

Ref: AW/PW/079

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Ofgem
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22 October 2007

Dear Joanna

Re: Gas Distribution Price Control Review Updated Proposals

I attach NGN's detailed response to Ofgem's Updated Proposals for the five year review with a summary of the key points provided below. These will form the basis of our presentation to the Authority on 25 October.

The Updated Proposals move some way towards addressing concerns raised following Initial Proposals, in particular moving the opex assessment to upper quartile and providing some additional allowance for apprentices, waste, environmental remediation and loss of meterwork. However there are still a number of areas where the allowances are insufficient and our primary concerns are discussed below. In particular, NGN is setting the frontier: for the top down analysis; for several individual activities on the bottom up analysis; and for repex, but doesn't seem to have been appropriately rewarded for this compared to other GDNs.

Cost of capital

The allowed Cost of Capital remains unacceptable. The total allowed cost of capital return on assets has reduced from 6.25% in 2006/07 to 4.96% (including 0.12% regulatory tax allowance) for NGN. This is a reduction of 21% in allowed return which is not the "gradual change" in cost of capital that we understand is Ofgem's approach to ensure long term stability in returns.

Gearing

Ofgem has assumed gearing at 62.5% for GDNs compared to 60% for transmission companies. There is no basis to assume that gearing can be higher for GDNs than for transmission. 60% is also consistent with the Competition Commission's conclusion for BAA given "the uncertainties that surround the rating process".

The CAPM approach results in a higher cost of equity and cost of debt with a higher gearing and we do not understand why Ofgem has not taken this into account in its assessment of these two parameters. Either gearing should be set at **60%** in line with transmission or the impact on cost of higher gearing must be taken into account in the calculation of cost of equity.

Cost of equity

We welcome Ofgem's analysis of risk differentials between distribution and transmission. A number of factors such as safety and security of supply indicate that gas distribution is riskier than transmission. This has been backed up using market evidence by a report from Oxera that demonstrates statistically that gas distribution companies in Europe and America have a significantly higher beta than transmission companies. The evidence suggests that the cost of equity is above transmission's and is at least at the top of Ofgem's range of 7% - 7.5%. The cost of equity should be **7.5%** if gearing is set at 60% to reflect the risk differential with transmission and should be **7.78%** if gearing remains at 62.5%.

Cost of debt

The level of PMICR consistently below 1.4x in Ofgem's financial model means that the costs of raising debt will increase and that the 3.55% that Ofgem has assumed is insufficient. Ofgem has suggested that an appropriate range for PMICR is 1.5-1.6x.

The 3.75% cost of debt for TPCR set in November 2006 was 0.26% above the ten year trailing average and 1.24% above average spot rates. The 3.55% that Ofgem is proposing for GDNs is just 0.18% above the ten year trailing average and 0.39% above average spot rates. This clearly provides insufficient headroom for GDNs which means that there is a strong likelihood that GDNs will not be able to finance new capex or refinance existing debt at the allowed cost of debt. Cost of debt should be set at **3.75%** in line with TPCR.

Conclusion

NGN expects to see a substantive increase in the allowed cost of capital when Final Proposals are published. The evidence suggests that the allowed vanilla cost of capital should be above the 5.05% set for transmission companies and should be set at **5.26%** in line with the top of the range implied by the parameters that Ofgem proposed in Initial Proposals.

Operating costs – rewards for efficiency

NGN is still concerned that it is not being rewarded for setting the efficiency frontier. Ofgem's methodology provides NGN with exactly its base year costs whereas an upper quartile methodology would be expected to reward a frontier company with more than its base year costs.

	Top down ranking	Bottom up ranking	Average ranking	Actual costs 06/07	Bottom up cost estimates	% of actual costs	Top down cost estimates	Bottom up + 6.2% uplift	% of actual costs
EoE	5	5	5	103.9	88.2	85%	95.8	93.7	90%
Lon	7	6	6	65.7	55.7	85%	57.5	59.1	90%
NW	8	7	8	83.8	70.7	84%	72.5	75.1	90%
W Mids	4	4	4	57.4	52.7	92%	57.0	56.0	98%
NGN	1	2	1	71.2	67.1	94%	74.0	71.2	100%
Sc	2	3	3	55.3	51.4	93%	56.0	54.6	99%
So	3	1	2	96.4	95.4	99%	96.0	101.3	105%
WWU	6	8	7	76.1	63.7	84%	69.9	67.7	89%
TOTAL	-	-	-	609.8	544.8	89%	578.7	578.7	95%

Note: Actual costs are Ofgem's normalised model costs, consistent with Ofgem's allowed base year costs

The table above illustrates that no company in the bottom up approach is allowed its actual costs as the 2006/07 base. Even after the uplift only Southern is allowed more than its actual costs and neither of the two most efficient GDNs under the top down methodology (NGN and Scotland) gets allowances above actual costs. This does not incentivise companies adequately to achieve future efficiencies.

Our detailed response attached suggests three alternatives to address this issue (none of which involve additional costs for customers) and we depict one of these solutions below. One reason why the outcome is worse than might be expected for the most efficient companies is that the 6.2% uplift has been spread equally across all GDNs rewarding both the efficient and the inefficient. An alternative is to band the GDNs into three efficiency bands – the three most efficient, two of average efficiency and the three least efficient; an approach broadly similar to Ofwat’s which categorises companies into five efficiency bands. The top band could then get, say, a 2% efficiency bonus and the bottom band a 2% inefficiency penalty as illustrated in the table below.

	Bottom Up Cost Estimates	Top Down Cost Estimates	Uplift	Bottom Up + Uplift	Actual Costs	% of Base Year Costs
EoE	88.2	95.8	6.2%	93.6	103.9	90%
Lon	55.7	57.5	4.2%	58.0	65.7	88%
NW	70.7	72.5	4.2%	73.6	83.8	88%
W Mids	52.7	57.0	6.2%	55.9	57.4	97%
NGN	67.1	74.0	8.2%	72.5	71.2	102%
Sc	51.4	56.0	8.2%	55.6	55.3	100%
So	95.4	96.0	8.2%	103.2	96.4	107%
WWU	63.7	69.9	4.2%	66.4	76.1	87%
TOTAL	544.8	578.7	6.2%	578.7	609.8	95%

This gives outcomes more in line with what might be expected – the two most efficient companies overall get an allowance above base year costs and the top down upper quartile company (Scotland) appropriately gets an allowance equal to base year costs.

The differential between high performing and underperforming companies ensures strong incentives for future efficiencies that should result in higher customer benefits at the next price control than Ofgem’s proposed methodology.

Operating costs – regional factors

NGN is surprised and disappointed that Ofgem has allowed “other regional costs” to four networks and not to NGN. NGN has a robust case for additional regional factors as submitted in our responses to your BPQ follow up questions and we fail to understand why Ofgem has ignored these points but yet allowed specific factors for four other networks.

Ofgem has allowed WWU £2m per annum of additional costs based on WWU’s claim of £6.8m: £4.2m for “costs associated with having a long and narrow network with a low customer density” and £2.6m of costs associated with additional network length. However, the table overleaf demonstrates that NGN has the **lowest** number of customers per km. of network (customer density). Hence NGN has the strongest claim to additional allowance for the costs it faces serving a dispersed customer base.

Network	Customers/km
NGN	67.9
WWU	70.0
Sco	76.0
NW	77.2
EoE	79.2
WM	79.7
SE	80.0
Lon	97.2

By area, NGN has the third lowest customers per square km., but it needs to be recognised that NGN's area is unique in having two densely populated urban conurbations (Leeds/Bradford and Newcastle) with increased maintenance and replacement costs due to access issues similar to the issues faced in London, and the remainder of the network sparsely populated which leads to substantially higher emergency and standby costs. In particular our low density Cumbrian network is remote from the rest of the network and requires significantly higher costs to service. Further evidence that NGN has the highest percentage of sparsely populated network is presented in our detailed response.

Ofgem has allocated £1.9m per year of additional allowance to London for underground congestion and higher reinstatement and has allocated £2m per year to WWU for their low customer density. NGN's comparable issues and larger network result in additional costs at least as great as WWU's. Consequently NGN should receive an additional allowance for regional costs of **£2m per year**.

Repex

Ofgem's approach has set a challenging and potentially unachievable repex cost target. Our operator's delivery partner contractors are currently facing a loss this year in costs achieved against the matrix targets and it is likely that at least one of the three partnership delivery contractors will walk away from the contract unless unit rates are increased. This clearly creates significant issues regarding our ability to deliver our repex programme.

<i>£m 05/06 prices</i>	East	Lond	NW	West M	NGN	Scot	South	WWU	ALL DN's Average	NGN % less than Average
Mains										
<= 3"	61	76	61	62	57	62	62	58	62	9.2%
4-5"	66	83	66	68	62	68	68	64	68	9.2%
6-7"	93	116	93	96	87	95	96	90	96	9.2%
8-9"	172	215	172	177	161	176	177	166	177	9.2%
10-12"	240	300	241	247	224	246	247	232	247	9.2%
>12-18"	348	436	349	358	326	357	359	336	358	9.2%
>18-24"	487	609	488	500	455	498	501	-	506	10.0%
>24"	601	751	602	618	-	615	619	-	634	
Services										
Relaid	454	567	447	494	470	498	529	485	493	4.6%
Transfer	279	339	270	255	287	304	323	296	294	2.5%
Non-dom	1523	1992	1553	1450	1605	1694	1803	1633	1657	3.1%

Note: table shows 5 year average abandonment costs from appendix 15 of Updated proposals

Ofgem's approach has penalised NGN for being the most efficient GDN and driving the frontier for repex in 2005/06 and 2006/07. NGN has driven rates as low as possible, but current rates are unsustainable. Since Initial Proposals NGN's repex allowance has reduced by 0.9% whereas the other, less efficient, GDNs have had allowances increase by an average

5.1%. As a result NGN has received a lower unit cost allowance for mains than every other GDN, 9-10% below the average and has also received allowances 2.5-4.5% below average GDN allowances for services.

Ofgem's methodology for assessing mains replacement costs takes no account of the lay to abandonment ratio. Historically NGN has abandoned 1.1m of iron main for every metre laid of replacement. However this is unachievable going forwards, firstly because there are fewer schemes available with a high abandon/lay ratio and secondly because there is an increased proportion of insertion, which has ratios much closer to 1:1, to try and achieve Ofgem's challenging efficiency targets. The benchmarking approach should either take account of abandonment delivered or should be based on a constant abandonment ratio of 1.05:1 for all GDNs.

2.5% efficiency target

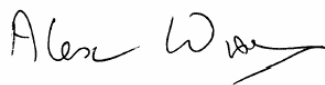
First Economics has submitted a robust analysis of Ofgem's Updated Proposals for frontier shift. In summary Reckon's analysis is weak and the comparative sectors that Reckon has chosen support a productivity assumption up to 1% less than Ofgem's assessment. Reckon's criticisms of the First Economics analysis do not stand up and it appears clear that the First Economics approach is more robust. We would urge Ofgem to use this approach in Final Proposals to assess the scope for efficiency improvements.

It is noteworthy that the Competition Commission has only set a 1.5% efficiency target for BAA and this is clearly based on specific identified efficiencies, ie it is more akin to "catch up" than to frontier shift. There is no rationale for GDNs to achieve in total more than this, in particular given that the average "catch up" assumed across all GDNs is 5% in addition to the annual 2.5% productivity target.

NGN welcomes Ofgem's recognition of the cost pressures that are driving real price increases for GDNs but the average 0.9% per year allowed inadequately reflects the impact of these cost pressures. Ofgem's net target of 1.6% productivity after relative price effects is extremely challenging and we would urge Ofgem either to reduce the 2.5% productivity target or to increase the 0.9% allowed for relative price effects.

Please note that our response can be regarded as non-confidential.

Yours sincerely



Alex Wiseman
Regulation Director

Gas Distribution Price Control Review – Updated Proposals

CHAPTER: Two

TMA

NGN welcomes the inclusion of TMA as a specific reopener and would expect that the full level of (efficient) costs will be allowed. It should be noted that the material amount in electricity was set at 1% but that this covered both TMA and ESQCR costs. The material amount in gas which covers only TMA costs should therefore be set at 0.5% of revenue and once TMA costs hit this threshold the full amount should be recoverable.

Deadband

It is not possible to accurately estimate shrinkage costs and we noted in our response to Initial Proposals that there was an unforeseeable reduction in projected 2007/08 allowed revenue of over 2% in the 7 month period June 2006 - January 2007. Additionally, the new proposed incentive mechanisms, in particular exit and interruption, are likely to add significantly to uncertainty in allowed revenue. Given the uncertainty in collected revenue NGN continues to believe that the deadband should be 4% representing 2% for uncertainty in allowed revenue and 2% for uncertainty in collected revenue.

CHAPTER: Three

Question 1: Do you agree with our revised approach to setting opex allowances and the proposed allowances we have derived using that approach?

Base year allowance – Ofgem methodology

Throughout the price review process NGN has consistently argued against the use of disaggregated, 'bottom-up' benchmarking expenditure as a basis for assessing relative levels of efficiency and in particular as a method for estimating appropriate allowances. Both the difficulty in obtaining a consistent dataset across companies and the tendency to overestimate the efficiency frontier and scope for efficiency makes this type of analysis an unsuitable basis for determining regulatory allowances. The approach employed to address this issue in Initial Proposals incorporated the results of the more robust and reliable 'top-down' methodology to derive a flat uplift to allowances. However, this uplift to allowances was still insufficient to ensure that even the most efficient companies received an allowance at least equal to their actual costs in the base year. Hence all companies had to achieve "catch up" as well as ongoing annual productivity targets. In addition the application of the flat uplift had a significant distorting effect on the results of efficiency analysis with allowances being reallocated from efficient to less efficient companies. Unchanged, this approach would have had a significant impact on the long term incentives for efficiency.

The changes made by Ofgem in Updated Proposals addressed these issues only in part. The calculation of the uplift factors with reference to the upper quartile measure of efficiency instead of the frontier is a welcome and appropriate amendment; it is essential to retain this in Final Proposals. This improves the statistical validity of the benchmarking results by accounting for the existence of estimation error in the econometric model and equally as importantly provides a level of consistency with the approach adopted in the disaggregated analysis and the wider incentive framework. However, there are still several issues that this approach raises in determining allowances.

NGN maintained its position at the efficiency frontier in 2006/07, extending further the efficiency frontier when compared to 2005/06. This frontier shift has provided a benefit to customers of £21m over the five years of the price control period¹. The benefit that NGN has received in improving benchmark levels of efficiency across the industry is, however, unclear.

As shown in the table below, NGN achieved the highest overall efficiency ranking between the top down and bottom up approach reflecting its frontier levels of efficiency. However, the reward for achieving this frontier status is to simply receive its actual costs in the base year.

	Top down ranking	Bottom up ranking	Average ranking	Actual costs 06/07	Bottom up cost estimates	% of actual costs	Top down cost estimates	Bottom up + 6.2% uplift	% of actual costs
EoE	5	5	5	103.9	88.2	85%	95.8	93.7	90%
Lon	7	6	6	65.7	55.7	85%	57.5	59.1	90%
NW	8	7	8	83.8	70.7	84%	72.5	75.1	90%
W Mids	4	4	4	57.4	52.7	92%	57.0	56.0	98%
NGN	1	2	1	71.2	67.1	94%	74.0	71.2	100%
Sc	2	3	3	55.3	51.4	93%	56.0	54.6	99%
So	3	1	2	96.4	95.4	99%	96.0	101.3	105%
WWU	6	8	7	76.1	63.7	84%	69.9	67.7	89%
TOTAL	-	-	-	609.8	544.8	89%	578.7	578.7	95%

NGN has, on average, been benchmarked as the most efficient GDN and yet receives an estimated allowance in the base year only equal to its base year costs. Southern is benchmarked similar to or slightly below NGN but receives an allowance that is more than 5% higher than its base costs. Scotland is operating on the quartile but receives an allowance that is 1% lower than costs in the base year when, based on a methodology employing quartile benchmarks, it would be expected to receive its costs in the base year.

It is clear then that the approach of simply applying a flat uplift to bottom up estimated allowances distorts the incentives for efficiency that flow from the analysis by not rewarding companies in line with their efficiency rankings. The simplicity of application of this approach is significantly outweighed by the inequitable regulatory allowances.

Base year allowance – NGN proposal

There are alternative approaches that retain the broad Ofgem methodology but preserve the long term incentives for efficiency that the framework requires. Three approaches are outlined below; it should be noted that each of these approaches will result in the same overall cost to customers. Given that Ofgem appears minded to retain the “hybrid” methodology, NGN recommends the adoption of approach 2 as this is a simple approach that clearly rewards efficient companies.

- i. NGN has consistently held the view that the most appropriate methodology for assessing efficiency and determining regulatory allowances is the use only of top-down modelling. It overcomes the difficulties and drawbacks of bottom up modelling such as differences in allocation to cost categories between companies and ongoing concerns with some of the disaggregated benchmarking methodology. It also provides a simple, robust, transparent, clear and consistent methodology that directly relates the impact of efficiency improvements to allowances. However, we recognise that Ofgem is minded to use the bottom up methodology and hence we propose below two alternative self-funding “tweaks”

¹ Calculated from Ofgem’s top down model with NGN’s costs increased to a level consistent with an efficiency ranking of 4 in 2006/7.

of Ofgem’s approach that improve its robustness as an incentivising benchmarking tool without adding to customer costs.

- ii. The uplift factor of 6.2% applied to all GDNs can be more appropriately allocated by identifying three categories of most efficient, average efficient and least efficient companies. Efficient companies receive a higher uplift than the 6.2% average (say 2% higher) whilst inefficient companies receive an uplift less than the 6.2% average (say 2% lower). This approach is illustrated in the table below.

	Bottom Up Cost Estimates	Top Down Cost Estimates	Uplift	Bottom Up + Uplift	Actual Costs	% of Base Year Costs
EoE	88.2	95.8	6.2%	93.6	103.9	90%
Lon	55.7	57.5	4.2%	58.0	65.7	88%
NW	70.7	72.5	4.2%	73.6	83.8	88%
W Mids	52.7	57.0	6.2%	55.9	57.4	97%
NGN	67.1	74.0	8.2%	72.5	71.2	102%
Sc	51.4	56.0	8.2%	55.6	55.3	100%
So	95.4	96.0	8.2%	103.2	96.4	107%
WWU	63.7	69.9	4.2%	66.4	76.1	87%
TOTAL	544.8	578.7	6.2%	578.7	609.8	95%

Note: uplifts rounded for simplicity of presentation to ensure that total costs are unchanged

This simple approach better aligns allowances with the results of the efficiency analyses. The differential between high performing and underperforming companies ensures strong incentives for future efficiencies that should result in higher customer benefits than Ofgem’s proposed methodology.

- iii. An alternative approach that recognises the rankings in the top down approach would be to average the results of the bottom up and top down analyses for each GDN and apply a smaller flat uplift to each GDN allowance to bring total allowances into line with the top down upper quartile results. This approach is illustrated in the table below.

	Bottom up cost estimates	Top down cost estimates	Average cost estimates	Average cost estimates + uplift	Average ranking	Actual costs	% of base year costs	Ranking
EoE	88.2	95.8	92.0	94.8	5	103.9	91%	5
Lon	55.7	57.5	56.6	58.3	6	65.7	89%	7
NW	70.7	72.5	71.6	73.7	8	83.8	88%	8
W Mids	52.7	57.0	54.8	56.5	4	57.4	98%	4
NGN	67.1	74.0	70.5	72.6	1	71.2	102%	2
Sc	51.4	56.0	53.7	55.3	3	55.3	100%	3
So	95.4	96.0	95.7	98.6	2	96.4	102%	1
WWU	63.7	69.9	66.8	68.8	7	76.1	90%	6
TOTAL	544.8	578.7	561.7	578.7		609.8	95%	

The ranking of GDN allowances as a percentage of base year costs is almost the same as the average ranking under Ofgem’s top down and bottom up analysis hence passing a “sense check” for base year allowances.

Both options (ii) and (iii) have the following benefits:

- The GDNs operating at the frontier (NGN and Southern) receive a base year allowance above their actual costs in that year to reflect their above quartile efficiency performance.
- The GDN operating on the quartile measures of efficiency (Scotland) receives an allowance equal to its base year costs again reflecting its efficiency position in that year.
- The GDNs operating below the quartile receive a base year allowance below their actual costs in that year to reflect the required efficiency improvements.
- Future efficiencies are better incentivised and hence the approaches are beneficial to customers.

Base year allowance - Marginal Costing of SSE Services to SGN

The recognition of the distorting effects of the marginal costing of SSE services to the SGN networks is a welcome adjustment to the analysis of indirect operating expenditure. The simple approach taken to adjust the frontier benchmark for this effect is a reasonable approach to account for these distorting effects in the analysis.

However, the adjustments are made only to the bottom up analysis and not in the top down analysis which means that the distorting impact of this marginal costing approach impacts the results of the top-down analysis. Given the frontier or close to frontier performance of the Scotia GDNs in the top-down analysis it has similar distorting effects on the benchmarking results. Currently all other GDNs are being penalised for SGN's artificially low and potentially unsustainable indirect opex costs as this results in an underestimated uplift factor.

Consequently an adjustment needs to be made to account for this effect. This could take the form of a similar adjustment to that made to the benchmark as applied in the indirect opex analysis or an ex-ante adjustment made to SGN costs in the base year so the impact is incorporated directly into the results of the top-down regression.

Productivity Assumptions

The GDNs have previously submitted a substantial piece of analysis prepared by First Economics that examined the potential scope for ongoing efficiency gains in the gas distribution industry. This report concluded that the price control determination should include a zero or slightly positive frontier shift assumption compared to the net 1.6% frontier shift assumed by Ofgem.

Ofgem's proposal to maintain a 2.5% per annum productivity assumption in updated proposals and not accept the results of the analysis presented by the GDNs is based on a challenge to First Economics' approach by Reckon LLP. First Economics has reviewed the basis on which Ofgem has determined the 2.5% assumption and the comments provided by Reckon LLP and have identified several key issues:

- Reckon's calculations assume that all historic productivity growth is attributable to labour productivity improvements alone. This is unrealistic and cannot be relied upon.
- The analysis of productivity trends in comparator sectors could be used to support a wide range of assumptions about future GDN productivity growth. This involves a large margin of error in estimation and is not an appropriate basis on which to set a specific efficiency target.

Sector	%
Construction	1.4
Finance, insurance, real estate and business services	(0.8)
Transport and storage and communication	2.2
Wholesale and retail trade	0.5

Reckon has chosen sub-sectors rather than sectors which unnecessarily distorts their analysis. The above table more appropriately shows total factor productivity growth at the sector level and uses the same industries as Reckon. The average productivity figure in comparable industries is 0.8% suggesting that Ofgem should use 0.8% and not 1.4% efficiency saving on top of the 1.1% benefit of comparative competition. This suggests a productivity target of 1.9% (1.1% + 0.8%) and not the 2.5% that Ofgem assumes.

- First Economics effectively and robustly challenges the key concerns that Ofgem and Reckon have with its analysis and NGN is convinced that First Economics' approach has more validity than Reckon's.

On this basis we continue to support the results of the analysis presented by First Economics. It is incorrect to expect the GDNs as an industry to continue reducing opex in real terms indefinitely. It is noteworthy that the Competition Commission has only set a 1.5% efficiency target for BAA and this is clearly based on specific identified efficiencies, ie it is more akin to "catch up" than to frontier shift. There is no rationale for GDNs to achieve in total more than this, in particular given that the average "catch up" assumed across all GDNs is 5% in addition to the annual 2.5% productivity target.

It is noteworthy that electricity DNOs underperformed allowances in the first year of their control. Water companies have also underperformed opex allowances by 2% in 2006/07 despite Ofwat using frontier shift assumptions of just 0.3% for water and 0.5% for sewerage and giving separate allowances for rising pension and energy costs. Large water and sewerage companies received an overall efficiency target of around zero – and are still unable to deliver! There is a danger that Ofgem will set GDNs an unachievable annual productivity target.

The evidence presented by Ofgem and Reckon does not justify the 2.5% per annum productivity assumption and the First Economics methodology is more robust and should be used to set productivity targets.

Real Price Effects

Ofgem's underlying 2.5% productivity assumption takes no account of forecast real price increases for particular items within the GDNs' costs base over the next price control period. Ofgem's recognition of these costs pressures is therefore welcome. However, the 0.9% average allowed for real price effects does not adequately reflect the impact of these cost pressures.

NGN has previously submitted evidence and justification for the forecast increases in these costs. In particular NGN is forecasting:

- real increases in contract labour costs of 4% per annum;
- real increases in direct labour costs of 2% per annum; and
- real increases in materials costs of 2% per annum.

However, the real price effects suggested by Ofgem of 2%, 1% and 1% respectively fail to take account of the market conditions that are expected to exist over the period of the next price control. Instead the estimates rely on current or historic statistics that underestimate the likely impact of future demand and supply conditions in particular on the three elements of cost.

1. Contract Labour Costs

The demand for contract labour is expected to be particularly high over the period to 2012 when compared to recent history. There are significant infrastructure investment programmes over the period including the water investment programme, Heathrow expenditure, electricity transmission network investment and the 2012 Olympics. This represents a significant increase in the demand for contract labour when compared to the previous price control period.

There is also a continued and increasing shortage of experienced gas personnel that require higher levels of training and competence that attract a premium to general contractor costs. However, the indices employed in the analysis are general indices that are not focussed specifically on the gas industry and hence do not include the implications of labour shortage within the gas industry.

NGN's evidence based on contract negotiations and its current partnership arrangements is that contractors are walking away rather than accepting modest unit cost price increases. Increased contract labour costs are resulting in our contract partners making significant losses on current arrangements. A major problem we have in the NGN area is lack of skilled resources resulting in excessive travel costs in both wages and fuel. Wage settlements by our main contractors for skilled team leaders, for example, have had to be in the order of 7%.

The weight of evidence suggests increases going forward of **4%** or more.

2. Direct Labour

There are several industry specific factors that are driving wage increases for GDNs:

- skills shortages;
- aging workforce; and
- historic trends.

As with contract labour costs these specific factors affecting the supply of appropriate direct labour is placing significant upward pressure on salaries. RPI captures general wage inflation but not the extent to which specific market conditions in gas are causing real price effects when compared to economy wide wage inflation and the general measure of price inflation provided by RPI.

The impact of these drivers of direct labour costs will increase over the next price control period as skill shortages and the loss of an aging workforce become more acute. These impacts are not represented in analysis of historic or current datasets but must be considered when evaluating appropriate real price effects for direct labour out as far as 2013. The direct labour RPE should be **2%**.

3. Materials

Significant differences in the growth in different categories of costs has been particularly evident over the last 8 or 9 years with the growth rates for services costs being significantly higher than for goods in the UK economy. The mix of goods and services purchased and consumed by GDNs imply that their costs are increasing at a rate far greater than RPI at present.

The cost of oil, raw materials, energy and services are continuing to rise at a significantly faster rate than RPI and it is these input prices that largely determine the costs of materials purchased and consumed by the GDNs.

The cost of steel and plastic pipes has been rising at an average of 5%-6.4% for the last four years. For example, at the end of 2006 there was a 22% increase for plastic pipes. Furthermore we have just experienced an increase in pipe costs of 4.5% and fittings costs of 5.5% which covers the 12 month period to October 2008.

Thus NGN believes forecast real price increases in materials costs of **2%** per annum is a realistic and possibly conservative assumption.

There is therefore clear evidence to show both that the 2.5% baseline productivity assumption is significantly overestimated and that the real price effects allowed by Ofgem significantly underestimate the impact of forecast market conditions over the period of the next price control. The consequent overall productivity requirements on the GDNs are extremely challenging and cannot be justified on the basis of the evidence presented.

Regional labour costs

NGN agrees with the general approach taken by Ofgem in identifying and accounting for the impact of regional differences in costs that exist between GDNs. It is clear that GDNs that operate in London face higher costs relating to direct labour and this should be accounted for in carrying out the comparative analysis. We also support Ofgem's assumption of higher salaries within the M25 and approximately consistent salaries across the remainder of the UK.

However, it is disappointing that Ofgem has ignored our response to Initial Proposals that presents evidence that the factors that Ofgem has applied to these two elements of cost for London significantly overstate the actual regional differences that exist between them and the rest of the country. Indeed Ofgem has inappropriately increased the cost differential for London thereby further disadvantaging all GDNs operating outside London. The Annual Survey of Hours and Employment 2006 is quoted by Ofgem as indicating a difference of 30% in labour costs between industries operating in London and the average of the rest of the country. It is inappropriate to use average salaries as London, for example, contains a greater proportion of workers in highly paid industries such as banking. A more appropriate statistic is the average salaries for workers in utilities. Examining data for annual gross salaries of industries that are directly comparable with the activities of the GDNs (utilities) from the same data source indicates that the difference is around 24% and not 30%. Using Ofgem's estimate of 22% for Southern and 53% for London within the M25 suggests that the regional factors to apply are 1.05 for Southern and 1.13 for London and that the factor to apply for NGN would increase to 0.97.

However even this lower difference in London and other UK salaries overstates the difference for gas networks as the networks had common ownership and national pay bargaining until very recently. We would suggest that Ofgem assesses NG's projections to ascertain the forecast salary differential between London and the other three NG networks. This is likely to

conclude that the salary adjustment is less than 24% and that NGN's factor should be higher than 0.97.

The evidence to support regional differences in contractor costs is even less clear. Contractors are more mobile than many other forms of labour resulting in small national cost variations and this should be taken into consideration.

Ofgem's own consultants, PB Power, disagree with Ofgem's assessment. PB Power's updated opex report published after Initial Proposals is based on the quarterly review of building prices published by the Royal Institution of Chartered Surveyors. PB Power's report continues to show substantially higher regional factors in NGN's region – 1.01 for contractors and 0.98 for direct labour. PB Power's factors for London are 1.11 and 1.10, and for Southern are 1.06 and 1.03. It is clear that Ofgem has overstated the London effect to the detriment of the regional GDNs. Inexplicably, Ofgem does not comment on why it has ignored PB Power's advice in either Initial or Updated Proposals.

The impact of the normalisation for these regional differences in costs is significant on the results of the benchmarking analysis. Accurate estimates of these differences are required to ensure robust analysis of efficient operation.

xoserve

xoserve has submitted a separate response and NGN fully endorses this response, in particular the inappropriate comparators used for property and IS costs. There is no evidence that xoserve's submission is inefficient and their proposed costs should be allowed in full in the base year.

Question 2: Do you agree with our approach to the additional operating cost items Included in these proposals covering the areas where our work was incomplete at initial proposals?

Regional factors

NGN is surprised and disappointed that Ofgem has allowed "other regional costs" to four networks and not to NGN. NGN has a robust case for additional regional factors as submitted in our response to Ofgem's question and we fail to understand why Ofgem has ignored these points but yet allowed specific factors for four other networks.

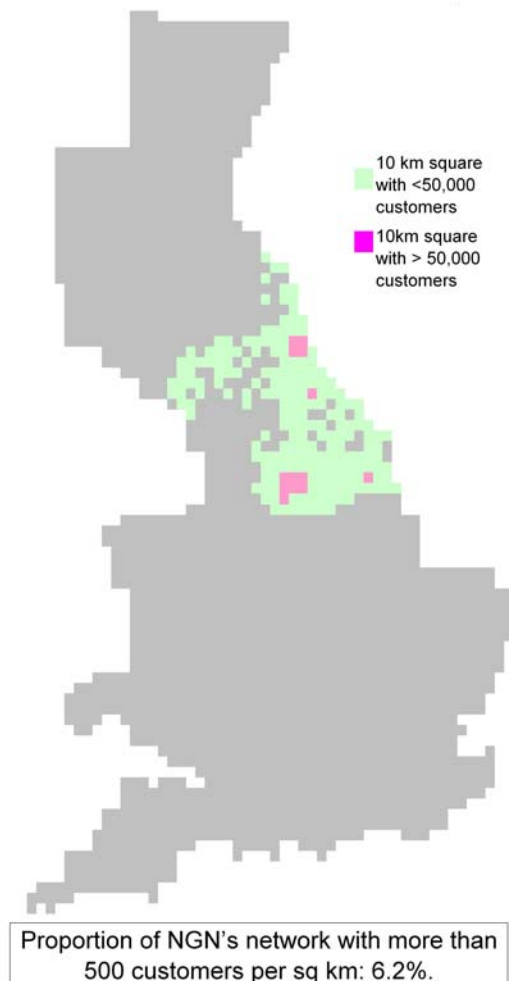
Ofgem has allowed WWU £2m per annum of additional costs based on its claim of £4.2m for "costs associated with having a long and narrow network with a low customer density" and £2.6m of costs associated with additional network length. However, the table below demonstrates that NGN has the **lowest** number of customers per km. of network (customer density).

Network	Customers/km
NGN	67.9
WWU	70.0
Sco	76.0
NW	77.2
EoE	79.2
WM	79.7
SE	80.0
Lon	97.2

By area, NGN has the third lowest customers per square km., but it needs to be recognised that NGN's area is unique in having two densely populated urban conurbations (Leeds/Bradford and Newcastle) with increased maintenance and replacement costs due to access issues similar to the issues faced in London, and the remainder of the network sparsely populated which leads to substantially higher emergency and standby costs. In particular our Cumbrian customers are remote from the rest of the network and require significantly higher costs to service.

NGN has undertaken some detailed analysis of the spread of customers across the UK to underpin our claim for additional costs due to the sparseness of the network. The map below shows NGN's region divided into 10km squares.

NGN relative network density



Source: Gas Demand Data by postcode 2004 from National Grid website.

Areas of high density are shown in red and areas of low density in green. NGN has two concentrated areas of population. The separation of our Cumbrian network is also highlighted and this increases costs as it is a very low density region that cannot be serviced by staff in the remainder of our region.

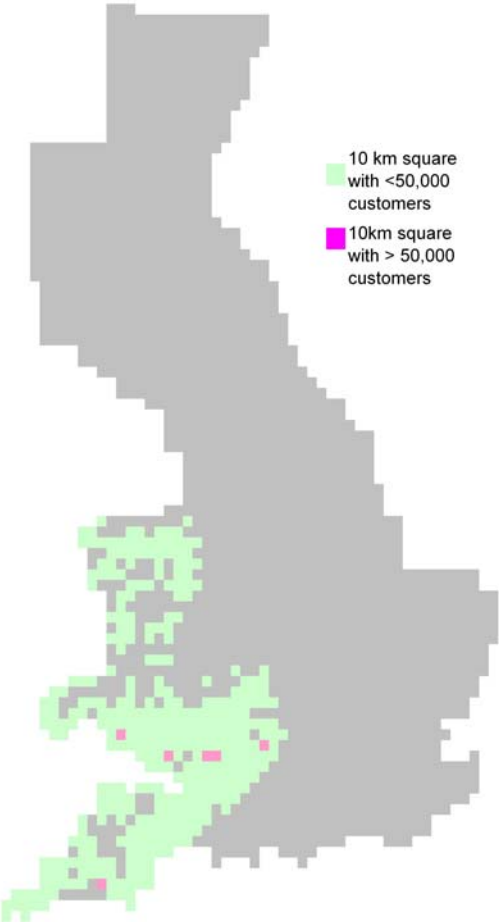
For comparison, maps for WWU and Scotland are shown overleaf. Both have a more even spread of customers with fewer high density areas. The proportion of their area with high density is just 1.7% for each network compared to 6.2% for NGN.

Scotland relative network density



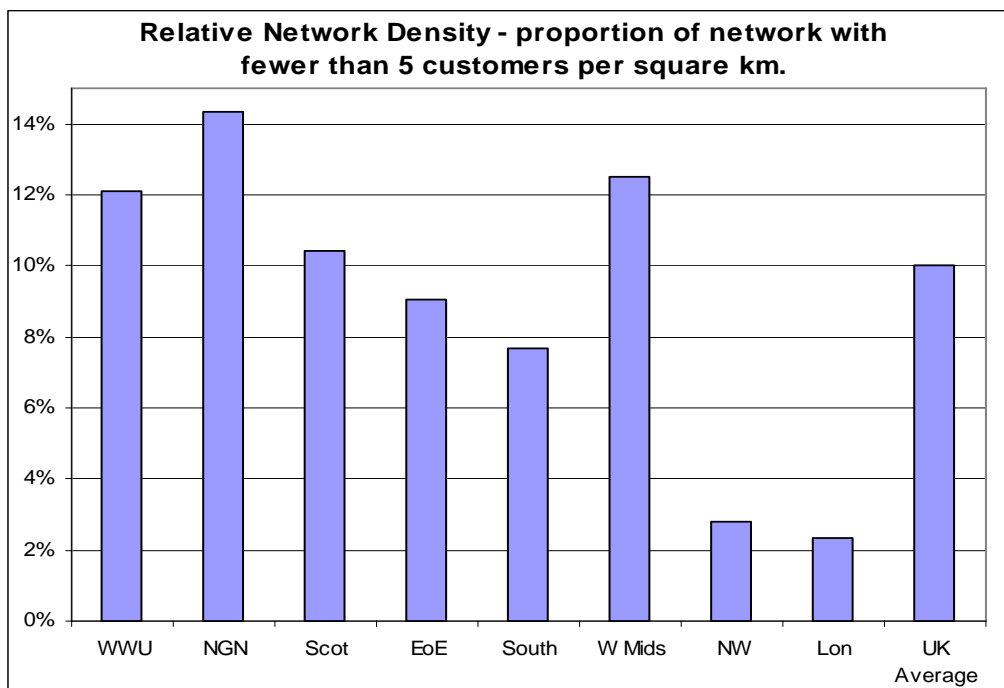
Proportion of Scotland's network with more than 500 customers per sq km: 1.7%.

WWU relative network density



Proportion of WWU's network with more than 500 customers per sq km: 1.7%.

Evidence that more of our area is sparsely populated is depicted on the bar chart below. This shows that NGN has the highest percentage of network with fewer than 5 customers per square km. Thus NGN has both a greater proportion of densely populated network and a greater proportion of sparsely populated network than either WWU or Scotland.



It should also be noted that NGN has the highest number of offtake points of any GDN which explains our relatively high total maintenance costs, but NGN has received no allowance for this.

In summary, NGN suffers both from areas of high density and also areas of very low density. Overall, the evidence demonstrates that NGN's network is sparser than both Scotland's and WWU's. Ofgem has allocated £1.9m per year of additional allowance to London for underground congestion and higher reinstatement and has allocated £2m per year to WWU for their low customer density. NGN's comparable issues and longer network result in additional costs at least as great as WWU's. Consequently NGN should receive an additional allowance for regional costs of **£2m per year**.

Apprentice and training costs

NGN welcomes Ofgem's recognition of the skills shortage and the need to allow costs for training and apprentices in the next price control. It has become apparent that the skills shortage will result in additional costs being required over and above our business plan submission. The revised EU skills model (provided as a confidential attachment), using more prudent and realistic assumptions, suggests that NGN's total costs to cover skills shortages will be £13.8m compared to the £8m that Ofgem has allowed. This is probably an overestimate but NGN believes that **£12m, £2.4m** per year, is needed to cover the likely skills shortage in the next five years. We suggest that Ofgem uses the EU skills model, revising the assumptions if appropriate, to assess the requirement for additional funding.

Waste Management

Whilst NGN agrees with the approach taken there are significant uncertainties surrounding the future legislative and regulatory requirements for waste management and disposal. In the short term the major uncertainty is the potential for inert waste to be re-classified as non-

hazardous with a significant increase in costs. NGN's forecasts and the allowances proposed by Ofgem do not include the additional costs that would arise under this scenario. We accept it is not possible at this time to provide clear evidence that this change will occur but as it is a matter outside the control of GDNs driven by regulatory changes any increased costs during the price control period should be subject to logging up and refunded through the next price control or alternatively included in items subject to a reopener.

Environmental Decontamination

NGN agrees with the approach taken to the treatment of these costs.

CHAPTER: Four

Question 1: Do you agree with our revised approach to setting capex and repex allowances and the proposed allowances we have derived using that approach?

Repex – base year costs

Ofgem's approach has set a challenging and potentially unachievable repex cost target. Our operator's delivery partner contractors are currently facing a loss this year in costs achieved against the matrix targets and it is likely that at least one of the three partnership delivery contractors will walk away from the contract unless unit rates are increased. This clearly creates significant issues regarding our ability to deliver our repex programme.

Ofgem's approach has penalised NGN for being the most efficient GDN and driving the frontier for repex in 2005/06 and 2006/07. NGN has driven rates as low as possible, but current rates are unsustainable. Since Initial Proposals NGN's repex allowance has reduced by 0.9% whereas the other, less efficient, GDNs have had allowances increase by an average 5.1%. As a result NGN has received a lower unit cost allowance for mains than every other GDN, 9-10% below the average and has also received allowances 2.5-4.5% below average GDN allowances for services. The table below shows the unit cost allowance for each DN and highlights that NGN is given the lowest unit cost allowances of any DN, significantly below the industry average.

Repex Incentive Unit Cost Allowances (5 year Average)

<i>£m 05/06 prices</i>	East	Lond	NW	West M	NGN	Scot	South	WWU	ALL DN's Average	NGN % less than Average
Mains										
<= 3"	61	76	61	62	57	62	62	58	62	9.2%
4-5"	66	83	66	68	62	68	68	64	68	9.2%
6-7"	93	116	93	96	87	95	96	90	96	9.2%
8-9"	172	215	172	177	161	176	177	166	177	9.2%
10-12"	240	300	241	247	224	246	247	232	247	9.2%
>12-18"	348	436	349	358	326	357	359	336	358	9.2%
>18-24"	487	609	488	500	455	498	501	-	506	10.0%
>24"	601	751	602	618	-	615	619	-	634	
Services										
Relaid	454	567	447	494	470	498	529	485	493	4.6%
Transfer	279	339	270	255	287	304	323	296	294	2.5%
Non-dom	1523	1992	1553	1450	1605	1694	1803	1633	1657	3.1%

Source: GDPCR Updated Proposals Appendix 15

This arises because the methodology used by Ofgem takes no account of the ratio of abandonment to lay. For every metre of new PE replacement main laid by NGN historically we have been able to abandon 1.1 metres of iron main though this ratio is now falling. However, NGN's relatively high ratio is penalised under Ofgem's methodology which uses different abandonment to lay ratios for each company. GDNs like NGN that have achieved efficiencies through high ratios get relatively lower unit cost allowances and companies with low ratios get relatively higher unit cost allowances. This results in less demanding targets for some DNs and greater outperformance opportunities through improving their lay to abandonment ratios.

To remove this penalty, and the skewed incentives it creates, the benchmarking should either take account of the output delivered by the laid main (i.e. the abandonment delivered) or the benchmarking should be based on abandonment costs. If the present benchmarking continues then a constant abandonment ratio of 1:1.05 should be used to calculate the unit cost allowances for all GDN's.

This effect is further compounded by the IQI calculation which takes no account of any revisions made by Ofgem to forecast lay volumes. Companies whose forecast lay volumes are accepted unadjusted receive no recognition of this in the IQI calculation.

Repex – productivity

Given the extremely challenging assumptions used in setting the base level of costs and the efficiency savings already achieved by NGN, a target of 2% annual productivity is excessive. There is no rationale for this to be higher than the 1.5% for mains reinforcement and connections and the target should be **1.5%** for repex.

Connections Capex

NGN does not agree with the methodology used to set the connections capex allowance. We have two specific issues with the approach taken to setting the connections capex allowances:

Composite Scale Variable – the weightings applied to mains are too low and do not reflect the relative costs of mains to services. Within mains the relative costs of above 180mm mains to below 180mm mains are not reflected in weightings. The weightings used for connections are also inconsistent with those used for the repex CSV.

<i>Source PB Power Capex Report Tables 4-1 and 8-2</i>	CSV Weighting – Connections Regression	CSV Weighting – Repex Regression
Existing Housing Service (lay new service / relay existing service)	900	480
Existing Housing Main (lay new main below 180mm / relay main 125mm to 180mm)	110	132
Ratio service unit to mains unit in CSV	1:0.12	1:0.27

The table above shows that the weighting given to mains work in the repex CSV is nearly double that given to mains in connections work for similar type of work. Connections work will generally involve laying much shorter lengths of main than a repex job which would suggest a higher relative cost of mains to services in connections than in repex work.

Source PB Power Capex Report Tables 4-1 and 8-2	CSV Weighting – Connections Regression	CSV Weighting – Repex Regression
Existing Housing Main below 180mm (Lay new main below 180mm / Replace existing main 125mm to 180mm)	110	132
Existing Housing Main above 180mm (Lay new main above 180mm / Replace existing main 180mm to 250mm)	140	225
Ratio below 180mm mains unit to above 180mm main unit in CSV	1:1.3	1:1.7

The table above shows that above 180mm mains work is given 30% less weighting in the connections CSV than in the comparable repex CSV.

The repex weightings have been subject to more detailed examination and are more robust. Connections unit costs have been identified as an area of uncertainty by PB therefore the relative weightings in repex have more validity and should be used. The combined effect is to under weight mains work in the connections CSV and penalise companies with a relatively higher proportion of mains work. The connections regression should be re-run with a corrected CSV.

Workload Adjustment – NGN’s forecast mains workload has been reduced by 10% as the average mains length per connection (3.7) is higher than the industry average (3.2). The NGN forecast is based on the actual mix of work undertaken over the last three years as shown below:

Year	2004/05	2005/06	2006/07	3 Year Totals
No. of Services	14934	13532	11564	40,030
Mains laid (meters)	44,900	50,900	51,600	147,400
Avg Mains Length per connection	3.0	3.8	4.5	3.7

The mix of work is driven by customer requirements and is not within the control of NGN but to use historic splits is a reasonable basis for determining forecast workloads. NGN’s network has the lowest ratio of customers per km of main and this may in part explain why the NGN average length per main is higher than the industry average.

NGN’s forecast mains workload has been derived on a reasonable basis reflecting historic performance and network characteristics and should therefore be allowed in full.

LTS Capex

NGN has no issue with the proposed treatment of the Eggborough project as this is a pure customer driven project with a number of uncertainties. We welcome the proposal that an ex-post adjustment will be made to our allowances if an ARCA is signed after February 2007. Given that the taking forward or otherwise of this project is not within NGN’s control any such adjustment should be on a “pot 3” basis at the next review.

The precise timing of the Keighley to Calder Valley pipeline is sensitive to relatively small fluctuations in demand. We acknowledge that it may be possible to defer this project to 2013/14 as Ofgem have proposed but if this proves not to be the case then NGN would be exposed to a large financial penalty as a direct result of Ofgem’s changing the timing of the allowance for the project by one year. This would not normally occur should the project have been scheduled mid way through a price control period. To remove this anomaly if NGN can demonstrate at the next review that this pipeline had to be constructed in 2012/13 then the

construction costs incurred in that year should be subject to “pot 3” treatment rather than the capex roller treatment of overspends.

We would welcome confirmation of the pot 3 treatment for these two items in Final Proposals.

Mains Reinforcement Capex

NGN is unable to provide specific reinforcement costs where such work is undertaken by the connections provider. No account appears to have been taken of this when calculating the allowance for NGN. This needs to be corrected within the final proposals for reinforcement capex.

Governor Capex

NGN has no issues with governor capex.

Other Operational and Non-Operational Capex

NGN has no issues with other operational or non-operational capex.

CHAPTER: Five

Question 1: Do you agree with our updated proposals for the quality of service arrangements?

NGN supports many of the changes being made to the quality of service arrangements. We welcome the revisions made by Ofgem since the initial proposals. There are still a number of detailed issues that will be addressed through the working groups and NGN will contribute fully to these discussions.

Sub-deduct Networks. Ofgem is seeking views on:

- 1. The capability / willingness of DNs to conduct a survey**
- 2. The practicalities and challenges involved**
- 3. The timeframe required**
- 4. The estimate of costs involved per network**
- 5. Alternative methods of resolving the situation**

1. NGN would be willing to undertake a technical survey of sub-deduct networks within our area provided revenues were allowed to carry out this work and a reasonable timescale was set to prevent this having an adverse impact on normal operational activities.
2. Practicalities and challenges involved include:
 - (i) Locating the assets (both in terms of broad location and, once identified, being able to physically locate and inspect the buried asset).
 - (ii) Agreeing or accepting a common set of parameters nationally that could be used to determine if the asset was fit-for-purpose or if work was required to bring it to an acceptable standard.
 - (iii) Reluctance to accept the assets based on a sample. Sampling may be suitable to determine the level of financial risk within a given tolerance. The additional cost of future maintenance / upgrading etc. could then be built in. However, under Pipeline safety regulations (PSR), GDNs have an absolute responsibility for all pipes they own with a requirement that they should be fit for purpose. Sample examinations may

- give an indication of the likely rate of failure, but would not identify every individual defective pipe.
- (iv) For metal assets (especially iron), identifying a robust leakage / fracture history to enable risk scores to be calculated to allow the assets to be integrated into the mains replacement programme.
 - (v) Uncertain accuracy of records relating to location, material and size of the assets. This could have a knock-on impact on future activities including connection works.
 - (vi) Uncertainty of construction records in terms of materials, methods used, test details, etc.
3. It is very difficult to assess the timeframe. Assuming a uniform geographic spread (unlikely) and using the data in section 5.44, NGN is likely to have about 250 - 300 sub-deduct networks serving about 550 end users. Provided information was available on the location of the networks and details of current operators, technical assessment may be able to be completed in 18 - 24 months. Timescales may be longer depending on the network lengths and NGN has no data on these.
4. A cost estimate is difficult without knowing the lengths of main involved. An estimated 4-5 trial holes per network and 1.5 trial holes per day suggests 3 days per network. 3 FTEs at £300 per day gives a cost of £2,700 per sub-deduct network or about £800k in total. Allowing an additional 30% for travel, abortive works, consumables, etc. suggests £3,500 per network for the investigation works only and £1m in total.
5. Rather than attempting to assess the suitability of existing networks for adoption, it may be more efficient simply to pay the DNs to replace the existing assets with new, using a similar incentive scheme to MRIM. It is important to note that the MRIM rates would substantially underestimate the costs. On average, based on the Ofgem figures, each sub-deduct "network" feeds only 2 end users. These projects would be much less efficient than the replacement projects. As an alternative, all metallic pipes could be relayed and all plastic pipes disconnected, retested and reconnected.

CHAPTER: Six

Question 1: Do you agree with our view that an opex rolling incentive is not appropriate?

NGN strongly believes that the existing opex incentives affect management decision making to the detriment of customers. An opex rolling incentive is required to equalise the benefits of opex efficiencies across the five year price control, in particular to incentivise efficiencies towards the end of a price control period. The low incentives for opex savings at the end of a price control cannot be in customers' best interests.

Ofgem notes in Updated Proposals that benchmark GDNs are not incentivised to make savings at the end of a price control period. However, Ofgem's methodology means that most GDNs are benchmarks for at least part of the cost base and the likely behaviour in the next base year is for the most efficient GDNs to avoid making savings in the areas of operation where they are in the upper quartile for efficiency. The company setting the benchmark will be predictable once the cost reporting project has been implemented.

Thus NGN believes that it is appropriate to implement an opex rolling incentive to ensure that savings are achieved consistently through the price control period to provide greater benefits for customers.

If Ofgem is not minded to introduce a 100% opex roller then a scaled down version can be used as NGN has suggested previously in response to consultations. The percentage could be the same as the capex IQI incentive to provide a degree of consistency between capex and opex. Thus for a GDN allowed 35% saving for capex efficiencies:

- (i) Opex savings (or overspends) will be retained in full within the price control period as now.
- (ii) For the years beyond the price control, savings (or overspends) would accrue at 35%. For example an outperformance of £4m in year 3 would be retained during the price control and would also attract an additional revenue allowance of £1.4m in years 1 and 2 of the subsequent control period

Question 2: Is our approach to capping the expenditure under the mains and services incentive appropriate?

We understand the need to cap total repex expenditure to prevent significant additional costs being incurred by customers that were not forecast at the review. However, the approach taken by Ofgem to set the cap at the aggregate of the five year forecast exposes GDNs (like NGN) who have been more prudent in forecasting their diameter abandonment profile (i.e. lower percentage of large diameter mains) to greater risk, as the profile of mains to be abandoned is not within the full control of the GDN. This creates the wrong incentive framework and a cap of, say, 105% of the aggregate five year forecast should be applied to each GDN.

The forecast abandonment diameter profile is derived from a long-term projection from the Decision Support Tool based on the mains population and risk scores in Mains Risk Prioritisation System (MRPS) at the time the NGN forecast was produced. NGN's forecast is a best estimate with no "weighting" applied to the figures to skew the profiles towards the larger diameters.

The projected abandonment profile is based on the risk scores of individual pipes. The risk score of a pipe is calculated within MRPS by examining the history of an individual pipe (plus those in its immediate vicinity) and applying this to a series of global coefficients applicable to that particular class of pipe. The pipe-specific variables within MRPS are dynamic - risk scores of pipes are constantly being recalculated based on any failures of the pipe in question and those in its vicinity. As such, between MRPS extracts there may be a significant movement of individual pipes between risk bands, but if the global coefficients remain constant this movement does not tend to have a significant impact on the diameter profile.

However, on a periodical basis the global coefficients are recalculated based on detailed statistical analysis of data provided by all DNs on escapes, pipe failures, gas ingress into buildings, incidents, etc. Changes to the coefficients linked to the pipe's diameter could significantly alter the risk / diameter profile within MRPS and give larger diameter pipes relatively higher risk scores than now. Under the Mains Replacement Policy as agreed with HSE, the DNs would have to reflect this changed profile in the pipes selected for decommissioning in the subsequent year. As such, the DN could be obliged to exceed the MRIM cap (in terms of diameter mix, not total length of abandonment) in order to comply with its HSE obligations. Under these circumstances it would be unreasonable to penalise the DN for exceeding the cap value, and a cap of 105% should be allowed where this is driven by an abandonment diameter profile that does not match the one contained within the PCR.

The MRPS coefficients have not been reset since the forecasts were produced in 2006. In the last few weeks NGN (along with the other DNs) have provided Advantica with the raw data to recalculate the coefficients. The revised coefficients will be available to implement in April 2008 and these will influence the pipes selected for abandonment in 2009/10.

Question 3: Is our approach to allocating domestic purge and relight costs to services costs appropriate?

NGN has no issues with the approach used.

Question 4(a): Do you agree with our approach to the capacity outputs incentive?

The existing 7.5% cap and collar for flat capacity has worked well and we see no reason to increase this to the proposed 10%. We recommend that the existing 7.5% cap be retained for flat capacity and be similarly applied to any interruption incentive.

NGN believes that the new interruption regime poses substantial risks to GDNs: either that there are no bids for interruptible capacity by NSLs, or that interruptible bids are higher than expected and approach the cost of network reinforcement. Paragraph 6.26 suggests that there is substitutability between interruptible loads, however in NGN's region in network sensitive areas substitutability is either extremely limited or simply not available.

NGN agrees with Ofgem's proposal in 6.24 to set the interruptible capacity incentive at a level which incentivises GDNs to contract for interruption up to the point at which it becomes more efficient to reinforce the network to make NSLs firm. However, there needs to be clarity on how Ofgem will calculate the discounted level of GDNs exposure to the cost of reinforcement projects. There is a danger of disconnect between the 45 year asset life and the very much shorter time periods of interruption bids, incentive arrangements and price control reviews.

GDNs may be unable to trade generic interruption against their flat capacity requirements as there may be an absence of interruption bids in 2008. GDNs will therefore be obliged to book their required 1 in 20 exit capacity requirements. Consequently, it is essential that the exit capacity incentive reflects the full 1 in 20 network requirements.

Question 4(b): What are the issues raised by incentivising or not NTS flex capacity?

NGN agrees with the summary in the consultation of the current position relating to the potential for scarcity of a flexibility capacity. As a consequence, there is no evidence that a flex incentive is required for the period up to 2013. Moreover, industry participants have expressed a willingness to monitor behaviour and usage patterns to clearly understand the flex booking/requests to ensure that the available flex capacity is not exceeded. This should be adequate to ensure that the NTS can deliver the flex requirements of networks.

If Ofgem is minded to include an incentive then it should be based on the total flexibility capacity available on the NTS.

Question 5: Should the volume targets for the flat capacity incentive vary with changes in the calorific value (CV) of gas?

The volume targets for the flat capacity incentive should vary with changes in the CV as this would more correctly relate the target to the energy transported rather than purely to the volumes involved. GDNs have no control over calorific values; it is the energy transported that networks predict.

Question 6: Is it appropriate to allow a price control re-opener (subject to certain criteria) for any capex spend that may be required following the interruption auctions?

It is entirely appropriate that, providing it can be demonstrated that reinforcement is the cheapest option for customers in the long term, the full capex cost of reinforcement should be

allowed in the RAV. Consequently there should be a capex reopener mechanism that can be used by GDNs. We agree that any approved capex would reduce the interruption opex allowance consistent with the removal of any NSLs. However, NGN is concerned that a reopener would only be allowed if there is “evidence that the GDN had made all efforts to engage the customers in the auction process”. There needs to be more clarity on what evidence would suffice.

There should be a process for approving any proposed capex reopener before the GDNs have to commit on reinforcement so that GDNs can make a fully informed, efficient decision.

Question 7: Is it appropriate to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of metering? If so do you agree with our approach and methodology for the parameters?

It is appropriate to have an adjustment mechanism for the treatment of emergency services costs arising from the loss of metering work. Customers have significantly benefited from lower transportation charges through GDNs being able to employ emergency staff on metering work. However, the requirements for metering service providers (e.g. a dedicated workforce and improved service standards) are radically changing. Emergency staff must give priority to gas emergency calls and are therefore unable to meet these new requirements. These changes are outside the control of the GDNs therefore it is appropriate that allowances are provided.

The preferred approach of using a revenue driver based on the volume of meter work lost rather than ex-ante allowance with sharing factors is supported by NGN as it will be based on actual rather than forecast changes. However, NGN does not agree with the specific calculations of the parameters being used. Out of the £9m per annum costs associated with metering work NGN has identified that £3m per annum are avoidable if the work is removed leaving an additional £6m per annum of unavoidable costs as identified in our response to OP-NGN-1020. The parameters for the revenue driver allow a maximum of £3.5m of these costs to be recovered. Whilst we can understand the need to incentivise companies to retain meter work where possible an effective penalty of 42% is excessive where customers have benefited in full from the £6m reduction in NGN's emergency costs.

NGN has the most efficient GDN emergency operation, significantly below the quartile efficiency point in the benchmarking. The level of unproductive time within NGN's workforce is therefore less than the industry average. The loss of meter work will consequently increase the level of unproductive time by a greater percentage than a less efficient operator. This will explain some variances between companies. Ofgem by using industry averages to calculate both the tipping point and the unit cost is penalising NGN as the most efficient operator.

NGN's own parameters should be used not those driven by industry averages. Using Ofgem's methodology the appropriate parameters should be **186,000** for the tipping point and **£24.90** for unit costs as detailed in OP-NGN-1020. This will provide NGN with a maximum of around £4.5m out of £6m unavoidable costs and represents a fair balance between customers and NGN.

CHAPTER: Seven

Summary

We have included a summary of our response to the questions in this chapter as Ofgem's proposals for shrinkage and leakage incentive, methodology and baseline in Updated Proposals represent a substantial risk of significant loss to NGN. Nevertheless, we recognise

and welcome the ongoing engagement with Ofgem to ensure that Final Proposals provide appropriate incentives and baselines and the appropriate balance between customer and shareholder interests.

NGN's key points on the proposals for shrinkage are as follows:

- The baseline levels of shrinkage must be set with reference to the output from the leakage model as this will be the methodology for assessing actual shrinkage.
- We agree with using day ahead prices as a reference and the appropriate indices are the Heren Day Ahead Closing Offer Price and the Heren Weekend Closing Offer Price. However, a shrinkage uplift factor of around 2% is still required for the shrinkage proposals outlined to reflect purchasing costs and the risk of not achieving closing index prices.
- It is appropriate to set an environmental incentive for reducing leakage. NGN would go further and proposes that shrinkage reduction is incentivised via a single mechanism based on the proposed approach of baseline leakage levels referenced to the social/environmental cost of gas leakage with no requirement to purchase shrinkage gas. This will reduce costs to customers, will not impact the incentive to reduce shrinkage gas and will bring gas arrangements in line with those in electricity.
- It would be more efficient and hence reduce costs for customers, to base total shrinkage volumes on a fixed volume in each year and a fixed daily volume rather than maintaining the link between own use gas and theft of gas with throughput. Although this may not directly reflect daily usage the difference is not material. In total, costs for customers would be lower and the incentive for reducing shrinkage volumes would be unchanged.

Question 1: Is it appropriate to roll forward the existing shrinkage incentive and if so do you consider the leakage volumes appropriate?

The overall objective, as NGN understands it, is to set appropriate incentives so as to minimise shrinkage and leakage volumes to benefit customers and the environment. To achieve these objectives the arrangements should address the following issues:

- incentives should align customer and GDN interests;
- gas purchase risks should be borne by those best placed to manage them;
- the arrangements should be simple and transparent; and
- volatility of allowed revenue and hence customer prices should be minimised.

NGN has previously expressed concerns with the current shrinkage arrangements and their ability to achieve the above objectives. These concerns include:

- The inefficiency of allocating gas price risks to GDNs and customers. Customers' interests would be better served by allocating these risks more appropriately with shippers, the parties best placed to manage them efficiently.
- The incentives to reduce leakage are significantly distorted by the incorrect relationship between leakage and demand implied by the use of a shrinkage factor.
- Indexing allowances to wholesale gas prices introduces a significant amount of volatility into regulatory allowances and consequently into customer charges. Such volatility in charges for transportation services does not achieve efficient pricing signals.

The shrinkage incentive arrangements proposed in Updated Proposals address some of these concerns. In particular, the proposal to remove the direct relationship between leakage and throughput better reflects the real world driver of leakage.

To appropriately incentivise reduced usage and cost of energy an assessment needs to be made as to the appropriate baseline level of energy usage. NGN is already forecasting significant reductions in leakage over the period of the next price control, driven by its mains replacement programme, partly offset by forecast increases in Average System Pressure which themselves are used to offset the requirement for additional capital expenditure. These estimates are derived from the industry-wide accepted Leakage Model process based on the results of the National Leakage Surveys conducted in 2002 and 2003.

The proposed baseline levels of leakage within the Update Proposals document are significantly below the estimates derived from the leakage model. We understand however, that Ofgem accepts that baselines are incorrect and is minded to change the basis for deriving the baseline levels of leakage to those derived from the leakage model. This change in approach is essential to ensure the correct basis for the incentive arrangements.

The proposals to set a fixed and consistent volume of leakage each year for both the leakage incentive and shrinkage raises several key issues with the mechanics of how shrinkage gas purchases are made:

- With no relationship between demand and shrinkage leakage volumes in the proposed mechanism, the most appropriate means for calculating daily shrinkage volumes is to assume $1/365^{\text{th}}$ ($1/366^{\text{th}}$ in leap years) of the annual volume of baseline levels of leakage in each year.
- The Uniform Network Code (Section H) will require modification to ensure consistency with the new proposals.
- The Gemini system will also require changes to reflect the modifications to the UNC and replace the operation of a shrinkage factor with fixed volumes for leakage. This raises two separate issues:
 - The additional costs of implementing these necessary system changes need to be accounted for in xoserve's regulatory allowances.
 - The timescales for implementation of these system changes is very likely to extend beyond 1 April 2008. On this basis, it may be prudent to allow for a 'rollover' of the current shrinkage arrangements until 30 September 2008 when the current shrinkage factors expire. This is not a significant issue as shrinkage gas costs are low between April and September.

The proposal to maintain Own Use Gas (OUG) and Theft of Gas (TOG) as functions of throughput within the framework and the requirement to calculate and apply factors only for these elements adds unnecessary complication to the shrinkage arrangements. Efficiency will not be improved by incorporating these two elements into the arrangements on the basis of a shrinkage factors as opposed to a fixed volumes in line with leakage. There are several reasons to support including OUG and TOG in the flat volumetric arrangements:

- The two elements represent a very small fraction of overall shrinkage volumes – around 5% combined.
- Any link with actual throughput introduces an element of uncertainty into forecast and purchased volumes and is an unnecessary cost to customers as it requires an uplift to index prices to account for this as in the current arrangements.

- Buying flat/fixed volumes across each day of the year for all shrinkage gas will allow more efficient purchasing of gas by the GDNs. It will eliminate any additional volume risk that may apply to even short term forecasts and allow more accurate purchases of gas across weekends.
- The systems required will be simpler and hence cheaper.

The OUG and TOG factors within Update Proposals should be consistent with the latest information on the applicable rates for each GDN. The Shrinkage Factors approved for 2007/08 include 0.0113% for OUG and 0.02% for TOG. These figures should be applied in the mechanism used in setting allowances.

Question 2: Is the gas reference price formula appropriate?

The relevant index price to be used in calculating allowances need only ensure that GDNs can effectively achieve those prices in the market to hedge its exposure and that the liquidity of a particular product is sufficient to ensure that the required volumes can be purchased.

Given the relatively small percentage that volumes of shrinkage gas contribute to overall volumes of gas traded on any day then liquidity is unlikely to be problem for the most commonly traded products in the UK gas market. Liquidity seemingly increases as the duration of the product decreases and hence referencing prices to the Day Ahead poses no problems for liquidity.

In general we feel that referencing shrinkage gas allowances against a day ahead index strikes an appropriate balance between the more stable longer term prices and the increased volatility of within day prices. We continue to support the use of an independently published index of day ahead prices such as that published by Heren. The appropriate index price would therefore be the Heren Day Ahead Closing Offer price index for weekdays and the Heren Weekend Closing Offer Price for weekend purchases.

However, as was accepted in devising the shrinkage arrangements for the one year extension, there are several reasons why GDNs will face problems in both achieving market prices and incur costs in carrying out the trading activity. These reasons formed the basis of the justification for the 3.5% uplift to index prices applied in the current arrangements. These are summarised below, though some of these issues would disappear if all shrinkage was on a flat volume basis and not demand dependent:

- There are direct costs associated with purchasing gas. NGN uses an agency agreement with a third party that purchases the gas on its behalf in the open market following NGN's instructions. This service was competitively procured but the fees of approximately 1% of the purchase cost need to be provided for in the shrinkage allowance.
- The GDNS have an unavoidable and hence unhedgeable exposure to short term markets and the inherent volatility that exists in prices for products in these markets relating to changes in shrinkage volumes driven by unpredictable weather conditions.
- The nature of the volumes sold in the wholesale gas market means that GDNs cannot exactly match its requirements for gas with purchased volumes. The most liquid parts of the market consist of trades in denominations of 5,000 or 10,000 therm lot sizes. GDNs therefore have an unhedgeable exposure, of up to 5,000 therms, to the penal prices within the balancing mechanism hence average market prices are unlikely to be achievable.
- The ability of GDNs to achieve the average or closing index price in any period is severely restricted by the number of purchases that can be made in any month to cover the required volumes (eg across any period this can be as little as two separate purchases to achieve an index price).

- Unseasonal weather conditions result in both price and volume moving in the same direction resulting in a “double whammy” for GDNs either selling back volume at very low prices or purchasing additional volumes at higher prices when compared to the allowance index price.

The assumptions underlying the exclusion of such uplift to prices because the proposals move from a three month-ahead index to a day-ahead price index are incorrect. It is difficult to measure many of these factors directly in a mechanistic way that can be automated within licence conditions. However, prudent estimates of the impact of these factors on the costs of purchase can be made and need to be accounted for in setting allowances. Evidence for these adjustments is set out below:

Costs of Purchase

Actively trading in wholesale gas markets is not costless. Market participants either have to pay for the personnel, systems and administration of an activity that allows them to access the market directly or pay a service provider to do so on their behalf.

NGN employs a third party service provider to carry out these activities on its behalf that attract specific fees for service provided. The contract was put in place at the time of sale following an OJEU tender process for services to ensure the fees were adequately market tested and were negotiated down substantially from initial tender. Fees for this service are related to the volume of gas bought and sold on behalf of NGN to meet its shrinkage requirements. These fees for 2006/07 totalled ~£65k or approximately 0.9-1.1% of total shrinkage costs (at current gas prices). These costs need to be provided for in regulatory allowances.

Traded Volumes

The inability to match volumes exactly in any day exposes market participants to volumes of gas traded in the balancing mechanism where ‘penal’ prices apply to those purchased volumes above or below actual volumes on any day.

This effect is amplified by differences in actual volumes traded based on forecast and actual volumes required in any day even when purchasing in short term markets such day ahead and within day.

Prices in the balancing mechanism known as System Marginal Buy (SMP Buy) and System Marginal Sell (SMP Sell) prices, are on average 0.9p/therm higher or lower than System Average Price (SAP). This along with differences in price between short term markets and the balancing mechanism can lead to a premium in balancing prices of the order of 7-10%. Not all volumes purchased by GDNs are exposed to the balancing mechanism. However, given the small volumes traded by GDNs the imbalance volumes are on average of the order of 3.5-7% of volumes.

This suggests a premium to overall purchase costs of about 0.25-0.75% above market prices.

Low Volume of Trades

As already mentioned, the GDNs’ requirements for gas shrinkage requires very small volumes to be traded/purchased on any day. There is a maximum of 6/7 daily trades during winter months and as little as 1/2 trades during summer months which hampers the ability to achieve market prices across any given day as prices fluctuate within day.

This effect is still evident even when considering short term markets and day ahead and within day prices. The markets for these products trade 24 hours a day as opposed to longer term products such as monthly and quarterly products that trade primarily during normal business hours. With the gas day running from 6am to 6am each day, without a 24 hour trading function or service the ability to achieve closing prices or even average prices across any day is more limited.

The impact of this effect on achieved prices is estimated to be in the range 0.3-0.5%

Total uplift required

On this basis there is evidence to support the requirement for an uplift to prices to cover the additional costs that GDNs face in participating in the wholesale gas market. The proposed change from an index based on 3 month ahead index prices to day ahead index prices removes a significant element of forecasting risk that materialised in achieved prices. However, there are still significant risks and costs that suggest an uplift to index prices in the range 1.5-2.4%.

Question 3: Should Ofgem establish a new incentive to target harmful environmental emissions?

The proposal to implement arrangements that specifically incentivise reductions in leakage based on volumes and a pre-determined social/environmental cost for gas leakage is a significant improvement over the current shrinkage based arrangements. In particular, this breaks the incorrect link between gas leakage and throughput implied by the current shrinkage arrangements.

The approach provides a stronger financial incentive than currently exists and also provides a more stable basis, as it is independent of gas price movements, against which investment decisions can be evaluated and implemented.

However, it is not clear that it is necessary for emissions from gas leakage to be subject to two separate incentives one based on the social/environmental cost and the second on gas price. This results in "double counting", ie an overestimate of the environmental cost which may lead to uneconomic decisions. Additionally, the volatility and unpredictability of gas prices means that in appropriate investment decisions may be made for leakage reduction. An example of this volatility is that annual forward prices rose by 12% in the 2 days to 18 October.

NGN proposes that leakage reduction be more appropriately incentivised via a single mechanism based on the proposed approach of baseline leakage levels referenced to the social/environmental cost of gas leakage with no requirement to purchase shrinkage gas. This will reduce costs to customers and will not impact the incentive to reduce shrinkage gas. Furthermore, gas arrangements would then be in line with those pertaining to DNOs.

Question 4: Do you support the design of the environmental incentive and its parameters?

We agree that the proposed design of the environmental incentive scheme is an appropriate means by which leakage reduction can be incentivised. The reference to a social/environmental cost of gas provides a sound economic basis for delivering incentives.

The intention to set a baseline level of leakage associated with that level of leakage that would occur in the absence of the incentive scheme is again a sound basis for setting the parameters of the mechanism. This ensures that the scheme is potentially 'neutral' in its impact on GDNs if schemes cannot be identified that reduce leakage beyond the levels

implied by the mains replacement programme and included in forecasts. Setting baseline targets below this level will imply potentially significant additional costs not provided for in regulatory allowances.

As highlighted above the current proposal sets baseline levels of leakage below those identified from the planned work programme and the leakage. These reductions cannot be achieved and we welcome the changes that Ofgem is minded to make that result in baseline levels being set with reference to output from the leakage model.

Question 5: Are the strength and baselines for the incentive appropriate?

The strength of the incentive in the proposed approach is driven by the social/environmental cost of leakage. NGN is not in a position to challenge the validity of DEFRA's estimates in this area. However, accepting that they are accurate and representative of the true cost of gas leakage then the strength of the incentive is appropriate.

Any cost higher than the true economic cost will result in sub-optimal decisions that reduce leakage beyond economic levels that will result higher costs for consumers; lower costs will result in sub optimal decisions and lower costs for consumers, but a higher environmental impact.

It is interesting to note that Ofgem's proposals suggest the social/environmental costs of leakage are higher than DEFRA's estimates as they use a reference gas price approximately double actual gas prices. It is unclear what justification there is to assume that DEFRA's estimates are too low. This could lead to potentially higher costs for consumers.

Question 6: Are the cap and collar arrangements appropriate?

Given the uncertainty surrounding the outcome of the incentive arrangements on levels of leakage and associated incentive/penalty payments it is appropriate to implement upper and lower limits to avoid windfall gains/losses for customers and/or companies.

Question 7: Is it appropriate to introduce a mechanism to address periodicity of investment?

The proposed approach suffers from the problem of declining incentives for leakage reduction over the price control period. The financial benefits of leakage reduction schemes implemented in year 1 of the price control period will be retained for five years whilst schemes implemented in year 5 on the control period will receive the benefit for only one year.

Ofgem should consider a mechanism allowing companies to retain the benefits of leakage reduction below baselines for a rolling five year period.

Question 8: Are the leakage model and governance arrangements appropriate?

The three components of shrinkage gas (leakage, own use gas and theft) are not measured/metered elements of total throughput. Measures of these three elements are required to be accurately estimated to ensure that GDNs and customers pay for the appropriate level of shrinkage gas and that incentives are maintained to manage levels of shrinkage gas and cost accordingly.

The model has been developed over a significant period of time and was inherited from National Grid at the time of the gas network sale. None of the major functionality within the model has been changed since that time. An industry wide correction for the treatment of Pit Cast Iron within the model has been implemented this year.

The model has been accepted as the industry standard for estimating shrinkage volumes and factors for many years. The model provides a robust and accurate estimation of shrinkage volumes. It is not obvious how the accuracy of the model could be significantly improved. Consequently it is our belief that the model is 'fit for purpose' and should continue to form the basis of estimating shrinkage gas volumes.

The industry currently benefits from the use of a common model to estimate leakage, shrinkage and shrinkage factors. This single model approach, we believe should be maintained to ensure consistency and accuracy of estimation across the industry and ensure consistency of setting baselines and actual leakage.

The shrinkage forum, which includes GDNs, Shippers and Ofgem, is an appropriate forum to ensure that consistency is maintained across the industry. We would recommend the following changes to governance:

- Ensure that there is one common model for assessing leakage and shrinkage that is made available to all parties.
- A model change control process should be put in place as part of the Shrinkage Forum or within a specific sub-group workstream.

CHAPTER: Nine

Question 1: Does our risk analysis support a range for the cost of equity of 7.0-7.5%?

The table below summarises NGN's estimate of the cost of equity for GDNs.

	TPCR	GDPGR at 60% gearing	GDPGR at 62.5% gearing
Risk free rate	2.5%	2.5%	2.5%
Equity risk premium	4.5%	4.5%	4.5%
Asset beta	0.40	0.444	0.444
Gearing	60%	60%	62.5%
Equity beta	1.00	1.11	1.17
Cost of equity	7.0%	7.5%	7.78%

Ofgem's starting point for consideration of the appropriate cost of equity for GDNs is appropriately the conclusions drawn in TPCR4. The key question to consider given this starting point is to what extent the factors that impact the appropriate cost of equity are different for GDNs than for Transmission.

Ofgem has considered the extent to which gas distribution activity faces greater business risk than transmission. The broad conclusion from this analysis is to confirm that GDNs face higher business risk. This supports the previous evidence presented by the GDNs taken from analysis carried out by Oxera. However, despite this evidence and conclusions, Ofgem has not included this in its assumed cost of equity.

Oxera's report of September 2007 demonstrated statistically that distribution was riskier than transmission and showed a 0.2 higher asset beta for gas distribution. The distribution companies analysed had a confidence interval between 0.45 and 0.65 for asset beta. Ofgem has implicitly assumed an asset beta for transmission of 0.4 and it is probably an underestimate to assume an asset beta of **0.444** for GDNs which gives a cost of equity of 7.5% at 60% gearing.

In assessing the overall cost of capital for GDNs, Ofgem has assumed higher gearing (62.5%) than for transmission (60%). However, this assumption is inconsistent with Ofgem's other assumptions that gas distribution is at least as risky as transmission and the cost of equity is the same for transmission and for gas distribution. All three assumptions can only be made to be consistent if one of the fundamental principles of corporate finance (i.e. equity risks will increase with gearing) is ignored. Given this is not a sustainable assumption, the cost of equity must be adjusted to take account of the higher assumed level of gearing.

On the basis of an asset beta of 0.444 and gearing of 62.5%, the real post-tax cost of equity is **7.78%**.

Question 2: Is it appropriate to continue to maintain a consistent approach to cost of debt to that taken in TPCR?

We would agree that it is appropriate to maintain the approach to assessing cost of debt to that taken in TPCR. However, we would contend that Ofgem has deviated significantly from this approach in assessing the cost of debt set out in Updated Proposals.

The TPCR conclusion of 3.75% was based on a risk free rate of 2.5% (taking evidence within the Smithers report on long term risk-free rates) and a debt premium of 1.25% derived from a range of 98 to 130 basis points (based on A-rated and BBB rated debt respectively).

Current debt premia, calculated on the same basis as TPCR (over the relevant index-linked gilts) are 112 basis points and 144 basis points respectively. Ofgem's assumption of a debt premium of 105 basis points is below current market evidence. There is no evidence to suggest a change in the long-term risk free rate of 2.5% employed at TPCR (spot ten year index-linked gilt rates have risen significantly towards the long term rate). Taking a mid point of the current range of debt premia implies a cost of debt of **3.78%**.

During TPCR Ofgem used an approach based on long term averages and ten year trailing averages for the cost of corporate debt at the relevant credit ratings. The estimated cost of debt of 3.75% was 26 basis points above the ten-year trailing average and 126 basis points above the average spot rates through November 2006.

This approach correctly considered the evidence of both historical and spot rates and provided a reasonable (ex-ante) allowance for rising costs of debt over the price control period. The approach was also consistent with Ofgem's obligations to ensure that licence holders are able to finance the activities required to meet their statutory and licence obligations.

Since that time, the costs of borrowing have increased, with a general rising trend, whilst the ten year trailing average has continued to fall. It is this latter movement that has driven the 20 basis point reduction in the cost of debt proposed in the updated proposals of 3.55%. However, the increase in borrowing costs has significantly eroded the headroom to ten year trailing averages allowed in TPCR. The updated proposals are now only 18 basis points higher than the ten year trailing average and 39 basis points above the average spot benchmark in September 2007. Hence the headroom to allow for fluctuations in the debt rate has fallen substantially.

Given Ofgem's obligations, the assumed cost of debt must have a reasonable probability of covering actual costs of debt over the next price control period. Ofgem's proposals and market evidence suggest that the probability of actual costs exceeding allowance for GDNs over the next price control period is significantly higher than that assumed at TPCR.

The approach taken by Ofgem in Updated Proposals is not consistent with that taken in TPCR. The approach should be adapted to maintain the consistency between regulatory reviews. Cost of debt has risen since TPCR and needs to be at least **3.75%**.

Question 3: In the light of both the results of our risk analysis and the levels of actual gearing observed in the sector, is there a compelling reason to change our notional gearing assumption from 62.5%?

Ofgem has assumed a higher level of gearing (debt:RAV) for the GDNs of 62.5% compared to 60% for Transmission. There is no basis to assume that Gas Distribution can be more highly geared than gas or electricity transmission and there has been no trend in increased gearing since TPCR. Consequently the gearing level assumed for GDNs should be no higher than that assumed for TPCR.

It is our understanding that Ofgem confirmed during the presentation of Initial Proposals to analysts that the credit rating required for GDNs implied a PMICR ratio of 1.5x-1.6x. However the assumption of 62.5% gearing has resulted, for NGN, in a PMICR of 1.3x which is dangerously close to NGN's financial covenants in its credit facilities and is not akin to sound investment grade credit rating. This clearly suggests that either gearing is unsustainably high or that the cost of capital has been set too low. Furthermore, Ofgem's model is not consistent with its gearing assumptions. Because Ofgem (inappropriately) assumes that the full cost of equity is not returned to shareholders as dividend, the gearing level falls to 60% by March 2013. If Ofgem is to base its cost of capital assumptions on 62.5% gearing, then this should be the average gearing shown in the financial model and not the starting point. The impact would be even lower financial ratios.

A higher gearing level for GDNs (compared to transmission) with no change in risk results in a higher cost of debt and a higher cost of equity. Hence Ofgem's parameters are not consistent as cost of debt is lower and cost of equity is unchanged. The increase in gearing combined with an unchanged cost of equity implicitly suggests that Ofgem believes that gas distribution is riskier than transmission and contradicts Ofgem's findings in appendix 16.

There must be consistency between all the parameters that Ofgem uses in its cost of capital estimate. Either gearing should be set at **60%** or cost of debt and cost of equity increased to reflect the higher gearing.

Question 4: Is our approach to determining the GDNs' tax allowances appropriate?

General Principles

Ofgem's approach is to use the actual tax rules and apply them to its notional modelling. Our observation on the treatment of repex is that in the pre-tax regime the wedge acknowledged the treatment of 50% of repex as being capitalised for regulatory purposes, whereas the move to the post tax regime did not. Ofgem could have chosen to apply the tax rules notionally to the capitalisation of repex whereby no immediate tax relief would be available for the capitalised element or accept as Ofgem has that on a statutory basis a 100% declaration is available for expensed repex. Knowing that you have chosen the latter route it is reassuring to have IFRS treatment as a reopener.

In the regulatory environment the tax allowance may be somewhat different to the actual outturn tax liability but the point we would make is that the immediate change in treatment of repex in the transition to post-tax regime led to a step change in allowances, which we would expect the regulator of a long term business would seek to avoid.

We welcome the IFRS re-opener, but would have preferred to see at least a “glide-path” to the statutory tax treatment of repex from the pre-tax regulatory treatment.

Non- deductible expenses

We note your approach and we are not concerned with entertainment or expensive leased cars. Our concern is that HMRC, looking at these businesses for the first time on a stand alone basis, may seek to disallow items of capital which are expensed as revenue, or items of revenue in capital both these possibilities are adverse in cash tax terms. We do not know of any areas where an item which is capital for accounting purposes would receive 100% or more of tax relief. HMRC manuals contain guidance (RM42215) which clearly indicates that any revenue items in capital will only be eligible for relief as depreciation is charged to the Profit and Loss account.

Consequently an amount should be included which can be re-evaluated based on the evidence in the following price review. In particular we do not consider any eligible expenditure qualifying for R&D or land remediation reliefs would outweigh the cost of a general disallowance. NGN requested **£2.5m** be added back to annual taxable profits and this should be the allowed amount although we now believe that this could be an underestimate.

Tax Provisions not yet enacted

NGN welcomes the treatment which is clearly the appropriate approach to take.

Conclusion

Overall we welcome the use of current legislation in setting the tax allowance, but would request a review of the non-deductible expenditure particularly in light of the step change in return which has occurred by applying the repex assumption for the one year price review tax allowance to post tax regulation environment going forward.

Question 5: Should we make a financeability adjustment in cases where a GDN fails to meet our target ratios because of its own actions, such as penalties incurred under incentive schemes?

Ofgem has an obligation to ensure that companies can finance their functions in the next price control period. NGN proposed two principles to adopt in modelling and assessing financeability in the response to Initial Proposals:

- Ofgem must enable companies to finance their functions on the base level of revenue allowed and any increase or decrease as a result of incentives should act as an increase or decrease on allowed return and should be respectively a reward or a matter for companies to finance.
- Historic regulatory decisions prior to the period in question should be included in the modelling as Ofgem is assessing financeability for a future period. The starting point should be the pro forma balance sheet based on starting RAV and if this results in inadequate financial ratios then it suggests that the cost of capital is inadequate or a financeability uplift is required.

This is particularly the case as Ofgem uses pro forma and not actual gearing to assess financeability. Thus no adjustment should be made for the impact of penalties imposed prior to 2008/09 and if Ofgem’s modelling suggests non-financeability then either a financeability adjustment should be made or, preferably, it should be recognised that the allowed cost of capital is insufficient.