SCOTIA GAS NETWORKS PLC

RESPONSE TO THE GAS DISTRIBUTION PRICE CONTROL REVIEW – FOURTH CONSULTATION DOCUMENT

CHAPTER: Two

Question 1: Do you agree with our proposed accounting adjustments? Are there any other accounting adjustments that we should be considering?

We note the approach taken by Ofgem to accounting adjustments and broadly support this. We agree that these adjustments are the start of a process to develop a robust cost reporting framework which is vital in order to ensure comparability is achieved and maintained – a key requirement for effective benchmarking.

It would be helpful to see the material accounting adjustments applied to each DN in order to assist our understanding of the benchmarking, in particular the "Outer-Met" adjustment between East of England and London.

Question 2: **Do you agree with our adjustments for related party margins?**

UUOL - We note that margins will be allowed on charges from UUOL to NGN, on the basis that the contract was won by competitive tender and that NGN has a strong financial incentive to ensure that the contract is maintained on a normal commercial basis. We support the principle inferred that if charges from related parties have been market tested then margins should be allowed.

This operating model also has a bearing on comments made in the Fourth Consultation regarding SGN's receiving of support services from SSE and whether the level of charges to SGN are sustainable, in particular where SGN is the benchmark. In our view the same concerns apply to the NGN/UUOL relationship, and until UUOL's accounts have been inspected there must be similar concerns wherever NGN is the benchmark.

xoserve - We note the intention to disallow margins on xoserve charges from all DNs. This would appear to depend on whether xoserve charges are treated in the DNs' price controls as opex or capex (and hence in the RAV and earning a return), and what is meant by "margin". Our prime concern is that xoserve must be allowed a return on its investments, for example planned expenditure on IS.

Connections - We agree that, at the very least, margins earned in the competitive market should be retained. This is vital if competition is to be maintained. Margins should also be allowed in the non-competitive sector if it can be demonstrated that the cost has been market tested. In any event, we could only accept that related party margins in the "non-competitive" sector i.e. one-off domestic housing, are disallowed if a capex roller is in place i.e. a share of efficiency savings are retained. Otherwise, efficiency incentives are significantly weakened.

Question 3: **Do you think we should change our treatment of non-operational capex?**

We continue to support the current treatment of non-operational capex (i.e. as capex).

Given that capex incentives will be strengthened through the expected capex rolling incentive, we do not believe that there is any reason why treating non-operational capex as opex would provide more appropriate incentives to efficiency. Indeed, in view of the size of the IS projects planned by DNs and the impact these would have on initial p0s, it would seem more appropriate to treat them as capex.

Also, given that the RAV is not directly linked to assets, we do not believe that it would be necessary to have asset lives which are different to the average. This would just add an unnecessary level of complexity. The impact on financeability would be small compared with the 50/50 expensing of repex or changing the average 45 year regulatory asset life. In our view financeability issues should be addressed through setting a sufficient cost of capital.

We also agree that GDN's own non-operational capex and their share of non-operational capex incurred by xoserve should be treated in the same manner, and that software licence fees and internal software development costs should be included in non-operational capex.

CHAPTER: Three

Question 1: **How should we bring together the various consultants' analysis to establish an efficient cost benchmark and cost allowances? In light of our approach to setting a benchmark, what approach should we take to glidepaths?**

We support benchmarking in principle and believe that it will be central to delivering Ofgem's targeted efficiencies at GDPCR4, when the effect of the new management teams will be observable and data consistency issues will have been resolved. However, we are firmly opposed to the application of benchmarking of operating costs at this review. In particular:

- The 2005/06 data still largely reflects NG common ownership and will not reflect changes made to operating procedures, structures, etc by the new DNs. One would therefore expect to see little difference in performance across DNs since they would be operating under the same (NG) environment. Any observed difference in performance in this year is in our view due to inadequacies in the statistical approach or underlying data, rather than relative inefficiency of the DNs;
- This is exacerbated by the fact that 2005/06 was an atypical year. It was, for example, the year of DN sales and we have concerns about whether the underlying costs of each DN are fully reflected. We accept that the 2006/07 outturns may provide more complete information. However, given the amount of change in the industry, including significant work to complete the separation away from NG we would still have reservations about the comparative robustness of this data;
- The regressions are based on only eight observations, which provides very few degrees of freedom. It is also clear that half of the sample size is in one DN group. We do not have the visbility of cost reporting to be confident that common costs of NG have been allocated across DNs on a cost-reflective basis and clearly any inaccuracies in this regard will distort the analysis;
- We do not consider that the underlying regressions adequately reflect regional cost differences between the DNs;
- There are also clearly potential allocation/ business model differences between direct and indirect opex, which need to be resolved;
- The optimum scale variable and the cost drivers need much more work. We are not convinced that the variables used in the document are reflective of the underlying cost function of the DNs and this will distort the relative rankings. For example, top-down benchmarking can become overly complex with the inclusion of additional independent variables and bottom-up benchmarking risks "cherry picking" benchmarks and thus creating a "virtual" DN which cannot actually exist.

As a result of these issues, the benchmarking carried out by Ofgem and the various consultants, and set out in the Fourth Consultation document, is erratic and arbitrary. In particular, it is clear that the various regressions with differing assumptions produce different relative rankings. We also doubt they are statistically significant. In any event, the fact that the results swing about so much across the various iterations of the regressions proves, in our view, that there is no conclusive evidence that any DN is currently more or less efficient than any other DN.

We would contrast this with the efficiency assessment undertaken in the electricity distribution price control review. The various regressions carried out at that review, with differing variables, showed a consistent pattern in terms of, for example, relative rankings. The comparative efficiency work was also underpinned by a qualitative assessment of efficiency. This is demonstrably not the case in the present consultation.

The application of the results of the arbitrary benchmarking to setting operating costs will have sigificant implications for individual companies. We would therefore strongly urge Ofgem to abandon the comparative efficiency work at the current review in favour of an assessment of individual company costs.

We have set out below some more specific comments on each piece of work set out in the Fourth Consultation.

- Europe Economics – benchmarking: We agree that COLS ought to be in principle the best approach, with simple tests of logic based on our knowledge and understanding of the business. We agree that other statistical techniques are even more constrained by the lack of observations. We also agree that a simple regression of Total Controllable Costs (excluding shrinkage) against a single scale variable i.e. total customers is the simplest approach. We do not support the use of network length as a scale variable, as it does not reflect the fact that more than half of networks are made up of PE which are not associated with operational expenditure. In our view, the use of customers as the scale variable better encompasses total costs.

  We have submitted previously our more detailed comments on the Europe Economics benchmarking report. However, it is our strongly held view that account needs to be taken of the additional regional costs incurred by SGN's South DN for operating in and around London, and we discuss this further below. We note that there is precedent for this in DPCR4 where EdF's London network was allowed an additional amount in opex of c. £9m (c. £20m in total for opex and capex). Also, the regression needs to be adjusted for the additional costs of the Statutory Independent Undertakings, and the costs of supporting a more dispersed network, in Scotland DN.

  Even before adjustment for regional factors, we note that Scotia's two DNs are assessed as being close to the efficiency frontier.

- Europe Economics – Total Factor Productivity (TFP):

  The DNs have, through the Energy Networks Association, commissioned a report from First Economics on the potential for efficiency savings for the industry sector, including providing a critique of the Europe Economics report. The report is attached to this response and we would draw attention to the following key issues:

  - Whether the long-term trend in costs is one that permits perpetual year-on-year real terms cost reductions; and

  - Whether a continuing privatisation effect is credible given that privatisation of British Gas was 20 years ago.

  We would also highlight the key issues raised by First Economics as follows:

  - Much of the RPI basket is now manufactured overseas, hence costs have been falling and driving the UK's recent low inflation rate. Companies that rely on a UK-based labour force typically exhibit lower productivity gains. Europe Economics' UK focus misses this inherent productivity improvement and input price inflation already captured within RPI;

  - Europe Economics use a pre-1999 data set that is out-of date and cannot pick up the fundamental re-balancing between sectors over the last 10 years;

  - First Economics concludes that the underlying trend in GDN opex is in the range of zero to +0.5% per annum (in real terms).

In addition, TFP analysis takes no account of the upward cost pressures included in our forecasts, or of the costs incurred in delivering efficiencies. We would expect these to be recognised in ex ante allowances, including:

- Safety and Standards of Service improvements, including: asset maintenance driven by legislation, condition and lifecycles; improving performance on the repair within 12 hours standard; and, employee working practises, for example fatigue management and the Working Time Directive;
- Real wage inflation, for example: contractor costs where increases have been running on average at 4.43% p.a. above RPI; and
- Other costs, including insurance, training and skills replacement

Also, there are a number of expected additional costs which we have not included in our forecasts, due to the uncertainty over their level and timing, but which also need to be taken into account. These include:

- Costs of the Emergency Service and the expected loss of the contribution from the meterwork contracts with National Grid Metering/ shippers (we discuss this further below);
- Costs arising from the Traffic Management Act and Transport (Scotland) Act e.g. lane rentals, notices of direction;
- Congestion charges;
- Changes to tax rules i.e. move to IFRS;
- Expected Carbon Monoxide safety and monitoring obligations; and
- Increase in LNG storage costs for the SIUs.

- <u>PB Power - Direct Opex</u>: We note that PB Power identifies for Scotia below average reductions to its forecast costs (South DN being the most “efficient” DN). However, we are concerned about the level of efficiency savings expected going forward

  We have submitted separately detailed comments on the PB Power reports, however, we have set out below our key views on the findings and interpretation of the reports:

  - The allowance for additional regional costs has been understated and we discuss this in more detail below;
  - Real Price Effects (RPE) for both direct labour and contractor charges have in our view been understated, and again we discuss this further below;
  - The CSV needs further work, in order to improve the statistical “fit”, although we agree that once Total Costs (as used by Europe Economics) have been disaggregated between Direct and Indirect costs, then it is appropriate to identify better cost/ workload drivers than a simple scale variable;
  - The frontier shift assumptions are unrealistic: PB Power have overstated potential workload reductions, particularly the impact of external PREs on Emergency and Repair projections, and they take no account of the cost pressures outlined above;
  - Of the alternatives presented, we support the glidepath approach to determining allowances, particularly given the considerable uncertainties surrounding the whole benchmarking approach; and
  - We strongly caution against simply adding together Direct Opex and Indirect Opex benchmarks. There would be a significant risk, as we have said above, of “cherry-picking” benchmarks.

- <u>Ofgem – Direct Opex</u>: We have major concerns about this piece of work:

  - It does not add to the work carried out by PB Power, therefore it is not clear why it has been included;
  - As noted above, we do not believe that a single scale variable is appropriate once Total Costs are disaggregated;

    - It is incomplete. For example, no attempt has been made to allow for regional costs, therefore we fail to see how the conclusions about relative efficiencies can be substantiated; and
    - No explanation is given of how this would be linked to the LECG work on Indirect Opex, which is not on a per customer basis. In particular, the questions about SGN's business model are relevant to both.

- <u>LECG – Indirect Opex</u>: We note that SGN is at or below the benchmark in most of the categories. We have responded separately on some relatively minor matters for factual correction. In response to some specific points raised in the Fourth Consultation, our views are as follows:

    - We do not agree that regional allowances can be so easily dismissed. It is argued that these activities generally do not need to be located in specific areas, and National Grid is used as an example where services are provided to its London region from the Midlands. However, we do note that these services are still provided from within their area of operation.

      While it may be possible to locate some corporate functions or central functions such as IS in cheaper areas, this is not true for services which directly support the customer-facing activities e.g. human resources, property management, procurement and logistics;

    - We agree that there may be issues arising from different business models and residual differences in cost allocation. These need to be understood, and we would expect this to be covered as part of the development of the regulatory reporting framework, hence our concern about placing reliance on benchmarking at this review; and

    - We do not agree that SGN's contracting-out of support services to SSE necessarily creates an unsustainable benchmark. It is not true that SGN does not pay a share of fixed costs. While the marginal costing approach applies where resources can be wholly and uniquely identified to SGN, the "umbrella" MSA in effect recharges fixed costs. However, there may be some substance in the argument that the MSAs have been established on the basis of SSE having available resource/capacity i.e. if SSE or SGN needed to increase capacity then SGN would be expected to share the step increase in fixed costs. This may not be fully reflected in current MSA charges.

<u>Bringing together different elements of the opex analysis</u>

We agree that a simple mechanistic approach to combining the elements of the analysis is not appropriate at this review. There is far too much uncertainty about the robustness of the data and hence the benchmarks.

We also agree that a disaggregated approach risks "cherry picking" of benchmarks, in addition to the concerns about the robustness of the data.

We therefore believe that, if the consultants' work is to be used, Ofgem will need to set allowances based on judgement, using each of the consultants' analysis, as well as Ofgem developing a thorough understanding of each DN's forecasts. However, the optimum approach in our view would be to roll forward 2006/07 actual costs, subject to an assessment of additional cost pressures.

<u>Application of benchmarking and glidepaths</u>

While it may have been appropriate in DPCR4 to move to an Upper Quartile approach, where the understanding of comparative efficiency is more mature, we do not believe this is appropriate for this price control review. In our view, there is as much uncertainty around the level of the Upper Quartile as there is around the benchmarks/ frontier.

We also agree that there should be no additional allowance for singleton companies, for the reasons set out in the document. Indeed, the issue is irrelevant as every DN is linked to a larger group.

As we have said above, the comparative analysis carried out by the consultants has erratic results and is not conclusive. Therefore, in our view, any catch-up assumption has to be accompanied by an allowed glidepath. Our views, specific to the three approaches set out in the Fourth Consultation, are set out below.

- Approach 1 – Full gap closure: While we support the principle of rewarding frontier companies by allowing them to earn additional returns above the allowed cost of capital, in our view, there is no conclusive evidence that any DN is currently at the opex frontier.

  We agree that costs to achieve efficiency savings would need to be allowed. Also, additional cost pressures, including those set out above, would need to be added to the benchmark.

- Approach 2 – Glidepath: We therefore support for this review, if there is a catch-up assumption and similar to the approach Ofgem adopted for DPCR3, PB Power's recommended approach (i.e. DNs have to close 70 per cent of the gap with the upper quartile by 2012/13). This also has the major advantage of implicitly allowing costs to deliver efficiency savings.

- Approach 3 – Allowances based on historical costs: In our view, rolling forward GDNs' 2006/07 actual costs, and taking into account ongoing efficiencies that can be achieved by all companies, as well as additional cost pressures, would be the optimum approach in the circumstances of the present review. As noted above, we support benchmarking in principle and believe that it will be central to delivering Ofgem's targeted efficiencies at GDPCR4, once the new management teams have had sufficient time to implement changes. The proposed development of the Regulatory Reporting Framework will aid this process.

Question 2: Is there a case for making adjustments to allowances for real price effects, specifically direct labour, contract labour or materials?

We believe that future allowances must recognise the realistic cost pressures that networks face which include direct labour, contract labour and materials real price effects. We do not believe that the consultants' assumptions accurately reflect these cost pressures in Southern or Scotland and the application of the same assumptions for all eight DNs disregards the fact that indices used to inform their assumptions represent a national average and that regional variations are therefore largely ignored. For example, it is acknowledged by the DTI that Baxter Indices would show variations if assessed at a regional level.

These three cost pressures are key to SGN's submission and we therefore comment in more detail below.

a. Real Price Effects – Direct Labour

We believe the figures put forward for real wage growth in the fourth consultation document are significantly understated. The figures put forward of 0.4% to 1.7% (0.5% to 1.2% in the utility sector) are based on 'recent information'. In particular:

- Longer term historical trends (including Transco over the past ten years) support our assumption of at least 2% above RPI. The consultants' view has been based upon a short term reversal of the predominant historical trend. Given the current macroeconomic climate, we do not consider this to be credible;

- For example, the Bank of England Inflation Report (February 2007) contains details of an Agents Survey (Chart 4.4) which shows 89.4% of respondents expecting wage settlements to be at or beyond last years levels and 52.4% expecting them to be a little higher or significantly higher than last years levels. This would tend to indicate a general perception of no real decrease in wage inflation;
- PB Power have compared the ASHE data on earnings at 26 April 2006. We have already written to Ofgem setting out factual concerns about how the 1% assumption was derived from this work;
- Finally, it is important to note that real wage inflation comes not just from real increases in hourly rates but also as a consequence of individuals moving up the incremental pay scale. The consultants' work takes no account of this effect.

For these reasons, it is our firmly held view that our assumption of 2% real wage growth is more credible than the figures put forward in the consultation document.

b. Real Price Effects – Contractors

Baxter indices over the period from 2002 to 2006 showed a national average contractor wage increase of 4.43% per annum above RPI. Our submission included an efficiency factor that reduced this figure to 3.8% per annum.

PB Power have assumed 2.25% per annum assumed in their reports and we do not believe that this assumption, and the variance from our own assumption, has been adequately justified. We believe that the PBPower figure is based on last year only and, as with wage inflation generally, we do not believe that it is credible to simply roll-forward the most recent data point, particularly since last year was below the historical trend.

We also believe that in setting future allowances Ofgem should consider the extent to which there might be regional variations in real price effects for contractors. For example, it is acknowledged that an assessment of Baxter Indices at a regional level would in fact show variations. As a consequence, we believe that the application of a national average assumption to all DNs may not be appropriate, particularly as it will not take into account the highly unusual position in London where the high number of large construction projects planned over the same period as this price control will lead to an unprecedented demand for contractor labour. We believe that the large number of construction projects within the London area including the 2012 Olympics, Thames Water workload, Channel Tunnel Rail Link, Cross Rail & Thameslink, Heathrow Terminal 5, City Airport expansion and Thames Gateway development, will all place above average upward pressure on contractor wages throughout London and the South East.

c. Real Price Effects – Materials

Whilst we agree that no specific regional differences would apply to material prices, we would argue that recent trends in the price of steel have been far in excess of the consultants' assumption of 1% per annum and that this trend appears to be continuing, largely driven by the Asian market. This has and will continue to have a significant impact on the material costs associated with LTS & Storage projects. The unit cost analysis undertaken for LTS projects has failed to recognise this trend.

During the period from February 2003 to February 2007, the price of hot rolled steel plate (CFR Dubai Index) rose from $320 to $735 per tonne equivalent to an average of 23% per annum increase. In real terms, the price over this period has been extremely volatile, responding to variable demand.

Question 3: Is there a case for making adjustments to allowances for regional factors and if so what approach should be adopted?

It can be argued that many unique factors exist for each DN, however the additional costs of operating in and around London stand out compared to the rest of the country. This has been recognised in previous price control reviews where for example in DPCR4 EdF's London network received an additional allowance of c. £9m in opex (c. £20m in total). We therefore firmly believe that similar allowances are appropriate in South DN.

There is also precedent for recognising the additional costs of serving the remote populations in Scotland, and we discuss this in more detail below.

In previous reviews allowances have been largely subjective, and we would support moving towards a more mechanistic approach as used by PB Power but this needs significant more work. In particular, PB Power apply regional adjustments across all eight DN's on a total cost neutral basis risks taking into account only labour/contractor costs but missing the other costs such as:

- Increased travel time due to congestion;
- More expensive streetworks specific to London; and,
- In remote areas, long distances between population centres; and,
- The requirement to maintain an emergency presence in these centres.

In our view, the consultants have underestimated these factors, in particular the proportion of South DNs work which is within the M25. We set out below our more detailed comments:

a. London Factor

Whilst some account has been taken of regional effects in the consultant's assumptions, we believe that the factors allowed for London are significantly understated leading to overstated costs adjustments in all cost categories.

Direct Labour

PB Power have used a regional factor of 1.03 for direct labour in the Southern DN and 0.98 in Scotland based on the ASHE survey published by the DTI.

They appear to suggest that, whilst London costs are on average 30% higher than the national average (backed up by the ASHE surveys), we only have a small proportion of our employees working there. Whilst not explicit, it appears they are assuming around 10% of our employees in the South (since they have suggested 1.03).

In actual fact, one third of our employees in the South DN receive London Allowance. Basically this means within the M25. This is reinforced by examination of the repair workload in the South DN where over a third of emergency work and repairs are carried out in the London Area.

Applying the 30% higher costs to the one third of South DN employees in receipt of London allowance gives an RF of 1.10. We believe that this, if anything, understates the real cost of working in London as it does not fully take into account the additional costs incurred for increased travel time caused by congestion and the distance operatives are required to travel to site. SGN believe that an RF of at least 1.12 would more accurately reflect the position for South DN.

Contractors

PB Power have used a regional factor of 1.06 for contract labour in the Southern DN and 0.99 in Scotland DN. These factors are derived by using the Quarterly Review of Building Prices as published by the BCIS and weighting the different indices by county to give a weighted average per DN.

There are two fundamental issues with this approach which we believe understate the RF for contractors in both DN's.

- The BCIS index which is a broad based construction index does not adequately represents the contractor cost differences seen in the gas industry.
- The weightings applied by PB Power across post codes do not accurately reflect the spread of work, and utilisation of contractors, within each of SGN's distribution networks.

In addition to the above the BCIS indices do not appear to reflect operational factors impacting on costs, particularly the London factors referred to above and clearly identified differences in asset base such as large diameter mains and low pressure storage sites (holders) where South DN has the highest remaining volume.

These regional factors are built into the current EPC contractor rates and a fuller response has been provided to Ofgem which demonstrates that contractor rates in London are a third higher than in the South LDZ. Recognising that at least one third of the work is also in London (both Opex and Repex), we demonstrated in this response that the RF Factor applied to the South DN should be at least 1.12.

b. Geographical Sparsity

Scotland accounts for 40% of the GB land mass but only has 5% of the population. Mains gas serves a region from Dumfries and the Border communities in the South to Inverness and Aberdeen in the north. Within these extremities exist large areas of low population density that require a fixed level of costs (emergency cover / travel time). We do not believe this has not been explicitly recognised in regressions.

Finally, within remote areas of Scotland are independent systems (SIU's) where costs are significantly disproportionate to customer numbers, throughput and network length. The costs of the SIU's need to be addressed as a regional factor in any regression analysis performed.

Question 4: Should we adapt our pension principles to address the forecast defined benefit pension contributions, which are both extremely high and vary widely across GDNs, (despite funding very similar benefit packages)?

We agree that the calculated rates of funding for the four GDNs have been derived from assumptions which are in line with normal actuarial practice. If valuations had been carried out at a common date, the company rates for funding future accrual of benefits would be concentrated at just under 40% of pensionable salary for three of the GDNs with NGG being on the low side at 31%.

Differences in the calculated funding rates are not unexpected, especially due to differences in membership profiles and other demographic factors such as mortality rates. Had actual funding during PCR02 been at a rate closer to those currently in place the level of deficit and consequent deficit repair payments would have been reduced from those currently set.

Short term imprudent assumptions have the effect, all other matters being equal, of creating problems for future generations of consumers which creates additional volatility in the total cost of future and past service funding costs.

We agree that the level of benefit provision and associated funding is high but, unlike a lot of other companies in the private sector, it is not realistically possible to reduce the level of benefits due to the strength of legal obligation surrounding the benefit promise that was inherited by the GDNs i.e. the GDNs have no control over benefit levels.

The level of required funding for future benefits is comparable with the electricity sector and other private sector pension arrangements when allowance is made for the level of benefit promise and for differences in the date of calculation. Similarly, other factors, such as pension scheme asset allocation are not in the control of the GDNs, but rest with the pension scheme trustees.

Ofgem raise two areas of risk to customers. The first is of possible stranded surplus. In our opinion, this is unlikely given the monitoring of investment strategy and cash contributions that takes place in our scheme. It would be an unacceptable departure from Ofgem's current policy position to move away from funding the GDNs other than on a basis of the contribution levels set by the scheme actuary where these have been in accordance with normal actuarial practice and as such Option 1 and 3 are rejected.

The second risk, of differences in sponsor financing strategies affecting the trustees' attitude to risk, is likely to be minimised due to the fact that GDNs have to have an investment grade rating. There is no evidence to suggest that there exists a differential in contribution rates that has arisen as a result of company specific financial profile and our actuarial assumptions make no allowance for the strength of the employer's covenant. To the extent that no evidence exists at present Option 2 is not relevant at this time.

Question 5: Should we change our pensions recovery mechanism in order to avoid distorting incentives between making salary and non-salary cost savings.

The treatment of pensions is a highly specialised area. We have attached a report prepared by Hymans Robertson as our response to the issues raised.

We are fundamentally opposed to any potential reversal of the pensions principles that any efficiently incurred pensions costs are fully recoverable.

Other Issues - Meterwork

Meterwork provides a significant level of 'filler' work for emergency service engineers (Direct Labour and Contractors) which is used to cover downtime inherent in any emergency service and these costs are treated as an excluded service. This has the effect of reducing the true cost of the emergency service in Opex. However, SGN has already lost some of its existing Meterwork contracts and expects to loose the remaining ones shortly. This will expose our DN's to a significant increase in Opex as downtime increases (at least £17m per annum). It may not be possible to fill a substantial part of the gap and in any event , this would take time to find alternative filler work.

An incentive scheme was proposed in the third consultation document to deal with the uncertainty around the level of downtime which had some support from the DN's. However, we note that Ofgem do not believe the magnitude of costs associated with the loss of meter work warrants a separate incentive. PB Power have also assessed this impact as small. We are very concerned to note that there may be a perception this may not be as significant as we believe it is. As such, we are unclear how this cost pressure will be dealt with in the price control allowances to deal with this loss.

<u>Age Profile / Skill Shortages</u>

In addition to the real price effects on Direct Labour, it should be noted that the GDN's have an ageing workforce with circa 30% over 50. Whilst this demonstrates a significant level of skill and experience, the industry needs to attract, recruit, train and retain a new generation of people with the skills and knowledge to replace those leaving.

It is in the interests of all stakeholders to address this issue and collaborate to bring new people into the industry. Ofgem support this issue in the fourth consultation document 'to the extent that it brings benefits, for example, by being a more effective and lower costs means of securing future skills to the industry'. We believe that there will be a significant costs to the business through apprentice schemes in order to maintain the skill level currently experienced in an ageing workforce.

CHAPTER: Four

In our responses to Questions 1 and 2 we have summarised below our key issues on the work PB Power have done on capex and repex. We have then responded on detailed capex issues under Question 3 and detailed repex issues under Question 4.

Question 1: What are your views on PB Power's adjustments to the GDNs' forecast capital and replacement expenditure?

Question 2: What are your views on PB Power's general approach to the assessment of costs?

Workload drivers – A number of storage projects have been deferred by the consultants post-2012/13. We believe that this is due to different interpretations of the guidance given by Ofgem for completion of the BPQ. We have consistently applied these assumptions, and we discuss this in more detail under Question 3;

We also believe that our workload submission for mains and service replacement is consistent with the minimum required to meet HSE enforcement policy and pipeline safety regulations. In addition, we have submitted workload for riser replacement (an issue now recognised within the industry that requires a pro-active approach going forward). We are concerned that PB Power have reduced these workloads, and these issues are discussed further under Question 4;

Adjustments for inconsistencies between DNs – As we have said above, it would be helpful to have transparency on the detail of the Outer Met adjustment as this appears to have a significant effect on regression outcomes;

Regional differences – As we also said above, we believe that the consultants have significantly understated the impact of regional differences, particularly in London. This is a key issue for repex, again particularly in South DN;

Benchmarking across DNs – We repeat our comment s in relation to opex, in that we have significant concerns about the usefulness and reliability of benchmarking at this review. This issue is further compounded on repex, where replacement strategies are company-specific, depending on where each DN is in their programme, and therefore common unit costs assumptions are not appropriate. This issue has not been understood by the consultants;

Bottom-up or activity-specific analysis – We believe that the approach taken by PB Power to determine unit costs for LTS projects is flawed, and leads to significantly understated project costs. This is discussed further below;

Gap closure – Given the size of the gap between PB Power's views, for example on regional factors and real price effects, and those of SGN, we strongly believe that if a benchmarking approach is used then a glidepath is essential.

When frontier shift is also taken into account then DNs are effectively being allowed no more than 0.5% p.a. real price inflation. This is clearly unsustainable in the current contractor market.

Question 3: What are your views on PB Power's approach to the cost assessment for each activity?

1. LTS & Storage

We have developed our investment plans based on the assumptions set out in the June 2006 Ofgem guidance document. Forecast gas demand is based on the 10yr demand and supply statements and the long term development plan. It has been assumed that the existing transitional arrangements for NTS offtake and associated GDN incentives to purchase NTS offtake capacity continue to apply for the full period covered by the BPQ.

We have also considered the future reliability of NTS diurnal storage availability and have made written submissions to Ofgem setting out why this level of reliability should not be assumed in the long term.

In summary, it should be noted that NTS diurnal storage is not a product in its own right and no investment has ever been made or is planned in the NTS network to provide diurnal storage. It continues to be a by-product of the manner in which the system is operated. In future, this product will be constrained and it cannot be assumed that a network can have whatever it requests irrespective of price. Evidence demonstrating our concerns over current levels of commitment have been submitted to Ofgem. Constraints within the local transmission system (LTS) can also constrain the amount of NTS diurnal storage taken into the network irrespective of its availability. This is the case in South LDZ due to its historical design and development.

The fourth consultation document sets out our proposals for the reduction of LTS & Storage investment for a range of reasons that we dispute, as follows:

<u>Timing</u> – A number of storage projects have been deferred outside of the next price control period on grounds that the balance of storage required and storage available within the network does not merit planned investment in line with SGN's timing assumptions. However, this view appears to be largely based on the assumption that current levels of NTS diurnal storage will be maintained throughout the control period.

<u>Unit Cost Assessment</u> – Where projects have been allowed within the period, adjustments have been made to the required level of investment based upon an assessment of historical unit costs for pipelines. We disagree with this assessment, and believe that the sample of projects used is incorrect as it includes both pipeline and storage projects. It is well documented that these two types of project give rise to disparate unit costs due to the fundamental differences in design and operational duty. The inclusion of pipeline projects artificially and incorrectly lower the historical unit cost. A sample containing only storage pipelines would provide a more accurate assessment.

Notwithstanding the use of an incorrect sample, we are also concerned that recent changes to steel material costs and tendered labour costs in this sector have been far in excess of RPI or general inflationary pressures in the construction industry. Use of historical data to derive and extrapolate future unit costs is clearly unreliable being heavily weighted to historical costs that bear no resemblance to current market conditions.

Of particular concern is the assumption applied to 1200mm diameter pipe where the range of unit costs identified goes from £1.0m to £3.0m per km of pipe laid. The lower quartile unit cost of £1.2m per km is demonstrably inconsistent with our most up to date independent costing of current projects. This assumption also ignores independent work recently commissioned by Ofgem that shows this figure to be in the order of £1.6m per km of pipe laid. This appears to be the only diameter where a lower quartile figure has been used (median has been used for all of the other diameters) with no sound rationale provided for this decision.

2. <u>Mains Reinforcement</u>

We have included in this category general reinforcement required to meet demand growth, non-contiguous reinforcement associated with customer connection requests, upsizing of new replacement mains that are required to be capitalised under accounting rules and mains reinforcement required to manage existing network constraints within local networks.

Adjustments to the upsizing workload (50% reduction) to align with other network ratios appears to take no account of further evidence provided by us of historical levels of upsizing upon which our forecasts have been based. These levels are consistent with clearly defined planning processes that have been found to be robust by the consultants.

We repeat our concern that the cost assessment carried out is incorrect due to inaccurate assumptions concerning regional factors, real price effects and efficiency frontier shift all of which are addressed separately in this response.

3. Governors

We understand from the latest draft of the consultant's report that our concerns on disallowance of governors investment have now been addressed.

4. Connections

We note that our forecast workloads have been accepted without any need for adjustments. Our comments made above on real price effects and regional factors and their impact on the regressions also apply here. We have written separately on this particular issue.

5. Other Operational

Land & Buildings – We have a clear strategy for operating our networks, which is distinctly different from other networks, based around a depot structure. This is a well proven model within SSE (50% owner of SGN), where continuity and security of location are important factors for both employees and customers. We do not agree that the consultant's view that leasing, and potential flexibility benefits, is the most efficient solution for us.

6. Non-Operational

We note that we have yet to see the results of PB Power's assessment of IS spend.

Question 4: Is it appropriate at this time to reconsider the approach to prioritisation within the risk model for the Mains Replacement Programme and should the approach to encroachment and diversions be amended?

In our view PB Power, have failed to recognise that SGN's strategy, and therefore our forecast, for mains replacement is aligned to HSE expectations i.e.: -

- A requirement to maintain our entire pipeline population in accordance with Regulation 13 of the Pipelines Safety Regulations.
  Note: The duty contained within PSR Reg. 13 is absolute in nature and requires that the operator shall ensure that a pipeline is maintained in an efficient state, in efficient working order and in good repair. As such it requires us to do much more than manage risk;

- A requirement to comply with the requirement to remove all iron within 30m of property by December 2031 and to present a programme annually as required by Regulation 13a;

- To follow a programme that prioritises mains decommissioning on the basis of individual pipe risk assessment, any such programme removing risk at an equivalent or greater level than that achieved through a top-down risk approach over any given 5 year period.

We comment in greater detail in Appendix A to this document, however the key points are:

- While we agree that a move from a risk based to a zonal replacement approach can deliver some benefits eventually SGN's current position on the risk profile in each of its networks makes the timing of a move towards this approach some way off, as a high proportion of high risk mains continue to be removed year on year and the point at which the remaining population become more homogenous will not be seen for a number of years. In addition to the above, we believe that the benchmarking carried out by PB Power does not reflect DNs' different positions on this risk profile. We do not believe that future targeted unit costs are achievable even under a zonal replacement approach. SGN's approach in GDPCR4 is to continue with a risk based methodology supplemented by taking account of Network specific issues such as condition of pipes and proportion of remaining metallic pipes. This approach has allowed us to minimise workload over the period whilst achieving risk reduction and operational efficiency.

- It has been asserted in the consultant's reports that larger projects will deliver greater efficiency. Whilst it is recognised that larger projects have the potential to offer some positive benefit, there are also negative impacts (e.g. disruption, public inconvenience, congestion etc) that we believe clearly outweigh the benefits. We believe there is a limit on the size of an optimum efficient project.

- It is also our view that a proactive approach needs to be taken to the unprotected steel population and risers, rather than the piecemeal approach of a reactive response that will inherently leave an ageing population the volume of which will eventually become unmanageable;

- In setting out decommissioning workloads for both of its networks for the next price control period, we have ensured that our proposals do not fall below these agreed levels of risk and length reduction. While the consultants have supported this position in Southern, we disagree with workload reductions proposed by the consultants in Scotland network. These proposals would cause us to fall below levels agreed as part of the 2002 programme;

- We not believe that encroachment or diversions are a material issue.

In short, we consider that the results of PB Power's benchmarking exercise are unattainable and inconsistent with our safety responsibilities. It is therefore vital that this is addressed by Ofgem in setting repex allowances.

CHAPTER: Five

Question 1: *Is it appropriate to retain the current volume driver?*

We agree that the volume driver is not proportionate to the risks to which GDNs are exposed and therefore should be removed. We also do not consider that a significant proportion of costs are driven by throughput and hence a volume driver would not be cost reflective. This would result in windfall losses or gains for DNs depending on the direction of demand relative to the initial forecast.

Question 2: *Is it appropriate to implement any of the revenue drivers discussed in this chapter and are there any other drivers that we should consider that we have not included in this chapter?*

We also agree, for the reasons set out in the Fourth Consultation, that a capacity related revenue driver is not appropriate.

We do, however, believe that a customer number related driver would still reflect, and provide some protection to DNs from, year on year increases in underlying costs. Otherwise, we would expect to see explicit ex ante allowances for underlying cost growth, in addition to additional allowances for other cost pressures. This should be possible, given that growth in customers is reasonably low and predictable. Alternatively, this could be addressed through a reduction in any frontier shift assumption.

Connections related revenue driver: We do not believe that a connections related revenue driver, which acts through the allowed revenue formula, is practicable. It would involve a complex mechanism which paralleled the capex roller.

We do, however, see some merit in correcting for volumes in the non-competitive market through the capex roller.

Question 3: *Is it appropriate to strengthen the capex rolling incentives?*

We continue to support in principle having a capex rolling incentive combined with an information quality incentive.

We do not believe that having a strong capex incentive would raise any issues on safety or standards of service, as performance against these are strongly ring-fenced through the safety case and licence obligations.

We are concerned about the practical application of the IQI, for example how LTS and storage forecasts will be taken into account given the uncertain impact of offtake and interruption reform. We also see practical difficulties with only excluding costs impacted by offtake and interruptions reform from IQI, and distinguishing those from other LTS costs. In our view, either all LTS costs have to be excluded or none (and our preference would be for exclusion, given the uncertainties).

In addition, we are concerned about the inclusion of repex within IQI, which would dominate IQI especially if LTS is excluded. Presumably, this is intended for the purpose of aligning incentive rates between capex and repex. However, we are unclear how this would sit with the existing repex incentive mechanism and indeed the capex roller. We would therefore suggest that repex should also be excluded from the IQI.

We welcome the opportunity to revise our capex and repex forecasts in July, by which time the details of the IQI mechanism should be finalised.

Finally, we see no difference between the options set out on the Fourth Consultation for determining the unit costs and incentive rate for repex. The same outcome would result from setting the mains replacement incentive within the IQI as the alternative of excluding the mains replacement incentive from the IQI but using the IQI incentive strength and determining unit costs with reference to the consultants' analysis.

CHAPTER: Six

Question 1: Do you agree with the proposed plan of work to determine the cost of capital? Are there other key areas of analysis that we should be carrying out?

We submitted evidence as part of the one year review to support a cost of capital of at least 4.8% post-tax real, and our view has not changed. The DNs, through the ENA, have commissioned Oxera to produce a report on the Cost of Capital, specifically looking at risk differentials between distribution and transmission. The full report will be provided to Ofgem, as soon as available.

As regards the proposed plan of work, we agree that there needs to be an additional focus on the risks faced and rewards available in gas distribution.

Question 2: Is the range of key ratios we have identified adequate for carrying out an assessment of financeability?

We reiterate comments made in response to the Third Consultation that the choice of financeability indicators is a key factor in setting allowances. We are constrained by those ratios currently used by the rating agencies such as Funds From Operations

(FFO), interest cover and debt, net debt to RAV, EBITDA / Interest and PMICR, and all of these ratios should be taken into account in financial modeling.

We acknowledge the issues that Ofgem have highlighted with respect to the treatment of repex and the shortening of asset lives, and the fact that the PMICR measure remains unaltered by these changes.

However, PMICR remains a key ratio on which DNs are rated, by two of the rating agencies, and it is these ratings which future investors will use to assess our financeability position.

Question 3: Is our approach to the issues raised by adjusted interest cover ratios appropriate (see Appendix 10 for details)?

Credit rating analysts need to look more widely than traditional ratios in capital intensive industries such as network utilities. As we have said above, PMICR is an important ratio currently used by credit rating agencies and by which we are constrained when investors assess our financial health.

Fitch, in their February 2007 report on 'Post Maintenance Interest Coverage' state that if PMICRs are causing a financeability problem for the regulators, this can be addressed in one of the following ways:-

- Increase the stated WACC on the basis that a higher return is needed,
- Provide an additional equity return, or financeability adjustment, in years where this is required, but maintain the headline WACC value;
- NPV-neutral revenue profiling, which does not affect the RAV;
- Assume an injection of equity and an additional opex allowance to cover the cost of raising equity.

Profiling of revenue across the period will also be a key factor when assessing ratios including PMICR, rather than merely relying on an average over the five year period.

Fitch conclude that because PMICRs take into account the cash that must be spent in order to preserve the value of the RAV in calculating the amount of cash available to service interest, then PMICRs are the most appropriate interest coverage metric for UK regulated utilities.

Therefore, we believe this ratio is a vital part of assessing the financeability of DNs and where this ratio is weak, Ofgem should consider the options put forward above rather than assuming that the DN can adjust its financial structures.

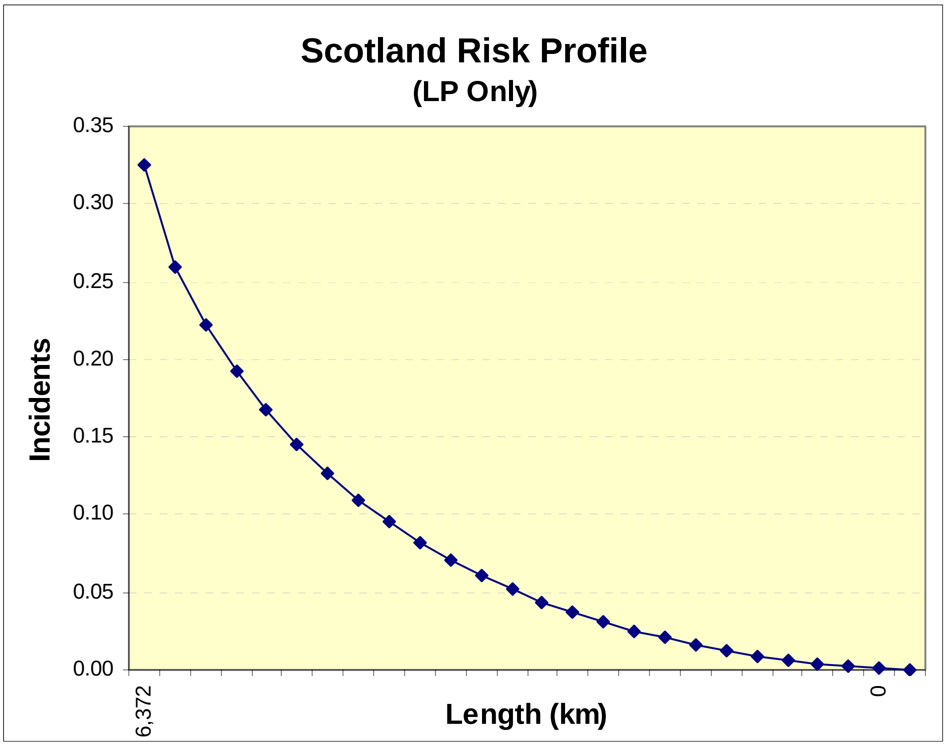
With regard to the three key areas which will materially affect the financeability review (the proportion of repex in the RAV, the treatment of non-operational capex and the funding period for capex), we have not changed our views from our Third Consultation response. We will be in a position to comment further once we have the results of the financial modeling which underpin the Initial Proposals.

REPEX WORKLOAD ASSESSMENTS

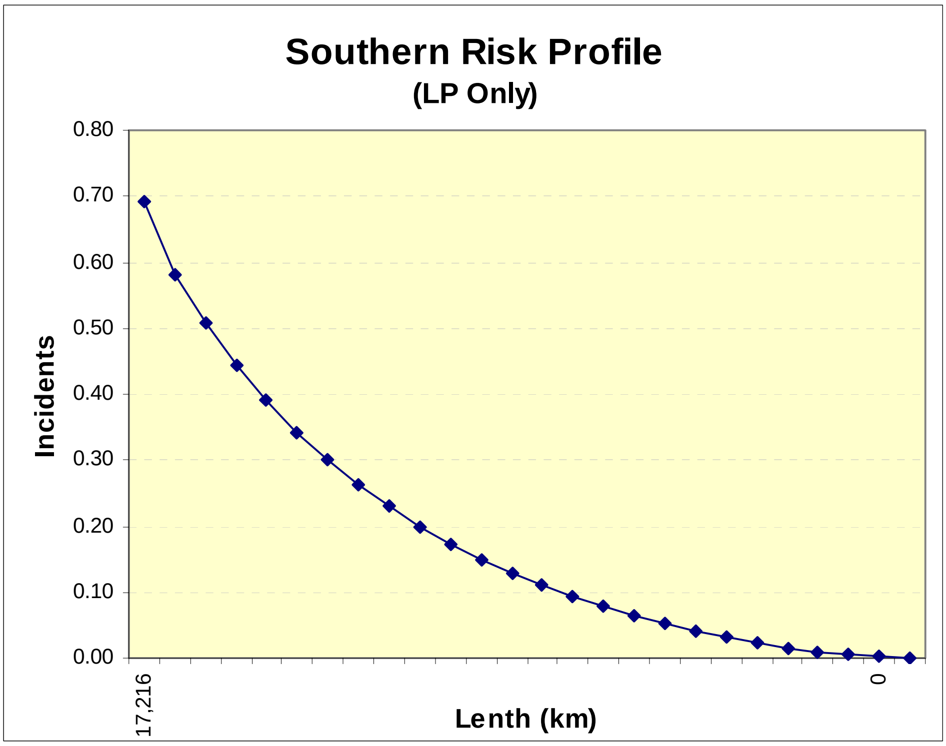
a. Pipes At Risk

The HSE use the term 'at risk pipes' to decribe iron mains within 30m of property. In reality, all pipes (mains, services & risers) present a risk and it is SGN's duty to set out a programme for managing these risks by maintaining its pipeline population as far as is reasonably practicable in line with the requirements of the Pipeline Safety Regulations, regulation 13 (all pipelines) and regulation 13a (iron within 30m of property)

With specific reference to the iron population (cast, spun & ductile), we assess risk at an individual pipe level and a risk score is held against each pipe. From this data, it is possible to derive the absolute risk present in Southern and Scotland networks. This is shown in the graphs below that show absolute network risk based on the entire population of low pressure iron mains.



The graph above shows a population of 6,372km of low pressure iron mains giving an absolute risk level in the network of 0.325 incidents. This increases to 0.341 incidents with the inclusion of medium pressure iron. As the length reduces to zero the level of risk falls and it can be seen that the population becomes more homogenous as risk reduces.



The graph above shows a population of 17,216km of low pressure iron mains giving an absolute risk level in the network of 0.693 incidents. This increases to 0.799 incidents with the inclusion of medium pressure iron. As the length reduces to zero the level of risk falls and it can be seen that the population becomes more homogenous as risk reduces.

The methodology for iron mains has also been extended to steel mains and the condition element of the risk score provides an additional input into replacement prioritisation, together with operational data, historical records and photographic evidence.

A survey of steel risers and laterals is also undertaken with visual inspection and NDT testing of those sections that are accessible. It should be noted that these systems offer limited accessibility due to building construction and this leaves large sections that cannot be visually assessed.

b. 30/30 Policy – Iron Mains Within 30m of Property

Whilst the focus of this programme is the removal of iron main within 30m of property, the HSE have consistently required that due attention be placed on the prioritisation of decommissioning based on risk. When the industry moved away from a top-down approach to the 20/70/10 methodology, the HSE required a demonstration that an equivalent level of risk would be removed. This was achieved by increasing workload by 10% per annum. This principle remains unchanged and any network considering a deviation from the current methodology will be required by the HSE to demonstrate that an equivalent level of risk can be removed.

When the 2002 Programme was agreed with the HSE this set expectations for both removal of length and an associated level of risk.

In setting out decommissioning workloads for both of its networks for the next price control period, we have ensured that our proposals do not fall below these agreed levels of risk and length reduction.

Whilst the consultants have supported this position in Southern, we disagree with workload reductions proposed by the consultants in Scotland network. These proposals would cause us to fall below levels agreed as part of the 2002 programme.

c. Other Policy - Steel Mains

In March 2006, we set out our plans to the HSE to take a proactive approach to the decommissioning of steel mains over a 50yr period from 2007. This was confirmed in our submission for the 1yr price control and remained the case in our main 5yr submission.

Historically the approach to steel has been reactive and this offers no management and control other than the need to prioritise immediate requirements against a constrained level of allowed annual workload.

We believe that a reactive approach is no longer appropriate given that this is an ageing population that is only seeing minor year on year reductions in length. The duty under PSR13 to ensure that our pipelines are maintained in an efficient state, in efficient working order and in good repair is an absolute one. While there is limited defence under Reg. 13A in relation to the iron population included within the 30/30 programme, this does not extend to our non-iron population (mainly steel), iron mains >30m from property or iron mains within 30m of property where we hold corporate knowledge on their condition and fail to do everything reasonably practicable to ensure the health and safety of our employees and the general public.

We have introduced processes which have not only improved our knowledge of our pipeline condition but which have also encouraged employees and contractors working on our pipelines to highlight pipelines where they feel we are not meeting our statutory obligations.

We therefore disagree with the consultant's proposals to reduce workload and their rationale that this activity should in some way be proportionate to the 30/30 programme. There is no requirement for this to be the case and the proportion is largely driven by network policy. For SGN, this means a continuing commitment to tackle iron found to be in an unsafe condition and a proactive approach to the replacement of unprotected steel over a 50yr period. 'Other Policy' workload is derived from our decommissioning strategy and its population and the condition of iron and steel mains, not an annual proportion of HSE Policy Workload. The two are unrelated and it is our view that they should not be linked. Our strategy provides a responsible approach to pipeline and risk management.

d. Steel Risers and Laterals

As with steel mains, we set out our proposals for risers and laterals to the HSE in March 2006 and subsequently set out its forecasts consistently in both the 1yr and 5yr control. This was supported by a high level paper indicating SGN's belief that it has in excess of 10,000 supplies (steel risers) to properties in its two networks. Surveys to identify this type of property continue as do the surveys of steel risers in buildings that are currently held on our database (T/PL/LC/20).

T/PL/LC/20 policy was implemented following discussions with the HSE to initiate a programme of integrity inspection and maintenance for internal metallic risers. This followed recognition of our duties under the Pipelines Safety Regulations in relation to this ageing asset group (average age circa 55 years in Scotland DN). Although pipeline operators have obligations under PSR for all pipelines this policy is focused only on the internal metallic riser population in high-rise buildings where the risks and consequences associated with pipeline failure is currently considered to be highest.

The initial programme of inspections is scheduled to be completed by July 2007, albeit SGN recognise that not all such buildings have been identified to date. SGN policy, in line with industry recommendations, is that subsequent inspection frequencies should not exceed ten years.

The consultants have highlighted that inspections carried out do not record the number of customers connected or their use of gas. They recommend that these factors should be incorporated, so that the consequences of isolation, in the event of an escape that cannot be located or repaired, can be considered in the prioritising work. We anticipate difficulties in collecting and maintaining dynamic information such as customer use of gas in such buildings. While such factors may be used in future to consider potential alternatives to replacement, it is our view that maintenance of these pipelines should be prioritised on the basis of the integrity and safety of these assets.

We will continue to fully support industry discussion on the treatment of these installations. However we believe it is inappropriate to continue with a ‘replace on failure’ approach which fails to appreciate our current duties in terms of continued gas supply, maintaining pipeline safety and integrity and the impact of extended unplanned supply interruption (3 month +) on our customers should emergency isolation be required.

SGN’s projections are for the selective replacement of a very small proportion of our riser population during the 5 year period. Projections also includes for a number which will require ‘unplanned’ replacement arising from pipeline damage or leakage failure that cannot be repaired as well as a number which will arise from the replacement of associated below ground pipelines.

Further work is being undertaken by SGN to support the ongoing debate in this area of work. This will be submitted in due course.

e. LTS Repex

With the exception of one project, this category mainly represents those rechargeable diversion projects currently identified within the networks based on plans submitted by third party organisations.

One non-rechargeable project has been identified where it has been clearly demonstrated that replacement is required on grounds of safety. As with other categories, we believe that incorrect assumptions concerning real price effects have led to an incorrect adjustment to the allowed costs for this project.

f. Planning Methodology (Prioritisation)

It is noted in the report that the consultants suggest a move towards zonal replacement as a means of improving efficiency and offering the optimum work delivery package.

SGN are currently implementing changes to its planning methodology but strongly disagree with the consultants assertions in two key areas as follows: -

Risk

The emphasis in the report suggests considering a move to a zonal approach to replacement but this fails to recognise the overiding duty to properly manage risk. We therefore do not agree with this assessment. Whilst significant progress has been made to reduce risk, the levels have not yet diminished to a point at which a zonal replacement policy should be considered on its own, without continuing to ensure that appropriate levels of risk are removed. This can be clearly seen in the graphs shown above in the section on pipes at risk.

SGN are proposing a move away from the existing 20/70/10 methodology by employing a new decision support tool (MRPGas) to assist in the prioritisation process. This model assesses both the risk and condition of iron mains and sets out a more flexible programme that removes almost identical levels of risk reduction without the neccessity to increase workload volumes or change the workload mix.

Our analysis tends to support a view that a move to a zonal based programme may be appropriate in the subsequent contol period.

Efficiency

It has been asserted in the reports that larger projects will see greater efficiency. While we recognise that larger projects have the potential to offer some positive benefit, there are also negative impacts that we believe clearly outweigh the benefits. In particular, our experience is that many authorities are unwilling to allow such large programmes of work over the short time scales proposed, expressing preference for a phased approach either within year to fit around holiday seasons or alternatively over a period of years. This tends to create an unbundling effect with the larger projects creating a set of smaller projects, each part timed to accommodate local authority requirements. We have also experienced constraints imposed by local authorities where a fair and equitable approach is being offered to all of the utilities seeking to undertake works within the same geographical areas (city centres, towns, villages, main trunk roads, etc)

We have submitted a separate report to Ofgem from our operations managers detailing anecdotal experience of this particular issue when liaising with local authorities.

g. Encroachment and Diversions

Other than work identified within our repex submission for the HSE 30/30 programme (iron within 30m of property), no further work (capex or condition monitoring) identified by SGN contributes to the HSE annual decommissioning target.

We continuously survey the iron population to identify encroachment issues that grow the total length of main within 30m of property required to be decommissioned. Our decommissioning plans take some account of this effect recognising this effect is extremely variable and dynamic in nature

The only capex work undertaken that contributes to decommissioning targets has already been identified in our submission as pipe laid as part of a replacement scheme where an element of replacement upsizing is involved. Full account of all mains decommissioning has been included in our repex submission and there is no further decommissioning that has not already been identified here. The comments in section 4.53 concerning general capex work do not apply to SGN's submission.

Where pipes are replaced as a result of their general condition, these pipes have been allocated to the 'Other Policy' category within our submission (i.e. not iron within 30m of property and not contributing to HSE 30/30 risk reduction targets). The only exception is where a pipe planned for replacement due to its condition falls within the HSE 30/30 decommissioning programme, in which case it has been counted towards the annual HSE 30/30 target in our submission. Our updated planning methodology offers this increased flexibility.

Mains diversions fall into two categories, rechargeable and non rechargeable. The likelihood of a non-rechargeable mains diversion contributing to risk reduction is extremely low as the majority of these mains are in easements (greenfield locations, etc) where the terms of the agreement include a lift & shift clause.

SGN has very low levels of rechargeable mains diversions representing 2.4% of the decommissioning length. These diversion projects include the decommissioning of most materials including polyethylene, pvc, steel and iron of which iron in our judgement represents around 60% (decreasing each year as iron mains are replaced). Of these iron mains that are subject to diversion, only a proportion will be within 30m of property; we judge this to be around 75%. It is therefore our view that this element should be ignored as it is very small amounting to around 1%.

In reality, the very small contribution to risk reduction arising from mains diversions is negligible when compared to the annual increase experienced as a result of encroachment (dynamic growth).