forecast defined benefit pension contributions, which are both extremely high and vary widely across GDNs, (despite funding very similar benefit packages)?
Question 5: Should we change our pension recovery mechanism in order to avoid distorting incentives between making salary and non-salary cost savings?

CHAPTER: Four

Question 1: What are your views on PB Power's adjustments to the GDNs' forecast capital and replacement expenditure?
Question 2: What are your views on PB Power's general approach to the assessment of costs?
Question 3: What are your views on PB Powers' approach to the cost assessment for each activity?
Question 4: Is it appropriate at this time to reconsider the approach to prioritisation within the risk model and should the approach to encroachment and diversions should be amended?

CHAPTER: Five

Question 1: Is it appropriate to retain the current volume driver?
Question 2: Is it appropriate to implement any of the revenue drivers discussed in this chapter and are there any other drivers that we should consider that we have not included in this chapter?
Question 3: Is it appropriate to strengthen the capex rolling incentives?

Question 4: Are our proposals for the treatment of offtake reform related costs and mains replacement costs under the IQI appropriate?

CHAPTER: Six

Question 1: Do you agree with our proposed plan of work to determine the cost of capital? Are there other key areas of analysis that we should be carrying out?
Question 2: Is the range of key ratios we have identified adequate for carrying out an assessment of financeability?
Question 3: Is our approach to the issues raised by adjusted interest cover ratios appropriate (see Appendix 10 for details)?

CHAPTER: Seven

There are no questions relating to this chapter.

Appendix 2 – The Authority's Powers and Duties

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

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. The Authority also has other statutory duties in respect of the environment, as set out in various other Acts[21]. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[22]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[23].

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

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

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[24]; and

[21] For example, the Environment Act 1995 and the Countryside and Rights of Way Act 2000.
[22] Entitled "Gas Supply" and "Electricity Supply" respectively.
[23] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[24] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[25]

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

- Promote efficiency and economy on the part of those licensed[26] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

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

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

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[27] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

1.9. The Authority has regard to all of its duties when carrying out its functions.

[25] The Authority may have regard to other descriptions of consumers.
[26] or persons authorised by exemptions to carry on any activity.
[27] Council Regulation (EC) 1/2003

Appendix 3 - Glossary

A

Agency Services Agreement (ASA)

Agreement for the provision of information, data processing, invoicing and supply point administration services in relation to the transmission and distribution of gas in Great Britain.

Area Control Centres (ACC)

The Area Control Centres currently carry out system control activities on behalf of all the GDNs and are located at National Grid Gas' facilities in Hinckley. Activities carried out include monitoring system pressures, flows and alarm management at LTS (Local Transmission System) sites and other key sites on the distribution networks.

B

Business Plan Questionnaire (BPQ)

Expenditure information requested by Ofgem from the GDNs to inform decisions about setting the price control.

C

Capacity (Gas)

The amount of natural gas that can be produced, transported, stored, distributed or utilized in a given period of time under design conditions.

D

Direct activities (operating expenditure)

Direct activities are the main activities of the GDN, e.g. LTS maintenance and repair.

Distribution Network Operator (DNO)

DNOs are holders of electricity distribution licences. Licences are granted for specified geographical areas. Currently in Great Britain there are seven companies who own the fourteen licensed distribution areas.

Distribution Price Control Review 4 (DPCR4)

The price control review for the electricity distribution network operators which covers the five years from 1 April 2005 to 31 March 2010.

F

Flat capacity

Flat capacity gives the holder the right to offtake a volume of gas during the day at a constant hourly rate.

Flexibility (flex) capacity

Flex capacity gives the holder the right to offtake a volume of gas according to a profile that varies over the day.

G

Gas Distribution Network (GDN)

GDNs transport gas from the NTS to final consumers and to connected system exit points. There are currently eight GDNs in Great Britain which comprise twelve LDZs.

Gas Distribution Price Control Review (GDPCR)

The review of the price control applying to gas distribution networks. The review will extend the existing price control for the year 2007- 08 and reset the control for the period commencing 1 April 2008.

Gas Transporter (GT)

The holder of a Gas Transporter's licence in accordance with the provisions of the Gas Act 1986.

Gas Transportation Management System (GTMS)

GTMS is the interface between the GDN outstations and the control centre.

Gemini system

The Gemini information system replaced the AT Link (energy balancing) information system and the RGTA (entry capacity trading) information system.

Guaranteed Standards of Performance (GSOP)

Guaranteed standards of performance set service levels that must be met in each individual case. If a gas transporter fails to provide the level of service required, it must make a payment to the consumer affected, subject to certain exemptions.

H

Health and Safety Executive (HSE)

The Health and Safety Commission is responsible for health and safety regulation in Great Britain. The Health and Safety Executive and local government are the enforcing authorities who work in support of the Commission.

I

Independent Gas Transporter (IGT)

IGTs are GT licence holders that own and operate small local gas networks and levy distribution charges on shippers.

Indirect activities (operating expenditure)

Indirect activities are costs that do not relate directly to the main activities of a GDN but are incurred to support the GDN's activities e.g. HR costs.

L

Local Distribution Zones (LDZs)

LDZs are low pressure pipeline systems which deliver gas to final users and Independent Gas Transporters. There are twelve LDZs which take gas from the high pressure transmission system for onward distribution at lower pressures.

Local Transmission System (LTS)

The pipeline system operating at >7barg that transports gas from NTS offtakes to distribution systems. Some large users may take their gas direct from the LTS.

N

National Grid Gas (NGG)

The GT licence holder for the North West, West Midlands, East England and London GDNs. NGG also hold the GT licence for the gas national transmission system (NTS). Prior to 10 October 2005, NGG was known as Transco.

National Transmission System (NTS)

National Grid's high pressure gas transmission system. It consists of more than 6,400 km of pipe carrying gas at pressures of up to 85 bar (85 times normal atmospheric pressure).

Network sensitive load (NSL)

GDNs can designate an offtake point as an NSL if certain pressure levels would be triggered in the network if the offtake at the site was not interrupted.

NTS offtake capacity

Built to ensure sufficient pipeline capacity is available to convey gas from the NTS to the GDNs and NTS direct connects at the required rate and quantities.

Northern Gas Networks (NGN)

The GT licence holder for North England GDN.

O

One in twenty planning standard (1 in 20)

A licence obligation imposed on GDNs under Standard Special Condition A9 (Pipe-Line System Security Standards). A GDN is required to plan and develop its pipe-line systems so as to enable it to meet peak aggregate daily demand for gas which is likely to exceed (whether on one or more days) only in one year out of twenty years.

Overall Standard of Performance (OSOP)

Overall standards of performance set minimum average levels of performance in areas where it is not necessarily appropriate to put in place guarantees for individual consumers. These are determined separately for each gas transporter by the Authority.

P

Priority Services Register (PSR)

PSR includes domestic consumers who are of pensionable age, have a disability, have long term ill health, and/ or are blind or visually impaired. Individuals on this register qualify for a selection of free services by gas and electricity suppliers.

R

Regulatory Asset Value (RAV)

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

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

S

Scotia Gas Networks (SGN)

The GT licence holder for South England GDN and Scotland GDN.

Shrinkage

Shrinkage gas is gas lost from the network through leakage, theft or own use gas.

System Operation Managed Service Agreements (SOMSAs)

SOMSAs are contracts between NGG and each GDN purchaser under which NGG carries out system operation on behalf of the new GDNs. They provide for the scheduling, monitoring and control (under the direction of the independent distribution network, i.e. IDN) of flows of has in the parts of the GDN system operable remotely from the control centre using the control system, in order to achieve a physical balance. Other services provided under the SOMSAs include:

- services for the notification of call-outs, alarms and faults;
- coordination services in the event of contingencies and emergencies;
- services to support the preparation of a plan covering scheduling of engineering; works and maintenance affecting the remotely operable parts of the GDN system; and,
- recording details of engineering works and maintenance carried out.

T

Therm

A unit of heating value equivalent to 29.3071 kilowatt hours (kwh).

Third party damage or water ingress (TPWI)

Third party damage occurs when a gas supply interruption is caused by a third party. Water ingress is an incident whereby water has escaped from pipes vested in water companies and entered pipes operated by public gas transporters. From there, water has then sometimes penetrated into domestic premises, causing damage to the customers' gas appliances[28].

[28] http://www.ofwat.gov.uk/aptrix/ofwat/publish.nsf/Content/rd032001

Traffic Management Act 2004 (TMA)

The Traffic Management Act is intended to provide better conditions for all road users through proactive management of the national and local road network[29].

Transco plc (see National Grid Gas)

Transco plc changed its name to National Grid Gas plc on 10 October 2005.

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, National Grid Electricity Transmission, Scottish Power Transmission Limited, Scottish Hydro-Electric Transmission Limited and to the licensed gas transporter responsible for the gas transmission system, NGG.

Total factor productivity (TFP)

TFP addresses any effects in total output not caused by inputs or productivity[30]. It is also known as the Solow residual.

U

UK-Link

UK-Link is the central information system that shippers and suppliers use to interface with the GTs and each other.

Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced National Grid Gas' Network Code as the contractual framework for the NTS, GDNs and system users.

W

Wales & West Utilities (WWU)

The GT licence holder for Wales & West GDN.

Water ingress

An incident where water enters gas pipes resulting in a loss of gas supply.

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[29] Department for Transport:
http://www.dft.gov.uk/stellent/groups/dft_roads/documents/divisionhomepage/032064.hcsp
[30] http://en.wikipedia.org/wiki/Total_factor_productivity

Water Services Regulation Authority (Ofwat)

Ofwat is the economic regulator of the water and sewerage industry in England and Wales.

X

xoserve

A transporter agency which provides a single, uniform interface between the IT systems of relevant GTs and shippers.

Appendix 4 - Feedback Questionnaire

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

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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