

AW/PW/050

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26 January 2007

Dear Joanna

Re: Gas Distribution Price Control Review Third Consultation Document

I have pleasure in providing NGN's response to the third GDPCR consultation. I would be happy to meet with you to discuss any of the content in more detail if that would be helpful. The key points from our response are as follows:

- NGN welcomes the focus on incentives and believes that strong incentives are the most appropriate way of encouraging GDNs to improve efficiency and customer service and hence provide benefits to customers. In particular NGN favours the "strong capex roller" methodology proposed for the main review because it is simpler to operate and it will enable GDNs to manage their capex programmes as a whole rather than manage each element against discrete allowances.
- It is appropriate that GDNs bear risks they can manage, but not risks outside their control or risk associated with items that are not forecastable. Consequently, for example, TMA costs should be passed through. Additionally costs associated with offtake and interruption should be passed through (with appropriate, modest, incentives applied) so that knowledge of the cost can be built up and the risk taken by GDNs in the future. Furthermore, any imposed IFRS change that impacts the tax relief on repex must be passed through in the year incurred or subject to a reopener as the £20m per year effect would not be supportable by NGN's balance sheet.
- The setting of cost of capital will need to recognise the higher risk of GDNs compared to transmission and other network utilities.
- It is important to recognise the substantive cost pressures on the business whereby utility costs are rising significantly faster than RPI.

- NGN continues to believe that the efficiently incurred costs of establishing separate control centres should be allowed given the long term benefits that may arise. Furthermore, it is totally inappropriate to disallow any efficiently incurred costs of operating control centres; this was never suggested pre-sale.

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

Yours sincerely

A handwritten signature in black ink that reads "Alex Wiseman". The signature is written in a cursive style with a long, sweeping underline.

Alex Wiseman
Regulation Director

Gas Distribution Price Control Review Third Consultation Document

CHAPTER: Two

Question1: Do you agree with our initial view on which services could be given excluded treatment? Are there any additional services that we have not considered?

As part of the sale arrangement a number of temporary consents were granted to NGN to permit some services provided by us to be treated as de-minimis activities. These temporary consents cover the provision of maintenance services to the NTS, provision of work force services to meter asset managers and the provision of emergency meter works to shippers and suppliers.

The consultation document helpfully clarifies that the metering related services and provision of maintenance services to NTS are to be treated as excluded services rather than de-minimis activities. We support this approach in the short term, however the whole area of metering obligations may need further investigation following completion of the Competition Act investigation.

Two changes are set out in table 2.1 – treating last resort payment claims as pass through instead of excluded services and treating any user pays services income from xoserve as excluded services income. NGN supports both of these changes.

NGN has not identified any other services that should be considered as excluded services.

Question 2: Should domestic one-off connections be treated as excluded services or ordinary price controlled services?

The volume of work is outside the control of the DN and consequently domestic one-off services should continue to be treated as excluded services. Furthermore, there will be a number of practical difficulties in separating domestic one-off connection work from other types of connections work if they were to be treated differently for price control purposes. These include:

- Costs, particularly the fixed costs, are largely indivisible.
- Year on year workload mix between one-off domestic and other types of connection work can vary significantly.
- Precise definition would be required as to what constituted a “one-off” (e.g. would a council seeking connection to 50 non-contiguous domestic properties be treated as 50 “one-offs” or a single connections job?).
- Consistent methodology and rules for allocating costs between price controlled and non-price controlled activities would need to be developed and applied by all DNs.

Question 3: Have we correctly identified the range of items that could be treated as pass through items? Should these items be treated as pass through items?

It is appropriate that costs beyond the control of GDNs should be treated as pass through.

The consultation document proposes that last resort payment claims, rates and NTS pension charges are treated as pass through. Though not expressly mentioned we assume licence fees will continue to be pass through. NGN supports all of these items being treated as pass through items as they are outside GDN control.

The pension protection fund (PPF) levy is also outside the control of GDNs and consideration should be given to passing this item through annually as incurred.

In addition, costs associated with offtake and interruption reform during the next price control period should be treated as pass through with incentives potentially introduced separate to treatment of the underlying costs. This approach should be taken because it is not possible to forecast with any degree of certainty the costs GDNs will incur (particularly in the initial years) following implementation of these reforms. This treatment would allow information and knowledge of the costs associated with these reforms to be built up during this price control period and, as understanding of the new regimes increases, a different treatment could be considered for the 2013/18 price control period.

We note that Ofgem is proposing a similar approach to the treatment of Traffic Management Act (TMA) costs for the gas distribution price control as implemented for the electricity distribution price control. NGN has no objection in principle to this approach, however the equivalent electricity term covers both TMA and ESQCR costs and the material amount is set at 1% of base revenue; consequently in the gas distribution control the material amount should be set at 0.5% of base revenue.

Question 4: Is there any reason why we should change our position on cost indices?

It is clear that RPI is not an appropriate basket of goods and services for infrastructure utilities. Utility costs are rising significantly faster than RPI. The last few years have seen sharp falls in the cost, for example, of clothing and leisure items whereas the costs of utility inputs such as oil, raw materials and energy have increased significantly more than RPI. NGN welcomes Ofgem's recognition in the consultation that real price effects, including contractor and material costs, will be taken into account when determining cost allowances and efficiency targets. In particular, utilities have a much higher exposure to construction prices than the average within the rest of the economy. NGN accepts that it would be challenging to develop a price index specific to utilities. NGN proposes the following approach:

- The annual inflation index applied each year should be part RPI and part a construction price index such as Baxters; for example, the sum of 50% of the increase in each index.
- When setting efficiency targets it needs to be recognised that forecast continued increases above inflation for material costs will greatly limit the scope for future reductions in "real" opex costs.

Question 5: Is there any reason why we should change our position on re-openers?

We agree that price controls should be set as far as possible ex ante. However, a lack of re-openers increases risk and this should be recognised in the allowed cost of capital.

We agree that it is appropriate for the TMA to be a reopener if costs are still uncertain when the price control is set. The costs of exit and interruption reform should be passed through (with incentives set appropriately), otherwise there should be the option of a reopener for material unforeseen costs, for example of no interruption bids and substantive reinforcement being required.

Additionally, please note the answer to chapter 6, question 1 in regard to the potential impact of IFRS.

Question 6: Should we introduce a two-tier correction mechanism for over and under recovery of allowed revenue, consistent with the arrangements that apply in electricity distribution?

The two tier mechanism is an appropriate way of providing incentives for accurate forecasting; furthermore, companies should not be penalised for unforeseeable changes in

revenue, for example due to weather. However, it should be noted that, even though some commodity charges may move to a capacity basis, there will be an increase in the likely over or under recovery amount. This is because of the shrinkage gas mechanism; for example, projected shrinkage costs for 2007/08 for NGN have reduced by over £6m in just 7 months between June 2007 and January 2008. This alone represents 2% of revenue and could not have been foreseen. Consequently, NGN favours the two tier mechanism, but the “dead band” should be wider than the 2% for electricity DNOs – say 5% to compensate for the increase in revenue uncertainty. In addition, Ofgem should increase the 4% limit for overrecoveries in the Licence after which a letter of explanation is required to the Authority and restrictions are imposed on future price increases.

Question 7: Should we calculate the GDNs’ allowed revenues in a way that creates a smooth revenue profile over the course of the price control period?

NGN agrees that stable prices over time are preferred, although it should be recognised that capex is very lumpy and a consequence may be substantial fluctuation in profits and dividends which may need to be recognised in the allowed cost of capital. This is also likely to lead to fluctuations in key financial ratios which would impact on financeability.

Ofgem suggests that altering the timing of changes to gas distribution charges from October to April will reduce variability. However, NGN believes that the effect would be to increase variability. This is because of the significant impact that weather can have on collected revenue and the impact that changes in gas prices will now have on the allowed revenue (for shrinkage). These effects are clearly harder to forecast 12 months in advance than 6 months in advance. Variability would be reduced if GDNs were able to adjust prices both in April and October, but shippers will have to consider whether they would find two price changes a year acceptable if this reduced price volatility.

CHAPTER: Three

Question 1: Is our proposed approach to setting capital and replacement expenditure allowances for 2008/9 to 2012/13 appropriate?

We agree that the proposed approach to assessing the required levels of capital and replacement expenditure is generally appropriate. The up-front detailed review, challenge and benchmarking of company forecasts is an important element of the incentive regulation framework though it is important to recognise the limitations for example for comparison of capex where networks are of different ages and have had differing historic investment. This process must continue to be accompanied by regulatory transparency and the opportunity for company review and challenge of consultants’ conclusions and proposals.

The proposed approach is potentially an aid to reducing the regulatory risk associated with capital and replacement expenditure programmes if it is accompanied by the removal of the detailed ex-post assessment of expenditure and disallowance of expenditure, particularly if below regulatory allowances.

However, the review and challenge process needs to ensure that several key factors are given full consideration including:

- an environment of increasing input costs;
- mature technology with little scope for further cost efficiencies;
- maintenance of security of supply;
- safety and risk;
- the difficulty of benchmarking given the different company capex profiles, the limited number of data points and the precedent of underestimated capex forecast by Transco in 2000.

NGN welcomes Ofgem's review of the treatment of non-operational capex. Items such as IS and vehicles have both an economic life and purchasing characteristics that means it may be more appropriate to fund these as operating expenditure rather than capital expenditure.

NGN continues to believe that disallowing any efficiently incurred costs of the required establishment of separate control centres is inappropriate given that this should result in opportunities for innovation and potential efficiencies in the price review period after next.

Question 2: Is our proposed approach to setting operating expenditure allowances for 2008/9 to 2012/13 appropriate?

As with the proposed approach for capital and replacement expenditure, we believe that the detailed review and in particular benchmarking is a key element of the incentive regulation framework and support the general approach proposed by Ofgem. However, there needs to be recognition that there will be limited scope for detailed comparisons until the next price control review in five years. There are several issues that should be borne in mind when considering the results of the basket of techniques proposed to review appropriate operating cost allowances:

- The limited dataset of eight distribution networks and four ownership groups suggests that the results of any statistical analysis should be treated with caution.
- There are genuine differences between networks in terms of their operating environment and physical characteristics which need to be understood before any conclusions can be drawn from comparative analysis.
- Differences will also exist between ownership groups due to different economies of scale and scope. Allowances should be made for 'singleton' companies to which these economies are not available as in the electricity DNO price review.
- It is inappropriate to set frontiers for individual activities as this takes no account of differences in categorisation and cost allocation policies and results in a "perfect company" which is impossible to achieve in practice. Such an approach would significantly overestimate the potential for efficiency gains for all networks. Even at a total opex level, there needs to be a degree of comfort that any frontier targets are achievable.
- Total and Partial Factor Productivity can provide useful information on the historic improvements in efficiency achieved in an economy or across industries or companies. However, drawing inferences from a study of historic performance will overestimate the scope for future efficiency gains in what is now a very mature industry, 20 years after privatisation, in which significant efficiency gains have already been made. Furthermore, it may ignore the impact of the potentially different operating and cost environment in which the GDNs will be operating over the period to 2012/13.
- Evidence from other comparable industries can provide useful indicators as to likely productivity and efficiency potential in other industries. However, just as comparative analysis between companies in the same industry requires a degree of normalisation before inferences can be drawn even more care is required when comparing between industries.
- As with the expert review of capital and replacement expenditure, regulatory transparency and the opportunity for company challenge is a necessary part of this process and must continue.
- It should be noted that there is an issue of the aging workforce and the shortfall of available skills within the gas industry. This may jeopardise the delivery of the

required outputs in the next formula period and the development of innovative solutions to manage the substantive changes within the industry over the next five years. NGN is managing this skills shortfall in part by an apprentice programme. However, tackling this skills shortfall is likely to require short term costs that will deliver long term benefits. These costs should be allowed for through a specific opex allowance and should be excluded from the benchmarking exercise.

The issues set out above highlight the problem already identified by Ofgem as to how to assimilate the data to arrive at final conclusions on appropriate operating expenditure allowances. We would agree that a mechanistic approach for weighting the basket of results from such analysis is not appropriate particularly when there is limited understanding of both the changing cost characteristics of the GDNs under the new ownership structure and the applicability of each technique within the industry. Greater use of benchmarking may be more appropriate for the 2013 review once “steady state” data is available and the cost reporting project has normalised this data.

It is totally inappropriate to disallow efficiently occurred system operation costs as Ofgem proposes. It is Ofgem, not GDNs that is insisting on system operation separation. There was no suggestion pre-sale that system operation operating costs may not be allowed and to disallow these would result in companies being unable to achieve allowed returns.

Question 3: Is our proposed approach to updating the GDN's RAV to 1 April 2008 appropriate?

It is appropriate to roll forward the RAV based on actual 2005/06 and 2006/07 costs. However, there needs to be clarity on how this would be undertaken. The process may be complex given the detailed methodology used to assess allowed capex in the current price control period. NGN suggests a simple approach – that a five year capex roller is applied comparing actual expenditure to the allowed expenditure in Final Proposals (ie over or underspend are treated as “pot 2”).

CHAPTER: Four

Question 1: Do you support the proposed changes to the quality of service outputs?

NGN supports Option 2 as this is an appropriate time to review and update the quality of service framework for gas distribution following sale of the networks and coincident with the next five year price control period. NGN would welcome the opportunity to work with Ofgem to improve the framework. We agree with Ofgem that a similar framework should also be applied to IGTs as it would be inappropriate to have different standards for different end users. Our comments on each of the changes proposed are as follows:

Rationalising and Simplifying Overall Standards

NGN has no objection to the removal and replacement of overall standards.

Telephone Calls (OS1)

NGN has no objection in principle to the inclusion of the 90% standard within the transporter licence though NGN believes this area is more appropriately dealt with under the safety case by the HSE. The service is one focussed on safety and the HSE has substantial powers to take action in the highly unlikely event that performance dropped below this level.

The service will always be provided on a national basis as required by safety legislation, and hence can only be measured at a national level. Given this framework and the fact that it is not possible to monitor accurately performance on an individual DN basis it is difficult to see what would be achieved by the inclusion of a licence condition on an individual DN. A

licensee that is not the national provider of the service would only have restricted contractual means to remedy the situation which may not be effective.

Notification of Planned Interruption (OS2)

NGN believes this standard should be replaced by a similar licence condition rather than a guaranteed standard because:

- The service provided by DNs before and during planned interruptions is covered by the customer satisfaction survey. This is made publicly available and enables Ofgem and others to compare performance across DNs providing an incentive to improve performance.
- It is not possible to achieve this standard on all occasions as DNs need to retain some flexibility to move resources to match workload at short notice.
- The additional cost to customers caused by the extra administration and IS required to operate a guaranteed standard is not justified by any potential increase in the level of performance. Current industry performance is consistently high.
- There would be difficulties in the precise definition required to convert this into a guaranteed standard.

Notification during Unplanned Interruption (OS3)

NGN supports Ofgem's proposals to remove OS3 and assess performance through the customer satisfaction survey. We would propose that the communications to customers during unplanned interruptions should be incorporated into the customer code of practice produced by each DN in respect of licence conditions A20, A22 and A23.

Complaints (OS4)

NGN supports the replacement of this standard with a new guaranteed standard. The current standard is for initial response within 5 working days and substantive response within 10 working days. If this becomes a guaranteed standard, the standard needs to be simplified and focussed solely on achieving a substantial response. We also believe the point at which payment is triggered should be extended to 12 working days to cater for those cases where individuals within the organisation who have perhaps dealt with the customer are absent due to holidays etc.

Attending Emergencies (OS5)

NGN has no objection in principle to the inclusion of this standard within the transporter licence though as with OS1 NGN believes this area is more appropriately dealt with under the safety case by the HSE. The service is one focussed on safety and the HSE has substantial powers to take action in the unlikely event that performance dropped below this level.

Rationalising and Simplifying Guaranteed Standards

NGN supports Ofgem's proposals to leave GS1, GS2 and the connection standards unchanged.

Alternative Cooking and Heating (GS3)

NGN supports the replacement of this standard with an appropriate licence condition. If the licence condition is to be extended to all customers reflecting current practice then this should be on a reasonable endeavours basis.

We believe a review as part of the work with customers should be carried out to determine if it is appropriate to offer cooking facilities as well as heating. The vast majority of households now have microwave ovens and easier access to take away food outlets etc which was not the case when this obligation was first established. Our recent experience from two major interruptions is that the take up rate for cooking facilities is significantly lower and when it is taken it is generally because it is freely available rather than to cover specific needs.

Amending the Scope of the Customer Satisfaction Survey

NGN supports extending the survey to include first call emergency services and connections.

Development of a Balanced Scorecard

NGN supports the development of a balanced scorecard of quality of service measures and agrees with Ofgem that this can only be done once there is robust and consistent data. Such an approach would enable benchmarking across GDNs and it may consequently be appropriate to develop incentives to encourage high performance.

Question 2: Do you support the proposed changes to third party damage and water ingress proposals?

NGN does not support Ofgem's proposals in this area. The guaranteed standards framework should be focussed on those areas of customer service that rest within the control of the DN. Damage to our network caused by third parties or water ingress which affects the service to customers is not within our control. Consistent with the current legislation it is reasonable that DNs are not liable in law in such cases. In addition, performance against GS standards is published, therefore a GDN's reputation could be damaged as a result of incidents occurring outside of its control.

NGN supports continuation of the existing voluntary arrangements.

Question 3: Do you support our proposals for improving the accuracy of pipeline records?

NGN believes that accurate pipeline records are important for reasons of safety, operational performance and economic efficiency both for ourselves and for other parties excavating to carry out work on our or other utilities' plant, and would support proposals that encourage the accurate, effective and economic updating of records. However, it should be noted that there are already commercial incentives in place to provide accurate records to IGTs and there should not be a double impact of any shortcomings from both incentives and payments to IGTs.

To this end, we closely control the capture, management and update of records for assets that we have installed, replaced or abandoned.

To further improve the accuracy of historical records, we also operate a system of "Positive Confirmation", whereby whenever a distribution main is worked on, the operative is required to either positively confirm that the records relating to that asset are accurate, or else complete an Error Management form so that records can either be updated or further investigations initiated. This scheme is an effective way of opportunistically checking and (where necessary) updating records at very little cost, and we believe it is important that if an incentive scheme is introduced it does not discourage the reporting of data errors whenever they are found.

We would welcome the opportunity to work with Ofgem, the HSE and other interested parties to develop proposals that would be of benefit to the industry as a whole.

Regardless of how accurate records are believed to be, we would stress that safe digging practices (such as those outlined in the HSE guidance document HS(G)47) should be followed at all times.

Question 4: Is it appropriate to introduce network capacity output measures? If so what type of output measures are appropriate and what sort of rewards/penalties should the GDN's be exposed to?

NGN believes that there are sufficient output measures already in place to ensure that asset investment and the management of the system are managed efficiently and that there is no need for incentives.

The NGN network is planned to satisfy the forecast 1:20 demand condition and to sustain that level of supply for a period of time only experienced in a 1:50 winter. The performance of the network against these criteria is a function of the demand forecast, the quality of the asset data and the system management services we have at our disposal.

Demand forecasts, which determine the 1:20 demand, are updated annually and make assumptions concerning the information used in the model. NGN has a robust demand forecasting process in place. The accuracy of the forecasts compared to actual demand is reported extensively in-house and to a lesser degree externally through the Long Term Development Statement and via D9.

Asset data quality is essential to network capacity planning and leads to accurate modelling of the networks asset resulting in efficient investment decisions. Incentives are already proposed elsewhere to encourage networks to improve and maintain accurate records.

System management reporting is concerned with the principles associated with and the procurement of services to be used in the management of the supply demand balance in the network. A report is produced annually detailing the utilisation of these services. Gas supply is incentivised through the offtake exit regime, where NGN contract with NG for the gas volumes, flat, flex and assured pressures, resulting from the demand forecasting process. There has been discussion with Ofgem about the figures used by NGN in the flat and flex forecasts. NGN is not persuaded that Ofgem should set the demand/supply conditions or reduce the forecasted levels without further detailed discussion as NGN produces these forecasts to ensure it is meeting its safety case.

CHAPTER: Five

Question 1: Have we identified all the issues for each of the incentives?

NGN has identified no additional issues.

Question 2: Is it appropriate to better align capex and opex incentives?

The incentive mechanisms within the regulatory framework should have the following objectives:

- ongoing efficiency improvements are incentivised;
- customers share in the benefits of efficiency improvements in a timely manner;
- companies can achieve an appropriate return on their investment in improving efficiency;
- the mechanisms do not encourage perverse behaviour.

An appropriate incentive mechanism should deliver these objectives and ultimately deliver maximum long term customer benefit.

It is clear that the traditional capex incentives need to be on a rolling basis to ensure that the incentive for making efficiencies is equally strong across the control period. A five year rolling incentive provides 31% of outperformance (or underperformance) to companies and 69% to customers. We believe that the split between companies and customers should be more even, perhaps commensurate with the 39/61 split for electricity DNOs to strongly incentivise efficiencies and to better align capex and opex incentives.

The current incentives for operating expenditure efficiency distort management decisions as operating cost efficiencies made at the start of a price control period attract a greater return than those made at the end of the period. There is little incentive for reducing opex at the end of a price control period. This along with a reduction in the scope for future efficiencies would suggest strengthening the operating expenditure incentives and a rolling five year incentive for opex would appear appropriate – a recent precedent is Ofreg's settlement for Northern Ireland Electricity.

Question 3: Do you agree with our initial view that a capex rolling incentive and information quality incentive should be implemented?

Rolling incentives are essential to encourage consistent and efficient behaviour across the price control period and we agree that these should be implemented. However, NGN believes that the power of the capital expenditure rolling incentive period should be increased to be consistent with the split between customers and companies in electricity distribution, for example by extending the period from 5 to 7 years, so that customers bear less risk from overspends and to incentivise a greater scale of efficiency improvements to ultimately deliver higher benefits for customers.

There are several issues that need to be considered when implementing the strong capex roller being proposed:

- A consideration of which risks should be borne by DNs and which are more appropriately borne by customers. For example, mechanisms should be in place to deal with cost uncertainties over the plan period including additional unplanned work that could not be foreseen at the time of setting prices e.g. substantive load growth related expenditure.
- Efficiencies must be considered at an aggregate level such that total spend is considered against total allowances. To this end we welcome the precedent of David Gray's recent letter confirming that for 2007/08 the capex roller will apply to the sum of capex and non-mains repex allowing a GDN to spend more in some areas and less in others as long as total spend is within the allowance.
- The approach should not include a detailed ex-post review of expenditure. Such review and particularly disallowance of expenditure below allowance would undermine the incentive properties of the approach and increase regulatory risk.

In addition, the experience from within the Electricity DNO price control would suggest that an information quality incentive arrangement could also be appropriate for GDNs. However, it does require confidence in the ability of the appointed consultants to accurately forecast long term expenditure requirements. Furthermore, it needs to be recognised that if consultants are reviewing capex by category there is a danger of asymmetrical treatment as it is unlikely that consultants will suggest higher capex requirements for any category than the company submission.

Question 4: Given the issues raised is there a case for an opex rolling incentive?

Introducing an opex rolling incentive would increase the scope for future efficiency improvements by increasing the number of initiatives that pass an investment appraisal, thus resulting in a much larger “cake” of efficiencies from which customers would get the largest slice. This is an important issue in a mature industry such as gas in which the scope for future efficiency improvements is limited.

Furthermore, the current incentive mechanism for operating expenditure distorts management decisions as discussed above. There is a greater reward for efficiencies made at the start of the price control period than at the end of the period. This provides a disincentive to make savings at the end of the period but instead defer them to achieve a longer period of benefits and ultimately defers the time when these benefits can be passed onto customers. The introduction of a rolling opex incentive would overcome this perversity within the current arrangements and better align opex and capex incentives.

Question 5: Do you agree with our proposals to retain the mains replacement incentive?

The mains replacement incentive has dealt effectively with the high level of uncertainty surrounding the exact mix of pipe lengths and diameters replaced each year. Similar uncertainties exist in services replacement and NGN has previously suggested that a similar arrangement to mains would be appropriate for services.

We are therefore in general agreement with the proposal to maintain the mains incentive scheme using a similar matrix approach but to include services costs.

We would agree with reviewing the sharing factors within the incentive scheme. We believe that now that the mechanism is well understood and there is a track record of historic costs, the sharing factors should become symmetric between GDNs and customers.

Question 6: Is flexibility capacity the key incentive to focus on for the capacity outputs? Should we assume that the use of existing NTS flex capacity is the most efficient flex capacity product?

It is only possible to provide a detailed assessment of offtake incentives when Ofgem has made a determination as to which flexibility capacity booking mechanism will operate. Nevertheless, it is unclear to us that flex capacity is the key incentive. Flex is a by-product of both the NTS flat capacity and investment on the GDN network and as such would appear to have minimal value. Furthermore, as far as we are aware there has never been a constraint on flex availability. Setting a meaningful incentive based on flex capacity would require a cost to be attributed to this product. It is doubtful if such an incentive would result in a meaningful measure for a GDN.

NTS flex capacity is clearly efficient given its abundance.

Question 7: Is it appropriate to assume that NTS and LTS flat capacity are complementary products? Should we incentivise tradeoffs between flat capacity and interruptible capacity?

NTS and LTS flat capacity would appear to be complementary products as they evolve together – a requirement for additional LTS capacity gives rise to an NTS capacity requirement. However, there is a trade-off between flat capacity and interruptible capacity; the challenge will be to develop incentive mechanisms that do not impose additional costs on GDNs and do not provide perverse incentives. There is a danger that network sensitive loads bid a high price in the knowledge that the alternative is a high reinforcement cost. In such a scenario the costs of measuring the cost of interruption against capacity costs would be inappropriate.

Question 8: Should we incentivise accuracy of pipeline records? If so, how could accuracy be measured and audited?

NGN would support the development of incentives for the accuracy of pipeline records, but note the comment in the answer to question 2 regarding ensuring that there is no double counting as a result of existing arrangements with IGTs. The following areas should be considered:

What is the definition of accurate records?

- For example a GDN can confirm that all known pipes are recorded in an asset repository but would have less confidence in accurately confirming the physical location of these pipes particularly with respect to older pipes. A simple approach would be to measure procedures for new pipes against the existing set of digital records.

What pipes are to be included in the incentive scheme?

- There needs to be a separation of pipes between distribution and local transmission system. Historically the databases have been separated out and hold different data sets. Service pipes are not identified within graphical systems therefore location details are not available.

Will there be a distinction between existing and new pipes?

- Existing pipes have a limited set of asset details whereas new pipes have more detailed data sets.

What systems will be audited?

- The focus should be on graphical based systems as they impact on both safety and commercial aspects of the GDN's business activities.

Question 9: Is there a case for an innovation funding incentive?

The innovation funding incentive (IFI) has worked well in electricity distribution to achieve innovations that benefit customers. Innovation is low in gas distribution and an IFI in gas similar to the DNO scheme should lead to new solutions and benefits for customers with minimal downside risk. Areas where an IFI may encourage technical innovation to reduce costs include:

- pipe laying;
- leakage monitoring systems;
- cathodic protection monitoring;
- on-line inspection;
- pressure management systems;
- storage utilisation; and
- asset life evaluation.

CHAPTER: Six

Question 1: Should we allow for an ex post adjustment for changes in tax treatment of certain kinds of expenditure, as outlined in paragraphs 6.3 and 6.4?

NGN agrees that there should be an adjustment to tax allowances if GDNs are required to restate their accounts under IFRS and, as a result, have to pay higher tax. However, a requirement to restate accounts under IFRS would be a substantive change for GDNs and, given NGN's repex programme, could result in an additional tax bill of over £20m per year.

This amount would not be supportable by NGN's balance sheet and should be the subject of a reopening and not just an ex-post adjustment.

Question 2: Which key ratios should we use as financeability indicators?

It is important that Ofgem liaises closely with the rating agencies to identify the appropriate indicators and the required level of these indicators to avoid downgrades. The target credit rating should be BBB+ or better to ensure sufficient margin above investment grade.

In our discussions with the rating agencies, we have identified four important financeability indicators:

- Debt / RAV
- PMICR (post maintenance interest coverage ratio – FFO Interest Cover adjusted for repex)
- FFO / Debt
- Net (post-dividend) cash flow/capex

It is important to recognise that some GDNs, including NGN, have bank covenants that require some of these indicators to be within specified bounds. NGN's covenants include six-monthly assessments of indicators. Although it is unlikely that Ofgem's modelling will enable six monthly assessments, this means that it is important that financeability is confirmed for each annual forecast in isolation and is not just assessed by averaging over longer periods. Furthermore, indicators must be above and not exactly at the targeted levels. Breach of a loan covenant would have an immediate impact on the financing of the GDN.

Furthermore, lenders and credit rating agencies require forecasts of future profitability and indicators and consequently it is important that Ofgem undertakes some modelling to confirm that indicators do not deteriorate beyond the end of the price review period by modelling forwards, say, 10 to 20 years.

Question 3: How should we finance replacement expenditure, having regard to its impact on the overall financeability of the price control?

In the current price control, the 50/50 treatment was established due to the scale of the expenditure and the fact that it was driven by current safety requirements and was not part of the GDNs natural investment cycle.

These aspects of replacement expenditure still remain and indeed the programme will be larger in the next five years than in the current review period. For the main review period total repex spend is projected to be £4.0bn (in 05/06 prices), 67% of the total forecast investment spend.

Consequently, the financial impact of the repex programme will be greater and it is important that the funding mechanism is adequate.

NGN's modelling suggests that a reduction in the 50% currently expensed is likely to lead to financeability issues and may leave our network vulnerable to an investment downgrade. Indeed, it may be appropriate to increase the opex proportion of the repex allowance. Additionally, about £30m of NGN repex is large diameter LTS projects. Such projects are capital in nature and should be treated as 100% capex.

Another concern raised at the previous price review was the potential impact of the treatment on current and future customers. The 50/50 split was deemed to strike the correct balance between the costs incurred and benefits received both for current and future customers and a broadly similar split would still provide an acceptable balance between the two.

Question 4: Should we change our depreciation rate for new assets in response to the changing mix of assets being capitalised?

The appropriate depreciation rate may depend on the outputs from the modelling and a lower asset life or expensing for non-operational capex may be appropriate.

CHAPTER: Seven

Question 1: Which of the two forms of the network extensions incentive scheme should we adopt going forward?

NGN favours option 3b as the appropriate incentive scheme as linking funding to the number of fuel poor connected will align rewards with the alleviating of fuel poverty.

NGN's preference to achieve a greater level of network extension is option 6 over option 5. This scheme puts such investment into the RAV as we assume that, consistent with the current economic test, any proposed connection which passes the revised test will have to be funded through capex allowances within the price control. This will deliver such connections at a lower cost than under option 5 as this option would result in shareholders/lenders requiring investment returns commensurate with a non-regulated activity to attract the necessary funds compared to other potential investment opportunities. NGN would not support this option if it required GDNs to make payments to IGTs for networks that were not to be adopted by the GDN (as appears to be stated by paragraph 7.20). We question whether Ofgem has the vires to implement such arrangements. In any event there is no competition for such connections under the present arrangements as no such connections are taking place. We fail to see therefore how this would distort competition in the connections market.

If this option (or any other option which results in increased connections) is adopted then GDNs will need to resubmit BPQs to ensure that allowances are consistent with the expected network extensions during the next five year period.

Question 2: Do you agree with our assessment of the risks, costs and benefits attributable to the options for facilitating network extensions (see Appendix 6)

The criteria used seem appropriate. As outlined in response to previous question we fail to see how either option 5 or 6 would have a detrimental effect on competition in connections.

Question 3: Is our proposed methodology for quantifying the costs and benefits associated with the various options appropriate (see Appendix 6)?

The proposed methodology seems appropriate though rather than using theoretical examples we would suggest that real examples of easy, intermediate and hard locations to connect are used. NGN would be prepared to assist with providing such examples.

Question 4: Is it appropriate to set an incentive scheme which recognises the initiatives that some companies undertake with respect to their corporate social responsibility?

NGN takes corporate social responsibility (CSR) seriously and has undertaken a number of initiatives within our local communities. Furthermore, we are discussing opportunities to provide assistance for fuel poor homes with north-east community organisations such as Warm Zone and Community Energy Solutions.

NGN would welcome a CSR incentive scheme and the electricity DNO scheme provides an appropriate precedent.

Question 5: What other criteria should be included in a Corporate Social Responsibility incentive scheme for GDNs?

Any CSR programme that delivers meaningful benefits to local communities such as community regeneration, environmental projects, assisting the fuel poor should be included in a CSR incentive scheme.

Additionally, it is recognised that there are growing skill shortages within the gas industry and improving the skills of the workforce could be considered under a CSR incentive scheme.

CHAPTER: Eight

Question 1: Do you agree with our assessment of the risks, costs and benefits attributable to the two options for the funding of xoserve?

NGN is comfortable with the high level risk assessment. The challenge will be to identify a viable solution that clearly separates the core services and their costs from the user pays services. There is a danger that the complexity of an option 2 approach overrides the other benefits that Ofgem has identified.

It should also be noted that the cost recovery process for user pays (outlined in figure 8.2) adds a layer of complexity and costs – xoserve bills GTs and GTs then charge users for user pays services. This will require an amendment to the UNC.

Question 2: If we adopt a core services plus user pays approach (option 2), how should we define core services and user pays services?

A line by line assessment of existing services is required to correctly define services which fall into either of these categories. The criteria for user pays services should be:

- The key stakeholders for the service are Users;
- Users have discretion on whether or not to use the service;
- The cost of the service line depends on usage;
- The costs associated with the service are clearly identifiable and separable from the core xoserve costs.

Question 3: What costs/benefits would your organisation incur in the event that we adopt Option 2?

This option would result in increased administration costs for GDNs who would need to engage in assessments of whether a service was Core or user pays services.

Option 2 will increase the uncertainty of revenue for xoserve with the potential for stranded costs.

Question 4: What questions do we need to ask GTs, xoserve and shippers in order to accurately quantify the costs associated with Option 2?

Shippers need to advise which potential user pays services they would utilise and xoserve needs to identify the likely costs of such services.

The absence of any shipper class 3 modifications since 1996 (where shippers bear the cost of change not borne by GTs) suggests that a cost mechanism must be fully understood and agreed by shippers ahead of an Option 2 approach being pursued. There is limited merit in a user pays model being progressed unless shippers accept both the need and the detail of a cost sharing methodology.

Question 5: In the event that the Secretary of State requires GDNs to put in place further alternative arrangements relating to independent systems, should the excess costs associated with independent systems be:

- **spread across all GB consumers via transmission charges; or,**
- **borne by customers located in gas distribution areas where independent systems are located (primarily Scotland)?**

The administration arrangements associated with independent systems should be proportionate to the value of transportation revenues and costs involved. In NGN's case we have a single independent system where costs and revenues are less than £20k per annum. A mechanism to spread such a level of cost over all GB consumers would be obviously disproportionate.

In Scotland we understand the sums involved are significantly greater, however, they still only represent a small proportion of total revenue. We therefore believe costs should be spread across customers within the gas distribution area involved and the mechanism to do this kept as simple as possible.